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Douglas C. Tingey
Assistant General Counsel

August 15, 2011

Via Electronic Filing and Messenger
Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem OR 97308-2148

Re: UE 228 – PGE's 2012 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

Enclosed for filing in the above-captioned docket please find the following:

Original and five copies of Rebuttal Testimony & Exhibits of PGE:

- **Pope-Valach (PGE/300[redacted], 301-302)**
- **Lobdell-Outama (PGE/400-403, 404C, 405, 406C, 407C, 408, 409C, 410-411, 412C)**
- **Stoddard (PGE/500-502)**

Three copies on CD of:

- **Work Papers (confidential and non-confidential portions)**

Confidential and non-confidential versions are included. Confidential portions are subject to Protective Order No. 11-102 and are provided in a separate sealed and marked envelope. They are not to be posted on the OPUC website.

These documents are being filed electronically with the Filing Center. Hard copies will be sent via messenger. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided. Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY
Assistant General Counsel

DCT:cbm
Enclosures
cc: UE 228 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PGE'S REBUTTAL TESTIMONY, EXHIBITS AND WORKPAPERS** to be served by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 228.

Dated at Portland, Oregon, this 15th day of August, 2011.

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UE 228 / PGE / 300
Pope - Valach

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Financial Implications

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Maria Pope
William Valach

REDACTED VERSION

August 15, 2011

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Maria M. Pope. I am the Senior Vice President, Finance, Chief Financial Officer and Treasurer for PGE. My qualifications appear at the end of this testimony.

My name is William J. Valach. I am the Director of Investor Relations for PGE. I am responsible for managing the relationships and communications with PGE's shareholders and the investing public. My qualifications also appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to testimonies submitted by ICNU witness Donald Schoenbeck and by CUB witnesses Bob Jenks and Gordon Feighner. Mr. Schoenbeck claims that PGE's hedging strategy is "fundamentally flawed by relying on 12 month forward strips and locking in far too much gas far too quickly" (ICNU Exhibit 100, p. 2). Similarly, the CUB witnesses claim that PGE "hedges that natural gas volume too early, creating significant financial risk to customers" (CUB Exhibit 100, p. 5).

As a consequence, Mr. Schoenbeck recommends that [redacted] in 2012 net variable power costs be disallowed. (CUB's testimony does not specify a dollar amount for their proposed disallowance.) However, should Mr. Schoenbeck's recommendation be accepted, PGE will be forced to recognize in total approximately [redacted] in expense in 2011 or in subsequent periods when the hedges expire. In addition, PGE would have to issue an SEC 8-K and revised earnings report.

Our testimony will address the fundamental problems with Mr. Schoenbeck's and CUB's analyses, and the effects that their recommended policies would have on PGE's financial condition and our ability to respond to customer needs. In addition, we address the long-term negative effect on investor perceptions. Should a disallowance of this type occur, investors would be hesitant to consider PGE because of the increased investment risk.

Q. Do Mr. Schoenbeck's and CUB's claims have any merit?

A. No. In carrying out its hedging strategy, PGE developed and then operated within sound hedging guidelines that were in place before the hedges in question were executed. These guidelines are part of PGE's comprehensive approach to risk management. PGE's hedging strategy and implementation have been presented at various times to the Commission, Commission Staff, and PGE stakeholders. As described more fully in the testimony of Jim Lobdell and Darrington Outama (PGE Exhibit 400), PGE has kept the Commission and stakeholders apprised of PGE's ongoing power cost expectations and risk management activities through PGE's quarterly power supply update meetings, regulatory filings, and the IRP process.

Q. Are there any other outstanding issues?

A. No. The parties have agreed in principle on resolution of all other issues, and are in the process of entering into a stipulation to be filed with the Commission.

Q. Can you briefly outline your testimony?

A. Yes. Our testimony will address the following key points in support of our hedging activities:

- Hedging reduces volatility; it is not possible to hedge to reduce expected costs.
- PGE's hedging activities are a response to customers' preference for stable rate levels.
- Perfect hindsight is not a valid perspective from which to evaluate the efficacy of a hedging strategy.

- A disallowance based on Mr. Schoenbeck's and CUB's recommendations would signal the investment community that regulatory risk is high and unpredictable in Oregon, and would have deleterious consequences for PGE's financial condition.

Q. Is PGE providing additional testimony?

A. Yes. Our testimony is followed by two sets of testimony that respond to Mr. Schoenbeck and the CUB witnesses. First, Jim Lobdell, Vice President of Power Operations and Resource Strategy, and Darrington Outama, from PGE's Power Operations Group, provide a detailed account of, and explain the rationale for, PGE's hedging activities during the period in question. Second, Robert Stoddard of Charles River Associates provides an independent assessment of PGE's hedging activities and a critique of Mr. Schoenbeck's and CUB's contentions.

II. Issues

A. PGE Hedges to Reduce Volatility.

Q. The outstanding issue in this proceeding is PGE's hedging strategy, known internally as PGE's mid-term strategy (MTS). Why does PGE hedge?

A. PGE hedges to reduce the volatility of price changes when it purchases over time in the wholesale gas and electricity markets. This hedging then reduces the volatility of retail price changes for our customers. Our effort to reduce exposure to volatility is effected through our mid-term strategy. In their testimony, Mr. Lobdell and Mr. Outama discuss the details of our mid-term strategy, which exists to reduce the expected volatility in our power costs.

Q. Why did PGE decide to reduce its exposure to wholesale price volatility?

A. PGE decided to reduce its exposure for two reasons. First, PGE is a "short" utility – its retail load significantly exceeds its long-term resources (owned and contractual). The scale of PGE's short position is unique among Northwest electric utilities. Because of PGE's larger resource gap, we are far more exposed to price fluctuations in the wholesale power markets than other electric utilities. Jim Lobdell and Darrington Outama provide a comparison of PGE's short position with those of other Northwest utilities in Section II of their testimony. Second, we have heard from customers, both directly and through surveys, that they value retail price stability. PGE developed the mid-term strategy to provide customers the stability they desired by reducing their exposure to the wholesale market.

1. PGE is a short utility.

Q. What do you mean when you say that PGE is a short utility?

A. As we noted above, PGE's long-term generation capacity falls short of its load and PGE must meet a significant proportion of its load through power purchases in the wholesale market. Consequently, PGE and our customers are exposed to price risk in the wholesale power market. In addition, PGE makes forward purchases of gas to fuel its combined cycle gas plants that are used to cover "baseload" requirements. So PGE also faces price risk in the wholesale gas market.

Q. How does PGE reduce its exposure to price risk?

A. For the most part, PGE hedges its price risk by either entering into fixed-for-floating financial swaps or (less frequently) by purchasing physical forward contracts (that deliver actual gas or power). In either case, the contract fixes the effective price that PGE pays. A change in the market value of the swap contract moves in a direction opposite to the change in the value of PGE's short position, resulting in a "hedged price" and a reduction in the price volatility that PGE customers face. It is important to remember that the hedging effect is symmetric; the change in the value of PGE's short position (in either direction) is offset by an opposite move in the hedging contract's value. Focusing only on the "gains" or "losses" on the hedging contract (as Mr. Schoenbeck and CUB do) misses the actual goal of the hedge, which is to offset movements in the short position with opposing changes in the value of the contract. The objective of hedging is to provide rate stability, not to realize gains on the hedging contract.

Q. Should PGE's customers expect hedging to result in lower rates?

A. No. Hedging transactions are typically spread out over a period of time and the average price realized through hedging will depend on the evolution of prices over time. The final average price may be higher or lower than an "un-hedged" price. But again, the objective is a more stable average price, not the lowest average price (which can only be determined in hindsight).

Q. What should customers expect from PGE's hedging practices?

A. They should expect more stable rates, which in fact has occurred (see Table 1 in PGE Exhibit 400).

2. Customers desire rate stability.

Q. How does PGE know that customers desire rate stability?

A. We have heard from customers that they value retail price stability. For example, PGE officers have met semi-annually with our largest customers since 2005 and have frequently discussed the importance of price stability. Since we had heard this directly from one group of customers, we decided to survey our customers more generally.

Q. Please describe the customer survey.

A. As part of the preparation for PGE's 2007 IRP, PGE conducted a customer survey in early 2006. The questionnaire asked customers if they favored giving up some potential gains through lower prices in exchange for more predictable prices (See PGE Exhibit 301).

Q. How did customers respond?

A. Responses were grouped by customer classification: residential, general business and key business. In every customer group, 50% or more of the respondents expressed a preference for predictable price increases.

Q. Why does hedging make sense for customers?

A. As a general matter, customers value, and the Commission works to achieve, rates that are relatively stable over time with predictable movement. Customers typically prefer a series of small increases, anticipating higher costs over time, rather than a large one-time increase. Many consumption decisions relate to equipment or processes that are hard to adjust immediately but that a customer can modify if given time to do so. For example, consider a large business customer with significant capital investment in equipment and complex manufacturing processes. This customer may be able to reduce its energy consumption over time through changes to equipment, processes, or both, but it probably cannot make such changes quickly in response to a one-time large increase in the cost of electricity. Spreading such an increase over time in rates that anticipate the higher costs that are coming allows customers to make orderly equipment and process changes. This also allows the customer to predictably incorporate changes in electricity prices into its own cost structure and reflect the resulting changes in electricity costs in the pricing of its final product.

3. The outcomes from PGE's hedging performance should not be adjusted in hindsight.

Q. How should the Commission evaluate PGE's hedging performance?

A. Actual hedging practice always proceeds without knowledge of how prices will change in the future. Thus, the Commission should avoid hindsight adjustments and instead evaluate PGE's hedging performance by asking:

- Did PGE have a sound hedging policy in place in advance of when the transactions took place?
- Were PGE's hedging transactions consistent with this policy?
- Did PGE adequately communicate its hedging policy, seek consensus, and provide updates on market and hedging outcomes?

As demonstrated by Mssrs. Lobdell and Outama, the answer to each question is "Yes."

Q. Will the investment community view the disallowance proposed by Mr. Schoenbeck and CUB as a "hindsight" adjustment?

A. Yes. The adjustment was not proposed when the policy was presented to the Commission or when the policy was executed, but only after the hedges were out-of-the money.

Q. What is wrong with the type of "hindsight" adjustment that Mr. Schoenbeck and CUB propose?

A. After the fact, it is always possible to describe an alternative set of transactions that would have resulted in a lower average price. This type of exercise completely misses the purpose of hedging, which is to provide stable rates, not lower average rates.

Q. Would PGE's willingness to hedge customers' price risk be affected by a disallowance of this magnitude?

A. Yes. PGE would be reluctant to hedge on behalf of our customers as we currently do in our mid-term strategy, which would lead to more volatility in customer rates.

B. Financial impacts from a disallowance.

Q. You stated that, if Mr. Schoenbeck's proposal is implemented, you expect a negative impact on PGE's position in the financial markets. What are these impacts?

A. There would be both direct and indirect impacts. Direct impacts would occur through the deterioration in PGE's financial condition. We would expect a decline in PGE's stock price, a general loss in investor confidence, and significant concern from rating agencies. We discuss below how Moody's factors a utility's regulatory framework and cost recovery prospects into its calculation of a utility's credit rating.

Indirect effects would also be significant, including higher collateral costs for our trading activities, a possible decline in Oregon's regulatory climate, and resulting impacts on other Oregon utilities that hedge some of their power purchases.

1. Impacts on PGE's financials.

Q. How could PGE's financial condition be weakened by Mr. Schoenbeck's proposal?

A. Since we cannot match the proposed reductions in revenue requirements with reductions in costs, our earnings will be reduced below authorized levels and our balance sheet would suffer. We estimate that ICNU's proposal would reduce our 2011 ROE by approximately [redacted]

Q. Why is a healthy financial statement important for a regulated utility?

A. It is important because it has a direct impact on our financing costs. The utility sector has the highest investment intensity of any sector. Relative to most industries, electric utilities are very dependent on external sources of financing for capital investments. Weaker financial statements increase our financing costs and impact access to capital from both the equity and bond markets.

2. Impact on PGE's cost of funds.

Q. How does PGE expect the financial markets to react to a disallowance of the magnitude proposed by Mr. Schoenbeck?

A large disallowance based on a hindsight review could be interpreted as a signal that prudently incurred costs are at risk and that PGE's "regulatory climate" has deteriorated. A decline in the regulatory climate increases shareholders' perceived risk and would increase PGE's cost to access funds through the issuance of stock. The regulatory climate that a utility faces is also a key variable influencing utility bond ratings.[1] Our bond rating, in turn, affects our borrowing costs.

[1]Pinches, Singleton, Jahankhani, "Fixed Coverage as a Determinant of Electric Utility Bond Ratings", *Financial Management*, 1978.

Q. Have rating agencies indicated how hindsight disallowances influence their credit analysis?

A. Yes. Moody's approach to assigning credit ratings to utilities is representative of the factors considered. Moody's considers four factors:

1. Regulatory Framework.
2. Ability to Recover Costs and Earn Returns.
3. Diversification.
4. Financial Strength and Liquidity.

In its August 9, 2009, *Rating Methodology* report, under "Regulatory Framework", Moody's considers the regulator's ability to "approve fuel and purchased power recovery"[2]. Under "Ability to Recover Costs and Earn Returns", Moody's states that "The ability to recover prudently incurred costs in a timely manner is perhaps the most important credit consideration for regulated utilities."[3] PGE Exhibit 302 is the full rating methodology report.

Q. Have your personal discussions with ratings agencies confirmed the link between regulatory climate and bond ratings?

A. Yes. The importance of regulatory climate is a topic in all of our discussions with ratings agencies and is always a major theme in their annual reviews.

3. Indirect effects.

Q. What are the indirect effects of Mr. Schoenbeck's proposed disallowances?

A. Our ability and cost to access wholesale energy markets are a function of our financial condition and resulting bond ratings. If our unsecured bond ratings were to slip, our market

[2] Moody's Investors Service, *Ratings Methodology: Regulated Electric and Gas Utilities*, p. 6, August 2009.
[3] Moody's Investors Service, *Ratings Methodology: Regulated Electric and Gas Utilities*, p. 7, August 2009.

access would be reduced and customer rates would reflect the cost of higher wholesale prices. In addition, we are required to post collateral when we transact in wholesale power markets. A reduction in our credit rating would increase collateral costs, resulting in higher costs to customers.

Q. You mentioned earlier that acceptance of Mr. Schoenbeck's proposal would have a substantial effect on PGE's 2011 financial results. Please explain.

A. Standard GAAP accounting requires that hedging transactions be included on a company's balance sheet at their market value rather than at cost, with changes in their market value recorded in earnings. In accordance with ASC 980 (formerly FAS 71), we are allowed to defer the fluctuations in value due to market movements until the settlement period only to the extent that our regulatory body (OPUC) provides recovery at cost. If such recovery is no longer highly probable, we must reflect the loss in value (including changes in value in subsequent periods) through a charge against earnings in the current or future periods.

Q. What would be the overall impact of adopting ICNU's or CUB's proposal?

A. The overall impact would be harmful to PGE and our customers. First, PGE would have to curtail much, if not all, of its hedging activity on behalf of its customers. Customers would then be exposed to greater price volatility risk over time. Second, PGE's financial position would be significantly weakened. In the next several years, we anticipate issuing significant amounts of equity and debt as well as a new revolving credit facility of up to [redacted] to fund needed investment. In anticipation of our need to access equity and debt markets, we have placed a high priority on strong fiscal management. Keeping healthy financial conditions and maintaining investment-grade credit ratings are essential to accessing debt and equity markets on reasonable and competitive terms. Adopting Mr. Schoenbeck's proposal would undermine our efforts to build a utility that can deliver safe, reliable, and reasonably priced power and secure necessary energy supplies at this critical time. Because CUB seeks to disallow transactions beyond a 36 month tenor (as compared to Schoenbeck's suggestion to disallow transactions beyond 48 months) CUB's proposal would have an even more harmful effect on PGE and our customers.

No business – and no utility – can continue to attract investment and maintain strong credit ratings if it is not allowed to recover its prudently incurred costs. If PGE is not allowed the opportunity to recover prudent costs of providing hedging service to its customers, the welfare of its customers will be impaired.

III. Conclusions

Q. Please summarize the effects of ICNU's and CUB's proposals on customers and PGE.

A. Both customers and utility investors have a stake in the resolution of this issue. Customers value price stability, and PGE acts in its customers' interests when it hedges power costs. A disallowance of the magnitude proposed by Mr. Schoenbeck, and the resulting regulatory uncertainty, would preclude PGE from acting on behalf of its customers with regard to price stability in the future.

All investors, debt or equity, focus on the regulatory environment of the company in which they are investing. Regulatory decisions that are understandable and fair decrease perceived investment risk. Regulatory decisions that rely on *ad hoc* hindsight reviews and put prudently-incurred costs at risk, elevate investors' perception of risk. Decreased risk increases the availability of capital and decreases its cost, while increased risk has the opposite effect. Thus, ICNU's and CUB's proposals would affect both investors and customers over time.

Q. If the Commission has concerns regarding PGE's hedging activities, what do you recommend?

A. The Commission's concerns should be addressed on a going forward basis. PGE is willing to adjust its hedging policy for the future if the Commission determines that a change is desirable. A collaborative process to discuss appropriate changes to PGE's hedging policy guidelines might be an effective way to deal with the Commission's concerns.

IV. Qualifications

Q. Ms. Pope, please describe your educational background and experience?

A. I received my Bachelor of Arts degree from Georgetown University in 1987 and my Master's degree in Business Administration from the Stanford University Graduate School of Business in 1992. I was named Senior Vice President, Chief Financial Officer and Treasurer for PGE in January 2009. From January 2006 through December 2008, I served on the PGE Board of Directors. Previous to January 2009, I served as Vice President, Chief Financial Officer at Mentor Graphics Corp., an Oregon-based software company, where I was responsible for multiple departments including financial affairs, corporate development and operations. Before I joined Mentor Graphics in 2007, I served for 12 years in a variety of capacities at Pope & Talbot, Inc., and worked previously at Morgan Stanley & Co., Inc.

Q. Mr. Valach, please state your educational background and experience.

A. I received a Bachelor of Science degree in Business Administration from the University of Montana in 1979. I received a Masters in Business Administration from the University of Oregon in 1986 with an emphasis in Finance. I joined PGE in 1991 as a Business Analyst and was Manager of Corporate Finance and Assistant Treasurer from July 1997 to September 2005 and from August 1, 2009 to February 4, 2010. Since fall of 2005, I have also held the title of Director of Investor Relations.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	Customer Survey
302	Moody's Rating Methodology

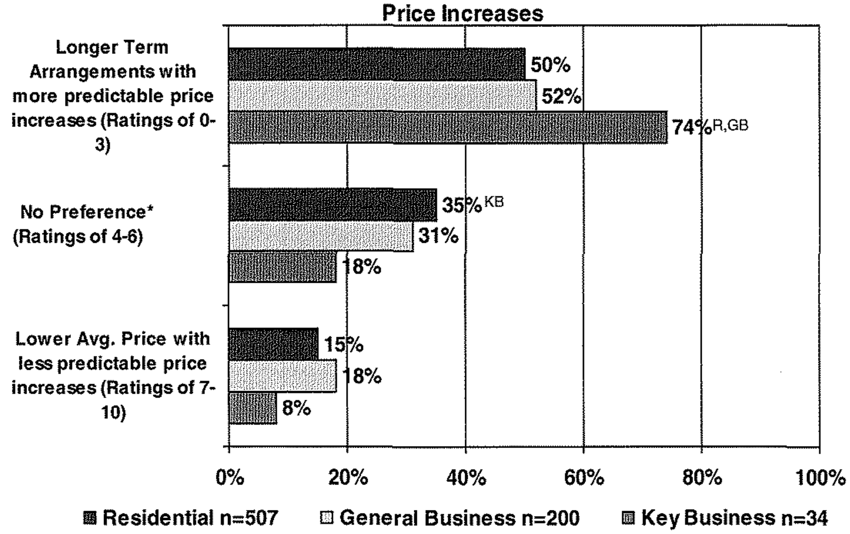
Exhibit 301

Customer Survey

Momentum Market Intelligence Predictive Insight

Customers overwhelmingly prefer that PGE pursue longer-term arrangements that focus on making price increases small and predictable, as opposed to pursuing resources that may be lower in average price, but with less predictable fluctuations

Preference for Lower Average Prices / Less Predictable Price Increases Vs. Longer Term Arangments / Small, Predictable Price Increases



- Key business customers express an even stronger preference for long-term arrangements than other PGE segments.

*While "No Preference" was not a point specifically identified on the rating scale, ratings of 4-6 do not indicate a clear preference for one of the two courses of action

Q38c. PGE could guarantee access to electricity supply resources with long-term arrangements that would mean "locking in" small (2-4%), predictable, annual price increases. Alternatively, PGE could access electricity supply resources that might have prices that fluctuate more as market conditions change. With these arrangements, price increases should be lower on average, but would be less predictable, both in terms of how often they occurred and how large they were. In general, would you prefer that PGE pursue longer-term arrangements that focused on making any price increases small and predictable, or pursuing resources that should have lower prices on average, but with price increases that are less predictable? 0=Longer term resource arrangements with small, predictable price increases; 10=Resources with less predictable price increases

R,GB,KB indicates a statistically significant difference between customer segments (R=Residential, B= General Business, KB = Key Business)

Exhibit 302

Moody's Rating Methodology

www.moodys.com

Rating Methodology

Moody's Global
Infrastructure Finance

August 2009

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(Continued on back page)

Regulated Electric and Gas Utilities

Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Moody's Investors Service

Regulated Electric and Gas Utilities

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

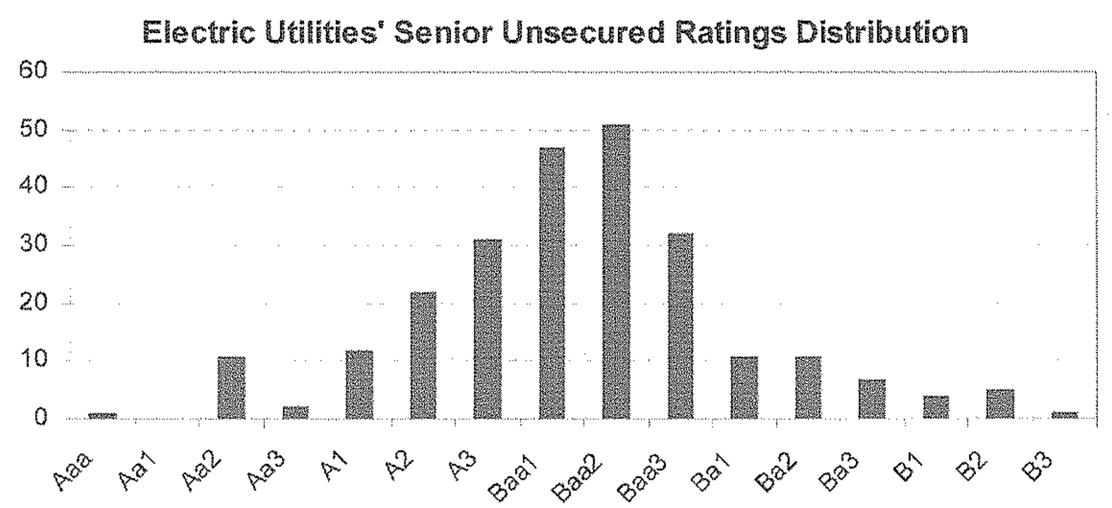
In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

About the Rated Universe

The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility businesses[1]. In addition, this methodology includes both holding companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

1 These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

2 The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC - Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	**100%**		**100%**

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating	
Indicated Rating	**Aggregate Weighted Factor Score**
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

[3] For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

Rating Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

Unlike Factor 1, which considers the general regulatory framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

More typically, however, and as is characteristic of most utilities in the U.S., the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost recovery or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score of A for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa rating for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with several businesses with large market shares are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the "Sustainable Profitability" and "Regulatory Support" assessments in the previous LDC rating methodology. While LDCs' authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

Factor 2 – Ability to Recover Costs and Earn Returns (25%)

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, the key criterion we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, most of the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Regulated Electric and Gas Utilities

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation **0% weight for issuers that lack generation*

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

Measurement Criteria

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

CFO pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial and can affect the ability of a utility to cover its debt obligations. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a utility to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP - Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Regulated Electric and Gas Utilities

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation   **0% weight for issuers that lack generation*

Regulated Electric and Gas Utilities

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/ Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	Aa	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

Regulated Electric and Gas Utilities

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	Aa	A	A

Positive Outlier

Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework		
Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns		
Factor Weight		25%
	Current Rating/BCA	Rate Adjustment and Cost Recovery Mechanisms
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification				
Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	Aa
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Sub-Factor Weights	Current Rating/BCA	Indicated Factor 4 Rating	10% Liquidity	7.5% 3 Year Average CFO pre-WC + Interest/ Interest	7.5% 3 Year Average CFO pre-WC / Debt	7.5% 3 Year Average CFO pre-WC / Debt	7.5% 3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa*
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba*
Eesti Energia AS	A1/[8]	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	Aa	A	A

**Debt/RAV*

Positive Outlier
Negative Outlier

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

Regulated Electric and Gas Utilities

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, constrained capital market conditions could severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The degree of notching (or rating differential) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody's treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody's treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility's balance sheet. In looking at cash flow coverages, Moody's analysis focuses on ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility's flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover debt service and are made irrespective of whether the utility requires the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- <u>Risk management:</u> An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- <u>Pass-through capability:</u> Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- <u>Price considerations:</u> The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

[4] When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.

- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.

- Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.

- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]

- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.

- Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

5 See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
6 SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be the cost of capital of the utility.
- Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total debt obligations.
- Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Regulated Electric and Gas Utilities

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Moody's Investors Service

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PGE's Mid-Term Strategy

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Jim Lobdell
Darrington Outama

August 15, 2011

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Jim Lobdell. I am PGE's Vice President of Power Operations and Resource Strategy.

My name is Darrington ("Dee") Outama. I am a Project Manager in PGE's Structuring and Origination group.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold. First, we explain how we developed and implemented our hedging strategy. Second, we rebut the analyses and recommendations of Industrial Customers of Northwest Utilities (ICNU) witness Don Schoenbeck and Citizens' Utility Board (CUB) witnesses Bob Jenks and Gordon Feighner.

Q. What is your initial response to ICNU's and CUB's accusations?

A. These recommendations, based on hindsight, flawed analyses, and fundamental misunderstandings of the commodities markets, are nothing more than opportunistic attempts to deny PGE recovery of prudently incurred costs. PGE's hedging strategy, known as the "Mid-Term Strategy" ("MTS"), which has been in place since 2007, was developed with considerable thought and analysis, is prudent, and has been communicated to parties on numerous occasions prior to the current proceeding. We note that no party to this proceeding has previously filed testimony or comments questioning PGE's hedging strategy. Further, a number of transactions proposed for disallowance in the current proceeding have been approved in prior AUT or GRC proceedings.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have seven sections:

Section II:	PGE's Short Position;
Section III:	Evolution of the Mid-Term Strategy;
Section IV:	The Hedging Policy is Reasonably Detailed;
Section V:	PGE's Mid-Term Strategy is Not New;
Section VI:	Reply to Mr. Schoenbeck;
Section VII:	Conclusion; and,
Section VIII:	Qualifications.

II. PGE's Short Position

Q. What is the goal of PGE's power supply decisions?

A. For both long-term planning and shorter term day to day operation of our resources, we aim to supply our customers with the highest level of reliability at reasonable prices. In doing so, we must recognize that we have been a substantially short utility since the closure of Trojan in 1993. Our inherent short position is a major factor in how we manage PGE's power supply portfolio, including its risks.

Q. In addition to the loss of Trojan, are there other factors that PGE considers when managing its power supply portfolio?

A. Yes. We consider numerous factors but five of the most important are:

<u>i. Load growth and volatility</u>: Over the fifteen year period preceding the development of the MTS (i.e., 1990–2005), PGE experienced average annual load growth of just less than 1%.[1] However, during that same period, we experienced annual growth rates ranging from -4.4 percent (1998) to 10.4 percent (1999), including a recession in 2001 and 2002. PGE's expected long-term annual load growth, as indicated in the 2007 IRP, was 2.2%.[2]

<u>ii. Loss of generating resources</u>: In addition to the loss of Trojan in 1993, PGE closed its Bethel gas generating plant in 1998.

<u>iii. Expiration of contracts</u>: Historically, PGE's customers have benefited from relatively low-cost hydroelectric power from projects on the Mid-Columbia ("Mid-C") that PGE purchased under contract. These hydroelectric projects included Priest Rapids and Wanapum (operated by Grant County PUD), Rocky Reach (operated by Chelan County PUD), and Wells (operated by Douglas County PUD). These contracts made available to

[1] Based on FERC Form 1 data
[2] PGE 2007 Integrated Resource Plan, page 37

PGE a share of the output of each project for which PGE paid our share of the costs (operations and a share of debt service). The shares of power available had been stable under 50-year agreements reached in the late 1950s and 1960s, but those rights began to expire in 2005. As a result, PGE has significantly lost access to both the energy and capacity that these resources provided.

iv. Periods of increased volatility in power and gas markets: We address this issue in great detail later in Sections III and VI of our testimony.

v. Limited resource additions: Since the loss of Trojan, PGE has added three major generating resources: [3]

1. Coyote Springs I (began operations in 1995),
2. Port Westward (began operations in 2007), and
3. Biglow Canyon (Phase I began operations in 2007 with all three phases in operation in 2010).

Both Coyote Springs and Port Westward operate as baseload gas-fired plants, while Biglow Canyon is a wind farm.

Q. Is PGE in a similar position relative to other utilities with regard to meeting customer load on a forward-looking basis?

A. No. Other electric utilities, even those in relatively close geographic proximity, are very dissimilar with respect to the resources available to meet customer load. A quick review of utilities' load resource balances presented in their respective Integrated Resource Plans (IRPs) illustrates this point.

[3] Average energy figures for Coyote Springs, Port Westward, and Biglow Canyon are as forecasted in PGE's July 15, 2011, power cost update filing in this docket.

Both PGE's 2007 and 2009 IRPs indicate that PGE expected to have an energy shortfall relative to load of approximately 30 percent on a MWa basis at the beginning of the evaluation period (2012 and 2015, respectively). This shortfall is even larger when the gas needed to fuel PGE's baseload gas-fired generation is considered. By comparison, other utilities in the region forecast substantially smaller short positions on an energy basis, with both Avista and Idaho Power anticipating to be in long positions for the coming years.

Avista's 2009 Electric IRP indicates that the company was forecasting to be in an energy surplus position until 2018.[4]

PacifiCorp expected an energy surplus until 2015 (on an annual average basis) in their 2011 IRP.[5]

Idaho Power Company's 2011 IRP indicates that the company expects to have surplus energy, relative to load, on a MWa basis across the 20-year analysis period.

Each utility's portfolio composition should also be taken into account when assessing their risk profiles.

Q. How have these factors affected the management of PGE's power supply portfolio?

A. As we discuss further below, PGE's short position creates substantial exposure to fluctuations in both the gas and power markets, resulting in a significant potential for power cost volatility that translates into the potential for end-use customer rate volatility.

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[4] Avista Corporation 2009 Electric Integrated Resource Plan, page i
[5] PacifiCorp 2011 Integrated Resource Plan, page 4

III. Evolution of the Mid-Term Strategy

Q. What is PGE's "Mid-Term Strategy"?

A. PGE's Mid-Term Strategy ("MTS") is the hedging policy whereby PGE secures power and gas hedges in the market by layering-in transactions with maximum terms or tenors of 5 years in order to lower customers' rate volatility. This hedging policy governs our annual analysis, market assessment, and Risk Management Committee ("RMC") oversight that we describe in Section III(C).

Q. Why did PGE develop the MTS?

A. The Mid-Term Strategy evolved out of customers' desire for improved rate predictability. As we discuss further below, PGE achieves this goal by reducing exposure to the power and gas markets for the period between our short-term strategy (through 24 months) and when the IRP action plan takes effect (after 5 years). PGE developed the MTS in 2006. 2007 was the first year that transactions were executed under the strategy for the delivery years 2008–2012. The PGE personnel responsible for developing and implementing PGE's MTS are highly-skilled individuals, with many years of experience in the utility industry, and the gas and power markets. The qualifications of some of these individuals are provided as PGE Exhibit 401.

Q. What evidence is there that customers desired rate stability?

A. PGE has heard from numerous customers, both directly and indirectly, that they value retail price stability. In order to verify this on a broader level, a customer survey was performed in preparation for PGE's 2007 IRP (Docket No. LC 43). One question in that survey asked customers to choose between electricity supply resources that could provide "small, predictable, annual price increases" or resources that would result in smaller, but less predictable, price increases. The survey results indicated that customers "overwhelmingly" preferred the option delivering small, more predictable, price increases rather than the lower average price.[6]

Mr. Schoenbeck agrees with PGE's findings that customers desire rate stability, "I would say most people, as a general rule, like more stable rates, predictable, but that always comes at a price" (Deposition of Donald W. Schoenbeck, pages 126, lines 6–8, included as PGE Exhibit 402, page 16).

Please also see PGE Exhibit 300, beginning at page 6, as well as PGE Exhibit 500, page 5, for additional discussion regarding customers' desire for rate stability.

Q. What is the goal of PGE's MTS?

A. The goal of the MTS is to reduce the <u>volatility</u> of customers' retail rates by reducing PGE's net open position ("NOP") for power and gas.

Q. What drives the net variable power cost ("NVPC") volatility to which customers are exposed?

A. There are two main drivers that determine the magnitude of PGE's customers' exposure to power cost volatility: first, the volatility of power and gas prices themselves, and second, size of the net open position. Of these two risks, PGE can only influence the size of the NOP.

Q. Please briefly explain what you mean by "net open position".

A. The net open position is the difference between PGE's needs and its resources, both owned and contracted. We explain this in greater detail below.

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[6] "Integrated Resource Plan Research – Relevant Insights from Residential, General Business, & Key Business Customers", February 2006, slide 69. Also see PGE 2007 Integrated Resource Plan, June 29, 2007. Pages 135–144 and Appendix F.

Q. How does PGE reduce NVPC volatility?

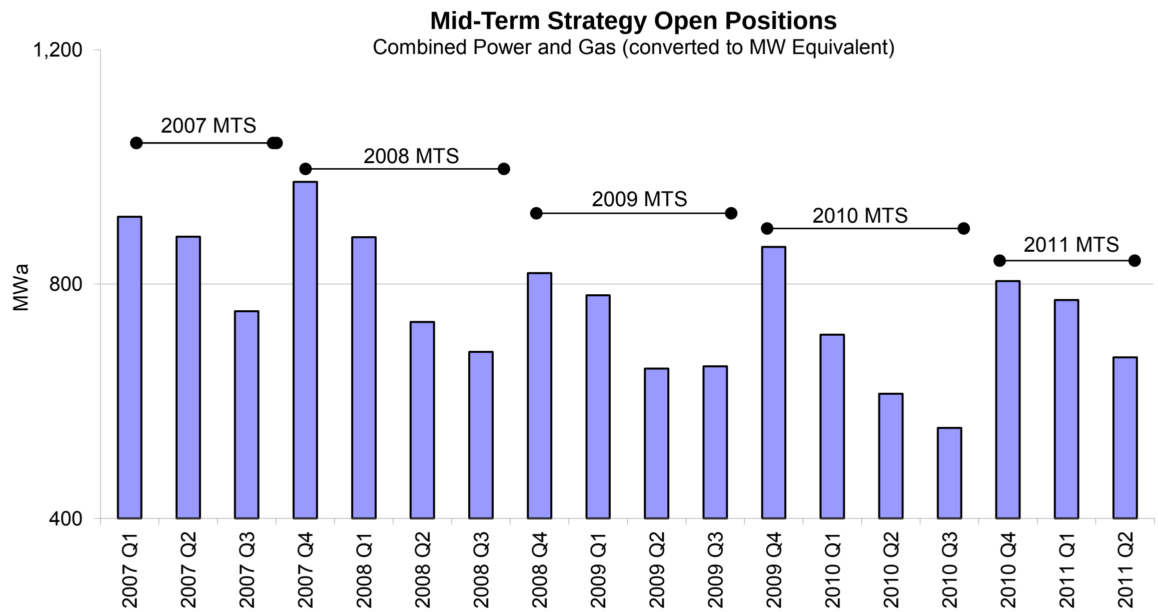
A. PGE achieves the goal of reduced NVPC volatility through the MTS, which strategically reduces PGE's NOP over the MTS window.

Q. Has the MTS reduced PGE's net open position?

A. Yes. Figure 1 below depicts the reduction in PGE's combined power and gas net open position through the MTS. The first three bars are the open positions at the close of each of the applicable three quarters of the 2007 MTS purchasing period. The 2007 MTS addressed the average NOP for the delivery years 2008 through 2012. The x-axis is the quarter end date at which the NOP was measured. The downward trend of the first three bars reflects the execution of transactions in the 2007 MTS purchasing period (for delivery in 2008-2012).

The increase in the fourth bar is the transition from the 2007 MTS to the 2008 MTS, which rolls off delivery year 2008 and rolls on delivery year 2013 (whose individual NOP is high). The fifth, sixth, and seventh bars reflect the reduction in NOP resulting from the execution of deals for the 2009 through 2013 tenor in the 2008 MTS.

The subsequent bars are the progressive reductions in NOP for the MTS years 2009, 2010, and 2011.



Q. Why does the MTS consider PGE's NOP out to 60 months?

A. PGE established a 60 month timeframe for the MTS in order to bridge the gap between PGE's short-term and long-term portfolio management strategies, creating one framework with which to manage customers' exposure to the price risk in the forward commodity markets. PGE identified this gap as a factor contributing to rate volatility that PGE could manage on behalf of customers. The short-term strategy executed transactions with tenors of up to 24 months and existed prior to the MTS. The long-term portfolio management strategy is addressed in the IRP planning process, which looks out beyond 5 years. Thus, the 3–5 year period was essentially uncovered prior to the MTS.

Q. Could PGE have implemented the MTS sooner?

A. No, not as effectively, because the relevant markets were not fully developed. The 2001–2002 energy crisis was followed closely by the bankruptcy of several major energy marketers. These events hurt the overall growth and liquidity in the market place. In 2005, commodities markets were subject to fundamental supply disruptions resulting from hurricanes Katrina and Rita. However, by 2006, new market entrants with stronger balance sheets and sophisticated risk management tools had entered the market, providing the liquidity necessary for PGE to contemplate the implementation of the MTS. Thus, by 2006 the markets were sufficiently developed for PGE to implement the MTS.

Q. Please explain how the MTS targets are determined.

A. We update the MTS targets annually. The annual update has 3 steps: 1) Analysis, 2) Market Assessment, and 3) Risk Management Committee presentation and approval.

A. Analysis

Q. Please describe the analysis that PGE performs annually for the MTS.

A. As part of the annual update, PGE's Risk Management team compiles and models the 5 year NVPC for customers. This model starts with a 5-year MONET power cost forecast that is populated with PGE's generation assets, both owned and contracted. We then dispatch this portfolio against power and gas prices that have been subjected to volatility using a stochastic approach to price simulations.

Q. What is a "net open position" for the purposes of managing PGE's portfolio of assets?

A. As we mentioned previously, the net open position is the difference between PGE's needs and its resources, both owned and contracted. <u>For purposes of the MTS, PGE simultaneously manages the cumulative NOP of two commodities: power and gas</u>.

The <u>power NOP</u> is calculated as load, less (Dispatched Generation Assets + Contracts). A "short" power NOP is when load exceeds the sum of Dispatched Generation Assets and Contracts, and a "long" power NOP is when load is less than the sum of Dispatched Generation Assets and Contracts.

The gas NOP is calculated as the energy-equivalent of the fuel requirements of Port Westward and Coyote Springs, less the fuel already under contract at the time of the calculation. A "short" gas NOP is when the gas requirement exceeds the gas contracted for, and a "long" gas NOP is when the gas requirement is less than the gas contracted for.

Q. Is PGE short for both power and gas?

A. Yes. For the MTS window, PGE is short for both power and gas. Even after procuring for all of PGE's expected gas need, customers will still be exposed to a short power position.

For example, at the outset of the 2007 MTS, the average combined power and gas NOP for the 5-year delivery period of 2008 through 2012 was 915 MWa (as illustrated in Figure 1 above). Said differently, on average, for every hour during the delivery window of 2008-2012, 915 MW (out of an approximate average load of 2,400 MW) of customers' rates was exposed to the volatility of commodities markets. More specifically, of this 915 MWa, approximately 441 MWa was exposed to the gas commodity and the remaining 474 MWa was exposed to power. These risks are additive since even if PGE was to procure all of its gas need, which would address the 441 MWa short position, it would still be exposed to the power need of 474 MWa.

Q. Does being short create a specific risk profile?

A. Yes. Being short vis-à-vis the market carries a specific risk profile. Short means that the owner of that position will be hurt if prices go up and will benefit if prices go down, while the owner of a "long" position would have the opposite risk profile. An owner of a "flat" position would no longer be exposed to price movement either up or down.

Q. Does PGE execute transactions for both power and gas?

A. Yes. Because PGE is short both gas and power, PGE at times executes power simultaneously with gas. In addition, PGE considers several factors in deciding which commodities to purchase, including: liquidity, market opportunities, credit availability, and collateral. PGE's Power Operations personnel will transact for either commodity as opportunities arise.

Q. What factors determine PGE's natural gas exposure for purposes of the MTS?

A. The economic dispatch profiles for Coyote Springs and Port Westward determine PGE's natural gas exposure. This exposure is reduced by the Fixed-For-Float Swaps contracted through the analysis date.[7] The resulting shortfall or excess is the gas NOP. Combined, Coyote Springs and Port Westward have the capability to generate 685 MW (nameplate). PGE is, therefore, exposed to gas volatility via our thermal resources for up to 685 MWa energy equivalent (actual expected dispatch is less than this maximum capacity). In other words, PGE can hedge up to 685 MW of power exposure via our thermal resources using natural gas. This short gas position is in addition to the power NOP relative to load described above.

Q. Why is the Beaver generating unit not considered in the gas NOP?

A. Beaver is not considered in the MTS because it is a peaking unit, rather than a baseload unit, due to its relatively high Heat Rate ("HR" – a measure of thermal efficiency). Plant dispatch is determined on an economic basis; when the cost of generation (heat rate multiplied by the price of gas plus the variable operations and maintenance costs) is less than the market price of power, the plant is dispatched. Forward gas prices are generally too expensive for Beaver

[7] Fixed-for-Float Swaps are financial instruments whereby the buyer pays a fixed price and receives the float (index) for a specific product for a specific duration. PGE enters into financial fixed-for-float swap contracts in order to set the future price of gas and power, which ultimately reduces the volatility in power costs that customers experience.

to dispatch and generate a positive margin relative to forward power prices. Beaver is, however, typically dispatched during the Heavy Load Hours (On-Peak) in the summer months of July, August, and September.

In addition, Beaver's ability to dispatch in order to meet intraday load excursions means that short-term gas procurement is more appropriate. For purposes of the MTS, Beaver's output is considered to be zero, and PGE does not make any mid-term gas purchases for the plant.

Q. Is gas more efficient at hedging the NVPC volatility exposure than power?

A. Yes. Gas is the more efficient hedge of NVPC volatility due to PGE's high efficiency gas-fired resources, Port Westward and Coyote Springs. For PGE's portfolio, expected gas need is the direct result of comparing the cost of gas-fired generation against the market cost of power. Embedded in this gas requirement is the determination that it is more efficient to purchase gas up to this volume than it is to purchase power. For example, assuming Port Westward's fully-loaded HR is 7 MMBtu per MWh, if the price of power is $50 per MWh and the price of natural gas is $5 per MMBtu, then the alternatives to meet one MW of load are either to buy power at $50 or to generate power for $35 ($5 per MMBtu X 7MMBtu per MWh). PGE can, therefore, buy down the same amount of risk (in MW terms) with $35 per MWh worth of gas or $50 per MWh worth of power. In this example specifically, and this is the case for the calculated gas NOP, buying gas to fill the NOP is a more efficient way to hedge the NVPC volatility.

Q. Earlier you mentioned that volatility influences risk. How does PGE measure the market volatility for gas and power?

A. For the MTS analysis, PGE's Risk Management department uses published volatilities from the IntercontinentalExchange (ICE) for power and gas options. The volatilities are verified using Black-Scholes option pricing theory-based models.

Q. Are any other inputs required for this modeling?

A. Yes. PGE also calculates the historical correlation between the two commodities at the locations that customers are most exposed to: the Mid-C power market and the Sumas and AECO gas markets. Correlation is the mathematical measurement of each commodity's relationship to the other as they are settled daily. This measurement will ultimately bound the commodities' simulations. For example, power and gas are highly correlated, which means that for a simulation in which gas prices are higher than the expected forward curve, power will more than likely have that same relationship within that specific iteration.

Q. How do the volatilities and correlations for gas and power translate into customer NVPC volatility?

A. The volatility and correlation data are used as inputs to a financial model that stochastically simulates the power and gas prices. The 5-year NVPC is subjected to 1,000 iterations of various power and gas prices. Within each iteration, a NOP is calculated with the proper dispatch of Port Westward and Coyote, given the simulated gas and power prices. The NOP is then "closed" or "flattened" by either buying or selling at the simulated commodity prices. For example, if the August monthly On-Peak price for power is greater than the dispatch cost in that month (for example, [Sumas gas prices X Port Westward heat rate] + [variable operation and maintenance costs]), then the model would "dispatch" the plant. The resulting power generated can either be consumed for load purposes or sold at the market price, if in excess of load. The gas need in excess of what has already been procured will be deemed to be purchased at the simulated price curves.

The model would then aggregate all the costs and revenues associated with the purchases and sales as well as the other components of NVPC to calculate the total NVPC for that iteration. The result is 1,000 NVPCs for each year representing the potential outcomes for customers given the portfolio NOP, and the correlation and volatility of power and gas.

Q. How are the data organized?

A. Once the model is run with the portfolio of resources and existing contracts for the 1,000 iterations, 10 more scenarios with varying degrees of purchases are generated. Each scenario represents incremental purchases of 10 percent of the NOP. With 1,000 iterations for each of these 10 scenarios, PGE can observe the "tightening" of the distribution of possible NVPC. The higher the percentage of assumed purchases (smaller NOP), the "tighter" the distribution of NVPC is around the mean expected value. A tighter distribution of NVPC signifies lower expected portfolio volatility. The data are compiled as a 5-year aggregate set of results as well as each individual year.

Q. What statistical measurement does PGE use to measure portfolio volatility?

A. PGE uses the percentage of the variation from the mean NVPC at 2 standard deviations, or a 95 percent confidence level, to measure the portfolio volatility.

B. Market Assessment

Q. What is the next step after the analysis is completed?

A. Along with analyzing the data, PGE's Power Operations group performs a market assessment before making a recommendation to the Risk Management Committee. This assessment considers several aspects, including:

- Market liquidity – must be sufficient in order to implement the strategy;
- Structural market changes – would make us recommend a slow down or acceleration of the purchase strategy; and,
- Availability of credit facilities – to weather the potential demand of margining calls.

Once we have considered these factors, Power Operations and Risk Management will proceed with recommending a target for procurement.

Q. Does PGE always set a 60-month window for its MTS?

A. No. The 60-month window is subject to change as market conditions change. As part of the implementation of the MTS, PGE's Power Operations personnel assess the liquidity in the market place. If there is enough liquidity to execute the strategy over the full 60 months, they will be allowed to transact for that entire period. However, because a significant segment of commodities trading is comprised of financial institutions, we have seen liquidity decline as a result of the recent financial crisis. PGE is currently hedging on behalf of customers through 2015, with Power Operations personnel regularly assessing 2016 for liquidity.

C. Risk Management Committee Presentation and Approval

Q. What is the role of the Risk Management Committee?

A. The Risk Management Committee makes recommendations to the Board of Directors on risk limits and provides oversight of the adequacy and effectiveness of the corporate policies, guidelines, and procedures for market and credit risk management relating to PGE's energy portfolio management activities.

Q. Who are the members of the Risk Management Committee?

A. PGE's Chief Executive Officer (CEO), Chief Financial Officer (CFO), the Vice President(s) with responsibility for power supply, and the individual responsible for Risk Management – Power Supply are the standing members of the committee.

The CEO chairs the committee and may add members at his or her discretion. As of July 2011, the additional members are the Vice President Customers & Economic Development, Director Regulatory Policy & Affairs, and an Assistant General Counsel.

Q. What policy provides guidance to the Risk Management Committee?

A. The Risk Management Committee operates pursuant to the guidance provided within PGE's Energy Risk Management Policies & Procedures (ERMP&P). Among many other factors, the ERMP&P dictates the risk limits, which include the time period within which the MTS transactions are to be executed, and the procedures for transaction approval.

Q. How does the Risk Management Committee set the target purchase level?

A. If the market assessment allows for implementation of a 5-year strategy, Risk Management, in conjunction with the Power Operations group, must address the following considerations:

- The level of purchases to best achieve the desired reduction in NVPC volatility;

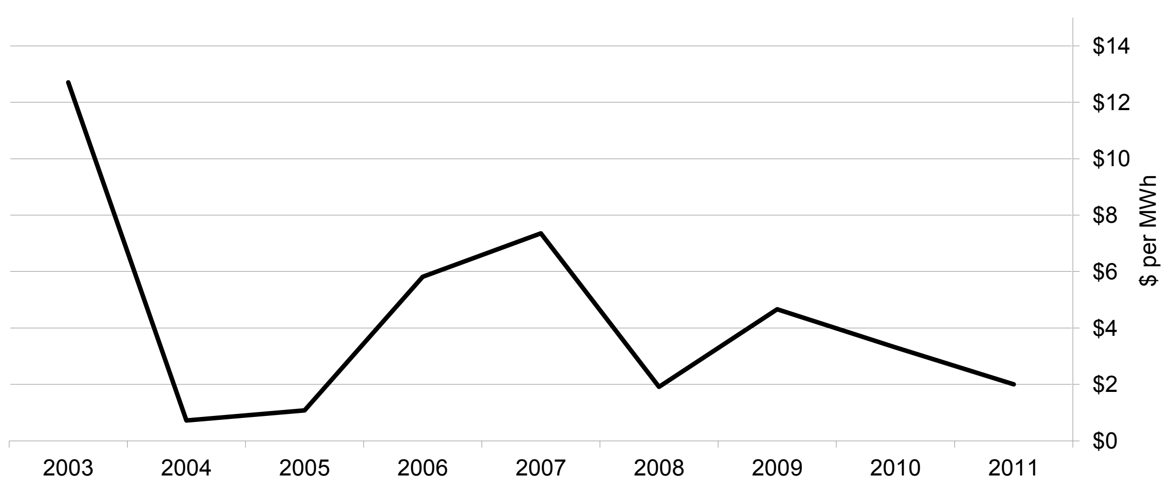
- The assessment of results as either linear or presenting an optimal point of inflection for a given level of purchases; and
- The presence of opportunities to "lock in" a year-over-year decrease in the 5-year string of NVPC.

The results of this process help guide the recommended target purchase level. The team presents the findings to the Risk Management Committee, which must approve that year's target.

Q. Has the MTS achieved the stated goal?

A. Yes. Figure 2 below compares the year-over-year change in final $ per MWh included in rates before and after the MTS implementation. Prior to MTS implementation, customers experienced rate variations of approximately $13, $1, $1, $5, $7, and $2 per MWh respectively from 2002 to 2008. NVPC varied widely, with an average year-over-year change of $5 per MWh and a range of $12 per MWh. After the Mid-Term Strategy was implemented, year-over-year changes were $4, $3 and $2 per MWh respectively from 2009 to 2011. The tighter distribution is partly due to the implementation of the MTS.

NVPC Year-over-Year Change



Q. Can you demonstrate volatility reduction in another way?

A. Yes. Because volatility of NVPC is also measured prospectively, PGE performs the same volatility analysis annually, and as such, each update informs us as to how the newly hedged portfolio behaves under the forward price scenarios. Table 1 below shows the portfolio volatility over time. The higher the percentage, the more volatile the portfolio is. The expected portfolio volatility has generally decreased over time as the MTS was implemented.

Table 1

MTS	Window	2std Dev Up
2007	08-12	6.57%
2008	09-13	7.77%
2009	10-14	7.17%
2010	11-14	5.09%
2011	12-15	3.93%

IV. The Hedging Policy is Reasonably Detailed

Q. What is the purpose of a policy?

A. A policy is intended to provide general guidelines for the effective and efficient achievement of business objectives. It should leave room for managers to make reasonable judgments regarding the varying business events they manage.

When policy guidelines become outdated (i.e., they do not readily apply to new business events) or become less effective (i.e., managers start making judgments that are deemed to fall outside a "reasonable interpretation" of the guidelines) then the policy can be modified to make it more flexible or more prescriptive.

Q. Does PGE's hedging policy achieve this goal?

A. Yes. The hedging policy provides clear direction to the operating departments regarding the objectives to be achieved.

Q. Please explain how the hedging policy provides clear direction.

A. On an operational basis, the PGE Power Operations and Risk Management Reporting & Control departments work to achieve the objectives by performing analyses to determine the annual MTS acquisition target, executing the necessary transactions, and ensuring that the transactions are executed in accordance with the policy.

The Risk Management Committee provides senior management oversight to ensure the annual MTS acquisition target is prepared in accordance with the policy and ensures the subsequently executed transactions are consistent with the policy.

In summary, PGE has a clear hedging policy, which is implemented by the operating divisions and reviewed by the Risk Management Committee to ensure the MTS is implemented in accordance with the policy.

Q. Is the policy reviewed periodically to ensure it remains appropriate?

A. Yes, the policy is reviewed annually and revised as needed.

V. PGE's Mid-Term Strategy is Not New

Q. CUB states that the hedging strategy at issue in this docket, "…appears to be a new strategy for PGE" (CUB Exhibit 100, page 2, lines 9–10). Is this a "new" strategy?

A. No. As we stated previously, the MTS was developed in 2006 and implemented in 2007.

Q. Was the strategy presented or explained to parties prior to its implementation?

A. Yes. PGE presented the MTS to the Commission at the July 27, 2006, public meeting, explaining its goals and principles. PGE's review of the audio recording from this presentation indicates that OPUC Commissioners and Staff were supportive of the strategy. No party attending the meeting questioned the strategy or voiced concerns when comments were solicited by the Commissioners. A copy of that recording and presentation are provided as PGE Exhibits 403 and 404C.

The strategy was presented to PGE's Risk Management Committee on September 21, 2006, and to PGE's Board of Directors on May 12, 2006, and October 26, 2006.

Q. Has PGE presented the strategy, and the transactions executed under the strategy, to parties since 2006?

A. Yes. The strategy has been presented to parties since its development and inception in 2006. As we discuss further below, PGE discussed the MTS in its IRP, the Quarterly Power Supply Update ("QPSU") meetings, and has included these transactions in past AUT proceedings.

Q. Was the strategy discussed in PGE's most recent Integrated Resource Plan?

A. Yes. PGE included discussions of the MTS in its IRP filed in 2009 (Docket No. LC 48), and acknowledged by the Commission in Order No. 10-457. Chapter 5 of the IRP addressed

"Fuels" and included the following discussion of the strategy within the specific context of the gas acquisition strategy:

> Gas-fired generation contributes to variability in electricity costs. In an effort to reduce volatility in our power supply portfolio, PGE developed the Mid-Term Purchasing Strategy. The Mid-Term Strategy is the next step beyond the 24-month rolling physical gas purchases. The goal is to reduce or minimize year-over-year increases in PGE's net variable power costs. While the Mid-Term Strategy includes both power and fuel, a primary focus is purchasing fixed-price gas via financial instruments with terms spanning two to five years forward. (PGE 2009 Integrated Resource Plan, page 82)

Chapter 7, "Supply-side Options", addressed the resources considered for meeting PGE's future capacity and energy needs, and contained the following additional information:

> …as a mid-term strategy, PGE enters into financial fixed-for-floating wholesale electricity swaps of durations up to five years to balance our portfolio to load and further reduce exposure to wholesale price volatility. As with natural gas, such hedge transactions are also subject to strict corporate governance requirements with regard to credit, collateral, contract limits, transaction authorizations, etc.
>
> **Cost and Limitations of Hedging**
>
> Hedging is basically a form of insurance to reduce the risk of physical supply disruption or to provide improved price stability. As such, over the long run, this risk reduction comes via a somewhat higher cost or

> premium. The premium is composed primarily of transaction costs and a liquidity premium, which typically increases with duration, for locking in a fixed price. <u>Financial price hedging can reduce the severity of unwanted price outcomes, but it does so at the cost of also foregoing potentially favorable price changes</u>. (PGE 2009 Integrated Resource Plan, page 145. Emphasis added.)

Q. Does PGE regularly update Staff and intervenors on power supply operations?

A. Yes. PGE voluntarily holds Quarterly Power Supply Update ("QPSU") meetings. Invitees typically include Staff and representatives from both ICNU and CUB. The dates of the QPSU meetings held since 2007 are provided in PGE Exhibit 405.

Q. What topics are typically covered in these QPSU meetings?

A. These meetings are intended to keep stakeholders informed about relevant power cost market trends and operational developments that may have an effect on power costs.

Q. Has PGE specifically reviewed the MTS for stakeholders at a QPSU meeting recently?

A. Yes. For example, at the QPSU meeting held in July 2010 PGE provided a comprehensive overview of the MTS addressing the question of how the strategy has benefited customers. That presentation is provided as PGE Exhibit 406C.

Q. Have transactions executed under the Mid-Term Strategy been included in prior AUTs and general rate cases?

A. Yes. PGE has been executing transactions under the MTS since the first year of its implementation in 2007. Transactions executed under the strategy have been included in AUTs and general rate cases since 2008.

Q. Have some of the same transactions included in the 2012 NVPC forecast at issue in this docket been included in prior AUTs and GRCs?

A. Yes. Some of the same transactions that Mr. Schoenbeck and CUB suggest should be excluded from the 2012 power cost forecast were included in the 2011 forecast approved by the Commission in Docket No. UE 215, and the 2010 forecast approved by the Commission in Docket No. UE 208.[8] PGE Exhibit 407C identifies the transactions that parties previously had an opportunity to review by appending transaction and docket numbers to Mr. Schoenbeck's analysis provided as ICNU Exhibit 102.

Q. Should CUB and ICNU have previously been aware of some of the transactions with tenors greater than 36 and 48 months that are at issue in this proceeding?

A. Yes. PGE provided information to parties in these prior dockets sufficient for them to have been aware of the fact that PGE had executed these hedging transactions with tenors greater than 36 and 48 months.

Q. Was the inclusion of these transactions in prior proceedings challenged by CUB or ICNU?

A. No. CUB and ICNU were parties to the Stipulations resolving power cost issues in the dockets referenced above and hedging was not an issue addressed in the Stipulations or in any party's testimony.

Q. Has CUB or ICNU previously filed testimony addressing PGE's current hedging strategy?

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[8] For instance, transactions numbers 174509 and 180074, among others. See PGE Exhibit 407C.

A. No. CUB and ICNU both concede that they have not filed testimony addressing PGE's gas and power hedging practices since the inception of the Mid-Term Strategy.[9]

Q. Is it true that both CUB and ICNU have participated in PGE's AUT, GRC, and IRP dockets, and been invited to attend the QPSU meetings in order to remain informed, yet neither party previously voiced opposition to PGE's Mid-Term Strategy or the manner in which it has been implemented?

A. Yes. PGE could find no record of CUB or ICNU raising concerns in testimony or written comments, or voicing opposition to PGE's Mid-Term Strategy or its implementation prior to the current proceeding.

[9] See CUB's Response to PGE's Data Request Nos. 005–006, and ICNU's Response to PGE's Data Request Nos. 006–007. Those Responses are provided as PGE Exhibit 408, and indicate that PGE's hedging practices have not been questioned by either party in prior proceedings.

VI. Reply to Mr. Schoenbeck

A. Mr. Schoenbeck Misunderstands the Markets

Q. What technical misunderstandings does Mr. Schoenbeck have about the commodities markets?

A. We believe that Mr. Schoenbeck misunderstands three general concepts:

- The availability of products in the marketplace – although Mr. Schoenbeck criticizes PGE for purchasing calendar strips of gas, the products that he recommends in their place were not available in the market at the time of execution.
- The issues surrounding Q2 – Mr. Schoenbeck ignores how conditions in Q2 affect the risks faced by PGE and mischaracterizes the products available to hedge the risks.
- The use of day-ahead prices to shape forward prices – Mr. Schoenbeck incorrectly asserts that historical day-ahead prices should be used to shape forward prices.

1. Product Availability

Q. What are yearly or calendar strips?

A. Yearly or calendar strips represent products with the same quantity of a commodity for each day of the year at a fixed price; there is no differentiation by month, quarter, or season.

Q. What is a seasonal strip?

A. Seasonal strips are a gas-only product. Seasonal strips represent products with the same quantity of a commodity for each day of the defined season. These tenors are quoted in 2 seasonal strips: April through October ("April-Oct"), and November through March (the "Winter strip" or "Nov-Mar").

Q. What is a "Quarterly" product?

A. Quarterly products (or "Q"s) represent instruments with the same quantity of a commodity for every day of a quarter. A "Q" is a product that is 3 months in duration, representing the grouping of delivery months as one quarter of the year. "Q1" refers to January through March, "Q2" is April through June, "Q3" is July through September, and "Q4" is October through December.

Q. Are there differences in the availability of products in the gas market vs. power market?

A. Yes. Power products, when available, are quoted in Monthly, Quarterly, or Calendar strips, while gas is typically quoted in Monthly, Quarterly, Seasonal, or Calendar strips.

Q. Are Seasonal or Calendar products typically more readily available and widely traded than products that focus on a smaller part of the year?

A. Yes. Calendar strips for both power and gas (and seasonal for gas only) are the most liquid and are sometimes the only product readily available for outer years (i.e., products of a longer tenor or time between execution and delivery).

Q. Are monthly or quarterly products with long tenor readily available in the market place?

A. No. As we just discussed, the further the transaction is executed from the date of delivery, the less liquid the market is likely to be for these products.

Q. Mr. Schoenbeck states that for 2012 delivery, during the time of "May 2007 through August 2008" PGE only executed yearly transaction and not enough "seasonal, quarterly or monthly transaction…when other financial hedge products (monthly, quarterly, seasonal) were readily available in the market" (ICNU Exhibit 100, page 7). Is this statement accurate?

A. No. This statement is in direct conflict with his testimony on page 13 when he states: "ICE does not provide individual monthly values beyond the prompt twelve to fourteen months at this hub. This is not unusual. Most sources generally go from monthly to quarterly to annual reported forward prices as you go out in time" (ICNU Exhibit 100, page 13). If there is typically no market indication of monthly or quarterly prices past twelve months, then these same financial hedge products cannot be readily available.

Our experience indicates that liquidity exists for <u>quarterly</u> and <u>monthly</u> products for the <u>prompt year only</u>, that is, in the year prior to the delivery date. Further than that tenor, calendar and seasonal products are the only products that are traded. Longer tenor quarterly and monthly products would be referred to as custom products, which would come at a material premium to customers relative to calendar strips.

Q. Mr. Schoenbeck observes that PGE executed, "no seasonal, quarterly or monthly transactions" in a period representing two- to three-years to settlement (ICNU Exhibit 100, page 7). Is this surprising?

A. No. As we just discussed, the "quarterly" and "monthly" products to which Mr. Schoenbeck refers were not readily available in the market. PGE could possibly have acquired these products, but would have paid a significant premium. Mr. Schoenbeck himself acknowledges this in his description of the market curve as we noted above (ICNU Exhibit 100, page 13). While seasonal products may have been available in the market further out, they would not have adequately addressed PGE's Q2 needs. We discuss this further in Section 2 below, with regard to the second quarter of the year.

Q. How does PGE execute gas transactions to match its need?

A. Rather than paying a significant premium for a counterparty to create a product that is not readily available in the market, PGE typically uses the products that are available and then modifies, or shapes, them to match our need as markets become more liquid. For example, PGE will buy calendar strips towards the longer-end of the 5-year window and then sell off portions of the year as the prompt year gets closer.

2. Q2 Issues

Q. If the region is energy rich in Q2, as stated by Mr. Schoenbeck (ICNU Exhibit 100, page 7), why is a Q2 energy product not liquidly traded past the prompt year?

A. The liquidity in the power market for a particular tenor is highly dependent on who the market participants are and their mandates. Owners of hydro generation are BPA, Public Utility Districts ("PUD"s) and other load serving entities. BPA and PUDs are not active in the market past the prompt 12 months, since it is not their mandate to hedge past the prompt year. Load serving entities' mandates are to procure for load. These entities are usually in a position similar to PGE's: buying to meet load. Other market participants (such as banks and energy marketers), whose mandate is partly to be market makers, do not have a competitive advantage to separate out the Q2, and would only do it for a premium. So, although the region would experience the hydro run off in Q2, past the prompt year, liquidity for Q2 power product is scarce.

Q. Could PGE have used the available Seasonal products for Q2?

A. While Seasonal products may have been available 2 years out, executing these products does not address the Q2 granularity issue. Seasonal products are Apr-Oct or Nov-Mar, neither of which fit PGE's Q2 need specifically.

Q. Mr. Schoenbeck states that PGE's transactions should match the projected "need" in Q2 (ICNU Exhibit 100, page 7). Do you agree?

A. No. Executing custom transactions to exactly hedge PGE's Q2 need would have been costly. It could also be deemed imprudent to incur these costs given the availability of other highly correlated and liquidly traded products.

Q. Mr. Schoenbeck's testimony references a February 22, 2008, PGE report. He draws the conclusion from slide 8 of the report that PGE was long on gas for Q2 2012 (ICNU Exhibit 100, pages 7–8). Is his conclusion accurate?

A. No. There are two main issues with his conclusion:

1. <u>PGE is not long gas on an annual average basis</u>. Using the same table that Mr. Schoenbeck references, but looking at the total annual column rather than Q2 alone, PGE is actually short on gas on an annual average basis. The February 22, 2008, report clearly shows a short gas position of 43,000 Dth per day for the year. Forward gas prices are highly correlated between quarters. The Q2 gas position should be viewed as an effective hedge against Q1, Q3, and Q4 gas needs. Thus, the hedging strategy correctly targets an annual gas requirement rather than each quarter individually.

2. <u>PGE is shorter on energy in Q2 than any other quarter</u>. Despite the fact that Mr. Schoenbeck only considered Q2 as the period in question to determine prudence for a calendar strip gas purchase, he should have at least included PGE's total Q2 energy shortfall. He only included slide 8 of PGE's report, which must be considered in conjunction with slide 7 in order to draw an accurate conclusion. The length in Q2 that Mr. Schoenbeck observes must be viewed in conjunction with PGE's significant

short power position in slide 7. Slide 7 shows an average power short position of 1,113 MW for PGE in Q2 for the 2012 delivery period. Slide 7 further explains that, "Although short throughout the year, MONET indicates shoulder months (April, May & June) are the shortest". In combination, on an energy basis, these two slides show that for Q2, customers are significantly exposed to power price movement. We include the entire report as PGE Exhibit 409C.

Q. What is the correct conclusion regarding Q2?

A. Although the correct conclusion may not be readily apparent, the impact of Q2 hydro run off is not as Mr. Schoenbeck states for a utility with a portfolio like PGE's. The Northwest is generally thought of as flush with energy in Q2. However, PGE's own hydro resources are not sufficient to meet its load. PGE is, therefore, in the position of being significantly "price short" in the Q2 since our gas generation fleet is not "in the money".

The price risk in Q2 exists in abundance. The decision PGE faces is whether to hedge with a structured product or to use the commonly employed strategy of hedging this risk with another highly correlated but more liquidly traded product, such as gas. PGE chooses to use the latter strategy and hedge this Q2 power risk with gas for several reasons:

- The premium associated with purchasing gas swaps for Q1, Q3, and Q4 individually (Qs) is high prior to the prompt year.
- The premium associated with purchasing power swaps for Q2 individually is high prior to the prompt year.
- Forward gas is highly correlated with forward power. Gas is therefore an effective hedge for customer's exposure to power price volatility.
- Q2 gas length is an effective hedge against a Q1, Q3, and Q4 gas short position.

- Although the yearly strip of gas purchases is not a perfect match for the projected gas need in Q2, this bit of length is highly effective when considering the aggregate exposure to power in that quarter and the annual average exposure to gas for customers.
- The quarterly shaping can be left for the prompt year when the monthly products become liquidly traded.

The Q2 gas position must be considered in conjunction with PGE's overall annual gas need, as well as Q2 short power position. Had Mr. Schoenbeck correctly identified the window of risk that PGE was hedging with the gas calendar strip, he would have come to the correct conclusion: in combination, the apparent Q2 gas length is in reality a hedge for the remaining short positions in gas for Q1, Q3, and Q4, as well as power in Q2.

Q. How would Mr. Schoenbeck know the risk PGE is hedging?

A. The risk that PGE seeks to hedge can be found in the same presentation from which slide 8 was quoted, in consideration with slide 9. PGE explains its approach to consider both power and gas for the procurement strategy.

3. Use of Day-Ahead Prices

Q. Do you agree with Mr. Schoenbeck's testimony regarding the use of day-ahead prices to shape forward prices?

A. No. Mr. Schoenbeck makes an erroneous observation that, "Generally, historic day-ahead reported prices are used to convert a quarterly value into monthly values if this granularity of data is needed" (ICNU Exhibit 100, page 13). Mr. Schoenbeck should know that the market recognizes that the day-ahead reported prices are fundamentally a reflection of a very specific set of circumstances and are not a good proxy for future shapes. Every day-ahead price is subject to that day's weather, hydro flow, electric plant availability, and gas pipeline operation, among many other fundamental factors. Thus, the historical day-ahead price is not "generally" used to shape forward prices. Instead, the prompt year's curves should have available monthly on- and off-peak prices for power and monthly prices for gas. This prompt year's monthly shape is devoid of historical distortions and is only the market's expectation of the value of each separate month. Using the prompt year's monthly shape to shape the outer year's forward curve is the method that PGE employs.

B. Mr. Schoenbeck's Criticisms and Recommendations Are Not Valid

Q. Do you agree with Mr. Schoenbeck's assessment of PGE's MTS and his recommendations?

A. No. In general, we do not agree with Mr. Schoenbeck's recommendations.

Q. Are there any points on which PGE does agree with Mr. Schoenbeck?

A. We agree with the statements made by Mr. Schoenbeck in his Direct Testimony that "Companies participate in hedging to manage gas commodity risk thereby reducing price volatility and providing some price certainty" and that, "it is highly unlikely that you will be able to 'beat the market' through hedging" (ICNU Exhibit 100, pages 4–5).

We also agree with the statements made by Mr. Schoenbeck during his deposition that reducing price volatility is "a major goal" of hedging (Deposition of Donald W. Schoenbeck, page 38, lines 23–25, included as PGE Exhibit 402, page 1). Further, we agree with Mr. Schoenbeck's statement that, "I would say most people, as a general rule, like more stable rates, predictable, but that always comes at a price" (Deposition of Donald W. Schoenbeck, pages 126, lines 6–8, included as PGE Exhibit 402, page 16). In fact, as we discussed above, PGE implemented the MTS in response to customers wishing to reduce volatility in their power costs. PGE informed stakeholders that reducing volatility may come at the expense of the potential for the absolute lowest possible cost. Understanding that trade-off is key to implementing a successful hedging strategy.

Q. What criticisms or recommendations does Mr. Schoenbeck make regarding PGE's MTS?

A. Mr. Schoenbeck makes five criticisms or recommendations in his testimony:

1. PGE hedges all of its risks too early (ICNU Exhibit 100, page 9);
2. PGE's gas need fluctuates too much farther out in time to make procurement decisions (ICNU Exhibit 100, page 8);
3. Other utilities only hedge 3 or 4 years out (ICNU Exhibit 100, page 10);
4. A programmatic approach should be employed (ICNU Exhibit 100, page 11), and
5. A 20% net open position should be maintained into the prompt year (ICNU Exhibit 102, page 18).

We address each of these criticisms and recommendations below.

1. PGE did not execute its hedges too early

Q. Were the gas and power transactions executed consistent with PGE's MTS?

A. Yes, transactions executed in years 4 and 5 were consistent with the MTS. In his deposition, Mr. Schoenbeck stated that in his review of PGE's hedging transactions, he found nothing that was in violation of the policy (Deposition of Donald W. Schoenbeck, page 97, lines 13-16, included as PGE Exhibit 402, page 13).

Q. Please respond to Mr. Schoenbeck's implication that certain transactions were beyond the maximum tenor for "after the fact" approval (ICNU Exhibit 100, page 6).

A. Mr. Schoenbeck is correct that certain transactions would have required preapproval under the guidelines of PGE's Energy Risk Management Policies and Procedures in place at the time of execution. However, as he clarified in his deposition, the transactions were permitted under the Policy with prior approval (Deposition of Donald W. Schoenbeck, page 97, lines 1–10, included as PGE Exhibit 402, page 13). PGE employees obtained all of the necessary pre-approval memos prior to executing any of these specific transactions.

Q. Were the strategy's targets filled in a "front end loaded" manner as suggested by Mr. Schoenbeck (ICNU Exhibit 100, page 9)?

A. No. As we demonstrate below, the transactions were layered over the 5-year window.

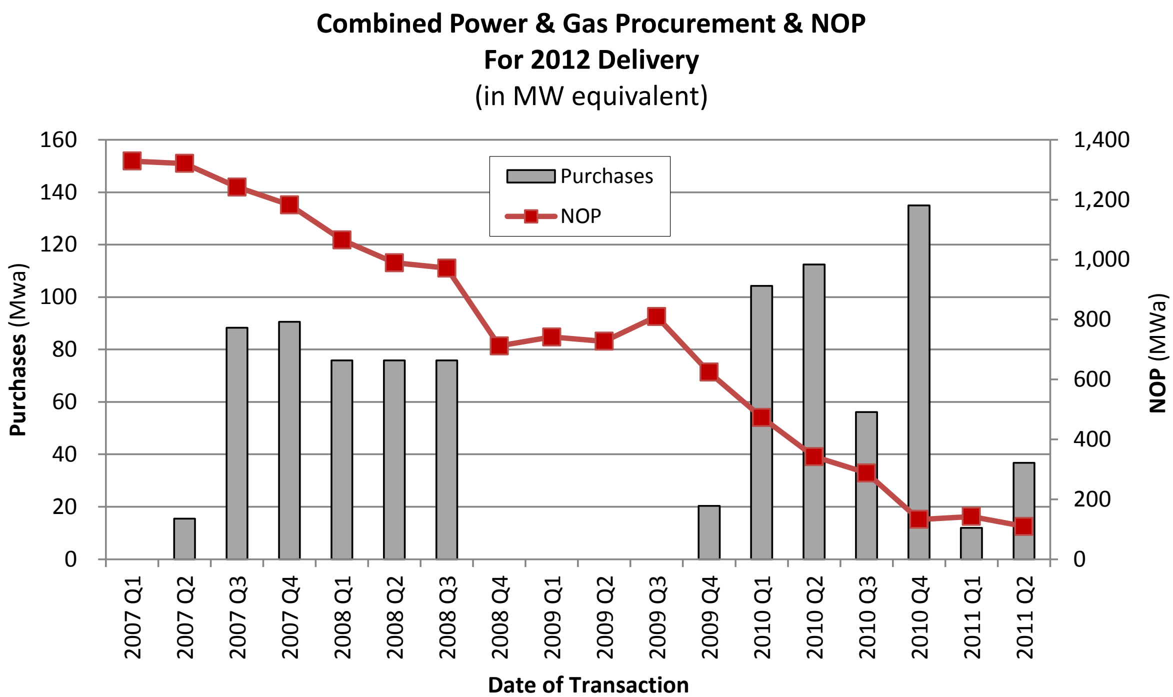
Q. Mr. Schoenbeck considers just gas transactions. Is that appropriate?

A. No. As we stated above, PGE is ultimately at risk to deliver energy in the form of power; gas is one means to achieve this end for a portion of PGE's load. PGE transacts in the power market as well. Thus, one must consider both gas and power.

Q. What measure do you use to determine PGE's net open position?

A. We use energy equivalents. As described in the PGE's MTS report referenced above, PGE converts all purchases of gas to equivalent units of energy. We make this conversion using the heat rate reflecting the generating capabilities of our Port Westward and Coyote Springs generation. These converted gas purchases are then added to the power purchases. The total is then aggregated against the total NOP determined on the same basis.

Figure 3 below illustrates purchases for 2012 delivery (the bar graph) executed between 2007 through the end of the second quarter 2011, and the corresponding NOP (the line graph). Purchases through 2008 totaled only 422 MWa. The NOP has decreased by 1,219 MWa progressively from 2007 to July 2011 due to 898 MWa of purchases, as well as load reductions and resource additions (e.g. Biglow) netting to 321 MWa.



Q. Please describe your purchases of energy for the 2012 delivery period.

A. As can be seen in the graph above, which is also provided as PGE Exhibit 410, PGE's transactions on an energy equivalent-basis have been fairly consistent across the time period, with the exception of Q4 2008 through Q3 2009.

Using the data represented above, the 2012 purchases have the following pattern:

Table 2

2012 Delivery	MWa	Pct. NOP
Initial NOP	1,329	
Purchases		
2007	194	19%
2008	227	23%
2009	20	2%
2010	408	40%
2011Q1&2	49	5%
Load & Resource Updates	321	
Current NOP	109	11%
Initial NOP w/ Updates	1,008	100%

Table 2 above demonstrates that PGE's gas and power purchases for 2012 delivery on an energy-equivalent basis were layered-in over time. 2007 and 2008 purchases only accounted for 42 percent of the revised (and lower) projected NOP ([194+227]/1,008). However, before PGE revised its 2012 load forecast in 2009, the 2007 and 2008 transactions represented only 32 percent of the projected NOP ([194+227]/1,329). PGE's 2009 purchases were less than average in response to market conditions. Subsequent purchases for 2012 delivery experienced an uptick in 2010 as a response to the gap in purchasing in 2009 and recognizing the new market realities in 2010 continuing to 2011 of the lower, more stable, gas and power market. PGE believes that Mr. Schoenbeck's assertion that PGE "procured virtually all the gas by the third quarter of 2008" (ICNU Exhibit 100, page 9) stems from only looking at the gas NOP rather than the more complete assessment of customer risk, which is power and gas over the 5-year period.

Q. Despite the fact that the "analysis" presented in his Direct Testimony focuses solely on the gas transactions executed under PGE's hedging policy, does Mr. Schoenbeck acknowledge that an electric utility must look at its entire open position (gas and power) when formulating a hedging strategy?

A. Yes. Mr. Schoenbeck indicated that both gas and power should be considered when he was asked (Deposition of Donald W. Schoenbeck, page 67, lines 17–20, included as PGE Exhibit 402, page 12):

> Q. Do you agree with me that an electric company should look at its entire open position, both as to electric and gas, when formulating its hedging policy?
>
> A. Yes.

Q. Why is there a gap in gas and power transactions for 2012 in 2009?

A. We held off purchasing during this period because of two events: the worldwide financial crisis and the emergence of gas fracking.

Q. Please explain how the financial crisis affected the execution of PGE's MTS.

A. The financial crisis was primarily characterized in the media as the bursting of the housing bubble, with the impact mostly felt by financial institutions. For the commodities market, these same financial institutions were providing much needed liquidity with what appeared at the time to be strong balance sheets and good credit profiles. However, with their survival in question, the financial institutions retreated from the commodities market. What may have started with the bursting of the housing bubble, cascaded, translating into a wider economic downturn with lower consumer consumption, which ultimately impacted our load. PGE's forecasted loads were revised down several times during this stretch, consistent with the national trend, leading to a fall in commodities markets.

Q. Please explain how the emergence of "fracking" affected the execution of PGE's MTS.

A. Hydraulic fracturing (or "fracking") is the process of extracting gas from shale formations deep in the ground. Fracking is not a new technology, but its emergence as the marginal cost technology in the gas exploration and production industry is recent. Its proliferation was preceded by a period of worldwide economic expansion until 2008, which drove commodity prices, oil and gas in particular, to historical highs. This high price environment provided gas producers the impetus to look for ways to access new gas reserves and the race to perfect gas fracking was on.

As the worldwide economy began to reflect the post-2008 economic realities, the commodities market started to reflect the new lower demand nationwide and prices abated from their highs. As prices continued lower, industry experts were surprised at the willingness of the gas producers to continue selling, rather than reduce production. The revelation here was that fracking proved to be much more efficient and less costly than previously thought. This new technology reversed the widely held sentiment that domestic gas supply alone could not satisfy domestic consumption. Experts termed this the "Shale Revolution". Efforts to build multi-billion dollar import facilities were scrapped in favor of the permitting and construction of export terminals.

Q. How did these two events, the financial crisis and the emergence of fracking, affect PGE?

A. These two events changed the national landscape in dramatic and unexpected ways. For PGE, the effects were felt immediately in the forms of less liquidity in the market, falling load, and more urgently in terms of short-term financing; the falling prices had triggered large collateral calls. These collateral calls reached $425 million in mid-2009[10].

As part of the normal procedure for MTS implementation, these factors were taken into account. These factors contributed to a much lower targeted volume for the 2009 MTS.

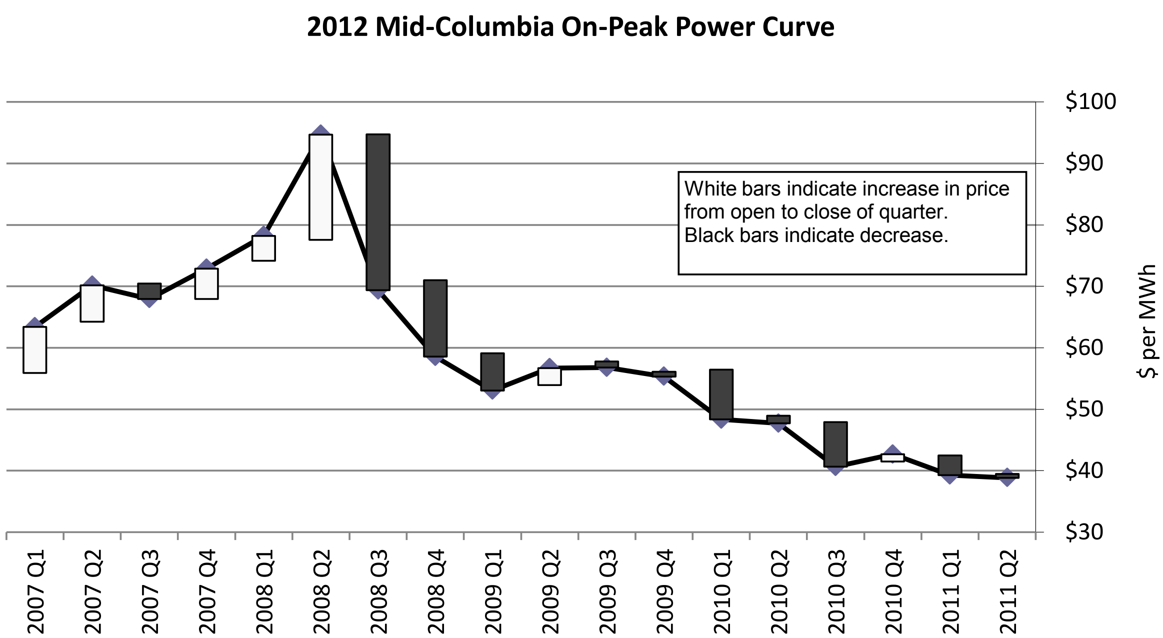
Q. Did this gap in purchasing hurt the customers?

A. No. Not being programmatic about the hedging strategy was not detrimental to customers. Figure 4 below depicts the power prices at the open and close of each quarter. Each bar represents the difference between the forward price of on-peak power for 2012 delivery at the beginning of the quarter and the end of the quarter. The white bars are when 2012 prices increased, while the black bars are when prices decreased in the time period. As can be seen, prices were in sharp decline throughout the period Q3 2008–Q3 2010. PGE's Power Operations personnel continued to monitor the markets but the decision was made to wait

[10] UE 215 – PGE Exhibit 1100, page 10, line 2.

until Q4 2009 to transact. At that point, market prices had found their footing, liquidity had returned, and PGE continued to implement its hedging strategy at the lower price level.

The discretion to factor market conditions into the decision making process afforded by PGE's MTS policy allowed for reduced volume and the leeway to execute it. Although achieving the absolute lowest price is not the goal of the MTS, this built in flexibility did, however, save customers the costs of buying in a market downturn that saw power prices go from $94.75/MWh to $56.13/MWh.



Q. Does Mr. Schoenbeck agree that it is appropriate to consider the factors that PGE evaluated during the 2008–2009 timeframe when developing and executing a hedging policy?

A. Yes. In his deposition, Mr. Schoenbeck agreed that it was appropriate to consider the implications of market shifts in the execution of a hedging strategy (Deposition of Donald W. Schoenbeck, pages 45–49, included as PGE Exhibit 402, pages 2–6). He also agreed that collateral costs are a component of the transaction costs, which can be taken into account when assessing hedging transactions (Deposition of Donald W. Schoenbeck, pages 61–63, included as PGE Exhibit 402, pages 7–9).

Q. What has PGE done to protect against a recurrence of the collateral issues experienced in 2009?

A. PGE has taken two key steps to minimize future collateral posting requirements similar to those experienced in 2009:

1. Pursue more bi-lateral transactions with enabling agreements, and
2. Reduce ICE Cleared transactions.

Q. Why does PGE pursue bi-lateral transactions with enabling agreements?

A. Enabling agreements impose less stringent collateral requirements on counterparties (relative to ICE Cleared transactions) because:

- The economic strength of each counterparty is analyzed;
- The credit threshold is negotiated;
- Collateral posting will not be called on until the mark-to-market is above the negotiated credit threshold, and
- The posting requirement is generally proportionate to the financial strength of the companies.

Q. Why is PGE moving away from ICE Cleared transactions?

A. PGE is moving from ICE Cleared transactions to reduce the amount of collateral that PGE must post. ICE Cleared transactions have initial margining requirements that must be posted at the time the transaction is executed without any reduction for a credit threshold. Then, additional collateral must be posted for changes in the mark-to-market value (i.e., dollar for dollar posting). Thus, all else equal, ICE Cleared transactions require more collateral support than bi-lateral transactions.

2. PGE can estimate its gas need in advance

Q. What is Mr. Schoenbeck's view on forecasted gas needs?

A. Mr. Schoenbeck agrees with PGE that the goal of the MTS is to reduce customers volatility, but he believes that "executing hedges more than 48 months from the prompt month is simply not prudent in this industry" because of the "fluctuations in gas generation projection levels" (ICNU Exhibit 100, page 8). PGE disagrees with this premise. Although it is true that the gas generation is the technology "on the margin" for power prices, it should not be confused as meaning that all gas generation technologies behave the same vis-à-vis market prices.

The market makes the distinction between baseload gas and peaking gas generation. The fluctuation in gas need due to changes in the forward market heat rate (the ratio of power prices over gas prices), while significant for peaking gas generation, is not as significant for baseload gas. Baseload gas generation is capable of more efficiently generating electricity than peaking technology. Baseload generation is deeply "in-the-money" for 10 months out of the year, while peaking units are only forecasted to be dispatched for on-peak generation through the summer months. For this reason, and as described earlier in our testimony, PGE makes the distinction between Port Westward and Coyote Springs (both baseload gas generation plants), and Beaver (a peaking plant). PGE's MTS only includes the projected gas needs for Port Westward and Coyote Springs, and does not make purchases of mid-term gas for Beaver.

Q. Mr. Schoenbeck asserts that "fluctuations in gas generation projection levels brought on by load forecast error…can have a dramatic affect on the amount of gas fuel needed in any one month" (ICNU Exhibit 100, page 8). Is that PGE's view?

A. No. This assertion is drastically different than general market (and PGE's) practices. When determining the gas need, the generation owner does not take into consideration whether or not the energy will be needed to serve load. For procurement of gas, the generation owner who is also serving load examines market prices and then decides whether to generate or buy electricity from the market. If the electricity is needed for load, then customers benefit from the least cost procurement decision. Even if the electricity is not needed to serve load, gas should still be purchased and the generated electricity sold into the market instead, with the margin reducing customers' rates. The decision to generate and, by extension, to purchase either gas or power is not driven by the load forecast, but rather, by market prices. Customers would not benefit from the adoption of Mr. Schoenbeck's proposed approach.

3. PGE's MTS is appropriate even if other utilities only hedge 3 or 4 years out.

Q. Mr. Schoenbeck compares PGE to several local distribution companies ("LDCs") in the NW. Do these LDCs provide an accurate comparison (ICNU Exhibit 100, pages 10–11)?

A. No. PGE believes that Northwest LDCs have similar risk exposures, but LDCs do not have the added electricity exposure that PGE customers have. Further, comparisons of PGE to other companies will inevitably yield differences, but "discovering" these differences does not offer evidence of right or wrong in terms of a hedging strategy. Assessing a hedging strategy is about determining how that policy fits with the stated goal and internal risk policies, rather than simply implementing a one-size fits all hedging strategy. The fact that

Avista or NW Natural manages its exposure only 4 or 3 years out does not mean that PGE's window of execution is right or wrong.

As Mr. Schoenbeck points out, all details of hedging strategies are typically confidential; thus, PGE can only offer comments regarding our approach. As we discussed above:

- The window of risk is the gap between what is planned for in the IRP and what was the 24-month strategy prior to adoption of the MTS;
- The NOP is both gas and power, with consideration given to the more efficient products for hedging, which is gas;
- PGE's execution is staggered and done with consideration given to market conditions, and
- PGE has kept Staff and intervenors informed of our progress.

Q. Please describe the comparison that Mr. Schoenbeck makes between PGE and Avista.

A. Mr. Schoenbeck's comparison of Avista's hedging strategy with that of PGE's is limited to just the results, in terms of the respective mark-to-market adjustments. The apparent conclusion to be drawn from this comparison is that a company incurring fewer "losses" on its hedges has a more prudent strategy. Given that the goal of an appropriately formulated hedging strategy is not to achieve the absolute lowest cost, this comparison is invalid and should carry no weight.

Further, Mr. Schoenbeck offers this comparison to Avista with no details of Avista's hedging strategy or risk management practices, and no discussion of why this strategy would be appropriate for PGE.

Q. Do Mr. Jenks and Mr. Feighner make the same comparison with Northwest Natural?

A. Yes. Mr. Jenks and Mr. Feighner compare PGE to Northwest Natural (NWN) as well.

Q. Do Mr. Schoenbeck, Mr. Jenks, or Mr. Feighner provide any sort of insight into how NWN's hedging policy was developed?

A. No. Neither the ICNU witness, nor the CUB witnesses, provide any sort of information regarding how NWN arrived at their policy or why that policy is appropriate for PGE.

Q. Could liquidity in the marketplace be a factor for Northwest Natural Gas' decision to hedge only 3 years out as CUB and ICNU indicate?

A. If liquidity is defined with respect to the transactions conducted by any and all market participants, then each market participant would experience the same liquidity. Given that definition, the market for some products is liquid past 3 years, as we discussed above. But, if liquidity is more narrowly defined with respect to the market that a specific company has access to, then each company would have a different view of what is "liquidly" traded in the marketplace. Individual companies would experience different levels of liquidity depending on:

- Size and health of their balance sheet;
- Appropriately sized credit facilities for the size of the hedging program being contemplated;
- Willingness to pursue bi-lateral enabling agreement with symmetrical collateral thresholds;
- Internal risk management procedures in place to monitor risk for the tenor of the strategy.

Given our internal policies, PGE's liquidity window is generally 5 years, while other firms with more restrictive internal policies may only see liquidity 3 years and in.

Q. CUB states that KPMG performed an analysis for Northwest Natural Gas that relied on a rolling 3-year hedging strategy as the "prudent default strategy" (CUB Exhibit 100, pages 2–3). Was that the only analysis performed by KPMG?

A. While KPMG did perform an analysis of a rolling 3-year hedging strategy as an alternative to the joint venture for <u>30-years</u> of physical gas supply that CUB supported in Docket No. UM 1520, it appears that KPMG also performed an analysis of a rolling 5-year hedging strategy.

In their Response to PGE's Data Request No. 008, CUB provided the "final" KPMG report. Page 34 of that report does in fact describe the rolling 3-year strategy that CUB references. However, page 35 of the same report details a rolling 5-year hedging strategy. There is no indication in this KPMG report provided by CUB that the 3-year strategy is preferable in any way to the 5-year strategy. PGE found no instance of KPMG referring to a 3-year strategy as the "prudent default strategy" in the report provided by CUB. CUB's Response to Data Request No. 008 is provided in PGE Exhibit 408. The KPMG report is provided as PGE Exhibit 411.

Q. Did CUB support Northwest Natural Gas' joint venture with Encana to secure physical gas supplies for 30-years?

A. Yes. This transaction can be viewed as a 30-year hedge.

4. A programmatic approach is not appropriate

Q. Mr. Schoenbeck recommends a programmatic approach (ICNU Exhibit 100, pages 5 and 11). Is a programmatic approach appropriate?

A. No. A policy that mandates a programmatic approach to executing hedging transactions leaves the company exposed to collateral considerations, event risk, and structural changes in the market.

Despite the fact that he recommends a "programmatic approach," Mr. Schoenbeck agrees with us that the factors mentioned above are all relevant to the development and execution of a hedging policy.

Q. What do you mean by collateral considerations?

A. When the market price moves against the price that a party pays in a swap, their counterparty might demand that an amount be "posted" to help ensure against default. A programmatic approach would not provide the flexibility to manage activity around these collateral requirements. In a period of falling prices, a utility that typically enters into swap agreements paying the fixed price (and receiving the index price) would be required to continue purchasing under a programmatic approach, as their need to post collateral was also increasing. Those collateral postings may strain the utility's liquidity.

Q. Does Mr. Schoenbeck agree that collateral costs should be considered when assessing hedging transactions?

A. Yes. In his deposition, Mr. Schoenbeck indicated that he does agree that collateral costs are a component of the transaction costs, which can be taken into account when assessing hedging transactions (Deposition of Donald W. Schoenbeck, pages 61–63, included as PGE Exhibit 402, pages 7–9).

Q. What is event risk?

A. Event risk means that market prices may be temporarily distorted as a result of a discrete event. For instance, natural gas prices were elevated after Hurricanes Katrina and Rita hit the Gulf Coast in 2005, despite the fact that mid-term and long-term supply and storage were largely unchanged. A programmatic approach would require the utility to continue transacting, despite the price dislocation.

Q. What are structural market shifts?

A. So-called structural market shifts occur when some fundamental aspect of the market has changed. The emergence and commercial viability of shale gas reserves in the continental United States is an example of a structural market shift. A programmatic procurement strategy would not recognize this shift. The leeway afforded in PGE's hedging policy setting provides the Power Operations personnel the ability to recognize these events and adjust the implementation of the strategy as appropriate.

Q. Does Mr. Schoenbeck agree that event risks and structural market shifts should be considered when formulating a hedging strategy and evaluating its execution?

A. Yes. In his deposition, Mr. Schoenbeck indicated that these factors are appropriate for consideration when evaluating a hedging strategy and its execution (Deposition of Donald W. Schoenbeck, pages 47–49, included as PGE Exhibit 402, pages 4–6).

5. It is inappropriate for PGE to maintain 20–25% NOP into the prompt year

Q. What are the issues associated with Mr. Schoenbeck's and CUB's proposal for PGE to maintain a 20% or 25% net open position?

A. There are at least two issues with the proposals that PGE maintain an open position into the prompt year. First, these proposals by Mr. Schoenbeck and CUB are not well-defined. It is unclear whether the proposals intend for PGE to have an open position going into the year of the AUT proceeding (i.e., 2011 for 2012 power costs in the current proceeding), to have an open position at the time of the final AUT update, or something else entirely.

Second, the effects on customers' rates are uncertain. PGE's power cost forecasting model, "MONET", assumes that deficits or surpluses to load are bought or sold on the power market at the prices indicated by the forward curve. As such, power prices are essentially fixed at the time the final AUT update is filed in November. The price included in customers' rates is either the price indicated by the forward curve or the price at which an actual transaction was executed. Any price fluctuations after the final MONET run will be incorporated into the PCAM results. The effect on customers' rates, however, will then be subject to the deadbands and earnings test. Prior to this final run, a sizable open position will likely subject customers' rates to greater uncertainty as forward prices fluctuate, contrary to the very intent of a hedging strategy.

VII. Conclusion

Q. Can you summarize Mr. Schoenbeck's proposed disallowances?

A. Mr. Schoenbeck proposes a disallowance related to PGE's hedging transactions. Of the 17 transactions that he proposes be disallowed due to their tenors being greater than 60 months, 13 have been previously reviewed by parties. As we discussed earlier, neither these transactions, nor PGE Mid-Term Strategy, were ever questioned prior to the current proceeding.

The remaining disallowance is the product of Mr. Schoenbeck's other chief complaint, "overhedging" in Q2.

As discussed above, these hedging transactions were prudent, and Mr. Schoenbeck failed to recognize that:

- The 60-month tenor was not randomly chosen, it is the residual window of risk when considering the gap left by the IRP planning horizon (5 years and out) and the short-term market (prompt 24 months).
- PGE was not "overhedged" in Q2 with gas. PGE made a conscious decision to use gas as a price hedge for customers' exposure to Q1, Q3, and Q4 gas prices and Q2 power prices. Forward quarterly gas prices are highly correlated with each other. Power and gas commodity prices are highly correlated in the forward markets. Liquidity for quarterly products in the gas market is simply not available at a competitive price past the prompt year. Further, these gas purchases were a mere fraction of the total risk customers are exposed to when considering the electricity NOP for these months. In his deposition, Mr. Schoenbeck acknowledged that power and gas commodity prices are highly correlated (Deposition of Donald W. Schoenbeck, pages 65, line 21 through

page 66, line 14, included as PGE Exhibit 402, pages 10–11) and that exposure to power prices could be hedged using gas (Deposition of Donald W. Schoenbeck, pages 124–125, included as PGE Exhibit 402, pages 14–15).

Despite his criticisms of PGE's MTS, Mr. Schoenbeck admits that he never actually analyzed whether the hedging strategy reduced the volatility in NVPC, but he would, "be very surprised if it did not" (Deposition of Donald W. Schoenbeck, pages 93–94, included as PGE Exhibit 412C).

Q. Please summarize your testimony.

A. PGE's hedging strategy executed as part of the MTS was prudently developed and implemented. Customers' risks were properly considered and appropriately addressed, while the best fit and least cost products available were used to hedge price volatility. Mr. Schoenbeck's and CUB's conclusions are based on hindsight, flawed analyses, and fundamental misunderstandings of the commodities markets:

- Customers are not only exposed to gas price volatility, but gas <u>and</u> power price volatility;
- Longer tenor monthly and quarterly products are costly, not readily available, and not necessary;
- A programmatic approach is not desirable for a market prone to short-term spikes in volatility and structural changes;
- The baseload gas generation profile does not fluctuate, in contrast to peaking gas generation;
- PGE's approach is not "front end loaded" when correctly looking at the total net open position.

As such, the proposed disallowances are simply opportunistic attempts to deny PGE recovery of costs prudently incurred in the course of hedging customers' risks.

VIII. Qualifications

Q. Mr. Lobdell, please describe your qualifications.

A. I received a Bachelor of Science degree from the University of Oregon in 1984. Since joining PGE in 1984 I have held a variety of positions at PGE and its affiliates including Vice President, Risk Management, Reporting, and Control, Vice President of Portland General Distribution Company, Vice President of Portland General Holdings II, Vice President of FirstPoint Utility Solutions, Manager of Financial Risk Management and Pricing at PGE, Treasurer of Tule Hub Services Company, Manger of Commercial Group Accounting for Portland General Holding, Project Manager for Columbia Willamette Development Company, and Supervisor of Accounting Operations for Portland General Corporation. I entered my current position of PGE Vice President of Power Operations in September 2002.

Q. Mr. Outama, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from University of Washington in 1996. I have over 14 years of experience with PGE working in accounting, financial planning, risk management, and structuring and origination. I have been a senior analyst in the past three departments I worked in. I have been involved in originating and pricing of custom products, asset acquisitions, as well as ad hoc project management on behalf of PGE's customers for the past five years.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
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PGE Exhibit 401

Qualifications of Key PGE Personnel

PGE Exhibit 401 – Qualifications of Key Personnel

Bill Casey

I received a B.S. in Electrical Engineering from Washington State University in 1988. I received a Masters in Engineering Management from Santa Clara University in 1994. I received a MBA from Marylhurst University in 2007. In the 16 years of working for Portland General Electric Company my work has been focused on managing PGE's generation portfolio from Term Trading (prompt month out) to Day Ahead. Since 2009, I have been the lead trader for the Mid Term Strategy

Joe Eberhardt

Economics and Geography, MA, double Masters (specialty: Resource Economics and Quantitative Modeling) 1997

Finance, BS (specialty: Portfolio Theory) 1993

Two years of additional doctoral work at Oregon State University 1998-1999 in Economics and Mathematical Probability.

10 years of experience at PGE as Origination & Structuring Team commercial lead.

6 years of experience teaching economics, finance and investments at Oregon State University and Linfield College.

3 years of experience private investing with individuals and high net worth clients/foundations/trusts at Edward Jones and Windermere Investments.

PGE experience includes: Commercial lead for structured trading activity, Primary options trader for PGE, Primary oil trader for PGE, Asset optimization (modeling, marketing and hedging), Asset acquisition (modeling, negotiation, planning and utilization), Long-term power procurement (modeling and negotiation), Renewable resource development (mainly geothermal and solar energy sources), Market analysis and strategic planning/decision making support.

George Gardner

I received a Masters of Science in Agricultural Economics from the University of California, Davis in 1992 and a Bachelor of Arts in Mathematics and Economics from Northwestern University in 1988. I have nearly 15 years of experience with PGE working in retail rate design and energy risk management. I have been involved in net variable power cost modeling, deal valuation and position reporting for the past 10 years.

Peter Lyman

I received a Masters of Arts in Economics from Cornell University in 1985 and completed all PhD qualifying exams and coursework requirements.

During my time at Cornell I was a teaching assistant and later instructor in both the Economics and Mathematics departments.

I received a Bachelor of Arts in Economics from Case Western Reserve University in 1975

I have nearly 20 years of experience with PGE starting in the Rates and Regulatory Department before joining the startup of PGE's trading floor in 1995.

In 1996 I left PGE to work for Phibro, the commodities trading division of Solomon Brothers, followed by a year at NatSource, a Wall Street energy commodities broker.

I returned to the PGE trading floor in 1998 and subsequently held positions as a term power trader and fundamentals analyst.

Kurt Miller

I received my Bachelors of Science in Economics from Willamette University, graduating Magna Cum Laude in 1992. After graduation, I worked two years for the Bonneville Power Administration, before moving to Euro Brokers, where I established the first successful electricity brokerage desk in the United States. In total, I have nearly 20 years of energy trading, marketing, and broker experience, including over 12 years of term trading and fundamental analysis of energy markets at PGE.

Terri Peschka

I received a Bachelor of Arts degree in Finance from Portland State University. I have been employed at PGE since 1999 in the following positions: Risk Management Analyst, Manager of Risk Management Reporting & Controls, and my current position General Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980–1999 in various retail, wholesale, planning and mergers and acquisition positions. In my current position, I am responsible for managing the Power Operations group that coordinates the NVPC portfolio over the next five years.

PGE Exhibit 402

Excerpts from the Deposition of

Donald W. Schoenbeck

could very well be some sort of mark-to-market adjustment on the credit and collateral that you have to post on a monthly basis because the market is much more concerned now about default.

That in and of itself has created -- some parties, because of that type of risk, will not enter into long-term supply contracts anymore or at a huge premium.

Q. And have you looked at those collateral risks in the hedging strategy that you formulated in your testimony?

A. I did not look at -- at PGE's credit and collateral obligations under the hedges they entered into.

Q. But did you consider the collateral risks in the hedging strategy that you are --

A. Yes, and that's in part why you -- it's one of the factors why I suggested the limited number of years, because, again, what happens the further out you go, your credit and collateral risk costs become greater. Your counterparties become less. The market becomes less liquid.

So all those things were -- I considered, basically, in my recommendation.

Q. Okay. Would you agree with me that the primary goal of hedging is to reduce price volatility?

A. I'd say it's certainly a major goal.

it's supply and demand. So this -- this really goes to the heart of my view that you truly can't beat the market and why you should use programmatic hedging as opposed to hedging all the gas at a particular time.

So in general, I'd say a radical movement upward or a radical movement downward, being several dollars per BTU, you could say is unexpected.

Now, having said that, there are -- again, there are certainly shifts. You know, what was it, back in 2005, if you have a world-class hurricane season, that's going to be a dramatic shift. If, you know, 2008, '9, you start developing shale gas, that's a dramatic shift.

So, yes, there are things that impact supply and demand of gas that can go either way.

Q. As long as we're talking about historic prices, and you've named a couple that have shifted the market, sort of a fundamental shift, where you have a hurricane season that was incredibly difficult or other events, I want to talk about some of those with you.

So back in 2000 to 2001, would you agree with me that the power crisis was sort of a fundamental shift in the gas prices or caused a fundamental shift in the market?

MS. DAVISON: Objection; ambiguous. I'm not sure which market, electric or gas, you're talking about.

MS. KANER: I'm just talking about gas. Thank you.

MS. DAVISON: Thank you.

THE WITNESS: I'd say about the 2000, 2001 crisis, there was a fundamental shift in the electric market that the gas market tried to capture some of the economic brunt that was occurring. There was a run-up in electricity prices, and the gas market responded by running up their prices as well.

So in that instance, I'd say the electric market pretty much drove the gas market in that crisis.

BY MS. KANER: (Continuing)

Q. Is there a correlation, then, between electric prices and gas prices?

A. Generally there is because within this portion of the country, gas is on the margin a great deal of the time.

I haven't looked at a recent study, but there was a FERC study a few years ago that said gas was on the margin approximately 80 percent of the time in the WCC.

So given that gas is driven -- or given that gas drives electricity prices as the incremental resource, it does have a significant impact within the WCC market.

Q. Okay. And then there was another push of gas when the hurricane season hit with both Katrina and Rita;

is that accurate?
A. Yes.
Q. Okay. And then following that crisis, gas prices abated somewhat?
A. Yes.
Q. And then there was sort of a global economic expansion with an increased demand that led to higher prices.
Is that somewhat accurate? Now I'm sort of into the 2007 to --
A. 2007, yes, that's -- that's true. And, again, you know, with this, it's all -- with the supply and demand, the higher prices created greater supply, you know, following that period. So the market's responding on all these events.
Q. And then --
A. You know, Katrina -- Rita and Katrina created a market shortage, obviously, of gas supply. So there's a market response. Looking in -- in the economics of 2007, there's been a market response. So, yes, it's -- it's an ongoing market.
Q. And then with the availability of gas through shale fracking, there's been yet another shift in the market as a result of expanded supply.
Is that accurate?

A. That's accurate.

Q. So in formulating a hedging strategy, do you believe that it's appropriate to evaluate each of those market shifts as you go along to determine how liquid the market is?

A. What are the market implications? Certainly all those things should be considered in evaluating your hedging strategy.

Q. And do you think that they should be evaluated in the execution of your hedging strategy?

A. In my mind, the evaluation of them would affect the parameters you would set for your hedging strategy so that, yes, having set those parameters based on those factors, then it's the execution of the hedging strategy.

Q. So I want to understand how those factors relate to the programmatic approach that you've described.

So my question is, given that there are some fundamental shifts that occur in the market, are those times when your programmatic approach would have to be adjusted in order to not necessarily purchase at a time when there's a crisis such as created by the hurricane season of Katrina and Rita?

A. That would be one factor. You'd also have to look at your total need, your total open position at the time.

I'd certainly say, yes, you would consider those in developing your hedging strategy and executing your hedging strategy.

MS. DAVISON: Are we at a good point where we can take a break?

MS. KANER: Sure.

(Pause in proceedings: 10:23-10:42 a.m.)

BY MS. KANER: (Continuing)

Q. We're back on the record. We were talking about historic events that have affected gas prices, and I wanted to ask you about one other historic event, and that would be the financial crisis that started in late 2008, going into 2009.

Did that affect gas pricing?

A. Can you be more specific on the exact time period? I guess I'm not recalling anything at the moment exactly with the gas price movement.

Q. Well, the financial crisis that sort of started with the -- I would say with the Stock Market crashing in September of 2008, if I have my dates right, moving into what was considered to be a recession.

A. Uh-huh.

Q. Did that affect gas prices?

But I'd say -- five years ago. Did I say five days?

Q. Yes, you said five days ago.

A. Five years ago.

But in -- I would say, in general, I'm seeing about the same counterparties from having reviewed transactions from five years ago versus now, seeing multiple counterparties, a lot of the same names, in other words.

Q. So do you think that the liquidity of the market for gas hedging in the last five years has changed? And we're talking about the market for three to five year out hedging instruments.

A. I don't believe so.

Q. Are you familiar with the specific costs associated with financial hedging for fixed -- for float costs, either for power or gas?

A. Are you talking about a fixed price versus an indexed price transaction, you know, a fixed floating swap?

Q. Yes, yeah, that is what I'm talking about.

A. Yes.

Q. And what costs are associated with those types of instruments?

A. Generally, a relatively modest -- again, you have to talk in terms of the term. But if you're certainly calling for a near term, short-term basis, it's generally a modest administrative charge.

What happens on the longer-term basis, because of the costs of the credit and collateral, under some of those agreements, what utilities have to process can be in the range of -- you know, in the range of a million dollars or more.

So, again, the critical -- what we've talked about, credit and collateral and even transactional costs, which I'm including to the extent you have to have a credit and collateral instrument out there, there's a cost associated with that. It can be small or large, depending on the time frame.

Q. And if we're talking about that midrange --

A. If we're talking, you know, three to five years, I'd again say, that's -- you're going to have some sort of a credit or collateral cost associated with that, as well as any sort of administrative costs associated with the transaction. I would lump that into it and say that's the cost of the transaction.

Q. And the magnitude of that cost would be?

A. For a utility, I would certainly think for their entire program, it would be in the range of a million dollars or more because of the -- because of having the credit and collateral posting costs associated with it.

Q. Are there other fees besides the collateral and posting costs?

A. There generally can be a transaction or modest administrative fee depending upon the arrangement. I mean, even to the extent you're doing it over the market, you know, in a short-term market, there is a fee for entering that transaction, but those are generally very modest.

Q. There could be brokerage fees?

A. That's what I'm talking about, market fee, brokerage fee, that type of thing.

Q. Okay. Do you believe that those transaction costs should be considered in executing the hedging portfolio of a company?

A. I'm sorry. In executing a transaction, you mean?

Q. Yeah. Do you believe those transaction costs should be considered in assessing the type of hedging that a utility should enter into?

A. You can certainly take it into account, sure. Again, what you'd expect is to the extent you're entering into longer-term transactions, those costs would go up, and that would be another thing to consider on why it may not be prudent or reasonable to enter into those longer-term transactions because of the transaction costs associated with them.

they face for a local distribution company is temperature related, weather related, not being able to know the load. It's uncertain from one day to the next.

For an electric utility, you obviously have that uncertainty associated with weather, temperature. In addition to that, you have supply uncertainties around the amount of hydro that's in the Northwest, the forced outage of units. Those are at least two other things that generally don't face a gas LDC.

Q. And would you consider a difference between a gas company and an electric company and their market risks to be -- let me start again.

Would you consider an electric company to be at risk for market conditions for both gas and power as opposed to a gas utility that would only be at risk for gas?

A. I guess I don't quite -- quite understand your question the way you've characterized it.

Are you talking -- could you try it again?

Q. Yes. Let me see if I can get it better.

Would you agree with me that the market risks for a natural gas company are different than those of an electric company because, for one thing, an electric company is open to the risks of the market for both gas and electric; whereas a gas company, its market risk or commodity risk is really limited to gas?

MS. DAVISON: I would object on the basis that it's vague and ambiguous still. It's so incredibly broad as to be meaningless.

You can answer.

BY MS. KANER: (Continuing)

Q. If you can answer it.

A. What I'm struggling with is basically the correlation between the gas and electricity markets.

We talked about earlier, within the Western United States, there's a great deal of correlation when gas prices go up, electric prices go up; when gas prices go down, generally electric prices go down. And, again, you have the -- the -- the spring runoff issue. So those are market risks.

So an LDC, if -- if -- if they're experiencing lower gas prices, the electric utilities are experiencing lower gas prices and lower electricity prices. If the LDC is experiencing higher short-term gas prices, the electric utility is experiencing higher short-term gas prices and higher electricity prices.

So if that answers your question, let me know.

Q. Let me ask you this: Given the correlation that you've just described between gas prices and electric prices, would you agree with me that it's appropriate for an electric company to use gas as a hedge for its -- for electricity?

A. Potentially. The electric utility should look at both the potential to hedge gas and/or electricity at a given point in time. They have the option of going either way. They can -- they can either buy gas or they can buy electricity. They can either sell gas or sell electricity. They could even simultaneously buy the gas and sell the electricity. So those are more options that they have versus a gas utility.

Now, is it giving them more risk, which I think was implicit in your question? That's what I'm not sure about.

Q. Do you agree, though, that they could -- that a gas company -- I'm sorry.

Do you agree with me that an electric company should look at its entire open position, both as to electric and gas, when formulating its hedging policy?

A. Yes.

Q. Okay. And then would you agree that looking at its entire open position, that it could use gas to hedge its entire open position, including the gas and electric open position?

A. It could hedge gas or it could hedge

Q. I want to make sure I understand your direct testimony in that your -- based on your review of PGE's hedges, you didn't find anything inconsistent in their execution of their hedging versus their hedging policy?

A. I believe what the testimony states is there are -- were some hedges that went beyond what I would call kind of a standard product hedge. So there would be additional approvals required pursuant to their hedging policy. And I said that was permitted under the hedging policy.

Q. Okay.

A. And what was the second half of your question?

Q. My question is, did you find anything that violated their hedging policy? That would be a different way of looking at it.

A. No.

Q. Okay. All right. I want to look at how you calculated the numbers that you are saying should be disallowed. So looking at page --

MR. TINGEY: This part better be confidential.

MS. KANER: Now we're getting into confidential.

(Confidential portion beginning on next page) only hedge your gas need up until the amount of gas that can be burned in your resources.

Q. Why would you not do that? Why would you not hedge gas to meet your power need, your electric need, even if it's beyond your capacity?

A. These are all gas financial hedges. What does that get you?

Q. Right. Well, given that we've already talked about the fact that gas and electric prices are correlated, why can't you use gas to hedge your electric prices?

A. Where are you going to get the electricity to serve the load? I'm really missing something. I -- are you just talking about your -- you're hedging the gas.

You've hedged gas and you've procured gas, based on the hedging strategy, to serve your gas-fired resources.

I'm sorry. Why would you want to enter into more gas financial transactions?

Q. To hedge your electric power risk, your open position on power.

A. But what's that getting the customers? It's not getting them power to be delivered.

Q. It's getting them -- it's a price hedge. It's getting them reduced volatility --

A. Uh-huh.

Q. -- in power prices.

A. Right. So you've -- you've -- you've done the gas hedge because you thought that was more advantageous for the market rate?

Q. Right.

A. You could do that.

Q. Okay. How would you describe the risk tolerance of residential customers to price volatility for electricity?

A. How would you define risk tolerance? That's --

Q. That's what I'm asking. How much of a -- how much volatility do you believe that residential customers are willing to absorb?

A. Well, if you look at what Pacific Gas & Electric put in, something akin to real-time rates in Bakersfield at the start of the summer, I would say not much. No one likes to get a $1,300-a-month electric bill.

Q. Right. All right.

And how would you -- and by comparison, how would you describe the risk tolerance for commercial customers in price volatility?

A. I would say for small commercial customers, it would generally be along the same lines as residential customers.

Q. Which is not much?
A. Uh-huh.
Q. Okay. And then how would you describe the risk tolerance for industrial customers to price volatility?
A. I would say most people, as a general rule, like more stable rates, predictable, but that always comes at a price.
No one likes to see a substantial jump in their power costs.
Q. Okay. So what percentage of the ICNU's members -- what percentage of their annual cost structure is energy consumption?
A. I have no idea.
MS. DAVISON: Objection; vague and ambiguous.
Q. Well, I --
MS. DAVISON: Each member has a completely different make-up of what energy is a portion of their cost.
MS. KANER: That's fair.

BY MS. KANER: (Continuing)
Q. Would you say that a considerable amount of a typical ICNU member, that their cost structure is based on their power consumption?

PGE Exhibit 403

Audio Recording from July 27, 2006, OPUC Public Meeting

Provided Electronically (CD) Only

PGE Exhibit 404C

Mid-Term Strategy Update to OPUC – July 27, 2006

CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER 11-102

PGE Exhibit 405

List of PGE's Quarterly Power Supply Update Meeting Dates

Dates of PGE Quarterly Power Supply Update Meetings
2007-2011

Date of meeting
February 2007
May 2007
August 2007
December 2007
February 2008
April 2008
July 2008
October 2008
January 2009
April 2009
July 2009
October 2009
January 2010
April 2010
July 2010
October 2010
January 2011
April 2011
July 2011

PGE Exhibit 406C

July 2010 Quarterly Power Supply Update presentation addressing

PGE's Mid-Term Strategy

CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER 11-102

PGE Exhibit 407C

PGE Gas Hedging Transactions Previously Reviewed

CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER 11-102

PGE Exhibit 408

CUB and ICNU Responses to PGE Data Requests

DR 3. Identify all testimony, hearing transcripts, or deposition transcripts since January 1, 2006, in which Bob Jenks, Gordon Feighner, or any other person on behalf of CUB addressed gas purchase strategies, or hedging by a gas or electric utility. If not available, please provide identifying information, for the case, the date of the testimony, and the parties involved.

Response: CUB objects to this request to the extent that it would require CUB to do work that can easily be done by Portland General Electric–this request is unduly burdensome to CUB. Portland General Electric is capable of researching historic PUC dockets without CUB's assistance. Notwithstanding the above, CUB submitted testimony regarding PacifiCorp's gas hedging strategies in UE 227 on June 24, 2011. CUB witness Lowrey Brown submitted testimony relating to the stipulation regarding Avista's gas hedging strategies in UM 1282 on March 16, 2007. (See http://edocs.puc.state.or.us/efdocs/HTB/um1282htb115238.pdf).

Bob Jenks' testimony in UM 1286 also discussed gas hedging. (See http://edocs.puc.state.or.us/efdocs/HTB/um1286htb144034.pdf).

Gas hedging was an issue in the recent NW Natural case regarding purchasing gas reserves. CUB filed three pieces of testimony in that docket:
http://edocs.puc.state.or.us/efdocs/HTB/um1520htb134241.pdf
http://edocs.puc.state.or.us/efdocs/HTB/um1520htb15919.pdf
http://edocs.puc.state.or.us/efdocs/HTB/um1520htb81549.pdf

In addition, gas hedging is an issue in annual Purchased Gas Adjustment (PGA) proceedings for each of Oregon's three gas utilities. CUB reviews and participates in each of these dockets, but the dockets usually settle without CUB sponsoring testimony.

DR 4. Identify and describe the purchasing strategies of other diversified fuel source electric utilities that CUB considered, consulted, or spoke with in coming to the conclusion that PGE's hedging activities and gas purchases were imprudent.

Response: CUB objects to this request to the extent that it would require CUB to provide information that is attorney client privileged or falls under the attorney work product doctrine. CUB further objects to this request to the extent that this request would require it to disclose information that is otherwise confidential or covered by protective orders. CUB did not conduct an analysis that compared PGE's approach to other electric utilities. CUB's conclusions concerning PGE's gas hedging strategy are based on the gas hedges that PGE purchased for 2012. See CUB/100/3-5 and CUB Exhibit 102.

DR 5. Did CUB provide any testimony regarding PGE's gas or electricity purchasing or hedging strategy, or PGE's mid-term strategy in any docket addressing PGE's power costs since January 1, 2006? If so, please provide the testimony.

Response: CUB objects to this request to the extent that it would require CUB to do work that can easily be done by Portland General Electric–this request is unduly burdensome to CUB. PGE is capable of researching historic PUC dockets without CUB's assistance and would already have possession of any such testimony. Notwithstanding the above, CUB believes that it last addressed PGE's hedging in the RVM in 2005. CUB's analysis in the current docket suggests that PGE has changed its hedging strategy (CUB/100/2).

DR 6. Please provide copies of all comments or other written filings made by CUB, or any person on behalf of CUB, regarding PGE's gas purchasing strategy, electricity purchasing strategy, or gas and electricity hedging strategy in PGE's last two IRP dockets, dockets LC 48 and LC 43.

Response: CUB objects to this request to the extent that it would require CUB to do work that can easily be done by Portland General Electric–this request is unduly burdensome to CUB. PGE is capable of researching historic PUC dockets without CUB's assistance and would already have possession of any such comments or filings. Notwithstanding the above, CUB believes that it did not submit comments or other written filings in LC 48 or LC 43 regarding PGE's gas purchasing strategy. CUB's analysis in the current docket suggests that PGE has changed its hedging strategy (CUB/100/2).

DR 7. Identify any other example of hedging strategy considered by CUB in performing its analysis in this docket.

Response: CUB objects to this request to the extent that it would require CUB to provide information that is attorney client privileged or falls under the attorney work product doctrine. CUB further objects to this request to the extent that this request would require it to disclose information that is otherwise confidential or covered by protective orders. Notwithstanding the above, CUB discussed the portfolio approach to gas hedging in testimony (CUB/100/4), which discusses managing gas hedging risk by spreading the hedges out over a period of time. CUB did not consider strategies beyond PGE's current strategy, which assumes a great deal of risk by concentrating most hedges in a narrow period of time, and the use of the portfolio approach, which reduces this risk.

DR 8. Provide a copy of the KPMG analysis referenced on pages 2-3 of CUB 100.

Response: CUB objects to this request to the extent that it would require CUB to do work that can easily be done by Portland General Electric–this request is unduly burdensome to CUB. Notwithstanding the above, CUB notes that, as stated in the Joint testimony for docket UM 1520, both the KPMG working draft report and the final KPMG report are included in the record: "The working draft report was included in the Company's filed binders and the final report is attached to this testimony as Exhibit JOINT/102." (Joint/100/14) See specifically: http://edocs.puc.state.or.us/efdocs/HTB/um1520htb81549.pdf

DR 9. Provide all evidence relied on by CUB regarding the lack of market liquidity for financial products with tenor greater than 36 months at the time the transactions in question were entered into.

Response: CUB objects to this request because it is unclear what CUB is being asked to provide – is PGE referring to the transactions PGE entered into and CUB reviewed in the UE 228 docket? In addition to the foregoing objection, CUB also objects to this data request to the extent that it would require CUB to provide information that is attorney client privileged or falls under the attorney work product doctrine. CUB further objects to this request to the extent that this request would require it to disclose information that is otherwise confidential or covered by

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 228

ICNU'S RESPONSE TO PGE'S DATA REQUEST NO. 006

July 27, 2011

Data Request No. 006:

Did ICNU or any person working on its behalf provide any testimony regarding PGE's gas or electricity purchasing or hedging strategy, or PGE's mid-term strategy in any docket since January 1, 2006? If so, please provide the testimony.

Response to Data Request No. 006:

With the exception of the Direct Testimony filed by Don Schoenbeck in the current rate case proceeding, neither ICNU nor any person working on its behalf provided testimony regarding PGE's gas or electricity purchasing or hedging strategy or PGE's mid-term strategy in any docket since January 1, 2006.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 228

ICNU'S RESPONSE TO PGE'S DATA REQUEST NO. 007

July 27, 2011

Data Request No. 007:

Please provide copies of all comments or other written filings made by ICNU, or any person on behalf of ICNU, regarding PGE's gas purchasing strategy, electricity purchasing strategy, or gas and electricity hedging strategy in PGE's last two IRP dockets, dockets LC 48 and LC 43.

Response to Data Request No. 007:

ICNU made no comments or written filings, nor authorized any other party to make comments or written filings on its behalf regarding PGE's gas purchasing strategy, electricity purchasing strategy, or gas and electricity hedging strategy in either docket LC 48 or LC 43.

PGE Exhibit 409C

Mid-Term Strategy Analysis – 2008 Update

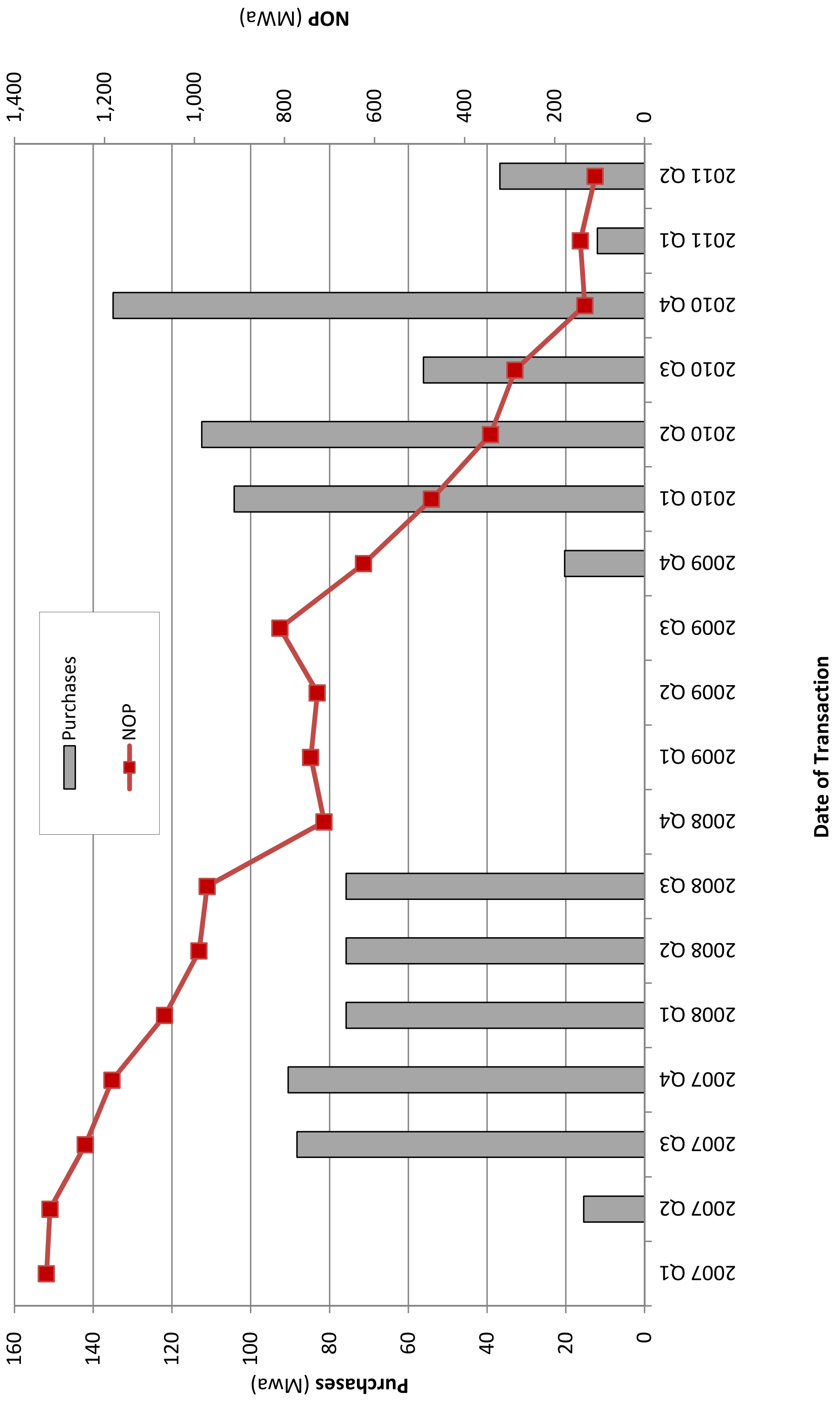
CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER 11-102

PGE Exhibit 410

PGE's Combined Power & Gas Procurement and

Net Open Position

Combined Power & Gas Procurement & NOP
For 2012 Delivery
(in MW equivalent)



PGE Exhibit 411

KPMG Report from

CUB's Response to PGE Data Request No. 008

Joint/102
Witnesses: Ken Zimmerman – Alex Miller – Bob Jenks – Paula Pyron

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1520 – UG 204

NORTHWEST NATURAL GAS COMPANY

Exhibit Accompanying Testimony of
Ken Zimmerman, Alex Miller, Bob Jenks, And Paula Pyron

KPMG Report

REDACTED VERSION

April 19, 2011

KPMG's analysis must be considered as a whole. Selecting portions of the analysis and of the factors considered, without considering all factors and analysis in connection with the preparation of this report, could create a misleading view of the processes underlying the opinion. Our work was based on a complex process and not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

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TRANSACTION ADVISORY SERVICES

Encana Partnership

Economic Assessment and
Comparison of Long-Term Gas Supply Alternatives
April 7, 2011

Prepared for the Northwest Natural Gas Company

AUDIT • TAX • ADVISORY

Glossary (1)

2P	Proved plus Probable reserves
Anadarko	Anadarko Petroleum
Bcf	Billion cubic feet
Boe	barrell of oil equivalent
BP	British Petroleum
CUB	Citizens Utilities Board
Deloitte	Deloitte & Touche LLP
Dth	Decatherm
Encana	Encana Oil & Gas (USA) Inc., a wholly-owned subsidiary of Encana Corporation
GBM	Geometric Brownian Motion
Henry Hub	Pricing point for natural gas futures contracts located in Erath, Louisiana
ICE	Intercontinental Commodities Exchange
IRR	Internal rate of return
KPMG	KPMG LLP
Jonah	The Jonah Field
LNG	Liquefied natural gas
NWN	Northwest Natural Gas Company
NSAI	Netherland Sewell and Associates Inc.
Mcf	Million cubic feet
MMbtu	Million British thermal units
MMcf/d	Million cubit feet per day
Monte Carlo	Simulation
NIGU	Northwest Industrial Gas Users
NPV	Net present value
NYMEX	New York Mercantile Exchange
Opal	The principle market centre for the Jonah and Anticline fields located in south-east Wyoming
OPUC	Oregon Public Utilities Commission
Probable	Probable reserves
Proved	Proved reserves
Shell	Royal Dutch Shell
Tcf	Trillion cubic feet
Ultra	Ultra Petroleum
Xcel	Xcel Energy

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Terms of Engagement

- Northwest Natural Gas Company ("NWN" or the "Utility") has agreed on terms for a "drill-to-earn" partnership with Encana Oil & Gas (USA) Inc. ("Encana") whereby NWN will fund a defined drilling program in return for certain working interests in related wells and leases (the "Transaction" or "Deal").
- KPMG LLP ("KPMG") was asked by management and the Board of Directors of NWN to assist with the following:
  - A "drill-to-earn" economic assessment – provide an opinion as to whether the Transaction is in accordance with the price paid for similar investments and whether the consideration to be paid is reasonable
  - Evaluate the deal economics in detail to assess value v. risk as it relates to pricing, production/supply volumes, costs, well/producer performance and other factors.
  - Comments on the scope of due diligence work performed by NWN
  - Review of long-term gas supply alternatives – a comparison of the Transaction with other options available to the Utility to secure a long-term gas supply
- We believe we are acting independently of NWN and are acting objectively. We have no present or contemplated interest in NWN or its affiliates nor are we an insider or associate of any of these parties.
- Fees payable to KPMG pursuant to our engagement are not contingent in whole or in part on the conclusions reached or the completion of the Transaction.
- We agree that our report may be shared with the Oregon Public Utilities Commission ("OPUC"), Citizens Utilities Board ("CUB"), Northwest Industrial Gas Users ("NIGU") and potential other parties to the OPUC proceedings.

Summary of Findings

- The proposed Deal provides NWN with a reliable long-term supply of long-term gas at a reasonable price.
- The financial models prepared by NWN agree with the proposed terms contained in supporting agreements.
- The scope of due diligence performed by NWN management was comprehensive.
- A key element of the due diligence relates to the reserve evaluation.
- The engineering firm Netherland Sewell and Associates ("NSAI") is well regarded within the energy sector across North America, particularly with respect to tight gas.
- With respect to the NSAI reserve study:
  - Pricing assumptions are consistent with market estimates
  - The reserve study contains several conservative assumptions and few, if any, aggressive assumptions
  - There is additional upside in the Deal that has not been considered by NSAI
- In many aspects, the Deal is consistent with a standard "farm-in" agreement commonly seen in the industry. However, a substantial number of NWN's risks in this deal have been mitigated.

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Introduction (2)

Summary of Findings (cont'd)

- There are several non-standard terms in the Deal that benefit NWN, including:
  - Working interest in existing production
  - [redacted]
  - Tax partnership
  - Land title
  - Cancellation clause
- We did not identify any material risks to NWN that have not already been considered by management.
- Key risk remaining is volumes in an area with consistent production history.
- Deal metrics imply NWN's investment equates to an [redacted]% pre-tax discount rate.
- Based on recent transactions found for the Jonah Field ("Jonah") and adjacent shale plays. NWN appears to be paying \$12.60/boe, a premium of \$3 to \$4/boe, which is still lower than the average price found for shale gas acquisitions across North America (\$16/boe).
- The implied full cycle cost to NWN is not significantly different than the estimated average cost to industry producers of shale gas (\$4.20/Mcf).
- The Transaction compares favorably to other long-term gas supply alternatives.
- We believe that it would be difficult for NWN to replicate this Deal with a credible partner, open negotiations, flexible terms and an asset with a similar risk profile.
- Our analysis and the basis of our conclusions are outlined in this report.

Scope of Work

- The information we reviewed and relied upon in arriving at our conclusions is provided in Appendix A. In addition, we attended the NWN offices and met with their management and other stakeholders from OPUC, CUB and NIGU. We discussed the Transaction with the following representatives from NWN:
  - Barbara Cronise, Director, Business Development
  - Keith White, Vice President, Business Development and Energy Supply
  - Kevin McVay, Manager, Integrated Resource Planning
  - Randy Friedman, Director, Gas Supply
  - Robert McAnally, Senior Gas Buyer
  - Jerry Fulps, Manager, Middle Office
- We also spoke with:
  - Jim Zadvorny, Advisor, Business Development and Julia Gwaltney, Team Lead, Jonah Field (Encana)
  - Bob Barg, Senior Vice President (NSAI)
  - Jerry Fish, Partner (Stoel Rives)
- Our review was limited in that:
  - We have not addressed any legal or other non-financial issues
  - We did not have access to Encana's data room. As such, our review was limited to the documents provided by NWN.
  - We have accepted the benefits associated with the tax credits reflected in the financial models provided

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Introduction (3)

Currency

- All amounts contained in this report are in US dollars, unless otherwise noted.

Assumptions

- The financial information provided by NWN is complete and accurate, including Encana's historical performance at Jonah
- The economics of the underling reserves as determined by NSAI are reasonable
- The tax benefits reflected in the reflected in the financial models are reasonable
- There is no additional information contained in the data room that would impact our assessment of the Transaction economics.
- There are no significant factors relevant to our analysis that have not been considered in reaching the conclusions herein
- Final agreements between NWN and Encana will not materially change from draft forms provided for the purpose of our analysis

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Summary of Transaction (1)

- NWN will enter into a drill-to-earn partnership whereby it will pay a $1 million "transaction" fee and $250 million over a five year period to fund drilling and completion costs in Encana's Jonah natural gas field located in Sublette County, Wyoming. In return, NWN will earn a working interest in Proved natural gas reserves that will allow it to deliver approximately 93.1 Bcf (approximately 104 million dth) to NWN customers over a 30 year period.
- The majority of the volumes (approximately 83%) will be delivered over the first 15 years of the agreement. NWN expects the volume of gas produced to provide an average of 4% to 5% of the total annual gas volumes it will deliver to its customers over the next 30 years. Volumes from Jonah will represent up to 15% of total annual volumes during the period when production is expected to peak sometime in 2015.
- NWN estimates that rate payers will save more than $50 million based on the net present value (NPV) of the project in comparison with other long-term supply alternatives.
- NWN's customers have experienced significant price volatility over the past 10 to 15 years.
- In practice, it is difficult to secure long term physical fixed price supply contracts at a reasonable price for a term extending beyond five years. Moreover, NWN is currently not authorized by its Board of Directors to enter into supply agreements longer than 3 years.
- NWN typically allocates approximately 10% of its supply portfolio to longer term physical supply arrangements. These have traditionally been executed either as fixed price agreements or index-based deals with financial hedges.
- With gas prices currently at or near historic lows relative to production costs, NWN is looking for ways to lock in longer term sources of low cost supply while prices remain subdued.
- The Transaction with Encana presents an opportunity to secure a significant source of low risk, long term supply (30 years) at a reasonable price and on terms that mitigate many of the risks the end user would normally assume in this type of structure.
- Encana is one of the largest producers of natural gas in North America and has been an industry leader in deploying new technology to develop previously uneconomic shale gas deposits.
- Encana currently has a massive project inventory; its value is not being maximized because low gas prices are restricting the generation of free cash flow required to fund drilling programs and draw the potential cash flows closer to the present (thus increasing the NPV's of these projects).
- To accelerate the development of these resources Encana is actively pursuing two strategic initiatives:
  - Execute a number of joint venture agreements in order to fund its drilling projects; and
  - Open new markets to increase demand for natural gas both in North America and over-seas.
- To date, Encana has focused primarily on the formation of joint ventures with sovereign energy companies from China and Korea, which it hopes will increase production volumes to levels required to justify a pipeline to liquefied natural gas (LNG) export facilities on the west coast of British Columbia to access over-seas markets.
- However, Encana is also very interested in creating new markets for its gas within North America by entering into long term farm-in / drill-to-earn agreements with large natural gas consumers such as power generation companies and domestic gas distributors.
- The Transaction with NWN is the first of what Encana hopes will be many partnerships that will increase demand for its natural gas in North America.

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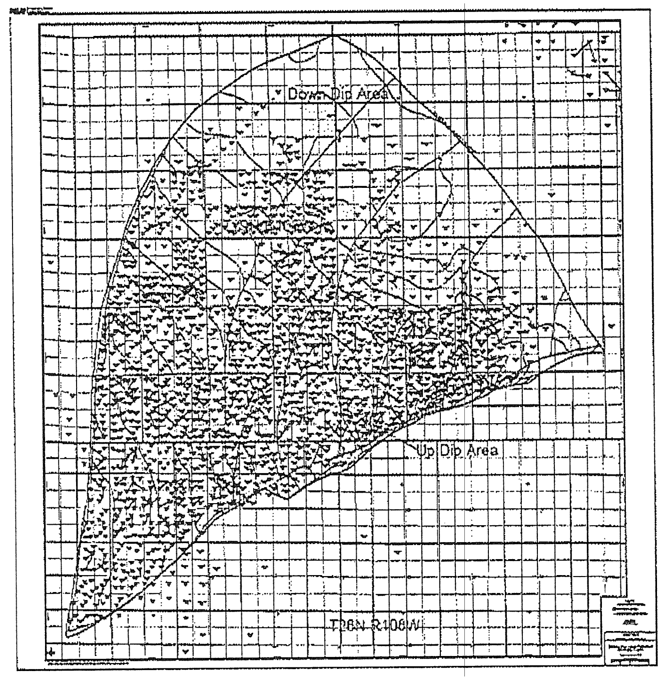
Summary of Transaction (2)

- NWN will farm-in on a minimum of four sections of Encana lands at Jonah and contribute $250 million of capital towards the drilling and completion costs of [redacted] wells. In return it will earn a working interest in approximately [redacted] Bcf ([redacted] Bcf net revenue interest) of low risk, high probability reserves to be produced and delivered to its customers over a 30 year period.
- [redacted] wells will be drilled in the "Up-dip" or shallower area of Jonah in Sections [redacted] and [redacted]. An additional [redacted] wells will be drilled in the "Down-dip" or deeper part of the Field located to the northeast of the Up-dip portion.
- Based on current well costs, NWN will pay an average of [redacted]% of the drilling and completion costs or $[redacted] million per well.
- ‚or each well that is drilled in the Up-dip area, NWN will earn a 1.2% gross working interest in one of sections 32 and 33 (to a maximum of 45%) and in section 34 (to a maximum of 32.4%).
- Importantly, the working interests assigned will include production already in existence at the time the wells are drilled.
- For wells drilled in the Down-dip area of the Jonah field where the producing horizon is further from the surface, NWN will earn a 1.2% gross working interest in one of sections 32, 33 or 34 plus 5% of Encana's net revenue interest in the wellbore being funded.
- [redacted]
- If the drilling costs fall below $[redacted] million, NWN will be credited with the "savings'" which will be rolled forward and applied to the cost of drilling an additional well.

Jonah Field – Up Dip and Down Dip Areas



Source: NSAI

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Summary of Transaction (3)

- NWN and Encana have agreed upon a drilling schedule, in which approximately twenty wells will be drilled in each of the first five years of the agreement. Encana is required to adhere to the drilling schedule regardless of the market price for natural gas.

Drilling Schedule

	Wells Rig Released				Maximum Interest Accrued		
	Section			Down	Section		
Year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%
	[redacted]	[redacted]	[redacted]	[redacted]			

- If Encana drills a dry hole, NWN will still earn its working interest in the section where the well is drilled, including the existing production.

NWN Working Interest - Net Revenue Gas

	Gas Reserves (MMcf)	%
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]

* As at May 1, 2011

- This means that of the approximately [redacted] Bcf of revenue interest reserves that will accrue to NWN through this Transaction, only [redacted] Bcf or [redacted]% are subject to drilling risk. The remainder will come from earned interests in wells that are already producing.
- NWN will have an option to participate in additional future wells (beyond the [redacted] specifically contemplated in the Transaction) in the sections where working interests have been earned.
- For these wells, NWN will pay its pro-rata share in return for the same share of the production and reserves from the well.
- These wells will not earn any additional interests in other acreage or production. However, all of the other terms and conditions covering the original [redacted] wells will extend to these additional wells.
- NWN may opt out of participating in these additional wells, in which case they will still earn their working interest after 300% of their pro-rata share of wells costs are recovered by other well participants from the revenue stream.
- As part of the Transaction a tax partnership will be formed to facilitate the timely recovery of drilling tax credits.
- NWN expects to receive more than $[redacted] in tax credits over the term of the Deal. [redacted].

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Summary of Transaction (4)

- Encana will be responsible to pay for all surface equipment and gathering and processing infrastructure required to produce the NWN funded wells. This includes the costs for both new construction and capital improvements in the future.
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
- If Encana decides it wants to retain its interests in the sections covered by the agreement but does not want to be the operator, it has the right to do so and appoint another party to operate the Field.
- Under this scenario, the terms of NWN's agreement with Encana will remain in place so long as the new operator performs as a prudent operator would be expected to do.
- With the consent of NWN, Encana could choose to either delay or accelerate the drilling schedule.

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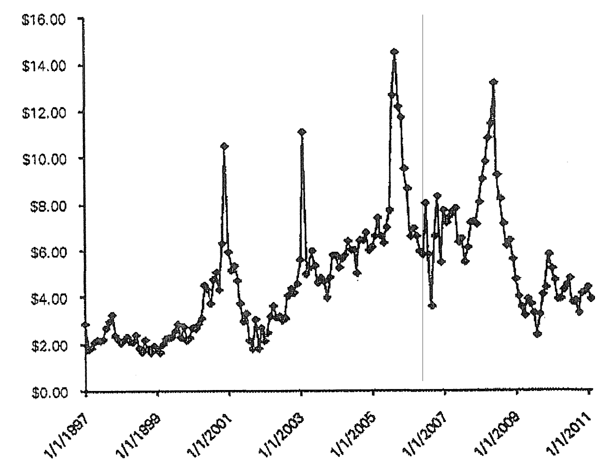
- Over the past decade, North American natural gas prices have been volatile. Prices have oscillated as demand growth has stayed on a relatively steady trajectory.
- Conventional supplies first fell during the middle of the last decade, and then increased dramatically as producers began booking large quantities of new, low cost shale gas reserves.
- For reasons beyond the scope of this report, North American producers have aggressively drilled these new shale plays even as falling gas prices have rendered the economics of many of these plays marginal. As a result, the North American continent is currently in a state of over-supply with a storage surplus so large that that natural gas prices are at or near historic lows relative to production costs, and on an absolute basis, are at their lowest point since the early 2000's.
- However, there are factors now emerging that suggest gas prices may not remain in the current band of low prices indefinitely.
- The extended period of low prices may finally be forcing producers to reduce their rabid pace of drilling. Rig counts are now starting to roll over and some industry experts are now beginning to look for prices to turn some time later in 2011 or early in 2012.
- Moreover, substantial investments in the past several months by sovereign energy companies and investment funds (particularly from Asia) in North American shale gas plays and associated pipeline and LNG terminals could transform North American natural gas into a global commodity subject to global pricing mechanisms over the next decade.
- Global natural gas prices are currently much higher than in North America (close to $10/Mcf as of March 7, 2011) because the pricing mechanism includes an explicit tie to the price of oil.
- Finally, there is evidence emerging that the low cost structures often referred to in the shale gas economics equation may be overstated. Although the jury is still out, confirmation of this trend will be another factor that points towards a higher natural gas price environment in the future.
- The result is that end users in North America are looking for ways to secure longer term sources of supply at low prices now.
- One option that is emerging is entry into joint ventures (also known as farming-in) in known natural gas fields. In return for funding a portion of the capital cost to drill wells, end users can secure a source of supply at a fixed price and over a longer term than that offered by the traditional sources of long term supply.
- NWN is an early mover in this regard with its farm-in on Encana's Jonah natural gas field.

NYMEX Natural Gas Price History



Source: Bloomberg

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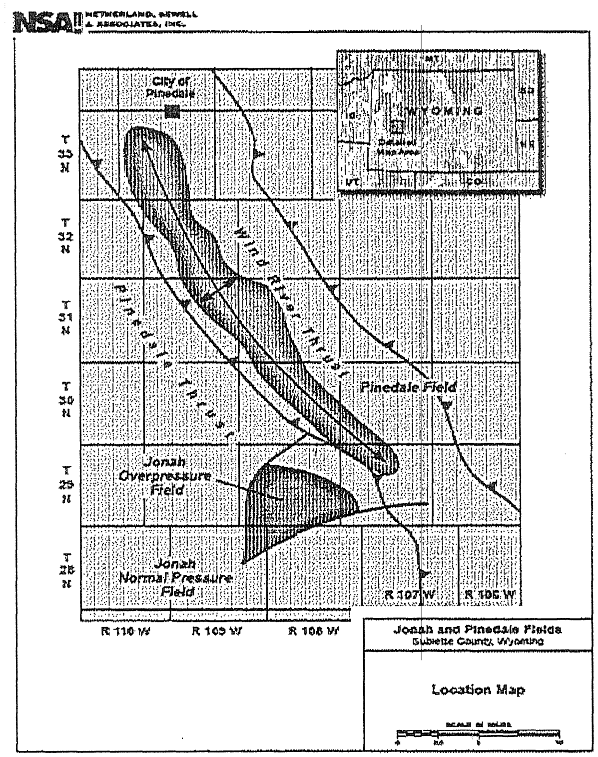
- Jonah is located in Sublette County, Wyoming and lies in the southeastern portion of the Hoback Basin, which is a northwestern extension of the Greater Green River Basin.
- Over the past several years, improvements in hydraulic fracturing technology have opened up massive new tight gas reserves in shale basins across North America. Within this context, Jonah is significantly ahead of its time.
- The Field was discovered in the 1990s, and was the proving ground for much of the new technology being deployed in other shale plays today.
- It now has a history of consistent production and reserves growth in excess of 10 years, while most other shale plays in North America are still in their infancy with production histories of less than three years.
- As such, Jonah is likely the most well understood of all the shale plays in North America in terms of production profile, reservoir parameters and projected reserves recovery.
- Today Jonah has more than 1,500 producing wells with a total field gas production rate of nearly 890 MMcf/d. Encana, British Petroleum ("BP") and Ultra Petroleum ("Ultra") are the principal operators of the Field, while several other companies have smaller operations in the area.
- A long history of consistent reserve and production growth combined with a steady improvement in the cost structure has propelled Jonah to its current status as a world class natural gas field.
- At the end of 2008, Jonah was one of the top ten US gas fields as measured by Proved reserves.

ocation of the Jonah Field



Source: NSAI

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The Jonah Field (2)

- Most of the natural gas at Jonah is found in the Lance Formation at depths of 8,000 to 13,000 feet.
- The gas is contained in ancient sandstones deposited in a series of meandering river channels that are interbedded between impermeable shale sequences, and are essentially stacked one on top of another.
- The gas bearing sandstones have very low permeability and porosity (making them known as "tight" in industry speak). This means that the gas is trapped in very small spaces between the grains of sediment, and it does not flow easily to a well bore because the pathways between these spaces are narrow or even non-existent.
- In order to make the gas flow, hydraulic fracturing techniques are employed to force open or stimulate the tight sandstone formations so that gas can flow at economic rates.
- The sandstone at Jonah contains much more gas than a typical conventional formation, so more wells are required to efficiently drain the reservoir than the typical one per 160 acres drilled into conventional reservoirs.
- At Jonah, one well is required for up to every 5 to 10 acres of surface area. As a result, a large drilling inventory remains.
- [redacted]
- Encana entered the Jonah field in 2001 and has since become the dominant operator in the area.
- Over the past decade Encana has consistently increased production and reserves, while becoming one of the lowest cost operators in the region.
- Encana is now producing approximately 725 MMcf/d from more than 1,175 wells.
- During the time it has operated at Jonah, Encana has also established a strong environmental track record and has become a leader among its peers in the preservation of the region's ecology.
- Some of the initiatives that have contributed to this reputation include aggressive land reclamation programs (the bar is set high with the goal of reclaiming at the same rate as any corresponding disturbances) and an 80% reduction in harmful atmospheric emissions over the past five years, largely through the introduction of natural gas powered rigs.
- Encana has received a number of environmental awards over the past several years for its efforts.

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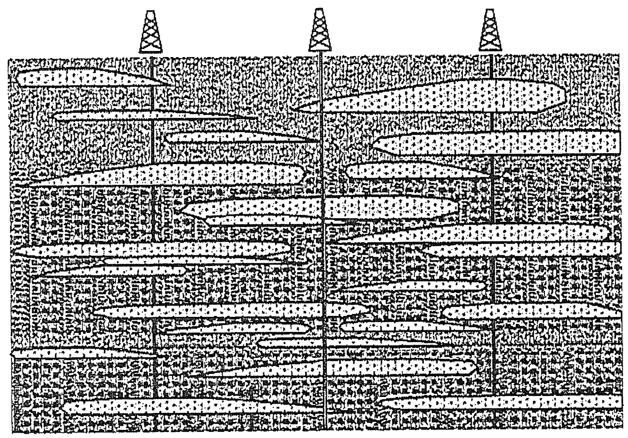
The Jonah Field (3)

Jonah Field Geological Profile



Source: NSAI

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Due Diligence

- We understand that NWN's due diligence on the Transaction was managed internally and led by Barbara Cronise, Director, Business Development. Jerry Fish of Stoel Rives also played a key role.
- Based on our understanding of the due diligence work performed by NWN, we concluded that the scope of work performed was comprehensive and appears to have covered the major risk areas.
- We note that only a high level summary of NWN's due diligence process was provided.
- As such, our comments are based solely on our review of a limited number of documents provided by NWN and discussions with Ms. Cronise and Mr. Fish.
- In summary, we understand NWN addressed the following areas:
  - Reserves (retained NSAI)
  - Historical costs
  - Land title (local counsel in Denver provided updated title opinion)
  - Environmental issues (addressed by Stoel Rives and environmental consultants ENVIRON)
  - Permits (reviewed by Stoel Rives)
  - Contracts (reviewed by Stoel Rives and covered existing contracts including drilling, gathering & processing, insurance)
  - Review of Encana documents (considered wells, contracts, regulatory and right of way issues)
  - Tax and tax partnership structure (opinion from Deloitte)
  - Legal matters including litigation (addressed by Stoel Rives)
  - Risk of Encana bankruptcy
  - Commercial terms of the Deal (negotiated terms to mitigate risk while maintaining the economic benefits of the Deal)

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Financial Model Review

- In the course of our work, we reviewed the following economic and financial models provided by and relied upon by NWN (collectively the "Models"):
  - Encana's Jonah production model
  - NWN's Jonah production model
  - NWN's economic model (including estimated costs to the rate payers)
- Based on our review, we were satisfied that the Models accurately reflected the agreed terms of the Transaction.
- We confirm that the production forecasts contained in the Models agree with one another.
- We note that logic employed in the NWN production model yielded slightly different month to month production profiles than the Encana production model.
- In our view, the differences are not significant and have little impact on our assessment of the economics of this Transaction.

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Risk Mitigation

- NWN has negotiated a number of terms that are not typically seen in farm-in agreements, and serve to reduce the risk normally assumed in this type of investment.
- The inclusion of these terms, in addition to the parties openly sharing technical data and relying on the same independent reserve evaluator (NSAI), has resulted in a highly transparent negotiation and terms that strongly align the interests of all parties.
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]

[redacted]

- [redacted].

Drilling Risk

- [redacted]

Reservoir Risk

- [redacted]
- [redacted].

Cost Inflation

- [redacted]
- [redacted]

Counterparty Risk

- [redacted]
- [redacted]
- [redacted]

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Risk Analysis (2)

Price Volatility

- The Transaction includes the formation of a tax partnership [redacted]

Regulatory Risk

- NWN and Encana both have the right to terminate the joint venture agreement if regulatory changes take place which eliminate substantially all of the tax benefits currently contemplated in the Transaction.

Cost of Mitigation

- We note that NWN has sacrificed some degree of upside in return for mitigating risk.
- [redacted]
- [redacted]
- NWN will still have an option to commit additional capital and participate in the drilling of Probable reserves in the future. However, it will have to pay its pro-rata share of the well costs at the time of drilling in order to participate and will earn no additional working interest outside of the interest it earns in the wellbores it funds.

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Risk Analysis (3)

Remaining Risks and Sensitivities

- Notwithstanding the risks that NWN mitigated, some risks still remain. These include:
  - Drilling risk
  - Production risk
  - Operator risk
  - Market risk
  - Regulatory risk
  - Counterparty risk
  - Termination risk

Drilling Risk

- Drilling risk consists of:
  - Risk of drilling a dry hole; and
  - Risk of delays
- Although Jonah is very well understood and the wells NWN will fund are low risk infill locations, the parties are still exposed to the risk of drilling a dry hole.
- The infill nature of the drilling means that there is near 100% probability of success for each drill, and the well understood reservoir parameters make it virtually certain that a wellbore will intersect gas bearing horizons. Therefore, a dry hole would only occur in a circumstance where mechanical issues in the wellbore rendered it unable to produce.
- [redacted]
- There would still be some loss of reserves and production potential but not of a magnitude to dramatically impact the projected economics of the Transaction.
- A delay in executing the drilling schedule could result in lost reserve volumes and a lower project NPV.
- NWN has run three alternative scenarios to the base case drilling schedule and have determined that the worst case scenario, a 12 month delay, would result in no more than a 1% decrease in net gas volumes. The NPV of the base case would decline by approximately $350,000.

Production Risk

- NSAI is a highly regarded reserves evaluator and has employed a number of conservative assumptions in preparing their reserves report.
- Moreover, NSAI has been granted access to reservoir data for Jonah dating back to 1996 and has completed an evaluation of Encana's reserves at Jonah since 2002.
- This gives us comfort in the accuracy of the production and reserve recovery forecasts assumed in this Transaction.
- However, there is still some uncertainty in even the best reserve evaluations, so we consider here the reservoir-related risk factors that could ultimately affect the economics of this transaction, either positively or negatively. These include:
  - Actual recovery factor
  - Reservoir decline rates
- NSAI has used a recovery factor of 85% in its analysis, meaning that it is more than 90% probable that 85% of the original gas in place will be recovered. We believe this is a conservative assumption.

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Sensitivity - Changes to Recovery Factor			
	Reserves	Variance**	
Recovery Factor	(Bcf)	($MM)	
90.0%	95.7	$	4.9
87.5%	94.6	$	3.0
85.0%*	93.1	$	-
83.0%	91.3	$	(3.4)

*Base case based on 85% recovery factor

** NPV for project calculated by NSAI based on a pre-tax discount rate of 10%

Sensitivity - Change to Exponential Decline Rate			
	Reserves	Variance**	
Decline Rate	(Bcf)	($MM)	
11.0%	89.2	$	(4.5)
10.5%	90.5	$	(3.3)
10%*	93.1	$	-
9.0%	97.7	$	4.8

*Base case based on 85% recovery factor

** NPV for project calculated by NSAI based on a pre-tax discount rate of 10%

- We note that the change is not perfectly linear, as the recovery factor is interrelated with other variables that contribute to NPV, such as the decline rate.
- However, we calculate that a 1% change in the recovery factor from the base case will change the NPV benefits to the rate payer by approximately $1.3 million.
- Given the production history and deep understanding of the reservoir parameters, we believe that the probability of exceeding the 85% base case recovery factor is greater than the probability of falling short.
- The NPV benefit to the rate payer is also sensitive to the decline rate.
- The faster the reservoir is depleted, the lower the recoverable reserves and NPV. NSAI used a 10% exponential decline in their analysis.
- Based upon the production history at Jonah, we consider it unlikely that the decline rate will exceed 10%, but believe it could ultimately be lower, perhaps 9%.
- Once again we note that the change is not perfectly linear as a change in recovery factor will in turn influence other factors that contribute to NPV.
- We calculate that a 1% change in the exponential decline rate from the base case will change the NPV benefits of this project to the rate holder by approximately $4.7 million.

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Operating Risk

- Encana is widely regarded in the natural gas industry as a world class operator, and has achieved low and stable operating costs at Jonah due to its operating skill and the economies of scale achieved through the concentration of its activities within a 36 square mile area.
- We expect their operating acumen to result in continued low operating costs and minimize the risks associated with sub-optimal reservoir performance and poor maintenance or performance of infrastructure.
- In spite of these benefits NWN could still be exposed to potential increases in gathering and processing fees beyond those currently negotiated, and to the degree that not every circumstance or challenge can be perfectly addressed, to the potential for poorer than anticipated reservoir performance.
- However, given Encana's size, track record and skill as an operator, we consider these risks to be minor.
- We also note that operating costs [redacted]
- We have examined the sensitivity of project NPV to changes in operating costs, the majority of which would likely come from changes in gathering and processing fees.
- We calculate that a 1% change in operating costs from the base case will change the NPV benefits of this project to the rate payer by approximately $750,000.
- NWN is also exposed to the risk associated with disruptions in gathering and processing service due to outages related to extended maintenance or repair of unforeseen damages.

- Encana is the dominant operator at Jonah and the attractive economics of this resource are due in no small part to Encana's technical skills in operating the field.
- Therefore, as long as Encana owns its interests at Jonah, we think it unlikely that they would abdicate their role as the operator.
- However, improbable as this may be, there can be no assurance that it will never happen.
- If Encana were to appoint another operator NWN would be exposed to potential erosion in operating margins and the possibility of diminishing reservoir performance should the new operator be less skilled than Encana.

Sensitivity - Change in Operating Costs

Operating Costs ($/Mcf)	Reserves (Bcf)	Variance** ($MM)
[redacted]	[redacted]	$ [redacted]
[redacted]	[redacted]	$ [redacted]
[redacted]	[redacted]	$ [redacted]
[redacted]	[redacted]	$ [redacted]
[redacted]	[redacted]	$ [redacted]

*Base case based on 85% recovery factor

** NPV for project calculated by NSAI based on a pre-tax discount rate of 10%

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Market Risk

- North American natural gas markets are undergoing rapid and dramatic change in terms of supply / demand dynamics, the emergence of new low cost shale gas plays, the consequential changes in transportation infrastructure and the direction and magnitude of product flows.
- In this context, we believe that natural gas prices are likely to move away from their current price band over the medium to long term.
- Although our bias is to price upside, further development of shale plays in both North America and across the world could potentially increase world supply to levels that push natural gas prices to levels below the current band.
- Under this scenario, the benefits of the Transaction to the end user would be eroded.
- The base case year 1 price of $4.60 and prices for the following years is that employed in the NSAI reserve report.
- We calculate that the project NPV will increase by approximately $910,000 for a 1% increase in price from the base case, while a decrease of 1% will lower the project NPV by approximately $2.9 million.
- The discrepancy is due to the impact of natural gas price on ultimate reserve recovery.
- NSAI has calculated that an increase in gas prices above the base case year 1 price of $4.60 per Mcf will have no impact on the 85% recovery rate.
- On the other hand, lower gas prices reduce the amount of recoverable reserves because less gas is economically recoverable the lower the price goes.

Sensitivity - Change in Natural Gas Price

Year 1 Price	Reserves (Bcf)	Variance** ($MM)	
$2.50	83.9	$	(133.9)
$4.60*	93.1	$	-
$9.00	93.1	$	97.1
$12.00	93.1	$	168.5

*Base case based on 85% recovery factor

** NPV for project calculated by NSAI based on a pre-tax discount rate of 10%

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Regulatory Risk

- The regulatory regime in Wyoming is progressive and friendly to the natural gas industry, and Encana has developed a reputation as an environmentally responsible producer.
- However, this does not preclude the possibility of future changes to environmental or tax laws that could increase taxes or operating costs.
- Should such change occur, the tone of the current regulatory regime suggests to us that changes in this regard would not be of a magnitude that would render production uneconomic and shut down the industry – the significant benefits from the industry to the State of Wyoming should place limits on the degree of change and financial cost that might be expected.
- Despite the friendly stance of the current regulatory regime, there is potential for increased interference and/or new regulations pertaining to the use of well fracturing techniques.
- Various environmental groups across North America have expressed concern that the chemicals and other materials used in frac fluids could contaminate valuable sources of underground water supply.
- Public awareness and concern over this issue is increasing and regulatory bodies in Pennsylvania and New York (Marcellus shale gas play) and Quebec (Utica shale gas play) are currently conducting environmental reviews on the impact of hydraulic well fracturing activities.
- If it is determined that this process does put underground water resources at risk, then there is a high probability that well fracturing activity could be curtailed or entirely outlawed.
- However, by the time all of the hearings and legal proceedings required to enact new laws are completed, we expect that most, if not all, of the wells NWN is committed to fund will already be drilled; we see little risk to NWN in this regard.

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Risk Analysis (8)

Counterparty Risk

- Encana is one of North America's largest natural gas producing companies and is in a solid financial position.
- Given its current financial stability and dominant industry position, Encana's status as a going concern is not presently in question. However, the terms of this Transaction cover a 30 year period, a very long time in the lifespan of a corporation.
- Therefore, although it is unlikely the Encana could cease to be a going concern, there is no guarantee that they will remain a viable entity over the entire length of the Deal.
- If Encana does become insolvent, NWN would retain legal title to the leases and ownership of the reserves in which it has earned an interest.
- However, it would be exposed to potential performance and cost management issues associated with the replacement of Encana by a new owner and/or operator.
- [redacted]
- This would not in itself be catastrophic and would likely have only a minor impact on the overall economics of the Transaction.
- [redacted]
- [redacted]

Termination Risk

- NWN is participating in a world class natural gas asset run by an industry leading operator in Encana, with whom its interests are closely aligned.
- Although the partnership structure has mitigated many of the risks that could sour the relationship between the two parties, it is possible that NWN could at some point determine that termination of the partnership is in its best interest.
- [redacted]
- [redacted]
- [redacted]

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Summary of Deal Risks and Sensitivity Analysis

- The table below shows that the decline rate is the most important of the variables impacting project NPV that we were able to analyze.

Summary of Sensitivities	
Based on 1% Change	**Variance****
Variable:	($MM)
Decline Rate	$ 4.7
Recovery Factor	$ 1.3
Operating Cost	$ 0.8
Gas Price (Increase)	$ 0.9
Gas Price (Decrease)	$ 2.8

*Base case based on 85% recovery factor

** NPV for project calculated by NSAI based on a pre-tax discount rate of 10%

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Market Benchmarks

- To assess the fairness of the implied pricing of the Transaction in the context of the current market, we considered the following:
  - Comparable transactions
  - Implied discount rates
  - Implied full cycle costs
  - Supply costs

Comparable Transactions

- An examination of 14 transactions weighted to tight or shale gas assets yielded the following conclusions:
- NWN acquired a total of 119.4 Bcf of gross Proved reserves in the Transaction, which translates into a price of $12.60/boe.
- When compared to the average price of $15.92/boe for tight/shale gas plays in the broad North American market it appears that the reserves were acquired at discount.
- Within Jonah, and the neighboring tight gas fields on the Pinedale Anticline and in the Piceance Basin there has not been much of any merger and acquisition activity in recent years.
- However, several transactions we observed suggest that there is support for valuations in this geographic area in the $9.00 to $10.00/boe range.
- On this basis, NWN appears to have paid a modest premium. However, we believe it is justified given the risk profile of the reserves acquired and the other risk mitigating factors inherent in the Deal compared to other transactions.
- The Transaction was also compared to a similar gas supply agreement between Anadarko Petroleum ("Anadarko") and Xcel Energy ("Xcel") that received regulatory approval in early 2011.
- This agreement provides Xcel with gas supply at fixed price of $5.48/Mcf for a ten year period.
- The average price to NWN's end users is $5.09 over the entire 30 years of the agreement with Encana and $5.21 over the first 10 years.
- The Xcel contract also requires that customers bear the risk of finding replacement supplies in the event of a contract default by Anadarko, while NWN customers do not bear this risk in their Transaction.

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Economic Assessment (2)

Comparable Transactions (cont'd)

- This further supports our view that the Transaction is financially fair from a market perspective.
- Overall, given the highly predictable nature of the reserves and other risk mitigating deal terms, we conclude that the price NWN paid to enter this joint venture is fair from a broad market perspective.

Comparable Transactions

	No.	Mean	Median	Low	High
$/boe					
Green River / Piceance	4	$ 8.53	$ 9.82	$ 3.73	$ 10.76
Other shale/ tight gas	14	$ 15.05	$ 9.63	$ 1.03	$ 68.36

Implied Discount Rates

- The present value of reserves calculations in the NSAI reserves report suggest that the pre-tax discount rate implied in this transaction is approximately [redacted]%.
- There was not sufficient publicly available information from the aforementioned tight/shale gas transactions we observed to determine the implied discount rates.
- However, KPMG has observed numerous gas transactions in Western Canada over the past six months that suggest the implied pre-tax discount rates for natural gas transactions for 2P reserves over the past six months have been in the range of 12% to 14% (discount rates on Proved reserves would be lower). We believe this is consistent across North America, not just in Western Canada.
- Based on the implied discount rates, the Transaction appears to have been priced at a premium but one which we believe is justified given the risk profile of the assets acquired.

Implied Full Cycle Costs

- The full cycle cost of a natural gas asset is defined as all of the costs required to find, develop, produce and sell the reserves.
- Specifically, this includes the cost of land, exploration and development (seismic, geophysical work, drilling and completions, etc), royalties, taxes, operating costs and fees for gathering, processing and product marketing.
- Assets of the highest quality are the ones with the lowest full cycle cost, as they produce the best returns on investment.
- We estimate that full cycle costs for tight / shale gas reserves in North America average approximately $4.20/ Mcf, which is in line with the implied full cycle cost of $4.30 for the Transaction.
- In accruing full cycle costs, natural gas producers assume substantial risk at the front end of the cycle as there is considerable uncertainty associated with exploration drilling and the development of a gas deposit to the point where reserves can be booked.

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Implied Full Cycle Costs (cont'd)

- Thereafter, the producers bear the risk of capital and operating cost inflation, environmental liabilities and a requirement to incur plug and abandon costs when the reserves are depleted.
- NWN is assuming virtually none of these risks and could therefore be seen as acquiring the Jonah reserves at a lower price on a on a risk adjusted basis.

Full Cycle Costs for Select Tight/Shale Gas Companies

Full Cycle Cost ($/Mcf)	EnCana (Jonah)	Ultra (Pinedale)	NWN	Questar (Pinedale etc)	Nextraction (Pinedale)	Sample Average	Industry Mean
Finding & Development[1]	1.36	1.48	2.10	1.07	2.25	1.65	2.61
Royalties[2]	0.88	0.88	0.88				
Production Taxes3	0.53	0.53	0.53				
Operating Cost4	0.20	0.20	0.78				
Transportation & Selling5	0.73	0.73		2.77			
Total Full Cycle Cost[6]	**3.70**	**3.82**	**4.30**	**3.84**	**3.64**	**3.86**	**4.23**
F&D % of Full Cycle Cost	37%	39%	49%	28%	62%	0.43	62%

1. For Encana as per Encana Investor presentation, for Ultra as per 2010 Annual Report for NWN based on cost to acquire gross reserves at Jonah, for Questar as per January 2011 Investor presentation, for Nextraction as per 2010 Investor presentation
2. Royalties of $0.88/Mcf for Encana based on 22% (as per Encana Investor presentation) and a natural gas price of $4.00/Mcf (chosen by KPMG). Extrapolated to NWN as it operates in same field as Encana and to Ultra, as royalty structures in Pinedale are assumed by KPMG to be very similar to Jonah due to the close geographic proximity of the two fields.
3. Production taxes as per Encana Investor presentation.
4. Operating cost for Encana as per Encana Investor presentation. Cost has been extrapolated to Ultra by KPMG as Pinedale and Jonah fields have similar operating cost requirements. Operating cost for NWN as per NWN economic model.
5. Transportation and selling cost for Encana as per Encana Investor presentation. Cost has been extrapolated to Ultra by KPMG as Pinedale and Jonah fields have similar operating cost requirements. Cost for Questar is composed of Q2/10 cash costs (lease operating expense plus production taxes plus G&A plus interest plus DD&A) as per company reports.
6. Full Cycle Cost for Encana, Ultra, NWN and Questar calculated as the sum of finding & development and cash costs. For Nextraction, the sample average and the industry mean, full cycle costs calculated by taking the average of F&D costs as a percentage of the full cycle cost, and then backing out the extraction cost and the sample and industry means based upon this information.

Source: Company reports, Tudor Pickering Holt & Co. LLC, KPMG

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Economic Assessment (4)

Supply Costs

- A Morgan Stanley study referenced in a September 2010 investor presentation by Ultra concluded that the breakeven gas price (the flat NYMEX strip price required for a shale gas play to generate a 10% IRR) for North American shale gas plays averaged approximately $4.20/Mcf.
- We have previously stated that evidence is now emerging that the cost structures for many of North America's shale gas plays may be understated.
- If true, the supply cost will rise above the current estimate of $4.20 and require that gas prices increase to higher levels than we are observing today.
- In a January 2011 investor presentation, Encana indicated that its expected supply cost (8% IRR, not including land costs) for Jonah would be in the $3.00 to $4.00 range.
- Given the long production history of the Jonah field and the consequent abundance of reservoir data, we believe that the cost structure (i.e. supply cost) of the natural gas assets NWN has acquired will not be subject to the upward revisions that could be in the cards for other shale gas plays in North America.
- If the cost structures of other shale plays are revised upwards, NWN will receive further validation that it has paid a fair and reasonable price for the assets it has acquired.

Summary of Market Comparison

- Based upon the preceding analysis, we believe that the Transaction with Encana is fair from a financial and market perspective.
- On some measures, NWN is paying a small premium. On other measures the assets are being acquired at a discount. However, when the valuation metrics we have used are observed in aggregate, the results suggest that NWN has paid a fair price for the Jonah assets.
- Moreover, the low risk nature of the reserves acquired, combined with the potential upside to be discussed later in this report, suggest that on a "risk adjusted" basis, the price paid by NWN will prove to be lower than $12.60/boe.

Other Considerations

- There are a number of sources of potential upside to the economics of the Transaction. These include:
  - Probable reserves
  - Conservative reserve assumptions
  - Favorable changes to the drilling schedule
  - Reduction in capital costs
  - Increases in natural gas prices

Probable reserves

- The Transaction only gives consideration to the Proved reserves that NWN is expected to own and produce. [redacted]
- NSAI has assumed a reasonable and prudent drilling schedule to determine that these wells could add approximately $16 million of incremental NPV benefit to NWN's rate payers.
- Regulatory approval to drill these locations has not yet been granted, but historic experience in this regard suggests approval should be little more than a formality.

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Economic Assessment (5)

Conservative Reserve Assumptions

- In calculating the 93.1 Bcf of net Proved reserves being acquired by NWN, NSAI has assumed a 10% annual decline rate on the exponential portion of the decline curve (the portion of the decline curve that flattens out after the period of high initial production when a well first comes on stream).
- NSAI has acknowledged that this is a conservative assumption. An exponential decline rate of 9% would result in the production of approximately 4.6 Bcf of additional reserves during Jonah's productive life and add incremental NPV of approximately $4.9 million.
- The 93.1 Bcf of Proved reserves projected to be recovered is predicated upon an 85% recovery factor.
- However, producers will often exceed the estimated recovery factor due to either natural factors or the skill of the operator. Exceeding the recovery factor by 5% would result in an estimated 2.6 Bcf of additional reserves and an incremental NPV benefit to the end user of $4.1 million.

Favorable Changes to the Drilling Schedule

- If Encana should choose to accelerate the drilling program, the recoverable reserves and NPV accruing to NWN's end users would increase. NWN approval would be acquired for any increase in the pace of drilling.

Reduction in Capital Costs

- If drilling costs were to fall below the $[redacted] of capital [redacted]
- At this time, we project that the aggregate "savings" from lower capital costs could approach but would not likely exceed the cost of one additional well. An extra well drilled with these savings would likely add 0.8 to 1.0 Bcf of incremental volumes to NWN.

Increase in Natural Gas Prices

- Our previous discussion of scenarios where shale gas cost structures may be revised upwards or gas prices are exposed to world market forces show that price increases far in excess of those assumed in the generation of reserves reports today area possible.
- We add to this the possibility that large price increases could also come about if new environmental regulations regarding the use of hydraulic well fracturing were to come into effect.
- Although we are not in the business of forecasting natural gas prices, we believe there is a possibility that the unfolding of these scenarios could result in natural gas prices rising over the medium to long term and offer additional upside to NWN in the form of:
  - Potential opportunities to attract new customers because of lower gas costs, and therefore lower rates, than competitors may be in a position to offer
  - Opportunities to generate trading profits by entering financial derivatives contracts and using the low cost physical gas from Jonah to back the trades. Profits could be used to subsidize the cost of gas to consumers in high price environments

Conclusion

- The Transaction price to NWN is reasonable in comparison with prices currently observed in the market.

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Long-Term Natural Gas Supply Alternatives

Overview

- KPMG was asked to review alternative gas supply transactions including but not limited to the review of indicative price quotes obtained by NWN.
- We note that all of the following scenarios are likely academic in nature, since:
  - The terms are shorter than the Encana Deal
  - There is no guarantee a counterparty would commit to these price, and
  - It is unlikely that NWN could in fact enter into any of these arrangements in any event.

Approach

- KPMG performed the following:
  - Compare the reasonableness of the quoted natural gas alternative transactions
  - Evaluate alternative gas supply transactions against identified risk categories

Summary of Findings

- [redacted] and [redacted] quotes are close approximations to KPMG's simulated price:
  - Indicative price obtained by KPMG from a financial institution is equivalent to the indicative price obtained by NWN from Shell before credit costs were applied
  - KPMG model simulated price of $6.54/MMbtu is in line with the [redacted] and financial institution indicative price assuming a $0.50 to $0.10 market premium additive
  - Credit requirement may be less than calculated by NWN due to the fact they are an investment grade rated entity and would be granted unsecured credit when dealing directly with a natural gas supplier/producer
  - Indicative prices include a credit cost assuming the transactions are cleared on ICE

Comparison to Other Supply Alternatives

	Cost of Gas Fixed ($/Mcf)	Cost of Gas Fixed ($/Therm)	Term (Years)
[redacted]	5.71	0.51	30
[redacted] *	6.68	0.60	20
[redacted] *	6.62	0.59	20
KPMG Physical	6.54	0.58	20
[redacted]	6.64	0.59	20

* Includes credit

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Summary of Findings (cont'd)

- _orward spot prices represent today's transaction prices and have limited predictive value in forecasting the price NWN could execute hedges three years from today.
  - NYMEX spot prices represent future prices executed today versus a future date
  - Unknown global and economic factors could impact a future spot price executed at a future date
- NWN's $0.40 per dth cost associated with a $3.00 price shock represents a close approximation to a 5% probability market event and related margin calculations appear reasonable:
  - KPMG calculated a two standard deviation price movement of $2.81/MMbtu based on 10 years of historical price; a close approximation to the $3.00 price shock assumption used by NWN
  - ICE has a standard margin calculation applied to initial and variation margin
- NWN's internal credit policy requires a counterparty to be rated "AAA" by a public rating agency to transact long-term fixed price deals
  - KPMG credit cost assumes NWN will clear all long-term fixed price transactions with ICE

Projected Henry Hub Natural Gas Prices

- In our analysis, we have relied on a Monte Carlo approach to estimate future natural gas prices from year 2021 to 2030.
- A Monte Carlo simulation is a technique used to approximate the probability of certain outcomes by running multiple scenarios, called simulations, based on a normally distributed random variables.
- We have run 100,000 random simulations in the projection of natural gas prices.
- The model we used to project natural gas prices is the Geometric Brownian Motion (GBM) with the following assumptions:
  - Spot price - $3.96 natural gas as at inception (Feb 11, 2011)
  - Variance – 76% calculated as 10 year historical weekly volatility on natural gas prices
  - Risk free rate – 4.36% US swap rate 20 year mark
  - Yield – 0%
  - Error term – randomly generated with mean of 0 and standard deviation of 1
- Under the GBM model, assets have continuous prices evolving continuously in time and are driven by Brownian motion processes.
- The model requires an assumption that asset prices have no jumps; that is there are no surprises in the market.
- This last assumption can be viewed as a potential limitation in using a GBM model to project natural gas prices which can have large jumps due to factors such as weather, natural disasters and unexpected constraints on pipeline transportation.

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- NWN obtained two indicative quotes on ten year fixed deals from [redacted] and [redacted] The indicative quotes provide NWN directional alternative gas supply prices vis-a-vis the Encana "drill-to-earn" deal. The table below summarizes KPMG's analysis of both indicative quotes. Note that the market premiums are proprietary to each supplier and KPMG is unable to model this price component due to lack of available market data.

Summary Analysis of NWN Assumptions

Category	NWN Assumption	KPMG Position	Rationale
Encana Comparable Price	Indicative quotes from [redacted] and [redacted] do not serve as firm execution prices or commercial commitments.	Obtained an indicative price quote from a financial institution market participant	Spoke with 3 industry marketers/traders who indicated that it is not likely to execute a fixed priced deal greater than 10 years. As you approach year 9 the market becomes thin with lower liquidity.
Forward curve (Fixed Price)	Ten year HH forward prices quoted in NYMEX serve as reasonable market data source for long-term deals.	Observed NYMEX transaction volume out ten years indicating long-term price transparency.	Calculated based on public market available data. Producers have supply and pipeline information to produce a quote where they would be willing to deliver physical natural gas.
Forward curve (Basis)	[redacted] and [redacted] indicative prices include OPAL basis.	Observed published OPAL basis quotes out 3 years only indicating short-term price transparency.	Utilized published 3 year OPAL basis quote. The following years were kept constant for the remainder of the analysis.
Credit Cost	[redacted] and [redacted] indicative prices exclude a risk premium based on NWN's creditworthiness. NWN expects [redacted] and [redacted] to request credit collateral / enhancements as a form of credit mitigation (See page 2 "Credit Cost" for further analysis).	Collateral requests are subject to NWN's cost of credit assumption is viewed as conservative.	NWN is a publically traded high A potential cost of credit adder would be equivalent to an 'A' rated industrial corporate debt issuer yield curve.
Market Premium	[redacted] and [redacted] indicative prices include a market premium (i.e., a price adder to cover the costs associated with physical settlement).	Inclusion of market premium in fixed price physical deals is considered industry practice.	KPMG did not calculate a market premium but interviewed select suppliers who indicated a market premium range between $0.05 - $0.10 / mmbtu.

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Long-Term Natural Gas Supply Alternatives

- A comparative analysis of long-term natural gas supply alternatives is summarized in the table below:

Summary Analysis - Alternative Natural Gas Supply Scenarios

	[redacted]	[redacted]	KPMG	[redacted]
Price Analysis			**Physical**	
Term 1 - 10 yr price *	$5.75	$5.64	$5.43	$5.64
Credit Cost	$0.37	$0.37	$0.39	$0.39
Term 1 total price	$6.12	$6.01	$5.82	$6.03
Term 2 - 10 yr price	$7.30	$7.30	$7.30	$7.30
OPAL basis	-$0.42	-$0.42	-$0.42	-$0.42
Credit cost	$0.37	$0.37	$0.39	$0.39
Term 2 total price	$6.99	$6.99	$6.99	$6.99
20 yr fixed price	**$6.68**	**$6.62**	**$6.54**	**$6.64**

* includes credit

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- KPMG evaluated a 3 year rolling hedge strategy by segmenting twenty-one years of forward prices into seven three year tranches. Each tranche's price represents the average NYMEX futures price over each three year period up to the first 10 years. KPMG then simulated forward spot prices for years 11 through 20 and calculated three year average price for the remaining tranches. The table below highlights the estimated pricing associated with a three year rolling hedge.
- KPMG believes there are too many market factors to model an approximate hedge transaction price. Forward spot prices represent today's transaction prices and have limited predictive value in forecasting the price NWN could transact three years from today. The prices below are intended to provide directional insight on executing a three year rolling hedge strategy.

Three Year Rolling Hedge Strategy – Estimated Pricing

Tranche	1	2	3	4	5	6	7
Years	2011 - 2013	2014 - 2016	2017 - 2019	2020 - 2022	2023 - 2025	2026 - 2028	2029 - 2031
Average Price	$ 4.71	$ 5.65	$ 6.32	$ 6.52	$ 7.35	$ 7.56	$ 8.92

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- Similar to a 3 year rolling hedge, KPMG evaluated a 5 year rolling hedge strategy by segmenting twenty-one years of forward prices into four 5 year tranches. Each tranche's price represents the average NYMEX futures price over each five year period up to the first 10 years. KPMG then simulated forward spot prices for years 11 through 20 and calculated five year average price for the remaining tranches. The table below highlights the estimated pricing associated with a five year rolling hedge.
- As discussed, KPMG believes there are too many market factors to model an approximate hedge transaction price. Forward spot prices represent today's transaction prices and have limited predictive value in forecasting the price NWN could transact five years from today. The prices below are intended to provide directional insight on executing a five year rolling hedge strategy.

Five Year Rolling Hedge Strategy - Estimated Pricing				
Tranche	1	2	3	4
Years	2011 - 2015	2016 - 2020	2021 - 2025	2026 - 2030
Average Price	$5.03	$6.31	$6.98	$8.11

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- Assuming alternative gas suppliers are unwilling to offer a 10 year fixed price physical deal, NWN performed a scenario analysis whereby fix/ float swaps are executed over ICE to synthetically lock in a price. ICE requires its market participants to post initial and variation margin as a mechanism to mitigate counterparty credit exposure. Executing exchange traded transactions are capital intensive and the table below analyzes NWN assumptions associated with financial hedges.

Summary Analysis of Financial Hedges Margin Calls

Evaluation Category	NWN Assumption	KPMG Position	Rationale
Price	A negative price shock of $2, $3 and $4 is appropriate to calculat price volatility.	Stressed volatility based on a statistical calculation to shock current natural gas prices	A two standard deviation price shock captures 95% of the movement in price based on historical Henry Hub prices.
Initial Margin Requirement	Initial margin requirement is based on a standard margin calculation model available in ICE and margin is required to transact with ICE participants.	Verified the NWN calculation and determined that the calculation was correct.	ICE standard calculation model used for initial margin requirement.
Variation Margin Requirement	Variation margin can be calculated by using a dollar price shock.	Calculated the variation margin based Applied the volatility shock to the ICE margin calculation.	Stress testing volatility rather than shocking prices is considered a more robust approach.
Stress Test	Volatility in market price movements is captured by the three different price shock assumptions.	Calculated based on a two standard deviation volatility shock based on historical prices.	Stress testing volatility rather than shocking prices is considered a more robust approach.

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- KPMG performed a two standard deviation stress test based on ten years of historical prices. A two standard deviation price movement represents a 5% probability that natural gas prices will decrease to $2.81 /MMbtu. Based on this analysis, NWN's $0.40 /dth cost associated with a $3.00 price shock represents a close approximation to a 5% probability market event and is therefore determined reasonable.

Summary Analysis of Financial Hedges Margin Calls

	Initial Margin	($2.00)	($3.00)	($4.00)	KPMG ($2.81)	
Initial Margin	$50,677,440	$50,677,440	$50,677,440	$50,677,440	$50,677,440	
Variation Margin		$21,322,560	$57,322,560	$92,322,560	$52,642,560	
Total _inancing	$50,677,440	$72,000,000	$108,000,000	$143,000,000	$103,320,000	
Interest Rate Spread	0.50%	0.50%	0.50%	0.50%	0.50%	Interest cost over benchmark
Borrowing Cost	$253,387	$360,000	$540,000	$720,000	$516,600	Annual cost
Upfront Facility Fee Cost*	$76,016	$108,000	$162,000	$216,000	$154,980	Assume 150 bps
Facility Fee Cost*	$380,081	$540,000	$810,000	$1,080,000	$774,900	Assume 75 bps
Total Cost of Credit Facility*	$709,484	$1,008,000	$1,512,000	$2,016,000	$1,446,480	
Cost Per Dth Annualized	$0.19	$0.27	$0.40	$0.54	$0.39	

* annualized

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- KPMG identified six key business risks associated with long-term gas supply contracts and performed a high level risk-based assessment. KPMG's assessment applied the definitions presented in the table below.

Risk Categories and Definitions

Risk Category	Risk Definitions
Credit Risk	The financial loss when a supplier/counterparty fails to perform (i.e., defaults on its contractual obligations.
Regulatory Risk	Potential financial event arising from public utility industry regulatory violations (e.g., rules misinterpretation, incorrect implementation, willful disregard(, rate recovery disallowance (e.g., imprudent procurement costs), adverse regulatory amendments / rulings decisions or unfavorable regulatory environment.
Market Risk	The financial loss resulting from adverse market movements in commodity prices due to risk factors such as weather, load and resource uncertainty, liquidity, and changes in price correlation.
Model Risk	The risk that model outputs fail to closely approximate or predict reality causing unexpected financial losses.
Liquidity Risk	The risk of an adverse cost or return stemming from the lack of a liquid market for a commodity or financial instrument. Liquidity risk may arise because a transaction's size and/or contract tenor is large relative to typical trading volumes, contracts are complex and customized, or market conditions are unstable. Wide bid-ask spreads and large price movements indicate illiquid markets. An organization facing the need to quickly unwind illiquid positions or portfolio may either find it necessary to sell at prices below fair market value or not be able to sell the instrument at the desired time.
Environmental Risk	The financial loss resulting from detrimental environmental (air, land, water) incidents (e.g., spill, emissions) and unexpected remediation costs.

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Long-Term Natural Gas Supply Alternatives

- The table below provides a summary of risks inherent in each long-term natural gas supply alternative.

Long-Term Natural Gas Supply Transaction Risks

Risk Category	10-Year Physical Transaction	ICE Financial Hedge	Financial Institution Physical
Credit Risk	Low risk as producers generally have higher credit ratings than energy marketers due to their asset base. NWN's strong credit rating positions itself as a desirable counterparty with expectations to receive favorable credit terms (e.g., minimum collateral requirements).	Little to no counterparty credit risk associated with ICE cleared transactions.	Low to moderate risk depending on the financial institution. Canadian Financial Institutions have strong investment grade ratings. Risk is mitigated due to NWN internal credit policy and standards.
Regulatory Risk	Low risk as many producers have a diversified portfolio of natural gas supply. If regulations on drilling/production or pipeline infrastructure development were to change in a specific state, region or country the producer could procure the required natural gas from other producing properties.	Low regulatory risk but Dodd/Frank bill will alter the way exchange-traded financial derivatives are traded and cleared.	Moderate regulatory risk because Do dd/Frank bill will alter the way OTC financial derivatives are traded and cleared.
Market Risk	Moderate risk as producers want to compensate themselves for the additional risk of offering deals over a longer time horizon (i.e., producers assume long-dated price risk). NWN's hedged exposure to price risk increases when natural gas price decreases but NWN has obtained cash flow and price certainty with a fixed price hedge.	Moderate risk as ICE hedges have limited time horizon. NWN could be exposed to market risk as the hedges expire.	Moderate risk as financial institutions want to compensate themselves for the additional risk of offering deals over a longer time horizon (i.e., financial institutions assume long-dated price risk).
Model Risk	Moderate risk as price uncertainty increases in future years and the ability to model a reasonable offer price becomes more difficult.	Low risk as ability to roll financial hedges in the forward market is limited based on ability to model future forward curves.	Moderate risk as price uncertainty increases in future years and the ability to model a reasonable offer price becomes more difficult.
Liquidity Risk	Low to moderate as market is liquid for the first 3 to 5 years and the bid / ask spread widens beyond 5 years. Market liquidity is non-existent after 10 years	Low risk as Henry Hub is a very liquid market with little trading constraints.	Low to moderate as market is liquid for the first 3 to 5 years and the bid / ask spread widens beyond 5 years. Market liquidity is non-existent after 10 years.
Environmental Risk	Low risk but specific to producer and pipeline. Risk can be mitigated based on contract terms between the counterparties.	Not applicable	Not applicable

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- KPMG identified six key business risks associated with long-term gas supply contracts and performed a high level risk-based assessment. KPMG's assessment is illustrated in the picture below.

Comparison - Transaction Risk v. Alternative Supply Scenarios

Risk Category	Encana Partnership	10 Year Physical	ICE Financial Hedge	Financial Inst. Physical
Credit Risk[1]	Very Low	Low	Very Low	Low to Moderate
Regulatory Risk[2]	Very Low	Low	Moderate	Moderate
Market Risk[3]	Low	Moderate	Moderate	Moderate
Model Risk[4]	Low	Moderate	Low	Moderate
Liquidity Risk[5]	None	Low	Low	Moderate to High
Environmental Risk[6]	Very Low	Low	NA	NA

Notes:

1. Credit Risk – The financial loss when a supplier / counterparty fails to perform (i.e. defaults) on its contractual obligations.
2. Regulatory Risk – Potential financial events arising from public utility industry regulatory violations (i.e. rules misinterpretation, incorrect implementation, willful disregard), rate disallowance (i.e. imprudent procurement costs), adverse regulatory amendments, rulings and decisions or an unfavorable regulatory environment.
3. Market Risk – The financial loss resulting from adverse market movements in commodity prices due to risk factors such as weather, load, resource uncertainty, liquidity, and changes in price correlation.
4. Model Risk – The risk that model outputs fail to closely approximate or predict reality causing unexpected financial losses.
5. Liquidity Risk – The risk of an adverse cost or return stemming from the lack of a liquid market for a commodity or financial instrument.
6. Environmental Risk – The financial loss resulting from detrimental environmental (air, land, water) incidents (i.e. spills or emissions) and unexpected remediation costs.

Source: KPMG LLP

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- We reserve the right (but will be under no obligation) to review all calculations included or referred to in this report and, if we consider necessary, to review our conclusions in light of any information which becomes known to us after the date of this report.

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Appendix A – Scope of Work

- Draft Carry and Earning agreement between Encana and NWN dated February 16, 2011
- Draft reserve report: estimate of reserves and future revenue to the NWN interest in certain oil and gas properties located in the Jonah Field, Sublette County, Wyoming as of April 30, 2011 prepared by NSAI
- _inal Reserve Report as of April 30, 2011 prepared by NSAI
- Reserve estimates provided by NSAI based on sensitivities to certain economic factors
- Submissions by Xcel to the Public Utilities commission of Colorado regarding projected coal and natural gas costs
- List of documents requested form Encana by Environ and documents uploaded by Encana to the _TP site
- Wellbore Assignment and Conveyance
- Record Title Assignment, Conveyance and Bill of Sale
- Model Form Operating Agreement
- Exhibit A to the Operating Agreement
- Article XVA. Other Provisions to the Operating Agreement
- Exhibit D to the Operating Agreement – Insurance
- Gas Gathering Agreement Attornment Letter
- COPAS Accounting Procedures Joint Operation
- Gas Balancing Agreement
- Non-Discrimination and Certification of Non-Segregated Facilities
- Tax Partnership Provisions
- Memorandum of Operating Agreement, and Mortgage, Fixture Filing and Financing Statement
- UCC _iling Statement and Exhibits
- [redacted]
- Transaction financial model (file name: Encana working 2-16-2011.xls) prepared by NWN
- Drilling, production and reserves model (file name: Duct TC's BASE new opex and excel) prepared by NWN
- Drilling, production and reserves model (file named: 2011.02.17_ProjectionModel_asof_5.1.2011_EncanaDrillSchedule_021711a_revised)
- Encana reserves model – 10 Year natural gas futures price analysis
- 10 Year supply model – NWP Rocky Mountains prepared by NWN
- 30 Year price curves model prepared by NWN
- NYMEX hedging cost summary dated February 18, 2011

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Comparable Transactions - Tight Gas / Shale Transactions in North America

			Proved Reserve Information							
Buyer	**Seller**	**Announced**	**Price $MM**	**Oil (MMBBL)**	**Gas (BCF)**	**Total (MMBOE)**	**$/Mcfe**	**$/BOE**	**% Gas**	**R/P Ratio**
PetroChina Company	Encana	2/10/2011	5,451.2	12.5	925.0	166.7	5.45	32.71	92%	10.7
National Fuel / Seneca Resources	EOG Resources	1/10/2011	23.0	0.0	42.0	7.0	0.55	3.29	100%	0.0
Nagnum Hunter Resources	Postrock Energy	12/27/2010	19.9	0.0	24.3	4.1	0.82	4.91	100%	73.6
Exxon Mobil; XTO Energy	Petrohawk Energy	12/23/2010	575.0	0.0	299.0	49.8	1.92	11.54	100%	8.4
Harvest / KNOC	Hunt Oil	12/14/2010	520.5	8.5	106.8	26.3	3.29	19.76	68%	7.7
Chevron	Atlas Energy	11/9/2010	3,006.6	1.6	837.7	141.2	3.55	21.30	99%	27.9
Atlas Pipeline Holdings	Atlas Energy	11/9/2010	30.0	0.0	175.0	29.2	0.17	1.03	100%	13.7
Milagro Exploration	Ram Energy	11/1/2010	43.7	2.4	11.9	4.4	1.66	9.93	45%	12.8
Enervest	Talon Oil & Gas	10/26/2010	667.0	35.3	519.1	121.9	0.91	5.47	71%	33.3
EV Energy Partners	Talon Oil & Gas	10/26/2010	300.0	15.9	233.2	54.8	0.91	5.48	71%	33.3
Undisclosed private company	Denbury Resources	10/12/2010	217.5	0.0	180.0	30.0	1.21	7.25	100%	14.5
Exxon Mobil	Ellora Energy	7/21/2010	695.0	0.1	60.4	10.2	11.39	68.36	99%	12.7
Noble Energy	Suncor Energy	1/5/2010	494.0	23.9	174.9	53.0	1.55	9.32	55%	14.3
Williams Companies	Orion Energy	8/10/2009	258.0	0.0	150.0	25.0	1.72	10.32	100%	17.1
						Mean	$2.51	$15.05		
						Median	$1.60	$9.63		
						High	$11.39	$68.36		
						Low	$0.17	$1.03		

Source: JS Herold
R/P Ratio = reserves to production

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Comparable Transactions - Green River Basin (Jonah, Pinedale etc.) and Piceance Basin

				Proved Reserve Information						
Buyer	Seller	Announced	Price $MM	Oil (MMBBL)	Gas (BCF)	Total (MMBOE)	$/Mcfe	$/BOE	% Gas	R/P Ratio
Denbury Resources	Undisclosed	9/15/2010	115.0	0.0	185.0	30.8	0.62	3.73	100%	0.0
Fidelity / MDU Resources	Undisclosed	3/15/2010	113.0	0.8	58.0	10.5	1.79	10.76	92%	11.9
Noble Energy	Suncor Energy	1/5/2010	494.0	23.9	174.9	53.0	1.55	9.32	55%	14.3
Williams Companies	Orion Energy	8/10/2009	258.0	0.0	150.0	25.0	1.72	10.32	100%	17.1

Range		
Mean	$1.42	$8.53
Median	$1.64	$9.82
High	$1.79	$10.76
Low	$0.62	$3.73

Source: JS Herold
R/P Ratio = reserves to production

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PGE Exhibit 412C

Confidential Excerpts from the Deposition of

Donald W. Schoenbeck

CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER 11-102

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Independent Assessment of PGE's Mid-Term Strategy

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Robert B. Stoddard

August 15, 2011

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Robert B. Stoddard. I am a vice president and the practice leader of the Energy & Environment Practice of Charles River Associates in its offices at 200 Clarendon Street, Boston, Massachusetts.

Q. What is Charles River Associates?

A. Charles River Associates (CRA) is a global consulting company. Founded in 1965, CRA offers economic, financial, and management consulting that applies analytic techniques and in-depth industry knowledge to complex engagements. It provides consulting services to corporate clients and attorneys in a range of litigation and regulatory proceedings, providing research and analysis, testimony, and support in litigation and regulatory proceedings in all areas of finance, accounting, economics, insurance, and forensic accounting and investigations. CRA's Energy & Environment practice brings the expertise of over 70 professionals to address the needs of utilities, independent power producers, customers, governments, regional transmission organizations, and regulators.

Q. Are you familiar with how utilities and other power market participants use financial markets?

A. Yes. I am an economist with over two decades of experience in energy market economics and trading. My experience in this area spans the electric, natural gas, and liquids markets, and I have been engaged by utilities, regulators, independent directors, competitive retailer suppliers, and financial institutions to review elements of their use of financial markets to hedge commodity price risk. Of particular note, in 2001-2002 I directed a comprehensive review of the hedging and portfolio management practices of one of the nation's largest electricity and gas utilities, concluding in a presentation to the executive committee and a blueprint for comprehensive reform, the core points of which were adopted. I was also retained by the State of Rhode Island to assist in the development of a legislative mandate for utility hedging of natural gas purchases, which concluded when the utility and its regulators came to an agreement. I am also currently engaged as an expert witness by a major financial institution that is undergoing a non-public investigation of its trading practices in the Pacific Northwest in the 2007 to 2009 period, which has refreshed and deepened my understanding of the dynamics of the energy markets in this region. My curriculum vita is PGE Exhibit 501.

Q. What is the purpose of your testimony?

A. I was asked by counsel for Portland General Electric (PGE) to provide testimony on two general areas. First, I was asked to make an independent assessment of whether PGE's risk management practices were generally consistent with common utility practice. Second, I was asked to review the testimony of the Industrial Customers of Northwest Utilities (ICNU) witness Mr. Donald W. Schoenbeck and of the Citizens' Utility Board (CUB) witnesses Messrs. Bob Jenks and Gordon Feighner, and to provide my expert opinion of the merits of their arguments regarding hedging, risk management, and regulatory policy.

Q. What assertions of Mr. Schoenbeck do you address in your testimony?

A. I will address a number of Mr. Schoenbeck's specific claims and also provide an economic framework for understanding risk management by a regulated entity such as PGE. With respect to his specific claims, I will address his assertions that:

- PGE lacked a sufficiently specified Mid-Term Strategy (MTS) for risk management during the period 3 to 5 years out;

- PGE was imprudently long against its gas requirements, especially in the second quarter or each year when its gas demand for generation typically falls, and that this was inappropriate and led to losses; suggesting instead that PGE should have used a mix of quarterly and monthly hedges instead of calendar year forwards ("Cal strips") to hedge its risks, given its production profile;
- It is imprudent in general to hedge more than a few years out in the utility industry; and
- PGE should move away from its current well-developed comprehensive risk management strategy and instead move towards a "programmatic" approach with shorter purchases conducted in a more mechanical fashion.

Q. Do you agree with Mr. Schoenbeck's and CUB's criticisms of PGE's hedging strategy and policies?

A. No. In some cases their criticism seems to be based on an erroneous interpretation of various PGE policies; in other cases they appear to contradict sound utility regulatory policy and experience from other jurisdictions; and in still other cases they ignore the practical limitations on what hedging instruments are available with sufficient liquidity to be used prudently by PGE.

Q. What materials have you reviewed in preparing your testimony?

A. PGE provided me full access to any and all materials in its possession. I requested and received PGE's presentations to Oregon Public Utilities Commission (Commission) staff on its hedging strategy, PGE's trading and risk management policies, presentations to the PGE Risk Committee and underlying data, and the professional qualifications of its trading and risk management staff. I also conducted interviews with PGE's Power Operations Group.

Q. Have you reviewed the testimony of other witnesses in this matter?

A. Yes. I have reviewed the testimony of Jim Lobdell, PGE's Vice President of Power Operations and Resource Strategy, and Darrington Outama of PGE's Power Operations Group (PGE Exhibit 400) and that of Maria Pope, Chief Financial Officer of PGE and William Valach, PGE's Director of Investor Relations (PGE Exhibit 300). I have also reviewed the testimony and deposition of Mr. Schoenbeck for ICNU and the testimony of Bob Jenks and Gordon Feighner for the Citizen's Utility Board of Oregon (CUB).

Q. Based on your review of these materials, what is your overall assessment of PGE's Mid-Term Strategy (MTS)?

A. PGE's MTS was thoughtfully constructed to meet its customers' needs, openly and frequently discussed with PGE's regulators and key stakeholders, and appropriately executed within reasonable bands of discretion. Although it is the purview of this Commission to reach the final answer as to whether PGE behaved prudently, it is my view that PGE's MTS was solidly within the bounds of good utility practice for hedging and, therefore, the costs incurred by PGE to implement the MTS should not be disallowed as imprudent.

II. Economic Framework for Understanding Hedges

A. Hedging exists to lower volatility, not costs

Q. Why would a utility enter into hedges for its gas and power purchases?

A. Hedges are used to reduce the volatility in rates, not to "beat the market" or to speculate on future commodity prices. Schoenbeck agrees (ICNU Exhibit 100) page 4, lines 11–13). Hedging is appropriate for a utility because its customers are risk averse and generally prefer stable rates over time, even if that results in some increase in the expected total cost.

Q. Will customers be risk averse over longer-time frames?

A. Yes. Customers cannot easily diversify their purchases of electricity, and they must make decisions based on their longer-term expected cost of power. For example, businesses must make decisions about their capital expenditures on equipment and, more dramatically, the communities where they will expand or contract their operations; residential customers must select home appliances. These decisions are influenced by the expected future cost of electricity. Customers therefore value longer-term price stability as much as short-term stability. This preference for stable rates over time is a well-recognized principle of sound utility ratemaking.

Q. Without going into specifics, how in your opinion should a utility hedge its price risk exposure in procuring gas and power?

A. As I discuss in more detail below, my experience in the industry suggests the following standards should apply to a utility hedging program:

- The hedging policy should have a clear and consistent objective function based on consumer preferences;

- The utility should have in place sound risk management policies and controls consistent with meeting the objective;
- The utility should consider risk on a comprehensive basis, including the interaction of prices where those are correlated (such as electricity and natural gas) and the ability of the utility to hedge power through hedges on its generation fuel; and
- The strategy should allow for an appropriate degree of flexibility in purchasing arrangements to reflect market conditions.

Q. Did PGE's hedging strategy during the instant period meet these standards?

A. Yes. Judging the strategy based on contemporaneous market data, PGE's overall hedging strategy, composed of its Integrated Resource Plan, Mid-Term Strategy, and short-term hedging, was a thoughtful and well-communicated strategy prudently implemented to manage the comprehensive price volatility risk facing its customers.

Q. Do you concur with Mr. Schoenbeck's conclusion that PGE's execution of its Mid-Term Strategy was neither "fundamentally sound" nor "appropriate" (ICNU Exhibit 100 page 7, lines 8–18)?

A. No. Mr. Schoenbeck's critique on these points fails on at least two grounds.

First, his critique appears to be primarily motivated by an after-the-fact assessment of the mark-to-market losses on PGE's hedge portfolio, inasmuch as neither he nor ICNU has previously objected to PGE's MTS or to its execution thereof. The success of a hedging strategy cannot be evaluated by calculating a mark-to-market after the fact, no more than you can discard your homeowner's policy after a year in which your house didn't burn down. In fact, like an insurance policy, where premium costs are incurred to reduce risk, there is an expected cost to a hedging program that will, on average over time, increase the *level* of the rates while decreasing their *volatility*. A utility like PGE uses its hedge portfolio to reduce price volatility; in so doing, it takes on the risk that its customers will not benefit as much from a decline in prices but simultaneously reduces the risk that its customers will suffer from an increase in commodity prices. So for example, if PGE buys power under a forward contract, and the price falls, then on a stand-alone basis the hedge appears out of the money. But on a portfolio basis, PGE was also buying gas for its electric generation plants, and that purchase price fell by the same amount. The net effect was to isolate PGE's customers from the inherent volatility in the power prices, and that was successful, as demonstrated in PGE Exhibit 400.

Second, Mr. Schoenbeck's critique fundamentally misapprehends PGE's open position in *power* as opposed to its open position in *natural gas*. Consequently, he reaches an erroneous conclusion. As an exclusively electric utility, PGE has a short natural gas position only to the extent that it anticipates using natural gas in its gas-fired generation facilities. PGE conservatively hedges only the expected annual average fuel use at its two base-load facilities, Coyote Springs and Port Westward (PGE Exhibit 400, page 31). This short gas position, however, is only a portion of the total short *energy* position that PGE has going into the MTS for any particular delivery year. PGE must make market purchases for the portion of its electric load that exceeds the net generation from owned and contracted generation resources; these market purchases contribute to closing PGE's total net open position. Mr. Schoenbeck's critique that PGE "front-loaded" its *gas* purchases is not on point; the appropriate question is whether PGE staged its *total* energy purchases appropriately over time. As I discuss below, I believe that PGE acted prudently in this regard.

Q. Do you concur with CUB's criticisms of PGE's hedging strategy?

A. No. I disagree with CUB's criticisms for the same reasons that I disagree with Mr. Schoenbeck's critique of PGE's hedging strategy.

B. Policy implications of *ex post* reviews of hedges

Q. What are the regulatory policy implications of adopting an "after the fact" review of hedging strategies that were intended to reduce customer rate volatility?

A. If hedges are to be reviewed after the fact, then utilities will not hedge, or will be very reluctant to do so. It is my understanding that PGE does not profit from its customer hedging activities; instead, hedging actually costs PGE shareholders money because of the capital tied up in collateral credit requirements. This is a common position for regulated utilities in the United States. If a regulator were to start reviewing utility hedging on a retrospective basis and to disallow hedging losses from a prudently constructed portfolio that was in accord with plans discussed with the regulator, this would create a "heads you win, tails I lose" situation for utility shareholders, who will rapidly and rightly demand that utility management not enter into future hedges. Mr. Schoenbeck agrees that a utility's hedging should reflect the "currently best available information at the time," (Deposition of Donald W. Schoenbeck, page 41, lines 16–23, included as PGE Exhibit 502, page 1) and that "it's appropriate to look at what was known at the time of the hedging policy to decide whether or not it was prudent at the time as opposed to looking back" (Deposition of Donald W. Schoenbeck, page 52, lines 4–9, included as PGE Exhibit 502, page 2).

Q. Is an *ex post* review of a utility hedging strategy based on its results supported by any academic literature?

A. No. To the contrary, other experts' writings are explicit that such a view is inappropriate. As one set of authors put it, in setting forth standards of review:

> "Always remember that the purpose of the hedge is to reduce price volatility. It is not a directional bet on future prices. Mark-to-market metrics, like other *ex post* analyses, can be useful for some purposes, such as credit management, but should have no role in evaluating the effectiveness of the hedging strategy. The use of mark-to-market metrics to evaluate the effectiveness of a hedging strategy can create a mis-impression that the utility is trying to "beat the market" or is "speculating" in energy commodities. Any such impression can be extremely damaging if, at a later date, it appears that the utility made the wrong 'bet.'"[1]

Q. Do you concur that such an *ex post* review could be harmful to customers?

A. Yes. Since customers are risk averse, creating a regulatory impediment to utility hedging would represent a real economic loss in customer welfare, as purchased gas and power risks would not get hedged, leaving customers exposed to volatile prices. Also, as discussed in PGE Exhibit 300, the effect of *ex post* disallowance of prudent hedging costs would raise the cost of capital to PGE over time, which it turn would lead to an increase in total costs, reduce the financial soundness of the utility, and decrease its ability to raise capital needed to maintain its system at reasonable costs.

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[1] Makholm, Jeff D., Eugene T. Meehan, Julia E. Sullivan, "Ex Ante or Ex Post? Risk, Hedging and Prudence in the Restructured Power Business, *Electricity Journal* Volume 19, Issue 3, p. 23 (April 2006).

Q. Is it your view that ICNU's and CUB's complaints are, in fact, *ex post* attacks on results, rather than method?

A. Yes, it appears that way. Although the particular hedging transactions have varied over time as market conditions have evolved, PGE has been using effectively the same MTS for many years. That ICNU and CUB—both of which were included in the key stakeholder consultative process—should only now raise a complaint appears to be correlated with the sharp decline in natural gas prices and, hence, a mark-to-market loss on PGE's hedging portfolio.

III. PGE Had a Well-Framed Mid-Term Strategy

A. Critical elements of a risk management strategy

Q. Are there well-accepted industry standards by which this Commission should judge the prudence of a regulated utility's hedging activities?

A. No. This is due in large part because the need for utility hedging through financial markets is comparatively new. Historically, utilities created long-run price stability primarily through vertical integration: by owning major assets at most or all links in the supply chain, a utility's customers were largely insulated from market prices (but, however, exposed to all of the risks associated with asset ownership). With utility restructuring in the 1990s and the corresponding broadening and deepening of financial markets for a spectrum of energy commodities, the delivered price of electricity and natural gas to consumers has become far more exposed to market pricing—or would be, but for the institution of hedging programs by load-serving entities such as PGE.

Because utility hedging is relatively new, there are not yet standards for hedging akin to Good Utility Practice for utility operations. My experience in the industry indicates that sound utility hedging should generally conform to the following principles:

- The hedging policy should have a clear and consistent objective function based on consumer preferences, well communicated to its regulators and other key stakeholders;
- The utility should have in place sound risk management policies and controls;
- The utility should consider risk on a comprehensive basis, including the interaction of prices where those are correlated (such as electricity and natural gas) and the ability of the utility to use generation asset fuel as hedges; and

- The strategy should allow for an appropriate degree of flexibility in purchasing arrangements to reflect market conditions.

Q. Does PGE's approach to hedging meet these standards?

A. Yes:

- PGE developed a clear standard for controlling the degree of price risk exposure, which is a function of its Net Open Position and the volatility of the underlying commodities. Inasmuch as a sound hedging policy should manage risk, not *ex post* outcomes, this focus on expected volatility is appropriate and allows PGE's trading desk to manage a dynamic position, rather than taking a rigid, programmatic approach that ignores market fundamentals.
- PGE had in place sound risk management policies and controls. The front line was the frequent meetings PGE held with its regulators and customer representatives to discuss its hedging approach. This degree of openness is rare in the industry and, in my view, represents a best practice. Internally, PGE had appropriate levels of executive oversight, software systems, and a highly trained and competent trading desk staff, which collectively ensured that trading conformed to the framework discussed with PGE's regulators and customers.
- PGE managed its price exposure systematically, with proper consideration of the full range of its combined exposure to power and natural gas price fluctuations and an appropriate recognition that, when its gas-fired generation is in the money, natural gas forwards are a more efficient hedging instrument than power forwards to manage its customers' exposure to electricity price volatility.

- PGE's trading desk considered the relevant market conditions in executing the MTS. As I understand it, the desk did *not* look to price level as a primary driver of market purchases; instead, it considered issues of market liquidity, underlying price volatility, credit availability, and major exogenous supply or demand shocks.

Q. Is a detailed audit of PGE's risk management practices at an operational level necessary to evaluate PGE's hedging strategy and its execution?

A. No. There is general agreement on the facts in this case, and no issues have been raised about specific transactions. Neither CUB nor ICNU claim that PGE's practices contradicted its policies. To the contrary, Mr. Schoenbeck states the gas hedges entered into were consistent with risk management limits (ICNU Exhibit 100, page 6). His criticism is generally limited to the volume targets used for longer tenor gas purchases and how these targets are met using calendar-year strips instead of shorter term products.

Q. Based on your review of the facts in this case, what is your general conclusion regarding PGE's hedging strategy and its execution?

A. I find that PGE executed the MTS in a sensible manner consistent with industry standards, and that PGE had (and has) in place a set of appropriate risk management controls and portfolio reviews.

Q. What is your understanding of the MTS risk management approach?

A. Messrs. Lobdell and Outama discuss this at some length in their rebuttal testimony. Their description is consistent with the presentation "Power Operations Mid-Term Strategy" dated February 22, 2008, referenced by Mr. Schoenbeck (PGE Exhibit 409C). In summary, I understand MTS to be a risk management program to fill the gap between PGE's short-term risk management function, which executes transactions of up to 24 months, and PGE's IRP, which *begins* five years forward (PGE Exhibit 400, page 9). MTS has the objective of managing the ultimate price risk to consumers downward such that the likelihood of a 5 percent rate increase was no more than 5 percent (PGE Exhibit 400, page 15). PGE executed this strategy by reducing its net open position (NOP) over time through market purchases, primarily of financial fixed-for-float gas and power swaps.

Q. Do you agree in principle with PGE's approach of managing power and gas price risks jointly in a single integrated framework?

A. As a matter of economic principle it is essential to consider these risks together, since (a) power and gas prices are significantly correlated in the Northwest market; and (b) PGE has gas-fired combined cycle units, which can be used to generate much of the power it needs or power for resale, depending on market conditions. The entire theory of risk management is predicated on considering a portfolio of instruments to hedge risks, while accounting for the interdependence of those risks.

Q. Is it common in the industry to use gas purchases to hedge short electricity positions?

A. Yes. There is greater market liquidity for typical natural gas products than for the corresponding electricity products, particularly beyond the prompt year. Given the close correlation in most markets (including the WECC) between natural gas prices and electricity prices, on a forward basis, it may often be more cost-effective to use gas purchases to hedge both gas requirements and power requirements. As the position moves closer to the prompt year and liquidity for electricity products improves, the basis risk between natural gas and electricity can be removed by selling the gas position and buying a matching electricity position, as PGE did in a typical second quarter (Q2), when its efficient gas units, which are normally base-loaded, may not run due to the impact on market heat rates from high regional hydro-electric generation. And, in other quarters, the gas serves PGE as a more efficient hedge because of PGE's ability to physically convert gas to electricity through its high efficiency combined-cycle gas turbines.

IV. PGE's Strategy of Relying on Calendar Strips Was Appropriate

A. PGE's long gas Q2 positions were part of a broader risk management plan

Q. What is Mr. Schoenbeck's criticism of PGE with respect to its purchase of calendar strips of gas?

A. Mr. Schoenbeck claims that PGE bought too much gas, especially in Q2, when there are generally ample hydro resources in the Pacific Northwest and consequently PGE's gas-fired plants run less. He would therefore have the mark-to-market losses from these alleged over-purchases disallowed.

Q. Do you agree with Mr. Schoenbeck's criticism of PGE's MTS in this respect?

A. No. His criticism misunderstands PGE's MTS, the role of natural gas hedges in the MTS portfolio, and how risk management should work for a utility exposed to correlated risks such as power and gas price risks. PGE is always short power (in the timeframe of the MTS), given its generation and loads, so it is always exposed to power price risk (PGE Exhibit 409C, page 7). It is also exposed to gas price risk (in the narrow sense of the price risk associated with gas purchases for its gas-fired generation) to varying degrees, depending on how much it expects its plants to run. But these gas and power prices are correlated, and hence can and must be addressed together in a prudent portfolio risk management approach.

Q. Is PGE too "long gas" in the second quarter as Mr. Schoenbeck claims?

A. No. Going into the MTS, PGE is short *energy* in all quarters. It covers this short position through purchases of power to meet its load and of gas to fuel its power plants to generate power. As part of its MTS, PGE only hedges forward as much gas as its expected annual requirement. Even if it needs less gas in Q2 than the annual average, the net long *gas* position in Q2 is simultaneously a hedge against its net short gas position in the other three quarters of the year (a gas-on-gas hedge) and against its net short power position in Q2 (a gas-on-power hedge). The risk of power purchases can be hedged using gas because the prices are correlated. Consequently, Q2 purchases of gas not only hedge the risk of gas needed to run power plants (in Q2 and in other quarters), but can be used alternatively to hedge power purchase risks.

Q. So even in the second quarter it could be prudent for PGE to be long gas against its expected generation uses in its own power plants?

A. Yes, as gas purchases can be an effective way to hedge power price risks on an annual basis looking forward. Because power prices are still linked to gas, the long gas position can be the most cost effective way to hedge this price risk.

B. Using calendar strips to hedge longer-term risks was appropriate

Q. Mr. Schoenbeck further criticizes PGE's Mid-Term Strategy for relying on calendar strips rather than quarterly, seasonal and monthly products. Is this critique justified?

A. No. Mr. Schoenbeck states that the full range of monthly and seasonal products is available in the future (Deposition of Donald W. Schoenbeck, page 72, lines 20–25, and page 77, lines 16–20, included as PGE Exhibit 502, pages 3–4), but he does not consider the liquidity of these shorter-strip, long-dated markets. Beyond two or three years, nearly all of the market liquidity is in calendar or half-year strip products. Consequently, a hedging strategy that relies on long-dated monthly or seasonal products would require trading in illiquid to non-existent markets, where prices may be poor, rather than calendar or half-year strips, which have greater liquidity out beyond 24 months. Programmatic trading in these illiquidly traded products could be an imprudent action of PGE on behalf of its customers.

In an ideal world, a utility like PGE would be able to hedge its purchase risks at zero cost, and manage its risks by precisely matching its hedges with its purchase obligations.

But risk management is a practical as well as a theoretical exercise and a utility like PGE must recognize that both power and gas markets have limited depth and liquidity going forward. PGE needs to be able to trade in the standard products traded in the market or else it could pay too much to reduce its customers' energy price risk**.**

Q. Can you give a hypothetical example illustrating this point?

A. Yes. Using a market that may be familiar to more people as an example, US mortgages are commonly dated at 30 or 15 years. There is a large secondary market in these products historically, and banks and other mortgage providers are used to quoting prices on these standard loans, for which the market is quite competitive, and for which transactions costs are quite low.

Suppose that you are looking to refinance your home, and that the mortgage product that would ideally meet your needs would be a 23-year mortgage, perhaps because you have 23 years to retirement and expect to move to Arizona thereafter. At some price, someone may be willing to offer a 23-year long mortgage, but you would probably have to pay well over the odds for such a non-standard financial product. The lender would not be able to resell the mortgage, as that is not a product that is traded in the marketplace. Faced with the prospect of a position that he could not sell, and with virtually zero liquidity, he would be unwise indeed to offer you a low price. Faced with this liquidity problem, you would almost surely be better off choosing a 30-year mortgage, even though it is not as theoretically a perfect match for your particular need.

Q. Have you examined any data on the relative liquidity of calendar year versus shorter-term (monthly, seasonal, and quarterly) strips in evidence of this conclusion?

A, Yes. I used data from ICE on forward strips traded over the period 2007 to 2008 to compare the relative liquidity of gas contracts of varying terms (calendar year strips versus monthly, quarterly and seasonal strips) more than one year out. This was a period with substantial forward liquidity, because major financial institutions had become active as intermediaries in the market. My examination confirmed my understanding that, even with this extra liquidity from the markets (much of which subsequently exited during the financial crisis), there were almost no volumes of natural gas or power forwards for a monthly or quarterly product traded more than 24 months forward.

Q. What are the conclusions of your analysis of the ICE forward strip data?

A. The strategy advocated by Mr. Schoenbeck is simply untenable. There is little or no liquidity in quarterly products out more than a year or two. If PGE had attempted to buy these products in the ICE OTC market, it would have been probably the sole buyer of any scale of such products. I am therefore led to believe that PGE would have been unlikely to have received attractive prices in the market.

Q. Is the ICE market the only potential market where PGE could have conducted these transactions?

A. No, and so this analysis cannot be completely definitive. ICE is however the most significant power and gas market forwards market in the US for these types of products, and Mr. Schoenbeck had advocated using its prices in setting forward curves (Mr. Schoenbeck at page 3) PGE could have conducted (and did conduct) OTC trades outside of ICE, but there is no comprehensive data available on these markets for purposes of comparison. In my experience, banks conduct quite a lot of business on a pure OTC basis, but the longer-dated bank products are generally Cal strips. Again, however there is no public data on the comparative liquidity in terms of product strips in these markets either.

Q. Do you conclude then, that PGE's use of calendar strips instead of shorter-term products may have benefitted customers through lower hedging and procurement costs?

A. Yes. Under a sound risk management strategy, a utility like PGE must balance the natural desire to match its purchases to its requirements with what the market offers in a reasonably priced, liquid market where it can get good prices and not run excessive risks. In this case, it made sense to buy calendar-year strips, potentially have bits left over, and sell those "tails" much closer to delivery (when quarterly and monthly product market finally become liquid).

V. Long-Dated Hedging is Not *per se* Imprudent

Q. What is Mr. Schoenbeck's claim with respect to hedges with a tenor of greater than 48 months?

A. Mr. Schoenbeck claims that entering into hedges “more than 48 months from the prompt month is simply not prudent in this industry” (ICNU Exhibit 100, page 8). This, he goes on to explain, is because “gas generation is the resource satisfying the last increment of load,” (ICNU Exhibit 100, page 8) and hence gas demand for power generation by a utility is subject to significant variation from year to year.

Q. Do you agree with Mr. Schoenbeck's argument?

A. No. Again he appears to have misunderstood the very nature of PGE’s risk management strategy, which starts with the known factual premise that PGE is and will remain a net short utility for the future. In this case, it can meet its needs in the form of power purchases or equivalent purchases of gas (which it can burn in its combined cycle units to generate power and whose prices are expected to remain highly correlated with power prices for the very reasons he states). No matter what the level of hydro generation in any particular quarter may be, PGE needs to buy energy (power or gas or some combination) to meet its customers' needs.

PGE bought gas instead of power over these longer terms for two reasons. First, the market for gas cal strips at these tenors was there and reasonably liquid, whereas liquidity for power forwards is typically lower. Second, and more importantly, gas forwards are a more efficient hedge against power price volatility for PGE’s customers because PGE can convert that gas into power at a heat-rate that is superior to the market heat-rate. Recall that the goal of the MTS is not to close PGE’s net open position fully, but rather to bring the risk volatility down to within a band. Because of the leverage created by PGE's efficient gas-fired generation at Coyote Springs and Port Westward, PGE can maximize the effectiveness of its hedging strategy by buying gas first, up to its total expected annual fuel usage at those two plants, and then using power forwards to complete the position.

Q. So these long tenor gas hedges were hedging a short combined gas/power position, not just the short gas position of the expected generation from PGE's plants?

A. Correct. To meet its customers' needs PGE needs to hedge a combination of gas and power quantities. The exact ratio of gas volumes to power volumes it will need at the time cannot be exactly determined, as they do depend on market conditions. But under any scenario PGE is net short power, which can be hedged using these long tenor gas strips.

Q. Do other interveners raise concerns about the use of these long tenor gas strips?

A. Yes. Messrs. Jenks and Feighner, testifying on behalf of CUB, raise "concerns about a utility hedging a significant portion of its gas supply through conventional hedges that are greater than 3 years (36 months)," citing concerns about sufficient liquidity and "price risk" of longer-dated products (CUB Exhibit 100, page 2).

Q. Are longer-term hedges in themselves problematic?

A. No. PGE concluded that its customers had a desire for longer-term price stability, as described in PGE Exhibit 300, beginning at page 6. Regulators regularly approve long-dated purchase contracts, or decisions to build generating assets which are in effect the equivalent in economic terms to a long-term tolling contract whose fixed costs must be paid for by customers. It is my understanding that PGE had presented its Mid-Term Strategy—bridging the gap between short-term purchases and longer-term IRP processes—to the Oregon Commission and staff at various public meetings open to ICNU, CUB and other stakeholders. If longer-term rate stability is a desirable objective in Oregon, then the inclusion of long-dated products as part of the hedge portfolio was the most practical way to achieve it in my view.

Q. But doesn't using a long-dated product introduce the "price risk" that CUB's witnesses cite?

A. No. The "price risk" already exists in PGE's intrinsic short power position. Hedging that position *reduces* that risk, rather than introducing risk. It is true, of course, that no one knows what the price of natural gas or power will be four or five years from now, and that there is greater uncertainty about prices farther forward. But that uncertainty cuts in both directions: realized outcomes could be higher or lower than the price of the financial futures product. PGE is not trying to "beat the market," however, but rather to reduce its customers exposure to price risk.

Q. Do you concur with Mr. Schoenbeck's statement that 48 months is the longest tenor that is consistent with industry practice for hedging?

A. No. The maximum tenor of the hedge portfolio should be developed based on market factors, not an arbitrary date. These factors include, on the supply side, the availability of long-dated products with sufficient liquidity or with other pricing mechanisms that ensure that the utility will pay a fair price for the hedge. On the demand side, the hedging tenor should reflect the degree to which the utility customers are exposed to price volatility and their willingness to pay to reduce that risk.

Q. Do you concur with Messrs. Jenks and Feighner that hedges beyond 36 months should be a source of concern?

A. No, for similar reasons. These gentlemen's comparisons of PGE's gas purchase strategy to that of Northwest Natural Gas is not on point. An appropriate hedging strategy for a utility must consider many factors that differ from utility to utility. Lacking even a cursory review of any differences between PGE and Northwest Natural Gas, Messrs. Jenks and Feighner do not have sufficient basis to conclude that the purchasing practices of Northwest Natural Gas would be prudent for PGE.

Q. Turning to your supply-side factors, how should the availability of long-dated products influence the maximum tenor of the hedge?

A. As I discussed earlier, longer-dated hedge products historically trade in the OTC and ICE markets with a lower liquidity and, consequently, a higher bid-ask spread. Consequently, as the maximum tenor of the hedge moves out, the hedge cost tends to increase. If liquidity is good out as far as five years, this premium would not be overly large. Conversely, liquidity even at the 48-month mark suggested by Mr. Schoenbeck may be too low in a given set of market conditions to justify incurring the proportionally higher risk premium. Consequently, a simplistic "programmatic" hedging function such as Mr. Schoenbeck advocates may simply not be prudent, either because it requires purchases too far in the future, relative to market liquidity, or it forecloses opportunities to hedge risk sooner, even if the liquidity in the market would support such a purchase at a reasonable premium.

Q. On the demand side, why would utility customers benefit from hedging forward with longer-dated products?

A. Because energy prices have very high volatility (relative to other commodities), being able to "layer" the hedges for a given delivery year over a longer period of time provides a greater degree of risk control, viewed *ex ante*. This principle of staggering procurement is a well-known concept in risk management.

Q. Do utilities historically hedge price risk out as far as five years?

A. Yes. Historically, however, most of these "hedges" are in the form of long-term contracts or outright ownership of assets. It is only with the restructuring of wholesale power markets in the U.S. that there has been either a need for, or a supply of, longer-dated financial hedging products. The fact that there was, for most of the MTS's history, good liquidity out five years is an indicator that market participants view such long-dated tenors as a reasonable part of a portfolio. Some FERC-regulated wholesale markets include fixed-price, forward procurement that extends out as far as six years (in PJM) or eight years (in ISO New England).

VI. Hedging Need Not be Programmatic to be Prudent

Q. Do you concur with Mr. Schoenbeck's proposal to require PGE's trading to be conducted under a simple program?

A. No. For a sophisticated purchaser such as PGE, it is entirely reasonable to use a more sophisticated hedge strategy. While Mr. Schoenbeck's industrial customers may be reasonably served by periodic purchases of a fixed portion of their anticipated forward requirement, I know of no utility that hedges its forward price exposure with so little regard to market dynamics. Most utilities the size of PGE maintain sophisticated risk management systems and employ well-qualified trading desk personnel precisely because a simple program does not serve the needs of utility customers well.[2]

Q. Why is a simple program not consistent with sound industry practice?

A. For several reasons. First, Mr. Schoenbeck tacitly assumes that the goal of a hedging program is to close a utility's NOP. This tacit assumption, combined with the observation that it is not generally possible to "time" the market, therefore leads him to conclude that the NOP should be closed like clockwork, with a fixed percentage of the NOP for each month or season purchased on a fixed schedule. Mr. Schoenbeck's prescription is premised on a faulty diagnosis, however. PGE's stated goal of the hedging program is not to close out the NOP, but rather to manage price risk to within a given band, at reasonable cost. That price risk derives in part from the remaining NOP for a given period, but also depends on the underlying volatility of the commodity price itself, which changes over time. Buying a fixed proportion of the NOP under a fixed schedule may, therefore, result in over- or under-achieving the risk management goal.

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[2] Several Eastern states do conduct auctions to serve unswitched retail loads, and these auctions are "programmatic." The wholesale hedging strategy to meet these retail obligations is not, however, dictated as part of these auctions.

Second, Mr. Schoenbeck's program ignores issues with market liquidity. Market liquidity changes over time. As I discussed earlier, shifting liquidity may therefore make earlier buying prudent, or it may make forward buying too costly. A small industrial purchaser may not be as sensitive to the market liquidity issue, but a large-scale buyer like PGE needs to take measures to ensure that its purchases do not "move the market" to the detriment of its customers.

Third, an overly prescriptive hedging program could hobble the ability of the utility to get the best price. Even in a reasonably liquid market, a large utility's purchase could easily account for a large fraction of the volume on a given day and, consequently, expose the utility to a larger bid-ask spread than would otherwise be expected. Any program would need to be carefully constructed to avoid swamping the market in this way, by allowing the utility's trading desk to sequence purchases based on market conditions.

Fourth, a locked-in programmatic approach would not provide PGE with sufficient flexibility to respond to structural changes in the markets. For example, had PGE been required to purchase systematically 2007 through 2009, the parameters set for the earlier part of that period (when markets were operating relatively efficiently but commodity volatility was high due to a series of external supply shocks) would likely have been inappropriate following the financial crisis in late 2008, at which time many potential counterparties scaled back or exited their participation in Northwest energy markets and the demand fundamentals for energy changed sharply.

Q. Mr. Schoenbeck criticizes PGE's hedging for 2012 as 'front-loaded.' Do you concur with this critique?

A. No. As discussed in detail in PGE Exhibit 400, pages 35–43, PGE did not set out to 'front load' its hedging of the NOP for 2012 when it began to close that position in 2007 and 2008. As PGE witnesses explain, PGE's purchases for 2012 were interrupted in 2009 because of changes in market conditions, in particular the sharply reduced liquidity in the market as major financial institutions scaled down or eliminated their participation in Pacific Northwest energy markets. This temporary cessation is entirely consistent with sound risk management principles and is a clear example of why PGE should *not* have employed a "programmatic" buying strategy that would have required it to purchase significant volumes of energy forwards in a market with historically low liquidity and unstable fundamentals.

My understanding of the situation is that the earlier purchases appear over-weight not because PGE was "betting" on the market price of natural gas, but rather because: (a) contemporaneous forecasts of customer demand for energy in 2012 has declined markedly from forecasts made five years ago, reducing PGE's total net short energy position; (b) PGE rationally begins its risk reduction in the MTS with forward gas purchases, rather than forward power purchases, reflecting the greater efficiency and liquidity of gas, as I discussed earlier; and (c) the volatility of natural gas prices had dropped, both because the level of natural gas prices has declined and because of the stability created by the availability of ample domestic gas from non-conventional sources. PGE therefore, in accord with good risk management practices, scaled back on its subsequent purchases to maintain the target risk exposure.

VII. Conclusions

Q. What conclusions have you drawn about PGE's MTS hedging during the relevant time period?

A. My review of the strategy indicates that it was, and remains, consistent with best practice in the utility industry. The MTS was thoughtfully developed to achieve appropriate levels of risk reduction for PGE's customers, well communicated to regulators and other key stakeholders, and implemented by well-trained and adequately supervised professionals within appropriate bands of discretion.

Q. Do you agree that any interveners' critiques of PGE's hedging strategy are a basis on which this Commission should deny recovery to PGE?

A. No. Contrary to interveners' claims: (1) PGE had a sufficiently articulated MTS strategy that it had presented, in advance, to the Commission and key stakeholders; (2) PGE used calendar strips appropriately as the primary hedge vehicle for long-tenor transactions, with the expectation of using shorter-tenor transactions to tune its portfolio to more closely match monthly and seasonal demand once there was sufficient liquidity to support these partial-year instruments; (3) PGE followed industry practice in using natural gas purchases to hedge price exposure to both natural gas and electricity; and (4) PGE executed its MTS strategy using trading desk practices that are consistent with those of other major utilities and market participants, which is more appropriate for a large utility facing complex risks and changing market dynamics than a narrowly prescribed "programmatic" purchasing strategy would be.

Q. In your professional opinion, were the costs incurred by PGE to implement its MTS prudently incurred?

A. Yes. Although the ultimate determination of prudence rests, of course, with this Commission, it is my professional judgment that PGE instituted and implemented its MTS in a manner fully consistent with the interests of its customers and in accord with sound industry practice. Although the unforeseeable sharp decline in natural gas prices (and, consequently, power prices) resulted in a mark-to-market loss on PGE's hedge portfolio, it would be inconsistent with sound regulatory practice to perform a hindsight assessment of PGE's MTS on the basis of these losses. Instead, sound regulatory practice is to recognize the successful achievement of the MTS' goal to provide rate stability for PGE's customers.

Q. Does this conclude your testimony at this time?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
501	CV of Robert Stoddard
502	Excerpts from the Deposition of Donald W. Schoenbeck

Exhibit 501

CV of Robert Stoddard

CRA Charles River Associates

Robert Stoddard

Vice President and
Practice Leader, Energy & Environment

PhD (ABD) Economics
Yale University

MA and MPhil Economics
Yale University

BA Economics and Music
summa cum laude
Amherst College

Vice President Robert Stoddard heads CRA's Energy & Environment Practice. He has over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and PJM. He has submitted testimony to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He recently was the lead economist for capacity suppliers in developing the New England capacity market, played a central role in negotiating the settlement of the PJM Reliability Pricing Model, and developed the leading proposal for the design of a capacity market for California. In related areas, Mr. Stoddard has served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction; devised an energy trading strategy audit and strategy redesign for a major northeastern utility; conducted a comprehensive review of operating flaws within the structure of an ISO; designed a market-based transfer pricing system for the distribution, trading, and generation subsidiaries of a leading western utility; and managed the federal and state regulatory filings for several large utility mergers and asset sales.

Experience

Mr. Stoddard has been a consultant on electric market issues to Abrams Capital, ArcLight Capital Management, AES, Astoria Generating, Bangor Hydro Electric Company, Boston Generating, California Independent System Operator, Citibank, City of New York, ConEdison Energy, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, CSG Investments, Dayton Power & Light, Devon Canada Corp., Dominion, Dominion North Carolina Power, Duke Energy, Edison Mission Energy, Electricity Supply Board of Ireland, Energia dos Portugal, Energy Capital Partners, Energy East, Energy Plus Holdings, Entergy Nuclear, FirstEnergy, FirstLight, Independent Energy Producers Association, Hydro Québec, International Power, J. Aron & Company, Maine Energy Recovery Co., MASSPower, Midlands Cogeneration Venture, Mirant Corporation, Morgan Stanley Capital Group, Morris Energy Group, NextEra Energy Resources (formerly FPL Energy), New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, Powerex Corporation, Rhode Island Speaker of the House and the House of Representatives, RRI Energy, San Diego Gas & Electric, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, Virginia Electric and Power, and Williams Power.

Strategy

- Led creation of business model and market-entry strategy for company developing an innovative renewable power technology.
- Led creation of business model and business plan for a combined wind-farm / transmission company in Canada.
- Assisted major utility in strategic and tactical plan to support transfer between Regional Transmission Organizations, providing both analytic and regulatory advisory support.
- Directed the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city’s future energy needs economically and reliably.
- Developing a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant’s strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developing a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identifying of key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developing a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisting a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

Electricity contracts and project valuation

- Testimony (in progress) to support the tax valuation of independent power production facilities in New York and Maryland, evaluating the free cash flows from sales of energy and other products’ net of fuel, emissions, and other relevant costs.
- Testimony successfully supporting claims against industrial customer in breach-of-contract claims by a retail energy provider.
- Testimony supporting the cost-effectiveness of a long-term power purchase agreement between Cape Wind and National Grid in furtherance of Massachusetts policy goals.
- Testimony regarding the market value of a nuclear power facility excluding idiosyncratic nuclear risks using a comparable transactions analysis.

- Expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.
- Testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.
- Testimony in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.
- Support of project financials for major purchase of New York City generation to investor community.
- Testimony in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.
- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.
- Testimony on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power and attendant retail rate design to fairly allocate the incremental costs.
- Assisting Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buyback of power for the license life of the units.
- Working with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading, and distribution affiliates to preserve appropriate performance incentives.
- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets, and long-term contracts.

Electricity market design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets. Subsequently offered a market-based approach to backstop capacity pricing in California on behalf of NRG Energy and the Independent Energy Producers Association.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.

- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.
- Project manager and testifying expert for litigation regarding the market rules governing use of phase angle regulators between New York and PJM. Subsequently, assisting the negotiated design of these rules pursuant to the FERC orders.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights, and transmission loss representation.
- Testifying expert on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.

Market power analysis and mitigation

- Testifying expert successfully defending against charges of market manipulation by largest capacity importer to New England.
- Led preparation of report successfully defending against charges of market manipulation by a power marketer scheduling transactions through multiple jurisdictions.
- Lead expert defending a major financial institution against charges of manipulating ICE index markets (ongoing).
- Lead economist in team developing alternative mitigation measures for buyer-side market power in the New England capacity market.
- Testified on appropriate metrics for market power in PJM energy and capacity markets.
- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.
- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, and presenting the results to the FERC, US Department of Justice, and the Connecticut Office of the Attorney General.
- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern US with a vertically integrated utility with substantial gas holdings.
- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Testimony and reports

California Independent System Operator Corporation, FERC Docket No. ER11-2256. Affidavit on behalf of the Independent Energy Producers Association protesting flawed elements of the Capacity Procurement Mechanism, December 2010; presentation to FERC Technical Conference, March 2011.

Expert Report on behalf of Mirant Mid-Atlantic, LLC, Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-294; and 09-RP-CH-294-298, July 2010; live testimony, February 2011.

PJM Interconnection, LLC, FERC Docket No. ER11-2288. Affidavit on behalf of GenOn Energy Management, LLC and Edison Mission Energy protesting the creation of a summer-only demand resource capacity product and the continuation of a limited demand resource capacity product in the PJM Reliability Pricing Model, December 2010.

Testimony on behalf of the PJM Power Providers before the Maryland Public Service Commission in Administrative Docket PC22 regarding the PJM Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 2010.

ISO New England Inc. and New England Power Pool, FERC Docket No. ER10-787-000, and *New England Power Generators Association v. ISO New England, Inc.*, FERC Docket No. EL10-50-000 (combined). Affidavit on behalf of New England Power Generators Association supporting need for revisions to Forward Capacity Market design, March 2010. Rebuttal affidavit, April 2010. Pre-filed testimony, July 2010; supplemental affidavits, September 2010.

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Proposed Long-Term Contracts for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83, Massachusetts D.P.U. Docket No. 10-54. Direct testimony on behalf of Cape Wind Associates, LLC, June 2010.

Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

Application of MidAmerican Energy Company for the Determination of Ratemaking Principles, IUB Docket No. RPU-2009-0003. Rebuttal testimony on behalf of NextEra Energy Resources, June 2009; surrebuttal testimony, July 2009, live testimony, August 2009.

Midwest Independent Transmission System Operator Inc., FERC Docket Nos. ER08-394-007 and -009. Affidavit regarding monitoring and mitigation of resource adequacy auctions on behalf of Duke Energy Corp., July 2009.

Calpine Corporation, Citigroup Energy Inc., Dynegy Power Marketing, Inc., J.P. Morgan Ventures Energy Corporation, BE CA, LLC, Mirant Energy Trading, LLC, NRG Energy, Inc., Powerex Corporation, and RRI Energy, Inc. v. California Independent System Operator Corp., FERC Docket No. EL09-62-000. Affidavit on behalf of complainants, June 2009; reply affidavit, July 2009.

Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements, prepared for New England Power Generators Association, Inc. and filed in *ISO New England, Inc.*, FERC Docket No. ER09-1282-000 (June 2009).

Richard Blumenthal, Attorney General for Connecticut, v. ISO New England Inc. et al., FERC Docket Nos. EL09-47-000 and EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports, June 2009.

Master Transmission Plan for New York City, report prepared for the New York City Economic Development Corporation, April 2009.

California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

“Contracting and Investment: A Cross-Industry Assessment” report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, LLC, FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008.

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, LLC, FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

"Reliability at Stake: PJM's Reliability Pricing Model" report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region, FERC Docket No. AD08-4-000, May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

Critique of the APPA/CMU Study "Do RTOs Promote Renewables?" (with David Riker) commissioned by Electric Power Supply Association, January 2008.

Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

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Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, "Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates," May 2007, and "Proposal for a Forward California Capacity Market," August 2007.

People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generating Co., LLC et al., FERC Docket No. EL07-47-000. Affidavit assessing reasonableness of outcomes in the Illinois power procurement auction on behalf of J. Aron & Company and Morgan Stanley Capital Group, July 2007.

PJM Interconnection, LLC, FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading et al., May 2007.

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In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert report on damage resulting from PPA rejection on behalf of USGen New England, March 2006; supplemental report, September 2006.

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Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

Assessment of the New York City Electricity Market and Astoria, Gowanus, and Narrows Generating Stations. Report prepared for Morgan Stanley Senior Funding, Inc. related to financing for US Power Generating Co. and Madison Dearborn Capital Partners IV, L.P., January 2006.

Review of Initial Execution of Protocol for Implementation of Commission Order No. 476. Report to FERC in Docket EL02-23-000, regarding operation of controllable lines between NYISO and PJM, on behalf of Con Edison, September and December 2005.

Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

Con Edison Energy, Inc. v. ISO New England, Inc. and New England Power Pool, FERC Docket No. EL05-61-000. Affidavit on behalf of complainant regarding bidding rules in capacity deficiency auction, February 2005.

KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc. regarding retroactive damage claims from a capacity market, November 2004.

Devon Power LLC et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February to March 2005; affidavit supporting Settlement Agreement, March 2006.

Application of Dominion North Carolina Power to Join PJM as PJM South, North Carolina Utilities Commission, Case No. E-22 SUB 418. Direct testimony and cost-benefit study on behalf of applicant, April 2004; rebuttal testimony, December 2004; examination, January 2005.

Application of Virginia Electric and Power Company to Join PJM as PJM South, State Corporation Commission of Virginia Case No. PUE-2000-00551; direct testimony and cost-benefit study on behalf of applicant, June 2003; supplemental direct testimony, March 2004; rebuttal testimony, September 2004; examination, October 2004.

Consolidated Edison v. Public Service Electric and Gas Co. et al., FERC Docket No. EL02-23-000 (Phase II); direct testimony on behalf of Consolidated Edison Company of New York, Inc., June 2002 regarding transmission facilities contracts. Remand testimony, January to March 2003.

In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

Testimony before the Rhode Island Special Legislative Commission on the Quonset-Davisville Steamplant, January and April 2002.

Testimony before the Committee on Corporations, Rhode Island House of Representatives, regarding 2002 House Bill 7786, *An Act Relating to Public Utilities and Carriers,* April 2002.

Keyspan-Ravenswood, Inc. v. New York Independent System Operator, FERC Docket No. EL02-59-000, direct testimony on behalf of Consolidated Edison Company of New York, Inc. regarding implementation of market power mitigation in installed capacity markets, March 2002.

DPUC Investigation Into Viability of Power Supply Contracts to the Connecticut Light and Power Company and the United Illuminating Company, Connecticut DPUC Docket No. 01-12-05, direct testimony on behalf of NRG Energy, Inc. and affiliates, February 2002.

Joint Study by the Department of Public Utility Control and the Office of the Consumer Counsel Regarding Electric Deregulation and How Best to Provide Electric Default Service After January 1, 2004, Connecticut DPUC Docket No. 01-12-06, direct testimony on behalf of NRG Energy, Inc. and affiliates, January 2002.

The Narragansett Electric Co. Rate Changes for January 1, 2002, Rhode Island PUC Docket No. 3402, direct testimony on behalf of the Hon. John B. Harwood, Speaker of the House of Representatives, State of Rhode Island and Providence Plantations, December 2001.

Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

Professional history

2009–Present	*Vice President and Practice Leader*, Charles River Associates, Boston, MA
2003–2009	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates, Boston, MA
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.
1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University
1983–1985	*Assistant Economist*, Federal Reserve Bank of New York

Exhibit 502

Excerpts from the Deposition of Donald W. Schoenbeck

of a normalized basis.

But near the term, there will be more volatility with respect to changes in maintenance schedules, changes in temperature, changes in hydro conditions in the Northwest. All of those are -- could have a dramatic impact on your gas needs within the prompt year.

Q. I want to better -- I want to understand what you mean by prompt year.

A. The current 12 months out.

Q. Okay.

A. From today to the next 12 months. Prompt month -- we're basically in August right now. So you'd consider the prompt month maybe September. So September to the next August, that would be the prompt year.

Q. Okay. So a utility such as PGE should continually be reassessing its resource needs in executing its hedging strategy; is that accurate?

A. Yes. Basically, you're looking at the open position, what you need with respect to the -- your best -- currently best available information at that time to determine what's needed to serve your load for the next day, the next week to the next month, the next year.

Q. And it should go beyond a year, right? I mean, I -- a utility's hedging strategy should probably be the hedging strategy.

You can certainly learn from doing a back cast.

Q. So in judging whether a hedging policy is prudent, you think it's appropriate to look at what was known at the time of the hedging policy to decide whether or not it was prudent at that time as opposed to looking back?

A. Yes.

Q. Okay. So given that, you'd agree that even if purchases were made that were -- that are now out of the money at the time, that those purchases don't necessarily reflect whether or not the policy at the time was prudent or not?

A. Yes, that's correct. The main -- the main criteria should have been the policy that was developed and then the execution of that policy.

Q. And based on what was known at the time of both the making of the policy and the execution?

A. And the execution.

Q. Okay. So we talked a little bit about liquidity. I want to focus on that for a minute.

Do you agree that liquidity is the measure of the volume of transactions in the marketplace at the time?

A. If you're talking, again, short-term, I guess

Q. And then in order to execute on this recommended hedging strategy that you just described, would a utility company be buying yearly strips or quarterly strips or monthly strips?

A. It could be a mix. I would certainly expect very few yearly strips to be bought. It's rarely seen because of -- there's generally -- as gas is on the margin, the short position generally varies from month to month.

So having -- you could have what I would call a base load amount of annual strips. It wouldn't be many. I would think it would be in the range of 5 to 15 percent of your entire transactions would be 12-month annual strips.

The predominant transactions, as I said in my testimony, would be either seasonal, quarterly and then some monthly; and, again, depends upon how you're doing the time.

I certainly expect the predominant of the transactions to be seasonal and quarterly.

Q. Did you look back historically into the availability of those types of seasonal strips, either quarterly or monthly, going out -- going back four years or --

A. Oh, they've been available for years and years and years and years.

at the specific question to -- and specific circumstances.

But I would certainly say the availability of quarterly strips or monthly strips three, five -- or prices three, five years out are less liquid and, therefore, there may be a premium.

Q. So the difference between the bid and the asked price might be wider?

A. Oh, it definitely would be wider, yeah, definitely wider.

Q. And there definitely would be a seasonal price difference if you're purchasing April, May, June for the second quarter versus the other three quarters of the year; is that right?

MS. DAVISON: Objection; vague and ambiguous. I'm not sure what time period you're referring to.

Q. Did you study whether or not, back in the 2007 to 2009 time frame, the monthly and seasonal strips that you just described were available looking forward three to four years?

A. I'm absolutely sure they're available.

Q. And have you studied what the difference in price was between those and yearly strips?

A. I have not done that.

Q. Okay. And you described earlier in your testimony that PGE's execution of its hedging strategy