UNIVERSITY OF CALGARY

Real Option Valuation of Electricity Generators in Alberta

By

Priya Parthasarathy

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE

DEGREE OF MASTER OF BUSINESS ADMINISTRATION

DEPARTMENT OF MANAGEMENT

CALGARY, ALBERTA

SEPTEMBER 2000

0-612-55178-4

ABSTRACT

The Electric Industry restructuring in Alberta has given the opportunity to Generators of electricity to view their asset as a Real Option on the 'spark spread'. Free trading of electricity and improvements in gas turbine technology have made it possible for the Generator to start up the turbine only when the spark spread exceeds a certain exercise price and shut down otherwise, at zero cost. The flexibility option, whose value was calculated between the years 1997-2000 using natural gas and electricity prices, adds as much as 70% to the earnings of a Generator in Alberta. Recognizing the value of the option is important to spur growth of generation in the province, which has very little excess capacity currently. The results of the earnings simulation for a Generator in Alberta, generated by bootstrapping actual spark spread data suggests that a simple-cycle gas turbine would be a profitable undertaking owing to the flexibility value.

ACKNOWLEDGEMENTS

I am extremely grateful to my supervisor, Dr. Gordon Sick, who believed in me and agreed to supervise my work and got me into the program. He was extremely supportive and full of ideas for my work and without his insight and experienced guidance, this work wouldn't have been possible. I am also grateful to all those in the electricity industry who patiently answered all my queries and helped me understand the industry and the technology. I would specially like to thank Mr. Dwight Redden of ATCO Power who emailed with answers promptly for all my doubts, some of them outright silly.

I am grateful to my husband, Sridhar Srinivasan, who took care of the household and my daughter while I was immersed in work. His support and encouragement helped me meet deadlines and finish this work in time.

To Sridhar and Sowmya

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES – CONTINUED

LIST OF DIAGRAMS

DEFINITIONS

Spark Spread:	A long position in electrical power and short position in fuel (typically natural gas) that simulates the profit from operating a power plant (e.g., a gas turbine generator). The heat rate determines the size of the short position in fuel.
Heat Rate:	Measure of the system's electrical efficiency and, is defined, as the amount of fuel energy input required to generate one Kilowatt Hour of power.
Megawatt Hour:	1000 Kilowatt Hours. Enough to light 10,000 100-watt light bulbs for an hour.
Spinning Reserve:	Unused capacity available from units connected to and synchronized with the grid to serve additional demand. The spinning reserve must be under automatic control to instantly respond to system requirements.
Generator:	Owner of a generating asset in Alberta.
Pool Price:	The hourly price of electricity per MWh traded through the Power Pool of Alberta.

ABBREVIATIONS

Disco	Distribution Company
EUA	Electric Utilities Act, 1996
EUB	Electric Utilities Board
IPP	Independent Power Producer
kWh	Kilowatt Hour
MCR	Maximum Capacity Rating
MMBtu	Million British Thermal Units
MWh	Mega Watt Hour
NPV	Net Present Value
PPP	Power Purchase Agreement
PV	Present Value
TA	Transmission Administrator

Chapter 1- Introduction

Since January 1, 1996, the electric industry in Alberta has been operating under a new structure – one that recognizes the worldwide push for more competition in electricity markets. In the past, large power plants were the cheapest means of supplying power to consumers. These plants were so large that there was no room for small marginal players. Government regulations ensured that power was produced cheaply and consumers paid fair prices. Today, advances in technology have made small scale power generation viable as well as competitive. In the new environment, independent power producers compete on an equal footing with existing utilities to supply power to the province wide consumers.

1.1 MOTIVATION FOR STUDY

An article in the *Wall Street Journal* summarizes the foundation concept for the thesis. "Electricity markets deregulated within the past two years use the 'uniform price' method to set prices. Under that method, central dispatchers first tap generators offering to sell electricity at the lowest prices. Then ever-more-costly generating plants are utilized until enough plants are operating to satisfy demand. Power purchasers pay all bidders the price charged by the last power plant called into service. In many cases, that final unit will be a clunky oil-fired plant, charging a higher rate because of escalating oil prices. That means that many other generators will reap a windfall profit, for they will be paid as if they were burning oil even though most are using cheaper coal or natural gas. "[1]

This suggests that the generation of electricity by burning natural gas is in effect a Real Option. To elaborate, suppose that the price of power runs between $15 and $50 per megawatt hour (MWh). An average gas turbine requires burning 10 Btu of natural gas to produce 1 MW of electricity per hour. With the cost of natural gas at $3/MWh, the marginal cost for producing 1 MWh of electricity is $30. If the market price for power is $15, it doesn't make economic sense to run the turbine, which can be shutdown at zero cost or at

[1] Rebecca Smith, "Northeast Faces Electricity-Price Surge; Costly Oil-Fired Plants May Drive Summer Rates," *Wall Street Journal*, 3/20/2000

some cost. If the spot price (S) is greater than \$30, the turbine is fired up and the generator makes \$(S - 30) per MWh. Thus, the hourly profit of the plant is like an option payoff of \$*Max* (0, S-30) and the plant has a portfolio of 24 options per day all at a strike price of \$30. If the power price rises above \$500 per MWh, then the generator would make windfall profits. The only other cost to consider here would be the fixed cost of financing the plant, which is incurred irrespective of whether the plant is operated or not. Hence, the generation of electricity by a gas turbine is actually a call option on the price difference in electricity and natural gas – a physically existing spark spread or a real option on the spark spread.

1.2 OBJECTIVES

Though in theory, all gas turbine generators have an inherent option, one has to examine the technological and regulatory constraints before we can view the generator as a real option. First of all, it must be possible to shut down the unit and restart the unit, costlessly or at some cost. There may be specific gas turbine technology that allow this and others that don't. Another thing that has to be considered would be the lead-time in the shut down/start up operation. Other than this, there may also be some regulatory restrictions that affect the operation. So, the first objective was to identify technology and operations that allow the flexibility required and also recognize regulatory limitations on such operations.

Secondly, if technology and regulation does permit the generator to shut down/start up as often as necessary, it is then possible to calculate the value of the flexibility option as against generation of electricity all 24 hours of the day. The main focus of this study is to calculate this value and the optimal price at which electricity should be offered in order to maximize this option value, given the costs involved in such an operation.

1.3 SUMMARY OF THE MODEL

The method of calculating the value of the option was to run a simulation of the cash flows of an aero-derivative gas-turbine Generator in Alberta. The input data for the analysis was the daily natural gas and hourly pool price for the period January 1997-June 2000. The simulation was carried out in an Excel spread sheet.

The value of the option was calculated as the difference in the Profit before Depreciation, Interest and Tax (PBDIT) of the Generator when running on an option plan and when running all 24 hours. The option plan was to set a strike price for the spark spread, the difference in pool price and gas cost. The simulation was done for various strike prices between $6 and $16. The lower limit was set at $6 because the hourly maintenance cost for the Generator is assumed to be $6/megawatt.

The option value sensitivity to the following input parameters was also calculated:

1. Cost of starts
2. Heat rate
3. Scheduling
4. Capacity of turbine

The optimal strike price was chosen as the price that maximized the option value.

1.4 RELEVANCE OF THESIS

Alberta's electric industry is the latest to join the bandwagon of deregulation. Countries like Norway, Sweden and the U.S., who have deregulated their electric industry, have moved forward to establish exchanges for the trading of electricity derivatives. Models for valuing these derivatives have been proposed by researchers, keeping in mind the non-storability of electricity. Of these, the valuation models for spark-spread options can also be used to value generation assets since the asset has an inherent spark-spread option. Alberta is only in the initial stages of setting up a derivatives market in the province and it would be quite impossible to value the generation assets, using any of those available models. This study is an empirical approach to valuing gas-fired generation assets in the province, using electricity and gas prices as traded in the province. The valuation of the generation assets, including the value of the spark-spread option is important to Independent Power Producers (IPP) who would have make deals with Distribution companies (Discos) in the future to market their electricity to consumers. Estimation of the profit potential of these assets is also important for regulators who would like to see the supply of power in the province grow to keep up with demand.

1.5 RESULTS

1. All gas-fired Generators do not have the flexibility option of generating only when the spark spread exceeds a certain hurdle rate.
2. Aero-derivative Combustion turbines have the maximum flexibility and least cost for taking advantage of the flexibility option.
3. The introduction of the Power Pool in 1996 and free trading of electricity through their exchange has allowed small scale Generators to sell power at the price they choose to.
4. Recent technology has made small scale generation feasible, cost efficient and allows them to shut-down/start up as many times without disrupting system support functions.
5. At a strike price of $6 over the spark spread, the Generator earns 8% more in terms of total spark spread than when the turbine is run continuously for 24 hours per day. This value decreases as the strike price is increased and at a strike price of $16, the Generator earns 8% less than the value earned when run at all times.
6. The Generator saves on maintenance cost as the strike price is higher and when this is combined with the savings/loss in spark spread, the Generator actually gains as much as 60% at a strike price of $6 and 47% at a strike price of $16.
7. The cost of starting and shutting down does not affect the value of the option significantly. Hence, the Present Value (PV) of the option exceeds 70% of the value of the generation asset when run all 24 hours of the day, at a strike price of $6.
8. The option value increases to a Generator with a higher heat rate (lower efficiency), though total earnings decrease.
9. The earnings of the Generator per unit of capital increase as the turbine size increases.

1.6 CORE IMPLICATIONS

Investment in a gas turbine generation unit is fraught with great uncertainties in terms of electricity price and gas price. But unlike most other projects with uncertainties, the owner of the generation asset has an inherent call option. This means that the owner is assured all the upside of the future but is protected from facing the downside. Traditional valuation measures do not take the value of this option into consideration while valuing the project. Ignoring this would mean underestimating the value.

Electricity price has surged in the summer of 2000 in Alberta owing to higher gas cost and ever rising demand, as the economy grows. Price as high as $500/MWh is not uncommon and this is not welcome news to consumers. Additional capacity is slow in coming and consumers are facing as high as a 25% increase in their electricity bills. Such a high price of electricity should spur investments in new generation plants. Of the 2000 plus megawatts of new capacity in Alberta, only about 6% is simple-cycle gas turbine. Though co-generation systems employ gas turbines (80% of new capacity is co-generation), they do not have as much flexibility as a simple-cycle gas turbine unit because of the requirement to supply the joint heat product for industrial process use. The correct estimation of the value of a simple cycle gas-turbine unit is important to spur growth in supply.

The Discos have an arrangement with the old regulated units for supply of electricity, which hedges them against price fluctuations. But with time, these units will be phased out and the Discos would want to strike a similar deal with the IPPs. Since recovery of capital cost could be achieved by selling an option on electricity, the value of the option has to be kept in mind when making arrangements with the Discos.

1.7 OUTLINE OF THE THESIS

The first chapter in the thesis, following this, begins with an overview of the electric industry in Alberta, with its changes and current structure. The various players in the industry and their roles in maintaining the system are then discussed. This chapter provides the background for the emergence of independent power producers.

Chapter 3 gives an introduction to the real option literature and also discusses the various models of valuing electricity derivatives. This chapter also explains the fit of the model used in the thesis within the framework of the various research works discussed.

Chapter 4 is a discussion of the technology of gas-fired power generation. This chapter discusses the various types of technology available and explains why the aero-derivative gas turbine was chosen as the choice for the simulation.

Chapter 5 is a discussion of the various guidelines set forth by the Power Pool of Alberta for a Generator based in the province. Chapter 6 is a summary of the model used in calculations with descriptions for the various variables and parameters. Chapter 7 is a statistical analysis of the gas price, pool price and spark spread values over the period under consideration.

Chapter 8 is a compilation of the results of the simulation discussing the various parameters that affect Generator value. Chapter 9, the concluding chapter, gives the overall picture in terms of results, their implications and the areas of further research.

Chapter 2- Overview of Alberta Electric Industry[2]

The Electric Utilities Act, 1996, introduced competition into the electric utility business in Alberta, keeping up with a worldwide trend of deregulation. The Act aims at making Alberta a competitive market for power with streamlined regulation in some parts. This would change the structure of the industry as well as the way electricity is generated and sold in the province. The Alberta consumptive market for electricity is 50,000,000 Mega-Watt Hours (MWh) of generation per year with a market value of over $2 billion. Hourly consumption varies from 5000 MW to 7500 MW dependent on various demand factors such as time of day and season. Of this total, 90% of the generation is currently price protected by a series of '*legislated hedges*' that arise as a result of Alberta's inducements to investment in long term generating capacity from the pre-1996 regulated world.

2.1 HISTORIC STRUCTURE

Alberta's electrical consumers have been historically served by vertically integrated regulated monopolies. Vertically integrated because Alberta's largest Utilities are involved in generation, transmission and distribution of power. They were given a right and an obligation to serve a particular geographical area in the province. They had to be big in order to achieve economies of scale and hence to protect consumers from monopoly pricing, the provincial regulator approved costs and rates set by these utilities. There are currently three large Utility generators in Alberta, namely Alberta Power (ATCO), Edmonton Power (EPCOR) and TransAlta Utilities, which supply more than three-fourths of the province's electricity needs. The remainder is from interconnection from other provinces and from Independent Power Producers (IPP s). Approximately 75% of electricity currently produced is by burning low-Sulphur coal. The remainder is from natural gas, oil and hydro.

The generation component of the industry is being deregulated by the Electric Utilities Act. The advent of cost effective small-scale generation technology has removed the reasons for the utilities to be big in order to be cost-effective.

---

[2] Alberta Department of Energy, *Moving to Competition – A guide to Alberta's new electric industry structure.* (1996)

Also, Alberta is now part of an electric grid that connects Alberta to B.C., and the western United States. It is possible with the current technology to reliably serve isolated communities and hence vertical integration of the utilities is no longer required. In the new structure, independent power producers compete on equal grounds with the existing utilities and consumers, if they wish, can choose who they want to buy their power from.

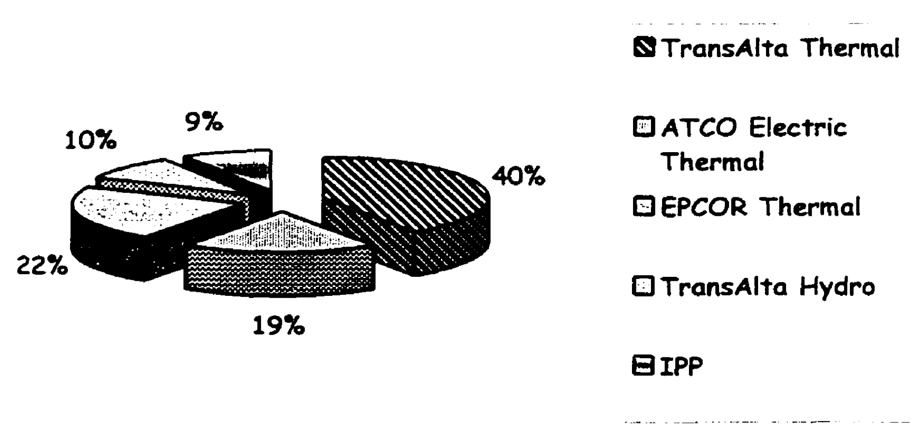
The transmission and distribution systems have not been affected by the Act. They still remain as natural monopolies since it would make no sense to have more wires around. However, these systems will be monitored and regulated by the Alberta Energy and Utilities Board (EUB).

TABLE 2.1 : ALBERTA ELECTRICITY GENERATION - GENCOS (MW)

Unit	*MCR*[3]	*Net*	*Reserve*
TransAlta Thermal	3290	2778	0
ATCO Electric Thermal	1668	1287	142
EPCOR Thermal	1609	1516	87
TransAlta Hydro	789	658	66
IPP	571	583	0
Total	7928	6832	295

Source : Power Pool of Alberta (Last Update : Fri Jul 28 14:17:12 MDT 2000)

FIGURE 2.1: ALBERTA ELECTRICITY GENERATION – SUPPLIER BREAK-UP



Source: Power Pool of Alberta

[3] Maximum Capacity Rating

2.2 ALBERTA ELECTRIC INDUSTRY - NEW STRUCTURE

The new system does not require any change in the way the existing utilities operate in generating and delivering power. But it will recognize generation, transmission and distribution as separate businesses and treat them differently for regulatory and accounting purposes. The main elements of the new structure are:

- *Open competition for generation* – Independent generators, who had to negotiate with the utilities to sell power, can now compete directly in the open market. They can sell power directly into the grid and also compete with the other players for new generating capacity.
- *Power Pool* – the market for buying and selling electricity. The pool is a co-operative venture overseen by a council formed from the participants in the pool. The pool establishes an hourly market price for exchange of power.
- *System access* – all generators and importers sell energy to the pool, regardless of who owns the power lines. The Transmission Administrator (TA), who contracts with the owners of facilities to provide transmission services, coordinates the grid that connects Alberta. The TA establishes the system access costs charged to the generators and the distributors to recover the transmission charges.
- *Regulated distribution* – Utilities will still have the basic right and obligation to serve the customers in their service areas. Distributors will buy electricity from the pool, and distribute the power to customers by paying a transmission charge to the TA. All distributors pay the same charge regardless of where they are located in the grid.
- *Import and export* – Anybody who has the capacity and necessary arrangements with the TA, can import or export power to and from Alberta. The importer/exporter has to be a member of the power pool and has to pay location based transmission charges to the TA.

2.3 POWER PURCHASE AGREEMENTS

Another important concept, introduced in the new structure, is the Power Purchase Agreements (PPA s). PPA s are a contract between the generator and the retailer of electricity. The PPA s are designed to get rid of market power and windfall profits for the generators and let the benefit accrue to the customers.

In Alberta, almost 90% of generation is owned by the regulated utilities. The distributors pay a reservation price to the utilities that cover their fixed costs. The electricity prices are determined at the Power Pool. If the prices at the pool are higher than the variable cost of the generator, they credit the surplus to the customers. With the entry of new, costly generation, the older generating units generated more and more surplus or what is termed as 'stranded benefits' for the customers.

PPA s were designed to enable the Alberta consumers to enjoy the stranded benefits and to do away with market power of the utilities. The PPA s were sold at an auction for the purchase of power from the generating units of the utilities. The original idea was that the bidder paid an up front fee for the right to buy and distribute power from the units. Some units have a very high fixed cost embedded in them and in order for the marketer to take up the risk of running that unit, they might bid a negative amount (in other words, they get paid for taking up the risk). All the proceeds from the auction go to a Balancing Pool, which also pays out to bidders who bid a negative value. Ultimately, the pool was expected to run a surplus, which was to be pro-rated among customers. But the outcome of the auction was different. Though the pool did earn a surplus, the total bids fell way short of the target and it is uncertain as to how this would affect the governance of these units. It has now been decided to distribute the surplus to consumers as a one-time remittance.

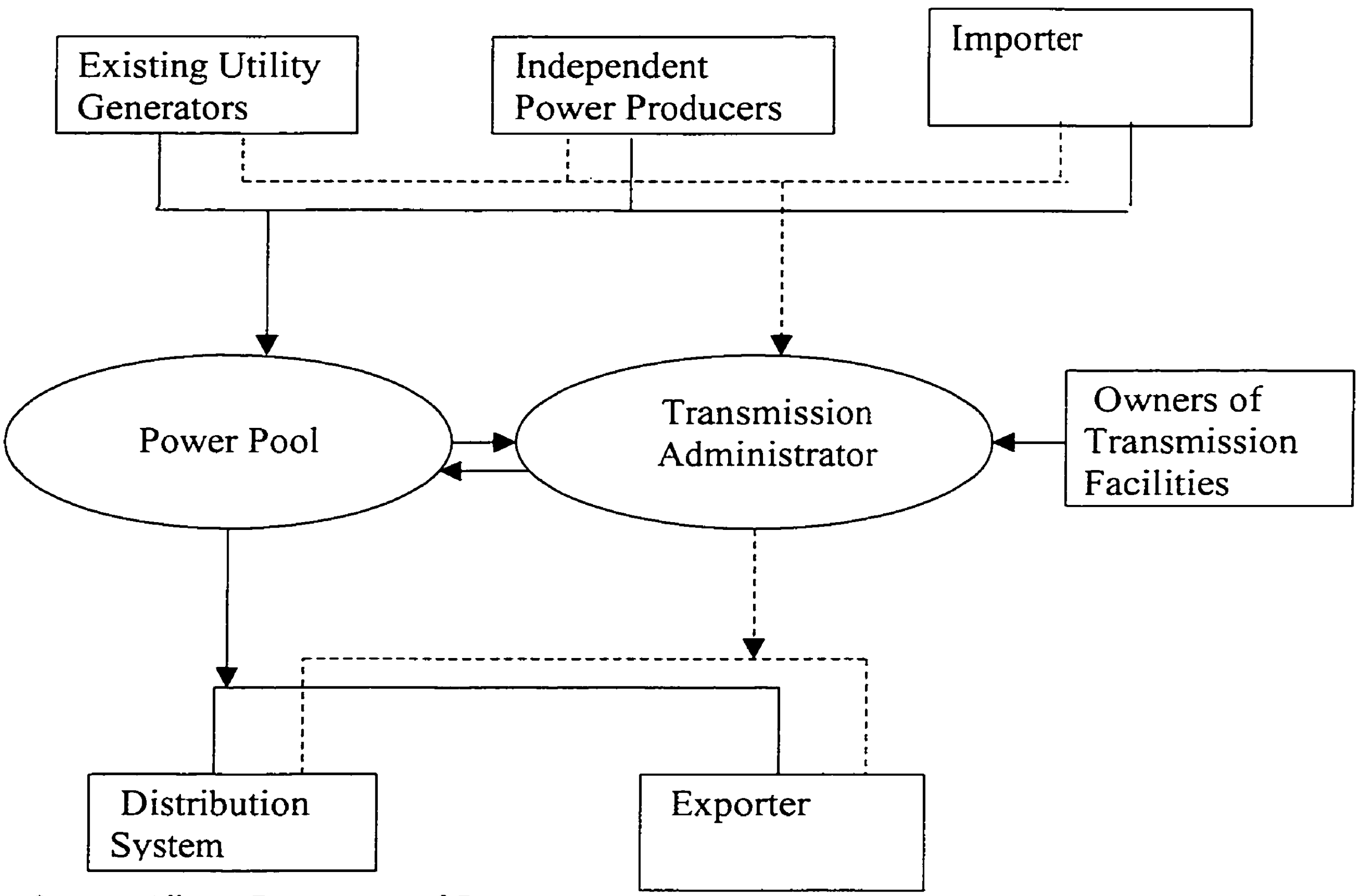
2.4 THE POWER POOL OF ALBERTA

The Power Pool of Alberta (also known as the "Pool" or the "Power Pool") is a central, open-access financial clearinghouse through which all electric energy, whether generated in Alberta or imported, is traded. The Pool is the first step towards a fully competitive electric market and began operation on January 1, 1996.

The Power Pool is an open-access market that accepts Bids and Offers on electricity, and trades electricity on the *lowest price* basis. The market is a spot market that matches demand with the lowest cost generation to establish an hourly pool price.

Since the Power Pool market is not an *open market*, it is not possible for Participant to view the Bids and Offers submitted by other Participants. All Power Pool Participants must have a valid contract with the Power Pool before they can submit Bids or Offers.

DIAGRAM 2.1 ALBERTA ELECTRIC INDUSTRY STRUCTURE



Source: Alberta Department of Energy

Generators or *suppliers* of electric energy can market their output through the Power Pool by submitting *Offers*. *Purchasers* of energy can place *Bids* to buy electricity through the Power Pool. It is a market for electricity where buyers and sellers interact to strike a price for exchange (similar to a commodity exchange). The Power pool sorts bids and offers into a merit order which is used by the system controller in the dispatch of energy.

Buyers of power place hourly bids to the Pool to indicate how much power they are willing to buy at different prices. Suppliers place their offers to the pool at various prices.

FIGURE 2.41a: DEMAND BIDS AND MERIT ORDER

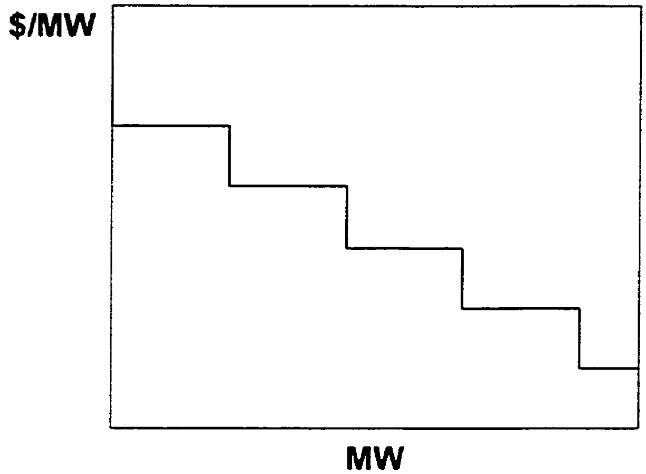
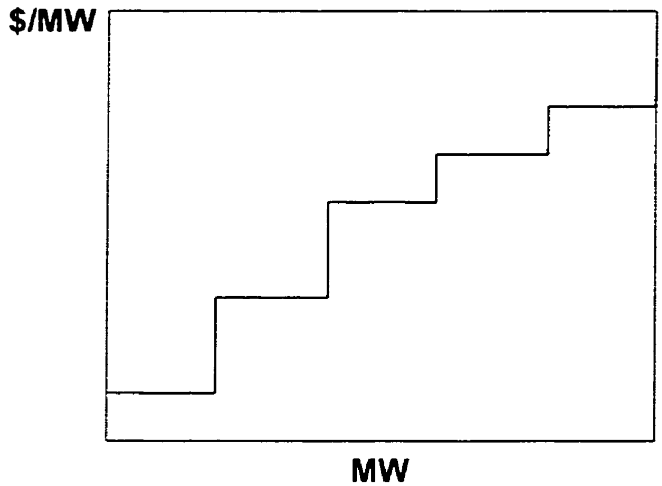


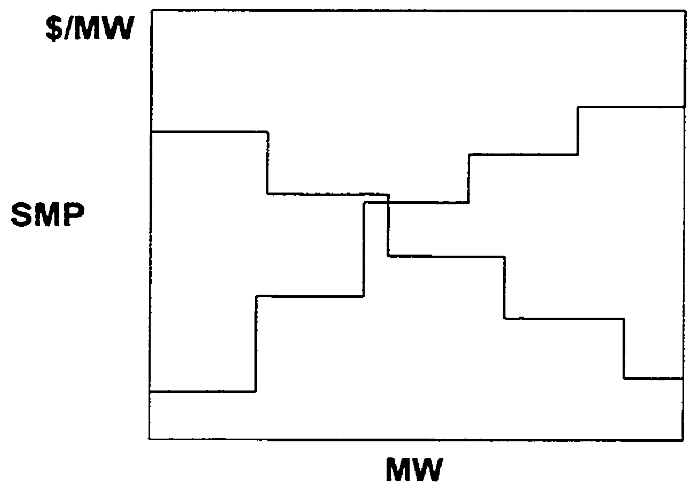
FIGURE 2.41b: SUPPLY OFFERS AND MERIT ORDER



Bids are ranked according to willingness to pay from highest to lowest into a merit order (Figure 2.41a). Offers are ranked by price from lowest to highest (Figure 2.41 b). The merit-order for any given one-hour period includes hundreds of blocks of energy. The bids and offers form the basis for a forecast of what load will be served and which units will be dispatched in the hour. The point at which the demand and supply balance out determines the System Marginal Price (SMP) and the actual pool price is a weighted average of the highest priced unit (or load block) dispatched during the hour to balance supply and demand

(Figure 2.41c). The pool price varies from hour to hour but remains constant within the hour.

FIGURE 2.41c: MERIT ORDER AND POOL PRICE



2.5 TRANSMISSION ADMINISTRATOR

Buyers and sellers who trade energy through the Power Pool arrange transmission access through the Transmission Administrator, which was created under the EUA. Transmission facilities are still owned by utilities but the province wide system is managed as a single entity. The TA plays a key role in providing access to the grid to all the participants. The TA contracts with the owners of the transmission lines to provide service, acts as the financial clearing house between buyers of transmission services (generators, distributors, importers and exporters) and the owners and sets province wide tariff for system usage.

Almost all of the transmission lines in the province is owned by the three big utilities, namely Trans Alta, Edmonton Power Corp and Alberta Energy. This gives them immense market power in the sense that any new generation unit has to depend on these firms to connect them to the grid. This gives the utilities, power to erect barriers of entry in terms of pricing or gives them advance information about market conditions. In order to control this, a transmission administrator was required. Till 1997, the transmission administrator in Alberta was just a consortium of the three utilities and that did not serve the purpose of the

TA. The Department of Energy then called for bids and chose ESBI, the Irish Utility firm, to act as the TA in Alberta.

The TA leases the lines from the utilities and then charges the Discos for the usage. The utilities submit a quote for leasing lines from them, which is approved by a board. ESBI then adds its costs and margins to that figure and then fixes the rate it charges the users of the grid. The utilities, which are also users of the grid, pay ESBI for using the lines.

For the construction of new lines, ESBI calls for a tender and awards the job to the cheapest cost bidder. In earlier days, the utilities, which built these lines, capitalized the costs, which means they got paid a return on the cost as well. The tender process invites engineering firms that may be able to do this job at a lower cost. But the lines could then be sold to the utilities, which have better economies of scale in maintaining the lines.

Line losses are estimated and included in the cost quoted by the utilities to ESBI. Any differences, in actual losses from forecast is adjusted by charging/crediting customers.

Starting in 1999, ESBI started charging the generators for system usage. The charges are based on capacity, load and also distance from the grid. The generators share the cost of erecting transmission lines and this means that it is cheaper to build a plant in Southern Alberta than it is in Northern Alberta, as the bulk of the energy used is near the cities.
A transmission system should also be able to deliver power at stable voltages and requires such support services as "spinning reserve" and automatic generation control to maintain the system within an acceptable load level as load rises and falls. There are also transmission losses in power, which must be accounted for. All of these costs are included in the costs recovered through system access rates.

2.6 GENERATION- EXISTING AND NEW

Almost 90% of Alberta's electric generation is by utilities but with scheduled retirement of existing generation, the share of the IPP s would grow. The EUB's forecasted demand and supply growth projects that there would be supply shortfall of 1000 megawatts by the year 2005 unless new units come up to compensate.

Though all units sell energy into the pool and receive the pool price as payments, there is a difference in the way the older units are treated. These fully depreciated units have a low variable cost of production and the regulators want to ensure that this low cost reaches the consumers. Since the pool price is set at the price the last unit was dispatched, the low cost generators do not normally set the pool price. Hence, these Generators, could see windfall profits, without intervention. The mechanism for ensuring that the consumers enjoy the benefit of low cost generation is the system called legislated financial 'hedges' between distributors and owners of existing generation units. Essentially, this ensures that the distributors pay the Generators close to their variable cost of generation in return for which the Discos pay the pool a fixed amount every month to cover the units' fixed cost of generation.[4]

The independent producers were required to go to their local utility first and try to negotiate a sale price, before the EUA, 1996. If no agreement could be reached on the terms, the Alberta Energy and Utilities Board could be asked to hold a hearing on the matter. This was an expensive and time-consuming process. Now any business can build new generating capacity in the province and compete freely in the generation market.

[4] See APPENDIX 1 for a detailed explanation of the way the 'hedges' work.

2.7 POOL PARTICIPANTS[5]

The Power Pool of Alberta participants include:

Generators (Suppliers): Generators *sell* electrical power through the Power Pool. Generators are currently divided into the following major categories:

GENCO	Generating units under legislated obligations in companies such as Alberta Power, TransAlta, and Edmonton Power.
IPP	Independent Power Producers.
SPP	Small Power Producers regulated by the Small Power Research and Development Act.

Distributors (Discos): Distributors *purchase* through the Power Pool. Current Power Pool distributors include Alberta Power Limited , TransAlta Utilities Corporation, Edmonton Power Inc., City of Calgary, City of Lethbridge and City of Red Deer

Importers: Importers *purchase* energy through tie-lines with Saskatchewan Power (SPC), BC Hydro (BCH), and City of Medicine Hat (CMH) and *sell* this energy through the Power Pool.

Exporters: Exporters *purchase* energy through the Power Pool, and export it via the tie-lines to SPC, BCH and CMH.

Transmission System: the Transmission Administrator (TA) provides access to the electrical transmission system in Alberta.

Power Pool Council: The Power Pool Council is a corporation established by the *Electric Utilities Act* to carry out the operation of the Pool and to promote a fair, efficient, and openly competitive market.

Power Pool Administrator

- Determines the economic merit order for energy dispatch.
- Sets the schedule for dispatching generating units.
- Reports the pool price for each hour.
- Carries out financial settlement for the electric energy exchanged through the Pool. Levels of system support services.

System Controller: The System Controller dispatches generation and import offers in economic merit order to meet system and export demand. The Controller is also responsible for ensuring the safe and reliable operation of the system and for providing adequate levels of system support services.

[5] Source: Power Pool of Alberta web site, http://www.powerpool.ab.ca/downloads/c1-part.doc.

Chapter 3 - Literature Review

The first section in this chapters introduces the concept of Real Options and its advantage over traditional valuation techniques. The next section discusses the various models proposed to value electricity derivatives and the approach adopted in this thesis.

3.1 INTRODUCTION TO REAL OPTIONS

Traditional investment theory is based on the Net Present Value (NPV) rule, which states that "invest until the value of the marginal unit of capital is equal to its cost". The NPV is calculated as the discounted value of all future cash flows at the cost of capital. The investment principal gives a green signal to investment if the NPV is non-negative. This principle is based on the assumption that either the investment is reversible or if it is irreversible, it is a now or never proposition.

Dixit and Pindyck (1994) argue that although this may be true in some cases, in most cases it is not. Most projects are irreversible but they can be delayed and these features greatly affect the value of the project. A firm with an opportunity to invest in a project is a holder of a 'call option' as in financial options; i.e. the firm has the right but no obligation to invest. By not investing immediately, the firm can wait for information on the project to arrive that might change the value or the desirability of the project. Such investment options are called Real Options, as they offer an option to invest in real assets.

To translate traditional option terminology to real options, one can consider the output of the project as the underlying asset. The value of the option is determined by the value of the product output and this is usually a commodity. The price of the commodity at which the investment is optimal is the 'exercise price' or 'strike price' of the option. The right to benefit from the cash flows of the project is acquired by paying a price, which is the capital cost of investment. As the value of the underlying asset changes, so do the value of the option and the value of the project, the NPV. Diagram 3.1 illustrates how the value of the option and project change with change in the underlying asset.

DIAGRAM 3.1: NPV VS OPTION VALUE

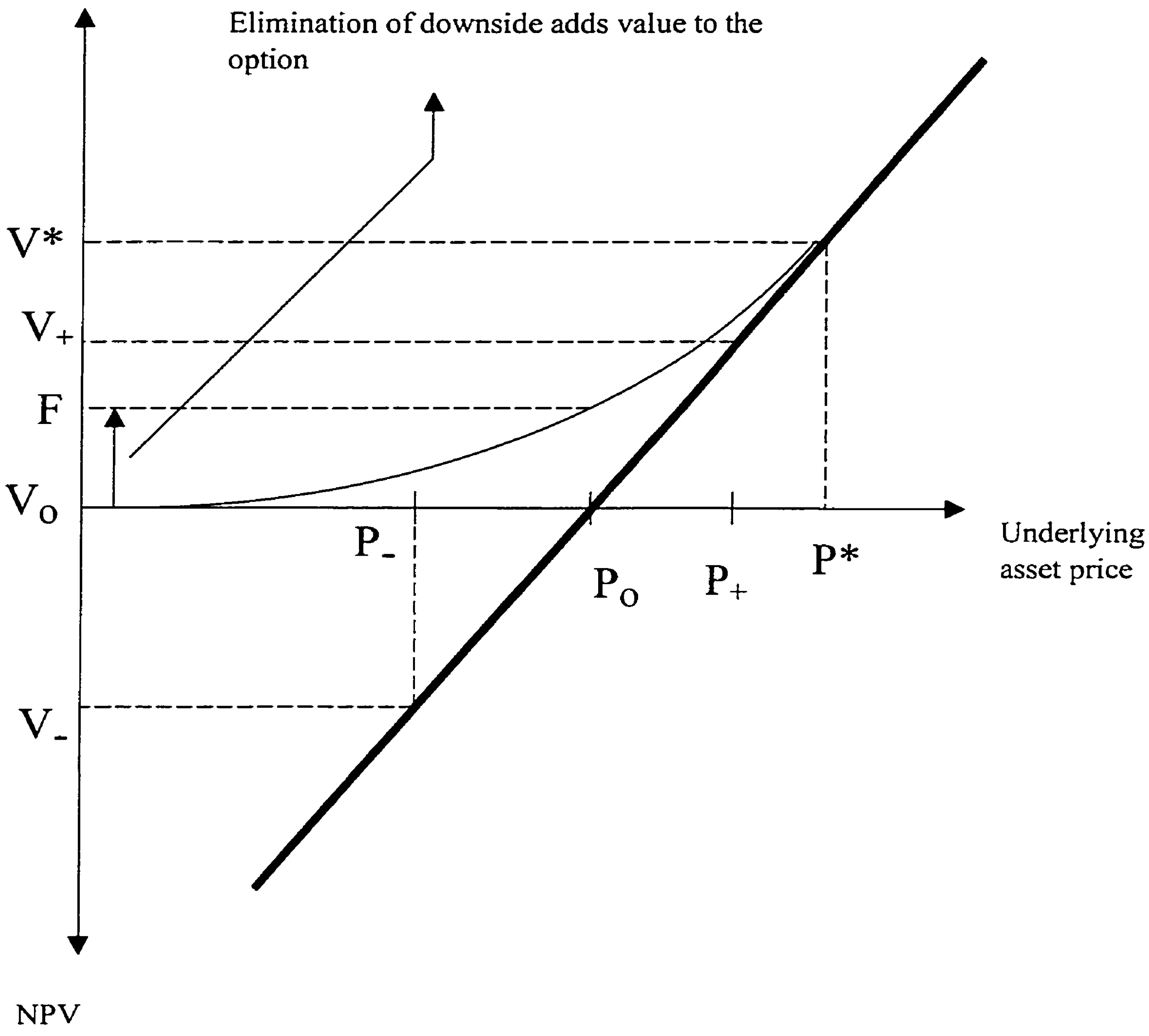


Diagram 3.1 illustrates how options add value to a project. The thick line traces the NPV of the project at various prices of the underlying asset. The price is at Po and may change in the future to P+ or P-. At Po, the NPV of the project is Vo, which is zero. According to the NPV rule, since the value is non-negative, the project should be adopted. But, in the second period, if price falls to P-, the value of the project becomes negative at V-. If the price rises increases to P+, the value of the project is V+. This risk of uncertain project value is taken when the project is adopted at Po. The curved line traces the value of the option at every

price level. At Po, the value of the option is F. By investing immediately, this value is foregone. The value of the option is an opportunity cost and must be included in the NPV, which then becomes negative since F is positive. Sick (1995) illustrates this and explains why it is optimal to exercise the call option only at the tangency point. To put it simply, it can be seen that at every price level, the value of the option is more than the NPV and this is because, the option guarantees to eliminate the risk of the downside. When the price is P*, the NPV and the option value coincide at V*, and hence, it is optimal at this price to adopt the project.

The option that is available to the electricity Generator is slightly different in the sense that the exercise point of the option is assumed to be fixed, without loss of generality. It is like a European call and can only be exercised at the time of maturity of the option. When the underlying asset price is high, there is additional value from the knowledge that the operations can be suspended if and when price falls below the hurdle value. When the price is low, there is additional value from the option to restart operations if price should rise above the hurdle in the future.

3.2 PRICING ELECTRICITY CALL OPTIONS

With deregulation sweeping through many electricity markets in the world, customers and market players are exposed to market pricing rather than regulated, cost-recovery pricing. The need to manage this risk is immense and electricity derivatives are expected to grow at a tremendous pace. A Generator of electricity, who trades the heat rate times the price of gas for the price of a unit of electricity is faced with the same uncertainties. The equivalence between holding a spark spread option and the right to operate a generation asset can be used to value the generation asset.

Electricity is a unique commodity in the sense that it cannot be stored and this presents a challenge to model the price process and valuing derivatives based on the traditional cash-carry, no arbitrage methodology. As a result, an entirely new approach is required.

McDonald and Siegel (1984) value a project with an infinite set of option, each expiring at a particular time, as a series of European Call Options using the standard Black-Scholes formula. The electricity generation project is similar in the sense that the Generator has an option to sell electricity by buying the spark spread at every hour of the day and the option can only be exercised at that particular time or it expires. It is in fact an European call option. But the problem with applying the Black-Scholes formula is the fact that electricity cannot be stored and traditional cash-carry relationship cannot be applied to value an electricity option. Alternate methods to value it have been developed though.

Sick, Elliott, Stein (2000)[6], develop a model of spot electricity price and incorporate seasonality on an annual basis and a daily basis around a mean reverting de-seasonalized intrinsic price. They model the jumps in the spot price as arising from supply shocks as large generators in the system come off line and go on line and the number of generators on line as a discrete Markov process. The Generator, that is not part of base load, can offer to supply electricity only when the pool price exceeds a hurdle value, or strike price, and is a holder of a strip of call options at every hour of the day.

Sick et al, price the call option based only on the spot price of electricity. But for a Generator who buys gas to produce electricity, the price of gas adds to the uncertainty as well. The Generator submits an offer to the power pool at the price above which the unit will supply electricity. If this offer is only based on a hurdle electricity price, fluctuations in the price of gas can swing the Generator's profit either way. It is therefore important to take the differential price, or spark spread, into consideration and price the option based on the movements of the spark spread rather than that of electricity alone.

Deng, Johnson and Sogomonian (1999) price spark spread derivatives and a generation asset by a replicating method by dynamically trading futures contracts of the appropriate maturity by making some simplified assumptions. Their assumptions are:

1. A complete set of futures contracts for electricity and for the relevant generating fuels are traded.
2. The risk-free interest rate r is constant.
3. Ramp-ups and ramp-downs of the facility can be done with very little advance notice.

---

[6] "Pricing Electricity Calls", Sick, Elliott, Stein, draft version, June 2000.

4. The facility's operation (e.g. start-up/shutdown costs) and maintenance costs are constant.

They first calculate the value of a spark-spread option and use that to solve for the value of a gas-fired generation asset. The value of a European spark-spread call option is given by:

$$C_1(F_e^{t,T}, F_g^{t,T}, \tau) = e^{-r\tau}[F_e^{t,T} N(d_1) - K_H F_g^{t,T} N(d_2)]$$ **Equation 3.21**

where,

τ = T-t

$$d_1 = \frac{\ln(F_e^{t,T} /(K_H F_g^{t,T})) + \nu^2 (T-t)/2}{\nu\sqrt{T-t}}$$

$$d_2 = d_1 - \nu\sqrt{T-t}$$

$$\nu^2 = \sigma_e^2 - 2\rho\sigma_e\sigma_g + \sigma_g^2$$

The European spark spread call option written on fuel G at a fixed heat rate K_H gives the option holder the right but not the obligation to pay K_H times the unit price of Gas at the option maturity T and receive the price of one unit of electricity.

This value is then used in calculating the value of the generating asset.

Let V be defined as one unit of time t's capacity of the generating asset over the remaining life of the plant.

$$V = \int_0^T u(t)dt.$$ **Equation 3.22**

Where $u(t) = \max(S_e^t - K_H S_G^t, 0)$, which is the same as the payoff to the spark spread call option.

The lower and upper bound for V are given by:

$$\int_0^T e^{-rt} \max(F_e^t - K_H F_g^t, 0)dt \le V \le \int_0^T e^{-rt} F_e^t dt$$ **Equation 3.23**

where,

S_e = Spot Price of Electricity

S_G = Spot Price of Gas

T = life of the plant

r = constant discount rate

F_e = Futures price of electricity

F_g = Futures price of the generating fuel (natural gas)

K_H = Heat rate

The value of the generating unit over its life time is then given by

$$V_{gen} = \int_0^T C_1(t)dt.$$ **Equation 3.24**

where $C_1(t)$ is the value of the spark-spread option at time t as in Equation 3.21.

The pivotal assumption in this model is that the futures for electricity and gas are both traded and with appropriate maturities. Now, the problem of applying this model to the Alberta situation is that there exists no derivatives market for electricity. Norway and Sweden have linked their electricity markets through the Nordic Electric Exchange (Nord Pool), a newly launched electricity futures exchange which is run by OM, the Stockholm-based futures and options exchange. Nord Pool trades contracts for weekly, monthly and, by grouping the monthly contracts, seasonal delivery. In the neighbouring U.S., the New York Mercantile Exchange (NYMEX) introduced two physically settled futures contracts in April 1996. One of the contracts is based on delivery at California-Oregon Border (COB) and the other at Palo Verde. Although volume remains low and both contracts are struggling, they are expected to continue to be traded. Such a market for electricity futures does not exist in Alberta at the moment. Though the Power Pool is negotiating with external parties for the setting up of one such exchange, it might take a while before an exchange is established.

The other problem in using this model is it assumes that all other costs of generation are fixed. In section 8.3 in this thesis, it is shown that the variability of maintenance cost adds a lot of value to the option and ignoring that would be underestimating the value. The cost per start does not matter so much to the option value but it is still a variable cost although some portions of it might be fixed.

This thesis takes an empirical look at the flexibility option value of a gas-fired generating asset in Alberta. The flexibility value arising out of the option has been calculated as the difference between flexible and 24-hour firing operations and is based on the pool price for the period spanning January 1997-June 2000. The assumptions and conditions presented in the research are specific to Alberta and may or may not apply to other markets.

The payoff of a spark spread call option is exact replica of the earnings of a gas-based Generator. But, the value of the generation asset is also dependent on the capital investment required. The thesis also calculates the Economic Value Added by operating such a generating unit in Alberta.

Chapter 4 - Power Generation Technology[7]

The heart of any power generation system is a prime mover, which converts thermal or chemical energy to power. The most commonly used prime movers include

- Internal combustion reciprocating engines
- Combustion turbines
- Steam turbines

Other available systems include reciprocating steam engines and Stirling engines. These systems vary in terms of size of engine and performance characteristics. Before venturing on an elaboration of the technologies, it is essential to understand some basic definitions.

4.1 BASIC DEFINITIONS

Prime mover : Engines that convert thermal or chemical energy into power

Mechanical efficiency: Prime mover's mechanical output divided by fuel energy input. Maybe expressed as percentage or as a heat rate. The higher the efficiency, the lower is the cost of gas.

Heat Rate: measure of the system's electrical efficiency and is defined as the amount of fuel energy input required for producing one kWh of power. The higher the heat rate, the higher is the cost of gas.

Scheduled Availability: Maximum time the engine is available for operation after deducting time for maintenance.

4.2 GAS TURBINE GENERATION IN ALBERTA

In Alberta, 70% of total electricity generated is from Coal based generators and 18% is from natural gas based generators. This ratio was 75:15 two years ago and the reason for the change is that almost 96% of all new, planned, proposed capacity are gas based (Table 4.22).

[7] Joseph A Orlando, "Prime Movers" in Co-generation Planner's Handbook, (PennWell, 1997), 17-70

TABLE 4.21: FUEL-WISE GENERATION IN ALBERTA

GROUP	*MCR*	*NET*	*% of total*	*RESERVES*
Coal	5,621	4,726	70%	195
Gas	1,434	1,215	18%	98
Hydro	818	737	11%	37
Other	0	48	1%	0
Total	7,873	6,726	100%	330
Source: Power Pool of Alberta, July 28, 14:17:12 MDT, 2000				

The primary turbine in combined cycle plants and most co-generation systems is a gas turbine, which means the concept of spark spread applies to them as well. But certain characteristics in their design and purpose, does not allow them the flexibility of switching off the turbine as and when needed. For example, co-generation is the simultaneous generation of both electricity and useful thermal energy. In other words, the usage of otherwise wasted heat for productive purposes. Typically, co-generation facilities burn fuel (usually coal or natural gas) to generate steam. This steam is then used to turn a turbine and generate electricity. Finally, the cooler and lower pressure steam is sent off for use in industrial processes or space heating. Some co-generation plants use so-called combined-cycle technology in which fuel is burned in a gas turbine (essentially a jet engine) attached to a generator. The exhaust from the turbine is then used to generate steam.
The dual uses to which fuel energy is put allows co-generation facilities to be much more efficient than conventional power plants, which simply dump their waste heat into the atmosphere or nearby body of water. While a typical utility power plant converts about 33% of its fuel's energy into useful electricity, a co-generation plant can utilize 80% or more of its heat input productively.

Since these units serve dual purposes, electricity has to be generated even at times of low or negative spark spread in order to satisfy the steam/heating needs. Also, the capacity utilization is determined by the dual needs and hence electricity generation based on spark spread alone is not an available option. Some co-generation units in the province are said to bid into the pool at zero dollars just so that they can continuously produce electricity without having to interrupt their steam supply. This robs them of the option that the simple-cycle gas turbine Generator has.

Table 4.22 : New, Planned, Proposed Generation Capacity in Alberta

Developer	*Location*	*Capacity*	*Type*	*% of total*	*Status*
Drayton Valley Power	Dapp	17	Biomass	0.76%	On line (Small Power R&D Program)
TransAlta Energy/Suncor	Steepbank	360	Co-generation	16.17%	115 MW on line Feb. 2000
NOVA/ATCO/EPCOR	Joffre	416	Co-generation	18.69%	170 MW on line mid-Feb. 2000
TransAlta Energy	Sundance	0	Co-generation	0.00%	370 MW (Deferred)
Syncrude Aurora	Fort McMurray	320	Co-generation	14.38%	First 80 MW on line Aug. 1999
Air Liquide/TransAlta Energy	Ft Sask	120	Co-generation	5.39%	Oct. 99
Amoco/ATCO Power	Primrose	84	Co-generation	3.77%	On line
Air Liquide	Scotford	82	Co-generation	3.68%	On line 2nd quarter 2000
Imperial Oil	Cold Lake	220	Co-generation	9.88%	On line 3rd quarter 2001
Shell	Muskeg	172	Co-generation	7.73%	On line 3rd quarter 2002
(Name Confidential)	Edmonton	30	Co-generation	1.35%	On line 3rd quarter 2003
EPCOR	Rossdale	170	Combined cycle	7.64%	On line 3rd quarter 2002
Renaissance	Taber	3.3	Flare Gas	0.15%	245 kW on line, remainder by Dec. 1999
Magrath Energy Corp.	RM House	0.9	Flare Gas	0.04%	On line
ATCO Power	Poplar Hill	43	Gas Turbine	1.93%	On line
ATCO Power	Rainbow	45	Gas Turbine	2.02%	On line
TransAlta	Fort Nelson	45	Gas Turbine	2.02%	On line
Canadian Hydro/EPCOR	Taylor Chute	12.75	Hydro	0.57%	On line 2nd quarter 2000
ATCO Energen	Oldman	25	Hydro	1.12%	On line 2nd quarter 2002
Canadian Hydro	Dunvegan	40	Hydro	1.80%	Preliminary Evaluation
Canadian Gas & Electric	Drywood	6	Natural Gas	0.27%	On line Dec. 1999
NOVA	Gold Creek	6.5	Waste Heat	0.29%	On line
Vision Quest	Castle River	7.8	Wind	0.35%	2.4 MW on line, 1.32 MW expected to be on line June 2000
Total		2226			

Source: Alberta Resource Development at www.resdev.gov.ab.ca/electric

4.3 FACTORS DECIDING PRIME MOVER CHOICE

- *Scheduled availability* – Since the idea is to run the engine whenever the spark spread is favorable, it wouldn't be suitable to have an engine that requires very long maintenance shut downs. Steam turbines require long overhauls while aero-derivative combustion turbines can be serviced off-site which gives it the highest scheduled availability.
- *Duty Cycle* – Since the generation of electricity must be shut down or restarted according to the spark spread, it must be possible to start and stop the engine as many times as necessary, without much lead time or adverse effects on maintenance requirements. Since the steam temperature in a steam turbine cannot be maintained while the system is shut off, the lead-time involved in a shut down/start up operation may be as high as 3 hours if the system has been shut off for more than 72 hours. The lead-time for a start up on the aero-derivative turbine is only 20 minutes.
- *Maintenance Requirements* – Reciprocating engines and aero-derivative combustion turbines are capable of unattended operation for prolonged periods of time. Shut down/start up operations do not affect the maintenance requirements of either type of these engines and also do not affect engine performance.

Considering all the factors, the reciprocating engine and the aero-derivative combustion turbine offer the maximum flexibility in electricity generation. However, the reciprocating engines are efficient only in the very small sizes of a few megawatts or less while the aero-derivative combustion turbines are efficient in small, medium to large sizes of more than a hundred megawatts. The aero-derivatives are also superior in the sense that the maintenance work can be done off-site while a replacement engine is fitted in place until the original can be brought back. Only two days are lost during engine changes while it would be more like a week if we were to employ any other kind of engine. Hence, an aero-derivative combustion turbine offers the maximum flexibility that allows the viewing of the generation asset as a Real Option.

4.4 COMBUSTION TURBINES

Combustion turbines are simple devices and operate through the *Brayton Cycle.* It consists of the compressor, combustor and a gas turbine. The air compressor, takes in air at atmospheric pressure, compresses it to reach very high pressure, thus increasing the temperature of the air. This is then led into the combustor, where air and fuel is mixed and burned, increasing the temperature further (can be 2200°F or more). This high-pressure, high-temperature gas mixture is then led into an expansion or power turbine. The expanding gases perform mechanical work and rotate the turbine shaft. During this, the air loses both pressure and temperature and the exhaust gas is at atmospheric pressure and temperature less than 1000°F. The mechanical energy produced in the turbine is converted to electrical energy in a generator. The generator operates on the principle that a conductor moving through a magnetic field will produce an electromotive force or voltage differential between the ends of the conductor. The important performance characteristics of a generator are rating, efficiency, voltage, voltage regulation, harmonics, power factor and fault current. Most engine manufacturers provide the engine and the generator as a single factory assembled unit.

There are two types of combustion turbines – industrial turbines that are larger in size and require more extensive maintenance and aero-derivative turbines that are light weight and can have maintenance work done off-site. The aero-derivatives are basically derived from aircraft engines (hence, the name) and can be shut down and started up as many times as required without causing any drop in efficiency or requiring any additional maintenance.

4.5 AERO-DERIVATIVE COMBUSTION TURBINES – MAINTENANCE FEATURES

A boroscopic inspection is performed 4 times every year and takes about 8 hours. Waterwashing is an 8-hour operation that is done every one or two months depending on site conditions. These events can usually be scheduled during low pool price hours.

A hot section overhaul is done after 24,000 hours and involves exchanging the hot section out of the machine. A re-built hot section is put in, the removed section is sent for refurbishment and sent to another user. This change-out takes 2.5 days.

After 48,000 hours a lease engine is brought in and used while rebuilding is carried out off site. The duration of this change-out is 2.5 days to install the lease engine and 2.5 days to remove the lease engine. The lease engine is usually used for roughly 20 weeks. Engine rental costs are in the region of US$160/hour or higher. In years with overhaul work, there are only 3 boroscopic inspections instead of 4.

All of these costs, except the inspections are typically covered under a long-term service agreement. Aero-derivatives are interesting in that after they have a major overhaul after 48,000 hours, the turbine is returned in like-new condition. Depending on the condition of the generator and balance of plant auxiliary equipment, it can be kept running after 30 years. Plants usually sign up for long-term maintenance contracts that charge based on fired hours. The original Rainbow lake units of ATCO Power have been running since the 1950's. Even though the turbine itself maybe capable of running past its original design life, one has to consider the other equipment in the facility. Major cost item would be rewinding of the generator and the present value of the cash flow from running the unit has to exceed the site refurbishment costs in order to keep the plant running. It is expected that after a facility has run to the end of its useful life, the salvage value of remaining assets would cover demolition and site rehabilitation costs[8].

4.6 AERO-DERIVATIVE TURBINES AND PRICES

Table 4.41 gives the heat rate, efficiency and price of some of the aero-derivative models available in the market. It can be seen that the efficiency of the turbine increases (heat rate decreases) with size. The larger the turbine, the more efficient it is. It is also cheaper per MW to install a larger turbine. It should be said here that the heat rate listed here apply when the turbine is run at full capacity. If the turbine is run at part-load, then the heat rate increases or in other words, efficiency drops. Section 8.7 deals with the effect the heat rate of the turbine has on the option value.

TABLE 4.61: SOME AVAILABLE AERO-DERIVATIVE TURBINE MODELS AND THEIR CHARACTERISTICS

Manufacturer	*Model*	*Rpm*	*Heat Rate (MMBtu/MW)*	*Efficiency*	*Output MW*	*$ in Millions*	*$/MW*
GE	LM5-ST120	3600	7.885	43%	51.50	15.30	$ 297,090.00
GE	LM5-ST80	3600	8.170	42%	46.30	14.70	$ 317,490.00
GE	LM6000PA	3600	8.720	39%	41.02	12.10	$ 294,980.00
GE	LM6 50HZ	3600	8.850	39%	40.41	12.60	$ 311,800.00
GE	LM5000PC	3600	9.350	36%	33.70	13.80	$ 409,500.00
GE	LM5000PD	3600	9.390	36%	33.35	13.60	$ 407,800.00
GE	LM2500	3600	9.404	36%	22.22	9.50	$ 427,620.00
GE	LM2500PH	3600	9.630	35%	19.70	10.30	$ 522,840.00
GE	LM1600	7000	9.560	36%	13.43	6.90	$ 513,780.00
GE	LM500	7000	11.430	30%	3.88	1.90	$ 489,690.00
RR	AVON	5500	11.885	29%	14.61	4.80	$ 328,540.00
TP&M	FT8	3600	8.875	38%	25.60	11.00	$ 429,690.00
TP&M	FT4C-3F	3600	10.875	31%	29.81	5.70	$ 191,210.00

Source: www.gas-turbines.com

[8] Source: Interviews with Mr. Carl Fuchshuber and Mr. Dwight Redden of ATCO Power, Calgary.

Chapter 5 - Power Pool Guidelines

This chapter discusses the guidelines laid down by the Power Pool for the pool participants. The first section discusses how bids/offers are submitted and how the Power Pool decides on the merit order and dispatch. The second section gives the reports sent by the Power Pool to the participants and how these reports are used for unit scheduling. The final section is how the requirement of the Power Pool for the participants' voltage support is being addressed by technology.

5.1 THE BID/OFFER PROCESS

The Power Pool's Participant's Manual[9] lays the following guidelines for bids and offers:

- For the next day's trades, Participants must have their Bids and Offers submitted and accepted by 10:00 AM. After 10:00 AM, the Participant is automatically prevented from revising the next day's Bids and Offers. Bid prices are only binding for the next day. Bid volumes, however, can be re–declared at any time.
- Advance Bids and Offers (for trading beyond the next business day) may be submitted at any time.
- All Bids and Offers submitted must apply for a *complete seven (7) day period.* However, the prices in these Bids and Offers are only *fixed* for the next trading day.
- Shortly after 14:00 each day, the Power Pool publishes the forecast hourly prices and schedules for the *next day*. These schedules show the forecast, of which Offers will be dispatched, and the forecast of which demand Bids will be supplied, the import and export amounts, and the Forecast Pool Price.
- Shortly after 16:00 each day, the Power Pool publishes the forecast prices and schedules for the following *7 days*. The information provided in these reports is similar in content to the *next day* reports, but spans the six days that follow the *next day* reports.
- Once the schedules have been built, the Power Pool also releases Unit Schedules that show the forecast schedule for each unit. This is confidential information that is only reported to the responsible Participant.

[9] Alberta Power Pool Participants Manual, July 2000, Version 1.0 available at http://www.powerpool.ab.ca.

- Normally the Pool Price is set by the price of the most expensive Offer that must be dispatched to meet Pool demands. It is also possible for a Distributor to set the Pool Price by reducing its load in accordance with its Bid.
- Any Participant may submit to the Pool Administrator at any time a revised daily Offer or Bid restating the Unit constraints (Startup Time, Max Run up Time, Max Ramp Rate, Min On and Off Time) stated in accordance with the Bid Offer Pro Forma for each remaining Settlement Period, including the current Settlement Period, of the current Trading Day and all other Days within the Forecast Scheduling Period.

5.2 PARTICIPANT REPORTS AVAILABLE FROM POWER POOL OF ALBERTA

The Power Pool issues both public and confidential reports everyday that guides the Generators to schedule their unit start up/shut down time.

Confidential Participant Reports

Confidential reports are Participant specific reports that provide details on the Bid/Offer schedule for a Participant as well as settlement information.

1 Participant Specific Offer/Bid Schedule–Day Ahead Forecast

2 Participant Specific Offer/Bid Schedule–Six Day Forecast

3 Equal Price Report

4 Settlement Information Submenu

Public Reports

Public reports are available to all Participants and provide general information about trading forecasts, hourly pool prices, and historical information. Public reports include:

1 Trading Day Data - Day Ahead Forecast

2 Trading Day Data - Six Day Forecast

3 Daily Forecast and Actual Data (See Exhibit I for model report)

4 Monthly Actual and Forecast Data

5 Previous Hour/Day Historical Information

6 Daily Supplier/Purchaser Information

7 Monthly Supplier/Purchaser Information

Of these reports, the one of interest is the Daily Forecast/Actual Data report. The *Daily Forecast and Actual Data* report (Table 5.21) provides the following information for each hour of the day.

If a Generator wishes to offer his supply only when the spark spread is over $10 say, the offer given to the Power Pool must be translated into a $ figure for the Pool Price. Since the offers for the next day are binding, the Generator has to forecast next day's gas price and state the offer at 10 times the gas price (heat rate) plus the $10. So, if the Generator expects the gas price for the next day to be at $3.5/MMBtu, he can offer his supply at $45. So, if pool price reaches or exceeds $45, his unit would be called in. This is assuming that the Generator buys his gas in the spot market. If he has a supply contract, then there would be no need to forecast gas price. But a supply contract would typically have a minimum consumption clause, which would mean that the Generator is forced to buy a certain amount of gas everyday, which robs some of the flexibility available..

The other important aspect is how would the Generator schedule the start up times before knowing the pool price. For a Frame machine, the start up time is roughly 30 minutes and for an aero-derivative turbine, it is roughly 20 minutes. This condition can be specified to the system controller as the Unit constraint, so the dispatches are done taking this into consideration. Since the bid volume can be changed at all times, the day ahead forecast for demand cannot be expected to be accurate. But the system controller forecasts demand and the resulting pool price prior to the dispatch period and notifies the units accordingly as the unit constraints are known in advance. Hence, it is possible for the Generator to be up and running for the dispatch period. It is possible that the actual posted pool price is different from the system controller's forecast. Though the dispatches are based on the system controller's expectations, the Generators are compensated on the basis of the actual posted pool price. The effect this has on the option value is discussed in section 8.2.

TABLE 5.21: DAILY FORECAST AND ACTUAL DATA REPORT FROM POWER POOL OF ALBERTA

This column...	*Provides information on...*
Hour	Hour of the day for which prices are forecast.
Forecast Pool Price (FPP)	The forecast pool price calculated by the Power Pool System. This calculation takes into account the scheduling of bids and offers, forecasted loads, system constraints, and so on. It is provided for each hourly settlement period.
Next Settlement Period Forecast Pool Price	The actual forecast pool price as determined by the System Controller prior to dispatch.
Actual Pool Price	The actual pool price that was used when electricity was dispatched for that hour.
Forecast Actual Pool Demand	Actual pool demand on electricity for each hour.
Bid/Offer Spread (BOS)	The price difference between the lowest priced Offer that is *not scheduled* to be dispatched (LPO) and the highest priced Bid (HPB) that is *not scheduled* to be filled. **BOS = LPO – HPB**

Source: Power Pool of Alberta

5.3 VOLTAGE SUPPORT

While a Generator can shut down the turbine when the spread is unfavorable, the TA requires that the Generator supply voltage stability to the grid at all time. Is it possible to do so? An article in the Calgary Herald provides the answer to this[10]:

"CU Power (CUPIL), an ATCO Company, officially opened its Poplar Hill power plant today. This new $30 million 45 megawatt power plant is located near Grande Prairie, Alberta..... The Poplar Hill power plant features an innovative design, which provides new generating capacity as well as low cost transmission system support services. The plant is unique in that the electric generator can be connected to the Grid and provide voltage

[10] "More power to Albertans - CU Power officially opens its Poplar Hill power plant", *Calgary Herald*, Friday, January 29, 1999

support while the turbine is intentionally disconnected from the generator. When the Grid needs electricity, rather than just voltage support, the turbine can be automatically reconnected to generate electricity for the region."

Chapter 6 - The Analytical Framework

This chapter deals with the methodology involved in the simulation model for calculating the option value and also the various underlying assumptions. The chapter also discusses the sensitivity of the option value to various parameters of the model.

6.1 ACTUAL DATA - ELECTRICITY AND GAS PRICES

The input data for the simulation are:

Date	Hour Equivalent	Actual Posted Pool Price	Previous Period Forecast Pool Price	Alberta Natural Gas Price
Jan 1, 1997-June 30, 2000	1 – 24	$/MWh	$/MWh	$/MMBtu

The pool prices (actual posted and previous period forecast price) have been obtained from the Power Pool of Alberta web site. The Natural Gas prices have been secured from the web site of Natural Gas Exchange INC, (www.ngx.com), headquartered in Calgary, Alberta providing electronic trading and clearing services to natural gas cash market customers. Both series of data have been obtained for the time period January 1, 1997 to June 30, 2000. Power Pool price is available for every hour of every day for the time period under consideration. However only the closing price of gas for each day is available. It has been assumed that the same gas price would prevail the whole day for the purpose of calculations. Gas prices are also not available for holidays like Christmas and New Year. In such cases, the previous day's closing value is assumed to be the day's price.

6.2 SIMULATION OF EARNINGS OF AN ELECTRICITY GENERATOR IN ALBERTA

The analysis mainly consists of a simulation model of the cash flows of a generation asset employing aero-derivative gas turbine. The purpose of the analysis is to calculate the profit (before interest, depreciation and tax) for the Generator when the turbine is run all 24 hours of everyday and when the turbine is run selectively when the spark spread exceeds a strike value. The difference in these two profit figures is the value of the flexibility option that is available to the Generator.

The analysis has been carried out in a Microsoft Excel worksheet and the option value has been calculated under two different scenarios:

1. The offer price to the pool for day 1, is based on the gas price of day 0 and the scheduling of the start up/shut down is based on system controller's forecast price. Hence, if the Generator's strike rate is \$X above the spark spread, then the offer price would be (heat rate)*day 0 gas price + \$X. So, the turbine is run whenever the forecast pool price exceeds this offer price.
2. The offer price is equal to (heat rate)*day 1 gas price + \$X. The start up scheduling is based on actual pool price. So, the turbine is run whenever the actual pool price exceeds the offer price.

The following values have been calculated from the raw data:

1. $SS_0 = FPP - H * G_0$
2. $SS_1 = PP - H * G_1$
3. $R_{f,t} = 1$ if $(FPP - H*G_0) >= E$ and $M = 0$, 0 if $(FPP - H*G_0) < E$
4. $R_{a,t} = 1$ if $(PP - H*G_1) >=E$ and $M = 0$, 0 if $(PP - H*G_1) < E$
5. $S_f = 1$ if $R_{f,t} = 1$ and $R_{f,t-1} = 0$
6. $S_a = 1$ if $R_{a,t} = 1$ and $R_{a,t-1} = 0$

Where,

SS_0 = Day ahead spark spread

SS_1 = Actual Spark Spread

G_0 = Day ahead Gas Price

G_1 = Actual Gas Price

FPP = Forecast Pool Price

PP = Actual Posted Pool Price

$R_{f,t}$ = Turbine On/Off with day ahead scheduling on day t

$R_{a,t}$ = Turbine On/Off with real time scheduling

S_f = Start with day ahead scheduling

S_a = Start with real time scheduling

M = Maintenance stops (zero if no maintenance stops, 1 if scheduled maintenance on)

Appendix A gives the dates for all scheduled maintenance.

The sum of turbine on /off column gives the total number of hours the turbine has run. This has been compared to the total hours available (365 days*24 hours – scheduled maintenance stops).

The starts summed up give the number of times the turbine has been shut down/started up. This has been compared for various strike values.

Revenue stream for the turbine would be the actual spark spread based on the scheduling chosen. That is, the Generator earns the actual spark spread if the turbine is on, whether the scheduling is based on scenario 1 or 2.

The costs for the Generator would be:

1. Maintenance Cost/hour = It has been assumed for the analysis that the maintenance cost would be \$6/MWh[11], which is the average rate for a mid-sized turbine.
2. Cost of Start = Though the aero-derivative turbine does not have any maintenance cost increase or efficiency drop owing to frequent start ups, there is a direct fuel cost. The turbine takes about 20 minutes to fire up to full capacity and optimum voltage level. But there is fuel consumption right from the minute it is on. For this time period, however, there is no revenue as no electricity is sold into the grid. But it is difficult to calculate the start cost exactly as fuel prices change and the rate at which the fuel is consumed is also not known. So, a sensitivity analysis for the option values for various start costs have been performed. If gas costs \$1/MMBtu, then at full consumption for 20 minutes, the fuel cost would be \$3.33 = 1*10*20/60 per start. If gas prices were \$5/MMBtu, then at full consumption for 20 minutes, the fuel cost would be \$16.70 per start. Hence the analysis has been done for various start costs in the range of \$2 to \$16. Section 8.5 discusses the results of this sensitivity analysis.

[11] Joseph A Orlando, "Prime Movers" in Co-generation Planner's Handbook, (PennWell, 1997), 50

3. Fixed costs = The Generator would accrue fixed costs like depreciation and a capital charge, whether the turbine is operated or not. Hence, these costs make no difference to the value of the option.

PBDIT $_{(24\ hours)}$ = Spark Spread – Maintenance cost
PBDIT $_{(spark\ spread\ >\ strike\ rate)}$ = Spark Spread – Maintenance cost – cost of starts
Value of Flexibility Option = PBDIT $_{(spark\ spread\ >\ strike\ rate)}$ - PBDIT $_{(24\ hours)}$
Optimal Strike Value = Max (Value of Flexibility Option)

6.3 RISK NEUTRAL VALUATION

The discount rate that has been used in the calculation of present value is based on risk-neutral valuation of the Generator's cost of capital. Typically while computing the cost of capital of a firm, a risk premium is added to the risk-free rate to account for the firm's risk potential. If one has to calculate the premium for an electricity Generator, the Beta of the underlying asset, the spark spread, has to be evaluated and the product of the Beta and the market's risk premium gives the risk premium for the firm's equity returns. In this case, the fact that the spark spread for individual Generators would be different owing to the differences in their heat rate makes it difficult to compute a single Beta value for all Generators. Even if we assume a uniform heat rate, the market asset that correlates with the electricity and gas prices is not known. If there exists a derivative market for the electricity industry, the risk premiums are already embedded in the prices of the derivative assets. Since there is none, it has been assumed for the sake of the analysis that the expected return for the Generator would be the risk-free rate at 10%.

6.4 SENSITIVITY ANALYSIS

The value of the option changes when the following parameters are changed:

1. *Cost of Starts* – As the strike rate is increased, the turbine is run for lesser and lesser number of hours, which also reduces the number of times the turbine has to start up. The Generator loses out earning positive revenue when the strike price is higher than the marginal cost of generation. But there is a mitigating factor in the fact that there is lesser

number of starts and hence a gain in value. The sensitivity analysis gives at what level of start cost the benefit from reduced starts overcomes the disadvantage of lost revenue.

2. *Maintenance Cost* – The average maintenance cost for a mid-sized turbine (greater than 20 MW capacity but less than 60 MW) is at present \$6. If for some reason, this should change, it affects the revenues and hence the value of the option. Since this is directly tied to the generation hours, the value of option increases as maintenance cost/hour increases.
3. *Heat Rate* – This is a crucial parameter for determining the Generator's profits. The higher the heat rate, more gas is consumed per MWh of electricity. So, a higher heat rate increases the cost and hence the strike has to be set at a higher level. By running the simulation for various heat rates, the strength of this parameter's influence on the Generator's profits has been determined.
4. *Turbine output and Efficiency* – Turbine efficiency is the inverse of the heat rate or in other words, the higher the heat rate, the lesser is the efficiency. Hence, we need not test explicitly for the effect this has on the cash flows. But the efficiency is linked to the turbine's size. By changing the efficiency, the effect of the turbine's size on the cash flows has been tested.

6.5 BOOTSTRAPPING AND SCENARIO ANALYSIS

The final analysis is an earnings scenario analysis for a simple-cycle gas turbine Generator in Alberta. The scenarios have been created by bootstrapping the actual spark spread data assuming three different growth rates. If we had a market price for the spark spread option that the Generator holds, there would be no need to assume any growth rates since all the information would be embedded in the price of the option. Since there is no market for such derivatives in Alberta, and since the prices in other markets cannot be used for Alberta Generators, it has been necessary to assume certain growth rates. The scenarios include the worst case scenario of negative growth, a neutral case of no growth and a third scenario of positive growth in spark spread.

Chapter 7 – Some Descriptive and Analytical Statistics

It would be helpful to look at the characteristics of the electricity and gas prices over the period under consideration (Jan 1, 1997 – June 30, 2000) and their co-movements, in order to appreciate the results of the simulation. Section 7.1 is a descriptive statistical analysis of the pool prices followed by that of the gas price and its relationship with the pool price in section 7.2.

7.1 CHARACTERISTICS OF POWER POOL OF ALBERTA'S ELECTRICITY PRICES

Electricity prices in Alberta have been steadily rising over the past three years. In 1997, the average price for the year was $20.40 while in 2000 the average was $70.38. While averages could be distorted by extreme values, the median shows a better picture of the price distribution. From $19.91 in 1997, the median pool price reached $44.12 in 2000. The fact that the pool price rose in excess of $100 as many as 438 times in the 6-month period of Jan-June 2000 as compared to only 12 times in the whole year of 1997 is proof to the fact that the pool prices have been tumultuous in recent times. Table 7.11 summarizes the descriptive statistics of pool price between 1997-2000.

Table 7.11: Pool Price Statistics

Pool Price	*1997*	*1998*	*1999*	*2000*
No of times >100	12	93	305	438
No of times >500	2	3	34	47
Average	20.40	33.02	42.74	70.38
Median	19.91	27.75	32.26	44.12
Minimum	3.68	5.15	5.76	5.84
Maximum	765.50	999.50	998.00	995.00

FIGURE 7.11: MONTHLY MEDIAN POOL PRICE – JAN '97-JUNE 2000

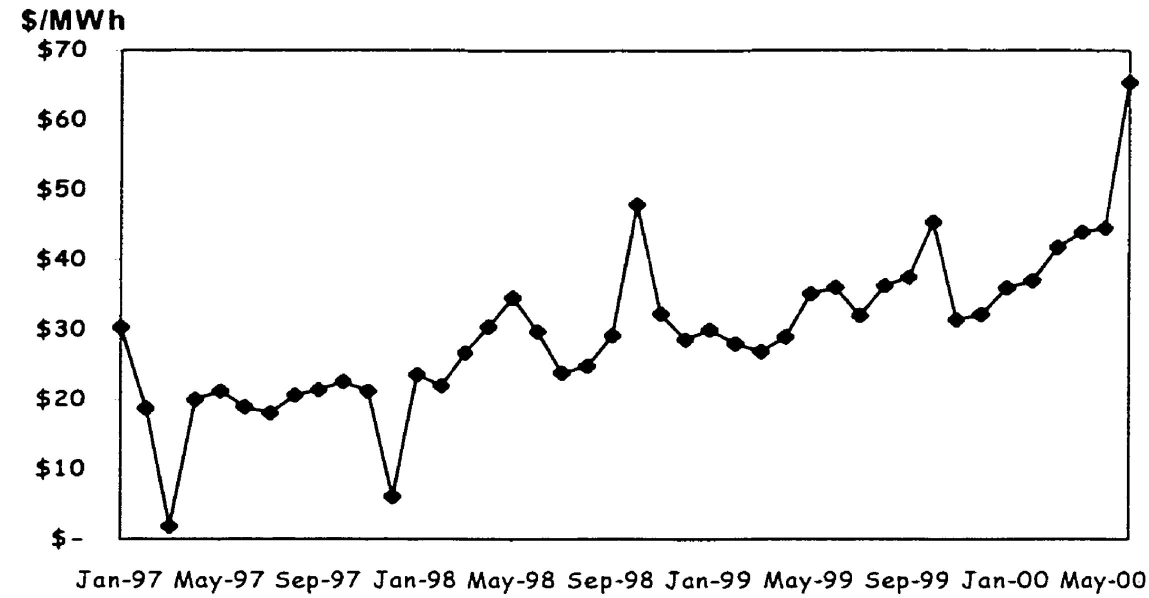


Figure 7.11 illustrates the median pool price over time. Though there are a lot of monthly ups and downs and a tendency to stay higher during summer months, a definite seasonal pattern doesn't seem to exist. However, there is a distinct upward trend over time.

FIGURE 7.12: POOL PRICE-MONTHLY HIGH, LOW, AVERAGE - 1997

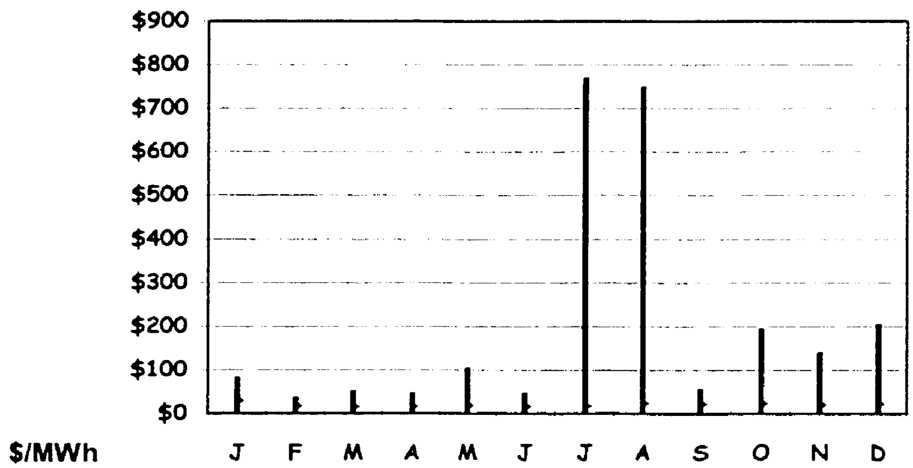
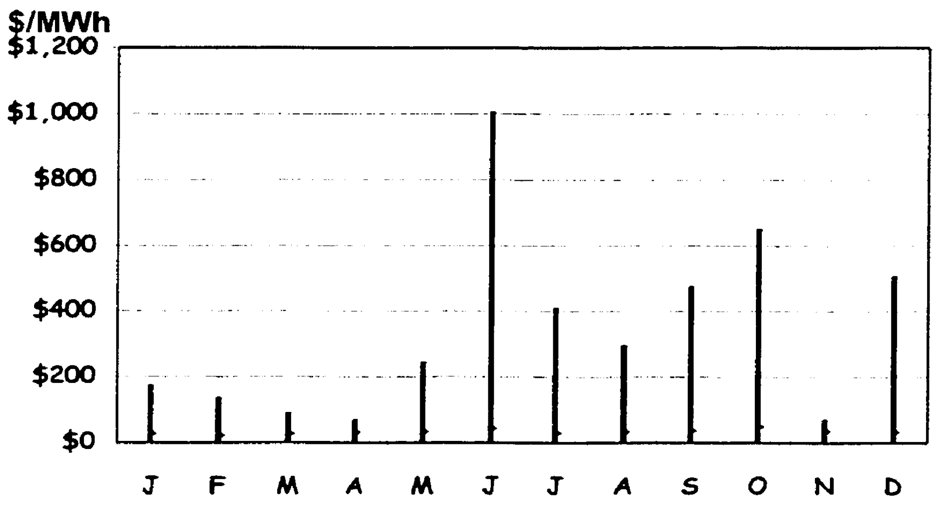


FIGURE 7.13: POOL PRICE – MONTHLY HIGH, LOW, AVERAGE - 1998



The monthly average pool price stayed in the $15-$30 range in 1997 while it was between $20-$50 in 1998. Not only did the average fluctuate wider in 1998 but the spikes in the price have been much more regular in 1998 than in 1997, as can be seen from Figures 7.12 and 7.13.

FIGURE 7.14: POOL PRICE – HIGH, LOW, AVERAGE – 1999

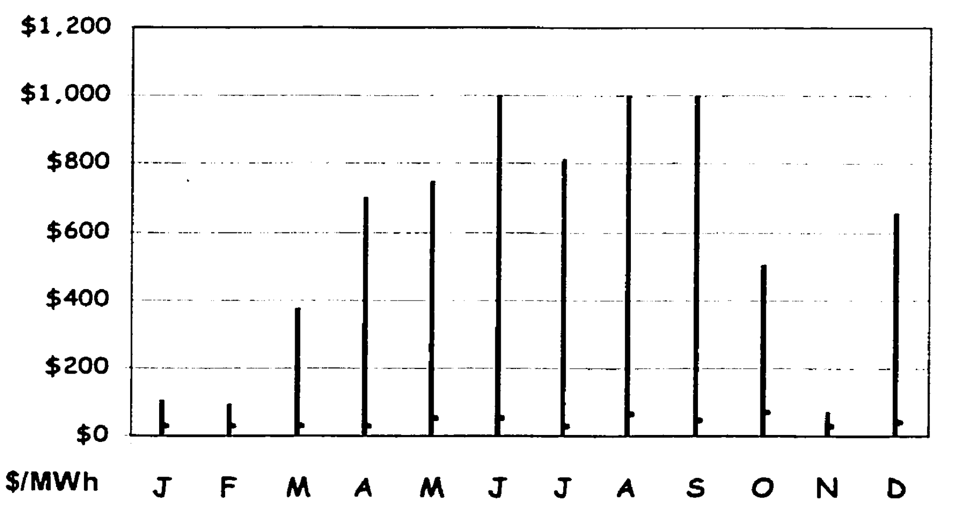
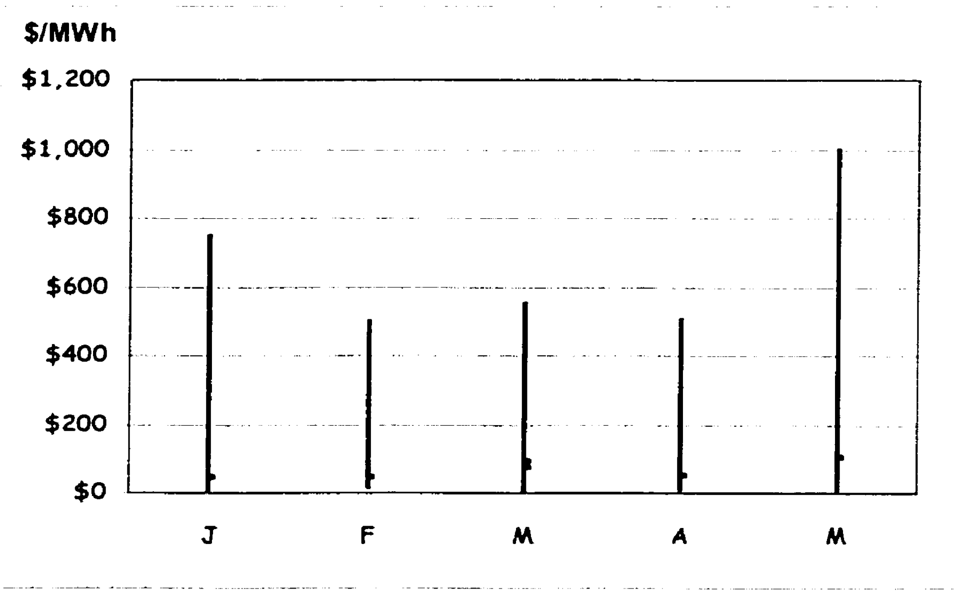
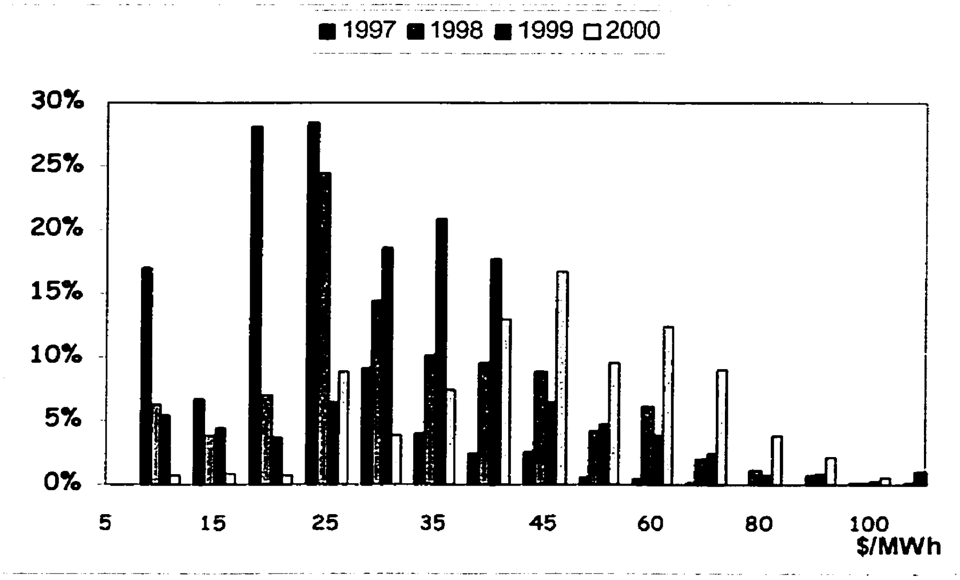


FIGURE 7.15: POOL PRICE – HIGH, LOW, AVERAGE - 2000



The pool price exceeded $200/MWh in 9 out of the 12 months in the year 1999, as seen in Figure 7.14. The average price also fluctuates from month to month a great deal and the reason for this could be the spikes that occur during those months.

FIGURE 7.16: POOL PRICE % FREQUENCY HISTOGRAM



The year 2000 was characterized by still higher pool prices that the averages for every month of the year was more than \$50 and for June 2000, it was as high as \$106/MWh.

Figure 7.16 gives the histogram for percentage frequencies of Pool Price for the years 1997-2000.

It can be seen that the bars of the histogram, representing the % occurrence of the pool price, is taller in the \$10-\$25/MWh for year 1997 while for year 2000, the bars are taller in the region above \$40/MWh. The tallest bar shifts from \$25/MWh for year 1997 and 1998 to \$35/MWh in year 1999 and \$45/MWh in 2000. This clearly indicates that the pool price has had a gradual and steady shift towards higher levels over the years.

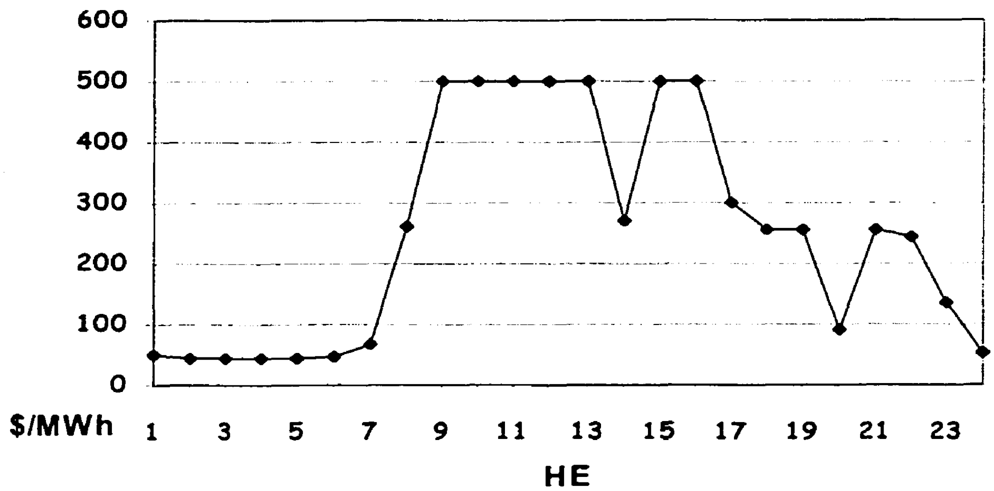
TABLE 7.16: POOL PRICE – REVERSE CUMULATIVE FREQUENCY

% of times	*1997*	*1998*	*1999*	*2000*
<10	32	54	56	112
10	30	52	54	92
20	26	42	42	65
30	23	35	37.5	57
40	21	32	35	49
50	20	28	32	44
60	18.5	25	30	41
70	17	23	28	38
80	12	21	25	34
90	6	15	16	25
100	4	4	4	7

The Power Pool of Alberta, in their Annual Reports, depicts the pool price statistic in the form as in Table 7.16. The table gives what percentage of time the pool price stayed in a particular price range. The first row gives what the pool price was for less than 10% of the time in each year. While in 1997, the price was greater than \$32 for only 10% of the time, in 1999 the price was greater than \$32 for 50% of the time and 80% of the time in year 2000. We can also note that there is not any significant difference in the distribution of the pool price between the years 1998 and 1999 whereas, there is a significant difference between 1997 and 1998 and between 1999 and 2000. The pool price seems to have jumped up in

1998 and more or less held its level through 1999 at which point it has jumped up again in a leap into 2000.

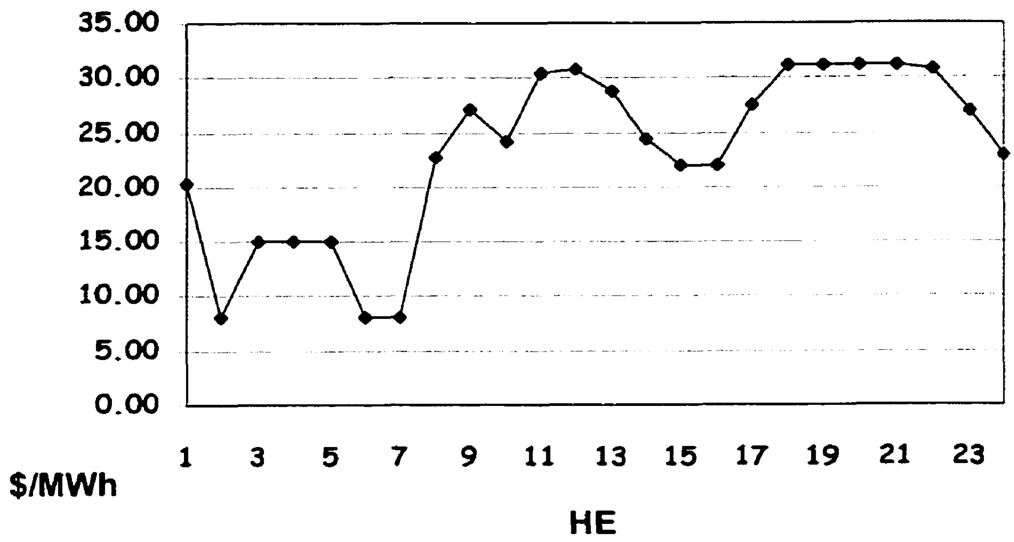
FIGURE 7.17: INTRA-DAY POOL PRICE 2/1/97



Other than the trend and seasonality of pool price over time, there is also the factor of intra-day pool price changes. Each 24 hour period follows a set pattern which is sometimes altered by sudden demand changes or unexpected unit shut downs. Figures 7.17 and 7.18 chart the pool prices on two randomly picked days for all 24 hours of the day. It can be observed that the pool price stays lower during hours 24 to 7 and then begins to rise when demand increases and gradually declines as hour 24 is reached.

Though the intra-day pool price movements can be explained by system load and unit shut downs, the trend over time requires more than demand-supply balance as an explanation. The next choice is to look for the influence from the cost side and the next section explores the relationship between natural gas price and pool price.

FIGURE 7.18: INTRA-DAY POOL PRICE 4/14/00



7.2 RELATIONSHIP OF ALBERTA ELECTRICITY PRICE WITH NATURAL GAS PRICE AND THE SPARK SPREAD

Figures 7.21 through 7.24 charts the daily closing price of natural against the daily average pool price for the years 1997-2000. From the charts, we can see that the pool price tends to follow the trend in natural gas prices. But the pool price lines have a lot more noise than the gas price trace and it makes comparisons slightly difficult. To eliminate some of the noise from the pool price, the data was filtered down to chart the monthly and weekly closing prices. Figure 7.25 traces the daily closing price of natural gas against the daily closing pool price (HE-24) for every 7th day in the data. In this chart, it can be observed that the pool price exhibits a strong tendency to follow the gas price. Figure 7.26 charts the closing price of gas against the closing price of electricity for the last day of every month. In this chart, the two lines almost track the same course but for the spikes in the pool price line. This may be due to the fact that we chose a particular day in the month to depict the relationship. In general, we can agree that the pool price is heavily influenced by the price of natural gas. The fact that the Pearson's correlation coefficient figure for the two series of data is 0.31

confirms this. The correlation coefficient is higher at 0.51 for the daily natural gas price and daily average pool price.

TABLE 7.21: AVERAGE NATURAL GAS PRICE 1997-2000

	1997	*1998*	*1999*	*2000*
Average Gas Price	1.82	2.06	2.91	4.01

Average gas prices have risen from 1.82 in 1997 to 4.01 in 2000 and this increase is partly responsible for the upward trend in electricity prices as well. The other part is the intra-day movement of the pool price, which can be explained by the fluctuations in demand and supply of electricity.

TABLE 7.22: SPARK SPREAD – KEY STATISTICS

	1997	*1998*	*1999*	*2000*
Average Spark Spread	2.45	12.34	13.54	30.38
Median Spark Spread	0.98	8.71	4.08	9.13

Table 7.22 lists the average and median values of spark spread in each year under consideration. Though the average spark spread has increased from year to year, the median spread increases in 1998 from the previous year and drops again in 1999 to rise up back in 2000. The reason for this is that, the averages are influenced by extreme values in the pool price while the median is a better reflection of the distribution of the values around it. Though the pool price has risen steadily from year to year, the sharp increase in gas prices from year 1998 to '99 is the reason why the median spark spread dropped in 1999. Gas prices did increase again in 2000 but the pool price increased faster than that and that is the reason why the median spark spread climbed up in 2000. This can be confirmed from Figures 7.21 through 7.24.

FIGURE 7.21: DAILY GAS PRICES VS AVERAGE POOL PRICE 1997

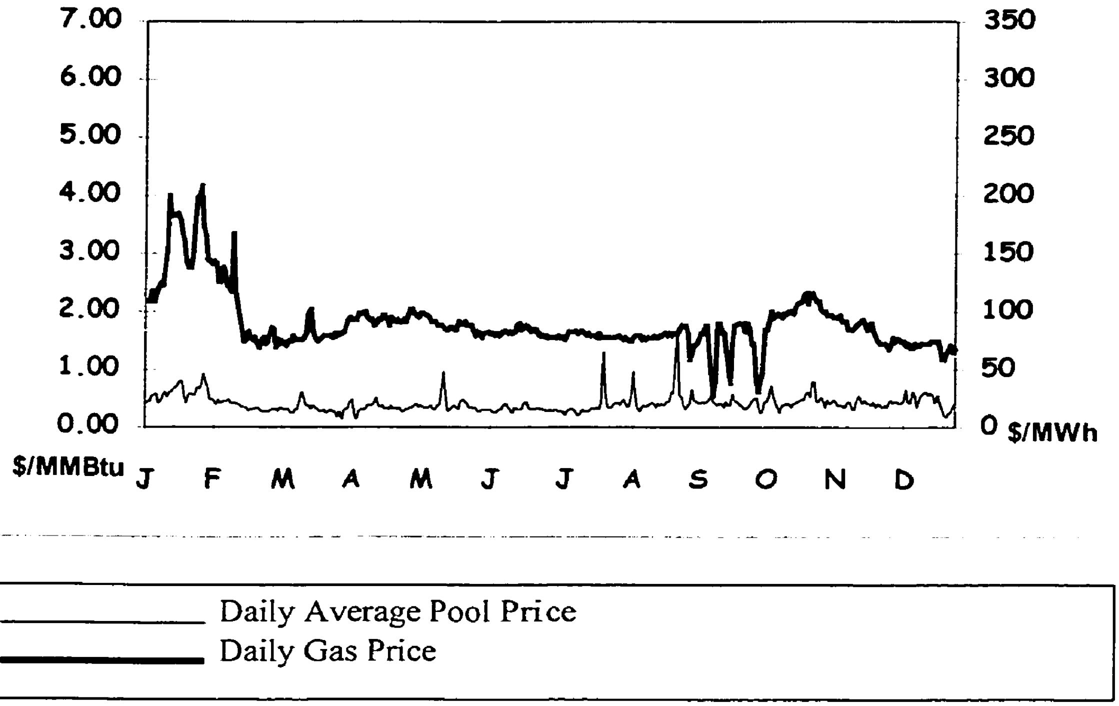


FIGURE 7.22: DAILY GAS PRICES VS AVERAGE POOL PRICE 1998

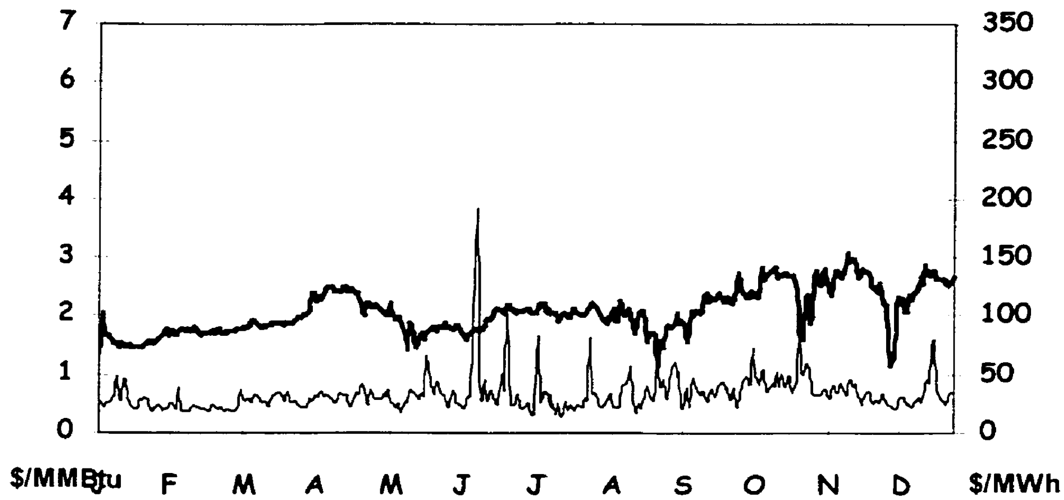


FIGURE 7.23: DAILY GAS PRICES VS AVERAGE POOL PRICE 1999

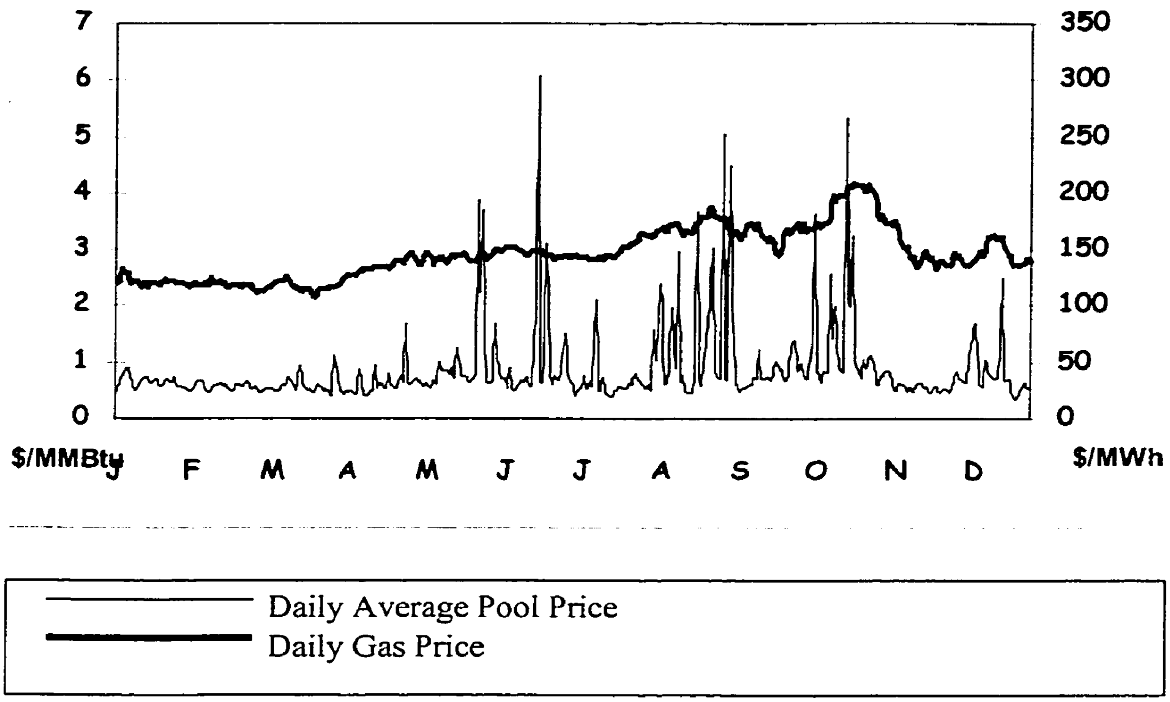


FIGURE 7.24:DAILY GAS PRICES VS AVERAGE POOL PRICE 2000

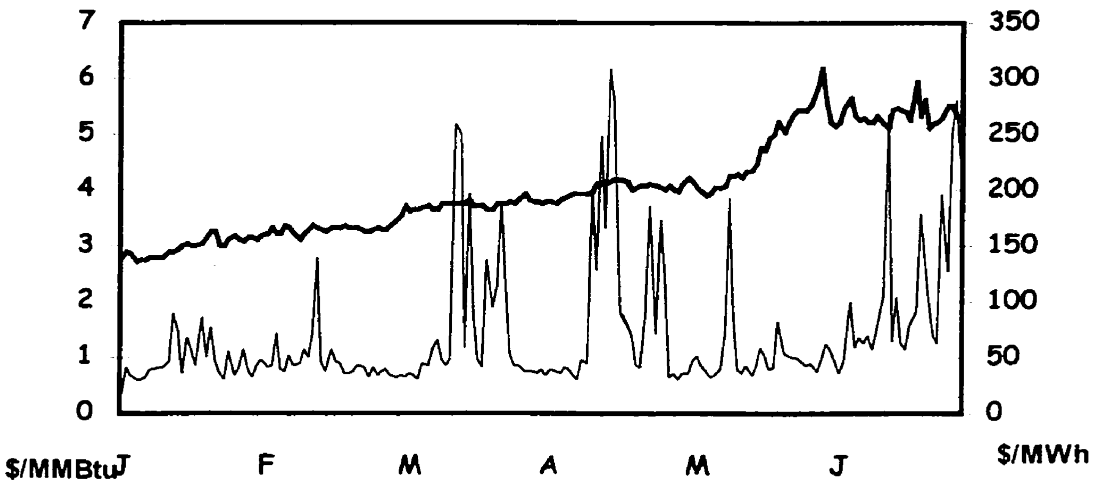


FIGURE 7.25: WEEKLY CLOSING ELECTRICITY VS GAS PRICES 1997-2000

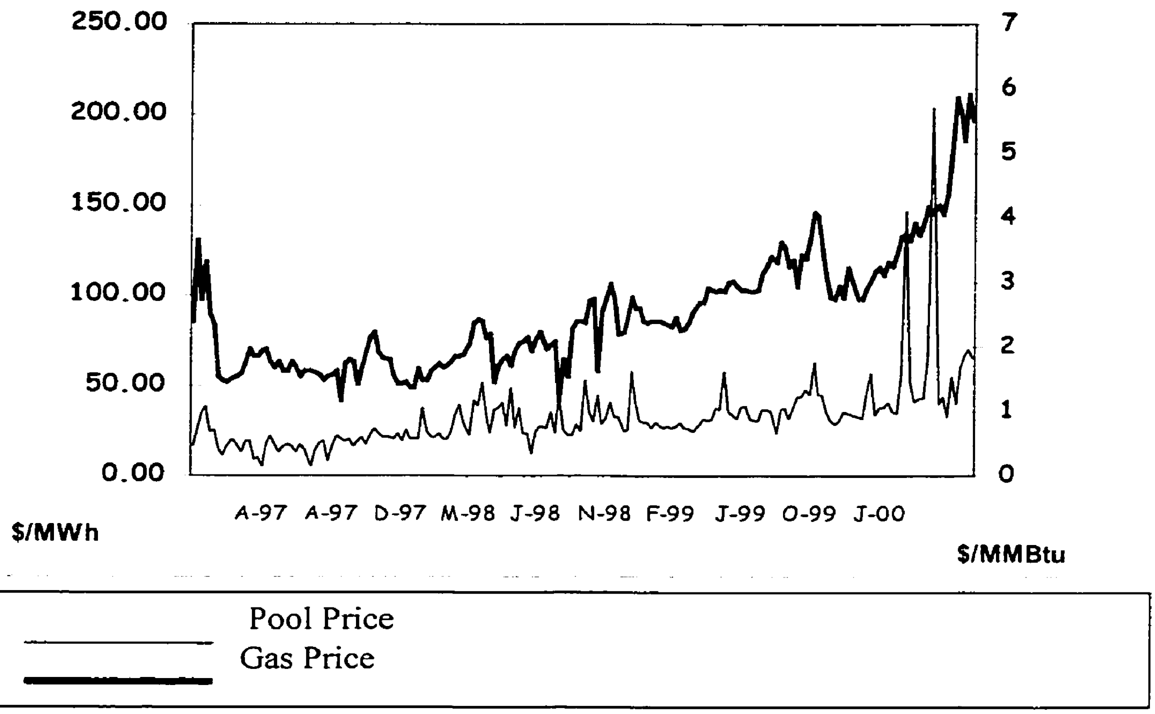


FIGURE 7.26: MONTHLY CLOSING ELECTRICITY VS GAS PRICES 1997-2000

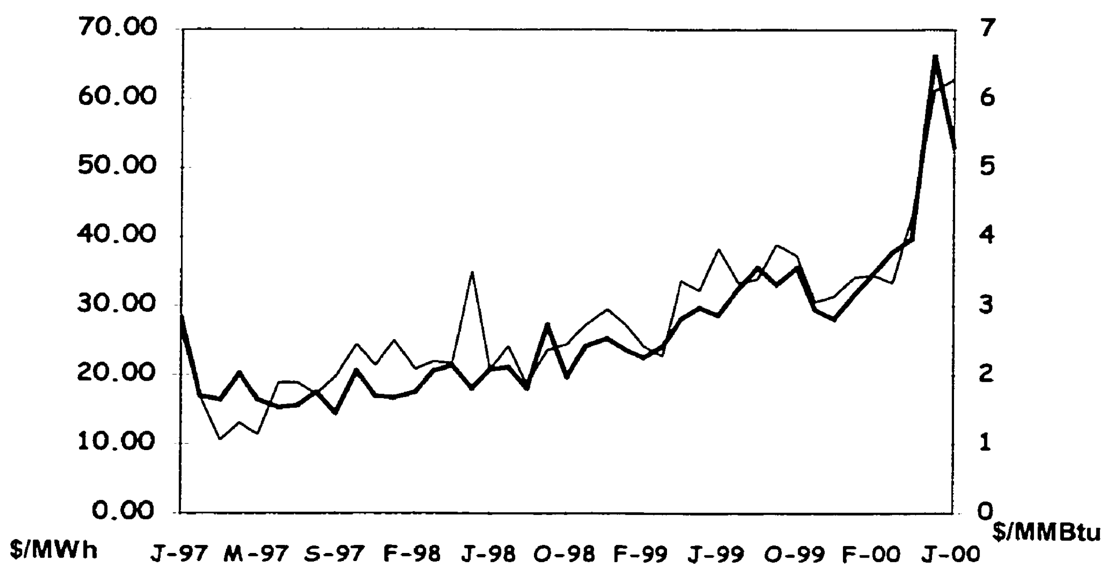
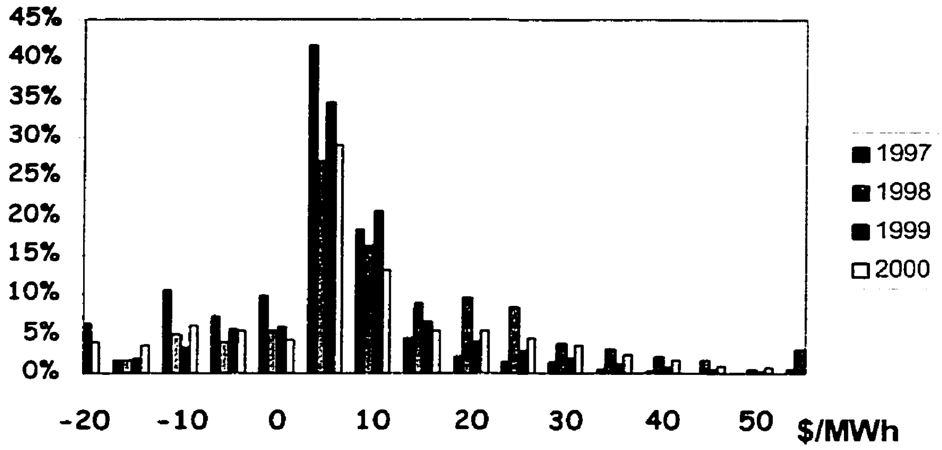


TABLE 7.23: SPARK SPREAD – REVERSE CUMULATIVE FREQUENCIES

	$/MWh			
% of times	*1997*	*1998*	*1999*	*2000*
0	11	32	24	70
10	10	30	22	50
20	7	21	12	24
30	5	16	8	14
40	3.5	10	6	8
50	3	7	4	5
60	2	5	3	3
70	0	3	2	2
80	-5	0.5	-2	-4
90	-11	-6	-12	-13
100	-20	-16	-30	-33

FIGURE 7.27: SPARK SPREAD % FREQUENCY HISTOGRAM



The reverse cumulative frequencies (Table 7.23) for the spark spread also exhibit a similar pattern like that of the pool price. But there is not a significant difference for almost 70% of the time between the distributions for the different years. For only the remaining percentage of times that the values differ significantly. For 0-10% of the time, the spark spread was only above $11/MWh in 1997 while in 2000 it was above $70/MWh for the same percentage of time. But for 70% of time, the spark spread/MWh exceeded $0 in 1997 and exceeded $2 in 2000 and hence the bulk of the distribution is similar in all the years while the tails vary a lot. In the histogram in Figure 7.27, the same phenomenon is evident from the height of the bars, which remain similar most of the time for all the years. This could be explained by the reason that while pool prices jumped significantly between 97-98 and 99-2000, so did the gas price. Hence the spark spread hasn't moved that much though there is a slight upward trend over the years. There is a large difference between the yearly distribution for 40% of the time and this is owing to the sudden high spikes in pool prices that have increased with time (Table 7.11).

Chapter 8 – Simulation Results and Implications

This chapter discusses the results from the simulation and also the sensitivity of the option value to various input parameters. The chapter takes a step-by-step approach to discussing the effects of the various costs of the Generator. Section 8.1 summarizes the total spark spread earnings of the Generator under the two types of scheduling. Section 8.2 explains the variations in the two types of scheduling and the difference it makes to the total spark spread earnings of the Generator. The next section introduces the hours of generation and maintenance cost and the difference this makes to the earnings. Section 8.4 and 8.5 deal with the starts and its cost and the value of the flexibility option. Section 8.6 breaks up the option value to the individual years and explains the trend with the help of movements in spark spread. The next section analyzes the sensitivity of earnings to various heat rates and Section 8.8 evaluates the EVA for different turbine models. The final section consists of simulation of the earnings stream of a Generator over its lifetime, generated by the method of bootstrapping based on actual spark spread.

8.1 SPARK SPREAD EARNINGS AND DIFFERENCES IN UNIT SCHEDULING

Calculating the spark spread is the first step of the analysis. Since the spark spread is the difference in the pool price per MWh and gas cost for the same, it is the marginal revenue per unit of output for the Generator. Other variable costs would be maintenance and cost of starts, which are discussed in later sections of this chapter.

The Generator has an inherent option in the gas turbine unit that electricity can be generated and sold only when the spark spread exceeds the marginal cost of generation. The Generator is then insulated from negative spark spread and hence negative cash flows. But when the Generator submits the unit's offer to the Power Pool, it has to be done on the basis of pool price alone and not the spark spread. So, the Generator can add the strike value to the gas cost and submit that as the offer price for electricity. But the offers have to be submitted one day prior to the day of supply, when the gas price is also not known. Hence, for the sake of analysis, it has been assumed that the Generator submits a bid based on the previous day's gas price. Also, since the turbine takes up to 20 minutes to start up, scheduling is based on the system controller's forecast price. Let this be called hour-ahead scheduling. But the Generator's cash flows are based on actual gas price and actual posted pool price for the hour of generation. Since the forecast pool price could be different from the actual pool price, it would be interesting to see if there would be any difference in the Generator's cash flows if the scheduling were also somehow done on the basis of actual prices. This shall be termed as real-time scheduling. The difference this makes to the unit's revenues is compared in Table 8.11.

The spark spread for every hour of the 3-½ year period was calculated from the pool price and natural gas price, with the heat rate at 10 MMBtu/MWh. The purpose was to calculate the cash fl'ows of a gas turbine unit under two circumstances. 1. All 24 hours of everyday except for planned maintenance stops and 2. Only when the spark spread exceeds a strike rate.

Table 8.11 lists the total revenue minus the total gas cost, in other words, total spark spread earned per mega-watt of generation in the years 1997 –June 2000 under the two kinds of scheduling and for various strike rates. The last column shows the percentage gain/loss in the PV of total spark spread earned, over the PV of total spark spread earned if run all 24 hours. This is a measure of the real option value of the flexibility to start and stop within the day.

It can be noted that the spark spread decreases with an increase in strike rate but at lower strike rates, there is a gain as compared to the total spark spread earned if the turbine is run all 24 hours.

Under real-time scheduling, there is gain in the total spark spread earned up till a strike rate of $10 while under hour-ahead scheduling, the value turns negative at a strike rate of $9 itself. Across all strike rates, there is 2-3% increase in value with real-time scheduling over hour-ahead scheduling. The next section analyzes the differences in these two scheduling that might explain this phenomenon.

TABLE 8.11: TOTAL SPARK SPREAD EARNINGS AT VARIOUS STRIKE RATES

	Hour-ahead Scheduling					
Strike Rate	*1997*	*1998*	*1999*	*2000*	*Present Value*	*% gain over 24 hr operation*
24 hrs	$21,674	$108,107	$119,297	$133,041	$423,925	
6	$28,326	$107,866	$131,213	$139,420	$451,975	6.62%
7	$25,261	$105,607	$128,049	$138,866	$441,127	4.06%
8	$22,293	$103,467	$124,939	$137,745	$430,045	1.44%
9	$20,651	$101,443	$122,379	$136,388	$421,238	-0.63%
10	$19,564	$99,596	$120,330	$135,006	$413,919	-2.36%
11	$18,202	$97,216	$118,552	$133,989	$406,255	-4.17%
12	$17,044	$95,764	$116,975	$133,514	$400,746	-5.47%
13	$16,292	$93,726	$115,919	$132,010	$394,614	-6.91%
14	$15,687	$92,355	$114,703	$131,431	$390,233	-7.95%
15	$15,225	$89,879	$113,384	$130,985	$384,726	-9.25%
16	$14,504	$87,135	$111,432	$130,103	$377,416	-10.97%
Real-time Scheduling						
6	$29,679	$110,222	$133,077	$141,379	$460,635	8.66%
7	$26,437	$108,277	$129,725	$140,686	$449,587	6.05%
8	$24,005	$106,483	$127,081	$139,720	$440,304	3.86%
9	$22,106	$104,303	$124,659	$138,690	$431,445	1.77%
10	$20,779	$102,305	$122,568	$137,906	$424,176	0.06%
11	$19,254	$100,278	$121,072	$137,107	$417,249	-1.57%
12	$18,139	$98,668	$119,343	$136,684	$411,492	-2.93%
13	$17,440	$96,956	$118,269	$135,961	$406,587	-4.09%
14	$16,780	$94,957	$116,884	$135,542	$401,346	-5.33%
15	$16,155	$92,505	$115,650	$135,098	$395,746	-6.65%
16	$15,393	$89,914	$113,860	$134,326	$388,856	-8.27%

8.2 REAL-TIME VERSUS HOUR-AHEAD SCHEDULING

The two types of scheduling, real-time and hour-ahead, are based on actual posted pool price and system controller forecast price, respectively. If exact information as to the future state of nature were available to Generators, it would be possible to schedule exactly like real-time. But it is not so and hence their scheduling is based on forecasts and hence there are differences in scheduling and earnings under the two cases.

Differences in scheduling may arise in two circumstances: one would be when the forecast price is less than strike price and hence the turbine is not on but the actual price is high enough for the turbine to be on. The other case is when the forecast price is higher than strike price and the turbine is on but the actual is lower than the strike price. In the first case (On actual, off forecast), the turbine would lose out on earning positive revenue flow but the loss is only the difference between the strike price and the actual price. In the second case, there is negative revenue as the actual pool price is lesser than the strike price. In either case, there is a loss in value for the Generator. Table 8.21 lists the number of hours there is a difference in the two scheduling, in either ways.

TABLE 8.21: NO OF HOURS OF DIFFERENCE IN REAL-TIME VS HOUR-AHEAD SCHEDULING

Strike		*On actual*	*On forecast*	*Total mismatch*	
		Off forecast	*Off actual*		*% of total hours*
$	*6*	1157	882	2039	6.71%
$	*7*	1062	886	1948	6.41%
$	*8*	1031	742	1773	5.83%
$	*9*	908	667	1575	5.18%
$	*10*	826	634	1460	4.80%
$	*11*	767	551	1318	4.34%
$	*12*	701	519	1220	4.01%
$	*13*	718	520	1238	4.07%
$	*14*	671	546	1217	4.00%
$	*15*	656	540	1196	3.94%
$	*16*	635	507	1142	3.76%

There seem to be more instances of the first case, on actual and off forecast, than the second case, under all strike prices. This is indicative of the fact that the forecast price has been less than the actual price more number of times than vice-versa. This is quite understandable as sudden demand spikes and unexpected unit shut downs lead to unexpected price increases.

The last column in Table 8.21 gives the total mismatch hours as percentage of total hours of scheduled availability in the time period under consideration. This percentage decreases as the strike price increases, which indicates that there are lesser errors in forecasting higher prices. What is interesting though is that, from Tables 8.21 and 8.11, at higher strike prices, the number of instances of incorrect scheduling decreases but the loss in value increases. This means that, at higher strike prices, every error is costlier than in lower strike prices.

The percentage error in scheduling in all the years is only a maximum of 6.7% at a strike price of $6. At this strike price, the error percentage in the individual years is listed in Table 8.22. It can be seen that the percentage of error does not vary very much from year to year and stays around the 6-7% level. The average pool price in these years has moved up steadily from a low of $20.40/MWh to $70.40/MWh. It does seem that the error in forecasting actual pool price does not depend upon the level of the pool price.

TABLE 8.22: HOUR-AHEAD VS REAL-TIME SCHEDULING @ $6 STRIKE

Year	*On actual Off forecast*	*On forecast Off actual*	*Total mismatch*	*% of total hours*	*Average Pool Price*
1997	308	214	522	6.01%	20.4
1998	338	246	584	6.73%	33.02
1999	348	290	638	7.35%	42.74
2000	163	132	295	6.82%	70.38

The forecast error leads to a 2-3% loss of value in terms of total spark spread earned, across all strike prices, as was seen in Table 8.11. But the number of "on actual, off forecast" is higher than "on forecast, off actual" at all strike prices. This would imply that the hours of generation under hour-ahead scheduling would be lower than under real-time scheduling, which means that there is a gain in terms of savings in maintenance cost. But at a rate of $6/hour of operation as maintenance charge, the reduced hours should be a lot more to compensate for the loss in spark spread. Looking at the values for the strike rate of $6, there is a saving of $1650 per MWh in terms of maintenance charge (275 hours is the difference in generation hours) which is much less than the $8000 plus loss in spark spread that could have been earned.

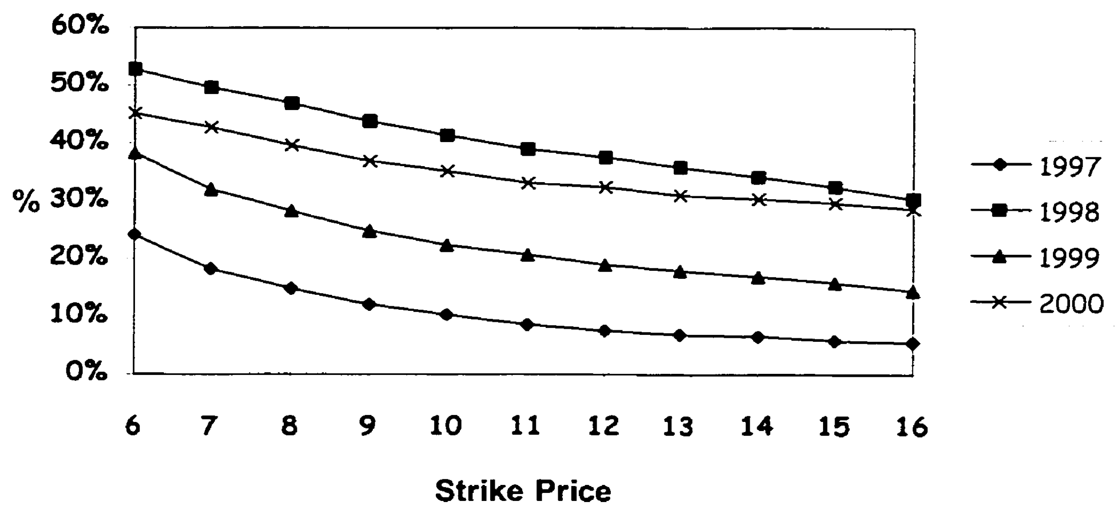
Hence, it can be said that there is a definite loss in value owing to information insufficiency. But, the loss is only of a small magnitude and can be ignored for the purpose of this analysis. For the rest of the analysis, it would be enough to look at the real-time scheduling only.

8.3 HOURS OF GENERATION AND MAINTENANCE COST

Section 8.1 discussed the total spark spread earned by a Generator under various strike prices and it was noted that the spark spread reduces with an increase in the strike price. Since we have already discussed the differences in the two types of scheduling, for all subsequent chapters, we shall only consider the real-time scheduling. Under that, the spark spread at a strike price of $10 dropped below the spread that could have been earned by running all 24 hours. That loss could be compensated by gains in the other variable cost, maintenance cost. Maintenance cost is directly tied to the number of hours of generation and at higher strike prices, the turbine can be expected to run lesser number of hours, which in turn reduces the maintenance cost.

Figure 8.31 depicts the total hours the turbine has been operated at different strike prices as a percentage of total available hours, for each year.

FIGURE 8.31: TOTAL HOURS OF OPERATION AS PERCENTAGE OF AVAILABLE HOURS



In year 1997, the turbine was operated for less than 25% of the time at a strike price of $6 while in year 1998, the turbine has been operated nearly 40% of the time even at a strike price of $16. The reason for this is that the average pool price has increased more than the increase in gas cost. But the percentage dropped in years 1999 and though there is an increase in year 2000 over year 1999, it is still less than the total hours run in year 1998. This has happened because in years 1999 and 2000, though the average pool price increased, so did the average gas price and hence the spark spread did not rise that much. But in year 1998, the pool price increased by a leap while the gas price did not increase as much. The median spark spread in 1997 was 2.93, increased to 6.8 in 1998, dropped back to 3.86 and went back up to 4.52, still less than that in 1998. This is the exact pattern in generation hours, which is in fact based on the spark spread.

The highest percentage hour of production was in 1998, which was only slightly more than 50% at a strike price of $6. This implies that there would be savings in maintenance cost over the option of running the turbine all 24 hours. But would this be enough to offset the losses in spark spread? Table 8.31 provides the answer.

TABLE 8.31: HOURS OF GENERATION AND MAINTENANCE COST FOR VARIOUS STRIKE PRICES

	Spark Spread	*Loss/Gain in Spark spread*	*Hours*	*Maintenance Cost*	*Savings in maint.cost*	*Total Gain*
24 hrs	$423,925		30368	$215,591		
Strike						
$ 6	$460,635	$36,710	11955	$83,667	$131,924	$168,634
$ 7	$449,587	$25,662	10538	$73,494	$142,098	$167,760
$ 8	$440,304	$16,379	9491	$66,050	$149,541	$165,920
$ 9	$431,445	$7,519	8601	$59,767	$155,824	$163,344
$ 10	$424,176	$251	7950	$55,187	$160,404	$160,655
$ 11	$417,249	($6,676)	7395	$51,242	$164,349	$157,673
$ 12	$411,492	($12,433)	6970	$48,232	$167,359	$154,926
$ 13	$406,587	($17,338)	6633	$45,875	$169,716	$152,378
$ 14	$401,346	($22,579)	6302	$43,543	$172,048	$149,469
$ 15	$395,746	($28,179)	5975	$41,233	$174,358	$146,179
$ 16	$388,856	($35,069)	5593	$38,564	$177,027	$141,959

Table 8.31 gives the PV of total spark spread earned, the total hours of generation, total maintenance cost and the resulting savings across all strike prices. At a strike price of $6, the turbine runs for less than half the total hours available and at a strike price of $16, the

turbine only runs for 1/5 of the time. As a result, there is a huge saving in maintenance cost, which is tied to hours of operation, and more than makes up for the loss in spark spread.

TABLE 8.32: SAVINGS FROM LOWER MAINTENANCE COST

	Spark Spread less Maintenance Cost	*% gain over 24 hour operation*
24 hrs	$208,334	
Strike		
$ 6	$376,968	80.94%
$ 7	$376,094	80.52%
$ 8	$374,254	79.64%
$ 9	$371,678	78.40%
$ 10	$368,989	77.11%
$ 11	$366,007	75.68%
$ 12	$363,260	74.36%
$ 13	$360,712	73.14%
$ 14	$357,803	71.74%
$ 15	$354,513	70.17%
$ 16	$350,292	68.14%

At a strike price of $6, there is a gain of over 80% in value over the 24-hour operation, as can be seen from Table 8.32. This gain decreases as the strike price is increased which means that the loss in spark spread by setting a higher hurdle, is not equally offset by savings in maintenance cost. This is because, at a lower strike price, the Generator earns all that could have been earned from setting a higher strike price, plus a positive cash flow at lower price levels, if the price is greater than the strike price. This would hold true only when the strike price is greater than the maintenance cost/hour. If the strike price is less than the hourly maintenance cost, for every hour of running the turbine, the Generator makes a loss. Since, we have assumed the maintenance cost to be $6/hour, the unit makes more at a strike price of $6 than at a strike price of $7 or $16 or any other price higher than $6.

8.4 HOURS OF GENERATION AND NUMBER OF STARTS

The option of running the turbine as and when the spark spread exceeds a strike price offers savings in terms of maintenance cost but incurs gas cost every time the turbine is shut off and restarted, when there is no revenue. To analyze the relationship between the generation hours, which decreases with increase in strike price, and the number of starts, would throw some light on the pattern of generation.

FIGURE 8.41: TOTAL NUMBER OF STARTS AT DIFFERENT STRIKE PRICES

Figure 8.41 shows a curious pattern in the number of starts of the turbine at different strike prices. In years 1997 and 1999, the starts decrease as the strike price decreases, as one would expect. But in years 1998 and 2000, the starts remain almost at the same level at all strike prices. The year 2000 has only 6 months of prices in it and hence the actual number of starts is less but the pattern is more critical here. Referring back to Figure 8.31, we see that the percentage of time the turbine has been operated, of the total available hours, is higher for the years 1998 and 2000, than for 1997 and 1999, and also flat across the strike prices. In 1998, the hours of generation, at a strike price of $16, is 57% of the hours of generation at a strike price of $6. That is, of the 4593 hours that the spark spread crossed $6, it also crossed $16 for more than half the time. Hence, the number of starts is more or less constant across all strike prices. The case is similar with the year 2000. The spark spread crossed $16 63% of the time that it crossed $6. This figure for years 1997 and 1999 are only 22% and 38% respectively. Now if the spark spread price for 8 consecutive hours were 8.5, 6.2, 7.3, 6.8, 6.9, 8.8, 12.5 and 4.2, at a strike price of $6, the turbine would have run for 7 hours and started just once. At a strike price of $7, the turbine would have been run 4 hours and started 3 times. So, as the strike price in increased, if the hours of generation vary a lot, then the number of starts would change a lot too.

8.5 COST OF STARTS AND VALUE OF FLEXIBILITY OPTION

For aero-derivative gas turbines, there is no added maintenance cost on account of frequent start-ups and shutdowns. However, there is the cost of fuel for every start-up. The turbine takes about 20 minutes to reach optimal voltage and full generation capacity. There is a burning of fuel during this time, the rate of which varies according to the turbine design and capacity. The more number of starts means that there is a higher cost of starts. If the maintenance cost is say $6, without including cost of starts, the strike value for spark-spread would be $6. Let us assume that the turbine has to start up 200 times a year at this strike and 150 times with the strike set at $7. If the reduction in revenue from setting a higher strike is off set by the reduced starts and its cost, then the higher strike price may be the optimal exercise price of the option.

TABLE 8.51: START COSTS AND OPTION VALUE/MWh

Strike	*Spark Spread - Maint. Cost*	*No. of Starts*	*Value of Option per MWh @ different cost per start*							
			$2.00	*$4.00*	*$6.00*	*$8.00*	*$10.00*	*$12.00*	*$14.00*	*$16.00*
24 hrs	$208,334									
$ 6	$376,968	1328	$165,978	$163,322	$160,666	$158,010	$155,354	$152,698	$150,042	$147,386
$ 7	$376,094	1271	$165,218	$162,676	$160,134	$157,592	$155,050	$152,508	$149,966	$147,424
$ 8	$374,254	1211	$163,498	$161,076	$158,654	$156,232	$153,810	$151,388	$148,966	$146,544
$ 9	$371,678	1164	$161,016	$158,688	$156,360	$154,032	$151,704	$149,376	$147,048	$144,720
$ 10	$368,989	1124	$158,407	$156,159	$153,911	$151,663	$149,415	$147,167	$144,919	$142,671
$ 11	$366,007	1110	$155,453	$153,233	$151,013	$148,793	$146,573	$144,353	$142,133	$139,913
$ 12	$363,260	1058	$152,810	$150,694	$148,578	$146,462	$144,346	$142,230	$140,114	$137,998
$ 13	$360,712	1051	$150,276	$148,174	$146,072	$143,970	$141,868	$139,766	$137,664	$135,562
$ 14	$357,803	1028	$147,413	$145,357	$143,301	$141,245	$139,189	$137,133	$135,077	$133,021
$ 15	$354,513	995	$144,189	$142,199	$140,209	$138,219	$136,229	$134,239	$132,249	$130,259
$ 16	$350,292	959	$140,041	$138,123	$136,205	$134,287	$132,369	$130,451	$128,533	$126,615

Since the rate of fuel consumption during the start-up phase is not known, a sensitivity analysis for the option value was performed at various costs per start. If gas costs $1/MMBtu, then at full consumption for 20 minutes, the fuel cost would be $3.33 (1*10*20/60) per start. If gas prices were $5/MMBtu, then at full consumption for 20 minutes, the fuel cost would be $16.70 per start. Hence the analysis has been done for various start costs in the range of $2 to $16.

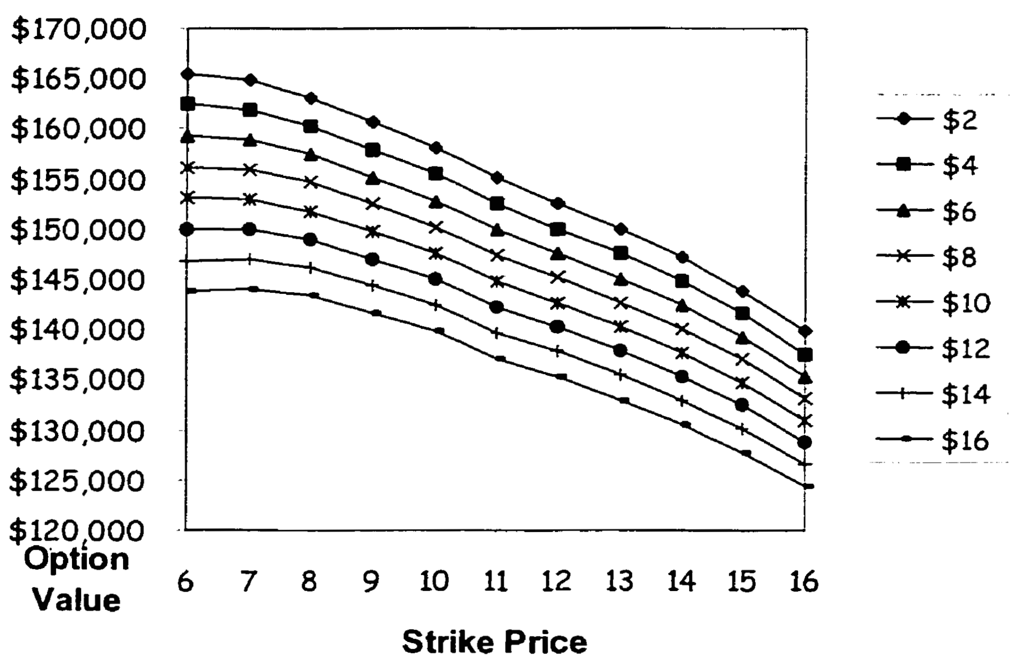
The value of the flexibility option has been calculated as:

Value of Flexibility Option $_I$ = (Spark Spread $_I$ – Maintenance Cost $_I$) – Cost of Starts $_I$ – (Spark Spread $_{24\ hrs}$ – Maintenance Cost $_{24\ hrs}$)

where I is the strike price for the option.

Table 8.51 shows the total number of starts for the turbine during the entire time period under consideration and also the resulting value of the option, for different costs/start. Understandably, the total number of starts reduces, as the strike price is set higher. Also, at the same strike price, the option value decreases as the cost/start increases. But what is interesting is the rate of decline in the option value as the strike price increases. Figure 8.51 illustrates the change in the option value at different strike and cost/start.

FIGURE 8.51: OPTION VALUE SENSITIVITY TO COST/START



In figure 8.51, each line represents a fixed cost per start and traces the change is option value at different strike prices. At each cost/start, the value of the option decreases as the strike price is increased. Since the number of starts and production hours, decrease with an increase in strike price, this indicates that the reduction in maintenance and start cost are not enough to compensate for the loss in value from lower spark spread earnings.

However, at a high cost of $15 or $16/cost, the value of the option is maximized at the strike price of $7 and not $6, as is with the rest of the cases. When the cost/start is sufficiently high, the saving in that cost at higher strike price, compensates for the loss in spark spread earnings together with the savings in maintenance cost. But a cost/start of $16 is only reached when the gas cost is in the region of $5/MMBtu which is quite high. The option values in Table 8.51 have been calculated on the basis that the cost/start is the same throughout the 3-1/2 year period under consideration. Since the average price for gas for this time frame has only been $2.7, the average cost/start would be $9 at which the optimal exercise price is $6. In Table 8.52, the option values at $9/start for the different strike prices have been summarized. The option adds as much as 75% to the earnings of the Generator at this start cost, at a strike price of $6.

TABLE 8.52: PV OF OPTION VALUE AT $9/START

Strike	*PBDIT*	*PV of*	*%*
		Option Value	
24 hrs	$208,334		
6	$365,016	$156,682	75.21%
7	$364,655	$156,321	75.03%
8	$363,355	$155,021	74.41%
9	$361,202	$152,868	73.38%
10	$358,873	$150,539	72.26%
11	$356,017	$147,683	70.89%
12	$353,738	$145,404	69.79%
13	$351,253	$142,919	68.60%
14	$348,551	$140,217	67.30%
15	$345,558	$137,224	65.87%
16	$341,661	$133,328	64.00%

8.6 CORRELATION IN YEAR-WISE OPTION VALUE AND SPARK SPREAD

The underlying asset in the flexibility option available to the Generator is the spark spread/MWh of electricity. The relative movements in the spark spread therefore, affect the value of the option. Table 8.61 compares the year-to-year change in the option value (at strike price $6 and $9 cost/start) to the characteristics of the spark spread.

TABLE 8.61: YEAR-WISE OPTION VALUE AND SPARK SPREAD

	1997	1998	1999	2000	PV
Spark Spread					
*Standard Deviation**	51%	38%	45%	85%	
Average	2.45	12.34	13.54	30.38	
Median	2.93	6.8	3.86	4.52	
PBDIT (24 hours)	$(30,406)	$ 56,027	$ 67,217	$ 107,072	$ 208,334
Option value	$ 43,957	$ 21,053	$ 40,413	$ 18,784	$ 156,682
($6 strike & $9					
Start cost)					
% value of option	145%	38%	60%	18%	75%

* - Standard deviation calculated for day to day change in average spark spread

The option adds value to the project by eliminating the negative spark spread earnings and the percentage gain over the choice of operating all 24 hours, ranges from a high of 145% in year 1997 to a low of 18% in year 2000. As the value of the project fluctuates, so does the option value. The movements in spark spread offer a simple enough explanation for it. As with any option, the value increases as the standard deviation of the underlying asset price increases. The standard deviation of the spark spread changed from 51% in 1997 to 38% in 1998, increased a little to 45% in 1999 and rose sharply to 85% in 2000. The pattern of movement in the value of the option is the same as that except in year 2000 when standard deviation increased but option value dropped. This could be because of the fact that the average spark spread is $30 which makes the option so much in the money that there is not much to be gained from holding an option.

The PV of the earnings and option value indicate that the Generator stands to gain as much as 75% in value by adopting the flexible generation plan.

8.7 SENSITIVITY OF OPTION VALUE TO HEAT RATE

The engine heat rate is a measure of the system's electrical efficiency and is defined as the amount of fuel energy input required to produce 1 megawatt hour of power. A heat rate of 7 would mean that the turbine requires burning of 7 MMBtu of natural gas to produce 1 MWh of electricity. So, the higher the heat rate, the lower is the efficiency of the turbine, which is a ratio of output (electrical energy) to input (heat energy). As the heat rate increases, the input or gas cost per unit of electricity increases. So, for the same pool price and gas cost, the spark spread earned by a turbine of higher heat rate is lower than that earned by a turbine of lower heat rate. This can be witnessed in Table 8.71, which lists the spark spread earned at various heat rates and the resulting option value.

TABLE 8.71: SPARK SPREAD EARNINGS AND OPTION VALUE AT VARIOUS HEAT RATES

Heat Rate	*Total Spark Spread*	*Spread @ $6 strike price*	*Generation Hours*	*Starts*	*Option Value*
7	$686,891	$710,343	23993	1132	$ 25,815
8	$599,236	$626,285	21673	1246	$ 45,644
9	$511,580	$531,478	16356	1339	$ 75,978
10	$423,925	$460,635	11955	1328	$123,058
11	$336,269	$410,573	9124	1187	$181,753
12	$248,614	$375,944	7580	1133	$246,084

It can be seen that the Generator earns a larger spark spread at lower heat rates whether the turbine is run all 24 hours or selectively at spark spread > strike rate. The hours of generation decreases as the heat rate increases since the number of times the spark spread crosses over the strike rate would be less and less as the heat rate increases. The value of the flexibility option, on the other hand, increases as the heat rate increases. This is because, a Generator with a higher heat rate is more vulnerable to losses when the pool price drops. For example, at a pool price of $30 /MWh and gas price of $3/MMBtu, the Generator with a heat rate of 7, faces a positive spark spread of $9/MWh. At the same prices, the Generator with a heat rate of 12, faces a negative spark spread of $6/MWh. At those prices, the Generator with heat rate of 7 is 'in the money', one with a heat rate of 10, is 'at the money' and one at heat rate of 12, is 'out of money'. So, it is crucial for the Generator with the higher heat rate to adjust the unit's schedule to run only when the spark spread is greater than the unit's marginal cost. Hence, the option adds more value to the Generator who has a higher heat rate.

In Table 8.72, the option values for three different turbine models currently available in the market have been summarized.

TABLE 8.72: OPTION VALUES FOR VARIOUS TURBINE MODELS

Manufacturer	*Model*	*Heat Rate (MMBtu/MW)*	*Efficiency*	*Output MW*	*PBDIT/MWh (24 hour)*	*Option Value/MWh*
GE	LM5-ST80	8.170	42%	46.30	$368,983	$ 80,301
TP&M	FT8	8.875	38%	25.60	$307,186	$ 102,572
Nuovo Pignone	PGT10	10.500	32%	9.98	$156,587	$ 182,652

The GE LM5-ST80 model turbine has the lowest heat rate and hence the least value of option. The PGT10 model turbine has the highest heat rate and the highest option value. These values were calculated with the data for the 3-1/2 under consideration and the heat rate specific to the model, at a strike price of $6 and a start cost of $9.

8.8 PROJECT VALUE AND ECONOMIC VALUE ADDED (EVA)

So far in the analysis, the option value has been considered per megawatt of output and before adding fixed costs of financing and depreciation and also tax. Since these are fixed charges, the option value would not change as it would be the same if the turbine is run all the time or only when the spark spread exceeds the strike price. But it would be interesting to calculate the EVA for a gas turbine Generator in Alberta based on the 3-1/2 years data. For this purpose, the three models of turbines discussed in the previous section have been considered. The features of these models can be read from Table 8.81.

TABLE 8.81: TURBINE MODELS AND COST OF PROJECT

Manufacturer	*Model*	*Heat Rate (MMBtu/MW)*	*Output MW*	*$ in Millions*	*$/MW*	*Total Project Cost#*
GE	LM5-ST80	8.170	46.30	14.70	$ 317,490	$ 36,750,000
TP&M	FT8	8.875	25.60	11.00	$ 429,690	$ 27,500,000
NUOVO PIGNONE	PGT10	10.500	9.98	5.20	$ 521,040	$ 13,000,000

- It has been assumed that the turbine cost forms 40% of the project cost 100% of the project cost is assumed to be depreciable as CCA asset class 9 (rate = 25%).

The LM5-ST80 model has the highest capacity and lowest capital cost per unit of output while the PGT10 model has the lowest output and highest capital cost per unit. It can be seen that the GE turbine has more than 4.5 times the capacity of the Nuovo Pignone turbine but the capital cost is increased by less than 3 times, which is why the $/MW is least for the GE turbine. The unit is assumed to have a tax rate of 40%. Each of these turbines has a different heat rate, which would affect the spark spread earned and hence the hours of operation, and different capital costs which alters the fixed costs. Assuming that the projects are 100% equity financed, the simulation model ($6 strike price) was run separately for each of these models. The tax depreciation was calculated using 25% CCA for all depreciable asset. Straight-line depreciation was used as accounting depreciation.

TABLE 8.82: TURBINE MODELS, PV OF EARNINGS AND EVA

				GE LM5-ST80			
	PBDIT	*Tax Depreciation*	*PBT*	*Straight Line Depreciation*	*PAT*	*Cost of Capital*	*EVA*
1997	$1,095,983	$9,187,500	-$8,091,517	$1,225,000	-$129,017	$3,675,000	-$3,804,017
1998	$4,663,935	$13,781,250	-$9,117,315	$1,225,000	$3,438,935	$3,675,000	-$236,065
1999	$6,323,051	$3,445,313	$2,877,738	$1,225,000	$5,098,051	$3,675,000	$1,423,051
2000	$6,891,067	$2,583,984	$4,307,083	$1,225,000	$5,666,067	$3,675,000	$1,991,067
PV	***$20,948,537***	***$35,277,703***	***-$14,329,166***	***$5,685,225***	***$15,263,312***	***$17,055,675***	***-$1,792,363***
				TP&M FT8			
	PBDIT	*Tax Depreciation*	*PBT*	*Straight Line Depreciation*	*PAT*	*Cost of Capital*	*EVA*
1997	$487,386	$6,875,000	-$6,387,614	$916,667	-$429,281	$2,750,000	-$3,179,281
1998	$2,335,969	$5,156,250	-$2,820,281	$916,667	$1,419,303	$2,750,000	-$1,330,697
1999	$3,170,081	$3,867,188	-$697,106	$916,667	$2,253,414	$2,750,000	-$496,586
2000	$3,567,511	$2,900,391	$667,120	$916,667	$2,650,844	$2,750,000	-$99,156
PV	***$10,529,834***	***$22,543,984***	***-$12,014,150***	***$4,254,250***	***$6,275,584***	***$12,762,750***	***-$6,487,166***
				NUOVO PIGNONE PGT10			
	PBDIT	*Tax Depreciation*	*PBT*	*Straight Line Depreciation*	*PAT*	*Cost of Capital*	*EVA*
1997	$129,382	$3,250,000	-$3,120,618	$433,333	-$303,951	$1,300,000	-$1,603,951
1998	$743,225	$2,437,500	-$1,694,275	$433,333	$309,891	$1,300,000	-$990,109
1999	$1,051,826	$1,828,125	-$776,299	$433,333	$618,493	$1,300,000	-$681,507
2000	$1,238,526	$1,371,094	-$132,568	$433,333	$805,193	$1,300,000	-$494,807
PV	***$3,467,044***	***$10,657,156***	***-$7,190,113***	***$2,011,100***	***$1,455,944***	***$6,033,300***	***-$4,577,356***

The Profit-After-Tax (PAT) was calculated as:

PAT = ((PBDIT – Tax depreciation) * (1-Tax rate)) + Tax depreciation – Accounting Depreciation.

In Table 8.82 the earnings for each turbine model is at the stated capacity of the turbines and the PV of the values in individual years has been calculated at a discount rate of 10%, since the cost of capital has been assumed to be 10%. The EVA has been calculated as:

EVA = Profit after Tax – (cost of capital x capital employed)

It can be seen that the FT8 and PGT10 models have negative EVA in all the years while the LM5-ST80 has positive EVA from the year 1998 onwards. The reason for this is that the FT8 and PGT10 models have very high capital cost/MWh. The cost of the turbine does not increase at the same rate as the capacity and hence it is cost efficient to install turbines of higher capacity than smaller ones. Though the PV of PAT or profit margin in all cases is positive, the return on the capital decreases as capital/unit output increases.

8.9 SCENARIO ANALYSIS WITH BOOTSTRAPPING

The analysis in the previous section only serves as a comparison between the profitability across the different turbines. It does not give us the NPV of the project and hence the profit potential cannot be gauged. For example, the Nuovo Pignone turbine has negative EVA in all the years under consideration. The project with a Pignone turbine could turn around and generate positive EVA in the future, which depends upon the characteristic of the spark spread.

The spark spread has grown nearly 10 times between 1997 and 2000. But this growth rate is not likely to be sustained in the following years. The Power Pool was only created in 1996 and trading began in late 1996. Initially, it was the price protected Generators selling power at their variable cost, which kept prices low. Slowly as more and more IPP s came on line, the prices increased. This and the widening demand-supply gap led prices higher. At this stage, three scenarios are possible. The spark spread can continue on a growth phase, stay flat or fall lower. The growth might occur if supply growth doesn't quite match demand growth. When the demand is just matched by supply, the spread would stay flat or when the spark spread is sufficiently high, new generation becomes more attractive and the resulting excess supply would pull back spread.

The spark-spread series, to match the three scenarios, was generated for the next 26 years (till the lifetime of the project) using the approach of bootstrapping. Bootstrapping is achieved by simulating unknown values on the basis of some characteristic of known values. The basis for this forecast was the assumption that the volatility in spark spread in the existing data during the period 1996-2000 would repeat itself over the years. So, the percentage changes in hour-to-hour spark spread were retained. At the beginning of every cycle, discrete jumps in values of the spark spread were introduced to achieve a change in the growth rate. For example, if the spark spread for hours 1,2 and 3 for Jan 1st 1997 was say 6,12 and 4, then the rates of change would be 2 and 0.33 respectively for hours 1-2 and 2-3. By assuming that the spark spread in HE 1 on Jan 1st 2001 were 12, we would have spark spreads for hours 2 and 3 as 24 and 8 respectively. The volatility, measured by the standard deviation of the rate of change in the spark spread hour to hour, would remain the same, as the rates of change have been kept constant.

This method was applied for generating spark spread values for every hour of the day till year 2026 to complete the lifetime of the turbine.

8.9 a. EARNINGS SIMULATION FOR SCENARIO 1

The earnings simulation was performed based on this data to arrive at the results in Table 8.91 for the scenario when the spark spread would grow at a negative rate of –1.5%. It can be seen that the option value is higher when the profit is lower and vice-versa. When the spark spreads are high, the Generator is very much in the money and the option value decreases while profits increase. When the spark spreads are generally low, the earnings drop but the value of the option increases, since without it, the Generator is likely to make a loss.

Though the present value of the Generator's profit is \$6.5 million, we can see that \$6.3 million is from the option value. But when we take the cost of capital into consideration, the Generator does not make enough to cover for it. After charging a 10% cost of capital to the profit, the Generator ends up with a value of -\$11.5 million. This result is obvious since the initial project cost was \$13 million while the Generator only recovered \$6.5 million in profits and the time value of money makes the loss steeper. What is interesting though is the fact that the EVA for the Generator is pretty much the same when the EVA from Table 8.82 is replicated to fill out the 30 years. That is, by repeating the same values of spark spread as in years 1997-2000 till 2026, the compound annual growth rate of the average spark spread is –2.5% and still we arrive at a PV of EVA of -$11.6 million and $6.3 million in the PV of profits. This indicates that the option prevents the Generator from the down side and ensures all the upside of the project. The negative EVA is the result of fixed costs and there is no loss from operation by itself.

TABLE 8.91 a: EVA AND NPV FOR GENERATOR WITH NUOVO PIGNONE TURBINE AND –1.5% COMPOUND ANNUAL GROWTH RATE IN AVERAGE SPARK SPREAD

Year	*PBDIT*	*Tax Deprec*	*PAT*	*Capital cost*	*EVA*	*Option Value*	*Average Spark Spread*
1997	$129,382	$3,250,000	-$303,951	$1,300,000	-$1,603,951	$510,670	1.55
1998	$743,225	$2,437,500	$309,891	$1,300,000	-$990,109	$273,648	11.31
1999	$1,051,826	$1,828,125	$618,493	$1,300,000	-$681,507	$505,161	12.10
2000	$1,931,198	$1,371,094	$1,497,865	$1,300,000	$197,865	$295,472	24.64
2001	$943,617	$1,028,320	$510,284	$1,300,000	-$789,716	$973,181	5.48
2002	$3,218,773	$771,240	$2,785,440	$1,300,000	$1,485,440	$231,654	40.06
2003	$707,133	$578,430	$273,800	$1,300,000	-$1,026,200	$486,070	8.39
2004	$507,842	$433,823	$74,509	$1,300,000	-$1,225,491	$254,617	8.83
2005	$200,306	$325,367	-$233,028	$1,300,000	-$1,533,028	$543,376	1.96
2006	$1,025,431	$244,025	$592,098	$1,300,000	-$707,902	$288,868	14.36
2007	$174,705	$183,019	-$258,628	$1,300,000	-$1,558,628	$428,878	3.01
2008	$2,109,434	$137,264	$1,614,235	$1,300,000	$314,235	$153,185	28.72
2009	$1,132,055	$102,948	$287,079	$1,300,000	-$1,012,921	$1,170,578	6.40
2010	$112,022	$77,211	-$335,236	$1,300,000	-$1,635,236	$287,569	5.15
2011	$879,579	$57,908	$117,578	$1,300,000	-$1,182,422	$519,496	10.03
2012	$650,722	$43,431	-$25,527	$1,300,000	-$1,325,527	$247,207	10.55
2013	$271,124	$32,573	-$257,630	$1,300,000	-$1,557,630	$580,979	2.35
2014	$1,087,433	$24,430	$228,899	$1,300,000	-$1,071,101	$126,260	17.15
2015	$227,682	$18,323	-$289,395	$1,300,000	-$1,589,395	$430,218	3.59
2016	$145,246	$13,742	-$340,689	$1,300,000	-$1,640,689	$334,009	3.78
2017	$1,607,637	$10,306	$535,371	$1,300,000	-$764,629	$1,381,954	8.40
2018	$5,608,498	$7,730	$2,934,857	$1,300,000	$1,634,857	$752,736	61.44
2019	$1,187,168	$5,797	$281,286	$1,300,000	-$1,018,714	$570,545	12.88
2020	$710,756	$4,348	-$5,140	$1,300,000	-$1,305,140	$39,366	13.55
2021	$400,836	$3,261	-$191,527	$1,300,000	-$1,491,527	$651,026	3.01
2022	$1,755,706	$2,446	$621,068	$1,300,000	-$678,932	$348,332	22.03
2023	$313,822	$1,834	-$244,306	$1,300,000	-$1,544,306	$441,250	4.62
2024	$204,776	$1,376	-$309,918	$1,300,000	-$1,609,918	$299,453	4.86
2025	$67,075	$1,032	-$392,676	$1,300,000	-$1,692,676	$490,192	1.08
2026	$435,545	$774	-$171,697	$1,300,000	-$1,471,697	$264,424	7.90
PV			*$6,468,825*	*$17,942,529*	*-$11,473,704*	*$6,300,406*	

8.91 b. EARNINGS SIMULATION FOR SCENARIO 2

The second scenario is where the average spark spread does not achieve any growth in the 26 years between 2001-2026. Though there are ups and downs in individual years' values, the compound annual growth rate of the average spark spread is zero. The earnings of the Generator, in this scenario, is tabulated in Table 8.92.

TABLE 8.91b: EVA AND NPV FOR GENERATOR WITH NUOVO PIGNONE TURBINE AND 0% COMPOUND ANNUAL GROWTH RATE IN AVERAGE SPARK SPREAD

Year	*PBDIT*	*Tax Deprec*	*PAT*	*Capital cost*	*EVA*	*Option Value*	*Average Spark Spread*
1997	$129,382	$3,250,000	-$303,951	$1,300,000	-$1,603,951	$510,670	1.55
1998	$743,225	$2,437,500	$309,891	$1,300,000	-$990,109	$273.648	11.31
1999	$1,051,826	$1,828,125	$618,493	$1,300,000	-$681,507	$505,161	12.10
2000	$1,931,198	$1,371,094	$1,497,865	$1,300,000	$197,865	$295,472	24.64
2001	$2,136,134	$1,028,320	$1,702,801	$1,300,000	$402,801	$1,713,716	10.53
2002	$3,609,904	$771,240	$3,176,570	$1,300,000	$1,876,570	$332,942	43.39
2003	$2,294,763	$578,430	$1,424,662	$1,300,000	$124,662	$791,270	22.93
2004	$1,084,246	$433,823	$390,743	$1,300,000	-$909,257	$252,638	15.44
2005	$1,325,538	$325,367	$492,136	$1,300,000	-$807,864	$1,238,641	7.11
2006	$3,356,521	$244,025	$1,678,189	$1,300,000	$378,189	$508,095	38.50
2007	$1,846,490	$183,019	$747,769	$1,300,000	-$552,231	$704,353	19.46
2008	$607,647	$137,264	-$13,839	$1,300,000	-$1,313,839	$68,848	12.38
2009	$2,596,385	$102,948	$1,165,677	$1,300,000	-$134,323	$2,000,981	12.46
2010	$983,608	$77,211	$187,716	$1,300,000	-$1,112,284	$286,151	13.91
2011	$2,132,780	$57,908	$869,498	$1,300,000	-$430,502	$793,619	21.47
2012	$1,742,103	$43,431	$629,301	$1,300,000	-$670,699	$285,070	22.59
2013	$3,310,585	$32,573	$1,566,047	$1,300,000	$266,047	$2,436,186	15.58
2014	$2,981,719	$24,430	$1,365,470	$1,300,000	$65,470	$325,233	36.72
2015	$633,452	$18,323	-$45,933	$1,300,000	-$1,345,933	$474,078	7.70
2016	$764,109	$13,742	$30,629	$1,300,000	-$1,269,371	$245,214	11.87
2017	$3,366,445	$10,306	$1,590,657	$1,300,000	$290,657	$2,493,683	15.69
2018	$8,143,903	$7,730	$4,456,100	$1,300,000	$3,156,100	$1,155,045	87.73
2019	$1,790,894	$5,797	$643,522	$1,300,000	-$656,478	$688,019	18.39
2020	$1,245,557	$4,348	$315,740	$1,300,000	-$984,260	$73,740	19.40
2021	$1,750,101	$3,261	$618,032	$1,300,000	-$681,968	$1,473,139	8.90
2022	$4,440,124	$2,446	$2,231,720	$1,300,000	$931,720	$624,596	49.55
2023	$1,153,634	$1,834	$259,581	$1,300,000	-$1,040,419	$535,209	12.83
2024	$2,049,389	$1,376	$796,851	$1,300,000	-$503,149	$301,980	25.91
2025	$2,394,252	$1,032	$1,003,630	$1,300,000	-$296,370	$1,874,863	11.61
2026	$4,415,219	$774	$2,216,108	$1,300,000	$916,108	$621,923	49.30
PV			***$13,184,607***	***$17,942,529***	***-$4,757,923***	***$9,613,679***	

The Generator, in this case, makes a profit of $13.2 million but has a negative EVA of -$4.8 million. The option has contributed to almost 3/4 of the profits of the Generator. The difference in values of PAT and PBDIT is increasing with time since the tax shield from the declining balance depreciation goes down and the Generator has to pay higher taxes. The option values exhibit a discernible pattern that is more or less the opposite of the pattern of the average spark spread. The option values increases and decreases almost every alternate year, and this is due to the fact that the simulation has replicated the price process of the first four years through the entire life of the project.

8.91 c. EARNINGS SIMULATION FOR SCENARIO 3

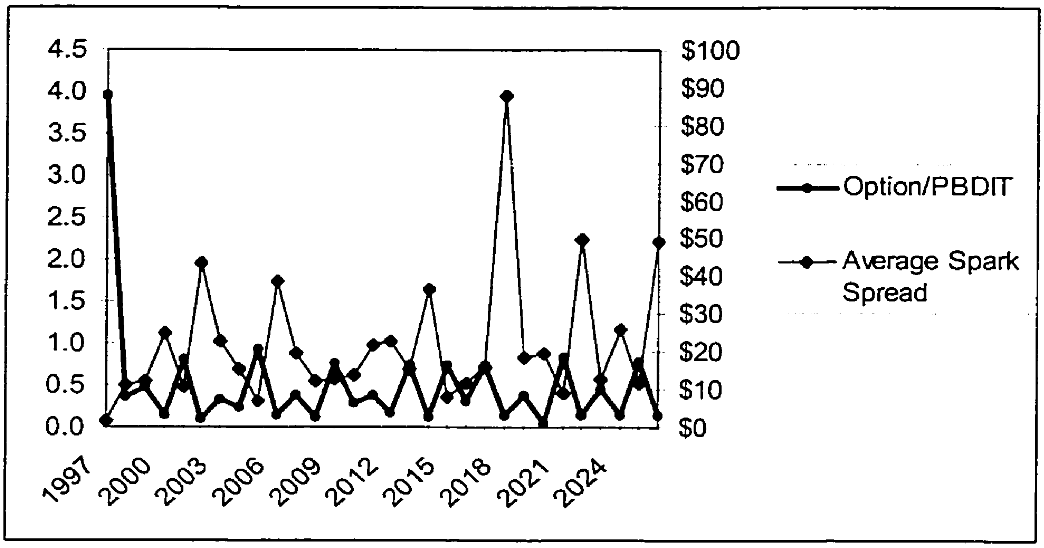
Finally, the scenario where the spark spread grows at a compound annual rate of 3% till the year 2026 from the year 2000. The results are in Table 8.93. The Generator has a positive EVA when the pool prices are steadily rising, at a nominal rate of 3% per annum. The option value as a percentage of the PBDIT is lowest in scenario three. It is highest in scenario 1 of negative spark spread growth. In scenario 1, the ratio is almost equal to one, meaning all the profits are due to the option. In scenario 2, it is equal to 0.72 and in scenario 3, the ratio is 0.57. The option gains significance when the underlying asset price is low and diminishes as underlying asset price increases. This phenomenon holds true for the individual years as well. A look at the ratio of the option value to the PBDIT and the spark spread would make it clear. Figure 8.91 charts the course of the ratio of option value to the PBDIT against the average spark spread for all the years under consideration. It can be seen that the movements are almost identical albeit in opposite directions.

TABLE 8.91c: EVA AND NPV FOR GENERATOR WITH NUOVO PIGNONE TURBINE AND 3% COMPOUND ANNUAL GROWTH RATE IN AVERAGE SPARK SPREAD

Year	*PBDIT*	*Tax Deprec*	*PAT*	*Capital cost*	*EVA*	*Option Value*	*Average Spark Spread*
1997	$129,382	$3,250,000	-$303,951	$1,300,000	-$1,603,951	$510,670	1.55
1998	$743,225	$2,437,500	$309,891	$1,300,000	-$990,109	$273,648	11.31
1999	$1,051,826	$1,828,125	$618,493	$1,300,000	-$681,507	$505,161	12.10
2000	$1,931,198	$1,371,094	$1,497,865	$1,300,000	$197,865	$295,472	24.64
2001	$943,617	$1,028,320	$510,284	$1,300,000	-$789,716	$973,181	7.31
2002	$5,725,079	$771,240	$5,291,746	$1,300,000	$3,991,746	$524,346	65.31
2003	$1,832,300	$578,430	$962,200	$1,300,000	-$337,800	$696,541	18.76
2004	$1,423,391	$433,823	$594,230	$1,300,000	-$705,770	$267,902	19.15
2005	$3,267,939	$325,367	$1,657,577	$1,300,000	$357,577	$2,437,198	15.28
2006	$7,870,034	$244,025	$4,386,297	$1,300,000	$3,086,297	$1,003,130	84.43
2007	$2,702,937	$183,019	$1,261,637	$1,300,000	-$38,363	$957,685	26.75
2008	$4,153,351	$137,264	$2,113,583	$1,300,000	$813,583	$325,648	50.55
2009	$2,844,513	$102,948	$1,314,554	$1,300,000	$14,554	$2,155,837	13.50
2010	$478,198	$77,211	-$115,530	$1,300,000	-$1,415,530	$264,293	8.39
2011	$2,313,793	$57,908	$978,106	$1,300,000	-$321,894	$797,046	23.10
2012	$1,798,142	$43,431	$662,924	$1,300,000	-$637,076	$285,267	23.23
2013	$3,892,381	$32,573	$1,915,124	$1,300,000	$615,124	$2,810,480	17.90
2014	$8,826,148	$24,430	$4,872,127	$1,300,000	$3,572,127	$1,090,177	96.18
2015	$1,986,564	$18,323	$765,934	$1,300,000	-$534,066	$727,417	20.16
2016	$1,614,442	$13,742	$540,828	$1,300,000	-$759,172	$278,064	21.21
2017	$6,625,551	$10,306	$3,546,120	$1,300,000	$2,246,120	$4,660,238	29.47
2018	$9,446,204	$7,730	$5,237,481	$1,300,000	$3,937,481	$1,178,669	100.44
2019	$2,085,662	$5,797	$820,383	$1,300,000	-$479,617	$747,793	21.05
2020	$1,493,513	$4,348	$464,513	$1,300,000	-$835,487	$82,331	22.08
2021	$812,302	$3,261	$55,352	$1,300,000	-$1,244,648	$892,799	4.91
2022	$8,106,919	$2,446	$4,431,796	$1,300,000	$3,131,796	$912,090	88.18
2023	$1,801,316	$1,834	$648,190	$1,300,000	-$651,810	$687,377	18.48
2024	$1,450,857	$1,376	$437,731	$1,300,000	-$862,269	$268,953	19.45
2025	$2,164,686	$1,032	$865,891	$1,300,000	-$434,109	$1,731,585	10.65
2026	$7,223,062	$774	$3,900,814	$1,300,000	$2,600,814	$930,890	77.86
PV			*$19,381,752*	*$17,942,529*	*$1,439,223*	*$11,174,684*	

Given the demand-supply situation in Alberta, scenario 3 appears to be the most probable case. Slow growth in additional supply and subsequent phasing out of coal-based generation units would lead to price increases in future and 3% growth appears to be a conservative estimate. Given the fact that the Generator has positive EVA even at this minimum growth rate suggests that a simple-cycle gas turbine project in the province is a worthwhile venture and acquires all its value from the flexibility option that is inherent in the operations.

FIGURE 8.91: RATIO OF OPTION VALUE TO PBDIT VS AVERAGE SPARK SPREAD



Chapter 9 – Summary of Results, General Implications, Relevance and Further Research

This chapter discusses the results of the research and what it implies in the current context. Section 9.1 gives a brief summary of the research and the results; section 9.2 discusses what the results mean in the context of electric industry deregulation in Alberta and to who and how this research is relevant. The final two sections list the shortcomings of the study and the areas of further research, respectively.

9.1 SUMMARY OF RESULTS

The purpose of the study was two fold: one was to research the technology of power generation and the regulatory environment to confirm if the Generator does in fact hold a series of call options at every hour of the day on the spark spread; and if one held true, the other one was to calculate the value of this option and analyze its sensitivity to various parameters.

It was found that all Generators that operate on a gas turbine do not have the flexibility in their operations to qualify for a holder of a call option on the spark spread. For example, the co-generator who uses gas turbine cannot shut down electricity generation at will since the other product of the operation, namely heat, was required at a steady rate throughout the day The Profit-After-Tax (PAT) was calculated as:

PAT = ((PBDIT – Tax depreciation) * (1-Tax rate)) + Tax depreciation – Economic Depreciation.

A Generator with a combined cycle unit (gas turbine and steam turbine) faces a long lead time in starting up after each shut down to truly take advantage of the favorable spark spread. It was only the Generator with a simple cycle combustion turbine that really had the flexibility to run the unit as a real option on the spark spread.

Of the two types of combustion turbines, industrial and aero-derivative, the latter had a shorter lead time, maintenance work could be done off-site with replacement engines fitted in and did not get affected by frequent start up/shut down operation. It was found to be more suitable to take advantage of the real option inherent in the operation.

The next step was to verify that the regulatory framework allowed the Generators to supply only when the spark spread was favorable to them. The formation of the Power Pool in 1996 allowed any Generator to directly connect to the grid and offer its supply for distribution. There was no need for the Generators to strike a deal with the utilities to sell their power. Also the bid/offer process for setting the pool price only required the Generator to stand firm on the price offered for the next day's generation. The scheduling of the units' ramp ups could be done an hour prior to the hour of generation, when the system controller forecasts the next hour's pool price. So, the offers could be placed based on the previous day's gas price and scheduling could be done based on the system controller's forecast as the turbine only requires 20 minutes to start up and connect fully to the grid. The system controller also requires the Generator to offer voltage support to the grid at all times, irrespective of whether the turbine is running or not. Recent technologies do allow this and it is hence possible to view the Generator with an aero-derivative gas turbine as the holder of a real option on the spark spread at every hour of the day.

Having confirmed that it was technically feasible and allowed by regulations to run the turbine only when the spark spread exceeded a certain strike price, the next step was to find the optimal strike price and the value of the flexibility option at that price. The value of the option was calculated as the difference in the PBDIT of the Generator under the two schemes.

It was found that the Generator earns lesser in terms of spark spread but makes up for the loss by saving on maintenance cost. Maintenance cost for the turbine is linked to the hours of generation and the lesser the hours, the lesser is the maintenance cost. Since the turbine is not run all the time, there is a saving in the cost of maintenance. This cost was estimated at $6/hour for the Generator and basic economics would suggest that the strike price has to be at least $6 above the spark spread to cover all variable costs of generation. But there is also a cost associated in terms of cost of fuel per start of the turbine when no revenue is accumulated. The result of the simulation showed that the number of hours of generation declined as the strike price was increased and so did the number of starts. Hence, by setting a higher strike price, the Generator might be able to save on start costs. But it was found that the savings in start costs became significant only when the cost per start exceeded $16. Considering that there is only the cost of fuel during starts, it is highly unlikely that this level of cost/start would be maintained. The average gas price for the 3-1/2 years under consideration was $2.7/MMBtu and this translates to $9/start. At this cost, there is no significant saving in terms of cost of starts. Therefore, the optimal strike price for the Generator would be the marginal cost of generation, which is $6 above the spark spread.

Though the bulk of the analysis was performed using actual posted pool price and gas price, it was necessary to calculate the option value based on forecast pool price and previous day's gas price as that is the basis for scheduling for the Generator. It was found that the mismatch in scheduling remained in the range of 6-7% for each year in terms of total number of hours available. The value of the option over and above the 24-hr operation, calculated under this was only 2-3% below that calculated using actual prices. In the 3-1/2 year period considered, the pool prices and gas prices have moved around a lot. Yet, the difference has remained at the same level year to year. This difference also decreased as the strike price increased, suggesting lower levels of forecast errors in the higher price region.

The Generator's option value using actual prices for scheduling, at a maintenance cost of $6 per fired hour and $9/start, exceeded 60% over the value of the unit running all 24 hours. This percentage ranged from a high of 145% in 1997 to a low of 18% in 2000, but the present value of the option over that of continuous operation was 64%. Ignoring this value while estimating the value of the project might result in not adopting the project.

All of the above analysis was done assuming a heat rate of 10 MMBtu/MWh. The next step focussed on studying the effect of the heat rate on the option value. The higher the heat rate, the higher is the gas cost per unit of electricity. So, a Generator with a higher heat rate is more sensitive to changes in gas price and hence has a higher value for the option. Though earnings, per se, decrease at higher heat rates, the value of the option increases as the heat rate increases.

Comparing the value of the option year on year, it was seen that the option value increases, as the Generator goes deeper out of money. When the pool prices are high, the Generator is in the money so that the option is not as valuable anymore. In years 1998 and 2000, when the pool prices were quite high, the option value was lesser compared to 1997 and 1999 when the pool price increases were dampened by gas price increases.

The simulation was also run on the specifications of some of the models of aero-derivative turbines currently available in the market. For the other parts of analysis, the values were calculated on a per MWh basis. But for this, the value was calculated on the total capacity basis. Assuming that the turbine price forms about 40% of capital cost and 80% of the total cost is depreciable, the tax depreciation for a unit was calculated assuming the equipment were in Class 9 of CCA. The tax rate was set at 40% (never used since all models made losses and never paid taxes in the years considered) and the accounting depreciation was straight line. Supposing that the unit were 100% equity financed, the EVA was calculated as the difference in net profit margin and cost of capital (assumed at 10%). The result showed that the turbine with the lowest capital cost/MW capacity had the highest EVA and the one with the highest capital cost/MW had the lowest EVA. Since turbine efficiencies increase with size and the cost/unit of capacity decreases with size, it would make economic sense to put up larger units than smaller units.

A scenario analysis was undertaken to study the earnings potential of a Generator in Alberta. Three scenarios were created: one with negative (-1.5%) future growth in spark spread, second with no growth and the third with a 3% compound annual growth rate in spark spread from years 2001 through 2026. This would complete 30 years in the life time of the turbine and enables the calculation of the NPV of the project. For the purpose of the simulation of the future values of spark spread, it was assumed that the volatility pattern of the years 1997-2000 would be preserved in the coming years and repeat itself over and over again. The earnings of the Nuovo Pignone turbine with a heat rate of 10.5 and capital cost of $13 million was generated in the simulation. The results showed that the Generator would make a positive profit in all cases but the EVA, which includes the cost of capital, turned positive in only the last case, namely the positive growth rate scenario. In all the cases, the value of the option contributed significantly to the earnings of the Generator, without which, there would have been negative earnings apart from the fixed costs.

9.2 GENERAL IMPLICATIONS AND RELEVANCE

One of the main features of the electric industry deregulation in Alberta was to introduce competition in the generation part and providing open access to the Power Pool. This feature was expected to provide a signal for new generation when pool prices increased as a result of tightening demand supply gap. Table 9.21 provides a concise picture of the pool price scenario since the time the Power Pool came into existence.

TABLE 9.21: ELECTRICITY DEMAND AND POOL PRICE STATISTICS

	1996	*1997*	*1998*	*1999*
Peak demand (MW)	70,565	72,506	72,097	74,088
Maximum (peak) Pool price ($/MWh)	1009	765.501	999.5011	998.0012
Minimum (non-peak) Pool price ($/MWh)	2.7413	3.6814	5.1515	5.7616
Total energy traded (MW)	97,452,000	101,105,000	102,920,000	102,844,735
Number of Power Pool participants	33	38	40	50

Source: Alberta Resource Development at www.resdev.gov.ab.ca/electric

Comparing Table 9.21 to Table 7.11, one can see that the pool price has been steadily increasing over the years. The introduction of free trading through the Pool has enabled small independent producers to be able to set hourly prices. But this alone cannot explain the increasing prices. The demand for power is expected to grow at a rate of 1.8%[12] for the next 10 years and the supply side is not keeping up. In Table 4.22, all new capacity additions and planned generation has been listed. The total of all new capacity (planned, proposed and under construction) after 1999, is only 2% of the peak demand level of 74,088 MW in 1999. Some of the new capacity mentioned in Table 4.22 are only expected to go online in the latter half of 2002, by which time the demand growth would have outstripped supply, unless new generation comes up quickly. Could the reason for this slow growth in supply be that the value of the option is not being recognized? Adding to this suspicion is the fact that only 6% of the new capacity is in the form of simple cycle gas turbines, which have the real option on spark spreads. More than 80% of the new capacity is from co-generation which does not have the flexibility to take advantage of the call option on spark spread.

[12] Source: 1993 EUPC forecast as mentioned in "Moving to Competition", Alberta Department of Energy.

Alberta Department of Energy's publication "Moving to Competition – A guide to Alberta's new electric industry structure" says the following about new generation:

> "In Alberta's new industry structure, there is no longer a requirement for the regulator to approve new generating units on the basis of province-wide need for capacity. Instead, market forces will come into play as distributors forecast the pool price and make appropriate financial arrangements with new generators in order to hedge the hourly pool price. Alternatively, a generator may build a new unit on the basis of forecast revenue at the pool price."

Distributors of electricity have a financial arrangement with regulated generation units called the "legislated hedge" to protect themselves from volatility in pool price. The portion of the electricity that they buy from non regulated generation units and IPPs is very small as of now. But in due course, when the older units are phased off, they will have to buy more and more from the IPPs and will have to face volatility in their cost. When that happens, they will want to enter into private arrangements with IPPs to hedge their cost. But the Generators have a natural hedge against pool price volatility by way of the real option. The option is more valuable when the volatility is more. So, the Generators have to keep this value in mind in order to strike a fair deal with the Discos for supplying their power.

Some of the countries that have achieved electric industry deregulation have developed forward markets where derivative products on electricity are traded. Alberta is venturing out to have a home grown market where the pool participants can trade derivative products to hedge their position in electricity. The Power Pool bulletin board in their web page announces:

> "The Power Pool of Alberta is pleased to announce that California Power Exchange (CalPX) and Alberta Watt Exchange Limited (Watt-Ex) have each reached an understanding with the Power Pool to establish areas of cooperation with respect to the development of electricity markets in Alberta and the development of an interface framework between forward and real-time markets."

Deregulation in the wholesale markets has already occurred or is imminent in Norway, Sweden, the US, the UK, Finland, Australia and New Zealand. Other European Union countries are also moving towards deregulation ahead of economic and monetary union. Over the counter markets in forwards, swaps, swap options and options have emerged wherever deregulation is taking place. Making the transition from a regulated to a deregulated electricity market involves huge structural changes that have direct consequences for market participants. Primarily, the introduction of a competitively set market price for physical power (the spot price) introduces a significant price risk element to market participants, i.e, exposure to a volatile and unknown price. Hence, there is a strong market need for the introduction of hedging instruments with which market participants can manage this new volatile market environment.

The pricing of the derivatives can be based on theoretical framework or empirical research. The unique characteristic of electricity, non–storability, presents challenges to risk managers in terms of developing a sound theoretical model for pricing these derivatives. Some works like of Deng, et al.. (1999) and Routledge, et al.. (1998) provide interesting models to price these derivatives. But all these studies have been focused on changes in the U.S. power markets and may incorporate features that are unique to those markets. This research brings an Alberta outlook to the scenario. The study has been fully based on historic gas and pool prices in Alberta within the regulatory framework of the Power Pool of Alberta.

9.3 LIMITATIONS OF STUDY

The option value has been calculated on the basis of only 3-1/2 year's data, since the Power Pool has only been in existence for that long. To arrive at more conclusive results, the time frame has to be longer for two reasons: One is that the pool is a recent phenomenon and the market needs time to settle down. The other reason is that, the market is still not truly competitive. Almost 90% of generation is still under legislated hedges and is price protected. The pool price is only reflecting 10% of the entire market and cannot be expected to remain at these levels for long. Also, studies of electricity markets in the U.S. claim that the electricity prices are mean reverting. If that is the case, a three-year time frame may only capture some parts of the cycle and is not truly representative of the price process.

The entire cost for shut down/start up operation has been assumed to consist only of fuel cost. There could be additional cost of equipment, which enables system support even while the turbine is shut off. This is a capital cost must be factored against the value of the option.

While calculating the EVA of the project, cost items like administration, system access and other fee were not taken into consideration. Only in one case, there was a positive EVA, which was only a small percentage. Adding these costs may be enough to swing the EVA from being positive to negative.

The biggest limitation is that the turbine was expected to be up and running whenever the spark spread crossed the threshold strike price. The forecast of the system controller may not arrive in time for the Generator to be fully integrated into the grid at the start of the hour. If there is any lag in doing so, the Generator would miss out on revenue. Also, it is not clear if the Pool charges the Generators any penalty for defaults. If there is, it might add significantly to the cost of the Generator.

Another assumption has been that the standard maintenance procedures are always completed in time. There could be instances when the maintenance procedure takes longer than expected to be completed for a variety of reasons.

Also affecting the value of the option could be unexpected break down of some equipment. Though the aero-derivatives are very reliable engines, it is not impossible that unexpected breakdown happens. One can factor in a probability value for this into the option value calculations. It has not been done since it would be beyond the scope of this research.

The biggest advantage in using an aero-derivative gas turbine is that the maintenance work can be done off-site. For doing so, the Generator has to have a deal with the maintenance provider for supplying a replacement engine. Since the shut down/start up operation leaves the Generator with uncertainty about when the stipulated time for maintenance would be reached, there could be delays in securing the replacement or some added costs. The Generator would also have to inform the Power Pool about scheduled maintenance shut downs in advance. These problems never came up in the research since the period covered did not call for any maintenance stops. For the scenario analysis, the maintenance stops were programmed based on the hours of operation, assuming that there would be no problem in doing so. But one will have to consider the practical complications before arriving at the value of the option.

9.4 AREAS OF FURTHER RESEARCH

Almost 80% of the new generation in Alberta is in the form of co-generation and this brings up the question why co-generation is popular than simple cycle gas turbines. Co-generation is more efficient in the sense that it makes full use of the thermal energy of the system and the efficiency rating can be as high as 65% in some cases. Still, the electrical energy output is the same as that in a simple cycle turbine. The higher efficiency is due to the utilization of the exhaust heat to supply process heat. This does however rob the option out of the system. Some co-generators in the province bid in their electricity at zero dollars to ensure that their system is always online. Some others utilize the electricity in-house. In the first case, they may be selling electricity at a price less than their variable cost of production (even though the variable cost here is lesser than that of a simple cycle Generator). In the second case, the facility can buy electricity from the pool when the prices are low and generate only when the price is higher than its variable cost. But this means that the heat requirements are not met. It would be worthwhile to study if a separate simple cycle turbine and a heat plant would be better option than the combined co-generation, since the former retains the flexibility option inherent in electricity generation.

The electricity market is not widely understood outside the power industry and, not surprisingly, the participants are mainly large power generators, independent power marketers, large industrial consumers and a handful of derivatives dealers. Alberta has spearheaded the electricity deregulation in Canada and provinces like Ontario are trying to emulate the Alberta model in removing regulation. Alberta is also trying to establish a derivatives market for electricity in the province. The growth of the electricity derivatives market worldwide has been impeded by a lack of price transparency. The market tends to be based on physical delivery of power and privately negotiated transactions. As countries deregulate, the free trade exchanges have aided in resolving the problem of price transparency. In Alberta, though all electricity is traded through the Power Pool, only 15% of the total trade set the price since the bulk of the trades are between regulated generators and Discos who are protected by the legislated hedges.

An article in the Risk magazine reports[13]:

> "Norway and Sweden have linked their electricity markets this year through the Nordic Electric Exchange (Nord Pool), a newly launched electricity futures exchange which is run by OM, the Stockholm-based futures and options exchange. Nord Pool trades contracts for weekly, monthly and, by grouping the monthly contracts, seasonal delivery. Spot transactions can also be executed through the exchange. The two countries had to reform their national electricity markets extensively and agree on procedures for reconciling their different market-clearing mechanisms – the process by which the supply and demand for electricity are kept in balance throughout the day….. In April 1996, the NYMEX introduced two physically settled futures contracts: one based on delivery at Chicago Oregon Border (COB) and the other at Palo Verde. Volume remains low and two factors inhibit trading: the slow pace of retail deregulation in California means local utilities are still able to pass on costs to consumers; and the segmentation of electricity distribution into loosely interconnected regional power grids means that prices and volatility vary substantially across the US. As a result, hedging of electricity bought outside the delivery points, for example with NYMEX futures in the Pennsylvania-Maryland-New Jersey region, is impractical – the basis risk is too high. Instead, hedges are done bilaterally or through large brokers and power marketers with the experience to structure and price customized transactions tied to the local market".

Alberta is already connected with B.C., and Saskatchewan through an integrated grid. It would be interesting to study the regulations on electricity in the various provinces in Canada and the deregulation process to see if there is any hope for integration of these markets. A study of the volatility and prices across the various provinces can help to

---

[13] Gregory Hayt, "Who uses Derivatives", *Risk* magazine, August 1999.

analyze if Canada could face any of the hurdles faced by the other deregulating countries, in setting up a successful derivatives exchange.

Another important milestone in Alberta's deregulation process is the introduction of 'retail wheeling'. This would enable consumers to buy electricity from who they wish and the marketers will not be restricted to particular areas that they can serve, as was in the past. This is expected to begin by January 2001 in Alberta. Other markets that adopted this experienced fall in prices. Another study can be the effect this has on prices and volatility in Alberta and what it means to Generators across the province.

BIBLIOGRAPHY

Alberta Department of Energy. 1996. *Moving to Competition – A guide to Alberta's new electric industry structure.* Edmonton, Alberta.

Alberta Department of Energy. 1998. *Power of Competition – An outline of Alberta's new electric industry structure.* Edmonton, Alberta.

Alberta Energy and Utilities Board. 1996. *Electric Utilities Act.* Edmonton, Alberta.

Benaroch, Michel and Kauffman, Robert. 1999. "A Case for Using Real Options Pricing Analysis to Evaluate Information Technology Project Investments", Information Systems Research, Vol 10 (March), p.70 – 86.

Black, Alexander J. 1999. "Electricity Competition and Fair market Access in Canada", Energy law Journal, November.

Deng, S., Johnson, B. and Sogomonian, A. 1999. " Spark Spread Options and the Valuation of Electricity Generation Assets". Proceedings of the 32nd Hawaii International Conference of Systems Sciences.

Denhamer, Janet S. 1995. Taxation in Canada. (Richard D Irwin Inc)

Dixit, Avinash and Pindyck, Robert. 1996. Investment Under Uncertainty. (Princeton: Princeton University Press)

Elliott, Sick, Stein (2000). "Pricing Electricity Calls". Draft version, June 2000.

Kehlhofer, Rolf. 1991. Combined Cycle Gas & Steam Turbine Power Plants. (Lilburn: The Fairmont Press Inc.)

McDonald, Robert and Siegel, Daniel. 1985. "Option Pricing When the Underlying Asset Earns a Below Equilibrium Rate of Return: A Note." *Journal of Finance* (March): 26-265.

Orlando, Joseph. 1997. Co-generation Planner's Handbook. (Oklahoma: PennWell Publishing Company)

Pettit, Justin. 1999. "Applications in Real Options and Value-based strategy". Real Options and Business Strategy – Applications to Decision Making, edited by Lenos Trigeorgis. (Risk Books)

Power Pool of Alberta. 1997. *Annual Report*. Calgary, Alberta.

Power Pool of Alberta. 1998. *Annual Report*. Calgary, Alberta.

Routledge.B., Seppi and Spatt. (1998). "Spark Spread – An Equilibrium model of Cross-Commodity Price Relationships in Electricity". Presented at the Winter AEA Meetings (99) in New York.

Sick, Gordon. (1995). "Real Options". Chapter 21, Finance, edited by Jarrow, Maksimovic and Ziemba. (Amsterdam: Elsevier).

APPENDIX A – LEGISLATED HEDGES AND RESERVATION PAYMENTS

The formation of the Power Pool and the free trading of electricity introduced to distributors of electricity price uncertainty in cost while their revenues were fixed. In order for distributors to hedge against their cost and for consumers in the province to enjoy low cost of existing generation, the concept of 'legislated hedges' were introduced.

UNIT OBLIGATION

The existing regulated generating units – Alberta Power, Edmonton Power and TransAlta Utilities – provide a hedge of the hourly pool price to the distributors. In this, particular Generators and distributors are not tied but the hedge payments from all Generators are *pooled*. Distributors and the TA then share these payments according pre-set shares. The amount paid by each Generator is its 'obligation' and is determined by the capacity and variable running cost of the regulated units and also in part by the pool price. The regulators set a *Unit Obligation Amount* (UOA) in MW for each Generator based on certain criteria. The EUB determines a *Unit Obligation Price* (UOP) for each unit, which is the expected variable cost of the unit. The *Unit Obligation Value* (UOA) of each unit is then given by:

UOV = (Pool Price – UOP) x UOA.

If pool price for the hour is less than the UOP, then the UOA is equal to zero. The sum of all UOV of all Generators are pooled and distributed among the Distributors and the TA.

RESERVATION PAYMENTS

In return for providing the distributors the hedge, the Generators get *Reservation Payments* from the distributors towards recovering their fixed cost of generation. The payment from each Distributor is based on shares set by regulation. The shares varied between 1996 and 1999 but were fixed after 1999 at the same level.

The reservation payments made by the distributors are based on their forecast load and not their actual load. Similarly the UOA has to be paid by the Generators whether they run their unit or not. This has been done so that the TA and the Distributors try to forecast more accurately and the Generators try to avoid as much down time as possible.

APPENDIX B: MAINTENANCE SCHEDULE

For the aero-derivative gas turbine a boroscopic inspection is performed 4 times every year and takes about 8 hours. Waterwashing is an 8-hour operation that is done every one or two months depending on site conditions. These events can usually be scheduled during low pool price hours. Since the Generators get a 6-day forecast of pool price, it would be possible for them to carry out these procedures when the pool price is lowest. But, for the purpose of the simulation, the maintenance hours were fixed and the turbine was scheduled to be off during these hours, irrespective of the level of pool price. Since the pool price is usually the lowest during the hours of midnight to 7 am, it was at this time that the unit was scheduled for routine maintenance. Table B1 gives the days and hours on which the turbine is off for maintenance work.

TABLE B1: MAINTENANCE SCHEDULE

Date	*HE*
31-Jan	24
1-Feb	1-7
16-Feb	24
17-Feb	1-7
1-Apr	24
2-Apr	1-7
16-May	24
17-May	1-7
1-Jun	24
2-Jun	1-7
1-Aug	24
2-Aug	1-7
16-Aug	24
17-Aug	1-7
1-Oct	24
2-Oct	1-7
16-Nov	24
17-Nov	1-7
1-Dec	24
2-Dec	1-7

Since it is possible that the spark spread could be greater than the strike price during these hours, the Generator would lose out on earning a positive revenue at times. In 1997, there were only 4 hours when the spark spread actually exceeded the strike price of $6 during the maintenance shut down period. The loss in value as a result was $64.63 per megawatt output. In 1998, this was a5 hours and $143.30/megawatt, in 1999 it was 4 hours and $27.70/megawatt and in 2000, it was 5 hours and $44.02/megawatt.

A hot section overhaul is done after 24,000 hours and after 48,000 hours a lease engine is brought in and used while rebuilding is carried out off site. The duration of this change-out is 2.5 days to install the lease engine and 2.5 days to remove the lease engine. The turbine was never run for more than 24,000 hours under the option plan. The hours did reach 24,000 for the 24-hour operation. The values were adjusted suitably to account for this.

EXHIBIT I : POWER POOL REPORT – FORECAST AND ACTUAL DATA

FORECAST AND ACTUAL DATA FOR: FEBRUARY 26, 1996

Hour	Forecast Pool Price	Next Settlement Period Forecast Pool Price	Actual Pool Price	Forecast Actual Pool Demand	Bid/Offer Spread
01	3.38	5.38	5.30	5022	2.65
02	3.38	5.21	4.35	4891	2.65
03	3.17	5.21	3.81	4849	2.35
04	3.16	3.81	3.81	4838	2.15
05	3.16	3.81	3.39	4842	2.15
06	3.17	5.38	3.75	4926	2.35
07	5.44	5.53	5.44	5192	4.43
08	5.45	16.00	7.90	5660	4.43
09	5.45	8.01	14.15	5821	4.43
10	5.53	11.01	8.01	5824	6.91
11	5.53	8.00			

All dollar amounts are in dollars per megawatt hour.
A value of -1 indicates that the value is not yet available.

Note: This report is based on unreconciled data and is provided to the user for information purposes only. Final reports containing reconciled data will be available at the end of the month.

This report was created on Thurs Feb 26, 11:41:08 MST 1996

Press enter to return to menu: