# Tolling Valuation and Strategies for Powerex Corp.

by

Michael L. McWilliams
B.C.I.S., University College of the Fraser Valley, 1998

John M.T. Wilkinson, P.Eng.
M.A.Sc., Civil Engineering, University of British Columbia, 1995
B.A.Sc., Civil Engineering, University of Toronto, 1992

PROJECT SUBMITTED IN PARTIAL FULFILLMENT OF
THE REQUIREMENTS FOR THE DEGREE OF

Master of Business Administration
MBA-MOT Program

in the Faculty

of

Business Administration


SIMON FRASER UNIVERSITY
September 2003

## APPROVAL

Name: Michael L. McWilliams, John M.T. Wilkinson

Degree: Master of Business Administration

Title of Project: Tolling Valuation and Strategies for Powerex Corp.

Supervisory Committee:

Dr. Ian McCarthy
Senior Supervisor
Associate Professor
Faculty of Business Administration

Dr. Blaize Reich
Associate Dean
Faculty of Business Administration

Date Approved: Aug 14, 2003

Management of Technology
MBA

# Partial Copyright License



**Title of Thesis/Project/Extended Essay**

Tolling Valuation and Strategies for Powerex Corp.

**Author:**

Michael McWilliams

Aug - 29 - 2003

Date

Management of Technology
MBA

# Partial Copyright License



**Title of Thesis/Project/Extended Essay**

Tolling Valuation and Strategies for Powerex Corp.

**Author:**

John M.T. Wilkinson

August 29, 2003

Date

## ABSTRACT

Powerex Corp. (Powerex) is the wholly-owned power and gas marketing subsidiary of the British Columbia Power & Hydro Authority (B.C. Hydro), a Crown corporation of the Province of British Columbia. Powerex trades power and gas commodities in standard and custom contract volumes and tenors. Part of the company's long-term growth strategy is to increase trade volumes and seek market opportunities in a market of ever-tightening margins. Powerex has entered into several short-term, simple contracts with generators to convert gas, which Powerex supplies or is financially accountable for, into electricity, which Powerex acquires for trade. The aforementioned contracts are generally referred to as a type of tolling agreement. Powerex may consider seeking out longer-term, more complex tolling contracts to further satisfy these growth objectives. The objective of this report is to educate the reader on the concept of tolling agreements within the North American power industry and to provide a tolling valuation methodology and strategy to help shape or assess any proposed tolling contract.

## ACKNOWLEDGMENTS

The authors want to thank Chris O'Riley, Jeff Gingera, Kirsten Peck and Teresa Conway for providing support and direction for completion of this project. We are very grateful for the technical input of Tomoaki Nakashima and also for the input of Doug Eger and Brian Moghadam. We also appreciate Ian McCarthy's supervision to ensure this paper met the academic requirements for the MOT MBA. Finally, the support and patience of family, friends and co-workers during the tough time constraints of going through an MBA while working fulltime will not be forgotten.

## TABLE OF CONTENTS

## LIST OF FIGURES

## LIST OF TABLES

## LIST OF ABBREVIATIONS AND ACRONYMS

AC: Alternating Current
AGC: Automatic Generation Control
ATC: Available Transmission Capacity
BCTC: British Columbia Transmission Corporation
BTU: British Thermal Unit
CAISO: California Independent System Operator
CALPX: California Powerex Exchange
CaR: Capital at Risk
CCGT: Combined-Cycle Gas Turbine Units
CCRO: Committee of Chief Risk Officers
CERA: Cambridge Energy Research Associates
CPI: Consumer Price Index
CT: Combustion Turbine
DCF: Discounted Cash Flow
DCS: Distributed Control Systems
DOE: Department of Energy
DSCR: Debt Service Coverage Ratio
EEI: Edison Electric Institute
EIA: Energy Information Administration
EPACT: Energy Policy Act of 1992
ERCOT: Electric Reliability Council of Texas
FEA: Financial Engineering Associates
FERC: Federal Energy Regulatory Commission
FOM: Fixed Operation and Maintenance
FTR: Firm Transmission Rights
GAAP: Generally Accepted Accounting Principles
GBM: Geometric Brownian Motion
GJ: Giga-Joule
GTL: Gas-to-Liquid
GW: Gigawatt
GWh: Gigawatt-hour
HJM: Heath-Jarrow-Morton
HVDC: High Voltage Direct Current
ICE: Intercontinental Exchange
ICP: Island Cogeneration Project
ICS: Integrated Control Systems
IMO: Independent Market Operator
IOU: Investor Owned Utility
IPP: Independent Power Producer
ISDA: International SWAP Delivery Association
ISO: Independent System Operator
kV: Kilovolt
kWh: Kilowatt-hour
LC: Letter of Credit
LDC: Local Distribution Company
LOB: Line of Business
LNG: Liquefied Natural Gas
LSF: Least-Squared Fit

LSMC: Least Squares Monte Carlo
MCF: Millions of Cubic Feet
MCP: Market Clearing Price
MMBtu: Millions of British Thermal Units
MRJD: Mean-Reverting Jump-Diffusion
MtM: Mark-to-Market
MW: Megawatt
MWh: Megawatt-hour
NAERO: North American Electric Reliability Organization
NAEWG: North America Energy Working Group
NEB: National Energy Board
NERC: North American Electric Reliability Council
NGX: Natural Gas Exchange
NYMEX: New York Mercantile Exchange
NPV: Net Present Value
NWED: Northwest Energy Development
OASIS: Open Access Same-Time Information System
OTC: Over-the-Counter
P&L: Profit and Loss
PJM: Pennsylvania /New Jersey/ Maryland
PMA: Power Marketing Authorization
POD: Point-of-Delivery
POR: Point-of-Receipt
PSE: Puget Sound Energy
PSOSE: Power Supply Operations Shift Engineers Office
PUC: Public Utility Commission
PUHCA: Public Utility Holding Company Act of 1935
PURPA: Public Utilities Regulatory Policies Act of 1978
PX: Power Exchange
QF: Qualified Facility
RAROC: Risk Adjusted Return on Capital
RMR: Reliability Must Run
RTO: Regional Transmission Organizations
S&P: Standard and Poors
SMD: Standard Market Design
TSOC: Term Structure of Correlation
TSOV: Term Structure of Volatility
VaR: Value-at-Risk
VIGP: Vancouver Island Generating Project
VOM: Variable Operating and Maintenance
WACC: Weighted Average Cost of Capital
WECC: Western Electricity Coordination Council
WSPP: Western Systems Power Pool

# 1 INTRODUCTION

Powerex Corp. (Powerex) is the wholly-owned power and gas marketing subsidiary of the British Columbia Power & Hydro Authority (B.C. Hydro), a Crown corporation of the Province of British Columbia. Powerex trades power and gas commodities in standard and custom contract volumes and tenors. Part of the company's long-term growth strategy is to increase trade volumes and seek market opportunities in a market of ever-tightening margins. Powerex has entered into several short-term, simple contracts with generators to convert gas, which Powerex supplies or is financially accountable for, into electricity, which Powerex acquires for trade. The aforementioned contracts are generally referred to as a type of tolling agreement. Powerex may consider seeking out longer-term, more complex tolling contracts to further satisfy these growth objectives.

The objective of this report is to educate the reader on the concept of tolling agreements within the North American power industry and to provide a tolling valuation methodology and strategy to help shape or assess any proposed tolling contract. To address this objective the paper is structured as follows:

Chapter 2 – North American Energy Industry

This chapter provides the reader with an introduction to the North American Energy Industry. A basic understanding of the concepts discussed in this section will be required for the tolling valuation and strategy portion of this paper. While this section is mandatory reading for those not involved in, or those just entering the industry, it may help to complete a picture for industry workers who are only focussed on certain portions of the business.

Chapter 3 – Powerex

At the time of writing both authors are employed by Powerex. The tolling valuation methodology introduced in this publication, the application of it, and the recommendations based on it are intended to benefit Powerex. This chapter introduces the reader to Powerex itself. It provides insight into how Powerex became what it is, the functions required to do so, the relation to its parent, B.C. Hydro, and the reason why Powerex is considering tolling arrangements balanced against the inherent risks of such constraints.

Chapter 4 – Tolling

This chapter describes the concept of a tolling agreement. It explains a variety of different details that may form a contract. These agreements may hold obligations that are simple to complex and physical to financial.

Chapter 5 – Tolling Analysis

This is a relatively technical section that identifies several methods for analyzing a tolling proposal. It describes quantitative analytical valuation techniques, and discusses the importance of physical plant location. It goes into detail on how profit may be achieved and covers risk considerations and the performance metrics associated with these types of long-term positions.

Chapter 6 – Application of Framework

The application of the analytical techniques introduced in the previous chapter is applied here. This chapter introduces the concept of scenarios to provide forecast data beyond available market pricing. These scenarios form the basis for measuring the potential value of a proposal under a variety of circumstances. Two tolling opportunities, a merchant plant in Arizona, and a utility-backed plant in Oregon, are analyzed and the results are presented.

Chapter 7 – Recommendations

Although each proposed tolling agreement will be unique and require individual analysis, general tolling and tolling analysis recommendations are provided here in the report's conclusion.

# 2 NORTH AMERICAN ENERGY INDUSTRY

## 2.1 Introduction

The primary purpose of this report is to evaluate the merits and drawbacks of entering into tolling arrangements with natural gas generation plants as well as to provide a recommendation for B.C. Hydro's power marketing subsidiary, Powerex Corp. To appreciate this valuation it is important to have an understanding of the North American energy industry. This chapter presents a brief history of the development of the market and how it continues to evolve. It goes into detail about the infrastructure required for a power market and details different types of generation facilities and how they are connected to the market. The basics of power trading and risk management are also examined.

While other energy sources, most notably coal, merit research and understanding, this report focuses on natural gas and electricity. These are the only commodity markets where, as of 2003, Powerex actively trades and therefore this tolling analysis is specifically on tolling contracts with natural gas plants.

## 2.2 History

The North American energy industry has shown steady growth for the past 70 years. It produces about one-fourth of the global energy supply and consumes about 30 percent of the world's commercial energy. (Energy Information Administration, 2002) The development of the electricity and natural gas markets are examined in the following review of the industry's past.

Electricity across North America has historically been supplied through large, vertically integrated utilities. These utilities owned the generation facilities, the transmission lines to transport it, and the distribution to reach the end consumer. As with telecommunications, it was considered a natural monopoly where efficient production could only be achieved through the economies of scale of an integrated utility. The U.S. federal government entered the utility industry and started supplying power in 1933, however most utilities are investor owned utilities (IOU). To protect consumers from monopolistic abuse, federal and state regulations were imposed. The U.S. Public Utility Holding Company Act of 1935 (PUHCA) introduced the regulation of holding companies under the Securities and Exchange Commission. The Federal Power Commission held responsibility for regulating interstate utilities.

The Federal Power Commission acquired more responsibilities when it was given the authority to regulate natural gas pipelines through the Natural Gas Act of 1938. In 1954 their authority expanded to include the regulation of wellhead prices. This came out of a decision made by the Supreme Court known as the Phillips Decision. While the intent of regulation was to benefit to consumers, the result of regulated prices on the production, the pipelines and the local distribution companies (LDC) led to supply shortages. The fixed prices discouraged producers from replacing reserves due to reduced returns on investment.

In the electricity industry, utilities were becoming more and more interconnected through transmission grids. In 1965 an electricity blackout occurred that left almost 30 million people without electricity in the Northeast of the United States and the Southeast portion of Ontario. In an effort to prevent the reoccurrence of another major blackout, members from various power companies formed a North American Electric Reliability Council (NERC) a few years later in 1968. The NERC mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. It is responsible for setting standards for reliable operation and planning, as well as monitoring, and assessing compliance with those standards for the bulk electric system.

In 1977 the Federal Energy Regulatory Commission (FERC) was formed as an independent regulatory agency within the U.S. Department of Energy (DOE). This was a result of the DOE Organization Act. The Federal Power Commission was closed and FERC assumed their previous responsibilities.

In 1978 the Natural Gas Policy Act allowed the deregulation of wellhead gas prices and resulted in a drastic increase in natural gas production. The same year the Public Utilities Regulatory Policies Act (PURPA) was developed as part of the U.S. National Energy Act. The intent was to encourage more energy-efficient and environmentally friendly commercial energy production. With the rise in oil prices, PURPA was intended to stimulate the use of renewable energy sources to produce electricity. Generation produced through cogeneration or renewable sources could receive 'qualified facility' (QF) approval. PURPA required utilities to purchase needed power from these qualified facilities under reasonable terms and conditions. This forced the interconnection of the new generators to the existing transmission grids and led to the development of a non-utility generation sector.

FERC was instrumental in developing competitive markets. In 1985 FERC issued Order 436, which required open access to pipelines for transportation services. Gas marketers appeared as a result of this deregulation.

The natural gas market was given a boost with the U.S. Clean Air Act Amendments of 1990. This legislation required a reduction of sulphur dioxide and nitrogen oxide emissions and impacted electricity production for many coal-fuelled generators. At the time, gas-fired, combined-cycle power generators were less expensive and more efficient than previous coal-fired ones. The use of these generators resulted in a rise in natural gas consumption.

As technology advances were made in generating facilities, they were also made in transmission line technology. These improvements made the lines more efficient at sending electricity over long distances. There was now a clear benefit to using electricity from a variety of geographically dispersed generators.

The Energy Policy Act of 1992 (EPACT) encouraged development of a competitive wholesale power market to help balance the disparate prices paid by consumers across the continent. It created a new class of 'Exempt Wholesale Generators' that could produce electricity by any means, regardless of efficiency concerns. It allowed utilities to own generating facilities outside their franchise area, both within and outside of the country. It required some utilities to open their transmission systems for wholesale services and granted FERC the authority to regulate its access. The EPACT limited sales to wholesale customers but created the potential for competition at the retail level. That decision was left to the state legislatures and regulatory commissions.

Major restructuring of interstate pipeline operations occurred in 1992 with FERC Order 636 to un-bundle the sale of gas from transportation services. Enormous pipelines were built as a result. Both supply and transportation could be selected by customers. The same year the Government of Canada and Provincial Governments of Alberta, B.C., and Saskatchewan agreed to deregulate prices of crude oil and natural gas, and regulation allowed direct purchasing of gas by large consumers. In 1993 all price controls on wellheads were removed in the U.S.

In 1996 FERC issued Order 888 which required all IOUs with transmission lines to provide open-access service for all wholesale transactions. It also forced power pools to open membership to power marketers. In Canada the provinces of Alberta and British Columbia became the first to enter into wholesale electricity competition. Quebec and Manitoba subsequently followed in 1997.

Although FERC Order 888 strengthened wholesale competition, discriminatory transmission usage practices remained and FERC planed a new structure for transmission access. At the end of 1999, FERC issued Order 2000 that introduced a long-term necessity to create regional transmission organizations (RTO). The basic requirement for an RTO is that it has to be an independent entity that can control the transmission grid without discrimination.

By mid-2000, 24 U.S. states had passed regulatory orders or laws to implement competition at the retail level. That summer, California started going through an energy crisis.

California was an early pioneer in the deregulated energy market. Its restructuring efforts had a number of flaws. This ultimately resulted in the bankruptcy of utilities, black-outs, and a disruption and set-back for wholesale energy trade across North America. California required investor-owned utilities to sell their generation assets and allowed the new owners not to have to sell their output within California. A California Powerex Exchange (CALPX) was created as a commodities market for marketers and generators to compete to sell generation in response to bids from buyers. A California Independent System Operator (CAISO) was established to manage control of the transmission grid within the state. Utilities were required to sell and buy solely from the CALPX and were not allowed to enter into long-term contracts. The electricity price rate that utilities could sell to retail consumers was frozen by the government. In the summer of 2000 California was plagued by tight generation capacity, interstate transmission lines were constrained, and gas prices were high. Utilities were forced to purchase electricity from a limited market at prices higher then they were allowed to sell it for. As a result, they amassed huge debts, their credit ratings dropped and suppliers became reluctant to sell for fear of not receiving payment. With utilities facing bankruptcy, the CALPX was shut down.

Energy infrastructure improvements continued and in recognition of a mutual need for Canada, Mexico and the United States to work together to improve energy trade and international transmission interconnections, a North America Energy Working Group (NAEWG) was established in April 2001. That year the province of Saskatchewan entered into wholesale electricity competition.

On December 2, 2001 a major shake-up occurred in the industry when the company Enron filed for bankruptcy protection. Enron had become the seventh-largest company by revenue in the U.S. through energy trading and market making. Its collapse followed the revelation that it used complex partnerships to hide half a billion dollars of debt and that the company was vastly overstating its profits. Investigations were made into the company. FERC subsequently released internal Enron documents in which questionable trading practices appeared. In May 2002, California requested the Justice Department to investigate into Enron's dealings with California. Enron was accused of fraudulent trading practices that included intentionally over-scheduling power in California knowing the state would then pay to relieve the resulting transmission congestion; over-selling power to companies that didn't need it to create congestion knowing the excess power could be sold back to California for higher prices; buying power within the state cheaply, selling it to an out-of-state intermediary, and reselling it back to the state for higher import prices.

The province of Ontario had been preparing for deregulation since 1998 and split Ontario Hydro into five separate entities. The Ontario electricity market opened May 1, 2002 amidst strong concerns about the benefits of an open energy market. This was fuelled by the California and Enron situation. Ontario established an Independent Market Operator (IMO) to administer the market through power exchange operations. That new market was then subject to supply challenges partly due to an extremely hot summer and the high usage demands of air-conditioners. Electricity prices rose more than 23% within 6 months and retail prices fluctuated with the change. In response, the government enacted a retail rate freeze from December 1, 2002 to last until 2006. Another province, New Brunswick, will open for wholesale electricity trade in 2003.

Canada ratified the Kyoto Protocol on December 17, 2002. It seeks the reduction of overall emissions of greenhouse gases (including carbon dioxide, methane, and nitrous oxide) to levels below 5% of what they were in 1990 by 2012. This will impact the ability to build new fuel burning generation plants.

British Columbia's electricity utility, B.C. Hydro, has been structuring itself to have more distinguishable lines-of-businesses. To comply with the U.S. move towards regional transmission organizations, the B.C. government passed a Transmission Corporation Act on May 29, 2003 to place control of the B.C. Transmission grid with a newly formed independent crown corporation instead of the B.C. Hydro utility (the generator, marketer and retail distributor).

California continues to seek refunds on the prices it paid for electricity in 2000 and 2001. On July 7, 2003 FERC voted to initiate show cause proceedings against approximately 50 different power entities. It requires them to explain any conduct that appears related to fraudulent California trading practices. The number of energy trading firms has been decreasing as companies are closing trading arms due to the high risk market volatility.

As of August 2003, Alberta and Ontario are the only Canadian provinces to have initiated competitive retail markets. In the U.S. a number of states have delayed restructuring and California has suspended theirs. The status of restructuring by state, as of February 2003, is indicated in Figure 2-1. Nine utilities in the U.S. are federally operated.

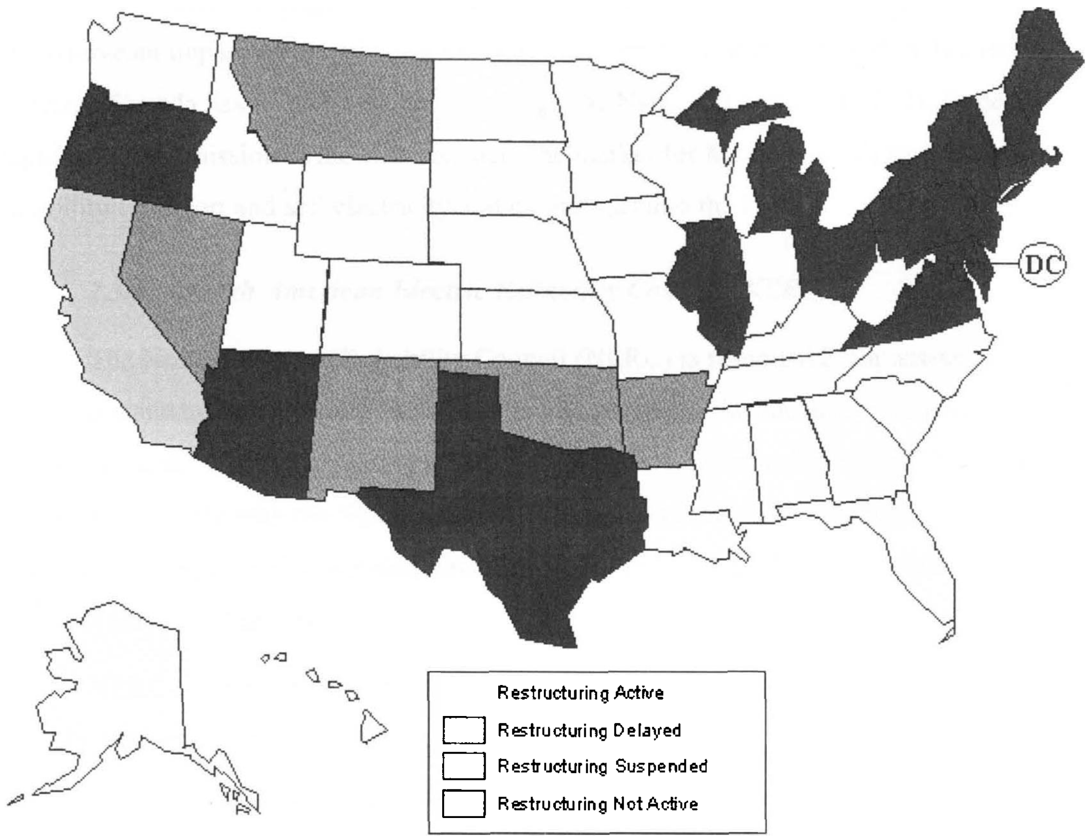



*Figure 2-1 Status of State Electric Industry Restructuring Activity as of Feb 2003. Source: Energy Information Administration, 2003.*

On the afternoon of August 14, 2003 a massive power outage affected millions of people in North America. The power loss impacted eight U.S. states, including New York, as well as southern portions of Ontario. This outage will force a review of the adequacy of the existing system and should confront the need to encourage development on an aging North American transmission grid which is subject tight regulation. Various news reports cited that power demand had increased 30 percent in the previous decade while transmission capacity only increased at half that rate.

The energy industry is and will be working through the difficulties of restructuring over the next several years. The benefits of free markets and the expectation that they drive down costs and prices and create innovative solutions to do so, have yet to be fully achieved in this industry.

## 2.3 Structuring and Regulation

Infrastructure changes within North American require approval. The organizations which have an impact on electricity trade and assets are listed and described in this section. Although Canada has its own regulation through the National Energy Board, the Federal Energy Regulatory Commission in the U.S. can steer the market for Mexico and Canada by controlling the ability to import and sell electricity and natural gas into the U.S.

### *2.3.1 North American Electric Reliability Council (NERC)*

The North American Reliability Council (NERC) is responsible for assessing and enforcing standards compliance and assessing and analysing the adequacy and performance of the electric grid. When considering a tolling agreement, it is critical to ensure the generation facility will comply with the NERC operation standards of the associated regional reliability council. This requires all generation facilities to be operated to achieve the highest practical degree of service reliability.

NERC is a non-profit corporation owned by the following ten regional reliability councils with an Alaska Council as an affiliate:

1. East Central Area Reliability Co-ordination Agreement – ECAR
2. Electric Reliability Council of Texas, Inc. – ERCOT
3. Florida Reliability Co-ordinating Council – FRCC
4. Mid-Atlantic Area Council – MAAC
5. Mid-America Interconnected Network, Inc. – MAIN
6. Mid-Continent Area Power Pool – MAPP
7. Northeast Power Coordinating Council – NPCC
8. South-eastern Electric Reliability Council – SERC
9. Southwest Power Pool, Inc. – SPP
10. Western Electricity Coordinating Council – WECC

Each council is comprised of members from electric utilities, independent power produces, and electricity marketers. The regions of responsibility are depicted in Figure 2-2.

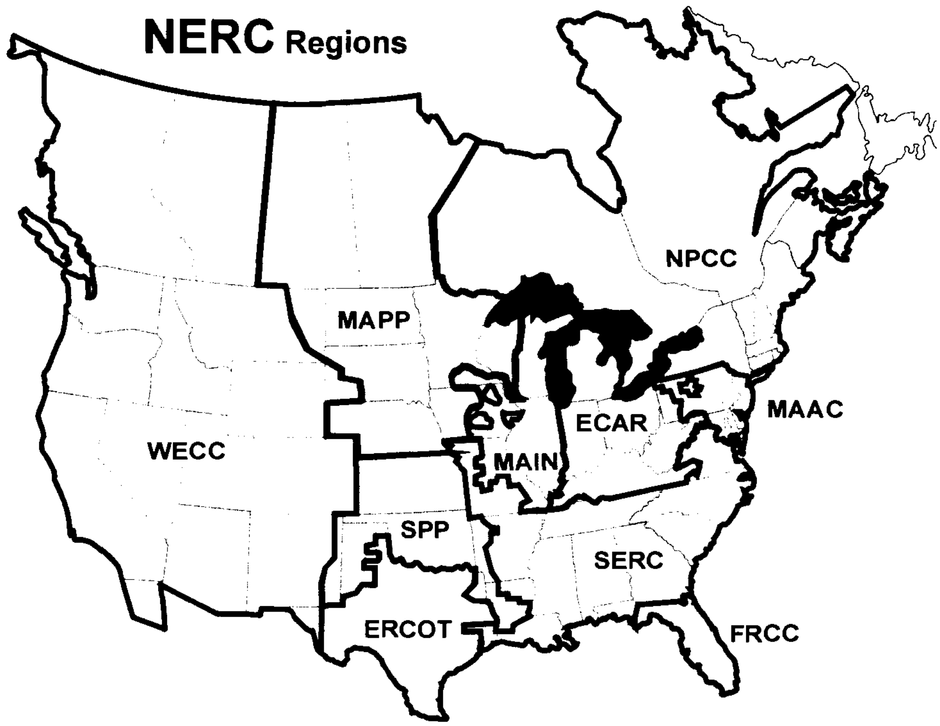



*Figure 2-2 NERC Regions. Source: NERC, 2003. (NERC material is protected by copyright and is used by permission)*

For over 35 years NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of everyone involved. The incentives and responsibilities of a voluntary system of compliance are no longer considered adequate. NERC is seeking legislation, currently pending in Congress, to enable it to become an organization with authority to enforce compliance with reliability standards among all market participants. NERC would then become the North American Electric Reliability Organization (NAERO).

### *2.3.2 National Energy Board of Canada*

The National Energy Board (NEB) was created in 1959 as an independent federal regulatory agency. The NEB is responsible for regulating the Canadian energy industry on behalf of public interest. This regulation covers tolls and tariffs on natural gas pipelines and electricity exports. They have imposed a restriction for a maximum duration of 30 years for electricity export licenses. The NEB maintains jurisdiction over international energy infrastructure decisions and inter-provincial ones, however provincial regulation is administered separately by provincial utility boards.

### *2.3.3 U.S. Federal Energy Regulatory Commission (FERC)*

The Department of Energy Organization Act of 1977 established the Federal Energy Regulatory Commission (FERC) to supersede the Federal Power Commission. FERC regulates natural gas sales and transmission, and may approve rates for wholesale electric sales of electricity, transmission, power marketers, power pools, power exchanges and independent system operators. It regulates construction of pipeline facilities and interstate energy commerce. FERC obtains its authority through the U.S. Department of Energy, which has exclusive jurisdiction over cross-border infrastructure construction and export of electric energy. State Commissions or Agencies are responsible for State generation and transmission facility approval.

## 2.4 Electricity Infrastructure

Electricity is consumed as it is produced on a near-real-time basis and thereby requires a tightly managed infrastructure to meet fluctuating real-time demands. As demand increases, so must supply. Most of the power grid is connected through transmission lines that transport alternating current (AC). The North American grid is built around an AC frequency of approximately 60 hertz (60 cycles per second). The supply-demand balance is controlled by monitoring slight shifts in this frequency whereby decreasing frequencies indicate that more energy is being consumed than produced. If this occurs, the frequency requires quick restoration to normal levels by adding generation on a dynamic and near-real-time basis to prevent damage to equipment connected to the grid.

Control Areas manage the grid and use technology to assist that management. An economic dispatch system that determines the lowest generation production costs and manages transmission bottlenecks may be used by a utility's energy management system to send information to automatic generation control (AGC) systems at the power plants.

Unanticipated electricity demand requires regulating reserves. These are supplied through spinning reserves, which are generators that are operating on the grid and are maintaining the potential for additional capacity. Contingency reserves are required to protect against unexpected outages. Half of these can be supplied by supplemental resources that are required by NERC to deliver electricity within 10 minutes of need. If the electricity usage, also known as load, is greater than the supply capacity then load shedding is required. This may be accomplished through rolling brownouts, that allow voltage to drop, and is followed by controlled blackouts, also known as curtailments. Curtailments may be involuntary where they are managed at the discretion of control areas, voluntary through implementation by residential, commercial and industrial sectors, and contractual in supply agreements with industrial customers.

The electricity infrastructure consists of three basic functions, the generation to produce the electricity, the transmission to transport it, and the distribution to the end-users. Industry restructuring requires utilities that maintain all the functions to separate their asset control to ensure an unbiased open market.

### *2.4.1 Generation*

Electricity is produced through generators that convert potential mechanical or chemical energy into electricity. Generating facilities may be owned by utilities or independently. Non-utility generators are known as independent power producers (IPP). These producers do not have the same restrictions that have been imposed on utilities. IPPs are fundamental to providing an open market for power supply.

Electricity supply comes from a range of generating facilities. They have different characteristics and some are more suited to specific load requirements. Load requirements are categorized as base-load, intermediate load, and peak load. Base-load generating units run continuously to meet continuous expected load requirements. There is no requirement to take them on or offline quickly. Peak-load, also known as on-peak, covers the heavy load hours of 06:00 to 23:00 for regular work days. It requires generation units that can be brought on-line quickly to match highly fluctuating peak loads. Intermediate-load generating units are used during transition periods between base and peak load requirements and usually run 12 to 16 hours during work days.

Weekly, daily, and seasonal demand changes are evident when looking at system loads. Usage also varies by location. In the hot California summer, electricity demand rises with heavy air conditioner usage, as shown in hourly system load averages for January and July (Figure 2-3). In British Columbia that trend is reversed. In the cold winters electric heating increases the system load and summers are more temperate and less electricity is used. Average hourly B.C. system loads are shown in Figure 2-4.

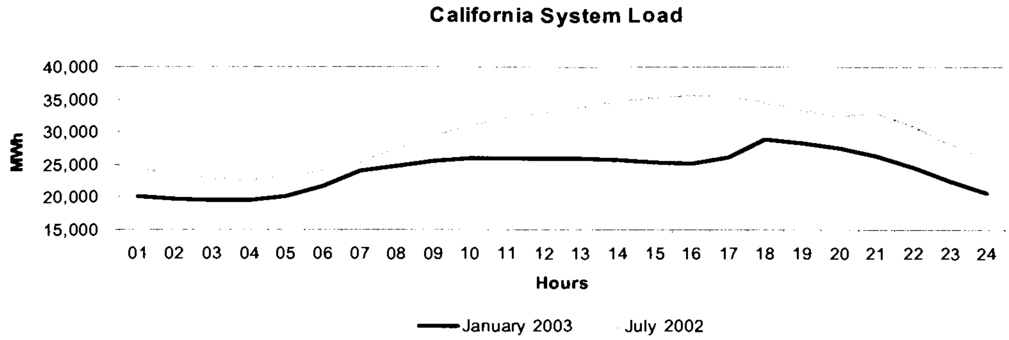



*Figure 2-3 January 2003 and July 2002 Hourly Averages for System Load in California. Figure by authors.*

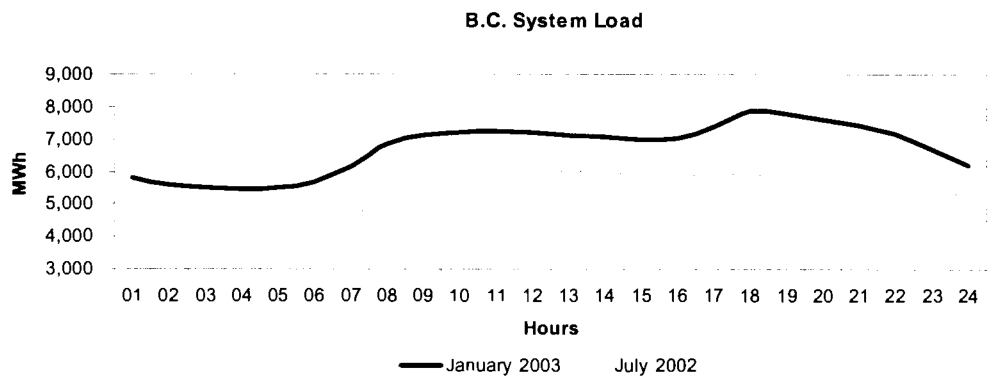



*Figure 2-4 January 2003 and July 2002 Hourly Averages for System Load in British Columbia. Figure by authors.*

There are many types of generation plants. The efficiency of a plant is most commonly measured by a heat rate. A heat rate is the quantity of fuel required to produce one kilowatt-hour (kWh) or megawatt-hour (MWh) of electricity. The quantity of fuel is typically measured as the amount of heat required to raise the temperature of water a given amount, and measured in British thermal units (BTUs) or in the metric unit Joules. For simplicity these are typically measured in millions of BTUs (MMBTU) or in Giga-joules (GJ). Conversion between these is calculated at 1 MMBtu = 1.055056 GJ.

The profitability of running a fuelled power plant is measured by the spark spread. This is the difference between the demand price of electricity and the cost of the fuel to produce it and may or may not include fixed and/or variable operating and maintenance costs, depending upon the context. Spark spread is a fundamental consideration when assessing tolling contract offerings.

#### 2.4.1.1 *Steam Units*

Steam units supply the majority of energy in North America. They are large, base-load plants that take considerable time to ramp-up for use. They are expensive to start and consequently discouraged from shutting down. These plants use boilers to turn turbines that drive an electric generator. They are typically only 33 to 35 percent efficient on a thermo-dynamic basis. In other words, only 33 to 35 percent of the total available fuel energy is transferred into electrical energy, with the remainder lost as waste heat and friction.

Most steam units are fuelled by coal. Coal is currently the cheapest fossil fuel, but produces higher pollutants than alternative fuels. Advances in technology should change that. In 2001 the U.S. government committed to invest $2 billion in "clean coal" power technology over the next 10 years.

Nuclear power plants also generate electricity through steam units by using nuclear fission as the boiler heat source. The cost for nuclear energy is high and a decrease in wholesale market prices will discourage the development of new nuclear energy generation facilities and will likely cause some existing plants to shut down.

Geothermal technologies may also be used for steam units, however it has only achieved a small volume of output and, with the exception of some geographic areas, is limited in viable potential.

#### 2.4.1.2 *Gas Units*

Gas units use hot gas from burning natural gas or petroleum to turn gas turbines or to run combustion engines to generate electricity. Combustion turbine (CT) plants can be built quickly and can be brought on line in a short time. They are ideal as peak-load plants. Their thermal efficiency is a little less than large steam units. Nearly 10% of the power consumed in the U.S. in 2002 was supplied by gas plants, and these plants provide upwards of 23% of total U.S. generating capability.

Before or after gas enters the main turbine it can be burned more to provide additional power output from the plant. This is called duct firing. This process reduces the overall efficiency of the facility and provisions are usually placed on how often and for what duration this can be done.

The Energy Information Administration (EAI) forecasts for the period 2001 through 2005 that electric utilities are reporting plans to add 44,726 megawatts of generating capacity, 91% of which is gas-fired. (Energy Information Administration, 2002)

### *2.4.1.3 Combined-Cycle Gas Turbine Units (CCGT)*

A Combined-Cycle Gas Turbine (CCGT) can achieve up to 50 to 60% efficiency by making more efficient use of its fuel. The most efficient plant in commercial operation is a GE H system that claims up to 60% net efficiency. The waste heat from gas turbine generation is reused with a boiler to produce steam generation. These plants have a life expectancy of more than 25 years. The effective efficiency of CCGT units can be further increased through cooperation with, and sales to, a steam host, or user of otherwise wasted heat. Construction of CGGTs within transmission constrained areas can be favourable as it can be less expensive to site and build gas pipelines than high voltage transmission lines. These units have relatively low capital costs due to a number of competing equipment vendors. They have high variable costs though related to their use of fuel.

Examples of thermal efficiencies of large CCGT systems designed for 60Hz power are provided in Table 2-1. The net thermal efficiency is calculated based on the lower heating value of the fuel and electrical output at 60Hz. Heat rates for plants typically range from 6.1MMBtu per GWh to over 10MMBtu per GWh.

| ***Manufacturer*** | ***Gas Turbine Output (MW)*** | ***Steam Turbine Output (MW)*** | ***Total Output(MW)*** | ***Net Thermal Efficiency (%)*** |
|---|---|---|---|---|
| Alstom Power | 176 | 84 | 260 | 56.6 |
| GE Power Systems 7FA | 170 | 95 | 265 | 56.0 |
| GE Power Systems 7FB | 181 | 99 | 280 | 57.3 |
| Siemens Westinghouse | 2 x 182 | 197 | 561 | 55.8 |
| Siemens Westinghouse | 250 | 115 | 365 | 58.0 |
| Mitsubishi Heavy Industries | 178 | 103 | 281 | 56.7 |
| Mitsubishi Heavy Industries | 247 | 124 | 371 | 58.0 |

*Table 2-1 Net Thermal Efficiency of Large CCGT Systems. Table by authors*

#### *2.4.1.4 Cogeneration Units*

Some industries generate heat from their manufacturing process or produce it as a central heating need. This is found in industrial sectors for pulp and paper, chemical products, and refined petroleum products. In cogeneration plants the heat is recycled as part of the electricity generation process. The two ways this is done are called bottom-cycling or top-cycling. The latter uses produced heat to create steam and produces electricity first with remaining heat cycled on to other business needs. Although the thermal efficiency in cogeneration plants are higher than stand alone ones, there is a lower efficiency of electricity production and reduced plant electrical output capacity. The interconnection between generation and industry need increases the operational and control complexities.

#### *2.4.1.5 Hydroelectric Units*

Hydroelectric plants use the potential energy of water stored at differing elevations to turn turbines to generate electricity. Water is considered a renewable resource, but its supply is intermittent by nature. High reservoir levels provide more generation for the same amount of water and therefore low water levels are more costly. Hydroelectric plants provide flexibility by being quick to ramp-up for demand, and by providing a virtual way to store electricity as potential energy from stored water by not running the damns and acquiring other energy from the grid or other markets. Creating a hydroelectric plant can have a costly environmental impact. There will be concerns with flooding of the surrounding areas and the impact to wildlife including the fish which use the water way.

#### *2.4.1.6 Other Units*

There are a number of other generation plants providing a small amount of capacity to North America. These plants may produce power through kinetic energy as acquired through wind or ocean tides, or chemical energy as collected through solar power through photovoltaic panels. "Green Energy" is a commonly used term for energy projects coming from environmentally friendly resources. Generators fitting this description include those that produce energy from small hydro facilities, biomass energy, wood waste, solar, geothermal, tidal, and wave energy.

Electricity price disparity is a factor of available energy sources in a particular region. The use of different resources to produce electricity in the U.S. is shown in the U.S. government published numbers of Table 2-2.

| Period | Coal | Petroleum | Gas | Nuclear | Hydro-electric | Geo-thermal | Other | Total |
|---|---|---|---|---|---|---|---|---|
| 1990 | 1,560 | 117 | 264 | 577 | 280 | 9.6 | 2.1 | 2,808 |
| 1991 | 1,551 | 111 | 264 | 613 | 276 | 8.1 | 2.1 | 2,825 |
| 1992 | 1,576 | 89 | 264 | 619 | 240 | 8.1 | 2.1 | 2,797 |
| 1993 | 1,639 | 100 | 259 | 610 | 265 | 7.6 | 2.0 | 2,883 |
| 1994 | 1,635 | 91 | 291 | 640 | 244 | 6.9 | 2.0 | 2,911 |
| 1995 | 1,653 | 61 | 307 | 673 | 294 | 4.7 | 1.7 | 2,995 |
| 1996 | 1,737 | 67 | 263 | 675 | 328 | 5.2 | 2.0 | 3,077 |
| 1997 | 1,789 | 78 | 284 | 629 | 337 | 5.5 | 2.0 | 3,123 |
| 1998 | 1,807 | 110 | 309 | 674 | 304 | 5.2 | 2.0 | 3,212 |
| 1999 | 1,768 | 87 | 296 | 725 | 294 | 1.7 | 2.0 | 3,174 |
| 2000 | 1,697 | 72 | 291 | 705 | 248 | 0.15 | 2.1 | 3,015 |
| 2001 | 1,560 | 79 | 264 | 534 | 190 | 0.15 | 2.0 | 2,630 |
| 2002 | 1,519 | 56 | 229 | 507 | 233 | 0.18 | 2.0 | 2,547 |

*Table 2-2 U.S. Electric Utility Net Generation, 1990 through December 2002 (thousand GWh). Source: Energy Information Administration.*

### 2.4.2 Transmission

Electricity can travel over long distances via high voltage transmission lines made of copper or aluminium. Bulk transmission lines in B.C. operate at 500,000 volts (500 kV). The voltage is first stepped-up from the relatively low voltages provided by the generating facilities then stepped-down (normally to 230 kV or 138 kV) for distribution using transformers once it has reached a load center. Terminal stations control energy flow in the transmission system and reduce voltage to sub-transmission levels. Distribution substations reduce voltage for retail consumption. Transmission voltage can be anything over 60 kV.

North America may be viewed as one large electricity grid, but it is essentially divided into three major power grids: the Western Interconnect, the Electric Reliability Council of Texas (ERCOT) Interconnect, and the Eastern Interconnect. The networks have limited connections to each other and ERCOT is connected by only a few direct current lines. High voltage direct current (HVDC) lines are also found on the grid. In B.C. they are used for underwater passage. HVDC lines connect Vancouver Island to mainland B.C. Almost all major generating facilities are connected to at least one other through the grid.

When electricity travels long distances energy is lost through heat due to resistance in the conductors. This is referred to as line-losses or shrinkage. The longer the distance, the greater the losses incurred. These line-losses are reduced significantly by increasing the voltage at which the energy is transmitted. Transmission line capacity is restricted to handle a maximum volume of electricity. Exceeding this capacity may cause fires or line faults.

There is a need to balance energy generation and its consumption. This is handled by over 150 Control Areas across North America. Control Area Operators dispatch to generators to control the supply and demand balance. They determine available transmission capacity (ATC) by accounting for planned or unexpected outages of transmission lines, and the individual capacity ratings of the lines due to environmental factors.

Electricity may only be imported to a region if there is sufficient transmission capacity available to get it there. If there is insufficient line capacity and there is available supply waiting to be delivered, this is referred to as transmission congestion. One way to alleviate transmission congestion is to re-dispatch generation and use generators within the congested region to supply local power.

Transmission usage rights are leased for set durations of time and capacity. Rights may be bought on an hourly, daily, weekly, monthly or yearly basis. They are sold under different classifications such as firm and non-firm. Non-firm transmission is usually less expensive but holds risk as these usage rights are first to be cut if a line capacity is de-rated (reduced due to environmental factors such as high temperatures or lightening risk). Transmission is managed by numerous regions, called nodes, across the continent. Available transmission capacity is posted over the Internet on Open Access Same-Time Information Systems (OASIS). Transporting electricity over long distance may require complex scheduling that involves marketers, control areas, managers, and transmission owners.

Transmission has the characteristics of a natural monopoly. Open access to that grid is a critical component to ensuring an efficient electricity marketplace. In the U.S. existing transmission lines are owned predominantly by investor-owned utilities. Regional transmission organizations promise to simplify the current market complexities. The following organizations are proposed or currently exist: RTO West, California ISO, WestConnect (Southwestern U.S.), ERCOT ISO, Midwest RTO, Northeast RTO, and Southeast RTO.

### *2.4.3 Distribution*

Distribution is the delivery of power to the end-use retail customer. It includes metering and billing its use. In the U.S., distribution falls under the jurisdiction of State Public Utility Commissions (PUC). With restructuring, the responsibilities should eventually change and PUCs will not control retail electricity prices. In Canada retail electricity prices are regulated by provincial utility boards.

## 2.5 Natural Gas Infrastructure

The world's largest natural gas consumer is the United States. Demand for gas-fired generators increased in the late 1990s. On the world's largest physical commodity futures exchange, the New York Mercantile Exchange (NYMEX), natural gas is the most active commodity and also the most volatile. Gas deregulation has been successful as production and profits have increased, while prices decreased.

Industry reports indicated that as of June 2003, the U.S. was facing the worst shortage of natural gas in 25 years. There is speculation about the short and long-term availability of natural gas. While there appears to be a shortage, it is also possible that exploration and production was slowed while producers waited for prices to rise. Supporting this theory is the fact that record injections into gas storage facilities were observed in June 2003. The Rocky Mountain area has potential for huge reserve bases, as do vast regions of the Canadian western provinces, including Hecate straight of the B.C. coast.

The natural gas infrastructure consists of production, transportation, storage, and distribution to end consumers through local distribution companies.

### *2.5.1 Production*

Natural gas is extracted from inside the earth's crust. Exploration geologists search for formations in the earth that can hold natural gas, typically sedimentary basins. Wells are drilled and gas is pumped out or extracted by natural pressure. There are thousands of natural gas companies in North America.

Different types of gas may be found, such as wet and dry gas. Wet gas is found alongside oil and is full of hydrocarbons. Wet gas goes directly to a refinery for processing before using shared pipelines. Dry gas is found in a reservoir on its own.

Huge oil and gas reserves have been found in the Mackenzie Delta region of northern Canada. A consortium including Imperial Oil, Conoco Canada, Shell Canada and ExonMobil Canada are seeking to develop Mackenzie Delta gas and a new pipeline to transport it. Combined initial production rates from key fields are expected to be between 800 million and 1 billion cubic feet per day. The NEB estimates nine trillion cubic feet of discovered gas reserves exist there.

Gas may be converted into liquefied natural gas (LNG) for storage and transportation. This is an expensive process that takes considerable time. The gas will turn to liquid at -160° C. Once in liquid form it uses 600 times less volume than in its gas state. This alternative is only viable when gas prices are high. Currently there are only three LNG facilities in operation in the U.S.

### *2.5.2 Transport*

Pipelines carry natural gas across North America. Compression stations are used to keep the pipelines pressurized. The largest pipeline owners are El Paso Corp, Williams companies, and Duke Energy Gas Transmission. Pipeline capacity is measured in volumes of million cubic feet (MCF) per day (MMCF/d), calculated at a standard temperature and pressure.

Pipelines are interconnected by hubs. The Henry Hub is the largest in North America. It interconnects nine interstate and four intrastate pipelines. Nearly half of the U.S. wellhead production occurs at or passes near the Henry Hub. Spot prices at the Henry hub are consequently strongly related to North American wellhead prices.

A number of new North American pipeline projects are being considered including a Blue Atlantic Pipeline project, which has potential to transport 1,000 MMCF/d of natural gas from the Scotian Basin to Southern Nova Scotia, New York, and New Jersey. The Carter Pipeline would provide a 180 MMCF/d link from the Maritimes and Northeast Pipeline to the TransQuebec and Maritimes Pipeline. An Offshore Calypso Pipeline is proposed to transport 832 MMCF/d from Bahamas to Florida. The Georgia Strait Crossing will introduce transport capacity of 100 MMCF/d from the Washington State Sumas border to British Columbia's Vancouver Island.

Natural gas may also be transported in liquid form (LNG) by barges, train and other land transport. Small quantities of LNG are trucked to Mexico.

### *2.5.3 Storage*

An important practice to hedge natural gas price risk is to use gas storage facilities if prices are presumed to be low. Large storage is held underground in porous rock formations. Storage is typically held in an aquifer storage field, an existing depleted gas reservoir or salt caverns. Sometimes it may be stored in abandoned coal mines and empty oil wells. No natural storage formations have been found near the south-western portion of British Columbia.

LNG Storage facilities are also available. They are large storage tanks with capacities up to 180,000 cubic meters. They act as a thermos to keep the gas cool enough (-160° C) to remain in liquid form. An equivalent volume of usable natural gas at standard temperature and pressure is 600 times the amount in storage.

## 2.6 Power Trading

Power trades may be physical or financial. Physical trading requires actual delivery of the commodity, electricity or gas, to settle a contract. Financial trading uses derivative contracts that derive their value from the commodity without actual delivery of the good. The use of derivatives is a way to reduce risk. Traders will take a long position if they have too much energy and want to sell and a short position if they want to buy. Speculation and hedging are two trading strategies. Speculation seeks profit and involves taking on risk under the belief there may be potential for large gains. Hedging reduces risk by taking offsetting contracts to protect against unpredicted price changes. Hedges, when applied correctly, can lock in profits associated with other trades, typically capping the upside gains of the other position but also insulating the trader against losses due to subsequent market changes.

There are over 450 entities registered with NERC (as of June 2003) that hold purchasing and selling rights in North America. Energy producers and consumers sell and buy respectively, but it is power marketers that maintain a holistic market view to optimize and fill its respective needs. While wholesale electricity trade is now common, retail trade for consumers including residential, commercial, industrial, and others, is still in the early stages of adoption in North America.

### *2.6.1 Trading Basics*

Electrical energy is measured in watt-hours, which is power multiplied by time, and is usually bought and sold in the wholesale market as dollars per megawatt-hour ($/MWh). One thousand megawatt-hours can serve approximately 100 residential consumers per year. Natural gas is bought and sold as dollars per millions of British thermal units ($/MMBTU) in the U.S. and as dollars per Giga-joule ($/GJ) in Canada.

Electricity trade has a number of complications. Electricity is difficult to store. One of the few ways to do this is to capture potential energy. By acquiring energy elsewhere and not using the resources to produce generation, there is potential to produce that generation later. Energy delivery is also restricted by transmission constraints and its value is often determined by location and accessibility. It is further complicated by inelastic demand as the cost of using electricity in many regions is fixed for retail consumers despite fluctuating wholesale prices. Demand is also unpredictable due to weather variations.

Energy marketing companies maintain portfolios of trades that are done. Within a portfolio may be many trading books. Trades are usually categorized into books that may be specific to a particular strategy, region, or trader.

#### *2.6.1.1 Markets*

Wholesale purchasing and selling may occur in a number of ways with numerous discrepancies between markets. FERC has encouraged the development of large regional independent system operators (ISO). An ISO must be an open access, non-profit organization. It is responsible for managing power flows, maintaining reliability, administering non-discriminatory transmission access, and maintaining operational integrity of an electrical grid. ISOs cannot own transmission lines or generation assets. To help commoditize the market, FERC has further pushed for a standard market design (SMD) and has ordered U.S. utilities to operate under SMD by October 2004. The following independent system operators are in place and operating in the U.S.:

- PJM ISO (Pennsylvania/New Jersey/Maryland)
- Midwest ISO
- ISO – New England
- New York ISO
- California ISO
- ERCOT ISO (Texas)

Centralized, regional auction markets are provided by independent system operators, power pools, and power exchanges (PX). Sellers place power supply offers in the market.

Demand is filled starting with the lowest price for supply. Many offers may be required to meet current demand and the highest price paid becomes the market clearing price (MCP). This market clearing price is then used to pay for the capacity sold by all the suppliers. This creates a high degree of price transparency and provides a signal of hourly and daily market prices. This type of market is not without problems. By shorting supply when demand is high it is possible for large suppliers to manipulate or "game" the market and over-inflate prices.

Bilateral contracts may also be made directly or indirectly with the consumer and supplier. This may be done on the spot-market up to a day ahead, or as a forward contract. The spot price is the current delivery price in that market. These contracts contain price risk that can be reduced by alternative trading methods.

Trade may also be done in financial over-the-counter (OTC) markets. This may be done through brokers or electronically in large trading arenas including:

- New York Mercantile Exchange (NYMEX)
- Intercontinental Exchange (ICE)
- Bloomberg
- Natural Gas Exchange (NGX)

#### *2.6.1.2 Contracts*

Energy on the grid needs to be managed constantly by real-time dispatching. It is traded through next-hour, day-ahead and long-term transactions. Contract terms usually refer to timed delivery of on-peak and/or off-peak. On-peak times are between the hours ending at 06:00 and 23:00. On-peak may be a Monday to Friday contract known as "5x16" or a Monday to Saturday which is a "6x16". Off-peak is the remaining hours such as "5x8, 2x25" and a flat contract is "7x24". Contracts may be sold as a standard product or as structured products which are unique and may consist of numerous options.

The length of a contract is known as its term. Spot contracts are for immediate or next-day delivery. Contracts beyond this are forward contracts. These are traded bilaterally or in the over-the-counter market. Forward contracts may involve firm delivery, optional delivery or variable volume, which is referred to as a swing.

Option contracts provide flexibility as to when the contract will be executed and whether it is based on a predetermined strike price. A daily-settled option can be exercised for the next-day. The premium for an option is paid up-front. A call option provides the right but not the obligation to buy at the strike-price, thereby taking a long position; whereas a put option provides the right but not the obligation to sell at a set price and thus a short position. Options may include a variable-price contract. There are different classes of options. European and Asian options can only be executed at set dates whereas American options may be exercised anytime prior to or on the expiration date of the option. Asian options use an averaged market price for the strike price and subsequent settlement.

Forward contracts are not settled until delivery, at which point (in the case of fixed forward contracts) the forward price that was set at the time of the contract is paid. To monitor the current value of a position, contract valuation will be estimated by marking-to-market. This is the measure of realized and unrealized profits and losses (P&L) of the contract by calculating the realized income from the delivered position of the contract, and comparing the market price for the undelivered portions of the contract to the prior trade price. Futures contracts involve daily settlement that is based on marking-to-market. At futures exchanges margin accounts are held to maintain a counterparty's difference in position. Basis is the difference between the futures contract and the spot price.

Determining the price for forward contracts involves looking at the forward price curves. These show the price that would be paid today for delivery and payment of the good for dates in the future. The prices need to be adjusted to incorporate risk tolerance and the net expense of the good based on predicted spot prices.

A swap is another type of forward trade where a party agrees to purchase one asset and in exchange the other party purchases another asset. This can be used to move from a fixed position to a floating position. Correlations may be intra-market or cross-market. Electricity prices and natural gas prices are closely correlated. Correlation factors are symbolized by the Greek letter rho.

#### *2.6.1.3 Physical Delivery*

To complete the physical delivery of energy, numerous entities need to be well coordinated. First a physical path needs to exist between the point of receipt (POR) and the point of delivery (POD). The entity responsible for the trade must have rights to send the megawatt capacity over the transmission lines at the time of delivery. Many transmission legs may be required as electricity is wheeled from one zone to another. All electricity trades are scheduled over the Internet through electronic tagging systems. Any control areas which need to give approval must do so prior to the start of the schedule or the contract will not be satisfied.

### *2.6.2 Trading Requirements*

Trading companies require government approval permits. To take natural resources out of Canada permits need to be obtained from Canada's National Energy Board. To purchase exported power from the U.S. a permit needs to be acquired from the U.S. Department of Energy. For all trade within the U.S., Power Marketing Authorization (PMA) needs to be granted by FERC and transaction reporting commitments need to be made. To take natural gas out of Alberta a permit is required from the energy utilities board.

Agreements with other trading entities can be obtained through association membership, such as through the Western Systems Power Pool (WSPP). Everyone in the association is set to trade with one another. Without association memberships, direct customizable agreements need to be made and these usually follow standard templates, such as those from the Edison Electric Institute (EEI). The International SWAP Delivery Association (ISDA) has customizable agreements for futures trading.

Credit concerns receive significant coverage in the agreements. Each company may have their own internal credit management department, or may follow independent assessments provided through companies including Standard & Poors, Moody's Investors Services, and Fitch Ratings. For a direct assessment of a private company, financial statements need to be reviewed and confidentiality agreements need to be established. If a company is not rated, guarantees are required from their parent company. Collateral is offered mostly through letters of credit (LC), prepayment, or cash. Holding cash in a separate account as collateral may not relieve credit concerns. If a company goes bankrupt there may be others first in line entitled for that money.

For companies trading in multiple markets, master netting agreements are put in place. These agreements are used to net-out, or take cross trades down to one final price since payments for different commodities may occur on different dates.

To ensure requirements are met for physical trading, transportation and transmission permits are required. Long term complex deals may also require specific custom agreements.

### *2.6.3 Organizational Structure*

Trading companies are typically divided into front, middle, and back offices. Trading activities occur in the front office. The decision for setting a trading position will come from the head trader and portfolio managers with support from the middle office. Trading is then negotiated by traders within day-ahead, real-time and forward trade desks. These trades may be made directly, through brokers or online exchanges.

The middle office provides control and support functions. Risk management will ensure the trades are made within the company's risk management policies. Trade capacity will face additional constraint through ceiling caps set on counterparties by a credit risk department. After approval has been given and the deal has been negotiated, deals must be captured and booked into energy trading risk management systems. This will also include the scheduling and confirmation of the deal from start to finish, and includes assuring rights and coordination for transmission paths for the times the capacity will be sent.

The back office confirms deal settlement and ensures payment at delivery. Support functions including information technology and legal are also essential to a trading organization. These roles may also be considered part of back office.

### *2.6.4 Risk Management*

Energy trade carries a high degree of risk and risk management groups are an essential part of any power marketing company. By valuing and monitoring trade positions, the risk group can ensure that traders are staying within acceptable risk tolerance levels and can manage the company's exposure to market change. Each trading company may have different risk-return strategies and defined stop-loss limits.

Quantitative modelling is done to analyze price behaviour. This is done using stochastic tools and applied statistics. The Black-Scholes option equation is commonly used. Black-Scholes modelling uses price behaviour assumptions and contract settlement details. It considers volatility to be flat during the term of an option. Structural modelling looks at market fundamentals including the prediction of production capabilities, resource costs and other influences that affect price.

An important risk measure is the sensitivity a position or portfolio of positions has to changes in the market place. Changes in price and the changes in portfolio values due to the changes in price are the most commonly monitored sensitivities in energy trading. Other sensitivity measurements include time to expiration, volatility, and discount rate. The sensitivities are all symbolized by Greek letters and they are therefore referred to as "Greeks". Price sensitivity is symbolized by delta and delta sensitivity is symbolized by gamma.

Volatility may be measured by looking at the historical volatility of forward price curves, the historical volatility of actual prices (day ahead and real-time), or market-implied volatility over the trade horizon based on quoted prices for options. Stress testing is done on a position or portfolio to simulate a large change in one or more particular value and assessing what affect that will have on the mark-to-market valuation.

A common measure for assessing a position or portfolio of positions is to look at the Value-at-Risk (VaR). This provides a numeric value with a chosen confidence level for the probability of profit-and-loss over a period of time, or holding period. Variance/covariance calculations are used to provide VaR estimates following a mark-to-market valuation. For long-term analysis a number a Monte Carlo methodology may be used. This method computes a number of simulations, commonly 1000 to 10,000, to simulate stochastic price processes that may occur in the market over time.

A VaR estimate is provided by stating, for example, that there is a 1 in 20 chance over the next 10 days of the mark-to-market valuation of the portfolio losing more than x dollars.

The risk group is also responsible for hedging analysis. This is important to ensure a hedging position does minimize related risk. It is essential for ensuring the company stays within its risk limits, typically quoted as VaR limits by book, market, commodity or trades. The risk group may encourage traders to look at options, swaps, forward contracts or electricity futures for hedging purposes.

There are a number of other important subjects that contribute to risk. Credit risk looks at a buyer's ability to complete a commitment and the potential of loss from credit defaults. Credit ratings of counterparties are assessed to determine the level of credit risk the company is willing to take on with a counterparty. Credit limits are set to restrict the levels of trade made with the counterparties. Other types of risk include operational, emissions, regulatory, and political risk.

Political risks cannot be overlooked. The California market had set rules and many participants participated within those market rules and completed physical delivery of power at set prices. Years after the power was delivered many companies are yet to be paid for the product and strong political forces have forced numerous lawsuits for refunds on the prices for the electricity. There is now precedence for contracts to be broken under political influence. As the government changes, so may the energy policies. There is also potential for re-regulation of markets, and the potential for assessment of liabilities or environmental levies associated with emissions resulting from generation.

### *2.6.5 Capital Requirements*

There are significant capital requirements for power trading. Capital is necessary to satisfy the credit requirements of trading counterparties before any trading can occur. It is needed to staff an organization from the front office through to the back office. It is needed to purchase and implement information technology systems used to initiate, manage, coordinate, and settle the trades. With the risks inherent in trading, capital is also required to ensure a company can survive if trades do not go as expected. There are only so many shops that meet the requirements to do this. These requirements are built from a quantification of market, credit and operating risks against which multipliers are applied to account for target credit rating.

## 2.7 Conclusion

This chapter introduced a significant amount of industry information. Understanding the history of the industry provides insight into the current state of the market, its possible direction and should lend to an appreciation for the political and regulatory risks that weigh heavily on any investment decision in tolling. Knowledge of the electricity infrastructure clarifies why combined-cycle gas turbines are a primary target for tolling agreements. A basic understanding of the North American transmission grid will become a key component to understanding the significance of physical plant locations and how they impact the profitability of tolling opportunities. Knowledge of the natural gas infrastructure will contribute to a better understanding of forecasted gas prices and the ability to hedge price risk through storage facilities.

Tolling agreements depend on the potential to profit from buying natural gas from one market, using it to run generators, and selling the electrical output to another market. The basic power trading concepts, associated risk management, and required capital to participate in the trade of either commodity were covered to explain what must be done to carry a tolling arrangement.

# 3 POWEREX

## 3.1 Introduction

This report is intended to provide Powerex Corp. with a methodology and strategy to value tolling arrangements. This section explains who Powerex is and how the company is structured to ensure long term trading capability, thereby enabling it to consider long-term contracts. It speaks to how the gas trading opportunities have evolved internally and discusses growth strategy that is aligned with finding profitable tolling contracts.

Powerex is the wholly owned power marketing subsidiary of B.C. Hydro. The company has achieved notoriety in the West as a leader in the ability to profitably source and move physical power in the WECC. Powerex has a direct mandate to create economic value for its shareholder, the province of B.C., by trading power and natural gas in the Western Electricity Coordination Council (WECC) and other select regions in North America, within prescribed risk parameters.

powerex

Reg. U.S. & CDN. Pat. & Tm Of.

*Figure 3-1 Powerex Company Logo. Source: Powerex, 2003. (Used by permission of Powerex Corp.)*

B.C. Hydro benefits from revenues of electricity trade through Powerex. Powerex trading also helps optimize B.C. Hydro system resources, and improves the security and reliability of B.C.'s electrical supply.

## 3.2 B.C. Hydro

B.C. Hydro is a Crown Corporation owned by the province of British Columbia. It is regulated by the BC Utilities commission and reports to a board of directors which is appointed by the Lieutenant-Governor in Council. B.C. Hydro is the third largest electric utility in Canada and has 1.6 million B.C. customers.

B.C. Hydro is responsible for generating and distributing power. This includes upgrading existing facilities and requires electricity purchasing and selling functions. The system's generation capacity is 11,000 megawatts of which over 87% is produced by hydroelectric generators. Each year 43,000 to 54,000 GWh of electricity is produced.

In April, 2003 B.C. Hydro was divided into three Lines of Business (LOB), Generation, Distribution and Transmission. In the summer of 2003, the transmission LOB was separated from B.C. Hydro to ensure non-discriminatory access to the B.C. transmission system. A new crown corporation was made to carry these responsibilities, the British Columbia Transmission Corporation (BCTC).

B.C. Hydro has subsidiaries including Powerex Corp. for power marketing, and Powertech Labs for research and development functions. It also has competitive service organizations for Engineering and Field Services. On April 1, 2003 approximately 1600 back-office support functions moved from B.C. Hydro, and out of provincial ownership, to a new company, Accenture Business Services of British Columbia. B.C. Hydro contracts back these services through an outsourcing agreement.

In Fiscal 2003 B.C. Hydro paid the Province of British Columbia approximately 741 million dollars through taxes, water rentals, and dividends.

### 3.3 Powerex Background

B.C. Hydro had been directly involved in short-term electricity trade from 1973 to 1988. In 1988 a separate subsidiary was founded under the name British Columbia Power Exchange Corporation to facilitate trade with Alberta and the U.S. The company went by the abbreviated name Powerex. On September 6th, 2000 it officially changed its name to Powerex Corp. In 1997 Powerex received Power Marketing Authorization from FERC. Powerex sales have grown by over 500 percent since inception. In fiscal 2003 (April 1, 2002 – March 31, 2003) Powerex trade activities generated sales revenues of approximately $2 billion Canadian with electricity sales exceeding 31,000 Giga-Watt hours (GWh). The company has approximately 120 employees.

### 3.4 Products and Services

Powerex trades electricity and natural gas commodities in standard and custom contract volumes with counterparties located across North America; in real time (hour-ahead), day-ahead, and futures markets; and using standard and non-standard (derivatives) physical and financial instruments. These trades are completed both over-the-counter (OTC) and via exchange-based systems or by custom bilateral negotiation. Some of the more significant trading hubs which Powerex operates in are shown in Figure 3-2. Powerex is committed to providing highly flexible, reliable energy solutions.

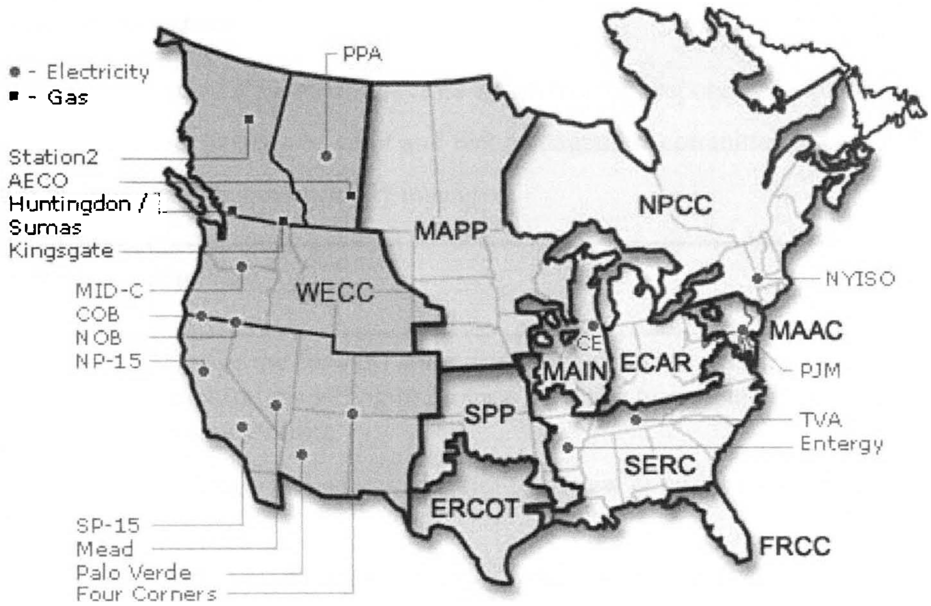



*Figure 3-2 Powerex Marketplace & Key Trade Hubs. Source: Powerex, 2003. (Used by permission of Powerex Corp.)*

Traded physical products include: fixed-price forward contracts on power and gas; fixed-price forward contracts on transmission and gas transportation (spread options); European options on power and gas; exotic options on power and gas, including hourly, super-peak, swing, binary and look-back options; heat rate swaps; gas to power tolling contracts; gas storage; forward, fixed-price contracts and options on products such as Green Tags and other emerging products.

Traded financial products include: NYMEX power and gas futures and option contracts; fixed-for-floating swaps on power, gas and transmission; and firm transmission rights (FTRs) (financially-settled transmission).

Canada has rights to the power produced on the Columbia River in the western U.S. This Canadian Entitlement is marketed on behalf of the B.C. Government through Powerex. Powerex also has access to the B.C. Hydro hydroelectric system and participates in seasonal energy exchanges. The company can also provide scheduling services.

Powerex has over 150 customers including investor owned utilities, municipalities, power pools, large industrials, and other power marketers.

## 3.5 Company Structure

Powerex reports to a board of directors which has the responsibility of approving business risk parameters and has an audit and risk management committee to ensure the risks undertaken by Powerex are appropriately managed.

| ***Department*** | ***Mandate*** |
|---|---|
| Analytics | Manage the forward and actual price database. Use quantitative and structural modelling to provide portfolio management theory for options and deal structuring. |
| Business Development | Seek new business opportunities in new or current markets |
| Contracts | Assist in contract development and negotiations. Responsible for regulatory filings and completing enabling agreements. |
| Credit Risk Management | Ensures trading approval with counterparties. Evaluates, measures, and reports on counterparty credit risk on a daily basis. |
| Custom Marketing | Responsible for development and negotiation of agreements for non-standard energy products and services. |
| Finance | Produce financial reports, forecasts, tax planning and its compliance. Help prepare the company business plan and budgets. Manage accounts payables and receivables. |
| Gas Trading | Procure natural gas for B.C. Hydro's four thermal plants. Seek gas trading opportunities on the open market. |
| Information Technology | Contribute to corporate objectives and maximize company competitiveness through information management and enabling technology investments. |
| Operations Risk Management | Ensure energy sales and purchases comply with contractual scheduling guidelines. Control the consistency, reliability and accuracy of data capture for all transactions. Produce profit & loss, position, mark-to-market reports. Provide settlement management with counterparties on settlement amounts. |
| Real Time Trading | Buy and sell spot electricity each hour. |
| Risk Management | Manage and mitigate price, operational and supply risk. |
| Sales and Marketing | Responsible for Day Trading, Power Marketing, and Portfolio Management. Looks to maximize Powerex and B.C. Hydro's bottom line. |
| Trade Policy and Development | Ensure access (license, permits, authorization) to markets. Monitor and contribute to industry initiatives. Manage external and internal communications. |

*Table 3-1 Powerex Department Overview. Table by authors.*

Powerex retains services from B.C. Hydro for legal and treasury management, and payroll and benefits. As with B.C. Hydro, Powerex uses an outsourcing model for non-core activities. Commoditized information technology support and development are provided through Accenture Business Services of British Columbia. Powerex internal departments are listed and described in Table 3-1.

B.C. Hydro's Power Supply Operations Shift Engineers Office (PSOSE) is responsible for maximizing the returns on B.C. Hydro's generating facilities. PSOSE works closely with Powerex to capitalize on opportunities in the spot and forward electricity markets.

Powerex trading portfolios are broken down into region, and specialty. These books are described in Table 3-2.

| ***Book*** | ***Description*** |
|---|---|
| Forward | Financial and physical forwards throughout western North America. May transact with all other books. |
| Trade Account | Shaping of imports and exports from B.C. Hydro's system. Buys and sells to the Northwest and Alberta books. May buy from the forward book for domestic consumption. |
| Alberta | Buys and sells energy with the Trade Account Book. Includes custom contracts and other trading activity in Alberta |
| Northwest | Buys and sells energy for the trade account book. Includes locational arbitrage deals, custom contracts, and other trading activity in the U.S Northwest |
| Southwest | Locational arbitrage trading, custom contracts, trading activity with the California ISO and in the U.S. Southwest. |
| Gas | Margin on gas purchases for B.C. Hydro, and other trading throughout western North America. Buys from the Trade Account book. |
| East | Locational arbitrage, custom contracts, other trading in North Eastern North America |
| Entitlement | Margin earned on selling Canadian Entitlement Energy for the Province of B.C. |
| Term Trading | Trading energy financial forwards and options with limited interaction to other books. |

*Table 3-2 Powerex Book Structure. Table by authors.*

### 3.6 Evolution of Cross-Commodity Trading Opportunities

B.C. Hydro's generation system includes three natural gas fuelled plants. These are grouped under the Thermal Generation Area of B.C. Hydro. There is a 950 MW Burrard Thermal Generating Station that supplements the hydroelectric system when water levels are low and provides power supply security for Vancouver and neighbouring regions. The 50 MW Fort Nelson plant is continuously providing energy to the grid whereas the 46 MW Prince Rupert plant is only used for short-term energy when necessary for the local area. B.C. Hydro did not originally have internal gas purchasing expertise and was thereby subject to market prices.

At the end of 1997 Powerex acquired a natural gas trader to procure natural gas for the B.C. Hydro generating stations requiring it. This gas trading position was also intended to develop company expertise in a cross-market, power-related commodity. This set the stage for providing Powerex additional value to tolling arrangements.

In 1998 B.C. Hydro negotiated a tolling deal for an Island Cogeneration Project (ICP) on Vancouver Island, B.C. In May 2002, the 230 MW ICP combined-cycle natural gas plant went into commercial operation. B.C. Hydro and the project owner, an Alberta-based, Canadian Calpine subsidiary, entered into a 20 year agreement whereby B.C. Hydro supplies the fuel and receives all the electricity output for a toll price. The resulting steam from the plant then goes to an adjacent Norske Canada pulp and paper mill for industrial processing. Powerex is responsible for natural gas procurement for the ICP.

To extend Powerex's business beyond the dependency on the B.C. Hydro system, the company has been looking at sources for physical power generation within favourable trading markets. Location is important for reducing transmission costs, congestion problems and curtailment risk.

In the past generators were looking for 15 to 20 year off-take agreements with a creditworthy customer. The risks were too high and the past forward price curves were indicating negative spark spreads. Powerex would need to hedge the risk through a long term supply arrangement, but no customers could be found.

After the energy crisis of 2001, the market was left with an over-supply of natural-gas fuelled power plant projects either completed or near completion. In some cases these plants were unable to sell enough electricity to recover their costs, thereby leaving their financers looking for a way to minimize their losses. This produced a 'distressed' owner situation that enabled a buyers market.

Powerex entered into its first tolling agreement by making a deal with a distressed generation station in Hermiston, Oregon. This plant is also owned by Calpine Corporation. At the time Calpine was no longer credit-worthy and could not procure the gas required to run the plant. A short-term agreement was made for Powerex to deliver natural gas from Alberta through Calpine's gas transmission position to Kingsgate hub in B.C. In return Powerex receives electricity based on Mid-C deliveries. Unlike typical tolling deals, this situation did not require Powerex to pay capacity fees or a portion of the variable costs to run the plant.

Powerex has since entered into a few simple tolling contracts and is examining more tolling opportunities. Powerex is evaluating the opportunities and risks associated with entering into tolling arrangements with plants outside of the province versus the lower risk options of staying within B.C. For example, a proposed 265MW CCGT Vancouver Island Generating Project (VIGP) by B.C. Hydro could be optimized by Powerex through a tolling arrangement. As a subsidiary of B.C. Hydro, Powerex would be able to toll through the plant without paying a capacity charge.

### 3.7 Company Direction

Powerex reviews its risk profile on an annual basis. For fiscal year 2004 (April 2003, to April 2004) the company retained its historically-consistent risk adverse position. Powerex will not commit to any agreement beyond its capacity to deliver. The company maintains risk threshold limits which include a minimum net income for its accountability framework with B.C. Hydro, a negative mark-to-market threshold for its forward contracts, and a maximum gross margin loss tolerance for its Eastern, Forward and Term Trading Books. Powerex has a target for return on capital between 16% and a stretch-target of 25%.

The Powerex long-term growth strategy includes increasing trade volumes by approximately 55% by fiscal year 2007. Powerex is also looking at expanding its eastern market arbitrage trading. There is an anticipation of increased gross profits which will be gained through additional electricity and gas arbitrage opportunities. Powerex has entered into several short-term, simple tolling agreements with generators to convert gas, which Powerex supplies, into electricity, which Powerex acquires for trade. Powerex may consider seeking out longer-term, more complex tolling contracts based on a detailed analysis and strategy recommendation.

Internally, the company is looking at IT and business process changes which will benefit operational efficiency.

### 3.8 Conclusion

Powerex is a well structured and successful trading company in the power and gas markets. Powerex has gained tolling experience through performing tolling functions for B.C. Hydro and its ICP plant. Powerex has entered into simple tolling arrangements and, as per its growth strategy, is ready to consider longer term, complex agreements.

# 4 TOLLING

## 4.1 Introduction

This chapter provides an introduction to the concept of tolling as it relates to tolling through natural gas generators. A variety of tolling arrangements are discussed including the risks inherent to each.

Tolling contracts offer advantages to both the developer / contractor of the generating facility and the gas and power marketer. A tolling contract is typically structured to best suit the risk tolerances of both parties, and similarly, to assign specific risks to the individual parties that are most able to accommodate, mitigate, or hedge the risks associated with the development, construction, operation and marketing of the generating facility. Briefly, a tolling arrangement for a proposed or new generating facility typically assigns the completion and performance risks of the facility to the developer / contractor, and the operating and market (gas and power price) risks to the gas and power marketer.

## 4.2 Description

The tolling arrangement serves as a long-term off-take agreement for the developer, who must finance the development and construction stages of the project on the strength of a long-term (20+ year) agreement from a third party to bear the price risk associated with the purchase and sale of gas and power. This represents the advantages sought by the developer / contractor.

The tolling arrangement also represents a form of real option, whereby the operator and dispatcher may choose from day to day, and even hour to hour whether or not to operate the plant and sell the generated power into the market. This decision to operate the plant is based on the difference (or spread) between the current local power prices and the price paid for gas multiplied by the conversion rate (heat rate) for the generating facility. This difference is referred to as the spark spread. The daily optionality (real option) to operate and dispatch power from the facility has an inherent (or intrinsic) value due to the current and forecasted spark spread and an additional extrinsic value associated with the optionality going forward. Naturally, the more volatile the price of the two underlying commodities, the greater the likelihood that positive spark spreads will be observed, leading to greater extrinsic value. This real option feature of the tolling arrangement represents the advantages or value sought by the power and gas marketer.

Despite the apparent advantages and value realized by both parties, certain analyses and decisions regarding the risks, the resulting requirements for capital, and the expectations for returns on this risk capital must be completed and discussed. Risk considerations beyond those associated with typical power and gas trades (credit, market and operational) include regulatory risks, environmental / emissions risks, political / legal risks (including a FERC triennial review of market power), and the risks associated with a severe power or gas market correction or reversal during the 20 years of the agreement.

Possible tolling contracts include simple, complex, financial, and physical. Their typical grouping and descriptions are provided in the following sub-sections.

## 4.3 Forms of Tolling

### *4.3.1 Gas and Power Delivery: Financial versus Physical Tolling Agreements*

Physical tolling contracts require the purchaser to arrange for the delivery of natural gas to the plant gates and the wheeling of generated electricity to an off-taker's point of delivery. Physical contracts are usually complex and may blend differing obligations of the purchaser for the gas and power components. In contrast, a financial tolling arrangement is usually a simplified contract and neglects physical gas and power delivery opportunities and constraints and exposes the purchaser only to market (typically index) prices of the two commodities.

These categories of simple versus complex and financial versus physical are convenient descriptors but in reality all combinations and forms of the above are observed in the marketplace.

### *4.3.2 Operating Obligations: Simple versus Complex Tolling Agreements*

Simple tolling arrangements reduce the complexity of the product by approximating operating limits and conditions. A premium is paid for a simple toll as the operation risk remains with the plant owner. A complex toll exposes the purchaser to operational risks such as labor disputes, unscheduled maintenance, force majeure, and environmental levies amongst others. In other words, a tolling contract is considered 'complex' if the terms of the contract oblige and expose the purchaser to the same or similar rights, obligations and risks as the owner of the facility. Complex tolls typically result in slightly improved margins due to lower operating and maintenance costs on average, but can similarly expose the purchaser to additional, unforeseen costs. Simple tolls are usually preferred in scenarios where less than the whole amount of energy is being contracted or when the output of the plant is being contracted to more than one tolling party.

| | ***Financial*** | ***Physical*** | |
|---|---|---|---|
| ***Simple*** | No purchaser requirement for physical gas and power delivery<br><br>Operation risk remains with the plant owner | Purchaser needs to arrange natural gas delivery and electricity wheeling<br><br>Operation risk remains with the plant owner | Purchaser Risk ↓ |
| ***Complex*** | No purchaser requirement for physical gas and power delivery<br><br>Contract exposes purchaser to operation risk | Purchaser needs to arrange natural gas delivery and electricity wheeling<br><br>Contract exposes purchaser to operation risk | |

Purchaser Risk →

*Figure 4-1 Tolling Contract Purchaser Risk. Figure by authors.*

## 4.4 Plant Operation and Maintenance

The operating and maintenance costs for the physical plant are categorized as fixed or variable, and are specified in many forms across different tolling contracts. Fixed Operating and Maintenance (FOM) costs may take the form of a fixed, and sometimes escalating, monthly payment, made regardless of the number of operating hours during the period, or a specified minimum monthly payment within the monthly variable operating and maintenance costs. FOM costs may be passed through to the tolling counterparty by the operator on a pro-rated and as-incurred basis, or as a predetermined amount, depending upon the contract.

In contrast, Variable Operating and Maintenance (VOM) costs are related to the usage of the facility over a given period (typically a month), and may be specified to be a function of the total number of operating hours within the period, the number of cold or warm combustion turbine starts, or the number of steam turbine starts (if applicable). The VOM costs are typically specified in units of dollars per megawatt-hour or dollars per kilowatt-month of operation, and this rate may be specified through a tabulated ratio of the operating hours within a period over a number of starts for the combustion turbine, steam turbine, or both. As the ratio of operating hours to number of starts increases, the VOM costs on a dollar per megawatt-hour basis is typically expected to increase, reflecting the accelerated wear on the facility associated with higher start frequencies. Escalation rates are also typically applied to VOM costs over the duration of a 5 to 20-year tolling agreement through the specification of either a fixed escalation rate or a rate that is calculated as a fraction or multiple of the Consumer Price Index (CPI) for the year of operation.

The facility developer or operator, and possibly the turbine manufacturer (e.g. Siemens, ABB, GE), may provide guaranteed heat rates and duct firing provisions, but these guarantees will typically depend on the use of the facility in terms of dispatch (on/off) frequency and adherence to minimum off times and ramp rates for the facility. Duct firing can add an additional 10 to 20 percent capacity to the facility, but again, typically triggers an additional VOM cost, and results in slightly higher (less favorable) overall heat rates for the facility. Other forms of operating and maintenance costs include contributions to parts pools by the owner or operator and any tolling partners.

All plants are subject to scheduled maintenance on a monthly and annual basis. Overhauls and re-builds are also required approximately every 10,000 operating hours with a major overhaul after 100,000 hours. Scheduled maintenance is typically and preferentially completed in off-peak hours of the day and off-peak seasons of the year, resulting in estimated plant availability levels of approximately 92 percent in off-peak seasons and 95 to 97 percent in on-peak seasons. Plant availability may be guaranteed with associated liquidated damages for non-performance depending upon the complexity or simplicity of the tolling agreement.

For reference purposes, annual direct operating and maintenance costs for the proposed Vancouver Island Generation Project (VIGP) are expected to be approximately $CDN 17.8 million, including $CDN 2.3 million for wages and benefits. Blended VOM and FOM costs associated with a tolling facility are typically in the range of $US 2 to $US 4 per megawatt-hour ($US 1.46 to $US 2.92 per kW-month), depending upon the applied escalation rate, dispatch characteristics, and other negotiated contract terms.

### 4.5 Merchant versus Utility-backed Projects

The development of power projects can be broadly classified as merchant or utility-backed. Merchant developers are focused on the shorter term wholesale marketing of energy into markets and points of delivery offering the highest current margins over generation costs. A merchant developer may also arrange for the long-term sale of a portion of the energy to a utility or other wholesale counterparty at a fixed price. Clearly, financing of a merchant plant is more challenging, and offers creditors a less secure stream of revenues. On the other hand, merchant developers are better positioned to take advantage of occasional price spikes and other prolonged periods of elevated prices. A merchant developer and operator may also choose to partially hedge the inherent short gas and long power positions through medium or long-term and seasonal forward purchases of gas or gas transportation or forward sales of the corresponding power or power transmission.

In contrast, a utility-backed development benefits from the guaranteed off-take of generated power, typically sold by the generation arm of a utility to the distribution organization with an obligation to serve retail customers. This power may be transferred to the distribution organization at a price derived from the cost of production plus a guaranteed return to the developer. Alternatively, power may be transferred at a price that is fixed for a period of time between what is set at a distribution company's retail rate hearing or, less commonly, at a prevailing market or index price.

The allocation of capital and financing of merchant facilities varies significantly in comparison to utility-backed developments. Depending upon the source of capital (bank or capital markets), the tenor of the debt, payment schedule flexibility, and total cost of financing, financing can vary with capital markets typically offering the lowest overall cost over longer maturities, but with the least flexibility regarding repayment and construction period financing. Developments that have committed power purchase or tolling agreements, or are utility-backed, tend to benefit from lower borrowing costs and lower equity return expectations with debt to capital ratios of up to 80 percent. For these benefits, utility-backed developments trade off the potential upside associated with market price spikes. Merchant developers are typically able to leverage less than 50 percent of the required capital and incur higher capital costs for both debt and equity, but are also better able to take advantage of occasional (and inevitable) market price spikes. Given recent difficulties in the North American energy markets, new merchant development has all but completely stopped as capital sources have turned away from the apparent (and probably real) risks of this sector.

The higher risks associated with merchant power generation result in a cycle of negative effects in terms of financing and maintenance of credit ratings. The costs of debt and equity increase for merchant power developments at the same time as debtors increase requirements for debt service coverage ratios (DSCR) to over 2.0 in comparison to DSCR requirements of less than approximately 1.5 for fully contracted or tolled facilities. These higher DSCR requirements for merchant developers translate into greater challenges to maintain investment grade credit ratings, which in turn impact the cost of capital for the development company (Veron & Iaconetti, 2001). This situation leads to a preference for portfolio financing over individual project financing for reasons of risk diversification and the ensuing financing benefits.

### 4.6 Current Development Conditions

Project permitting and financing typically spans several years, during which site investigations, ownership, zoning, environmental, gas transportation, power transmission, tax, and insurance studies must be completed. Significant equity investments are often required during this phase to fund the required studies. Deposits or other commitments are typically required at an early stage in order to confirm the availability and delivery of a turbine from the selected manufacturer at the correct time. This lengthy process may, as seen over the past 12 to 24 months, lead the project developer to the unfortunate position of 'breaking ground' or starting construction just as the local, regional, or national energy market is starting into a depressed cycle. Due to sunk costs, the developer is often committed to pushing through a development with the hope that a purchaser, tolling counterparty, or other favorable gas supply or power off-take agreements can be found. For a highly leveraged project, or for a smaller under-capitalized developer, this situation may not be sustainable due to cash flow and creditor problems. This may lead to the sale of partially developed projects at prices below costs. Although unfortunate for the developer, these situations may be well suited to the entry of new market participants and investors seeking to purchase an incomplete or existing 'distressed' asset.

'Brown field' opportunities are a reference to partially developed generation projects or projects that have advanced significantly through the permitting and possibly construction stages. Brown field sites also refer to expansions or additions to existing industrial sites where ownership, permitting, and infrastructure issues are less significant. Although some projects have currently been halted, pressure from the financial lenders may force their completion. Financial institutions would rather have a completed asset should a borrower not meet their debt obligations. Delays or cancellations of development may be subject to substantial penalties and force a developer into more distress, making the recognition of sunk costs relevant, but not the only determinant of project continuation.

## 4.7 Typical Financial Modelling Assumptions

The following project characteristics are used as typical assumptions for the purpose of financial modeling of new gas generation facilities. These characteristics are based on those used by Cambridge Energy Research Associates (CERA, 2003a).

- Capital costs of $US 600 per installed kW of capacity based on a two-year construction period;
- Average heat rate (gas to electricity conversion rate) of 7.2 MMBtu/MWh;
- Variable Operating and Maintenance (VOM) of $US 1.23 per MWh;
- Fixed costs, including Fixed Operating and Maintenance (FOM), replacement capital, and general and administrative costs of $US 27.67 per kW;
- Property taxes at 1 percent of project market value;
- Debt-to-equity ratio of 60/40;
- Cost of debt at 8 percent;
- Cost of equity at 14 percent;
- 20-year bond used to finance plant;
- 20 year project life;
- Zero salvage value;
- Marginal tax rate of 39 percent; and
- Accelerated capital recovery schedule for depreciation.

## 4.8 Risk Considerations

### *4.8.1 Types of Risks*

Basic tolling risk descriptions are outlined in Table 4-1. Risks fundamental to the valuation discussions (credit, market and operations) are detailed in the tolling analysis section of this report.

| *Tolling Risk* | *Description* |
|---|---|
| Business continuity risk | Risk of loss from a disruption of normal business functions |
| Credit risk | Risk of loss due to a counterparty defaulting on its commitment to deliver contracted gas or pay for power received. |
| Environmental risk | Risk of non-compliance with environmental laws |
| Financial risk | Risk of large difference between the estimated costs for financing and the original forecasts. Includes risk of interest rate and foreign exchange rate changes. |
| Infrastructure risk | Risk of reduced ability to transport electricity due to transmission constraints, or to receive gas due to pipeline constraints. |
| Legal risk | Risk of inconsistencies in contractual arrangements resulting in arrangements not being enforceable |
| Market risk | Risk of loss due to changes in market prices on the value of the contracts in the portfolio |
| Operations risk | Risk of loss from inadequate internal processes to run the system |
| Organization risk | Risk of failure from resources (due to staffing levels or skills) to execute the business strategy |
| Political | Risk of government actions. Risk of political instability, public policy changes, and regulatory changes |
| Price Risk | Risk of high gas prices and low electricity prices resulting in a negative spark spread |
| Regulatory risk | Risk of loss due to unexpected changes in laws or market rules |
| Reporting risk | Risk of loss from failure to satisfy regulatory and statutory reporting requirements. |
| Strategic risk | Risk brought on by business decisions |
| Technological risk | Risk of loss due to better technology that may provide more competitive, efficient systems. |
| Valuation risk | Risk that the valuation provides inaccurate results |
| Volumetric risk | Risk of not being able to deliver the full contractual volume amount |

*Table 4-1 Tolling Risks. (Based on Committee of Chief Risk Officers, 2002, p. 6)*

### *4.8.2 Risk Analysis Framework*

In simple terms, risk quantification in a trading environment involves: the measurement or estimation of volatility around expected profits and losses, earnings and cash flows;

quantification of the risks associated with non-performance by trading counterparties, including default probabilities and the resulting expected and potential losses; and operational risks associated with deal entry and flow, trader error and other events external to the company's operations. These risks may be quantified and accumulated with appropriate adjustments and requirements for other capital (e.g. broker deposits, capital equipment, working capital and parental guarantees) to establish the total capital requirement to conduct business for a given year. A return on this allocated capital is naturally expected, and the volatility or standard deviations of these expected returns must be acceptable to the providers of this capital. Risk management in such an organization rolls up managing and reporting these capital requirements, returns on capital, and volatility of returns. The return on allocated (risk) capital is typically referred to as the RAROC (actually Risk Adjusted Return on Capital) and is a summary metric used by organizations at two distinct levels: i) the portfolio level, including all transactions and forward positions, and ii) the project or opportunity level, as a measure of the relative attractiveness of a potential project over an alternative or relative to the existing portfolio.

Each new opportunity or position has its own (often unique) risk characteristics, which are not independent to the risk characteristics or profile of the rest of the portfolio. In other words, due partially to the correlation of commodity prices, the risks associated with a portfolio of two trading positions are almost certainly different than the sum of the risks of the individual positions. The addition of new trading positions may exacerbate an existing portfolio exposure, or may reduce this exposure and act as a form of hedge for the portfolio. The addition of a potentially large tolling agreement to an existing portfolio of forward gas and power trading positions is no different in that the tolling agreement may offset an existing net short power and long gas position in the portfolio, and vice versa. With this in mind, the evaluation of any new opportunity should include an assessment of the opportunity on a stand-alone basis, but must also consider the effect of the addition of the position on the overall portfolio. It is an interesting observation that the ability of a trading organization to compete effectively in the marketplace is certainly related to the organization's risk tolerances, return expectations, access to capital, creditworthiness (borrowing costs), and market knowledge (trading skills); but also related to the risk diversification effect of adding a position to the existing portfolio. In other words, two companies that are identical in all ways except the net positions (and hence risk profile) of their portfolios should have different competing bids on the same product, reflecting the unequal increments or decrements to risk capital associated with the addition of the new position to their respective portfolios.

In addition to the RAROC metric, another measure of the attractiveness of a potential trading position or asset is the Sharpe ratio (Sharpe, 1964 and Lintner, 1965), which is a measure of the expectation of returns above the risk-free rate of return normalized by the standard deviation of these returns. The Sharpe ratio is defined as follows:

$$SharpeRatio = \frac{\mu - r}{\sigma_\mu};$$

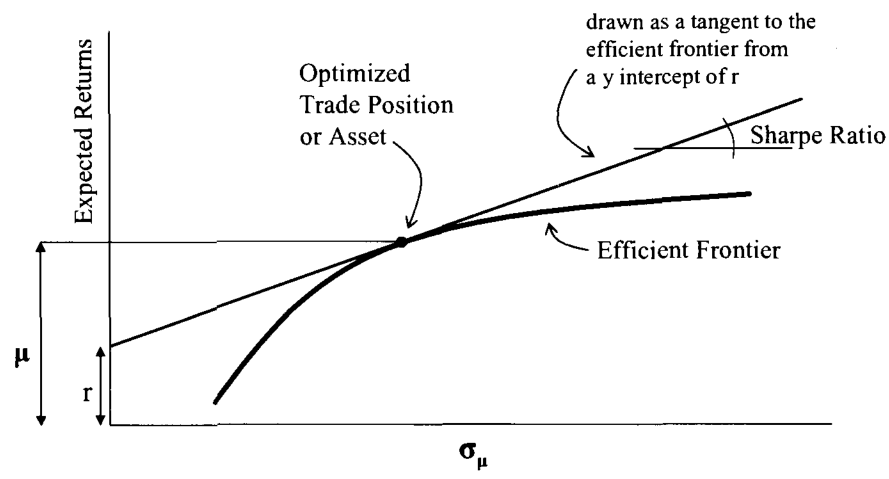



*Figure 4-2 Sharpe Ratio Depiction. Figure by authors.*

The expected returns and the standard deviation of these expected returns from the position or asset respectively are $\mu$ and $\sigma_\mu$, and $r$ is the risk-free rate of return that could be achieved from the market. Higher Sharpe ratios are indicative of more favourable opportunities, and the Sharpe ratio for an entire portfolio can be calculated and maximized through adjustment of the positions within the portfolio. Positions and portfolios for which the Sharpe ratios have been maximized are said to be located on the 'efficient frontier' which forms the basis for the trading objectives of some organizations. Details regarding the efficient frontier are beyond the scope of this paper, but simply stated, the efficient frontier is a line plotted in $\mu$ - $\sigma_\mu$ space showing all possible positions and portfolios for which the Sharpe ratio has been maximized.

## 4.9 Accounting Treatment of Tolling Contracts

Recent accounting and auditor opinions suggest that, due partially to the recent events surrounding firms like Enron and WorldCom, and resulting Sarbannes-Oxley Act of 2002, financial reporting obligations of public companies have been more strictly defined with respect to the reporting of debt and other financial obligations. The concern with commodity trading organizations is that some trading-related earnings are realized within a fiscal year while others extend beyond the financial year-end and typically expose the organization to expected profits or losses that may not be reported to the investor.

The estimation of future value for these longer term contracts is referred to as 'marking to market' and is notoriously subject to manipulation by a trading organization wishing to overstate income in the current fiscal year. When market prices and liquidity are poor, the estimated future value of trading positions are obtained through a 'marking to model' process, which can be very subjective and are naturally sensitive to assumptions regarding future commodity prices.

This difficulty regarding the accurate reporting of realized and unrealized income is compounded by an additional practice of off-balance-sheet accounting, which has allowed some companies to structure purchases and agreements such that a narrow interpretation of Generally Accepted Accounting Principles (GAAP) avoids the obligation to report the item as an asset on the balance sheet with an associated component of debt. This off-balance-sheet accounting has typically been achieved through the formation of special purpose entities or partnerships with financial obligations flowing back to the parent company through guarantees or service commitments that have avoided reporting or obfuscated the reported information. This combined ability to manipulate earnings results while avoiding the reporting of associated debt and other financial obligations associated with an asset has resulted in the calculation of erroneous or misleading returns and ratios used to value a company and measure performance.

In an attempt to remedy this, recent best practices - some of which are legislated through the Sarbannes-Oxley Act - apply a different test to the reporting of assets and debt on the balance sheet. These improved tests consider the terms of a financial obligation, the control and management of an associated asset, and the sharing or adoption of risks associated with an asset rather than simply the name on the deed or loan documents. The effects of these adjusted accounting standards on the reporting of a potential tolling agreement for Powerex are twofold:

1. Powerex may be required to show marked to market profits or losses associated with future years of the contract, and potentially marked to *model* profit or loss expectations for years beyond the availability of market price data, and;

2. Due to the nature of the financial obligations, rights and risks associated with a tolling agreement[1], Powerex may be required to show the value of the agreement as an asset on the balance sheet with an associated debt and equity component. These balance sheet items would in turn be consolidated up to BC Hydro's reporting, and may be counter to Powerex's mandate to engage in trading activities to maximize the benefit of BC Hydro's existing assets rather than the acquisition of new assets.

It may be possible to avoid the second of these effects through the adoption of a shorter term contract with less than 100 percent of the plant capacity, simple operating obligations and risks, and financial settlement of commodity prices rather than physical delivery. This arrangement would in turn allow for the treatment of the agreement as an operating lease with premium payments (capacity charges) expensed as they are incurred. These shorter and simplified agreements also, however, reduce the ability of Powerex to find value through time diversification and operating flexibility. They are typically sold by developers with a risk premium, and prevent the unilateral operation and dispatch of a plant due to the requirements or rights of other off-takers.

### 4.10 Conclusion

This chapter provided a basic description of tolling arrangements and their benefits. It provided insight into why a tolling deal can be preferential to developing and directly owning generation assets as shown in discussions of the complexity of operations and maintenance of the physical facility and the challenges of project permitting and financing. Risks to consider when entering into a tolling arrangement were identified as were descriptions of how risks can be quantified for analysis.

A study of the risk-reward balance associated with long-term tolling agreements is required. The risks associated with such agreements extend beyond the normal consideration of market (price), credit and operational risks to include risks associated with environmental, regulatory, legal, and market dynamics issues (reversal of forward price curves and change of correlation between commodities). Additional challenges include the financial accounting and reporting of the obligations associated with the contract. The rewards, however, are hard to

---

[1] Namely the duration, percentage of the total off-take from the facility, dispatch control of the facility, and exposure to operating and other legal risks similar to those accepted under typical ownership scenarios.

deny, and include: flexibility to take advantage of a physical generation facility to back-stop trade positions, the intrinsic and extrinsic values associated with real options, and the satisfaction of Powerex's growth objectives.

# 5 SELECTED TOLLING ANALYSIS METHODS

## 5.1 Introduction

The valuation of a tolling contract is analogous to the valuation of a spread option, which gives the purchaser of the option, the right, but not the obligation to trade one asset for another at a known weighting factor. The value of such an option depends primarily upon the current (spot) and forward prices, the time-dependent volatility, and the time-dependent correlation between the two underlying commodities or assets, and the weighting factor (the heat rate in the case of a natural gas tolling contract). Spread options can be difficult to value for two primary reasons: i) measuring or estimating the time-dependent volatility of and correlation between assets is difficult given the typical limitations and challenges of time series data analysis; and ii) applying these price process characteristics of volatility and correlation in closed-form analytical solutions results in the requirement to make several important assumptions and approximations or the use of computationally-intensive numerical approximation methods such as Monte Carlo simulation or binomial and trinomial trees.

Tolling agreements can involve significant financial obligations in the form of monthly capacity charges (option premium costs), fixed operating and maintenance costs, and fixed gas transportation and power transmission costs. For this reason, it is important to be able to assess the value of these assets in terms of intrinsic and extrinsic value and the expected value (and statistical distribution) of the payoff function from which the fixed and variable costs are subtracted to provide earnings estimates.

The following sub-sections introduce the concept of market spark spreads and operational spark spreads, which account for the additional costs associated with taking advantage of a positive spread between power and gas prices: fixed and variable gas transportation costs, and fixed and variable power transmission costs. Historical daily power and gas prices are used to demonstrate the volatile behavior of market spark spread and market-inferred heat rate data. This same historical daily power and gas price data are also used to calculate the volatility of the two commodities and the observed correlation between them.

Later sub-sections describe a stochastic price process that is subsequently applied to forecast and market price data for Heavy Load Hour (HLH) power, Light Load Hour (LLH) power, and natural gas. These price processes allow for the generation of many series (iterations) of semi-daily (HLH and LLH) power and daily gas prices, which may in turn be used to estimate the value of a 20-year tolling agreement using Monte Carlo simulation. In addition to Monte Carlo simulation, a closed form approximation of the value can also be obtained using an approach proposed by Margrabe (1978) and modified to account for the costs associated with exercising the option during a given HLH or LLH block of a given day. Potential tolling (dispatch) optimization analysis methods are discussed briefly, as are potential hedging strategies and the quantification of risks associated with tolling. The final sub-sections of this chapter describe the process of estimating risk capital requirements and calculating returns on this capital.

## 5.2 Strategic Benefits

Tolling agreements can provide a number of strategic benefits for a trading company. The location of the tolled generator may provide market access to areas that were challenging to reach due to the physical distance from existing assets that result in: power transmission line-losses of power, wheeling complexity and the difficulties in coordinating through multiple control areas to confirm transmission rights, and the potential not to get power in due to transmission congestion. Having a physical asset also reduces trading risk by allowing asset-backed trading. Commitments to deliver electricity can be met through supply generated at the plant rather than acquiring it exposed to prevailing market prices. This type of option provides significant flexibility to a trading organization and allows the company to seek alternative supply sources when spark spreads are low, but ramp up trade volumes when there is a temporary power price spike or any disconnect between power and gas prices.

For a power trading company like Powerex, that is regionally focused, entering into a tolling arrangement outside of its regular market expands the trading knowledge and market understanding of its staff. This experience may lead to future benefits through earlier recognition of market changes and the ability to quickly react to new opportunities.

## 5.3 Options

The purchaser of an option is provided with the right but not the obligation to buy (in the case of a call option) or sell (in the case of a put option) an asset at a known price at some time in the future. The future time at which the option can be exercised is determined by the type of option purchased: American or European. A European option can only be exercised at a predetermined expiry date and not before, whereas an American option may be exercised at any time up to and including a predetermined expiry date.

If the purchaser of an American option believes for some reason that the value of the underlying commodity is higher today or will be higher in the near future than it will at the expiry date then the purchaser could choose to exercise the option at an earlier date and benefit from this expectation. For this reason (the enhanced optionality of an American option over a European option), American options are always valued slightly higher than European options. Despite this enhanced optionality, the premium of an American option over a European option is typically very small and American options are rarely exercised prior to the expiry date. The reason for this is related to the time value of the option. The valuation of two options that are identical in all terms except the expiry date will result in the option with the later expiry date having the higher value. The reason for this is that over a greater length of time, the possibility of an underlying price reaching levels that provide positive payoffs to the purchaser is increased. In other words, the confidence interval or variability around an expected asset price tomorrow is less than the confidence interval or variability around the price of the same asset in a month's time. This greater variability of prices in one month over one day leads to greater value for an option with a strike price that must be exceeded in order to have a positive payoff. For similar reasons, the valuation of two options that are identical in all terms except the volatility of the underlying assets will result in the option with the higher volatility having the higher value.

The potential for early exercise of American options makes their valuation more difficult than the valuation of European options, which can be calculated using the closed-form, Black-Scholes analytical solution. The valuation of American options requires consideration of potential price paths over the duration of the option, and hence requires the duration of the option to be discretized into smaller time steps, with the price in each time step being estimated as a function of the price in the prior time step. This discretized process is typically achieved through the use of binomial or trinomial trees, which start from a single node at time zero (today for example), and build 'branches' out from the node at each incremental time step as the price is estimated to either increase or decrease by a given amount (in the case of a binomial tree) or alternatively (in the case of a trinomial tree) stay at an intermediate level.

There are two components of value to an option: intrinsic value and extrinsic value. The intrinsic value of an option is sometimes referred to as the 'moneyness' of an option, and refers to the difference between the strike price of the option and the level of the forward price curve at the time of expiry. An 'at-the-money' option has a strike price equal to the forward price curve at the time of expiry. Similarly, 'in-the-money' and 'out-of-the-money' options have strike prices respectively below and above (in the case of a call option) the forward price curve at the time of expiry of the option, and respectively above and below the forward price curve in the case of a put option.

The moneyness of an option is always accounted for in the value of the option, so purchasing an out-of-the-money call option is not necessarily a poor strategy or of lesser net benefit to the purchaser than the purchase of an in-the-money option. The intrinsic value of an option is always equal to or greater than zero given the right but not the obligation of the purchaser to exercise the option at the strike price – no purchaser is expected to exercise an option that is out-of-the-money at the time of expiry. The other component of value of an option is the extrinsic value, which is related to the time to expiration of the option. In the special case of an at-the-money option (i.e. an option where the strike price is equal to the forward price curve at the time of expiry of the option), all of the option value is extrinsic by default: there is no built-in difference between the strike price and the forward price. Extrinsic value is derived from the volatility of the underlying asset price; whereby the wider the distribution of possible asset prices at the time of expiry (due to the combination of the volatility and time to expiry) the greater is the extrinsic value of the option.

A complete valuation of an option will also typically include a listing of the 'Greeks', or the linear sensitivities of the option value to the various option parameters. The Greeks are described as follows, and provide reasonable estimates of the adjusted option value provided relatively small shifts are made to the option parameters:

- **Delta:** the change in option value due to a 1 unit change in the price of the underlying asset or commodity;
- **Gamma:** the change in delta due to a 1 unit change in the price of the underlying, or the second partial derivative of option value with respect to the price of the underlying;
- **Vega:** the change in option value due to a 1 unit change in the volatility of the underlying price returns;
- **Theta:** the change in option value due to a 1 unit change in the time to expiry of the option;
- **Eta:** in the case of a spread option (where the option value is dependent upon the prices of two underlying assets or commodities to be exchanged) the change in

option value due to a 1 unit change in the correlation between the price returns of the two underlying assets or commodities; and

- **Rho:** the change in option value due to a 1 unit change in the market risk-free rate of return.

The Greeks are useful in determining an appropriate hedge position for a call or a put option that has been bought or sold. A delta-hedged portfolio protects the portfolio value against small changes in the price of the underlying asset or commodity, whereas a delta-gamma-hedged portfolio protects the portfolio value against larger swings in the underlying prices and requires less frequent rebalancing of positions than does a delta-hedged portfolio. An example of a delta-hedged position is provided as follows: a call option is valued and the delta of the option is calculated to be 0.68. This delta value suggests that the net value of a portfolio will remain unchanged under small underlying price variations if 0.68 units of the underlying asset are purchased and 1 unit of the call option is sold.

As described in the introduction to this chapter, the value of a tolling contract is often estimated as that of a spread option, which provides the purchaser with the right but not the obligation to exchange one asset for a given number (or weighting) of another asset. The value of a spread option is dependent upon the correlation and volatility between and of each of the two underlying assets (power and gas); the time to expiry of the option; the risk-free rate of return; the strike price of the option (or in the case of a tolling agreement, the cost of making the exchange in terms of operating and maintenance or other charges); and the forward prices of the two assets at the time of expiry of the option. Given a tolling agreement typically provides the purchaser with operating control on an hourly or daily basis, the complete tolling contract can be considered a strip of consecutive European spread options. Depending upon the dispatching time increment (hourly, daily, weekly, etc.) and the level of detail required in the analysis, a one month tolling contract could, for example, be analyzed as a consecutive strip of 30 1-day European spread options or 730 1-hour European spread options. The tolling contract provides a lot of operating flexibility to the purchaser in terms of when the plant is operated, but is modeled as a strip of European options instead of American options because the output from the plant in the $8^{th}$ hour, for example, can only be traded (or not) in the eighth hour, and no earlier.

## 5.4 Real Options

The study of real options is a developing field, and provides a unique approach to the evaluation of capital investments by accounting for the inherent flexibility in managerial decision making. As an example, typical discounted cash flow evaluations of capital investments do not consider the option value associated with management's ability to expand or contract a facility according to market conditions. Real options analysis accounts for this latent optionality and, when compared to discounted cash flow results for the same opportunity, describes the value that is attributable to this flexibility. Real options analyses are becoming commonplace in oil and gas exploration, IT, and pharmaceutical research industries (Mun, 2002) and represent a potential enhancement to the analyses of tolling contracts in that a trading organization may choose to hedge most or all of the contract at a given time during a 5 or 20-year contract according to market conditions and other factors. Using common terminology, various types of real options include the options to delay, wait and see, expand, contract, choose, switch, or develop in sequential phases.

In broad terms, real options analyses typically involve a three-step process whereby:

1. The discounted net present value of an asset or opportunity is calculated using conventional means;

2. A binomial or trinomial tree is constructed with each branch of the expanding tree representing an equal time increment through the life of the project or opportunity. The tree is populated with a price or asset value process with all up, down and intermediate price adjustments being constant and with the probability of occurrence of each up, down and intermediate branch being constant. The up, down and intermediate adjustments and probabilities of each are controlled by the level of discretization of the time period being studied and the volatility of underlying asset or commodity;

3. A binomial or trinomial tree of the option values at each possible underlying value of each time step is calculated using backward induction by comparing the value of the underlying at a given node to the original discounted value at time zero. This backward induction process, when complete, leads to a single value for the value of a real option at time zero.

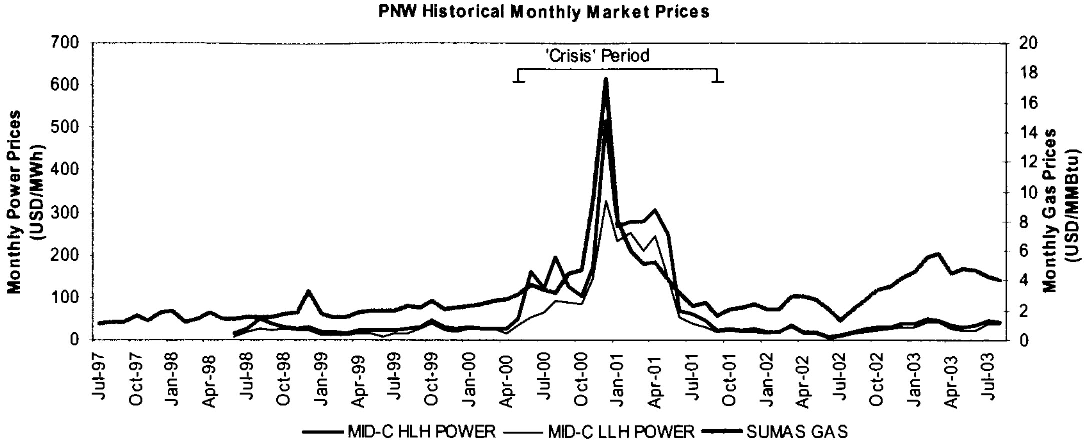
The attractiveness of this approach is that it offers great flexibility regarding the types of decisions and information availability that can be considered and entered into the decision process at each stage of the project or contract. For example, a real option approach allows for the analysis of the option value associated with the choice of generating electricity using water from a reservoir to serve the current load, versus storing the water and purchasing energy from the market. Also, the analysis of American-like options and complex, sequential options is possible using this approach, including the definition of early exercise boundaries and optimized decision making.

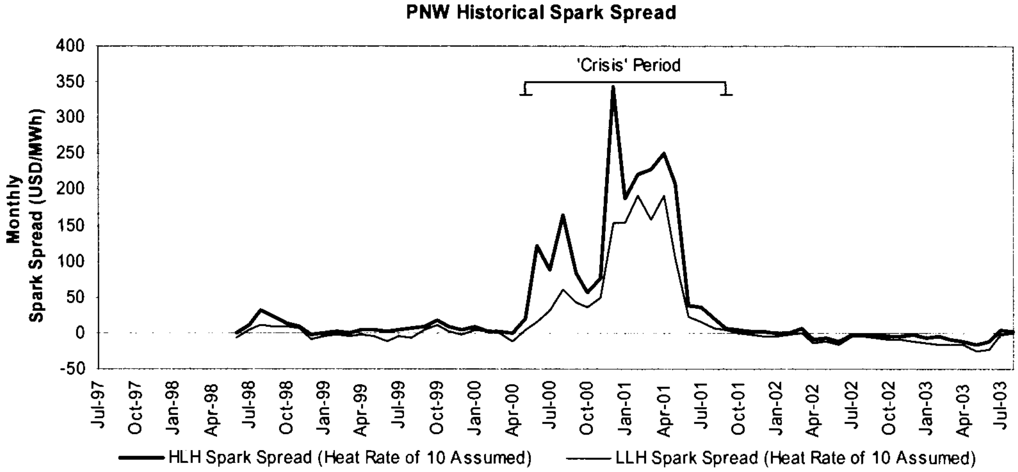
## 5.5 Spark Spread

Historical and forward power and gas prices are known and expected to be positively correlated at most times and to an extent that varies by location, season, economic condition, and short-term weather. The volatility and correlation of these two commodities leads to favourable and unfavourable conditions for the generation of electricity using natural gas. It is primarily the relative prices of the two commodities rather than their absolute levels that lead to the degree to which it is favourable to generate using natural gas over some other means. This relative measure is commonly referred to as the spark spread, which accounts for the conversion rate between natural gas and electric energy (the heat rate), and allows for the comparison of prices of the two commodities in the same units: $/MWh.

The spark spread is calculated by subtracting the product of an assumed heat rate for a single or group of generation facilities and the price of natural gas from the price of power during the same period, and results in an effective margin that would be realized if one was to buy gas from the market, convert the gas to electricity at the stated heat rate (MMBtu / MWh) and sell the resulting electricity into the market at the market price. Spark spreads can be calculated on a gross or net basis, where the net basis follows the same calculation but also accounts (at a minimum) for the following variable costs: gas transportation costs and power transmission costs. These additional variable costs are incurred because a generation facility is generally not located at precisely the same location as the power and gas trading hubs from which the reference market prices have been obtained. There is typically a variable cost associated with the transportation of gas from a reference point to the plant gates, possibly including losses, and a separate power transmission variable cost, plus losses, to transmit the generated electricity from the plant gates to the reference point. These variable costs may be incurred on top of fixed costs associated with both commodities as described below.

In addition to the spark spread, a market-inferred heat rate can be calculated for a time series of historical gas and power prices by calculating the varying heat rate of a fictitious generating facility that would be operating with precisely zero gross margin (zero spark spread). This represents a simple transformation of the spark spread calculation described above, and allows for a rough estimation of how often a given plant with a near-constant heat rate would be operating in that gas and power market. The historical (July 1997 to August 2003) natural gas and power prices; spark spreads (calculated using monthly prices and an assumed average heat rate of 10.0 MMBtu/MWh); and market-implied heat rates are plotted separately for HLH and LLH periods in Figure 5-1 for the Pacific Northwest (Mid-Columbia power and Sumas natural gas) and Figure 5-2 for the U.S. Southwest (Palo Verde power and Socal natural gas). These figures also show the 'crisis' period experience in the WECC between May, 2000 and September, 2001, where the market spark spreads and market-inferred heat rates were observed to 'disconnect' on a fundamental basis, demonstrating that conditions other than just the price of the primary generating fuel were influencing the wholesale market prices of power.



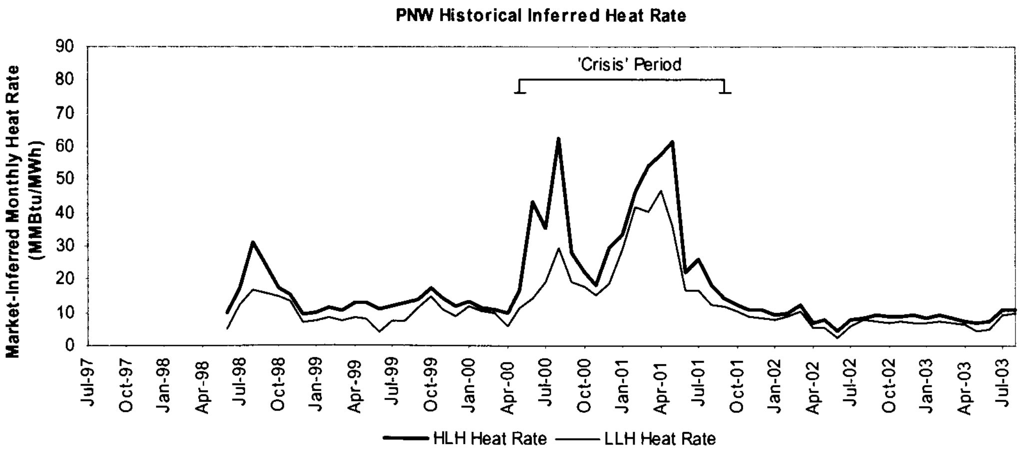
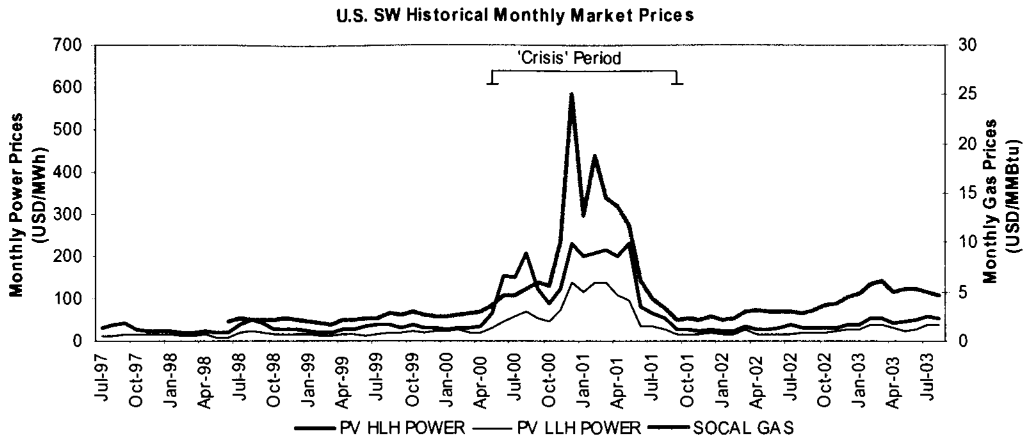
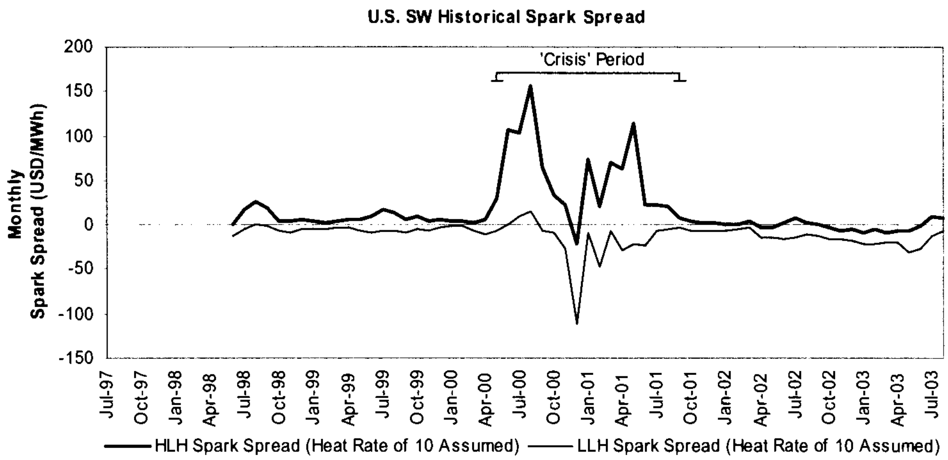




*Figure 5-1 Pacific Northwest Monthly Historical Spark Spreads and Inferred Heat Rates. Figure by authors.*



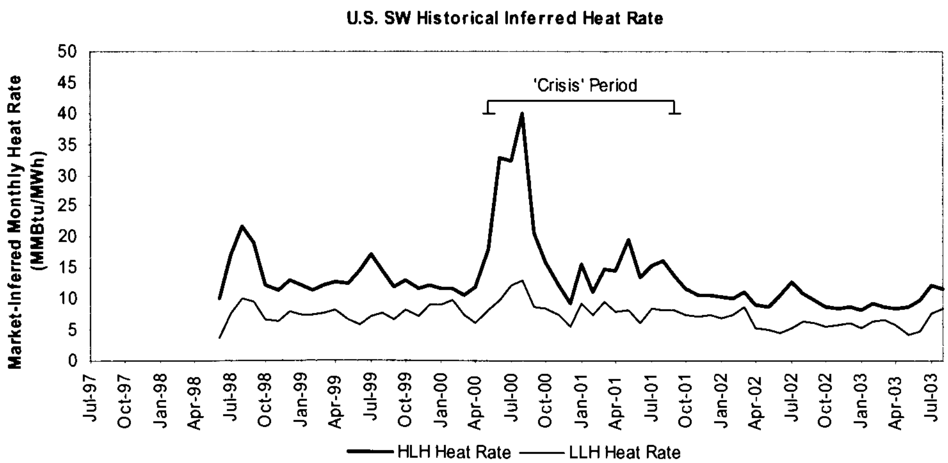




*Figure 5-2 U.S. Southwest Monthly Historical Spark Spreads and Inferred Heat Rates. Figure by authors.*

### *5.5.1 Gas Procurement and Transportation*

Spark spread measurements are only approximations. In reality, the use of fuel to generate electricity is a complex issue. When a generator is started and ramped-up to output electricity, the fuel requirements per unit production of electricity are significantly higher, therefore the cost of shutting it down is also high. Plants usually set minimum up and down times. Depending on the state of the plant, the fuel requirements for energy generation may be very high compared to its peak performance. To account for this a plant's dispatch frequency are often assumed and the additional costs and constraints are then added to the strike price. These issues require the procurement of fuel at levels above the stated (and guaranteed) heat rate of the plant. In addition to these higher procurement volumes, gas transportation requirements and costs are often grossed up to cover miscellaneous costs and losses. Finally, due to the details of gas pipeline financing and construction, the seasonality of gas transportation, and other physical characteristics of gas compression and transport, it is often necessary to buy a fixed portion of the total capacity of a pipeline for an extended period of one or more years or at least by heating and cooling season in order to be sure that access to the pipe is available when the conditions for generation are favorable. This often makes the costs associated with gas transportation fixed rather than variable, resulting in the potential for gas transportation costs even when the generation facility is uneconomical to run. It is important to establish realistic estimates of the fixed and variable costs associated with gas transportation when assessing the viability of a tolling contract and the appropriate level of tolling capacity charges.

Natural gas is a commodity with liquid forward and options markets. The future distribution of fuel prices can be estimated through stochastic simulations. Short-term gas price volatility can be affected significantly through factors such as weather changes and constraints on pipelines. Long-term gas prices are forecast to be relatively stable but are known to be influenced significantly by several geo-political and economic factors.

### *5.5.2 Power Sales and Transmission*

Another challenge with valuing spread options is the fluctuations in power prices, which are affected by many factors. These factors include: electricity system loads that are related to weather changes, available generation, transmission constraints, water in-flow predictions, existing reservoir levels, and fuel prices. Power prices can vary drastically despite production costs. Therefore, a joint lognormal distribution of electricity and natural gas prices, as expected in many valuations, may not always be a good predictor of the co-movement of gas and power prices. Indeed, power and gas prices often completely 'disconnect' due to factors related to the two infrastructures (gas pipelines and power transmission networks), and economic, weather, and regulatory conditions to name a few. Spikes in power prices are often due to extreme temperatures, loss of transmission or shortage in supply.

As with the transportation of gas, power transmission costs can be both fixed and variable. Fixed transmission costs are incurred in the purchase of Firm Transmission Rights (FTRs), which are charged at a fixed level over an extended duration. In contrast, variable transmission costs are sometimes incurred through the 'wheeling' of electricity from one grid point (possibly the generating facility) to another according to the level of production by the generating facility, the path selected to take the energy to market, and the current levels of transmission. Transmission losses and the potential for additional revenues associated with the sale of ancillary (reliability-related) services to the local system operator should also be considered in a detailed tolling valuation.

### 5.6 Price Processes

The underlying price processes of natural gas and power markets can be extremely complicated, involving the use of stochastic calculus and the application of many recent theories and pricing models. A complete study and discussion of this broad topic is beyond the scope of this paper, however, several common features and important considerations are worth mentioning to provide the reader with an appreciation for the effects of time, volatility and correlation on the co-movement of gas and power prices. As discussed in the previous sub-section, the relative pricing of power and gas, and the resulting spark spread are key to the value of a tolling contract, so any price process that is adopted for an analysis must be defensible, reproducible, and objective. Combined with this heavy reliance upon the co-movement (correlation) of power and gas prices, the spread option analogy to the tolling contract is itself quite non-linear in its payoff, resulting in the compounded importance of realistic underlying price processes.

Each day that power and gas are traded, a new forward price curve for each commodity is created. These forward price curves evolve over time, with previously distant delivery months getting progressively closer to the current day, or spot market. With this march through time, information regarding a certain delivery month gets progressively better and more reliable, but the arrival of newer information as a delivery month gets closer also tends to cause the market to react more clearly in one direction or another. Examples of this type of information are long and short-term weather forecasts: if asked in August, 2003 to predict the number of heating-degree days in December, 2003, one is limited to looking at historical averages and possibly a long-range almanac prediction, but as the end of November approaches and the local, near-term weather systems become observable, one is much better able to predict the heating-degree days over the coming week and month. Also, greater volumes of energy are traded in near months and weeks than in distant periods, leading to increased price discovery and detailed reactions to conditions in the near months and weeks. This availability of market and fundamental information, combined with the existence of a 'real-time' (next hour) power market to balance generation with actual loads, leads to extremely high price volatilities in the real-time, next day, and balance-of-week portions of the forward price curve and increasingly lower volatilities as the prices of distant months, quarters and years are observed through trading volumes. This time variation of volatility is referred to as the Term Structure of Volatility (TSOV) and is extremely important if one is attempting to construct or predict the evolution of forward price curves over the coming days, months and years. The upward or downward trend of the forward price curve (higher or lower traded prices in distant years) is referred to as 'contango' and 'backwardation' respectively, the degree of which is determined partially by a convenience yield, expectations regarding long-term market fundamentals, and the risk-free rate of return.

As discussed above, gas and power prices are often observed to move in a similar, correlated fashion due to the relatively high reliance upon gas for the generation of electricity, particularly in areas with less hydroelectric generation. Due to this general tendency to move together and for reasons related to the availability of market, fundamental and climatic information as described in the paragraph above, the correlation between the movement of forward price curves for gas and power also varies between the near and long-term delivery periods. A plot of the correlation between the prices of two assets against delivery month or year is referred to as the Term Structure of Correlation (TSOC) and is typically shaped in the opposite direction to the TSOV, with highest correlations (c.f. lowest volatilities) observed in distant delivery months and lowest correlations (c.f. highest volatilities) observed in near days, weeks and months. Again, the TSOC is very important if one is attempting to simulate the progressive evolution of forward price curves for power and gas. The prediction of future spot prices for power and gas should be simpler due partially to the requirement to predict only two numbers for each increment of time rather than an entire forward curve at each increment. The importance of the TSOV and TSOC also reduces when trying to simulate only the evolution of spot prices as the interaction between forward price curves is not accounted for.

Introductory comments regarding the volatility and correlation of power and gas prices have been provided above, and additional details regarding the use of historical price data to estimate these parameters for the purposes of simulation will be provided in subsequent sections. However, before moving on, the following additional characteristics of market-traded commodities are provided as background for the subsequent description of price process models in use in the power and gas trading industry. Spot, and to a lesser degree, forward power prices are often observed to jump from relatively stable, mean levels to high price levels that may be several multiples higher than mean levels. These jumps are often observed to persist for a few days or weeks, and occasionally months, after which prices tend to diffuse back to mean, long-term levels until the next jump or aberration occurs. This behavior is referred to as a 'jump-diffusion' process and is accounted for in some price process models. The parameters required to describe this type of behavior include the frequency of jumps (expected number per year) and their average duration (days or weeks), the determination of which requires some judgment in terms of defining the size of a jump.

Power and gas prices are also generally observed to 'mean-revert' or return to average long-term levels that tend to be consistent with market and geo-political fundamentals. The rate of mean reversion can also be measured from historical price data, but again relies upon reasonable judgment to include or exclude certain price events and define the range of mean levels to which prices revert. To further complicate matters, commodity prices are also observed to display autocorrelation and autocovariance, meaning there tends to be a non-zero correlation between today's price for a given commodity and yesterday's price for the same commodity (autocorrelation), and between today's price and yesterday's price for a different commodity (autocovariance). Heterscedasticity, or non-constant volatility, is also observed in commodity price data, related primarily to the observation of increased volatilities with increasing absolute price levels. A complete study of these behaviors, and the ability of various price process models such as Exponential or Geometric Brownian Motion (GBM), Cox-Ross-Rubinstein, and Heath-Jarrow-Morton (HJM), is certainly beyond the scope of this report, but are mentioned for the interest of the reader and for completeness.

Other price behaviors include seasonality and trend, which may in some circumstances cause an over-estimation of the volatility of and correlation between commodity prices. Seasonality can include repetitive price behaviors of any frequency, including hourly, daily, weekly, monthly and even multi-annual (reflecting, for example, the cyclic arrival of El Nino weather patterns). Two strategies to minimize the potential for errors in the estimation of volatilities and correlations can be applied independently or in conjunction with each other:

1. The volatility and correlation of price *returns* instead of absolute price levels can be calculated. Price returns are calculated simply as the natural logarithm of the ratio of the price for a given period to the price observed during the immediately prior period (e.g. the natural logarithm of the ratio of today's price to yesterday's price). With the exception of a slight upwards or downwards bias, these price return data tend to be more indicative of the real, random nature of the price movements than the absolute prices themselves. This approach is a standard across the financial industry, and results in a log-normal price process with the added benefit of preventing the erroneous sampling of negative prices in Monte Carlo simulations.

2. The absolute price data or the series of calculated price returns can also be deseasonalized and de-trended through an optimized exponential weighting methodology such as the Holt-Winter method. Such an analysis provides a residual set of price or price return data, the volatility and correlation of which can be attributed purely to the inherent random nature of commodity prices instead of trend and seasonality.

The most common and important price process in terms of capturing the basic forward behavior of prices is the Geometric Brownian Motion (GBM) model, which captures the increasing uncertainty of price predictions over increasingly distant time periods (widening of price distributions) through the Wiener increment: a stochastic term that includes a random sample from the standard normal probability distribution, the square root of a constant time increment, and the standard deviation or volatility of the price returns data scaled to the time increment being used. It is possible to add a Mean-Reverting Jump Diffusion (MRJD) term or factor to the standard GBM process and additionally to continuously adjust a trend factor to force the mean of the simulated forward price curve to follow an assumed price scenario or predicted price shape with the superposition of daily and/or monthly price volatility.

For the purposes of the analyses completed during the preparation of this report, a simple GBM price process with a continuously adjusted trend factor has been adopted to obtain a widening (with time) distribution of possible spot prices over each heavy and light load period of each day over a 20 year period, which in turn follows the shape of a specified forward price curve or scenario.

The stochastic equation for $S_T$, the underlying commodity price at time 'T', when the spread option (one daily spread option in a 20-year strip of daily spread options) on the underlying commodities expires, takes the form (for risk neutral valuation):

$$S_T = S\exp[(r - q - 0.5\sigma^2)T + \varepsilon\sigma\sqrt{T}]$$ (Jackson & Staunton, 2001);

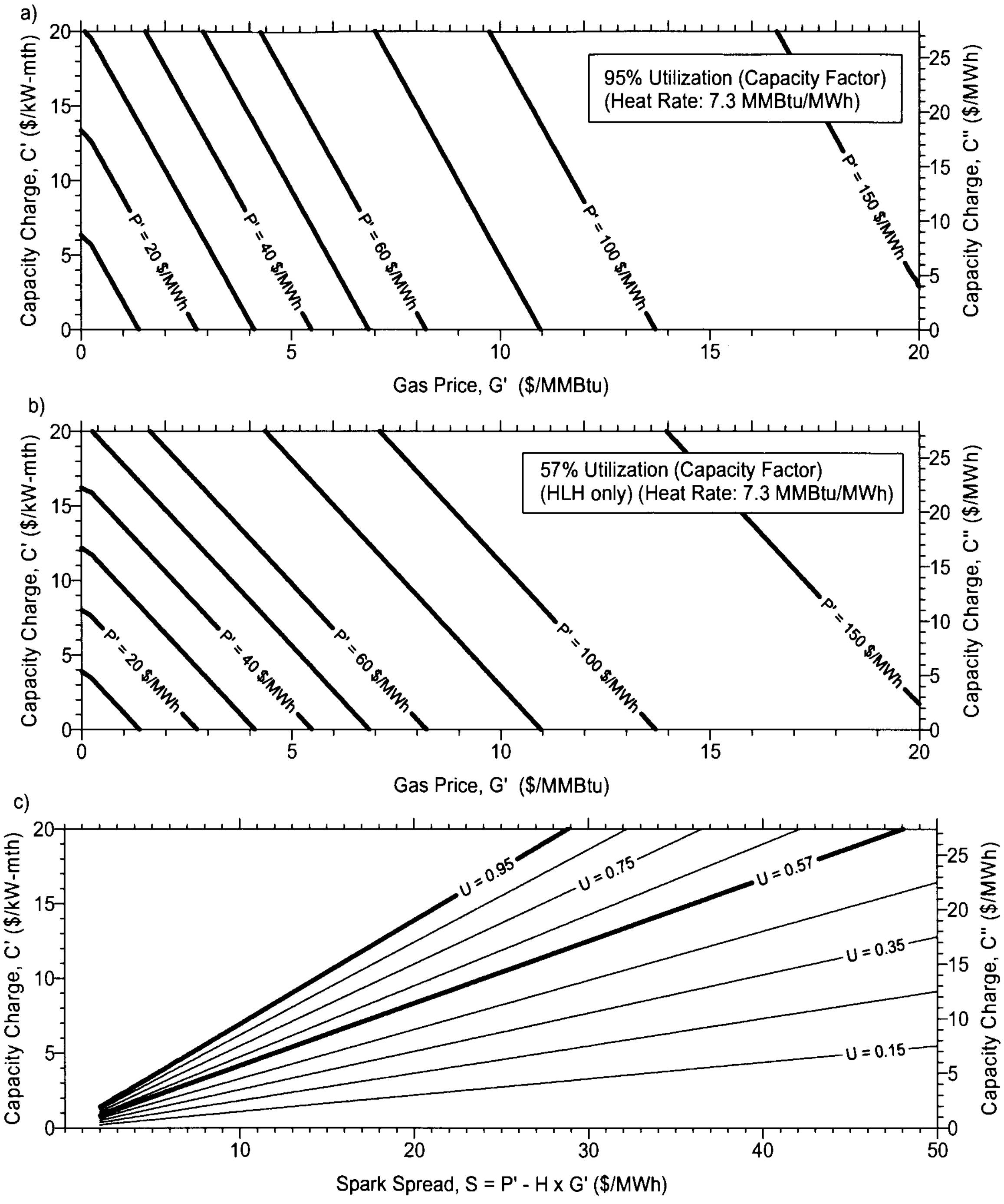
where 'S' is the commodity price in the prior period; 'r' is the risk-free rate of return or yield curve; 'q' is a continuous dividend yield in the case of an underlying equity stock, or the trend required to maintain a mean of the resulting price distribution that tracks the known forecast scenario or forward price curve; sigma, 'σ', is the standard deviation of the price returns as discussed in sub-section 5.10.1; and 'ε' is a random sample from the standard normal distribution. This price process is applied at two different frequencies in the Monte Carlo analyses that are described in the following sections and sub-sections: daily and monthly; and the specific values of 'r', 'q', 'ε' and 'T' are scaled appropriately and applied separately to reflect the two frequencies when generating each price series iteration in the simulation.

## 5.7 Valuation Techniques

The valuation of a tolling contract is most certainly part art and part science; dependent upon several intangible and non-quantifiable factors such as the likelihood and impact of development of unforeseen technologies or the content and impact of future regulations and environmental or emissions legislation. In the special case of Powerex, the value of a tolling contract to Powerex and the citizens and rate-payers of British Columbia is further complicated by international trade and market development and the tax-exempt, Crown corporation status of the company. Adding to these complications is the reality that no two tolling contracts appear to be the same; each differing in fixed and variable costs associated with operating and maintenance, fuel procurement and transportation, and power wheeling; access to markets; rights and obligations of the owner and tolling party; physical and financial risks; efficiency; potential long-term off-takers; and tenor.

### *5.7.1 Intrinsic Value*

The first and simplest of steps is to calculate the intrinsic value of a generation facility using basic operating assumptions and data for the facility and any available market price data or scenarios for the given location. By studying the forecasted or forward spark spread data for heavy and light load periods separately and by considering the level and timing of hedges that would be expected, it may be possible to estimate the approximate and average levels of utilization (capacity factor) for the facility. Of the 8,760 hours in a given year, approximately 57 percent of them are considered using NERC definitions to be Heavy Load Hours (HLH). Given the common disparity between power prices in HLH versus Light Load Hours (LLH), it is quite common to predict that the plant will operate primarily during HLH. On the other hand, some newer facilities with relatively low heat rates and favorable market conditions may tend to operate during as many hours in the year as possible. The practical limitation in this regard is approximately 95 percent due to scheduled maintenance and other outages. Given these two simple utilization scenarios, and for an assumed heat rate of approximately 7.3 MMBtu/MWh, the nomographs of Figure 5-3 a) and b) have been prepared to allow a user to determine the required power price, gas price or capacity charge to just break even with the contract depending upon the assumed utilization (a: 95 percent, or b: 57 percent) of the facility. As an example, for capacity charge of \$5/kW-mth, gas prices of \$5/MMBtu, and an anticipated utilization of 57 percent, the power price required to just break even during the given operating period is approximately \$48/MWh (taken graphically from Figure 5-3 b)). Through dimensional analysis and normalization of the x-axes in parts a) and b) of Figure 5-3, it is possible to prepare a single figure and family of curves for the calculation of intrinsic plant value that has been generalized for all heat rates and utilizations by using the spark spread in the x-axis (Figure 5-3 c)). The two bold lines in part c) of the figure again show the 57 percent (HLH only) and 95 percent utilization levels for ease of use and comparison to the results above. The nomographs have been further generalized through the use of C', G', and P' for the capacity charge, gas price and power price respectively. For a simple, gross margin estimate, these variables are populated using market or assumed prices for all three directly. For a more accurate measure of the potential net margin or to require power prices (or heat rate, or utilization, etc.) to break even, the equations at the bottom of Figure 5-3 can be used to transform these variables, accounting for fixed and variable operating and maintenance costs, gas transportation costs, and power transmission costs (VOM and FOM).




C' = Capacity Charge + 0.73 ($HT_{FG}$ + $T_{FP}$ + $O_F$) [$/kW-mth]
C'' = Capacity Charge + $HT_{FG}$ + $T_{FP}$ + $O_F$ [$/MWh]
P' = Power Price – $T_{VP}$ – $O_V$ [$/MWh]
G' = Gas Price + $T_{VG}$ [$/MMBtu]
H = Heat Rate [MMBtu/MWh]
U = Utilization (Capacity Factor)

$T_{FP}$ = Fixed Power Transmission Costs [$/MWh]
$T_{FG}$ = Fixed Gas Transportation Costs [$/MMBtu]
$O_F$ = Fixed Operating and Maintenance Costs [$/MWh]
$T_{VP}$ = Variable Power Transmission Costs [$/MWh]
$T_{VG}$ = Variable Gas Transportation Costs [$/MMBtu]
$O_V$ = Variable Operating and Maintenance Costs [$/MWh]

*Figure 5-3 Nomographs of Intrinsic Value. Figure by authors.*

### *5.7.2 Black-Scholes: Closed-Form Solutions*

In 1973 Fisher Black and Myron Scholes developed an option pricing formula. The theorem is as follows. Consider a European call option (only exercised at expiration) on a stock whose current price is *S*. Suppose that the stock price is lognormally distributed with volatility $\sigma$, that the option's exercise price is *X*, that the exercise date of the option is *T*, and that the continuously-compounded risk-free interest rate is *r*. Furthermore assume that the stock will pay no dividends before the option exercise date, *T*. Then the call price is given by:

$$C = SN(d_1) - Xe^{-rT}N(d_2) \quad where \quad d_1 = \frac{\ln\frac{S}{X} + (r + \frac{\sigma^2}{2})T}{\sigma\sqrt{T}} \quad and \quad d_2 = d_1 - \sigma\sqrt{T}$$

*where $N()$ indicates values of the cumulative standard normal distribution*

As discussed above, an option that permits the exchange of one asset for another is referred to as a spread option. Margrabe (1978) provided a closed-form solution, based on the Black-Scholes process, for the value of a spread option, which was subsequently modified to account for a strike price, K, associated with exercising of the option. This is calculated by:

$$C = e^{-rT}\left[P_t N(d_1) - (hG_t + K)N(d_2)\right]$$

where

$$F = \frac{P_t}{hG_t + K} \qquad d_1 = \frac{\ln F + \sigma^2 T/2}{\sigma\sqrt{T}} \qquad d_2 = d_1 - \sigma\sqrt{T}$$

$$\sigma = \sqrt{\sigma_1^2 + \left(\sigma_2 \frac{P_t}{hG_t + K}\right)^2 - 2\rho\sigma_1\sigma_2\frac{P_t}{hG_t + K}}$$

With the following hedges:

$$\frac{\partial C}{\partial P_t} = e^{-rT}N(d) \qquad -\frac{\partial C}{\partial(hG_t)} = e^{-rT}N(d - \sigma\sqrt{T})$$

This strike price represents a combined variable cost that could include operating and maintenance, variable gas transportation, and variable power transmissions components. Known fixed costs should be estimated and incorporated into the valuation by converting and adding them to the gas price estimates or converting and subtracting them from the power price estimates. Despite the attractiveness of providing a closed form solution, this modified Margrabe solution, including the adaptation for a strike price (additional variable costs), K, is known to lack accuracy when the volatilities of the two underlying assets are high and worsened by high correlations between the underlying assets. Despite these limitations, the modified Margrabe approach is used here for comparison and reporting purposes.

The volatilities and correlations expected by all Black-Scholes approaches, and hence the modified Margrabe approach also, are all what is referred to as 'flat' volatilities, meaning that the instantaneous volatilities and correlations captured from the daily or monthly changes in the historical forward price curves and reported (as described above) in the TSOV and TSOC curves must be integrated to provide a weighted average ('flat') volatility and correlation for each time step in the strip of spread options being used to model the tolling contract. In other words, the modified Margrabe solution is evaluated many times to capture the spread option value associated with each day of operation of the generating facility, with each successive evaluation being conducted over an increasing duration until the full length of the contract (e.g. 20 years) has been captured. Each evaluation must also use the flat volatility and correlation calculated through numerical integration of the instantaneous TSOV and TSOC curves. The modified Margrabe described above and as applied here assumes a joint bivariate lognormal distribution for the combined (correlated) relationship between HLH power and gas, LLH power and gas, and HLH power and LLH power, with the additional stipulation that all sampled LLH power prices are forced to be less than the corresponding HLH power price calculated for the same time interval.

### *5.7.3 Binomial Lattice*

The binomial lattice model was first published in 1986 by Ho and Lee. A binomial approach assumes underlying asset or commodity prices follow a process where prices can jump up or down by a given amount at given increments of time. A binomial model breaks down the time to expiration into a number of time intervals. At each step the commodity price can be assumed to move up or down by an amount calculated using the volatility and time to expiration. This produces a tree which represents a discretized version of all possible paths the commodity price could take over the duration of the contract. The binomial model can accurately price American or European options, and two or three lattices (one for each of the heavy and light load power and gas price processes) can be assessed together to value the spread option analogy to a tolling contract.

### *5.7.4 Monte Carlo Simulation*

Monte Carlo simulation involves the repetitive generation of a string of daily price returns for each of the modeled commodities (gas and heavy and light load power), which are in turn converted to absolute price level iterations over the 5 or 20-year (or other) duration being simulated. The Monte Carlo simulation method has the advantage of providing great flexibility in the price process and analyses, in that variable and fixed costs associated with the tolling contract can be accounted for by counting or referencing (for example) the frequency of on / off operations of the facility or the total number of operating hours within a given month or year, thereby allowing for the detailed inclusion of variable operating costs.

Daily Monte Carlo simulations of the price processes can be calculated and calibrated or at least compared to the observed historical daily spot prices for the same commodities and markets. For the Monte Carlo analyses reported here, up to six years of daily power and gas data have been used to calculate the monthly and daily volatilities and correlations for input to the simulation. The simulation process provides a set of 3 correlated power (HLH and LLH) and gas prices for each day of each year of the tolling simulation, and for each of potentially thousands of iterations. A daily payoff function is evaluated independently for LLH and HLH blocks and for each iteration to build up a distribution of potential option payoffs for each HLH and LLH block of each day of the contract with measurable mean, median, mode and extreme value (1$^{st}$ and 99$^{th}$ percentiles) statistics. These payoff distributions can be adjusted to account for additional fixed and variable costs associated with the current operating state to provide statistical distributions of daily earnings, which are summed and discounted back to any level of summary period that is desired or required for subsequent return analyses. For example, the distribution of monthly net incomes is accumulated and levelized to provide a capacity value by month, and further accumulated to annual, 5-year summaries, and 20-year distributions of earnings.

## 5.8 Asset and Dispatch Optimization

A challenge of the methodologies described above is the determination of optimized operating rules for a given facility given a set of price processes and resulting spread option values. Through trial and error, general on / off rules can be established and tested, particularly in the Monte Carlo simulation process, to account for the specific variable and fixed costs described by a specific tolling contract. These operating rules could specify spark spreads above which a plant is turned on, and (likely) a lower spark spread that specifies the level above which a facility that is currently on stays on. There are many approaches to optimize the operation of a facility and to capture these optimized benefits in the valuation; two of which are briefly discussed here: perfect foresight and Least Squares Monte Carlo (LSMC).

A perfect foresight valuation generally follows these steps: Step 1: Generate time series of simulated prices for HLH and LLH power and gas from the start of the operation (time zero) to time T, the duration of the tolling agreement. Step 2: Work backwards through the iteration of price processes from time T determining the facility's value at each preceding time interval, time t-1. Assume maximum dispatch commitments and optimally dispatched spark-spread payoffs. Step 3: Continue until time zero. Step 4: Repeat steps 1 thru 3 a number of times, usually more than 100, and determine the average of all the optimal objective values. It is important to include price uncertainty to determine dynamic dispatching decisions. There are flaws with this form of valuation, including the fact that the optimized solution only provides an upper bound on the plant's expected value due to the unrealistic knowledge of the entire price process available to the optimization. Each simulation yields an independent set of dispatching rules.

An alternative Least Squares Monte Carlo (LSMC) method works as follows: For any number of simulations, it is necessary to establish the optimal dispatching rules. These rules are determined through the expected generator value of each hour or discretized time increment (daily HLH and LLH blocks) and are conditional upon the state of generation and the spot prices of the previous hour, which are then fitted using simulation data. The dispatching rules are then applied to all the simulations to obtain an optimal expected value. This can be used to continually optimize the spark-spread payoff using expected prices. To link traditional spark-spread and plant valuation while taking into account plant constraints and costs, an FEA (Financial Engineering Associates) Power Generation model allows for the specification of a traditional lognormal mean-reverting price process for both electricity and natural gas and can produce more realistic power price processes. Using LSMC simulation to capture multi-stage decisions involved in operating a generation asset and the hybrid approach to simulate co-movement of power and fuel prices, FEA's @Energy / Power Generation represents a powerful tool for an analyst to determine expected value and risks of these assets.

### 5.9 Potential Locations and Spark Spread Expectations

The location of a generating plant considered for tolling is important. Ideally it would be located within favourable trading markets. This is critical to reduce transmission costs, congestion problems and curtailment risk. The capabilities of the connecting transmission grid can determine a plant's profitability. Changes to the grid will also cause an impact. Opening up more ATC to a region may enable more competitive pricing around the generator location, but it may also provide more export capability, resulting in higher plant usage due to the average realization of higher spark spreads available in adjacent or inter-connected markets.

The U.S. Southwest is becoming one of the most overbuilt markets on the continent (CERA, 2003a). Intense competition amongst generators is expected to reduce profits and will frustrate investor expected rates of return, creating the likelihood that many assets will become distressed as operators fail to service debt loads.

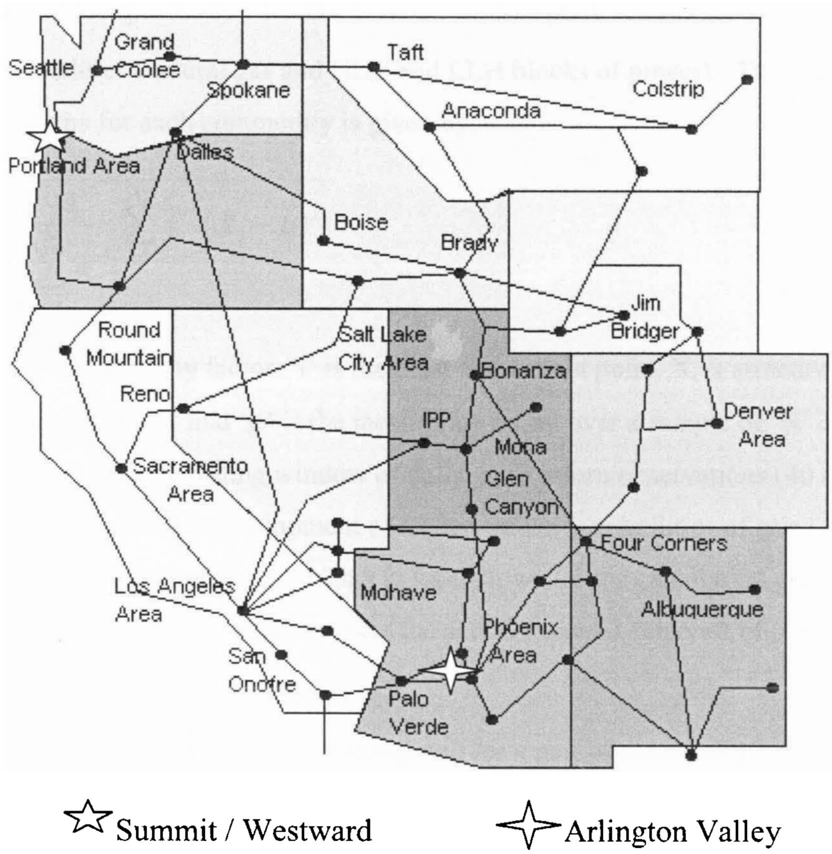



*Figure 5-4 Location of Oregon and Arizona tolling opportunities within the WSCC. Adapted from: NERC, 2003. (NERC material is protected by copyright and used by permission.)*

Methodologies for valuing tolling contracts have been studied as part of this report, and three approaches (intrinsic, modified Margrabe, and Monte Carlo) have been adapted and applied to potential tolling agreements with two generator facilities. The locations of these plants are shown in Figure 5-4. Efforts have been made to represent realistic fixed and variable costs associated with the operation and maintenance of the facilities, the gas procurement and transportation to the plants, and the power sales and transmission from the plants.

## 5.10 Volatility and Correlation of Underlying Commodity Prices

### *5.10.1 Instantaneous Historical Daily Spot Price Volatilities and Correlations*

The instantaneous historical daily spot price volatilities and correlations, as required for the Monte Carlo simulation method described above (versus the volatilities and correlations required for Black-Scholes based valuations), are calculated as follows:

As discussed in the previous sub-sections, historic price returns are calculated as $R_t = \ln(P_{t+1} / P_t)$ and reported as a historical time series of price returns for each of the underlying commodities (natural gas and HLH and LLH blocks of power). The volatility, sigma, of these price returns for each commodity is given by:

$$\sigma_x = \sqrt{\frac{1}{\sum_{i=1}^{N} \lambda^{i-1}} \sum_{i=1}^{N} \lambda^{i-1} (X_i - \mu)^2}$$

where 'λ' is the decay factor, 'i' is the most recent data point, $X_i$ is an individual price return observation at time 'i' and 'μ' is the mean price return over a sample of 'N' observations, which can be any reasonable rolling window of daily price return observations (40 at Powerex). This calculation allows for the development of a curve of daily volatilities of price returns over the duration of the historical price data. This in turn allows for the calculation and summary of volatilities by year or by month, which reflects the actual seasonal behavior of prices at different locations.

The correlation coefficient, rho, is computed for a pair of commodity price return histories by:

$$\rho_{xy} = \frac{\sigma_{xy}}{\sigma_x \sigma_y}$$

where:

$$\sigma_{xy} = \sqrt{\frac{1}{\sum_{i=1}^{N} \lambda^{i-1}} \sum_{i=1}^{N} \lambda^{i-1} (X_i - \mu)(Y_i - \eta)}$$

and the two volatilities of price returns are calculated for the separate commodities as:

$$\sigma_x = \sqrt{\frac{1}{\sum_{i=1}^{N} \lambda^{i-1}} \sum_{i=1}^{N} \lambda^{i-1} (X_i - \mu)^2}$$

$$\sigma_y = \sqrt{\frac{1}{\sum_{i=1}^{N} \lambda^{i-1}} \sum_{i=1}^{N} \lambda^{i-1} (Y_i - \eta)^2}$$

where

$$\mu = \frac{1}{N} \sum_{i-1}^{N} X_i$$

$$\eta = \frac{1}{N} \sum_{i-1}^{N} Y_i$$

again representing the rolling mean of 'N' price return observations for each of the two commodities.

This calculation is referred to as an exponentially weighted moving average (EWMA) estimate of volatility and correlation and is completed for the entire history of each commodity price data set and for each individual and combination of commodities. Alternative calculation methods include simple, rolling standard deviation (without exponential weighting), and the use of market-implied volatilities (back-calculated from price discovery of traded options in the underlying commodity), but the EWMA method described above and as used here and by Powerex is common across the energy industry and more reliably calculates the volatility and correlation parameters in the absence or poor liquidity of the options market. For analysis purposes, HLH power and LLH power are considered separate commodities in order to capture their correlated but separate movement.

Results from the application of this volatility and correlation estimation method are provided in tables Table 5-1 through Table 5-4. The results are provided on a monthly, annualized basis for all three underlying commodities (natural gas and HLH and LLH power), and for the two frequencies (daily and monthly) as described above in sub-section 5.6. An inherent assumption in the provision of these results is that the relationship between spot (not forward) gas and power price returns (not absolute prices) will remain constant over the period of the analysis in terms of both volatilities and correlations. The TSOV and TSOC are observable from the daily evolution of forward price curves as described in the following sub-section 5.10.2, but no such information is available (beyond what is used here) for the time variability (term structure) of spot price volatilities and correlations. The authors believe this assumption to be reasonable given the use of forecast scenarios and market price data, which inherently includes assumptions regarding the co-movement of gas and power prices. Beyond these forecast scenarios and market information, there is no reason to believe the relationship between these commodities will necessarily intensify or diminish over the coming decades.

Two sets of results are provided; the first for the Mid-Columbia power Sumas gas markets, which are the appropriate markets for analysis of an opportunity in Oregon as shown in Figure 5-4; and the second for the Palo Verde power and Southern California (Socal) gas markets, which are the appropriate markets for analysis of an Arizona opportunity.

*Historical Volatility of Daily and Monthly Price Returns*

| Month | Annualized Daily Volatility of Price Returns (count) | | |
|---|---|---|---|
| | Gas | HLH Power | LLH Power |
| January | 94% (155) | 251% (124) | 257% (124) |
| February | 58% (141) | 125% (113) | 120% (113) |
| March | 69% (155) | 158% (124) | 138% (124) |
| April | 46% (150) | 222% (120) | 192% (120) |
| May | 42% (155) | 262% (124) | 185% (124) |
| June | 49% (127) | 391% (127) | 279% (127) |
| July | 76% (124) | 384% (124) | 234% (124) |
| August | 50% (116) | 304% (94) | 155% (94) |
| September | 54% (120) | 226% (90) | 107% (90) |
| October | 72% (154) | 123% (123) | 104% (123) |
| November | 84% (150) | 152% (120) | 133% (120) |
| December | 130% (155) | 181% (124) | 161% (124) |
| ***Annualized Avg. Daily Volatility*** | ***70%*** (1702) | ***232%*** (1407) | ***175%*** (1407) |
| ***Annualized Avg. Monthly Volatility*** | ***3.3%*** (1701) | ***7.5%*** (1394) | ***6.8%*** (1394) |

***Notes:***

1. Volatility decay factor, lambda: 0.9
2. Gas: DGSUMAS - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
3. HLH Power: DPMIDCHLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'0
4. LLH Power: DPMIDCLLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01

*Table 5-1 Volatility of Historical (1997-2003) Daily Price Returns: Mid-Columbia Power and Sumas Natural Gas. Table by authors.*

*Historical Volatility of Daily and Monthly Price Returns*

| *Month* | *Annualized Daily Volatility of Price Returns (count)* | | |
|---|---|---|---|
| | ***Gas*** | ***HLH Power*** | ***LLH Power*** |
| January | 43% *(124)* | 201% *(155)* | 205% *(155)* |
| February | 34% *(139)* | 161% *(141)* | 221% *(141)* |
| March | 56% *(155)* | 185% *(155)* | 212% *(155)* |
| April | 45% *(150)* | 183% *(150)* | 176% *(150)* |
| May | 48% *(155)* | 224% *(155)* | 172% *(155)* |
| June | 55% *(127)* | 305% *(128)* | 361% *(128)* |
| July | 63% *(124)* | 390% *(124)* | 333% *(124)* |
| August | 47% *(94)* | 371% *(116)* | 267% *(116)* |
| September | 47% *(90)* | 296% *(120)* | 219% *(120)* |
| October | 63% *(123)* | 216% *(154)* | 176% *(154)* |
| November | 80% *(120)* | 227% *(150)* | 198% *(150)* |
| December | 74% *(124)* | 203% *(155)* | 181% *(155)* |
| ***Annualized Avg. Daily Volatility*** | ***54%*** *(1525)* | ***240%*** *(1703)* | ***222%*** *(1703)* |
| ***Annualized Avg. Monthly Volatility*** | ***2.0%*** *(1515)* | ***6.6%*** *(1701)* | ***5.1%*** *(1701)* |

***Notes:***

1. Volatility decay factor, lambda: 0.9
2. Gas: DGSOCAL - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
3. HLH Power: DPPVHLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
4. LLH Power: DPPVLLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)

*Table 5-2 Volatility of Historical (1997-2003) Daily Price Returns: Palo Verde Power and Socal Natural Gas. Table by authors.*

*Correlation of Historical Daily Price Returns*

| Daily Correlation (all months) | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.12 | 0.13 |
| Power HLH | 0.12 | 1 | 0.52 |
| Power LLH | 0.13 | 0.52 | 1 |

| January | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.09 | 0.01 |
| Power HLH | 0.09 | 1 | 0.91 |
| Power LLH | 0.01 | 0.91 | 1 |

| July | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.21 | 0.14 |
| Power HLH | 0.21 | 1 | 0.54 |
| Power LLH | 0.14 | 0.54 | 1 |

| February | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.48 | 0.48 |
| Power HLH | 0.48 | 1 | 0.58 |
| Power LLH | 0.48 | 0.58 | 1 |

| August | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.01 | -0.04 |
| Power HLH | 0.01 | 1 | 0.31 |
| Power LLH | -0.04 | 0.31 | 1 |

| March | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.10 | 0.14 |
| Power HLH | 0.10 | 1 | 0.57 |
| Power LLH | 0.14 | 0.57 | 1 |

| September | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | -0.02 | -0.02 |
| Power HLH | -0.02 | 1 | 0.41 |
| Power LLH | -0.02 | 0.41 | 1 |

| April | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.05 | 0.05 |
| Power HLH | 0.05 | 1 | 0.56 |
| Power LLH | 0.05 | 0.56 | 1 |

| October | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.24 | 0.05 |
| Power HLH | 0.24 | 1 | 0.40 |
| Power LLH | 0.05 | 0.40 | 1 |

| May | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.13 | 0.16 |
| Power HLH | 0.13 | 1 | 0.31 |
| Power LLH | 0.16 | 0.31 | 1 |

| November | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | -0.04 | 0.11 |
| Power HLH | -0.04 | 1 | 0.53 |
| Power LLH | 0.11 | 0.53 | 1 |

| June | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.24 | 0.19 |
| Power HLH | 0.24 | 1 | 0.41 |
| Power LLH | 0.19 | 0.41 | 1 |

| December | Gas | Power HLH | Power LLH |
|---|---|---|---|
| Gas | 1 | 0.21 | 0.27 |
| Power HLH | 0.21 | 1 | 0.66 |
| Power LLH | 0.27 | 0.66 | 1 |

*Notes:*

1. HLH: Heavy Load Hours, LLH: Light Load Hours
2. Gas: DGSUMAS - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
3. HLH Power: DPMIDCHLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
4. LLH Power: DPMIDCLLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)

*Table 5-3 Correlation of Historical (1997-2003) Daily Price Returns: Mid-Columbia Power and Sumas Natural Gas. Table by authors.*

*Correlation of Historical Daily Price Returns*

| *Daily Correlation (all months)* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.13 | 0.03 |
| *Power HLH* | 0.13 | 1 | 0.20 |
| *Power LLH* | 0.03 | 0.20 | 1 |

| *January* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.18 | 0.11 |
| *Power HLH* | 0.18 | 1 | 0.10 |
| *Power LLH* | 0.11 | 0.10 | 1 |

| *July* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.21 | -0.10 |
| *Power HLH* | 0.21 | 1 | 0.22 |
| *Power LLH* | -0.10 | 0.22 | 1 |

| *February* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.42 | 0.32 |
| *Power HLH* | 0.42 | 1 | 0.33 |
| *Power LLH* | 0.32 | 0.33 | 1 |

| *August* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.08 | -0.13 |
| *Power HLH* | 0.08 | 1 | 0.22 |
| *Power LLH* | -0.13 | 0.22 | 1 |

| *March* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.01 | 0.10 |
| *Power HLH* | 0.01 | 1 | 0.30 |
| *Power LLH* | 0.10 | 0.30 | 1 |

| *September* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.12 | 0.00 |
| *Power HLH* | 0.12 | 1 | 0.22 |
| *Power LLH* | 0.00 | 0.22 | 1 |

| *April* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.10 | -0.10 |
| *Power HLH* | 0.10 | 1 | 0.20 |
| *Power LLH* | -0.10 | 0.20 | 1 |

| *October* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.18 | 0.12 |
| *Power HLH* | 0.18 | 1 | 0.34 |
| *Power LLH* | 0.12 | 0.34 | 1 |

| *May* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.11 | -0.10 |
| *Power HLH* | 0.11 | 1 | 0.14 |
| *Power LLH* | -0.10 | 0.14 | 1 |

| *November* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.07 | 0.09 |
| *Power HLH* | 0.07 | 1 | 0.46 |
| *Power LLH* | 0.09 | 0.46 | 1 |

| *June* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.12 | -0.12 |
| *Power HLH* | 0.12 | 1 | -0.05 |
| *Power LLH* | -0.12 | -0.05 | 1 |

| *December* | *Gas* | *Power HLH* | *Power LLH* |
|---|---|---|---|
| *Gas* | 1 | 0.18 | 0.13 |
| *Power HLH* | 0.18 | 1 | 0.40 |
| *Power LLH* | 0.13 | 0.40 | 1 |

*Notes:*

1. HLH: Heavy Load Hours, LLH: Light Load Hours
2. Gas: DGSOCAL - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
3. HLH Power: DPPVHLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)
4. LLH Power: DPPVLLH - Jul.'97 to Aug.'03, excluding 'Crisis Period' (May'00 - Sep.'01)

*Table 5-4 Correlation of Historical (1997-2003) Daily Price Returns: Palo Verde Power and Socal Natural Gas. Table by authors.*

### *5.10.2 Flat (Black-Scholes) Daily Volatilities and Correlations*

As stated in sub-section 5.7.2, option valuation techniques derived from Black-Scholes price processes and assumptions require single 'flat' or weighted average volatilities and correlations. These flat parameters are determined using historical forward price data instead of historical spot price data, but the calculation methodology is precisely the same as that described in sub-section 5.10.1. There are two key features that distinguish the flat volatilities and correlations described here from the instantaneous parameters described in the previous sub-section:

1. The volatility of daily price returns is calculated for each point on an entire forward curve instead of just one point: the spot (day ahead) price, resulting in a curve of volatilities: the Term Structure of Volatility (TSOV); and
2. This TSOV is integrated over time from the instantaneous values determined above to flat or weighted average values for use in the Black-Scholes process.

Other than this brief description, the detailed calculation of flat (Black-Scholes) volatilities from historical forward price data is beyond the scope of this paper, but the results of these analyses, obtained from the current database of historical forward price curves, for the same market locations are shown in Figure 5-5 and Figure 5-6 for the Mid-C / Sumas and Palo Verde / Socal markets respectively. The results of these analyses are plotted only to June 2005 as the results of the analyses, due partially to the poor availability (liquidity) of market forward prices beyond this date, are constant thereafter. The results of these analyses, for Palo Verde and Socal in particular, are not as good as one would hope, nor a perfect demonstration of the typical (or perhaps textbook) behavior of price return volatilities and correlations as described in sub-section 5.6. That said, these are the data, and if nothing else, they demonstrate the challenges of maintaining and analyzing good historical forward price data and their application to standard Black-Scholes based methodologies.

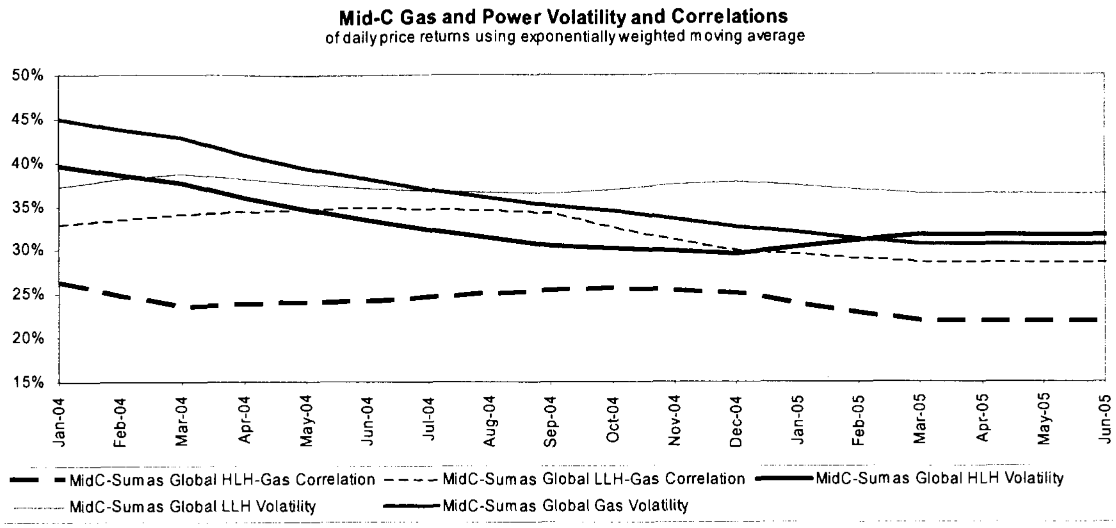



*Figure 5-5 Power and Gas Power Volatility and Correlations for the Mid-Columbia and Sumas trading hubs. Figure by authors.*

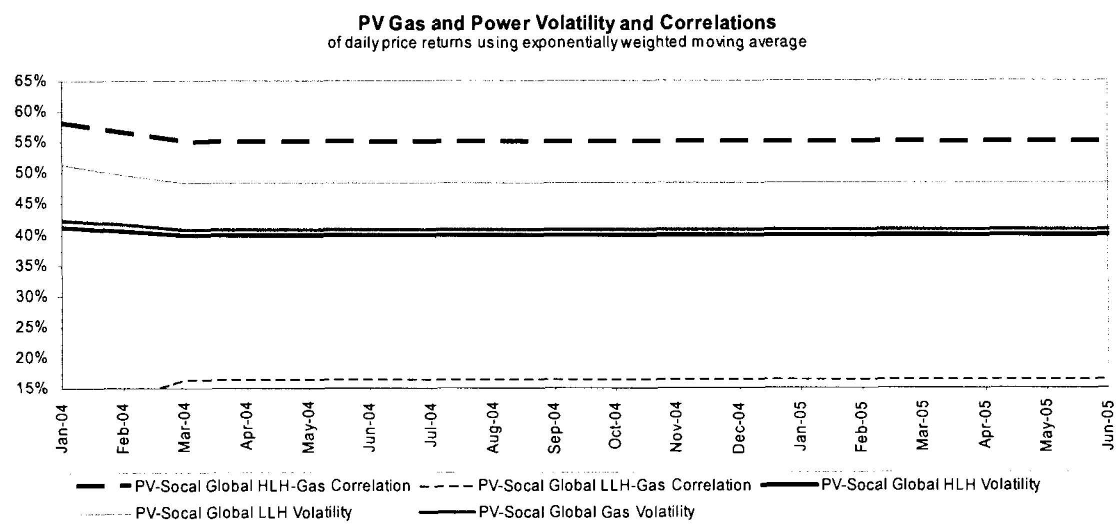



*Figure 5-6 Power and Gas Volatility and Correlations for the Palo Verde and Socal trading hub. Figure by authors.*

## *5.11* Hedging

Life would be too simple if the issues related to the valuation of a straight tolling agreement as described above were all that had to be considered. Hedging strategies are also often adopted as a means of managing risks associated with fluctuations in the price of the underlying commodities (market risk). An appropriate hedge is typically expected to cause a slight reduction in expected earnings, but a larger reduction in associated risks, resulting in an improved return on Capital at Risk (CaR). Specifically the application of a hedge in the form of future power sales, future gas purchases, heat rate sales, or even a subsequent sale of a portion of the original tolling capacity, is typically designed to reduce the absolute level of risk (measure as risk capital) for the project while hopefully causing a lesser decrease (on a percentage basis) in expected returns; thereby improving the overall return to risk ratio. Example hedge scenarios could include:

- No forward hedges;
- Purchasing 50% of the expected gas consumption in advance for 1 year or up to 5 years; and
- Selling 50% of the expected power generation in advance for 1 year or up to 5 years.

Dynamic hedging strategies are also a worthwhile consideration, but require near real-time monitoring of spot and forward prices over the duration of the tolling agreement in order to constantly rebalance the optimal hedge position for the remaining contract. Such a strategy can also introduce risks of its own, including operational and (significant) model risks associated with the dynamic hedging strategy. Delta-hedging strategies, which protect a portfolio of positions against smaller swings in the price of the underlying commodities, and delta-gamma-hedging, which provide protection (earnings stability) against larger underlying swings, are certainly worthwhile (and likely necessary) considerations for a tolling contract, but it must also be expected that hedge positions will tend to reduce market risks while increasing credit risks, hopefully by a lesser amount.

The inclusion of hedges significantly complicates the overall valuation of a tolling agreement. For example, if a fixed price and volume power sale of say 300 MW is taken on as a hedge against a 500 MW tolling agreement, there exists three sets of prices that require comparison at each increment of a Monte Carlo simulation: i) market or index power and gas prices, $M$, ii) marginal generation costs associated with the conversion of gas into electricity, $G$, and iii) the fixed hedge price, $H$. There are six possible combinations for the relative ordering of these current prices (e.g. $H < M < G$ or $M < G < H$), which result in at least three different operating regimes for the generator: 0 MW, 300 MW, and 500 MW, depending upon whether (for example) it is more cost-effective to satisfy the hedge volume with purchases from the market or through generation. These price scenarios and resulting operating regimes complicate the option payoff function and introduce additional fixed and variable cost considerations.

Finally, reliance upon the finding and application of positive mark-to-market hedges as a means of improving the absolute earnings expectations may provide a desired improvement to the estimated returns, but may not be a realistic expectation of the market.

Despite these challenges, the accurate analysis of the effects of proposed (and on-going) hedges on the risk profile of the tolling portfolio and the resulting returns on capital at risk are critical considerations for an organization contemplating the execution of a tolling agreement.

## 5.12 Quantifiable Risks

Almost all forms and types of risk can be quantified in one way or another, but the primary sources, and in some ways the most controllable forms of risk are market risks, credit risks and operational risks.

### *5.12.1 Market Risk*

Market risks consider the frequency and magnitude of regular fluctuations and jumps in market commodity prices, and are quantified through the determination of volatilities and correlations as described in the preceding sub-sections and their inclusion in calculations of Value at Risk (VaR). VaR is a measure of the minimum amount that can be expected to be lost over a certain holding period and with a certain frequency due to shifting market prices. For example, a 10-day, 95$^{th}$ percentile VaR of $500,000 means that on average, over a 10-day holding period and with a frequency of 1 in 20, more than $500,000 is likely to be lost due to changing market conditions. What is meant by 'lost' is sometimes counter-intuitive. Losses, for the purposes of VaR calculations are assumed to be losses relative to the current Mark-to-Market (MtM) value of the portfolio. In other words, today's portfolio MtM may be $9 million, which is an estimate, based on today's forward price curve for all traded commodities and derivatives, of the earnings that are currently unrealized but are expected to be realized over the remaining tenor of the portfolio. A current 10-day VaR of $500,000 is therefore an indication only of the minimum drop from the current MtM value of $9 million that should be expected to be observed in one occasion out of 20 and over the next 10-day holding period. On this 5$^{th}$ percentile occasion, the resulting MtM 10 days from now would still be in the order of $8.5 million, without any expectation of losses related to market price changes (at least at this level of exceedance probability). The difference is in the definition of losses, with VaR losses being from current MtM levels, and typical accounting and credit analysis losses being relative to zero earnings and having an impact on cash flows.

Market risk, and the resulting VaR estimates are often used by credit rating agencies to calculate capital requirements and adequacy of trading companies. A comparison between the average VaR of a trading organization and the level of capital that it has allocated to the trading activity of the company is often used to estimate its annual probability of default and hence its credit rating – clearly an important characteristic of the company. A multiple of the current VaR is often used in capital allocation studies and credit ratings in order to account for: i) the likelihood or possibility that more than one VaR-predicted 'loss' will occur within a given year, which requires the company to be able to cover a multiple (say three) of the predicted losses (VaR); ii) any differences in the cumulative probability standard used to calculate VaR (typically 95 percent) versus that used by credit rating agencies (typically 99 percent), resulting in a factor of approximately 1.4 (2.33 divided by 1.64); and iii) the credit rating objectives of the company to allocate sufficient risk capital to result in (say) an investment grade company (BBB rating) instead of a B credit rating, resulting in a factor of approximately 4. The first and third items in the preceding list may be somewhat redundant, resulting in a range of market risk capital multipliers of approximately 4.0 to 5.6 times the current VaR estimate to achieve or maintain an investment grade rating.

An astute observation of the potential downside (real losses) of a tolling agreement (exclusive of the potential for over-hedging) is that the company may, in a worst case scenario, forfeit all of the capacity premiums for a given year and any additional fixed gas transportation, power transmission and operating and maintenance costs. This effectively caps the potential losses at the level of the fixed commitments for the year, which is likely less than the potential losses associated with market price shifts on the entire tolling contract volume. For this reason, it may be more appropriate to calculate the appropriate capital allocation for the tolling contract based on a multiple of the potential annual losses rather than a multiple of the VaR estimate. Both capital allocation calculations are considered in the following chapter.

Other market risk considerations include the differences between reporting and use of the mean, mode and median of an output distribution. The potential upside of a tolling agreement is very significant, but also highly dependent upon the choice and parameterization of the underlying price process. No single price process captures all features and behaviors of commodity market prices, and the greatest uncertainties in the price process are related to the frequency and magnitude of simulated price spikes, which naturally affect the top end of any distribution of earnings from the perspective of a purchaser of a tolling option. Due to the assumed lognormal (non-negative) distribution of prices, the bottom end of any earnings distribution should be expected to be less sensitive to the underlying price process. Without entering into a detailed statistical discussion, under these conditions, the mean of such a distribution will be more significantly affected by imperfections in the underlying price process than will be the median (the 50$^{th}$ percentile of the distribution). The reason for this is that the 'weight' associated with the extreme values that may be generated due to an overly aggressive price process will tend to impact the estimate of the mean of the distribution more than the median. For these reasons, the authors recommend the use of the median value rather than the mean or mode of the distribution of earnings to calculate risk capital requirements and expected returns. That said, the use of the mean or mode of the earnings distribution may be valuable in arriving at a strategic and competitive bid for a tolling contract.

### *5.12.2 Credit, Operational and Other Risks*

Credit risk may be managed through multilateral netting of accounts receivable and accounts payable, centralized collateral management, standard margining, and credible guarantors backing events. Multilateral clearing is considered the best way to reduce collateral requirements and improve the credit characteristics of an entire market. Unlike equivalent volumes of power sales and gas purchases, a stand-alone tolling agreement is not expected to create a large credit risk and resulting credit risk capital requirement due to the exclusive nature of the contract with a special purpose entity in which the tolling purchaser (Powerex for example) has some control and ownership. Non-performance of the special purpose entity is not in the best interests of the toll purchaser or seller, and the assets associated with the toll are protected from collateral calls by creditors of the parent companies.

This favourable credit situation is forfeited somewhat with the placement of hedges against the tolling agreement. Hedges will tend to reduce the market risk associated with the complete portfolio of positions, but likely increases the overall credit exposure due to long-term sales of power to a hedge counterparty and the expectations of long-term gas and gas transportation from others. A complete analysis of a proposed tolling agreement will include the credit risks associated with the actual and anticipated hedge positions.

The operational risks associated with a hedged tolling agreement are not insignificant. The on-going rebalancing of hedges to minimize market risk exposure and the daily (if not intra-day) dispatch of the generating facility based upon a shifting knowledge of the market conditions, local loads, gas delivery, and the potential for transmission congestion all lead to a significant effort being required to avoid tolling pitfalls and associated losses.

Other risks (Table 4-1) associated with a potential tolling agreement need to be described, at least qualitatively, and fully explained to the Board of Directors for their consideration. Some of these other risks can be mitigated or avoided through careful contracting and operational decisions, but environmental, regulatory and political risks in particular are difficult to quantify or describe and more difficult to mitigate prior to entering the tolling agreement. Environmental risks include the potential for significant levies to be assessed against the production of electricity using natural gas and the potential exposure to greenhouse gas liabilities associated with future Kyoto-like obligations or commitments made at a state or national level. Although limited in potential, these environmental risks could be partially mitigated through the forward purchase of greenhouse gas credits from BC Hydro or other marketers of these credits. Regulatory and political risks are also difficult items to quantify and mitigate, particularly given the recent rate of change observed in the deregulated markets of California and the outstanding issues to be resolved with FERC and potential RTO considerations. This category of risks may be partially mitigated through the establishment of a wholly-owned U.S. subsidiary to hold the rights and obligations of the tolling agreement, but would obviously require careful legal, tax and regulatory considerations prior to finalizing the agreements.

### 5.13 Capital at Risk

As described in sub-section 5.12.1, the allocation of capital in trading organizations, and the interpreted ability of this capital to cover potential losses or multiples of losses is a key determinant of the organization's credit rating, which in turn affects the level of trading activity for the firm, the cost of debt, and expectations regarding returns on equity. The components of capital to the organization are required to cover market, credit and operational risks; working capital, broker deposits; and parental (BC Hydro) guarantees. There are a number of alternatives for the annual allocation of capital for a potential tolling agreement, the simplest of which is the full amount of the fixed obligations for the given year plus a calculated allowance to account for the credit and operational risks of the agreement and associated hedges. This approach treats the tolling agreement like a more typical capital investment against which the expected earnings are compared to assess the relative attractiveness of this capital investment.

An alternative involves the calculation of the Value at Risk or potential losses of the agreement as described in sub-section 5.12.1 and the application of a factor to these values in keeping with the method of allocating capital to the existing trade portfolio. The expected earnings (median suggested) are then compared to the allocated capital in order to assess the strength of the investment. An appropriate factor to apply to either the potential losses or VaR estimate is related to the earnings exceedance percentile selected as the lower bound of the confidence interval used in the potential losses and VaR estimate (e.g. for a *normal* distribution 2.33 standard deviations: 99 percent earnings exceedance probability; 2.0 standard deviations: 97.7 percent exceedance; or 1.64 standard deviations: 95 percent exceedance typically). Being closely tied to credit ratings, capital adequacy calculations tend to incorporate relatively high non-exceedance values – typically 99 percent or higher. Using a lower non-exceedance value of 95 percent should theoretically result in a desire to use a higher factor (multiplier) in order to approximate the capital adequacy that would have been calculated using the higher standard.

An interesting observation, however, is that the multiplier applied to the standard deviation to move from the $95^{th}$ percentile to the $99^{th}$ percentile of a *normal* distribution is approximately 1.4 (2.33 divided by 1.64). Due to the significant right skew of the distribution of earnings outcomes, a given number of standard deviations to the left (i.e. towards the lower confidence interval) of the mean will tend to result in a confidence interval that is too low. The opposite occurs at the right side of the earnings distribution, where a given number of standard deviations will tend to underestimate the actual value associated with the upper confidence interval. The result of this is that, particularly given a non-normal output distribution, it is more accurate to measure a percentile directly from the collected iterations and data rather than constructing them from a mean using the standard deviation.

The observation was made in sub-section 5.12.1 that the maximum possible loss associated with the standalone tolling agreement is simply the sum of all capacity charge payments of the year plus all fixed or minimum operating and maintenance costs, all gas transportation costs and all power transmission costs. Given this limited downside (related to the payoff function of the spread option plus the underlying log-normal price process), it is the authors' opinions that a small factor or a factor of only one should be applied to the calculated potential losses (based on a $1^{st}$ percentile analysis) as the market risk component of a required capital calculation. In the absence of quantifiable or measured credit and operational risk, it is further recommended that credit capital and operational capital requirements be scaled on a pro-rata basis to the pre-multiple risk capital assigned to the current portfolio in order to provide an estimate of the appropriate credit and operational risk capital to assign to the tolling agreement.

The extent to which the proposed tolling agreement supplements or replaces existing capital requirements must also be considered. This can be estimated by calculating the VaR and potential losses (currently a step in the process of determining the credit capital at risk for the existing portfolio) of the existing portfolio alone and again with the addition of the complete tolling agreement, including hedges. The degree to which the proposed tolling agreement mitigates the existing VaR due to portfolio diversification is credited to the tolling agreement as a portion of the capital that does not need to be allocated. If, however, the tolling positions exacerbate the risk characteristics of the existing portfolio, then an additional risk capital premium may be required to account for the resulting unbalanced nature of the resulting portfolio.

A final question and discussion point is related to the objective of the potential tolling contract. Is the tolling agreement to be stand-alone or part of the larger portfolio? If stand-alone, it could be argued that an *additional* amount of capital should be allocated to this project in order to cover market, credit and operational risks specific to the opportunity. If the agreement is to be added into an existing portfolio then the opposite argument could be made, suggesting that a portion of the existing capital needs to be allocated to the tolling agreement. This decision to allocate new or existing capital will likely affect the numerator and denominator of the return on capital calculation, and the degree to which portfolio diversification effects are incorporated into the market and credit capital calculations.

### 5.14 Return on Capital and Other Performance Metrics

In a manner similar to typical discounted cash flow analyses, a Return on Capital at Risk, or Risk Adjusted Return on Capital (RAROC) can be calculated for the tolling agreement alone, the tolling agreement and associated hedges, and the entire portfolio with and without the addition of the tolling agreement. The appropriate hurdle rate for RAROC measurements of various opportunities is very specific to the mandate of the company considering the opportunity, to the risk appetite or pre-disposition of the Board of Directors, and to a certain extent, the availability of required capital to complete the agreement. In a capital-constrained environment, hurdles must be set and returns calculated carefully to take advantage of a limited number of opportunities given the constrained resources.

As described in section 4.8.2 a ratio of the expected return premium to the standard deviation of the expected return can be a useful measurement of the efficiency of the tolling investment. This performance metric, referred to as the Sharpe Ratio, provides a similar but alternate method for the comparison of the tolling opportunity to other opportunities and to the existing portfolio. The advantage of the Sharpe Ratio is that it accounts directly for the stability of earnings[2] associated with the opportunity. As a Crown corporation and wholly-owned subsidiary of BC Hydro, the Board of Directors and provincial government are concerned about the stability of earnings to be expected from Powerex. Powerex trade revenues also have an impact on regulated rates through the passage of the first $200 million in annual trade revenues to the benefit of B.C. rate payers.

Finally, the shape of the returns over the 5 or 20-year tenor of the agreement and the sensitivity of the expected returns to key input assumptions such as the average plant heat rate, capacity charge, capacity charge escalation factor, and fixed and variable operating, transmission and transportation costs is critical to the assessment of a tolling opportunity. All of these returns and performance metrics are presented and considered in the results of two example opportunities that are assessed in Chapter 6 of this report.

### 5.15 Conclusion

Despite the uniqueness of each tolling opportunity there is a common set of valuation techniques that should be applied to assessing each contract. To estimate a contract's value key inputs are required. Price forecasts for both electricity and gas are fundamental components. Although there is a positive correlation between each, both commodities are volatile and subject to price swings. While forward price curves are produced daily and made available to the market, knowledge of time variation of volatility and the correlation of movement between each price curve can provide a range of expectations for future price direction. This chapter discussed strategies to minimize potential errors in volatility and correlation estimations. Power prices are impacted by location and an efficient plant in one location may not be profitable, while a less efficient one in another location may be profitable.

Armed with reasonable price expectations, the potential for profit can be measured through a spark spread based on the heat rate of the plant to convert the natural gas input to electricity output, the facilities fixed and variable operating costs, and its operation risks. Quantitative ways to measure other critical risks including the market risk and credit risk were covered. Entering a tolling agreement also subjects a company's capital to risk as capital will be

[2] The denominator of the ratio is the standard deviation of the expected returns from the tolling investment.

required to sustain a minimal level of payment and/or operation level as expected and committed to in a tolling contract.

A number of valuation techniques were introduced including a way to assess the intrinsic value of a generating facility, a Black-Scholes option pricing formula and a modified Margrabe solution for basic option valuation. Models that can account for jumps in prices were discussed in the binomial lattice and Monte Carlo subsections. Each method has merits under different contexts. The Monte Carlo simulation method, however, provides the most flexibility in the price process and analyses. It allows for the optimization of dispatching the plant given each price scenario. The application of these various techniques is provided in the following chapter.

# 6 APPLICATION OF ANALYSIS METHODS

## 6.1 Introduction

A succinct analysis and strategic discussion is required to provide recommendations regarding the valuation and risk-reward balancing of a proposed tolling arrangement. The strategic discussion will include the consideration of all risks, the Powerex and B.C. Hydro approval process, and the partially intangible benefits associated with increased trading flexibility associated with such an arrangement. The following sub-sections describe the application of the: i) intrinsic, ii) modified Margrabe, and iii) Monte Carlo simulation methods described in Chapter 5 to two examples of tolling possibilities. The two examined opportunities differ significantly in location: Pacific North West versus U.S. Southwest; backing: utility-backed versus merchant; tenor: 20 versus 5 years; and market: relatively stable versus over-supplied and transmission constrained.

## 6.2 Market Price Data

Key determinants of the expected intrinsic value of a proposed generation facility are the local or regional market prices of natural gas and HLH and LLH power. Forward price curves for both commodities are available for a number of locations across North America, but they differ significantly in liquidity and reliability. At Mid-Columbia and Sumas, the respective power and gas trading hubs for the Oregon tolling opportunity, good market prices are available through 2011 for power and 2010 for gas. At Palo Verde and Socal, however, the respective power and gas trading hubs for the Arizona tolling opportunity, the quality of market data used in the following analyses is not as good, running through 2007 for power and only 2004 for gas. Given the shorter tenor of the Arizona opportunity, this lack of market price data is less of a problem than it would have been for the Oregon tolling opportunity. In the absence of market data, and for the purposes of these analyses, the last 12 months of price data have been copied forward to the remaining years through 2023. A key assumption in the use of any forward price curve or scenario data is that historical price behaviors are indicative of future behaviors, and that there is no better alternative to the use of these historical data for the purposes of the current analyses. As discussed in Chapter 5, the differences between the use of historical forward prices (all available pricing data) versus only historical spot prices (a subset of the entire forward price curve) can be significant depending upon the type of analyses being completed and the reliance upon Black-Scholes based methodologies, volatilities and correlations. The assumption stated above, however, that historical price return characteristics are applicable to future price returns is required regardless of the type of historical data being used in the analyses.

### 6.3 Scenarios of Future Prices

As an alternative to relying solely on the availability of market prices, the use of scenarios, developed by unbiased market observers and experts, represents a worthwhile alternative. Shorter-term forecasts of gas and power prices are prepared by several consulting and market groups, but the availability of 20-year forecasts, and in particular, scenarios around these long-term forecasts is quite rare. Cambridge Energy Research Associates (CERA), of Cambridge, MA is one such provider of 20-year monthly gas and power forecasts. Four CERA scenarios are summarized in the following sub-sections. Forecasts based on scenarios for several locations can be applied with the appropriate transmission and transportation assumptions to the two projects being studied in this chapter. BC Hydro also produces long-term gas and electricity price forecasts, based in the near 3 years on market data surveys and studies by groups such as the PIRA Energy Group; the mid-term (years 4 through 8 approximately) on fundamental supply-demand analyses completed using Henwood energy modeling software; and the long-term (to 20 years) on the estimated Long-Run Incremental Cost (LRIC) of energy as estimated using financial cost modeling of the latest generation of gas turbine generators. These additional forecasts should also be considered should Powerex move to the next stage of entering either one of the proposed agreements.

Forecasting in the energy industry is a daunting task and no single forecast can accurately predict the future. Markets can change drastically from unexpected events. It is important to develop scenarios that consider various possibilities. Scenarios benefit business users by preparing them to deal with changes as they occur.

Scenarios should be developed through a well thought-out process. They need to be plausible but divergent. A scenario should account for: predetermined events, who may be responsible for changes, what will drive these changes, and major uncertainties.

Four primary scenarios and a subset of scenarios are considered for the purpose of this analysis. They follow the potential evolution of the market until 2020. These scenarios are based upon a long-range scenario planning study in which B.C. Hydro participated. CERA is a third party industry expert with knowledge of market fundamentals including supply/demand balances, fuel reserves and supply, technology enhancements, political events, regulations, infrastructure developments (pipeline and transmission) and other fundamental market drivers. This report was completed in August 2002.

A total of ten scenarios have been selected for valuation. The variations on these scenarios deal with the potential for additional costs due to potential environmental levies. In the "World in Turmoil" scenario it is prudent to consider serious supply constraints and the combination of variations are included as part of the forecasted values for valuation. Each scenario is identified in Table 6-1. A basic description of the four base scenarios is provided in the following sub-sections.

| ***Abbreviation*** | ***Description*** |
|---|---|
| SG | Shades of Green |
| SGE | Shades of Green with Environmental (emissions) adjustment |
| RM | Rearview Mirror |
| RME | Rearview Mirror with Environmental (emissions) adjustment |
| TE | Technology Enhanced |
| TEE | Technology Enhanced with Environmental (emissions) adjustment |
| WT | World in Turmoil |
| WTE | World in Turmoil with Environmental (emissions) adjustment |
| WTSC | World in Turmoil with Supply Constraint |
| WTSCE | World in Turmoil with Supply Constraint and Environmental (emissions) adjustment |

*Table 6-1 Ten Scenarios Used for Assessment. Table by authors.*

The 'E' Scenarios with environmental adjustments indicate higher prices for electricity. This holds with the assumption that emission levies will be applied to the generators and those additional costs will be passed through to the power purchasers.

### *6.3.1 Technology Enhanced*

The current recession turns out to be a short detour before the economy resumes the path of strong growth. The combination of technology gains, competitive markets, greater globalization, increased immigration, and higher retirement ages fuels strong long-term economic growth of 3.2–3.5 percent annually. (CERA, 2002)

### *6.3.2 Rearview Mirror*

This scenario begins with a continuation of the muddled move toward competitive markets, with some states operating deregulated power markets and others remaining regulated—an unsustainable situation. Around 2005/06 a regional power market crisis leads to the abandonment of competition, and the industry moves toward a reregulation of the market. (CERA, 2002)

### *6.3.3 Shades of Green*

The environment becomes an increasing concern, leading to US participation in an international agreement to control greenhouse gas emissions (a "Kyoto Lite" accord). As a result, a significant portion of coal generation (over 30 percent) is shut down. Several drivers contribute to this outcome, including the oversupply of new generating capacity, increasing scientific evidence of global warming, and a shift in the public's concern for the environment. (CERA, 2002)

### *6.3.4 World in Turmoil*

The global economy experiences low economic growth exacerbated by very high oil prices due to geopolitical instability and turmoil in the Middle East. Terrorism becomes a more protracted problem. Homeland security and security of energy supplies dominate the agenda in North America. (CERA, 2002)

### *6.3.5 Market Indicators*

Market indicators clarify which scenario is dominant at a particular time. These indicators can change rapidly and conditions may go from one scenario to another quickly. As time passes, changes in political and regulatory environments, the electrical industry, and the natural gas industry can be compared back to the presented scenarios. Forecasts based on the dominant scenarios may be used for a better vision of future values.

## 6.4 Merchant Development: Arizona Tolling Opportunity

The Arizona tolling opportunity assumes a merchant facility with a 570MW gas fuelled CCGT. Commercial operation for this facility has already commenced. It consists of 2 GE-7FA class natural gas-fired combustion turbines and one steam turbine. Its location allows for the sale of energy directly into the Palo Verde (PV), Arizona wholesale trading hub. Gas for the facility would primarily be acquired from the Permian gas market.

This location of this facility has drawbacks. The U.S. Southwest is being overbuilt. Power supply will exceed peak demand in the region. Operating reserves may exceed 30 percent by the end of 2004. Demand growth is low and there are local and long-distance transmission constraints. The low displacement of older generators is limiting opportunities and intense generator competition is reducing profits.

This report contemplates a 5-year, simple, financial tolling agreement based on the Arizona opportunity.

## 6.5 Utility-Backed Development: Oregon Tolling Opportunity

The Oregon tolling opportunity assumes a 520 MW utility-backed CCGT. The project would yet to be built, but the site certificate would have been approved. Energy from this plant would be sold to the Mid-Columbia (Mid-C) trading hub which is based on the location of four substations located north of the Columbia River system in Washington State and resides in the Pacific Northwest power market. Natural gas to fuel the plant would be acquired from the AECO Gas Market from the Sumas, Washington hub.

Proposal assumptions for an off-take agreement include a 12-year warrant on the heat rate, availability, performance and operations and management. There would be no gas fuel taxes, no state sales tax on the project equipment.

A 20-year, complex, physical tolling agreement for this opportunity, with upwards of 300 MW (approximately 60%) of capacity being hedged is assumed.

## 6.6 Valuation Analyses and Results

### *6.6.1 Volatility and Correlation Analyses*

As discussed in sub-section 5.10.1, the annualized historical monthly volatility and correlation of daily spot power and gas price returns at the Mid-C, Sumas, Palo Verde, and Socal trading hubs have been estimated from approximately 6 years of historical daily prices using the EWMA method with a decay factor, $\lambda$, of 0.90. These volatilities and correlations are instantaneous estimates of the underlying price processes for use in the Monte Carlo simulation analyses described in sub-section 6.6.4. The results of these analyses, and hence the input to the

Monte Carlo simulations, are summarized in Table 5-1 through Table 5-4. Estimates of the second measure of volatility, calculated on a monthly frequency are also provided in Table 5-1 and Table 5-2 for Mid-C / Sumas and Palo Verde / Socal power and gas data respectively.

As discussed in sub-section 5.10.2, the annualized daily volatility and correlation of historical forward price returns at the Mid-C, Sumas, Palo Verde, and Socal trading hubs have been obtained from Powerex's historical price collection and reporting system, Zai*Net, and summarized in Figure 5-5 and Figure 5-6. These volatilities and correlations are the integrated, 'flat' values expected by Black-Scholes type analysis methods such as the modified Margrabe equations described in the same chapter and used as described below in sub-section 6.6.3.

### *6.6.2 Intrinsic Value Analysis and Results*

As described in sub-section 5.7.1, the intrinsic value of a tolling agreement may be calculated based solely on the deterministic estimates of future gas and power prices, whether they be derived from market forward prices, or scenario forecasts such as those prepared by CERA (CERA, 2002). Factors that can (and should) be incorporated into the intrinsic value analyses include the assumed, specified or guaranteed plant heat rate, and fixed and variable gas transportation, power transmission, and operating and maintenance costs. The following assumptions have been made for the purposes of these intrinsic value analyses:

| Input Parameter | Assumed Value |
|---:|---|
| Plant Capacity: | 500 MW |
| Average Plant Heat Rate: | 7.3 MMBtu/MWh |
| Variable Operating and Maintenance: | 3.00 USD/MWh |
| Variable Gas Transportation: | 0.38 USD/MMBtu |
| Variable Power Transmission: | 3.00 USD/MWh |
| Fixed Operating and Maintenance: | 0 USD/MWh |
| Fixed Gas Transportation: | 0 USD/MMBtu |
| Fixed Power Transmission: | 0 USD/MWh |
| Discount Rate (%): | Risk-free<br>Market Yield Curve |

*Table 6-2 Intrinsic Value Variable and Fixed Cost Input Parameters. Table by authors*

Plots of each of the 10 CERA gas and power price scenarios and for each of the two locations (Pacific Northwest and U.S. Southwest) are provided as appendices A and B of this report. The range of calculated spark spreads between the monthly LLH and HLH power price predictions are also plotted as grey bars on each of plots. A spark spread bar that crosses the x-axis in one of these plots indicates the combination of a gas price, HLH and LLH power prices, and the additional costs as summarized in the table above result in a positive spark spread during the HLH portion of the given month and a negative spark spread during the LLH portion of the same month. Application of the spread option payoff function to this scenario will result in no costs (and no revenues) other than the fixed capacity charge itself during the LLH portion of the month, and a positive payoff, net of all listed variable costs, during the HLH portion of the month. The same gas and power market price data have been used to show (Appendix C) the relative levels of power and gas prices according to market expectations, and the calculated net spark spread values for the HLH and LLH portions of each month.

To facilitate subsequent comparison against the results of the modified Margrabe analyses presented in the next section, the calculated monthly intrinsic values are discounted using the risk-free yield curve to obtain a single net present intrinsic value of the strip of monthly spread options, which are summarized for each location and each scenario in the rightmost column of Table 6-3. The average intrinsic value across the five CERA scenarios and the market prices is calculated to be 3.00 USD/kW-month for the Pacific Northwest and 1.21 USD/kW-month for the U.S. Southwest. It is interesting to note that no intrinsic value is expected under the WTSC price scenario in the U.S. Southwest, indicating that the payoff function of the spread option has returned a value of zero for all months and for all time periods (HLH and LLH), and that the only value that can be expected at that location and under those scenario conditions would be extrinsic value related to the potential for erratic price movements and other short-term opportunities.

### *6.6.3 Modified Margrabe Spread Option Analysis and Results*

The modified Margrabe analysis method described in sub-section 5.7.2 has been applied using flat (Black-Scholes) volatility and correlation data of Figure 5-5 (Mid-C / Sumas) and Figure 5-6 (Palo Verde / Socal), the risk-free yield curve, the fixed and variable costs of Table 6-2, and the same set of six gas and power price scenarios and market data. The analyses have been completed in a fashion that allows the individual HLH power and LLH power components of the total value to be determined as summarized in third, fourth and fifth columns of Table 6-3.

| *Location* | *Scenario* | *Total Capacity Value (Extrinsic and Intrinsic) (USD/kW-Month)* | | | *Intrinsic Value (USD/kW-Month) (% of total)* |
|---|---|---|---|---|---|
| | | *HLH* | *LLH* | *Total* | |
| Mid-C (Pacific Northwest) | Market | 4.57 | 2.21 | 6.78 | 0.98 (14%) |
| | TE | 6.87 | 2.44 | 9.30 | 3.55 (38%) |
| | RM | 6.32 | 2.48 | 8.80 | 3.10 (35%) |
| | SG | 6.69 | 2.58 | 9.28 | 3.00 (32%) |
| | WT | 6.62 | 2.49 | 9.11 | 3.17 (35%) |
| | WTSC | 8.16 | 3.78 | 11.94 | 4.22 (35%) |
| **Average** | | **6.54** | **2.66** | **9.20** | **3.00 (33%)** |
| Palo Verde (U.S. Southwest) | Market | 4.57 | 2.21 | 6.78 | 0.58 (9%) |
| | TE | 5.83 | 2.93 | 8.76 | 2.23 (25%) |
| | RM | 4.66 | 2.73 | 7.38 | 1.19 (16%) |
| | SG | 5.71 | 3.33 | 9.03 | 1.61 (18%) |
| | WT | 5.36 | 2.95 | 8.31 | 1.66 (20%) |
| | WTSC | 3.61 | 3.33 | 6.94 | 0.00 (0%) |
| **Average** | | **4.96** | **2.91** | **7.87** | **1.21 (15%)** |

*Table 6-3 Modified Margrabe Spread Option Value Results. Table by authors*

The total average capacity value at the Pacific Northwest location is calculated using this modified Margrabe approach to be 9.20 USD/kW-month, more than 70 percent of which is attributed to the HLH portions of the agreement tenor (20 years assumed). Referring now to the intrinsic values calculated in sub-section 6.6.2 for the same location and for the same price scenarios, the intrinsic value of 3.00 USD/kW-month estimated for the Pacific Northwest location represents approximately one third of the total estimated capacity value using the modified Margrabe method. Using the same approach, the total average capacity value at the U.S. Southwest location is calculated to be 7.87 USD/kW-month, almost 65 percent of which is attributed to the HLH portions of the agreement tenor (20 years assumed). For this location, however, the intrinsic value of 1.21 USD/kW-month is expected to represent less than one sixth (15 percent) of the total capacity value, indicating that much of the estimated total value relies purely on the volatility and co-movement of the commodity prices in that region, rather than an inherent (intrinsic) value related to the relatively efficient conversion of natural gas into power.

Of note also is the observation that the current market prices at these locations result in calculated intrinsic and extrinsic values that are consistently below all of the CERA price scenario results, and significantly below the average of the five CERA price scenarios.

It is possible, given the detail of the results from the modified Margrabe and intrinsic value analyses to plot the HLH and LLH components of the total spread option value for each location and for each price scenario. Figure 6-1 through Figure 6-12 provide graphical representations of these two additive components of value, with the two shades of grey area plots showing the additive value of the two components for a total extrinsic and intrinsic value at any given month over the assumed 20-year tenor. The calculated intrinsic values have also been added as a solid black line over the area plots. The extent to which the HLH and LLH portions of each month contribute to the total extrinsic and intrinsic value cannot be discerned from the detailed calculated results, but can be inferred from the relative height and proximity of the grey spark spread bars in the Appendix A, B and C figures[3]. The CERA WTSC price scenario for the U.S. Southwest location is again observed to be quite interesting given the zero intrinsic value over all 240 forecast months as shown in Figure 6-12. The figure does, however, show quite a significant extrinsic value for the same scenario and location, attributable in roughly equal parts to the HLH and LLH portions of each month.

[3] CERA forecast data is proprietary and may only be used under license. Powerex and BC Hydro are CERA customers. The graphs produced in Appendix A and B included CERA inputs and will be withheld from public copies of this report.

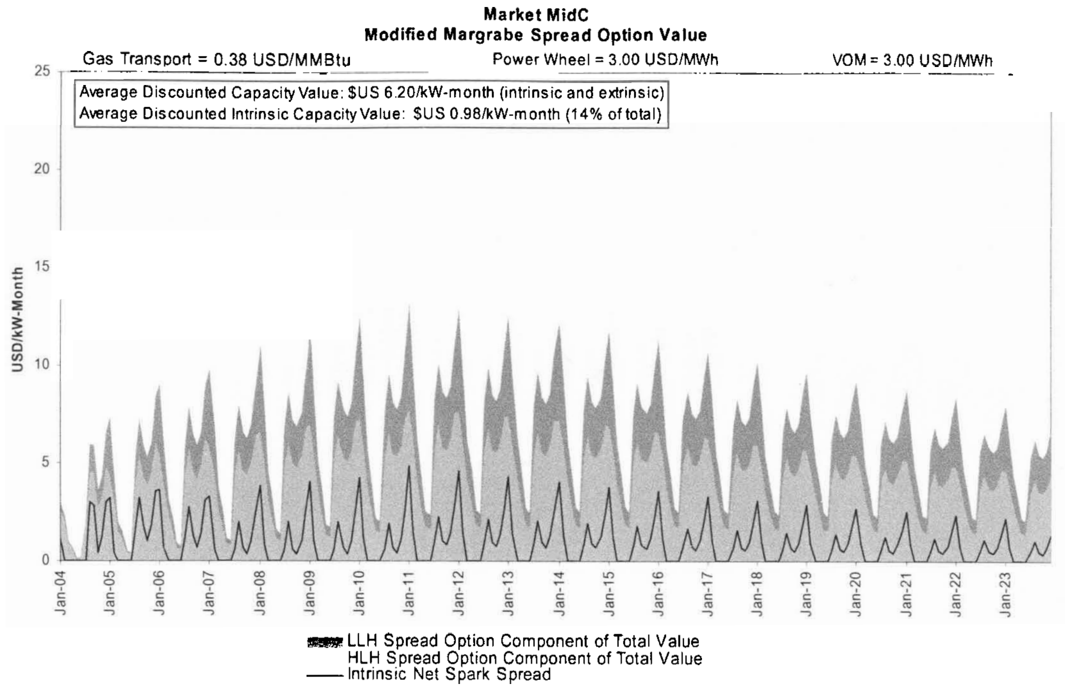



*Figure 6-1 Modified Margrabe Spread Option Value (Discounted Capacity Value) for Mid-C, Market Data. Figure by authors.*

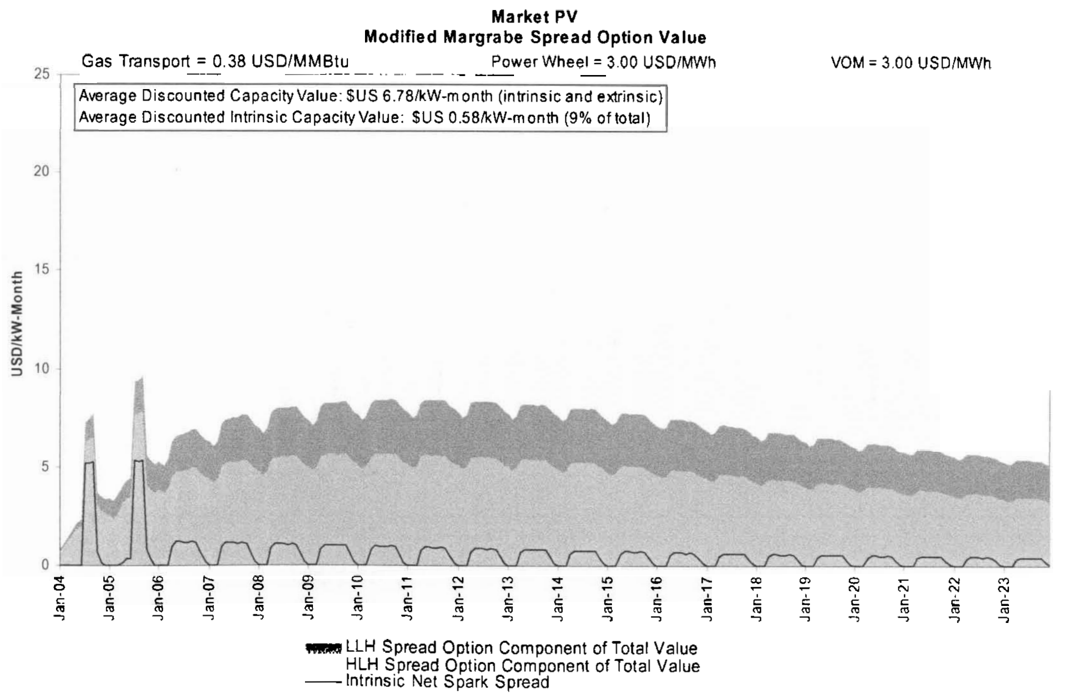



*Figure 6-2 Modified Margrabe Spread Option Value (Discounted Capacity Value) for PV, Market Data. Figure by authors.*

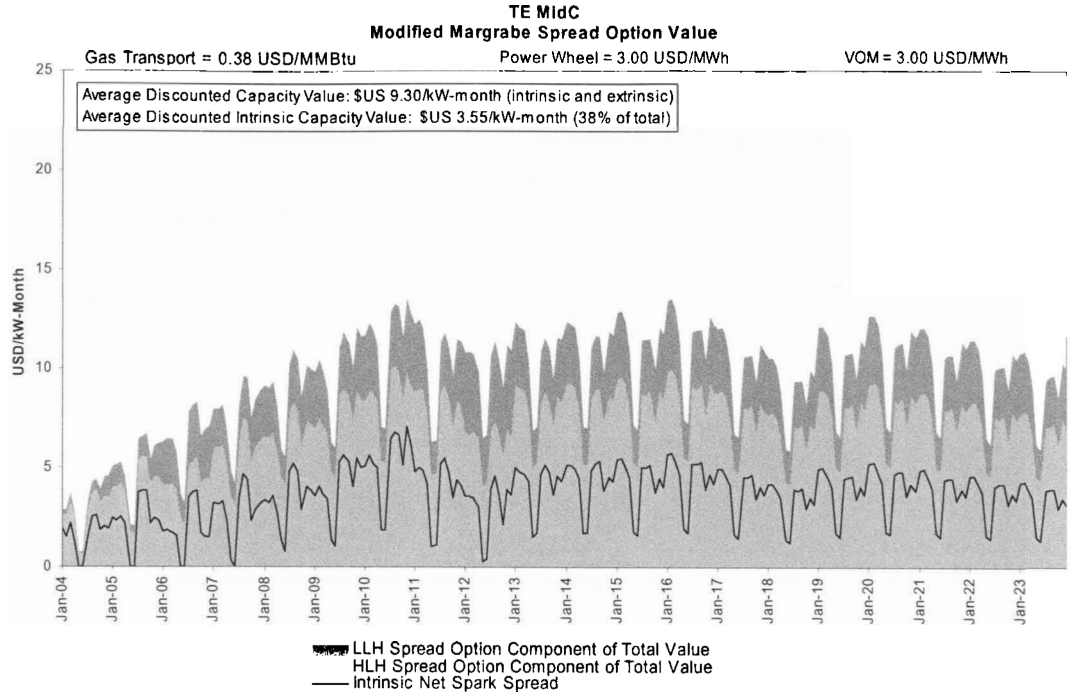



*Figure 6-3 Modified Margrabe Spread Option Value (Discounted Capacity Value) for Mid-C, Technology Enhanced Scenario. Figure by authors.*

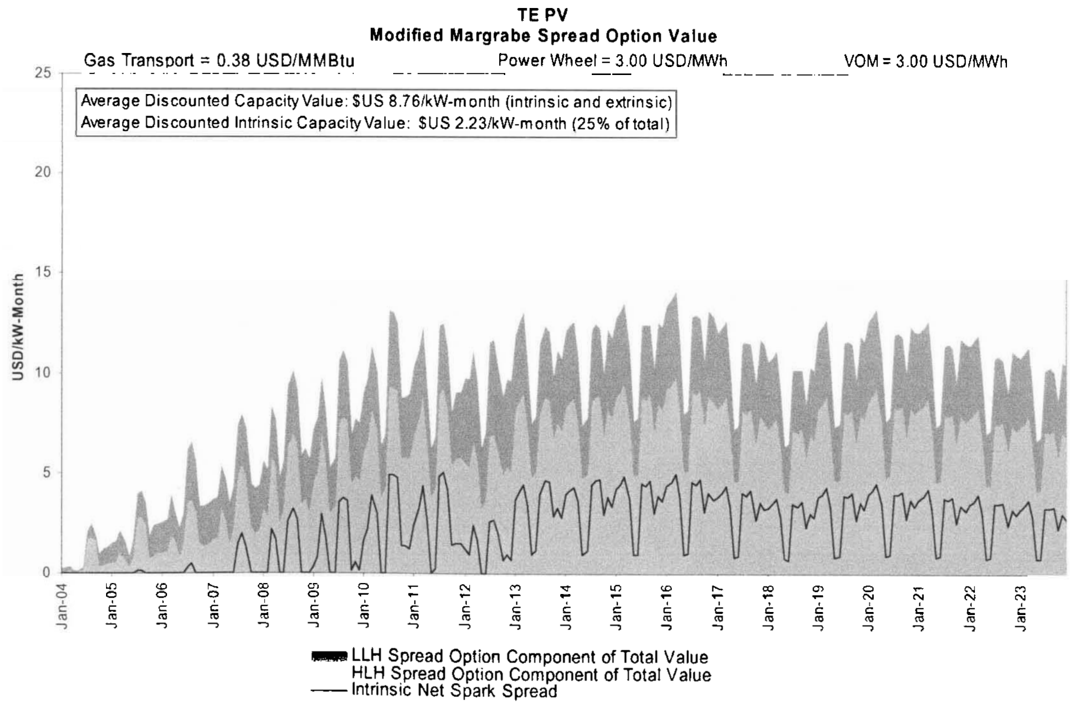



*Figure 6-4 Modified Margrabe Spread Option Value (Discounted Capacity Value) for PV, Technology Enhanced Scenario. Figure by authors.*

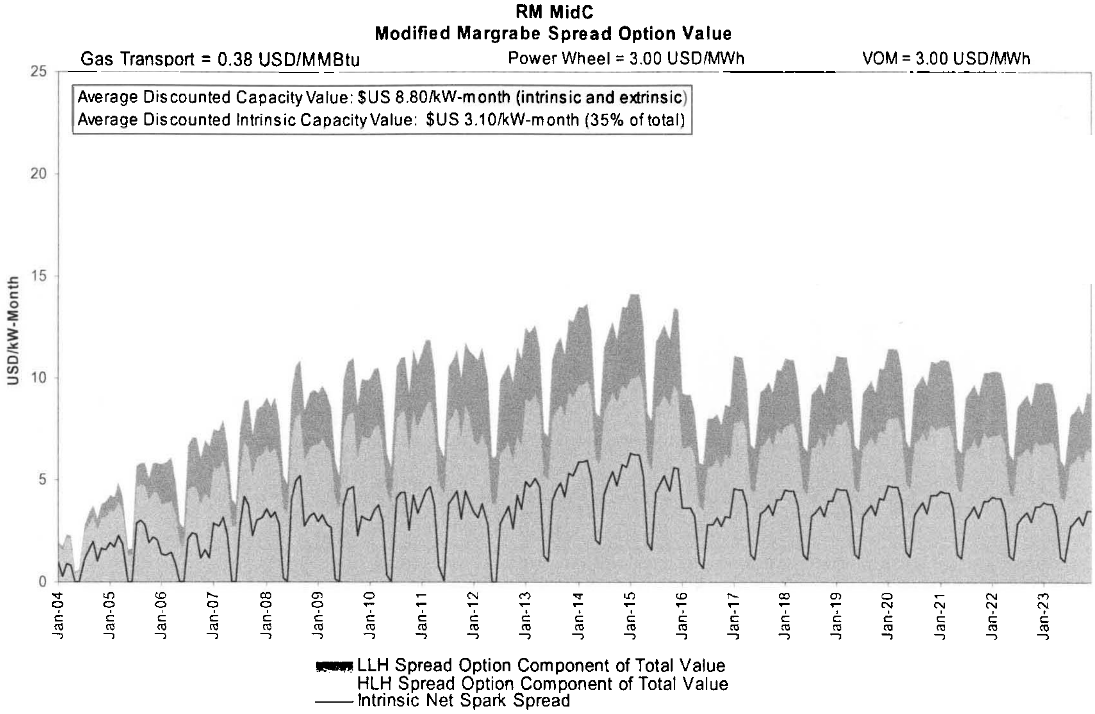



*Figure 6-5 Modified Margrabe Spread Option Value (Discounted Capacity Value) for Mid-C, Rearview Mirror Scenario. Figure by authors.*

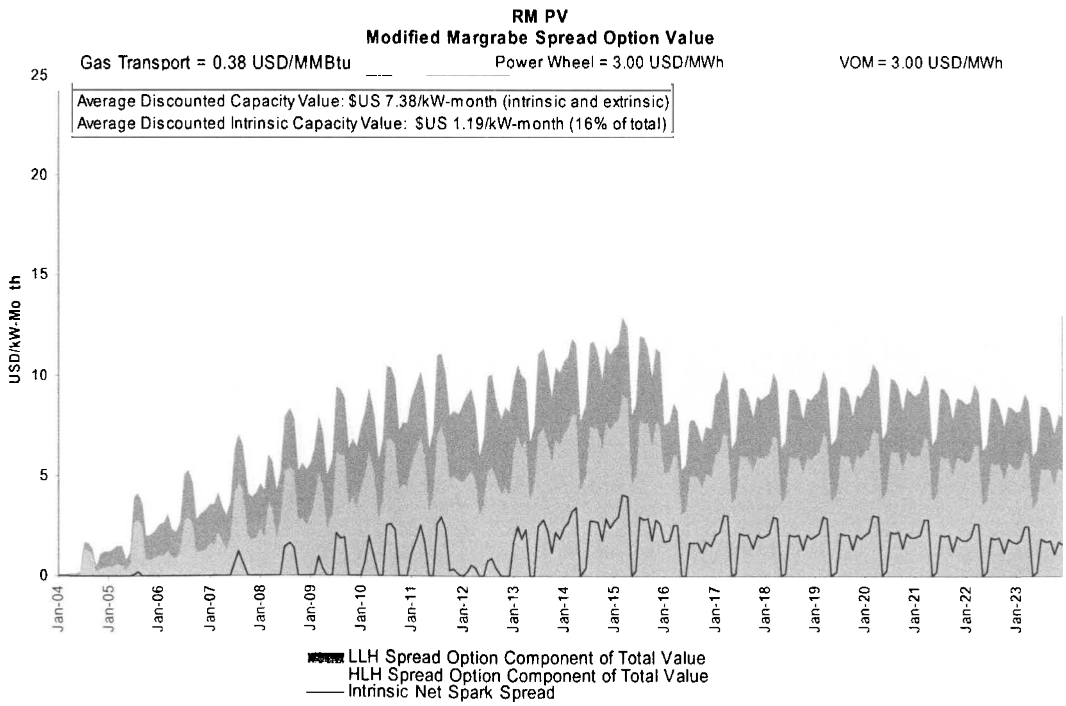



*Figure 6-6 Modified Margrabe Spread Option Value (Discounted Capacity Value) for PV, Rearview Mirror Scenario. Figure by authors.*

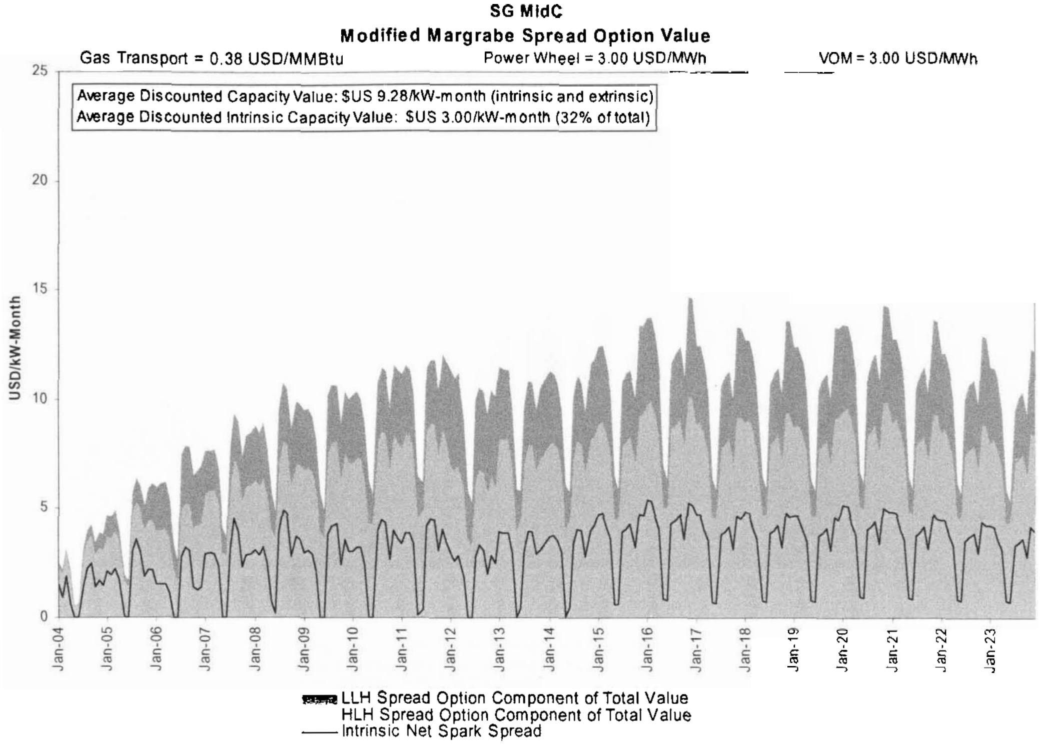



*Figure 6-7 Modified Margrabe Spread Option Value (Discounted Capacity Value) for Mid-C, Shades of Green Scenario. Figure by authors.*

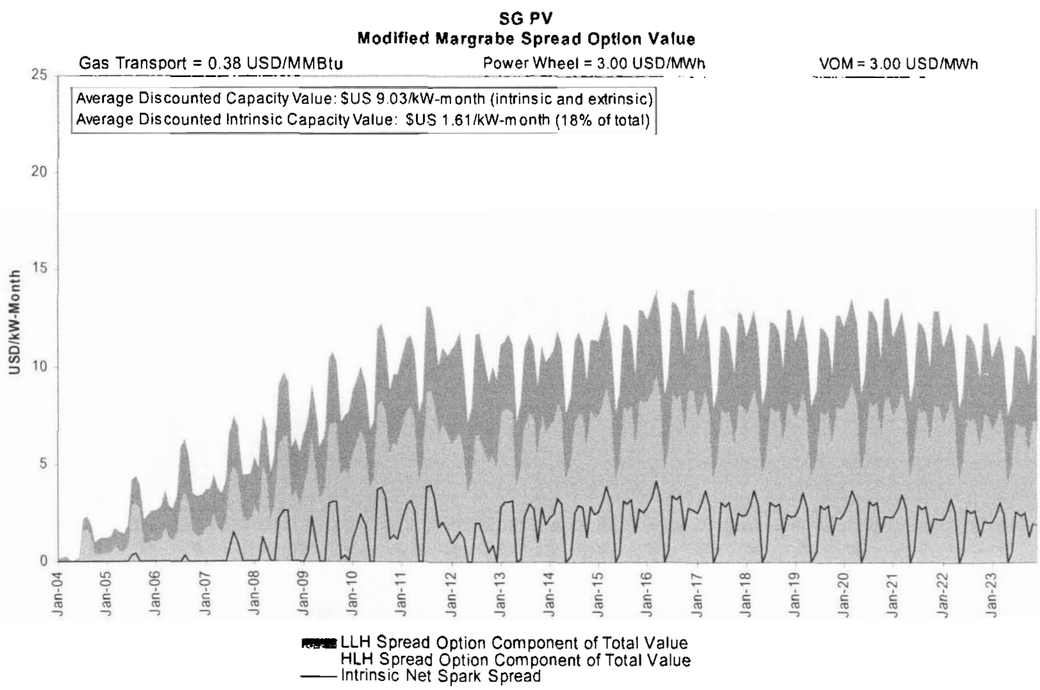



*Figure 6-8 Modified Margrabe Spread Option Value (Discounted Capacity Value) for PV, Shades of Green Scenario. Figure by authors.*

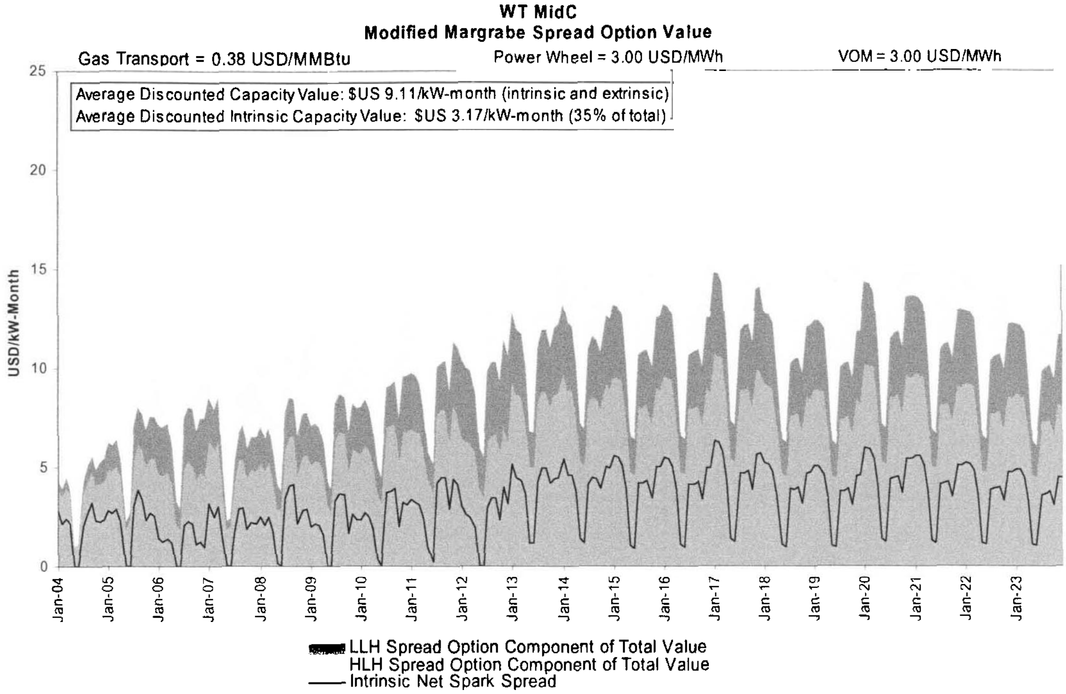



*Figure 6-9 Modified Margrabe Spread Option Value (Discounted Capacity Value) for Mid-C, World in Turmoil Scenario. Figure by authors.*

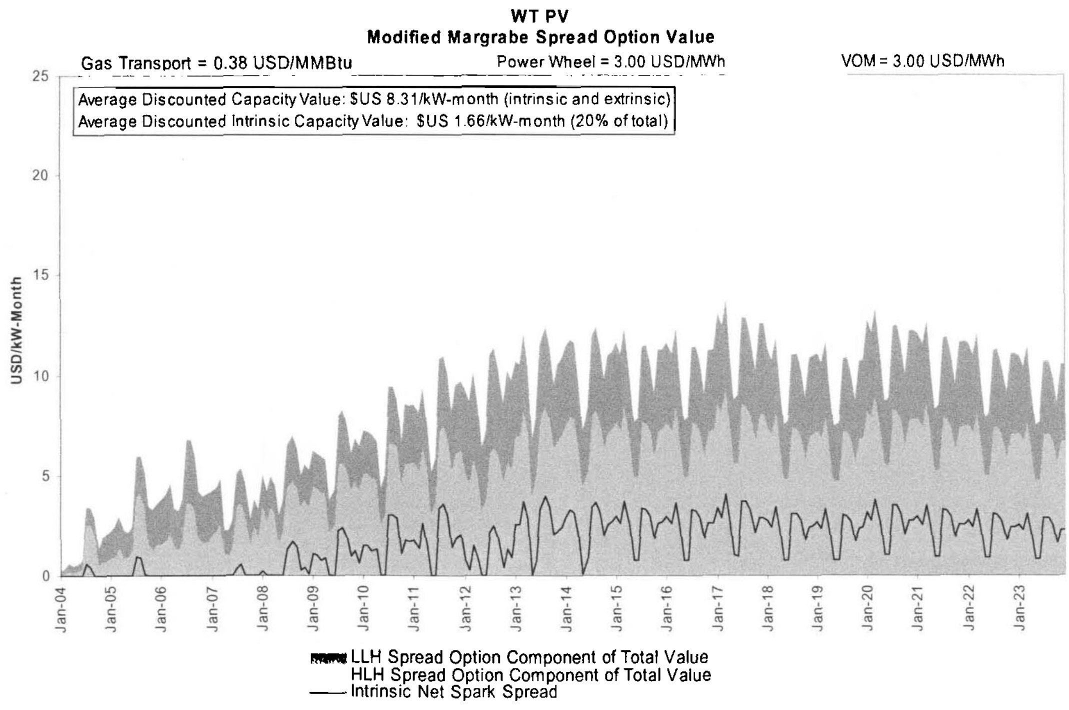



*Figure 6-10 Modified Margrabe Spread Option Value (Discounted Capacity Value) for PV, World in Turmoil Scenario. Figure by authors.*

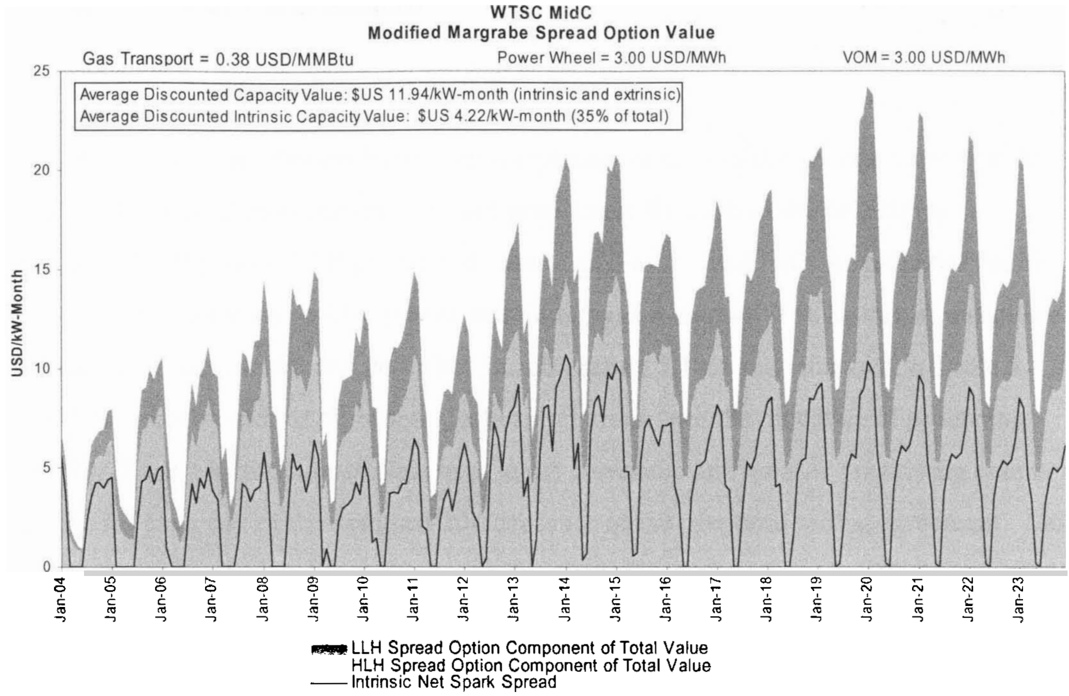



*Figure 6-11 Modified Margrabe Spread Option Value (Discounted Capacity Value) for Mid-C, World in Turmoil, Supply Constrained Scenario. Figure by authors.*

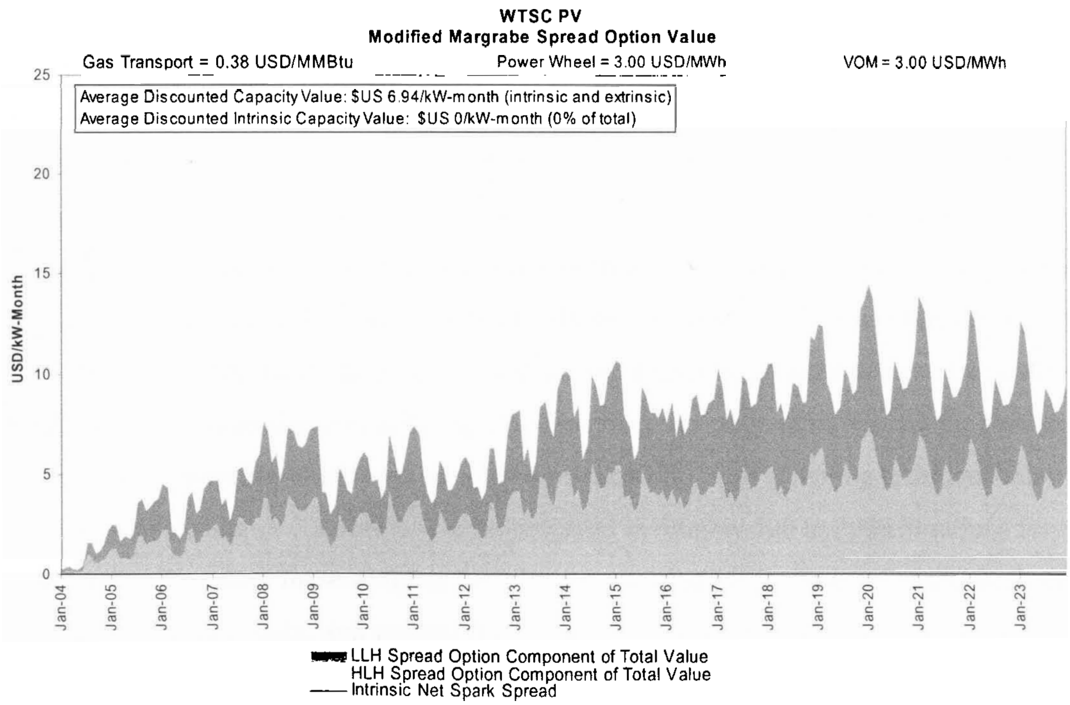



*Figure 6-12 Modified Margrabe Spread Option Value (Discounted Capacity Value) for PV, World in Turmoil, Supply Constrained Scenario. Figure by authors.*

### 6.6.4 *Monte Carlo Analysis*

#### 6.6.4.1 *Results and Capital at Risk Calculations*

Monte Carlo simulations have been completed for each of the six commodity price profiles (5 CERA scenarios plus one forward price curve for each of the underlying commodities: HLH power, LLH power and natural gas) associated with the potential Pacific Northwest project location (Mid-C power and Sumas gas markets). The historical instantaneous daily volatilities and correlations described in sub-section 5.10.1 and tabulated in Table 5-1 and Table 5-3 have been used for all Monte Carlo simulations with the objective of producing realistically (from a historical perspective at least) correlated and volatile underlying commodity spot prices for each day of the assumed 20-year tenor of the proposed tolling agreement. Monte Carlo simulation involves the correlated, repetitive sampling of random variables from specified distributions to build a distribution of potential outcomes that can be used to predict the expected outcome of a simulation and the confidence intervals around that outcome.

The input parameters used to complete the intrinsic and modified Margrabe analyses have been used to complete the Monte Carlo analyses wherever appropriate. Selected input parameters for the Monte Carlo analyses are summarized in table Table 6-4.

Using the stochastic price process equation described in sub-section 5.6 and the daily and monthly frequency of volatilities as described in the same sub-section, a Monte Carlo iteration is completed for each day in the 20-year period and for each of the three correlated price series; resulting in the generation of roughly 21,900 individual (but not independent) spot price predictions during each iteration. A pseudo-random form of sampling called Latin Hypercube sampling is used instead of the standard random Monte Carlo sampling. The advantage of this form of sampling is that good representations of the input distributions are achieved much faster than with standard random sampling through binning over the range of inputs and the forced selection of an appropriate number of samples from each bin. This sampling technique allows for relatively stable output distributions to be observed in roughly 500 to 2000 iterations for these analyses. That said, these analyses have been completed for preliminary assessment and demonstration purposes only, and warrant the detailed revision of all input parameters and Monte Carlo simulations of 5000 or more iterations each if reliable risk and capital allocation recommendations are expected. In particular, if reliable estimates of either high or low percentile (e.g. 1$^{st}$ or 99$^{th}$ percentile) values are desired, as is the case when calculating the potential losses or VaR, then a significant number of iterations (i.e. more than 5000 to 10,000) will certainly be required for the purpose of final analyses.

| **Input Parameter** | **Value** |
|---|---|
| Plant Capacity: | 500 MW<br>2 x 250 combustion turbines (CT) |
| Average Plant Availability: | 92 percent off-peak<br>97 percent on-peak |
| Average Plant Heat Rate: | 7.3 MMBtu/MWh |
| Variable Operating and Maintenance:<br>for Cumulative EOH < 25,000 hours | 507.50 USD/EOH per combustion turbine<br>EOH: Effective Operating Hours<br>escalating at 2% p.a.<br>minimum p.a. VOM based on 6000 EOH per CT |
| Variable Operating and Maintenance:<br>for Cumulative EOH ≥25,000 hours | 657.50 USD/EOH per combustion turbine<br>EOH: Effective Operating Hours<br>escalating at 2% p.a.<br>minimum p.a. VOM based on 6000 EOH per CT |
| Variable Gas Transportation: | 0.38 USD/MMBtu<br>escalating at 2% p.a.<br>no losses or miscellaneous charges assumed |
| Variable Power Transmission: | 3.00 USD/MWh<br>escalating at 2% p.a.<br>no losses or miscellaneous charges assumed |
| Fixed Operating and Maintenance: | 0 USD/MWh<br>minimum annual VOM specified above |
| Fixed Gas Transportation: | 0 USD/MMBtu |
| Fixed Power Transmission: | 0 USD/MWh |
| Discount Rate (%): | 0 %<br>Risk-free<br>Market Yield Curve |
| Capacity Charge: | 4.00 USD/kW-month<br>escalating at 2% p.a. |

*Table 6-4 Oregon Tolling Opportunity: Monte Carlo Analysis Input Parameters. Table by authors.*

Due to the use of a risk-neutral underlying price process as described in sub-section 5.6, it is appropriate to discount each output distribution of daily net earnings (calculated from the net option payoff function for each day) using the risk-free yield curve to calculate a distribution of net earnings for each year of operation, for sequential 5 year blocks of net earnings, or for the distribution of net earnings (provided on an average per annum basis) expected over the entire 20-year contract period. The distribution or confidence intervals around the annual average earnings over an observation period of say 5 years is naturally expected to be narrower than an annual earnings estimate observed over a shorter observation window such as a year. As an example, there may be only a 1 percent chance in any given year that earnings of less than $1 million dollars are achieved. Accepting this, it is realized that the chance of total, cumulative earnings being less than $5 million over a 5-year period is far less than the 1 percent likelihood that is applicable on an annual basis. For this reason, a 1st and 99th percentile confidence interval for expected average annual earnings over a 20-year period should be expected to be narrower than a distribution of the same parameter over a single observation year.

Results of the Monte Carlo simulations for the Pacific Northwest location with all six price scenarios are summarized in Figure 6-13 through Figure 6-18 with four parts to each figure:

a) The mean annual earnings for each year of a 20-year tolling contract are plotted along with the 1st and 99th percentile confidence interval. The 'potential losses' for each year can be measured directly as the vertical distance between the x-axis (zero net earnings) and the 1st percentile value of earnings. With the exception of the WTSC scenario where almost the entire 1st percentile net earnings line is observed to be above the x-axis (zero net earnings), indicating the improbable case that most years within this scenario are expected to have no probability of a loss. In a manner similar to the 'potential loss' measurement, a Value at Risk (VaR) measurement is made from the same yearly distributions as the vertical distance between the mean and the 1st percentile earning level.

b) The full 20-year duration of a potential tolling contract can also be summarized for each price scenario as the distribution of total net earnings over the 20 years, normalized to an annual average earnings distribution by simply dividing this total by 20. This 20-year average distribution is expected (and observed) to be narrower than the distribution around individual years within this 20-year period, reflecting the extremely low probability ( <<< 1%) of observing 20 consecutive years of 1st percentile or 99th percentile earning in each year. The shapes of these average annual distributions are as expected: skewed right due to the nonlinearity of the spread option payoff function, which tends to limit the downside and take full advantage of the potential upside.

c) The potential losses and VaR are calculated from the distributions of each scenario and for each year of the contract. The required amount of risk capital is then roughly (and for these demonstration purposes only) calculated using a factor of four times the given VaR and potential losses measurements. The resulting risk capital requirements for each year of operation are plotted using both the VaR and the potential loss measurements and the stated multiple of four.

d) The final step: a return on risk capital (or Risk-Adjusted Return on Capital, RAROC) is calculated for each year of the contract, for each price scenario, and using both calculations of the required risk capital (VaR and potential losses) by dividing the risk capital values into the expected (mean) net earnings for the given year. These returns are plotted as a percentage return on risk capital for each scenario. The risk capital and return on risk capital values for the WTSC scenario are not calculated using the potential losses method due to the (implausible) results that there are no potential losses for this scenario and location. Only the VaR-based risk capital and return on risk capital are provided in parts c) and d) of Figure 6-18 for this reason.

a)

b)

c)

d)

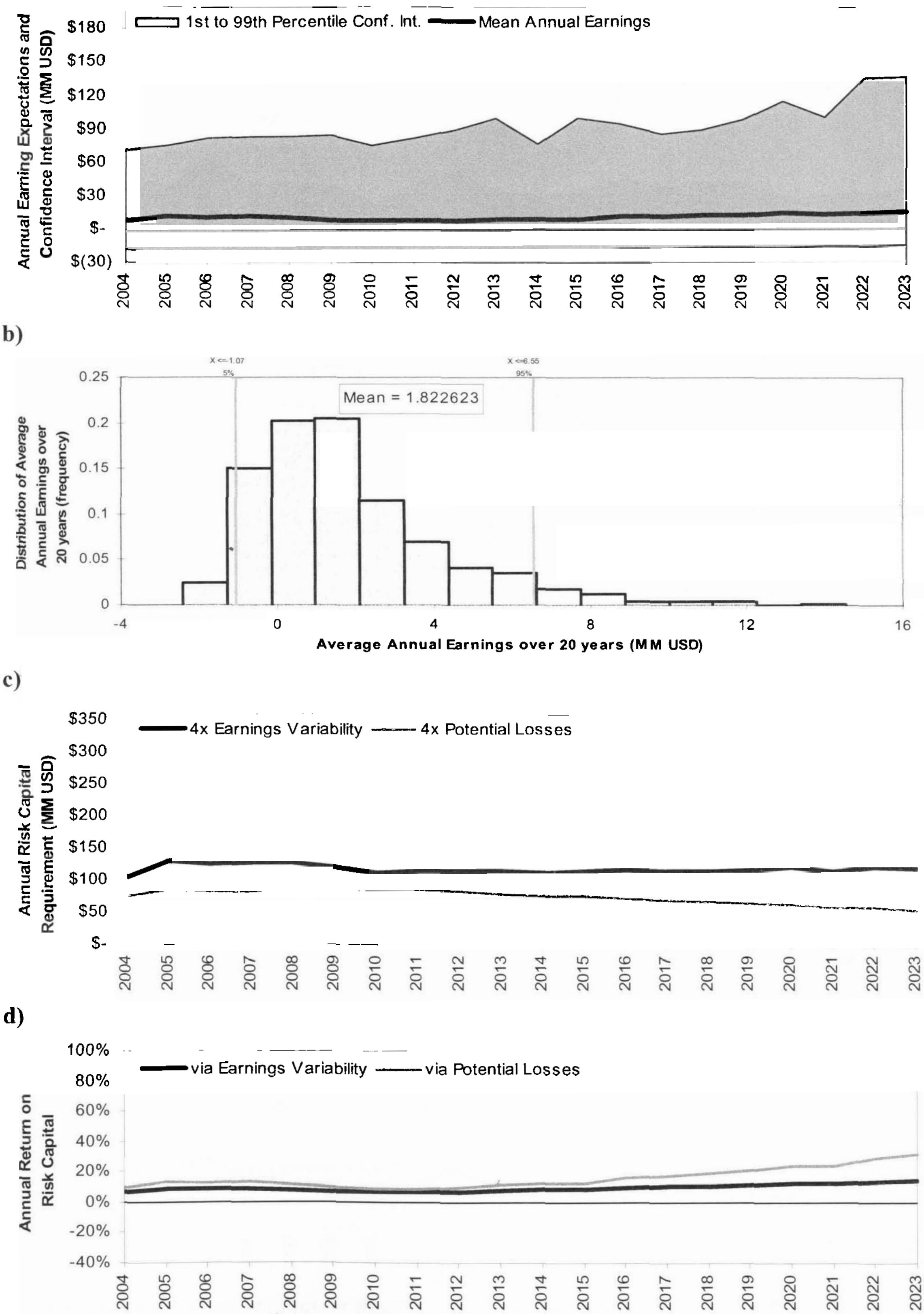



*Figure 6-13 Monte Carlo Valuation Results: Mid-C with Market Data*

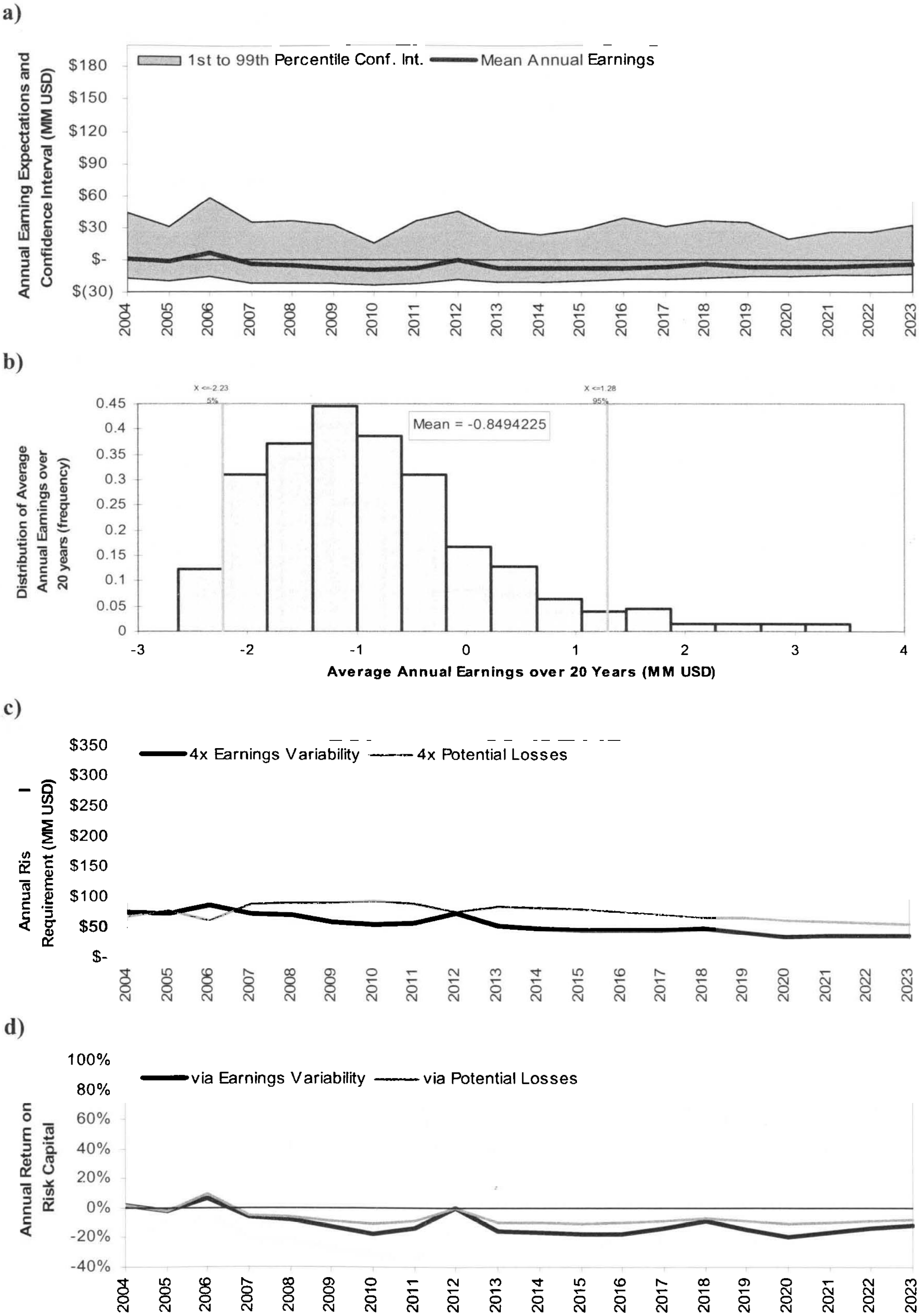



*Figure 6-14 Monte Carlo Valuation Results: Mid-C with Technology Enhanced Price Scenario. Figure by authors.*

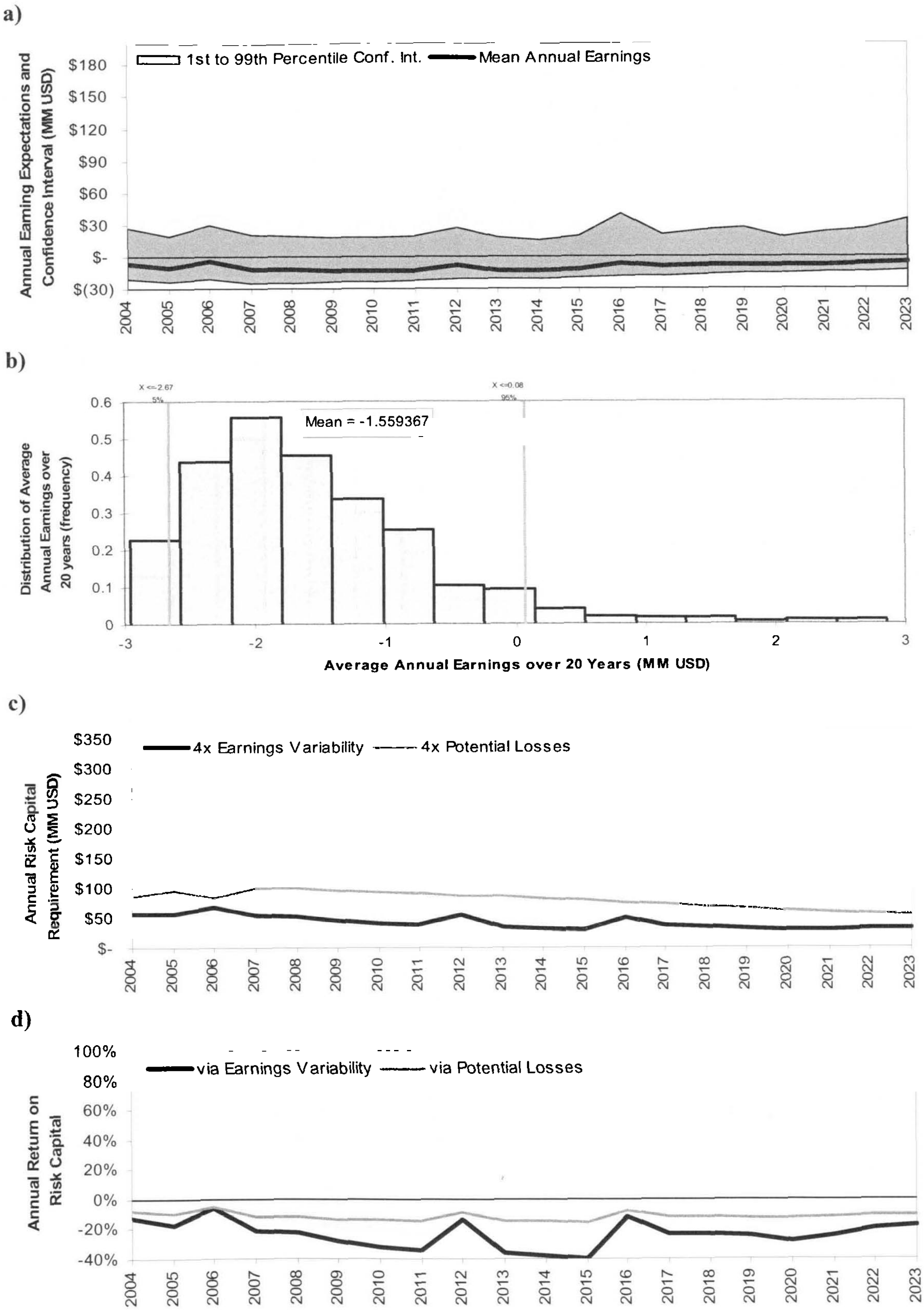



*Figure 6-15 Monte Carlo Valuation Results: Mid-C with Rearview Mirror Price Scenario. Figure by authors.*

a)

b)

c)

d)

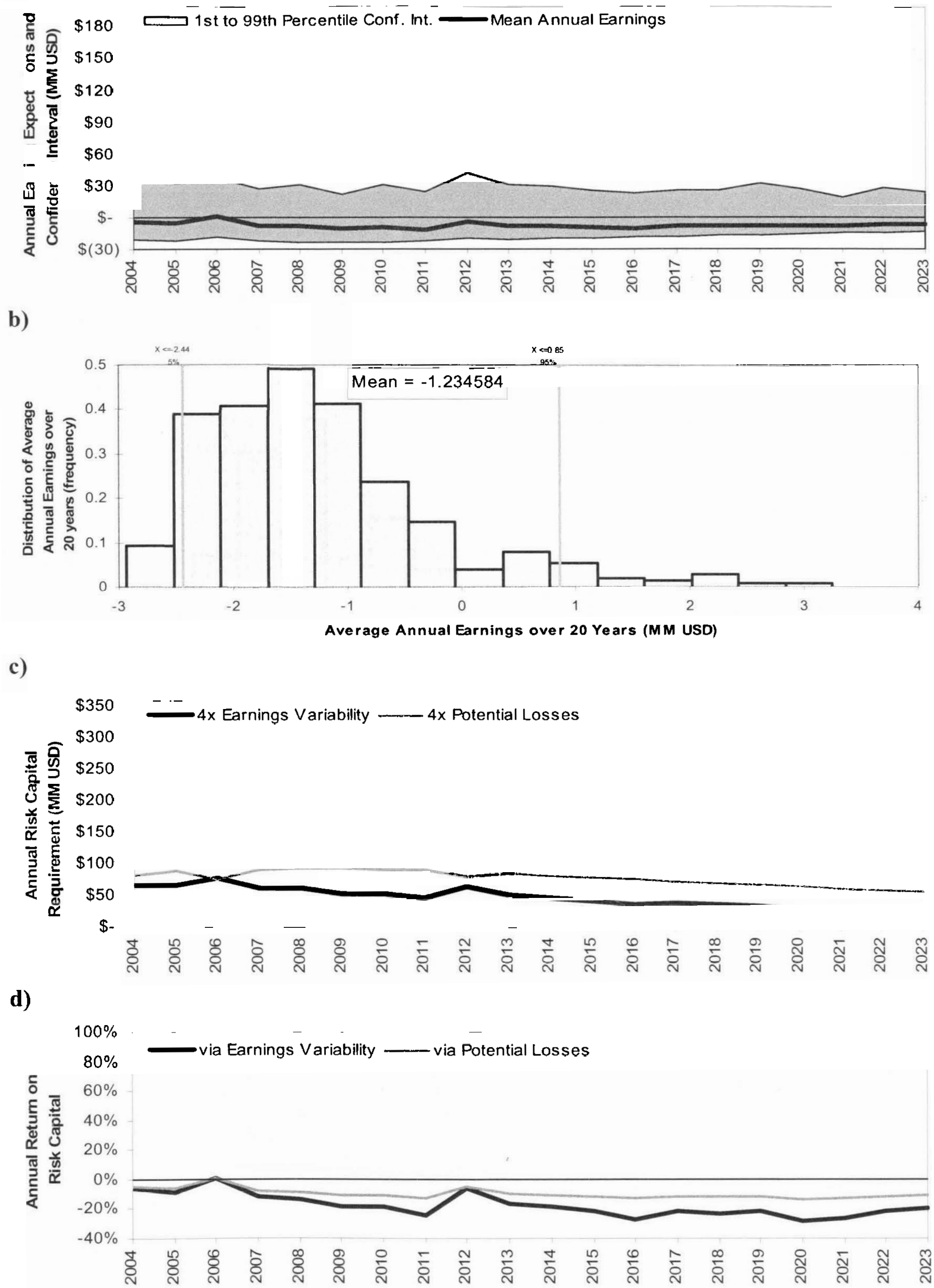



*Figure 6-16 Monte Carlo Valuation Results: Mid-C with Shades of Green Price Scenario. Figure by authors.*

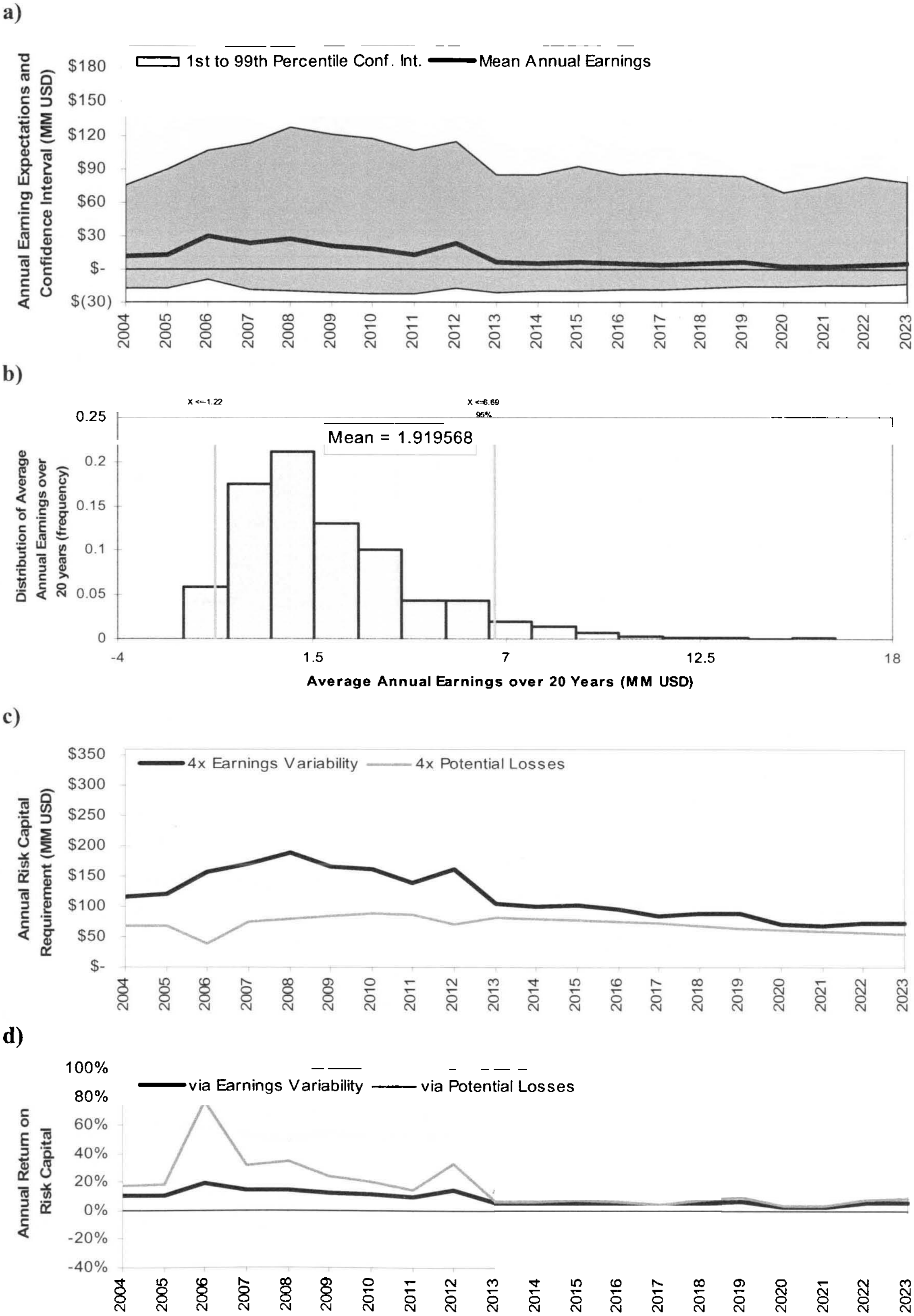



*Figure 6-17 Monte Carlo Valuation Results: Mid-C with World in Turmoil Price Scenario. Figure by authors.*

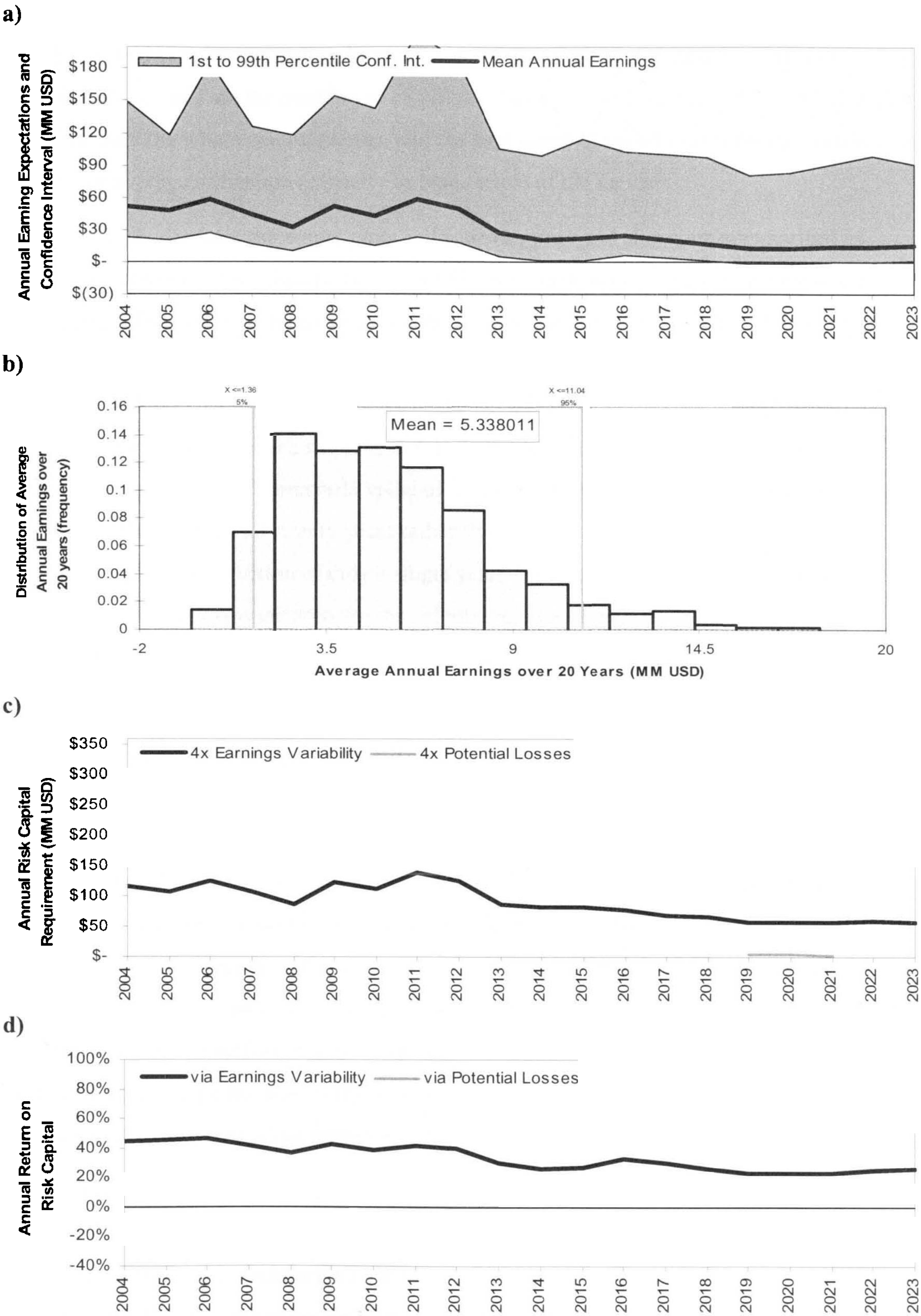



*Figure 6-18 Monte Carlo Valuation Results: Mid-C with World in Turmoil, Supply Constraint Price Scenario. Figure by authors.*

In addition to the average annual net earnings, any other calculated value in the analysis may be tracked as an output and made available for observations and iterative optimization. A few examples of this are the tracking of cumulative Heavy Load Hours (HLH) and LLH within a period or over the whole contract terms, and the total count of on/off events for the combustion turbines or average utilization (capacity or load factor) of the facility.

The results from the output plots and statistics provided above are summarized as follows in Table 6-5. Specifically, the 1st and 99th percentile net earnings expectations are summarized along with the mean value for the six price scenarios in the set of three columns under heading 'A' of the reported data. The reported net earnings values are discounted (using the current risk-free yield curve) averages of the net annual earnings over the full period of 20 years, but this aggregation to a single distribution has been completed for each iteration in the simulation, leading to a 1st percentile value of the net average annual earnings that is truly the 1st percentile value for the full twenty years rather than a more extreme distribution that would be expected from the observation of only a single year. Columns 'B' and 'C' of the same table provide the results of two methods for the calculation of a Capital at Risk (CaR) value for the six price scenarios.

A discussion of quantifiable risks and the resulting CaR is provided in sub-sections 5.12 and 5.13 respectively, and applied here. Column 'B' calculates the CaR from the column 'A' data by multiplying the difference between the reported mean and 1st percentile values by four, reflecting an effort to account for all associated capital and operating risks of the agreement instead of only the market risk. For a complete and detailed analysis of a specific tolling opportunity, this factor should be considered and decided upon based on the specifics of the opportunity and the attitude of the company regarding risk tolerance and credit ratings. The capital calculated in column 'C' is based on potential losses, and replaces the mean value from the calculation above with zero; providing instead a measure of the 1st percentile (or 99th percentile depending upon your perspective) potential losses that were observed over each of the 20 years of the analyzed tolling agreement.

From inspection of the results it can be seen that the capital allocated using a VaR multiplier is greater than that derived from a multiple of potential losses whenever the expected (mean) net earnings are positive (WT, WTSC and Market scenarios), and vice versa when expected (mean) net earnings are negative (TE, RM and SG scenarios). The specifics of the tolling agreement used in this example calculation have led to the unlikely result that the 1st

| Scenario | ***(A)* Annual Avg. Net Earnings Over 20-Year Observation Period (MM USD)** | | | ***(B)* Capital from VaR** | ***(C)* Capital from Potential Losses** | ***(D)* RAROC from VaR Years 1-20** | ***(E)* RAROC From PL Years 1-20** | ***(F)* RAROC from VaR (PL) Years 1-5** | ***(G)* RAROC from VaR (PL) Years 6-10** | ***(H)* RAROC from VaR (PL) Years 11-15** | ***(I)* RAROC from VaR (PL) Years 16-20** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***1st* Percentile** | ***Mean*** | ***99th* Percentile** | (Mean - 1st) x 4 | [max(0,0 - 1st)] x 4 | | | | | | |
| TE | -14.71 | -5.10 | 18.09 | 38.47 | 58.86 | -13% | -9% | -1% *(-1%)* | -13% *(-9%)* | -17% *(-10%)* | -16% *(-10%)* |
| RM | -16.97 | -9.36 | 9.72 | 30.46 | 67.89 | -31% | -14% | -22% *(-12%)* | -32% (-14%) | -29% *(-13%)* | -24% *(-12%)* |
| SG | -16.13 | -7.41 | 14.09 | 34.89 | 64.52 | -21% | -11% | -9% *(-6%)* | -18% *(-10%)* | -24% *(-12%)* | -25% *(-12%)* |
| WT | -11.78 | 11.52 | 59.61 | 93.18 | 47.11 | 12% | 24% | 18% *(68%)* | 12% *(23%)* | 6% *(7%)* | 5% *(7%)* |
| WTSC | 2.07 | 32.03 | 84.30 | 119.84 | - | 27% | | 43% *(-)* | 39% *(-)* | 28% *(-)* | 24% *(-)* |
| Market | -11.23 | 10.94 | 55.83 | 88.67 | 44.93 | 12% | 24% | 11% *(21%)* | 8% *(11%)* | 11% *(19%)* | 14% *(30%)* |

*Table 6-5 Oregon Tolling Opportunity: Monte Carlo Analysis Results – Expected Earnings, VaR,, Potential Losses and RAROC. Table by authors.*

percentile potential losses for the WTSC scenario are still positive (i.e. no potential losses are expected), which in turn makes the capital calculation based on this potential losses approach meaningless for this scenario (denoted in column 'C' as a missing entry). Again, this is related to the specifics of the tolling agreement that have been assumed for this analysis, including the relatively low capacity charge (4.00 USD/kW-month) rather than the plausibility of the price scenario itself.

The Risk Adjusted Return on Capital (RAROC) results of columns 'D' through 'I' is discussed in sub-sections 6.7 and 6.8.

*6.6.4.2 Sensitivity of Expected Net Earnings to Input Parameters*

A sensitivity study of the effect of several key input parameters on the expected outcome (average net annual earnings in this case) assists in the appreciation of which agreement terms are the largest determinants of value, and hence the most worthwhile to negotiate, hedge or mitigate. Whereas a VaR calculation or summary goes part way to answering the question of value sensitivity to *uncontrollable* market behavior, a separate sensitivity study can be conducted to study the impact of more *controllable* feature of the agreement. In a manner similar to the discussion regarding the other analyses and results, the following sensitivity study presents a concept or framework for a sensitivity study and follows through to demonstrate its application to a hypothetical tolling opportunity. A detailed or final valuation will require careful consideration of all factors and terms of an agreement.

The objective of the following sensitivity study is to select a group of agreement terms and physical plant characteristics that are believe to have a significant impact on the value of the agreement. In this case, a relatively simple approach was taken, whereby the six parameters shown in Figure 6-19 were selected for the study and three potential values were assigned to each: i) a low but still plausible condition, ii) the expected condition, and iii) a high but still plausible condition. The high and low conditions were not selected to represent a specific non-exceedance percentile or the basis of thorough statistical analysis, but rather were assigned according to the authors' belief regarding their potential variability. The high and low conditions along with the base case conditions used for this sensitivity study are shown in the top right corner of the same figure.

A single price scenario, CERA's WTSC price scenario for Mid-C power and Sumas gas, was used for this study to show indicative results. From Table 6-5, the expected average net annual earnings is seen to be approximately $32 million USD, which forms the base of the analysis around which input parameters are individually adjusted to their high and low conditions to estimate their partial impact on the expected earnings value. The six lines of Figure 6-19 show the impact on expected earnings of altering any one input parameter away from the base case and towards either the low or the high conditions. The steeper the resulting line, with either a positive or negative slope, the more sensitive the output being measured is to the given parameter. From this figure it is observed that all of the selected (indicative) input parameters are relatively key determinants of value, but that the heat rate of the plant is amongst the most sensitive to change, indicating a range of approximately $8 million USD (roughly ± $4 million USD) around the mean value.

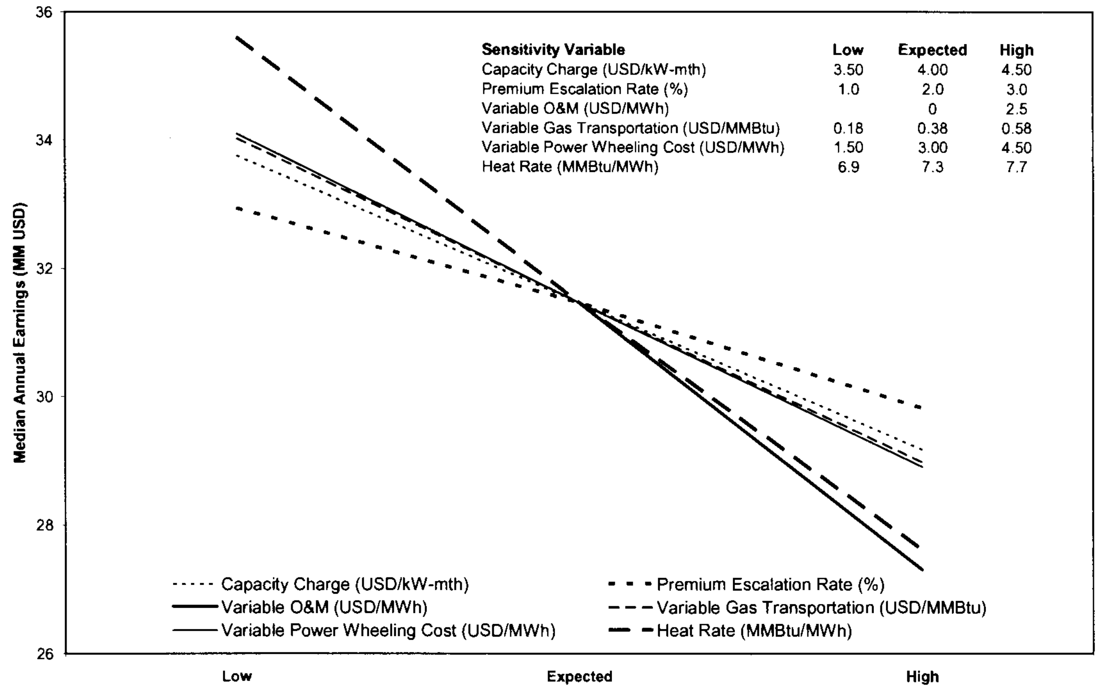



*Figure 6-19 Oregon Tolling Opportunity: Sensitivity Plot of Key Input Parameters. Figure by authors.*

An alternate method of visualizing the same sensitivity analysis results is shown in Figure 6-20, which is referred to as a 'Sensitivity Tornado'. This approach stacks the input parameters in descending sensitivity, from highest to lowest (hence the tornado reference), and the width of the bar is used to indicate the sensitivity of the results to the high and low input conditions of each parameter; where wider bars are indicative of larger shifts away from the base case.

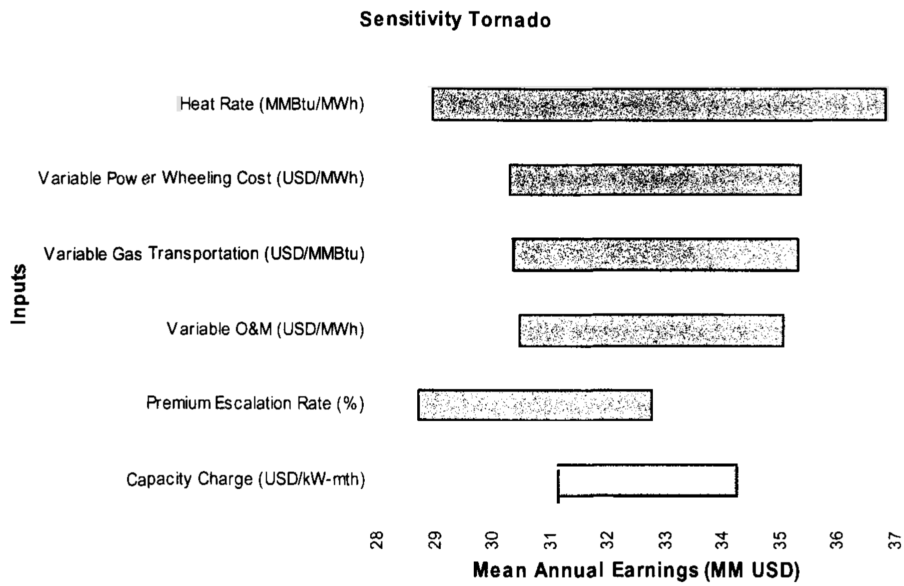



*Figure 6-20 Oregon Tolling Opportunity: Alternate Sensitivity Tornado for Key Input Parameters. Figure by authors.*

## 6.7 Summary and Performance Metrics

The results of three tolling agreement valuation methods have been presented in sub-sections 6.6.2 through 6.6.4. 'Results' from these analyses have included discussions around the intrinsic and extrinsic value of a given hypothetical tolling agreement, whereby two potential agreements were studied in generic terms and were assumed to be located in Oregon and Arizona, and in terms of the expected distribution of average net annual earnings. Sub-sections 5.12 through 5.13 have introduced a discussion regarding the measurement of risk and the subsequent requirement to allocate capital to an opportunity or portfolio to account for these risks and maintain an attractive credit rating.

The challenge at hand then is to recommend a level of risk capital to 'put aside' or allocate to such opportunities, then to recommend a performance measurement that could be used to decide between alternative opportunities or after the fact to assess the on-going risks and performance of the opportunity. The concept of Return on Capital at Risk (RAROC) was discussed in sub-section 5.14 and the Sharpe Ratio was mentioned due to its added advantage of directly incorporating the volatility or standard deviation of a return in the calculation.

Although of interest and value in gaining an understanding of the underlying price processes and assumptions, the intrinsic value methodology and the modified Margrabe solution are difficult to apply reliably to a long-term tolling agreement for a number of reasons:

- The intrinsic value calculation, although modified as described in sub-section 5.7.1 to allow for the incorporation of most variable and fixed operating and maintenance, gas transportation and power transmission costs, still by definition accounts for only the intrinsic, time discounted value of the spark spread inferred from the forward price curves and none of the option or time diversification value offered by a long-term tolling agreement;
- The modified Margrabe solution is acknowledged to provide only an approximation of the spread option value when the volatilities and correlations of the underlying are uncertain and/or high; and
- The modified Margrabe solution is capable of incorporating only a certain amount of flexibility in terms of unique or uncommon agreement terms.

Direct comparison of the calculated intrinsic and modified Margrabe values to the expected earnings distributions of the Monte Carlo simulation is also a challenge due: i) partially to the reasons above leading to the approximation of smooth VOM costs for input to the modified Margrabe approach instead of actual use charges as specified in the contract; ii) partially to the different underlying volatilities and correlations (historical forward curve versus 2-factor historical spot) used in the analyses; and iii) partially to the different underlying price processes assumed for the underlyings.

The Monte Carlo simulation results presented in sub-section 6.6.4.1 are used in Table 6-5 to calculate an indicative level of capital to allocate for a proposed agreement, based on potential losses and Value at Risk (VaR) calculations. The range of annual capital assigned to the project on the basis of VaR is between $30 million USD and $120 million USD (column ‘B’ of Table 6-5), depending upon the price scenario used in the simulation. In comparison, the range of annual capital assigned to the project on the basis of potential losses is between $45 million USD and $68 million USD (column ‘C’). The annual trends (plotted for each year of the hypothetical 20-year contract) of allocated capital and estimated returns on that capital are plotted as parts c) and d) of Figure 6-13 through Figure 6-18.

Columns 'D' and 'E' of the same table go on to calculate an average annual RAROC as the ratio of the expected (mean) average annual net earnings divided by the corresponding capital allocation calculated by means of the VaR (column 'D') or by means of the potential losses (column 'D'). These resulting RAROC values vary significantly more than would be expected from the ranges of capital allocation, due partially to the range of capital itself, but primarily to the simulated mean level of earnings being entered as the numerator of this ratio. The mean level of earnings is highly reliant upon the price scenario being used, resulting in some negative returns (TE, RM and SG) and some positive (WT, WTSC and Market). These results are, again, highly dependent upon the generic or hypothetical tolling agreement being simulated and the assumed capacity charge and escalation factor, and are therefore not indicative of the value of a specific tolling opportunity in Oregon or the suitability of the CERA price scenarios.

As previously indicated, a single estimate of the average returns over a 20-year period is likely not an adequate measure on its own. The volatility of earnings and the shape of the returns over the 20-year period is almost as important as the single return value itself in that it would likely be unacceptable to endure negative returns during the early years in order to hopefully take advantage of *modeled* positive returns in the later years. This stability of returns, or shape, issue is addressed partially by summarizing the expected average annual net earnings, capital allocations and returns on that capital in four 5-year blocks that make up the 20-year agreement, and by studying the shape and magnitude of these returns. Columns 'F' through 'I' of Table 6-5 summarize these data for the six price scenarios, and, not surprisingly, suggest mostly negative returns for the same subset of price scenarios (TE, RM and SG) and mostly positive for the others (WT, WTSC and Market). The data from these 5-year blocks are summarized in the same table and presented graphically for each of the price scenarios in Figure 6-21.

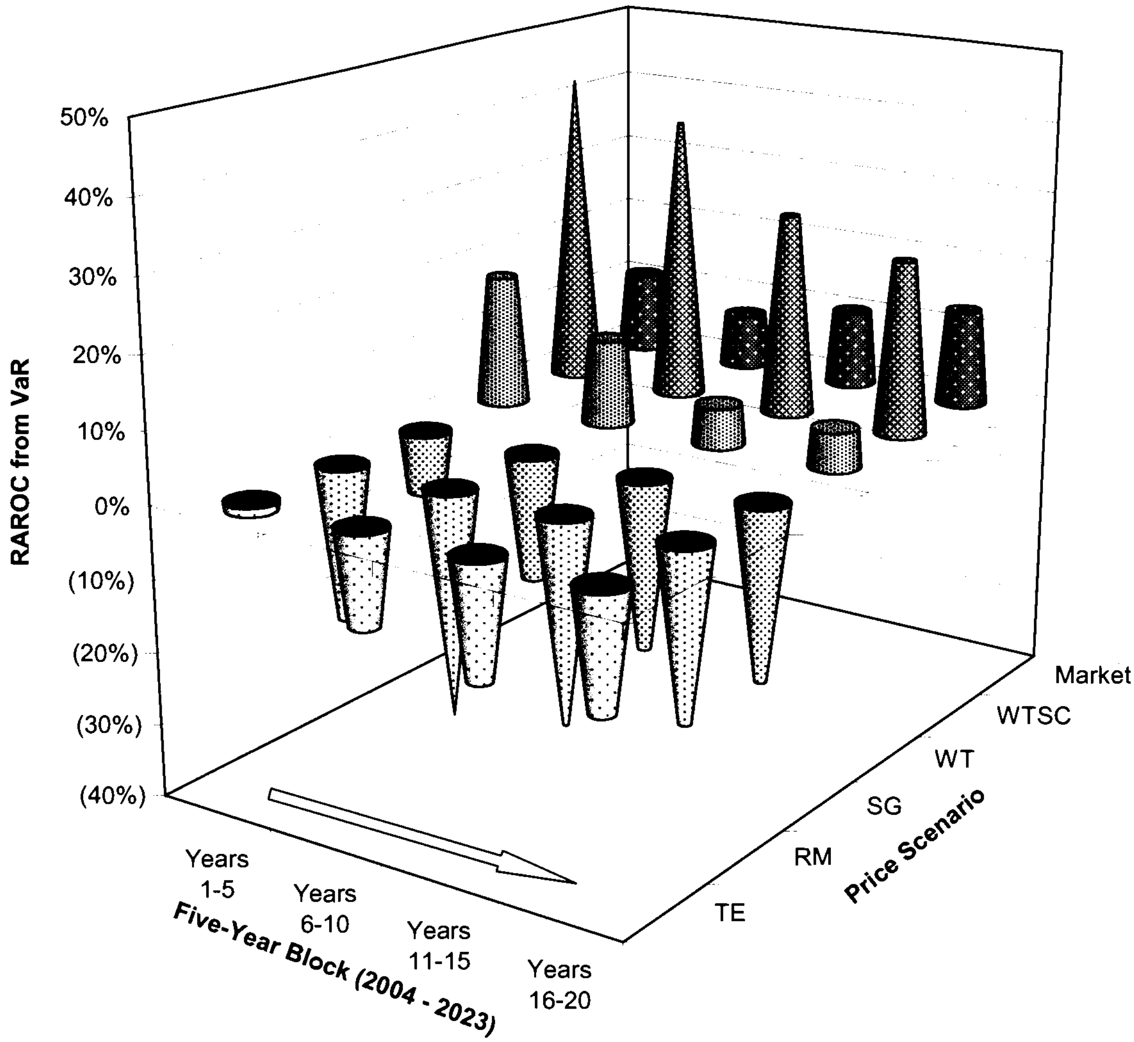



*Figure 6-21 Oregon Tolling Opportunity: Summary of RAROC Analysis Results for 5-Year Intervals of a 20-Year Tolling Agreement and by Price Scenario. Figure by authors.*

As an additional performance metric and as a common tool for the comparison of alternative opportunities in an environment of limited resources, the Sharpe Ratio could also be calculated for each of the 5-year blocks and for each price scenario. The Sharpe Ratio will naturally calculate to be negative for any scenario that suggests a return on capital at risk that is less than the risk-free rate (or yield curve average of approximately 3.5 percent). This leaves only the WT, WTSC and Market price scenarios with meaningful Sharpe Ratios (in this limited and hypothetical example) that are calculated as described in earlier sub-sections to be the expected return of the opportunity, less the risk-free rate of an alternative investment, and divided by the standard deviation of the return itself.

## 6.8 Opportunities and Conclusions

The preceding chapters have presented a framework for approaching and understanding the valuation of a tolling agreement, several metrics for the analysis of tolling opportunities, and the sensitivity of the value of these opportunities to several key parameters.

The specifics of an existing opportunity have not been presented, nor have the benefits and counterbalanced risks of various hedging strategies that may be appropriate; so, other than the estimated intrinsic values (including the specified fixed and variable costs) and the form of the Monte Carlo simulation, the results presented above should be considered indicative of a method rather than a general statement or expert review of the spark spread conditions and tolling potential in the Pacific Northwest.

Distributions of earnings have been presented, along with two methodologies for the calculation of capital adequacy (one based on the measured VaR, and the other based on the estimated potential losses for a year) that rely on the use of a factor to incorporate the effects of credit and operational risks at an early stage in the calculation. A complete, due diligence-oriented analysis would look at the specific market conditions, counterparties, hedges and operational risks prior to suggesting a capital allocation level for the agreement against which earnings are compared.

Despite the preceding remarks regarding limitations of models and caveats, the use of Monte Carlo simulation combined with an appropriate underlying price process, historical volatility and correlation data, and agreement-specific VOM and FOM terms is very promising and offers the flexibility required to complete a thorough valuation of an opportunity. The combination of these features with the potential for clear communication of output distributions, risk adjusted returns and sensitivity studies should be sufficient to win the approval of a Board of Directors if warranted.

# 7 RECOMMENDATIONS

The valuation of tolling contracts is a problematic task. The commodity markets for electricity and natural gas are highly volatile. While this creates substantial risk, it also creates opportunity. Powerex is actively involved in looking at tolling contracts and is still working through the challenge of valuing opportunities. The motivation for this paper was to provide a strategic assessment and recommendation on how Powerex should value tolling opportunities. This paper is structured to educate readers on:

- The North American Energy Industry, which provides the required background to understanding tolling agreements;
- Powerex, and why the company is contemplating more complex tolling agreements;
- Tolling, and the variations to contract structure, and the risks inherent to each;
- Tolling valuation techniques, to introduce reusable tools that may be applied to help value a variety of tolling opportunities;
- The application of valuation methodologies, which was applied to two opportunities that reflect the types of contracts Powerex would consider; and
- Tolling strategy recommendations for Powerex.

Now is the time to pursue tolling contracts. Generation asset values are declining. Spark spreads have decreased and there are parts of the power market where supply greatly exceeds or will greatly exceed demand. This situation has caused a period of owner distress. It offers opportunities to negotiate for long-term tolling contracts at reduced prices. Generation facilities that do not secure tolling arrangements may face a shift in ownership over the next few years through forced sales, or through acquisition by their financial lenders if owners are unable to fulfill their debt requirements. There are only a small number of possible buyers for these facilities, and gas-fired generating assets are expected to sell well below their original cost.

Despite the strategic benefits of long term tolling contracts, Powerex may be restricted from entering into complex contracts. Powerex has a mandate not to own assets. Indications that a long-term tolling arrangement may require the company who benefits, or suffers from 75% or more of the risks and rewards to recognize the generator as a capital asset may prevent even a well planned, strategic, and high-value deal from being pursued by Powerex. In addition to the potential treatment of the agreement as an asset, evolving income reporting requirements may lead to a requirement to report at least a portion of the mark-to-market and possibly mark-to-model income on Powerex's income statement and, on a consolidated basis, on BC Hydro's income statement. The income reporting risks associated with such a long-term view, should this requirement come to pass, could rule out the possibility of Powerex seeking a long-term tolling agreement.

Upon a review of the market conditions and prospects, it appears Powerex should wait to enter a tolling contract in the U.S. Southwest for at least another year or two, until asset prices are near their lowest and then proceed with caution. In the near term, the pursuit of a tolling opportunity in the Pacific Northwest with a carefully planned hedging program and at the right price may be worthwhile. Hedges should avoid the introduction of excessive credit risk, and a careful study of the VOM and FOM costs, terms and other obligations is crucial. It is also important to firm-up gas transportation and a power wheeling (to Mid-C) strategy.

It is necessary to recognize that a tolling arrangement may not be accretive to short-term earnings. Coal plant values are likely to have less erosion because of expected upward pressure on natural gas prices.

The window of opportunity won't last, but it is critical to asses the timing and level of company distress; perform a disciplined risk analysis; evaluate the level of cash, credit and collateral a lender will require; and understand the competitive landscape.

As opportunities present themselves or are sought out actively, it is a valuable exercise for the marketing, front office and risk management groups of Powerex to acquaint themselves with the standard terms and conditions of tolling contracts, establish a common language for the communication of these opportunities and risks – both within and outside of the organization – and gain comfort with the types of analyses and studies required to value these opportunities, assign risk capital and report the gains or losses. Such preparation will put Powerex in an excellent position to act swiftly, decisively and competitively when a favorable opportunity is uncovered.

## APPENDIX A – OREGON TOLLING OPPORTUNITY: PRICE SCENARIOS AND SPARK SPREADS

This appendix contains charts that identify the intrinsic, net spark spreads for the Oregon CCGT project. Each chart depicts a different forecast scenario and the expectation of profit based on each scenario's forecasted power market and gas market data. Power and gas market data are selected based on the plant location.

CERA forecast data is proprietary and may only be used under license. Powerex and BC Hydro are CERA customers. The graphs produced in Appendix A and B included CERA inputs and are be withheld from public copies of this report.

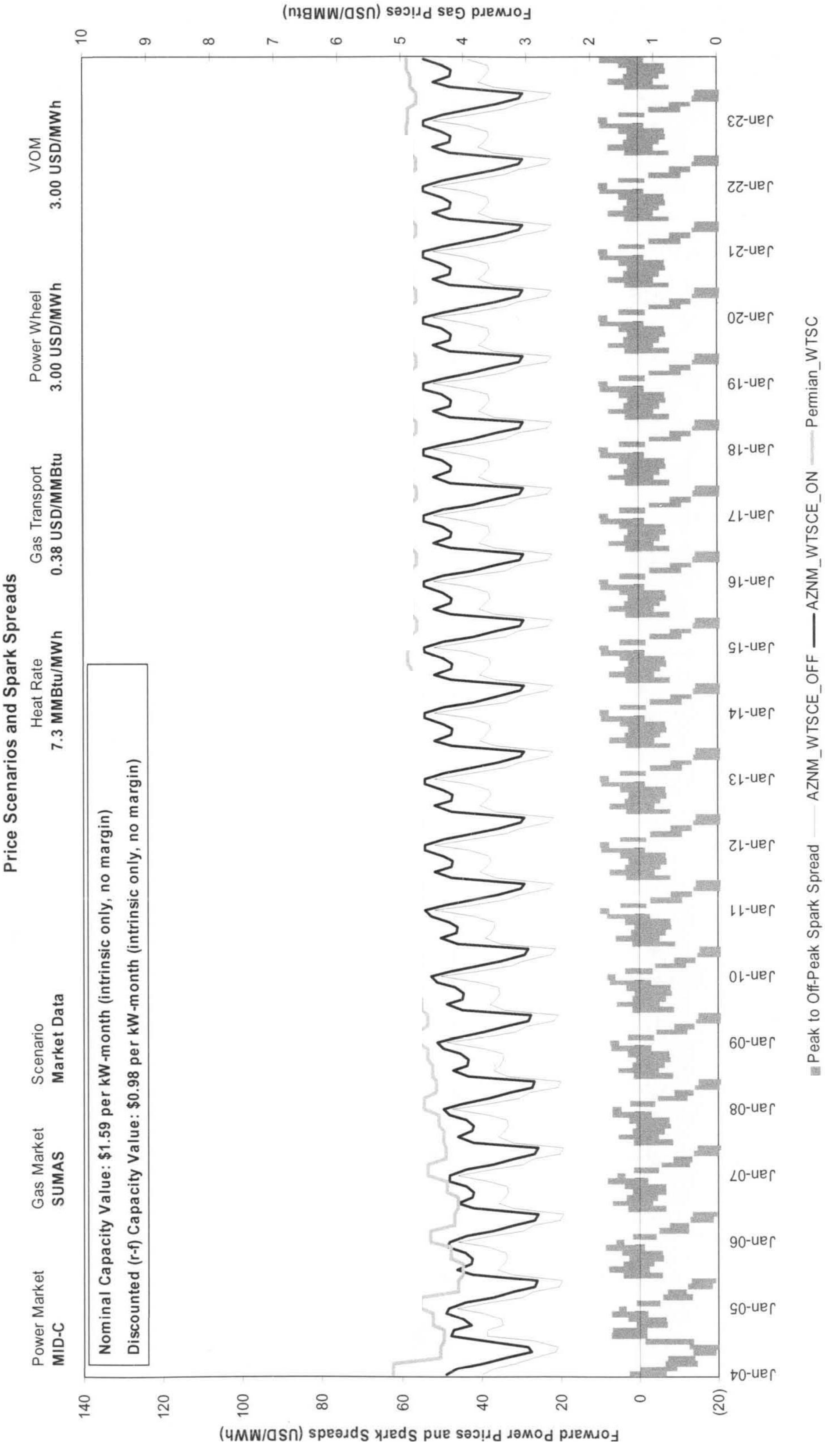
## APPENDIX B – ARIZONA TOLLING OPPORTUNITY PRICE: SCENARIOS AND SPARK SPREADS

This appendix contains charts which identify the potential spark spreads for the Arizona tolling opportunity CCGT plant. Each chart depicts a different scenario and the expectation of profit based on each scenario's forecasted power market and gas market data. Power and gas market data are selected based on the plant location.

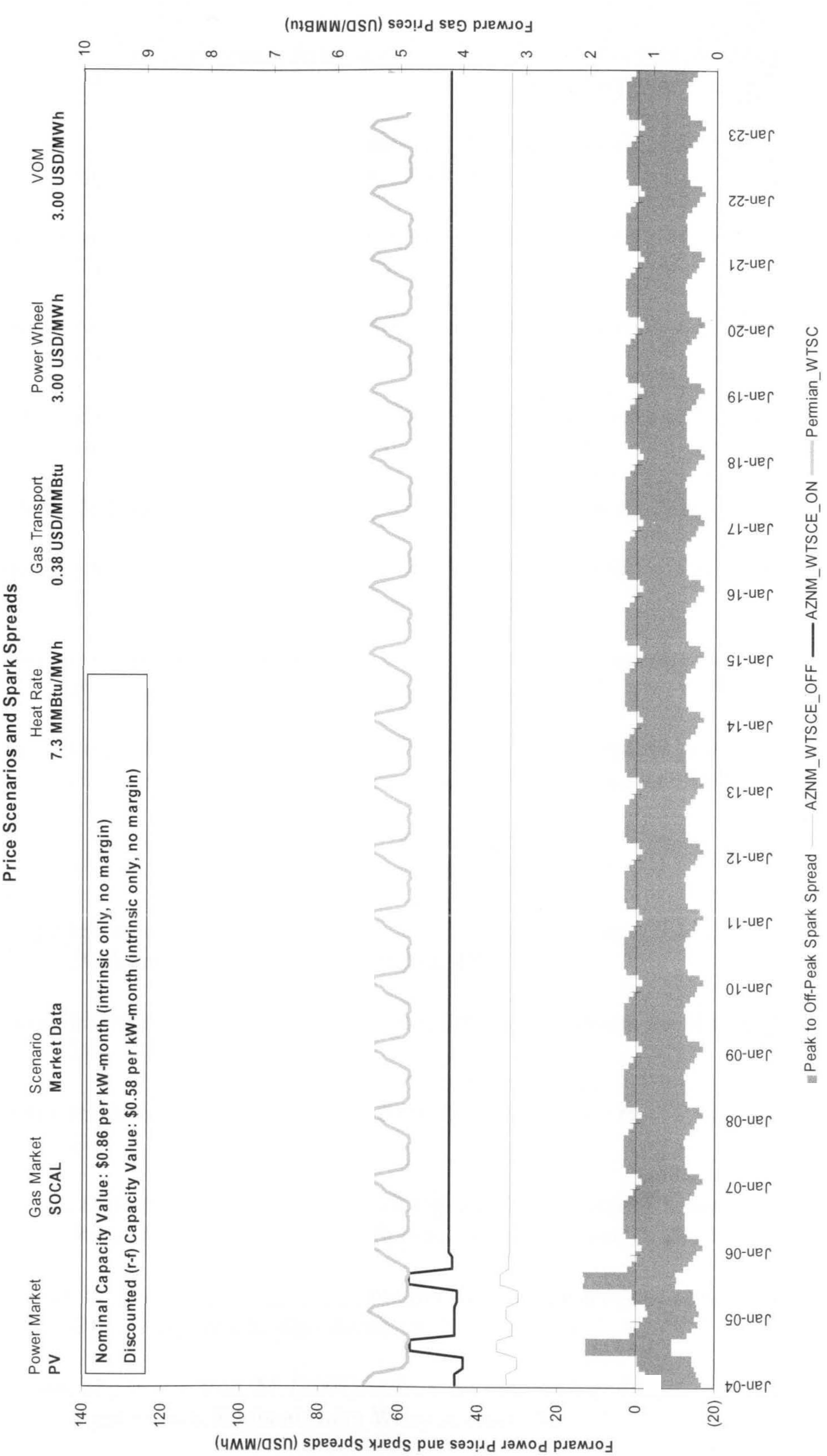
CERA forecast data is proprietary and may only be used under license. Powerex and BC Hydro are CERA customers. The graphs produced in Appendix A and B included CERA inputs and are be withheld from public copies of this report.

## APPENDIX C – OREGON AND ARIZONA TOLLING OPPORTUNITIES: MARKET SPARK SPREADS

The following chart shows the spark spread using market pricing to 2011 to determine the intrinsic (deterministic) nominal and discounted value. The first plot shows data based on the Mid-C power hub and Sumas hub. The second plot is based on Palo Verde and Permian.



Price Scenarios and Spark Spreads
Power Market
MID-C
Gas Market
SUMAS
Scenario
Market Data
Heat Rate
7.3 MMBtu/MWh
Gas Transport
0.38 USD/MMBtu
Power Wheel
3.00 USD/MWh
VOM
3.00 USD/MWh
Nominal Capacity Value: $1.59 per kW-month (intrinsic only, no margin)
Discounted (r-f) Capacity Value: $0.98 per kW-month (intrinsic only, no margin)
Forward Power Prices and Spark Spreads (USD/MWh)
Forward Gas Prices (USD/MMBtu)
140
120
100
80
60
40
20
0
(20)
10
9
8
7
6
5
4
3
2
1
0
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20
Jan-21
Jan-22
Jan-23
Peak to Off-Peak Spark Spread
AZNM_WTSCE_OFF
AZNM_WTSCE_ON
Permian_WTSC


Price Scenarios and Spark Spreads
Power Market
PV
Gas Market
SOCAL
Scenario
Market Data
Heat Rate
7.3 MMBtu/MWh
Gas Transport
0.38 USD/MMBtu
Power Wheel
3.00 USD/MWh
VOM
3.00 USD/MWh
Nominal Capacity Value: $0.86 per kW-month (intrinsic only, no margin)
Discounted (r-f) Capacity Value: $0.58 per kW-month (intrinsic only, no margin)
Forward Power Prices and Spark Spreads (USD/MWh)
Forward Gas Prices (USD/MMBtu)
Peak to Off-Peak Spark Spread
AZNM_WTSCE_OFF
AZNM_WTSCE_ON
Permian_WTSC

## REFERENCE LIST


Cambridge Energy Research Associates, Inc. (CERA). (2002). *New Realities, New Risks: North American Power and Gas Through 2020.* Cambridge, MA.

Cambridge Energy Research Associates, Inc. (CERA). (2003a). *New Southwest Power Plants: High Hopes Meet Hard Facts.* Cambridge, MA.

Cambridge Energy Research Associates, Inc. (CERA). (2003b). *Day of Reckoning for the US Merchant Power Business.* Cambridge, MA.

Committee of Chief Risk Officers. (2002, November 19). *Introduction and Executive Summaries of CCRO Recommendations (Volume 1 of 6).*

Damodaran, A. (2001). *Corporate Finance: Theory and Practice ($2^{nd}$ ed.).* John Wiley & Sons, Inc.

Deloitte & Touche. (2003). *Powerex F2004 Strategic Summary February 24, 2003.*

Energy Information Administration. (1998, September). *Challenges of Electric Power Industry Restructuring for Fuel Suppliers.* Washington, DC.

Energy Information Administration. (2000, October). *The Changing Structure of the Electric Power Industry 2000: An Update.* Washington, DC.

Energy Information Administration. (2001, February 9). *California's Electricity Situation: Briefing for the staff of the U.S. House of Representatives.* Washington, DC.

Energy Information Administration. (2001, August). *Cost and Quality of Fuels for Electric Utility Plants 2000 Tables.* Washington, DC.

Energy Information Administration. (2002, March). *Inventory of Electric Utility Power Plants in the United States 2000.* Washington, DC.

Energy Information Administration. (2003, February). *Natural Gas Annual 2001.* Washington, DC.

Energy Information Administration. (2003, March). *Electric Power Annual 2001.* Washington, DC.

Fowkes, D; Kahn, N. and Armstrong, D. (Spring, 2000). Leasing in project financing. *Journal of Project Finance.* New York: Spring 2000. Vol. 6, Iss. 1; pp. 21-32.

Gardner, D. & Zhuang, Y. (2000, December). Valuation of Power Generation Assets: A Real Options Approach. *Algo Research Quarterly, Vol. 3, No. 3.*

Jackson, M., & Staunton, M. (2001). *Advanced Modelling in Finance using Excel and VBA.* West Sussex, England: John Wiley & Sons Ltd.

Lintner, J. (1965). The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets. *Review of Economics and Statistics.* Vol. 47, pp.13-37.

Margrabe, W. (1978). The Value of an Option to Exchange One Asset for Another. *Journal of Finance, Vol. 33, pp. 177-86.*

Markowitz, H.M. (1991). Foundations of Portfolio Theory. *Journal of Finance.* 46(2), pp. 469-478.

Mun, J. (2002). *Real Options Analysis.* Hoboken, NJ: John Wiley & Sons, Inc.

North American Electric Reliability Council. (2002, October). *Reliability Assessment 2002-2011.*

North American Energy Working Group. (2002, June). *North America – The Energy Picture.*

Palisade. (2002). *@Risk – Advanced Risk Analysis for Spreadsheets.* Newfield, NY: Palisade Corporation.

Powerex Corp. (2003, July 3). *Powerex Corp. Strategic Business Plan Fiscal Year 2004.*

Powerex Corp. (2003, July 3). *Situation Analysis FY04/05, 18.7.03.*

Risk Books. (1999). *Energy Modelling and the Management of Uncertainty.* London, England: Risk Publications.

Risk Books. (2002). *Real Options and Energy Management: Using Options Methodology to Enhance Capital Budgeting Decisions.* Ronn E. I. (ed.). London, England: Risk Waters Group Ltd.

Scudder Publishing Group. (2003, July). *The Risk Desk (Vol. III, Number 7).* Crownsville, MD.

Sharpe, W.F. (1964). Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk. *Journal of Finance.* Vol. 19, pp. 425-442.

Skantze, P. (n.d.). Effectively using Real Options. *Energy Risk International.*

Vancouver Island Energy Corporation. (2003, March). *CPCN Application for the Vancouver Island Generation Project.*

Veron, E.L. & Iaconetti, L.D. (2001). The Brave New World of U.S. Power Project Finance. *The Journal of Project Finance, Spring 2001.* Institutional Investor Inc.

Wengler, J. (2001). *Managing Energy Risk: A nontechnical guide to markets and trading.* Tulsa, Oklahoma: Penn Well Publishing Company.

Wolinsky, J. (2002, August 23). Research: Evaluating Debt Aspects of U.S. Power Tolling Agreements. Standard & Poor's Ratings Direct.