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RONALD R. PETERSON

REPRESENTING AVISTA CORPORATION

Navigant Consulting Inc.

Review of Avista Valuation and Methodology

and

Independent Analysis and Valuation

of the

Coyote Springs II Facility

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Introduction

Scope of Engagement – Coyote Springs II Asset Valuation

Review of Avista Methodology and Analysis

Navigant Consulting Inc. (NCI) was engaged to provide a review and assessment of Avista Corporation's internal valuation of the Coyote Springs II (CSII) combined cycle facility located in Morrow County, Oregon. Avista is currently in negotiations with Mirant to purchase Mirant's 50% interest in the facility, which Avista currently co-owns with Mirant.

NCI Independent Analysis and Valuation

In addition to providing an assessment of Avista's valuation methodology, Avista requested that NCI perform an independent valuation of the facility, including a base case valuation and a high and low scenario to the base case results. NCI's valuation results reflect the combined revenue components associated with intrinsic, or plant dispatch value, and extrinsic, or option value.

Comparable Market Asset Transactions

Avista has also requested that NCI provide applicable, public information pertaining to recent power plant transactions occurring in the Pacific Northwest and Western US region.

Executive Summary

NCI performed a review of Avista's valuation analyses and methodology, a review of recent generation transactions in the market, and performed an independent valuation of 50% of the Coyote Springs II facility.

Avista's base case results reflect a valuation of \$66.7 million (\$468/kW) for 50% of the CSII facility. NCI finds Avista's base case valuation reflects a reasonable valuation approach, methodology, and result.

Our review of recent generation transactions consummated in the Western US region reflects an average price of \$569/kW for twenty-one transactions. NCI's independent analyses and valuation reflect a base case valuation of \$67.2 million (\$472/kW) for 50% of the CSII facility.

Based upon our review of the Avista analyses, our own independent analyses, and comparable generation transactions consummated in the market, NCI believes that Avista's negotiated purchase price of \$62.5 million for 50% of the Coyote Springs II facility is reasonable and compares favorably to other transactions consummated in the regional market. The negotiated purchase price is below the Avista and NCI base case valuation results of \$66.7 million and \$67.2 million respectively, and below the average generation transaction price of \$569/kW for the Western US region.

Review of Avista's Methodology and Analysis

Avista Fundamental Price Forecasting Process

As part of the overall scope to assess Avista's internal valuation process, NCI performed a review and assessment of the methodology that Avista employed to develop the fundamental valuation criteria and the results to ensure the approach was reasonable, and reviewed their financial models to determine the accuracy of their calculations. This process included discussions with Avista modeling personnel and subsequent evaluations to confirm that the described methodology was applied in the valuation process. NCI reviewed Avista's working spreadsheet models and discounted cash flow models to assess the reasonableness of Avista's overall valuation methodology and the accuracy of their modeling efforts. NCI did not perform an audit or confirmation of modeling algorithms, financial, or other assumptions as part of this assessment.

The key elements of NCI's assessment and review included (a) a comprehensive review of the fundamental pricing methodology used to determine intrinsic, or dispatch value, of the CSII facility; (b) an assessment of the methodology employed to determine extrinsic value; and (c) a review of the financial model that incorporated both the intrinsic and extrinsic valuations to determine an overall net present value based upon a twenty year study period.

Fundamental Power Pricing Methodology Overview

As the basis for the fundamental analysis performed for the CSII valuation, Avista utilized the production cost modeling results from their 2003 IRP process. For this process, Avista simulated the entire Western Electricity Coordinating Council (WECC) utilizing AURORA, an hourly chronological dispatch model that incorporates plant operating and cost characteristics and regional load profiles to simulate the operation of the electric system and derive a forecast of market clearing prices for each defined load region. To incorporate the effects of market uncertainty in the simulation process, Avista generated 200 sets of unique inputs to model 200 simulation iterations in AURORA, thus providing a comprehensive spectrum of potential outcomes given specific sensitivity assumptions. The average of these 200 simulations became the basis for the valuation that supported the valuation of the Coyote Springs facility.

After using AURORA to generate power prices on an hourly basis, Avista utilized AURORA as a dispatch model, using the generated power prices as fixed inputs and dispatching the CSII facility against these hourly prices, given plant fuel and other operational costs. The results from this process reflect the revenue, dispatch cost, and volumetric inputs into Avista's CSII financial spreadsheet model as one of five sensitivities performed in evaluating the CSII facility.

Post simulation analyses of the AURORA forecasted power-pricing results provided the framework for an additional analytical approach directed at evaluating the impacts of a

range of potential outcomes on the CSII financial valuation. Avista analyzed the hourly pricing results from the AURORA model simulations to determine the implied market spark-spreads for each hour over a twenty-year period, reflecting the seasonal profiles and characteristics inherent to the simulation process. This analysis of the fundamental AURORA simulations was then incorporated into a process that developed a range of potential market spark-spreads under different scenarios and, from this process, modeled multiple sensitivities to determine the financial impacts on CSII through changing market implied heat rates, or spark-spreads, over time.

The process involved holding the power prices from the IRP simulation fixed through the study period, and effectively changing the market spark-spread profile (relative to the IRP results) by adjusting natural gas prices to reflect the characteristics of several potential market spark-spread trends. Key sensitivities included developing a flat and expanding market spark-spread profile, relative to the simulated results, and dispatching the CSII facility against each of these spark-spread scenarios within the AURORA model to determine the hourly dispatch volumes and overall revenue impacts for the CSII facility.

A range of potential market spark-spread profiles was developed using this process, incorporating the initial shape implicit in the IRP simulations as the framework for developing each scenario. Scenarios included spark-spread profiles reflecting market-based, discoverable prices that escalate with inflation; a flat spark-spread profile through the study period, and an expanding spark-spread profile over the study period.

The CSII base case scenario reflected a blended spark-spread profile, incorporating market-based spark-spreads as observed through the discoverable traded markets for power and gas through 2008, and incorporated the prospective spark-spread profile derived from the 2003 AURORA IRP simulation results from 2009 through the remainder of the fundamental valuation period.

Extrinsic Valuation Development Overview

Avista also included an extrinsic component to the revenue side of the CSII valuation, reflecting the additional value associated with optimizing the facility and associated commodity positions during the twenty-year time horizon.

Avista applied an empirical approach to reflect the potential value captured through arbitraging forward natural gas and power positions over time, reflecting the potential optimization associated with reversing fixed forward positions to capture differentials between forward and spot prices. This approach was developed through analyzing differences between forward and daily settlement prices for Mid C power and Rathdrum natural gas pricing (which tracks closely to Stanfield). Upon locking a forward power and gas position, the analysis sought to optimize these fixed commodity positions (forward power sales and natural gas purchases) relative to the resulting daily settlement prices. As the daily settlement data reflected an opportunity to reverse forward positions (power or gas) at a profit, the transaction was reversed and the potential profit calculated

for that day. The annual sum of these potential monthly transactions became the basis for Avista's option or swap value for 2005, and this amount was carried forward and escalated at the assumed rate of inflation for the duration of the evaluation period.

Discounted Cash Flow Analysis Overview

Avista incorporated the intrinsic revenue results of AURORA modeling, spark-spread sensitivities, for both forward and fundamental pricing, as well as estimated extrinsic revenue into a 20 year discounted cash flow model to calculate the net present value associated with 50% of the CSII facility to derive a total base case valuation of \$66.7 million.

Navigant Consulting Inc. Assessment of Avista's Methodology and Results

Intrinsic Valuation Methodology and Results

Avista's utilization of AURORA to develop a forecast of hourly fundamental power prices, as well as utilizing AURORA as a dispatch model to evaluate the CSII plant dispatch against various pricing scenarios, reflects a reasonable approach to developing a range of potential market scenarios and stressing an intrinsic valuation using an industry standard model. The model incorporates chronological economic dispatch logic with regional load dynamics to dispatch system resources on an hourly basis, producing an hourly marginal price to service load for each modeled region. The process that Avista employed to simulate 200 discrete sensitivities in AURORA provided a comprehensive range of possible outcomes that were averaged into a single hourly point estimate, effectively capturing a significant range of sensitivities that may impact, either positively or negatively, regional power prices and the resultant CSII asset valuation.

Additionally, NCI has reviewed Avista's methodology for developing their spark-spread profile analyses and finds the approach to be both reasonable and effective in capturing the impacts of a range of potential market spark-spread scenarios. Approaching the CSII valuation in light of stressing prospective plant dispatch against a range of potential market spark-spreads (e.g. shaped, flat, and expanding profiles) affords the ability to quickly assess potential structural changes in market implied heat rates that could result from multiple and/or compounding factors.

NCI finds that Avista's intrinsic valuation methodology and results reflect a reasonable approach and outcome for a range of scenarios to base their valuation of the CSII facility.

Extrinsic Valuation Methodology and Results

Avista included swap or arbitrage value in their valuation that reflects the potential value that could have resulted from arbitraging the difference between entering into a fixed forward position in both natural gas and power, as reflected in the forwards price, and any subsequent daily opportunities to reverse these fixed positions at a profit, relative to the actual settlement prices.

For their analysis, Avista utilized a back-casting methodology to estimate the potential value arising from unwinding forward positions at a profit in the daily market. Their model incorporated historical forward electric and natural gas prices and the corresponding daily settlement prices over several pricing periods. For each trading day after the forward position was fixed, a buy vs. generate analysis was made between the cost to generate electricity from the CSII facility and the market price of power. If the plant reflected an uneconomic operating profile, relative to daily power and gas settlement prices, the model would reverse these forward positions (e.g. sell purchased natural gas and purchase electric power from the market to fulfill the power sale obligation) and calculate the resulting margin or net savings.

Three different pricing intervals were modeled including a 37-month, a 25-month, and a 13-month period, and the results for these three historical intervals for 50% of the CSII facility ranged between \$5 and \$11 million annually. Avista included \$2 million in annual swap value that escalates with inflation over the study period in their valuation of CSII.

NCI believes that historical observations are very valuable and provide a reasonable basis for potential near-term profit-maximizing opportunities. However, to forecast extrinsic value beyond the near-term horizon, and to maintain continuity between intrinsic and extrinsic valuation methodologies, NCI recommends a fundamental approach to extrinsic valuation as the preferred framework for forecasting value over the study period.

Arbitrage reflects a risk-neutral transaction environment in which the underlying premise assumes forward positions for power and natural gas that are hedged for the duration of the valuation period. Reversing these fixed positions to capture profit above the original transaction value, through a series of risk-neutral transactions when feasible, reflects an underlying assumption that the plant is hedged, either bilaterally or in the forward market, through the study period. If an arbitrage methodology is employed to determine extrinsic value, then the intrinsic valuation should also reflect a forward hedged position. Applying a merchant or spot market approach to the intrinsic valuation methodology requires similar treatment to derive an extrinsic valuation; the methodologies for intrinsic and extrinsic valuation should reflect a consistent view of the underlying position assumed, either hedged or open. Additionally, assessing the potential for prospective arbitrage value based solely upon historical data, and the opportunities reflected in that data, are reasonable for the near-term but do not provide a fundamental framework for estimating value for the outer years of the study period.

While such historical observations are very valuable and reflect a reasonable basis for potential near-term profit-maximizing opportunities, NCI recommends a fundamental analysis approach incorporating both historical and prospective data to provide a more robust framework to forecast extrinsic value for periods extending beyond the near-term. NCI performed a fundamental extrinsic analysis as part of its valuation of CSII, and a complete discussion of this methodology is provided later in this report.

Discounted Cash Flow Valuation Assessment

NCI reviewed Avista's discounted cash flow analysis to determine that (a) the results from the intrinsic and extrinsic valuations were included in the cash flow assumptions, (b) to assess the reasonableness and accuracy of the cash flow model, and (c) to review the inclusion of other cost components in the valuation.

In addition to the revenue assumptions derived from intrinsic and extrinsic sources, the cash flow model included assumptions relating to fixed operating and A&G costs, depreciation, interest expense, income tax, property taxes, miscellaneous revenue and expense items, revenue requirements, and applicable escalation and discount rates. NCI

did not audit or confirm these assumptions and does not present an opinion as to the accuracy or reasonableness of these assumptions; they reflect information provided by Avista's corporate and regulatory functional groups.

In reviewing the discounted cash flow analysis, Avista's valuation includes fixed O&M on an annual basis that reflects, in part, a long-term service agreement with the OEM. Avista's valuation does not reflect any other capital improvements to the facility during the study period, and does not include any terminal or residual value associated with the CSII asset at the end of the study period.

Regarding residual or terminal value, even though scheduled and major maintenance intervals are covered through a service agreement, typically these agreements are structured to maintain the normal operation of the plant through the duration of the agreement, and do not reflect a final maintenance interval that essentially leaves the plant owner with a newly overhauled facility at the end of the term. In the absence of analysis to determine the potential condition of the facility at the end of the study period in light of the terms of the service agreement, NCI agrees with Avista's approach to assign no terminal or residual value to the facility.

NCI finds Avista's approach and results to discounting cash flows over the study period to be reasonable and reflects the net present value of discounting all revenue and cost cash flow components at the assumed discount rate through the study period.

Navigant Consulting Inc. Independent Analysis and Valuation

NCI intrinsic valuation methodology overview

Developing energy price forecasts through modeling the dispatch and operation of generating assets requires a sophisticated and detailed market simulation tool. For this simulation process, NCI utilizes PROSYM for preparing its forecast of energy clearing prices and individual plant valuation assessments. PROSYM is a detailed chronological production-cost model designed to simulate plant bidding behavior and calculate resulting energy clearing prices. PROSYM integrates generation and transmission analyses, and has been designed for use in wholesale market price forecasting, unit profitability assessment, transmission congestion management, and system cost control studies. PROSYM offers detailed unit generation and revenue forecasts, unit bidding strategy development, regional and bus level location market price forecasts, transmission congestion and expansion studies, FTR bidding and valuation, emission allowance utilization and price impacts, maintenance planning and optimization, reliability assessment, and market price volatility assessment.

The Intrinsic Valuation Discussion, located in the appendices, provides a comprehensive overview of NCI's intrinsic valuation methodology and assumptions.

NCI extrinsic (option) valuation methodology overview

In addition to developing fundamental energy price forecasts through modeling security-constrained economic dispatch and operation of generating assets utilizing PROSYM, NCI has developed a sophisticated approach to modeling the prospective spread option value of a power plant utilizing a monte carlo simulation process that incorporates prospective pricing developed in the intrinsic valuation process as an input to evaluate the overall time value of the open, underlying commodity positions through the study period. Since the majority of option value is limited to peak operational hours, NCI's option value methodology reflects the 5 day, 16 hour interval of a typical week production cycle as reflected from the PROSYM pricing results.

Key inputs into NCI's option valuation model include:

- Daily power prices – hourly results from PROSYM simulation model are used as the basis for daily peak prices.
- Monthly natural gas prices – inputs utilized in the PROSYM model are reflected in the option valuation model.
- Correlation between power and natural gas prices – Correlations were calculated between Mid C and Stanfield daily settlements from August 2001 through July 2004 (the non-crisis period) and represent the going forward correlation assumption for the study period.
- Standard deviation of power and natural gas prices – For the CSII valuation, NCI utilized a relative standard deviation methodology to develop prospective

volatility (as measured by standard deviation). This methodology provides a reasonable framework to develop prospective standard deviations for daily power and natural gas prices as reflected by the historical standard deviation of Mid C and Stanfield daily settlements from August 2001 through July 2004 (the non-crisis period).

- Mean reversion assumption – Daily power and natural gas prices within each month are correlated to reflect mean reversion of prospective daily prices within the simulation process.
- Lognormal distribution of prices – NCI assumes a lognormal distribution of underlying prices for power and natural gas.
- Plant operating characteristics – Plant operational parameters, including capacity, heat rates, and variable O&M (including applicable escalation).

These key input assumptions are correlated and simulated in a daily Monte Carlo model for each year of the study period. The plant is struck, on a 16-hour basis, against the stochastic pricing results (power and natural gas) occurring from random draws of daily power and natural gas prices. When the plant is essentially in-the-money, relative to the stochastically generated power and natural gas prices, the option is struck and the daily results are tabulated. The model defines extrinsic value as the positive difference between the daily static intrinsic results and the stochastic modeling results occurring through 5,000 simulated iterations.

The result is a mean estimation of annual option value that essentially reflects a forward start theory that avoids the compounding effects of escalating volatility resulting over time. Additionally, the methodology remains consistent with the intrinsic valuation approach that reflects an unhedged, merchant valuation through the study period.

NCI Independent Valuation Results

The following chart depicts NCI's independent valuation results for 50% of the Coyote Springs II facility, reflecting intrinsic and extrinsic value, discounted consistent with Avista's net present value methodology and applicable financial assumptions:

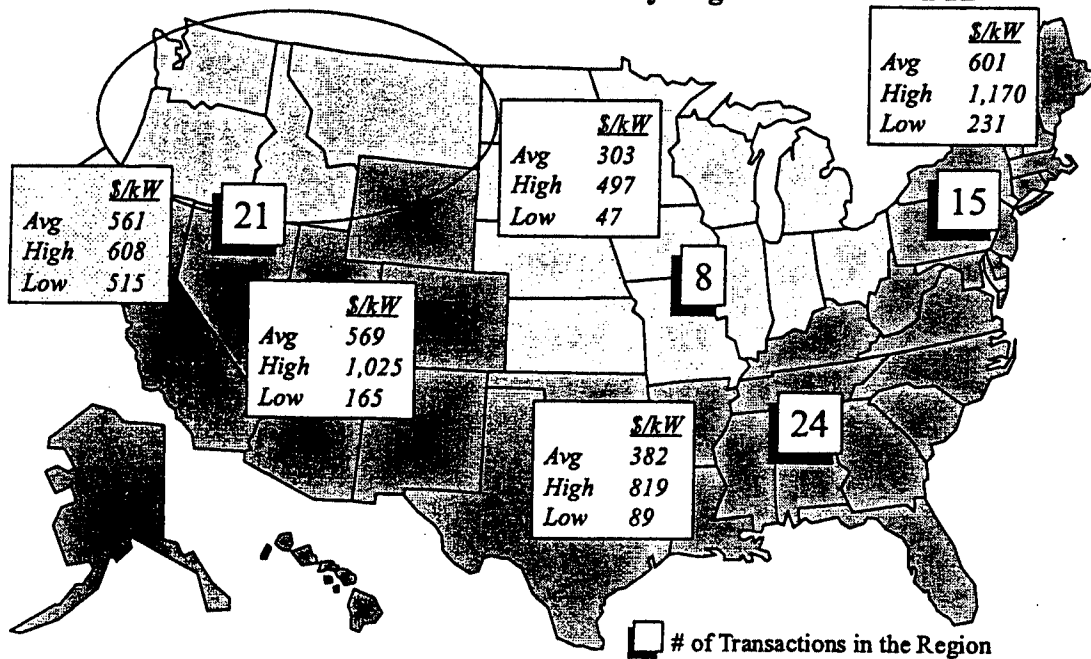
Scenario	NPV (\$1,000) based upon Avista pro forma structure	STW
Base Case	\$67,187	\$472
High Scenario	\$111,053	\$781
Low Scenario	\$34,161	\$240

Comparable Market Transaction Data

Background

Approximately 68 separate generation asset transactions have taken place since January 2003. While many of these transactions have involved multiple facilities, the majority of the deals have been for single facility locations. Of these deals, twenty-one have occurred in the western portion of the U.S. Almost half of those transactions involved facilities located in California. The majority of generation asset transactions have occurred in the southern region of the U.S with the central states having experienced the fewest number of plants changing hands (See Figure A). Among the facilities that have been sold over the last twenty months, forty-three of the sixty-eight transactions that have taken place involved a gas-fired facility (63%). The remaining 37% consisted of a mix of coal (15%), nuclear (7%), wind (6%), geothermal (6%), and hydro (3%) resources.

Figure A: Gas Transaction Valuations by Region 2003-2004 YTD



The value of gas asset transactions continues to vary widely depending on a number of factors including the physical plant location and the presence and duration of off-take agreements. Gas asset transactions that include long-term purchase contracts have been going at nearly twice the price of pure merchant assets. The national average for gas asset transactions has been \$520/kW on a nominal basis during this period. In the western half of the U.S., the average value of these transactions has been \$569/kW. Regional differences in the value of individual gas plants are directly correlated with the forecasted trajectory of electricity market prices. In the largely coal dominated regions of the Midwest and South, there are fewer perceived opportunities to dispatch gas-fired facilities due to the reduced number of hours that gas is expected to be on the margin.

This is in contrast to the Pacific Northwest where the volatility of hydro availability has continued to provide opportunities for the dispatch of gas-fired facilities. The higher valuations in the \$500 to \$600/kW range for gas assets in this region suggest this is the market's perception of where prices are expected to move in the future.

Specific deals in the Pacific Northwest have been limited relative to other parts of the country. Since early 2003, there were only four separate asset transactions that occurred (See Table 1). Three out of the four involved the transfer of gas assets between the respective buyer and seller. The two gas transactions where the terms of the deal were disclosed indicated an average valuation of about \$560/kW.

Table 1: List of Recent Pacific Northwest Generation Asset Transactions

Asset(s)	State(s)	Fuel Type	MW	\$/kW	Seller	Buyer	PPA?	Date (Announcement)	Total Deal Value \$M
Klondike	OR	Wind	24	\$ 700	Golden NW Aluminum (Brett Wilcox)	Pacificorp	LT	1/30/2003	16.8
Tenaska Frontier, Ferndale, Ulch, Cogen	TX, WA, Pakistan	Gas	132	n/a	Dynegy	Tenaska	LT	7/1/2003	Not disclosed
Frederickson	WA	Gas	125	\$ 608	EPCOR	Puget Sound Energy		10/22/2003	76
12 plants	NJ, NY, FL, PA, OR, MA, CO	Wind / Gas / Coal	1,082	\$ 515	NEGT	(Denali Power LLC) Caithness, ArcLight		8/2/2004	557
Average				\$ 608					

Conclusion

Avista's base case valuation of \$66.7 million (\$468/kW) for the remaining 50% of Coyote Springs II, reflects a reasonable valuation for this facility and compares favorably to the other transactions consummated in the Pacific Northwest, which have averaged \$561/kW. However, the number of comparable transactions in the Pacific Northwest is severely limited and there are not enough deals in this specific market to develop a sufficient data set. Therefore, it is more appropriate to compare this purchase price to the broader western region, in which twenty-one comparable transactions have taken place during this period. That comparison suggests that Avista's valuation of Coyote Springs II is reasonable when compared to this broader market, in which transactions have averaged approximately \$569/kW.

NCI's independent analyses and base case valuation results reflect a value of \$67.2 million (\$472/kW) for 50% of the Coyote Springs II facility, and suggests that this reflects a reasonable outcome based upon (a) the assumptions underlying NCI's security-constrained economic dispatch of the WECC electrical system to determine the intrinsic value associated with operating the CSII facility within this market, and (b) the results of combining the forecasted results from the security-constrained economic dispatch with historical data from the region to forecast the potential extrinsic value that may be realized in this market given these underlying assumptions and methods.

Therefore, based upon our review of the Avista analyses, our own independent analyses, and comparable generation transactions consummated in the market, NCI believes that Avista's negotiated purchase price of \$62.5 million for 50% of the Coyote Springs II facility is reasonable. The negotiated purchase price is below the Avista and NCI base case valuation results of \$66.7 million and \$67.2 million respectively.

Appendices

NCI Fundamental Simulation Scenario Assumptions

Scenario 1 – Bearish power prices and generation investment conditions

Economy and Electricity Demand - low growth

Under this scenario, NCI assumed slow economic growth during the initial three years of the study period. Electricity demand growth will also be stagnant reflecting expected correlation with a slow economy. For this scenario, we assumed zero growth in electricity demand for the first study year, one-half of the base case growth rate for the second study year, with resumption of the base case growth rate in the third and subsequent study period years.

Power Supply

In the interest of conservatism, despite reduced electricity demand, this scenario will assume the same power supply base as that used in the base case.

Fuel Prices

To reflect bearish power price conditions, fuel prices (natural gas and oil) are lower under this scenario than that seen in the base case (mixed impact on generator profitability, but generally negative for combined-cycle units in the WECC). Natural gas prices are 20% lower than the base case assumptions across all months/years, which reflects approximately one standard deviation based on historical natural gas price performance.

Scenario 2 – Bullish power prices and generation investment conditions

Economy and Electricity Demand - high growth

Under this scenario, NCI assumed more rapid economic growth during the initial three years of the study period. Electricity demand growth is also higher, reflecting expected correlation with an expanding economy. For this scenario, we assumed higher growth in regions where prospective population growth is expected to be strongest (Southwest, CA). A two percent higher electricity demand growth rate was assumed in this scenario than in the base case for the first study year, 1.5 percent higher in the second study year, and 1 percent higher in the third study year. In regions with stronger population growth, we assumed an additional 0.5% to the growth demand growth rates for the first five years of the study. In subsequent years, electricity demands grow at the base case growth rates for the relevant years.

The market is allowed to benefit from power prices that are higher than required to attract new entry for a period of four years between 2010 and 2014, and reverts toward the nominal cost of new entrant economics beyond this over-recovery period. This

assumption reflects the potential reluctance of participants to make capital investments until market prices remain above the investment threshold for an extended period.

Power Supply

In this scenario, NCI mothballs/retires generating units (other than peaking units required to maintain system integrity/reserve margins) that do not earn adequate profits in the first 5 study years. Adequate profits were measured as an operating loss less than \$10/kW year. In this scenario, we also implemented a delayed entry response, such that new entry would not occur until two years after power prices have been high enough to sustain investment profitability for new projects.

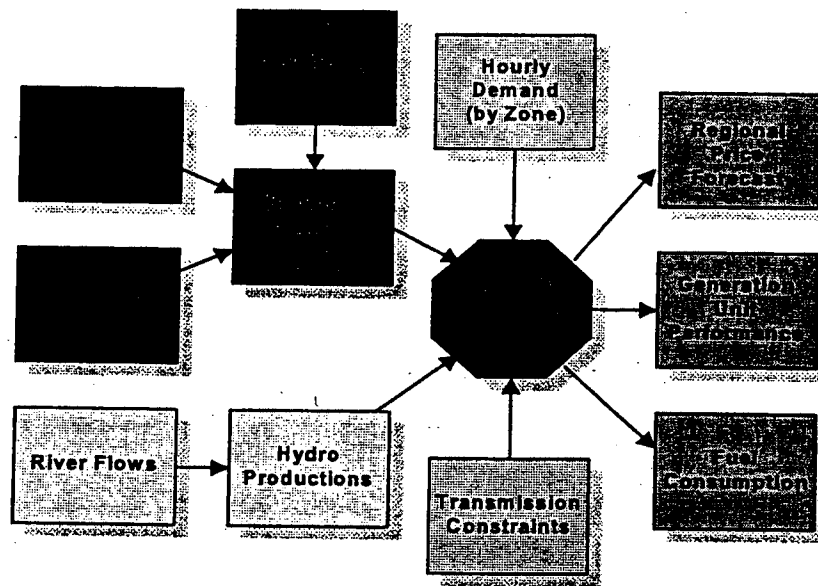
Fuel Prices

To reflect bullish power price conditions, fuel prices (natural gas and oil) are higher under this scenario than in the base case (mixed impact on generator profitability, but generally increased profits for combined-cycle units operating in the WECC). Natural gas prices under this scenario are 20% higher than in the base case, which reflects approximately one standard deviation based on historical price performance.

NCI Intrinsic Valuation Discussion

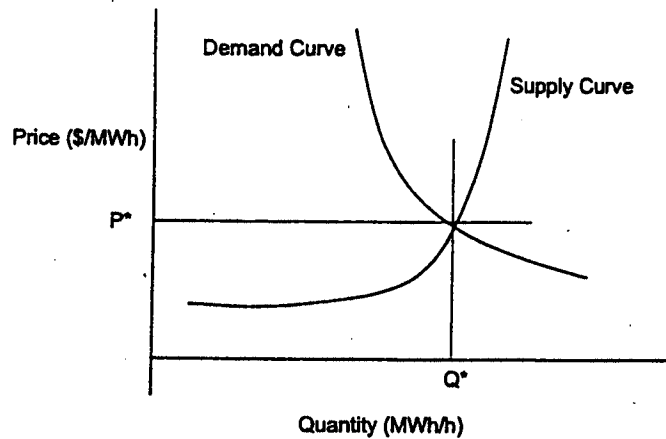
Using PROSYM, an hourly simulation is performed with sufficient detail related to the subject market area and neighboring areas to ensure that bilateral transactions and economic energy purchases are captured in the marginal clearing price calculation. The diagram below and subsequent discussion provides an overview of the energy simulation process.

Overview of Primary Inputs and Simulation Outputs



Translating the energy-clearing price calculation method described above into fundamental economic theory, the energy-clearing price calculated for any given hour reflects the price at the intersection of the supply and demand curves for energy in that hour, as illustrated below. The marginal energy-clearing price is calculated for each separate power market and constrained transmission area, as dictated by the prevailing transmission constraints for that hour.

Illustration of Hourly Energy-clearing Price Process



In the above figure, the hourly clearing price P^* , represents the bid price of the unit of supply needed to meet the last increment of the total system demand of Q^* . In effect, the PROSYM model prepares energy market supply and demand curves similar to those illustrated above for each of the 8,760 hours for each year of analysis, in each case calculates the clearing price at the intersection of the supply and demand curves. Thus, the algorithm used by the PROSYM model is consistent with the fundamental economic theory of supply and demand equilibrium that underlies the anticipated market behavior in the bid-based energy market in various restructured markets.

The following provides an overview of the modeling assumptions used by NCI in developing the fundamental pricing used in the Coyote Springs II asset valuation. For each of these assumptions, NCI relies on the most recent, reliable, and objective information in preparing this assessment.

1. Demand/Energy Forecasts

NCI relies upon a number of sources for its peak demand and energy forecasts. In regions where ISO-prepared demand forecasts are unavailable, we generally rely upon the demand forecasts submitted to the regional reliability councils as part of the OE-411 filings. In that case, the control area operators within each respective region prepare the underlying demand forecasts. In limited cases, NCI obtains demand forecasts directly from load-serving entities operating in a given region, or prepares a load forecast independently. The demand forecasts underlying the projections are weather-normalized so that extreme events are not reflected. The forecasts generally assume constant load

factors unless a given load-serving entity has projected significant changes in its customer's consumption profiles.

2. Hourly Load Profiles

The PROSYM model requires hourly load information for each of the various regional control areas included in the subject analysis. NCI relies on the most recent data information available for hourly load representation, and is derived from the respective FERC Form No. 714 filings for many of the U.S. power systems, and other regulatory filings for the Canadian utility systems. Where data is not readily available, NCI relies on information contained in the PROSYM database, scaled appropriately to reflect demand and energy growth. PROSYM derives hourly load profiles by averaging five years of actual hourly loads for each utility taking into account weekdays, weekends, and holidays. For example, a peak on a Monday won't be averaged with a Sunday load but will be representational of that typical Monday.

3. Existing Resource Capabilities

NCI relies on most recent ISO and NERC studies as the primary source for all generating unit capacity ratings. PROSYM was populated with both the summer and winter generating plant capability ratings defined in these reports. Additionally, any known changes to the future ratings of the existing plants are also incorporated in the unit database.

4. Hydroelectric and Pumped Storage Resources

Hydroelectric resources are modeled to produce median-year levels of energy production. Monthly forecasts of median-year hydro energy generation are developed based on each hydro resource's historical production levels. Run-of-river hydro energy production is scheduled throughout the day. Pumped Storage hydro energy production is scheduled by PROSYM during the highest demand periods of each month to capture the highest value for the system.

5. Existing Generating Unit Outage Parameters

In most cases, generator maintenance and forced outage parameters are the average of 1992 to 1996 NERC GADS data, weighted for plant size, plant type, and fuel type. The maintenance schedules for U.S. nuclear units are based on the actual schedule reported by the Nuclear Regulatory Commission. Maintenance parameters include both the frequency and duration of maintenance outages (mean time between maintenance periods, and mean time to repair). PROSYM optimizes maintenance outages to eliminate unlikely outage combinations over periods of weeks, months or years depending on specification. Thus, if a generator has a maintenance rate of 5% and the model is set to converge maintenance schedules on a monthly basis, it will be out 5% of the hours in each month of the simulation resulting in 12 starts per year. If however, the model is specified to converge maintenance on a yearly basis, that generator will be out on maintenance 5% of the hours of the year, and the number of starts and duration of each outage will depend on the specification of the minimum, maximum, and mean time to repair. PROSYM also allows fixed maintenance schedules to be input over periods of one to several years. However,

for most studies, the convergent maintenance method is preferred as it allows more accurate comparisons across scenarios.

6. Existing Unit Heat Rates

For existing plant heat rates, NCI relies on a number of sources of information, including heat rate information included in the PROSYM database. This information is primarily based on the U.S. Environmental Protection Agency's CEMS data, as well as information provided in various reports, FERC Form 1 filings, and internal analysis and judgment. PROSYM dispatches generators on heat rate curves that reflect minimum, mid, and full-load heat rates.

7. Fixed and Variable O&M Costs

Fixed and variable O&M costs for generators are based on information contained in the PROSYM database, and confirmed by NCI. This information is based on a variety of sources including FERC Form 1 filings, internal engineering studies, and other sources.

8. New Entrant Timing/Amount Assumptions

A significant amount of merchant generation is being developed in several regions throughout the US, and based on the current status of these proposed projects and NCI's assessment of the likelihood of each being developed, a number of these projects are included in the analysis. In general, NCI has assessed the permitting, financing, and construction stages of each project's development to form an opinion of whether the project should be included in the analysis.

9. New Entrant Installed Cost and Operating Assumptions

Provided below is a summary of the new entry cost and operating assumptions. This cost information is based on several sources, including a recent survey of merchant plant project developers, industry publications, and internal engineering estimates. NCI's philosophy on adding new entry in market simulations is to only add projects in locations where either the total market revenues can support a new project, or where there is a shortfall in capacity and either the required reserve margin will not be met or there is insufficient capacity to meet regional load pockets, resulting in energy not served.

- NCI estimates the going forward average cost for turnkey plant installations are as follows:
 - Combustion turbine installed cost of \$400/ kW
 - Combined cycle facilities \$600/ kW
- NCI believes that most new capacity going forward will reflect lower-cost technologies (installed and operational costs), and observe going forward new entrant installed costs, and variable operational costs, to be consistent with current FA and EA technologies and configurations.

10. Inflation Assumptions

NCI assumes an annual inflation rate of 2.5% for the U.S. This is consistent with sources that NCI has reviewed, including data reported by the Bureau of Economic Analysis, and the Bureau of Labor Statistics, and the Congressional Budget Office's *Budget and Economic Outlook: Fiscal Years 2002-2011*, dated January 2001. In this report, the Congressional Budget Office projects Consumer Price Index ("CPI") growth of 2.6% per year. Inflation estimates are used to escalate the fixed and variable O&M expenses for each generating unit, and therefore has an underlying influence on the inherent escalation of forecasted wholesale power prices.

11. Unit Retirement Assumptions

There are economic retirements that are likely to occur over the next several years. These retirements may be due to significant environmental compliance cost or plants that are located within supply pockets and do not receive sufficient revenue to meet projected revenue requirements. During the simulation process, NCI monitors each plant's revenue to determine whether it has met or exceeded its cost requirements for the year. Plants that experience a revenue shortfall in any two consecutive years (other than peaking resources that are required to maintain system integrity/reserves) are candidates for retirement. Barring any strategic, system reliability, or other reason for supporting the plant on ongoing basis, the plant is removed from the simulation after two consecutive years of significant revenue shortfall.

12. Nuclear Plant Assumptions

As a base case assumption, NCI assumes that all nuclear plants will remain in commercial operation through their reported licensing term.

13. Transmission Topology Assumptions

NCI has specified transmission areas in the PROSYM model that provides valuable information on the congestion costs associated with each of the transmission-constrained regions. Transmission limitations between each of the congestion zones and market areas are based on several recent studies as prepared by the various ISO/IMOs, NERC, and utilities within the control area. As a result of these studies and internal review, NCI has segmented the WECC into transmission areas by NERC sub regions.

14. Emission Allowance Assumptions

Emission allowance costs are an important consideration in simulating plant operation and preparing a price forecast. NCI closely monitors the trading activity of U.S. SO₂ and NO_x allowances as part of this process. Based on recent trading information, and NCI's own research on complacence and equipment costs, the following chart reflects NCI's price forecast for these emission allowances in nominal dollars:

When simulating the variable cost dispatch of generation units, NCI models NO_x emissions by assuming that all generators have initial allowance allocations at the rate of .15 lbs per MMBtu. The incremental NO_x emissions that are priced above the initial allowances are then calculated as the maximum of a) the NO_x rate - .15, or b) 0. The resultant incremental emissions allowances are priced at the assumed NO_x allowance

price per ton. This approach provides a representation of the initial emissions allowances that are allocated to each generator, but does not provide full recognition of unused allowances that can either be transferred to other units within a company portfolio or traded in the secondary market.

15. Natural Gas Price Forecast Methodology

Using inputs and assumptions specific to NCI, a proprietary model¹ is used to estimate natural gas prices at a number of market nodes and supply points across North America. Among other items, the outputs of this model reflect the monthly, marginal, or market-clearing, gas prices at each node. The differences between these gas prices are the projected basis differentials at each point.

To conform the model output to current market conditions, NCI makes a number of objective and subjective adjustments:

- First, a current forward NYMEX natural gas curve for the prospective 18 – 36 month period is used representing the model output for Henry Hub, and merged into the model output.
- Second, the model is sensitive to oil commodity price assumptions. To the extent NCI views the natural gas price response to be excessive, year-to-year gas price movements are tempered.
- Third, the model output is sensitive to significant changes in pipeline capacity. The price impacts of capacity additions are often smoothed, reflecting NCI's view that changes resulting in large market perturbations would likely be smoothed in reality.
- Finally, the proportional changes in Henry Hub commodity prices are applied to the individual pricing nodes to maintain the implicit volatility and prevent smoothing the basis differentials. All price projections beyond 2020 are held constant in real terms.

¹ This model is licensed and operated by Energy and Environmental Analysis, Inc.

50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

		Assumptions				
Installed Cost	67,187 2004 \$000s	Fixed Charge	0 2004\$ per KW-mo	201.56 2004 \$000s	Nominal Discount	8.22 P
Project Capacity	472 2004 \$/KW	Fixed O&M	1.75 2004\$ per KW-mo	0.00 2004 \$/dth/day	Real Discount	5.50 P
Heat Rate	142.3 MW	Escalation Rates	3.0 percent	3.0 percent		
Gas Usage Rate	7,444 Btu/KWh	Transportation	3.0 percent	0 2004 \$000s		
	25.4 000s dth/day		3.0 percent			
Pre-tax Option value NPV	241 2004 \$/KW					

Year	Fixed Costs										Total Fixed Costs (\$000s)	Operating Margin (\$000s)	Option Value (\$000s)	Net Project Benefit (\$000s)	Total Variable Costs (\$/MWh)	Total Pro Costs (\$000s)		
	Energy (GWh)	Project (\$000s)	Fixed Chrg. (\$000s)	Miscellaneous (\$000s)	Capital Recovery (\$000s)	Fixed (\$000s)	Guarans (\$000s)	Operatns & Maint (\$000s)	Insur. (\$000s)	Total (\$000s)								
1 2005	624.2	12,884	0	12,884	0	3,078	0	816	206	4,201	6.7	16,895	5,870	2,358	(8,658)	26,284	45.3	45,189
2 2006	619.0	12,399	0	12,399	0	3,170	0	884	214	4,268	6.9	16,667	5,079	2,787	(8,791)	25,700	48.0	46,386
3 2007	638.3	11,838	0	11,838	0	3,265	0	853	220	4,338	6.8	16,178	5,241	2,580	(8,655)	25,501	41.5	42,877
4 2008	648.4	11,542	0	11,542	0	3,363	0	821	227	4,411	6.8	15,953	5,046	2,528	(7,778)	25,477	44.1	44,429
5 2009	718.4	11,424	0	11,424	0	3,464	0	789	234	4,487	6.2	15,911	5,004	2,945	(3,962)	25,454	47.1	49,775
6 2010	795.5	11,357	0	11,357	0	3,568	0	758	241	4,568	5.7	15,923	3,744	3,560	1,381	25,429	50.3	55,944
7 2011	839.3	10,789	0	10,789	0	3,675	0	728	248	4,649	5.5	15,436	3,462	3,860	4,982	25,404	42.2	50,894
8 2012	768.6	10,588	0	10,588	0	3,785	0	695	255	4,735	6.2	15,323	3,103	3,843	3,222	25,379	48.0	52,122
9 2013	772.3	10,201	0	10,201	0	3,899	0	663	263	4,825	6.2	15,025	2,984	3,884	5,942	25,354	61.5	59,878
10 2014	727.7	10,237	0	10,237	0	4,015	0	632	271	4,918	6.8	15,155	2,811	4,589	5,344	25,329	61.5	59,878
11 2015	744.5	9,991	0	9,991	0	4,136	0	600	279	5,015	6.7	15,005	2,675	4,459	4,828	25,304	61.3	59,914
12 2016	737.0	9,803	0	9,803	0	4,260	0	568	287	5,116	6.9	14,718	2,548	4,330	5,120	25,279	61.3	59,914
13 2017	729.4	9,215	0	9,215	0	4,388	0	537	296	5,221	7.2	14,431	2,421	4,201	5,482	25,254	59.2	56,870
14 2018	721.9	8,827	0	8,827	0	4,519	0	505	305	5,330	7.4	14,157	2,294	4,072	5,822	25,229	59.2	56,870
15 2019	714.3	8,440	0	8,440	0	4,655	0	474	314	5,443	7.6	13,882	2,167	3,943	6,201	25,204	56.1	55,365
16 2020	706.8	8,053	0	8,053	0	4,795	0	442	323	5,560	7.9	13,613	2,040	3,814	6,703	25,179	56.9	53,844
17 2021	702.9	7,781	0	7,781	0	4,939	0	410	333	5,682	8.1	13,443	1,913	3,685	7,591	25,154	56.9	53,844
18 2022	698.9	7,469	0	7,469	0	5,087	0	379	343	5,809	8.3	13,278	1,786	3,556	8,407	25,129	59.7	54,986
19 2023	695.0	7,177	0	7,177	0	5,239	0	347	353	5,940	8.5	13,116	1,659	3,427	9,341	25,104	61.1	55,579
20 2024	691.1	6,886	0	6,886	0	5,396	0	316	364	6,076	8.8	12,962	1,532	3,298	10,123	25,079	62.5	56,167
Net Present Value		102,163		102,163		37,022		0	6,717	2,497	46,237	148,400	114,046	34,354	(0)	350,206	50.7	498,608
Nominal Levelized Cost (\$/MWh)						14.8					6.7		77%	23%	(0.0)			
Real Levelized Cost (\$/MWh)						12.0					5.4				(0.0)			41.0

50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

Installed Cost	34,161	2004 \$000s	Assumptions	102.48	2004 \$000s	Nominal Discount	8.22	percent
Installed Cost	240	2004 \$/kW	0 2004\$ per kW-mo	0.00	2004 \$/dth/day	Real Discount	5.50	percent
Project Capacity	142.3	MW	1.75 2004\$ per kW-mo	3.0	percent			
Heat Rate	7,444	Btu/kWh	3.0 percent	0	2004 \$000s			
Gas Usage Rate	25.4	000s dth/day	3.0 percent					
Pre-tax Option value NPV	178	2004 \$/kW						

Year	Energy (GWh)	Capital Recovery and Miscellaneous				Fixed Costs				Operations & Maintenance				Total Fixed Costs (\$000s)	Operating Margin (\$000s)	Option Value (\$000s)	Net Project Benefit (\$000s)	Total Variable Costs (\$/MWh)	Total Project Costs (\$000s)
		Project (\$000s)	Fixed (\$000s)	Total (\$000s)	(\$/MWh)	Fixed (\$000s)	Total (\$000s)	(\$/MWh)	(\$/MWh)	Pr.Tax (\$000s)	Insur. (\$000s)	Total (\$000s)	(\$/MWh)						
1 2005	574.8	6,850	11.9	6,650	3,078	468	108	3,848	6.3	10,498	3,814	1,905	(4,780)	(8.3)	21,128	36.8	31,627	55.1	
2 2006	554.1	6,679	12.1	6,679	3,170	450	109	3,728	6.7	10,407	3,652	1,843	(4,672)	(8.4)	21,181	38.6	31,786	57.1	
3 2007	600.4	6,418	10.7	6,293	3,265	433	112	3,810	6.3	10,229	3,771	1,741	(4,210)	(7.0)	20,200	33.6	30,428	50.0	
4 2008	606.6	6,288	10.4	6,288	3,363	417	115	3,886	6.4	10,189	3,821	1,823	(4,545)	(7.5)	21,889	35.8	31,878	52.1	
5 2009	664.2	6,364	9.5	6,268	3,484	401	119	3,984	6.0	10,272	3,773	2,150	(2,569)	(3.9)	25,532	38.4	35,804	53.1	
6 2010	755.5	6,364	8.4	6,364	3,568	385	122	4,075	5.4	10,439	3,744	2,478	(2,917)	(0.3)	30,898	40.9	41,335	54.1	
7 2011	783.2	6,021	7.8	6,021	3,675	368	126	4,170	5.3	10,191	3,722	2,388	(2,917)	(0.3)	27,404	34.6	37,586	47.1	
8 2012	721.1	5,942	8.2	5,942	3,765	353	130	4,268	5.9	10,210	3,909	2,588	(2,917)	(0.3)	26,267	40.6	39,477	54.1	
9 2013	720.7	5,731	8.0	5,731	3,899	337	134	4,388	6.1	10,101	3,909	2,702	(2,674)	(0.3)	28,319	39.3	38,420	53.1	
10 2014	674.3	5,826	8.6	5,826	4,015	321	138	4,474	6.6	10,301	3,723	3,172	(2,668)	(0.3)	33,734	50.0	44,035	65.1	
11 2015	665.9	5,718	8.3	5,718	4,138	305	142	4,563	6.7	10,203	3,584	3,372	(2,668)	(0.3)	34,901	50.0	45,202	65.1	
12 2016	678.2	5,508	8.1	5,508	4,268	289	146	4,695	6.9	10,203	3,484	3,547	(2,639)	(0.3)	33,144	50.0	44,144	65.1	
13 2017	670.5	5,288	7.9	5,288	4,398	273	151	4,811	7.2	10,109	3,385	3,367	(2,639)	(0.3)	32,861	48.2	43,090	64.1	
14 2018	682.8	5,088	7.7	5,088	4,519	257	155	4,931	7.4	10,019	3,285	3,357	(2,639)	(0.3)	32,020	48.3	42,040	63.1	
15 2019	655.1	4,879	7.4	4,879	4,655	241	160	5,056	7.7	9,834	3,182	3,268	(2,526)	(0.3)	31,060	47.4	40,994	62.1	
16 2020	647.4	4,689	7.2	4,689	4,795	225	164	5,184	8.0	9,653	3,081	3,318	(2,556)	(0.3)	30,100	46.5	39,953	61.1	
17 2021	655.2	4,581	6.9	4,581	4,938	209	169	5,317	8.1	9,678	2,981	3,317	(4,485)	(6.8)	31,248	47.6	41,123	62.1	
18 2022	665.1	4,453	6.7	4,453	5,087	193	174	5,454	8.2	9,907	2,881	3,317	(6,333)	(9.5)	32,392	48.7	42,298	63.1	
19 2023	673.0	4,345	6.4	4,345	5,239	177	180	5,598	8.3	9,941	2,781	3,317	(8,206)	(12.2)	33,536	49.8	43,478	64.1	
20 2024	682.7	4,237	6.2	4,237	5,398	161	185	5,742	8.4	9,979	2,681	3,317	(10,060)	(14.7)	34,684	50.8	44,663	65.1	
Net Present Value		56,994		56,994	37,022	0	3,415	1,270	41,707	98,701	73,363	25,339	(0)	(0.0)	265,281	41.2	363,982	58.1	
Nominal Levelized Cost (\$/MWh)			8.8							6.5	74%	26%	(0.0)	(0.0)					
Real Levelized Cost (\$/MWh)			7.1							5.2			(0.0)	(0.0)				45.1	

50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

Installed Cost	111,053	2004 \$000s	Assumptions	333.16	2004 \$000s	Nominal Discount	8.2%
Installed Cost	781	2004 \$/kW	Fixed Charge	0	2004\$ per kW-mo	Real Discount	5.5%
Project Capacity	142.3	MW	Fixed O&M	1.75	2004\$ per kW-mo		
Heat Rate	7,444	Btu/kWh	Escalation Rates	3.0	percent		
Gas Usage Rate	25.4	000s dth/day	Fixed O&M	3.0	percent		
			Transportation	3.0	percent		
Pre-tax Option value NPV	311	2004 \$/kW	Option Value	0	2004 \$000s		

Year	Energy (rwh)	Capital Recovery and Miscellaneous			Fixed Costs			Operations & Maintenance			Total Fixed Costs			Operating Margin (\$000s)	Option Value (\$000s)	Net Project Benefit (\$000s)	Total Variable Costs (\$/MWh)	Total (\$000s)
		Project (\$000s)	Fixed (\$000s)	Total (\$000s)	Fixed (\$000s)	Pr.Lax (\$000s)	Inflx (\$000s)	Total (\$000s)	Pr.Lax (\$000s)	Inflx (\$000s)	Total (\$000s)	Costs (\$000s)	Margin (\$000s)					
1	724.5	20,508	28.3	3,076	1,514	343	4,934	6.8	1,461	353	4,985	6.9	24,999	9,457	3,395	(12,601)	53.7	38,600
2	719.4	20,014	27.8	3,170	1,408	364	5,038	6.7	1,357	375	5,095	6.9	24,170	10,181	3,863	(11,149)	57.2	41,132
3	752.4	19,132	25.4	3,265	1,305	368	5,165	6.2	1,200	410	5,285	6.0	23,857	10,927	4,268	(9,958)	49.0	38,643
4	740.9	18,583	21.9	3,464	1,253	398	5,218	5.7	1,148	422	5,355	6.2	23,466	11,411	4,731	(6,516)	52.0	38,511
5	834.6	18,059	19.9	3,568	1,086	435	5,429	8.5	1,044	448	5,507	6.8	23,277	12,068	5,150	(989)	55.5	38,511
6	808.6	17,522	19.8	3,675	982	461	5,580	7.1	939	475	5,674	7.3	22,907	12,510	5,564	8,533	59.0	38,511
7	884.3	17,006	19.8	3,785	887	488	5,764	7.5	835	504	5,858	7.7	22,361	12,882	5,921	7,477	61.6	38,511
8	860.0	16,500	19.7	3,899	835	504	5,858	7.7	731	535	6,080	8.1	22,361	13,113	6,210	6,012	64.4	38,511
9	835.7	15,998	18.7	4,015	783	519	5,957	7.9	628	567	6,280	8.7	21,928	13,343	6,505	5,120	67.4	38,511
10	811.4	15,493	19.7	4,136	731	535	6,080	8.1	524	597	6,396	9.0	21,503	13,574	6,800	3,578	70.5	38,511
11	787.1	14,876	18.1	4,260	678	551	6,188	8.4	420	574	6,396	9.0	21,081	13,804	7,111	3,122	73.9	38,511
12	778.8	14,259	17.8	4,388	628	567	6,280	8.7	317	551	6,188	8.4	20,550	14,035	7,495	3,842	77.2	38,511
13	772.5	13,642	17.2	4,519	574	584	6,396	9.0	214	522	6,520	9.4	20,023	14,265	7,883	4,525	80.2	38,511
14	785.2	13,028	16.5	4,655	522	602	6,520	9.4	110	493	6,396	9.0	19,501	14,496	8,273	5,283	83.1	38,511
15	757.8	12,410	16.1	4,795	470	584	6,396	9.0	10	464	6,396	9.0	18,983	14,727	8,666	6,216	86.0	38,511
16	750.5	11,874	15.2	4,939	37	567	6,280	8.7	0	435	6,280	8.7	18,469	14,958	9,059	7,111	88.9	38,511
17	736.8	11,339	15.2	5,087	0	548	6,396	9.0	0	406	6,396	9.0	17,952	15,189	9,452	7,495	91.8	38,511
18	723.1	10,804	14.8	5,239	0	522	6,520	9.4	0	377	6,520	9.4	17,436	15,420	9,845	7,883	94.7	38,511
19	708.4	10,270	14.8	5,396	0	502	6,520	9.4	0	348	6,520	9.4	16,920	15,651	10,238	8,273	97.6	38,511
20	695.6	9,736	14.8	5,556	0	478	6,520	9.4	0	319	6,520	9.4	16,404	15,882	10,631	8,666	100.5	38,511
Net Present Value		162,461		37,022		11,103	4,128	52,253		7.0			214,714	170,484	44,280	(0)	62.5	489,302
Nominal Levelized Cost (\$/MWh)			21.6							5.8				79%	21%	(0.0)		
Real Levelized Cost (\$/MWh)			17.5													(0.0)		