B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Wholesale Power Rate Case Initial Proposal

MARKET PRICE FORECAST STUDY

November 2005

WP-07-E-BPA-03

BONNEVILLE
POWER ADMINISTRATION

STUDY TITLE
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COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFDUC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
Avista	Avista Corporation, Water Power Division
BASC	BPA Average System Cost
BiOp	Biological Opinion
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine

CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DMP	Data Management Procedures
DO	Debt Optimization
DOE	Department of Energy
DROD	Draft Record of Decision
DSIs	Direct Service Industrial Customers
DSR	Debt Service Reassignment
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
Energy Services	Energy Services, Inc.
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBPF	Forward Flat-Block Price Forecast
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers

GTA	General Transfer Agreement
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU REP Settlement benefits	Investor-Owned Utilities Residential Exchange Program Settlement benefits
IOUs	Investor-Owned Utilities of the Pacific Northwest
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISC	Investment Service Coverage
ISO	Independent System Operator
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
K/I	Kilowatt-hour/Investment Ratio for Low Density Discount
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRSCP	Lower Snake River Compensation Plan
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
M/M	Meters/Miles-of-Line Ratio for Low Density Discount
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)

MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NEW	Northwestern Energy
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PFR	Power Function Review

PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFA	Revenue Forecast Application
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
SCRA	Supplemental Contingency Reserve Adjustment
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
Slice	Slice of the System product
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge

TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

1.1 Definitions and Purposes. This chapter presents BPA's market price forecasts, which are based on AURORA modeling. AURORA calculates the variable cost of the marginal resource in a competitively priced energy market. In competitive market pricing, the marginal cost of production is equivalent to the market-clearing price. Market-clearing prices are important factors for informing BPA's rates. AURORA is used as the primary tool for (a) calculation of the demand rate, (b) shaping the PF rate, (c) estimating the forward price for the IOU REP settlement benefits calculation for fiscal years 2008 and 2009, (d) estimating the uncertainty surrounding DSI payments, (e) informing the secondary revenue forecast and (f) providing a price input used for the risk analysis. For information about the demand charge see Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-05, Section 2.2.1. For information about shaping the PF rate see WPRDS, WP-07-E-BPA-05, Section 2.1. For information about the calculation of secondary revenues, uncertainty regarding the IOU REP settlement benefits and DSI payment uncertainty, and risk run see Risk Analysis Study WP-07-E-BPA-04, Sections 2.4.7 and 2.4.8.

1.2 AURORA Model Framework. AURORA assumes a competitive pricing structure as the fundamental mechanism underlying the determination of wholesale electric energy prices during the term of this analysis. Two fundamental inferences for energy pricing follow from the economic theory of market pricing. First, the price in any hour will approximate the variable cost of the marginal generating resource. Second, the long-term average price will gravitate toward the full cost of a new resource.

As noted above, the inference on hourly prices follows directly from economic market pricing theory. Economic theory concludes that a firm will continue to produce additional goods or services as long as the revenue from the sale of those units covers the marginal cost. A competitive market will produce a quantity up to the amount consumers are willing to pay for marginal consumption which is equal to the marginal cost of production. Therefore, the market-clearing price is equal to the cost to produce the marginal unit for consumption. For the electricity market, the hourly market-clearing price translates to the variable cost from the marginal electric generator.

In the long-term, when the amount of capital is not fixed, the average price will move toward the full cost of a new resource. When prices are high enough to justify additional investment, the average investment cost will be lower than the average price. Therefore, new resources will bring down the price. When the long-term average price outlook is lower than the average cost of a new resource, new resources will not be built. In this case, demand growth will move prices up the supply curve until new resource investment is profitable.

Since long-term prices will gravitate toward the cost of new resources, the assumptions concerning the cost of a new resource will have an important impact on the long-term price forecast. It is assumed that the bulk of new electric power generation will be combined-cycle combustion turbines (CCCT). Another important assumption is the load forecast. This assumption will affect how quickly prices move up the supply curve and reach the point where investment in new resources is profitable.

Economic theory also concludes that until prices reach the level where new resource investment is profitable, excess capacity will decline. A decline in excess capacity will tend to exacerbate price increases in those periods when relatively less surplus capacity is available, i.e., the peak pricing months and heavy load hour periods.

2. METHODOLOGY

2.1 Overview. The principal tool used in this analysis is an electric energy market model called AURORA. AURORA is owned and licensed by EPIS, Incorporated. Production costing is a subset of AURORA's functions. Production cost models are widely used in the electric power industry for such things as forecasting electricity prices. Production cost models follow a general structure and AURORA is consistent with this structure.

To describe AURORA's methodology it is helpful to distinguish between two main aspects of modeling the electric energy market: the short-term determination of the hourly market-clearing price and the long-term optimization of the resource portfolio.

2.2 Hourly Price Determination. The hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource. AURORA sets the market-clearing price using assumptions on demand levels (load) and supply costs. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, and fuel price.

AURORA recognizes the effect that transmission capacity and prices have on the ability to move generation output between areas. AURORA recognizes 13 areas within the Western Electricity Coordinating Council (WECC, formally called the WSCC), largely defined by the transmission grid.

2.3 Long-Term Resource Optimization. The long-term resource optimization feature within AURORA allows generating resources to be added or retired based on economic profitability. Economic profitability is measured as the net present value of revenue minus the net present value of costs. A potential new resource that is economically profitable will be added to the resource database. An existing resource that is not economically profitable will be retired from the resource database.

In reality, the market-clearing price (hence the profitability of a resource) and the resource portfolio are interdependent. The market-clearing price will affect the revenues any particular resource will receive, and consequently which resources are added and retired. In parallel, changes in the resource portfolio will change the supply cost structure and will therefore affect the market-clearing price. AURORA uses an iterative process to address this interdependency.

AURORA's iterative process uses a preliminary price forecast to evaluate existing resources and potential new resources in terms of economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is economically profitable, it is a candidate to be added to the resource portfolio. In the first step of the iterative process, a small set of new resources is drawn from those with the greatest profitability and added to the resource base. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource portfolio is used in the next step in the iterative process to derive a revised market-clearing price forecast. The modified price will then drive a new iteration of resource changes. AURORA will continue the iterative solution of the resources portfolio and the market-clearing price until the difference in price between the last two iterations reaches a minimum and the iterative process converges to a stable solution.

2.4 Application of AURORA for informing rate setting. For calculating the demand rate and shaping the energy rates, AURORA was run in an hourly deterministic mode holding the expected natural gas price and the expected load forecast constant, while assuming average hydroelectric conditions. AURORA forecasted hourly prices for October 1, 2006 through September 30, 2009. The results of the AURORA runs used for determining the demand rate and shaping the rates can be found in the WPRDS, WP-07-E-BPA-05B, Chapter 4, Table 4.2. For informing the secondary revenue forecast, AURORA was run in a probabilistic mode. When running the probabilistic forecast for secondary revenues for the base rates, BPA ran 50 different games, reflecting hydro conditions for the 50 years 1928 through 1978. BPA kept the load conditions and natural gas prices constant. For the risk run, BPA altered hydro conditions, load conditions, and natural gas prices. BPA ran 3,000 different games for the risk run. Both the secondary revenue forecast and the risk run produced monthly HLH and LLH prices for October 2006 through September 2009. Results of the secondary revenue forecast can be found in the WPRDS, WP-07-E-BPA-05A, Chapter 3.8, Table 3.8.1. Information about the risk run can be found in the Risk Analysis Study, WP-07-E-BPA-04, Chapters 2.1 to 2.4. The Risk Analysis Study provided the variations in the inputs that were used to supply AURORA. For fiscal year 2006, AURORA was only used to produce a risk run.

As stated in the testimony of Petty, *et al*., WP-07-E-BPA-12, Section 5, BPA decremented the loads in Oregon, Washington, and Northern Idaho by approximately 2,500 aMW to reflect the fact that BPA does not market power in a market that has an exact hourly marginal clearing price. Instead, BPA markets power in a bilateral market in which parties are not assured of receiving the highest hourly marginal clearing price. This was done only in the secondary revenue forecast and the risk run.

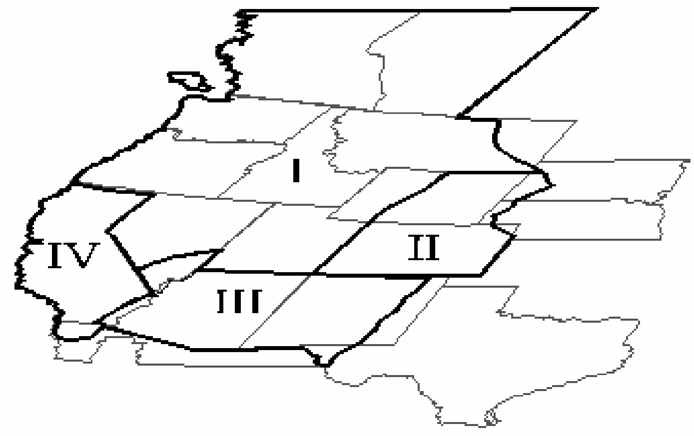
3. ASSUMPTIONS

3.1 Overview. Three primary assumptions are relevant to the price forecast: the load forecast; the natural gas price forecast; and assumptions about hydroelectric generation conditions. The load forecast determines where on the supply curve the marginal clearing price will occur. Natural gas prices will generally determine the variable cost of the resource on the margin that sets the marginal clearing price. Hydroelectric generation conditions determine the amount of hydroelectric generation that can be used to meet loads and thus add to the location on the supply curve where the marginal clearing price is reached. The assumptions on the load forecast, natural gas prices, and hydro conditions are described in detail below. A number of other relevant assumptions are also discussed. Remaining data and assumptions required to run AURORA are listed in the Market Price Forecast Documentation for WP-07-E-BPA-03A.

3.2 Load Forecast. The load forecast for AURORA consists of four parts: the base-year load forecast; the annual average growth rate; monthly load-shape factors; and hourly load-shape factors. The base-year load forecast determines the starting level for the loads. The annual average growth rate increases the loads over time. The monthly load-shape factors shape the annual loads into monthly loads. The hourly load-shape factors then shape the monthly loads into hourly loads.

3.2.1 Base-Year Load Forecast. For the base-year load forecast input to AURORA, BPA relied on the WECC 10-Year Coordinated Plan Summary (2005-2014) load forecast. The WECC forecasts loads for four regions: the Northwest Power Pool Area; the California–Mexico Power Area; the Rocky Mountain Power Area; and the Arizona–New Mexico–Southern Nevada Power Area. Figure 1 represents these areas:

Figure 1: 2005 WECC Regions



Where: I = Northwest Power Pool Area

II = Rocky Mountain Power Area

III = Arizona–New Mexico–Southern Nevada Power Area

IV = California–Mexican Power Area

The four WECC regions were converted into 13 AURORA areas for BPA's forecasts. Table 1 represents the 13 AURORA areas:

Table 1: AURORA Areas

AREA NUMBER	AREA NAME	SHORT AREA NAME
1	Oregon/Washington/IdahoNorth	OWI
2	Northern California	NoCA
3	Southern California	SoCA
4	British Columbia	BC
5	Idaho South	IDSo
6	Montana	MT
7	Wyoming	WY
8	Colorado	CO
9	New Mexico	NM
10	Arizona/NevadaSouth	AZNV
11	Utah	UT
12	Nevada North	NVNo
13	Alberta	AB

The methodology used to convert the WECC regional loads can be seen in the following example. With the Northwest Power Pool Area, the loads in the original AURORA database for OWI, BC, IDSo, MT, UT, NVNo, and AB were summed to produce an aggregate total load. The loads for OWI, BC, IDSo, MT, UT, NVNo, and AB were each divided by the aggregate total load to develop individual percentages. The individual percentages were then applied to the aggregate WECC regional load forecast for the Northwest Power Pool Area 2000 load forecast for AURORA areas OWI, BC, IDSo, MT, UT, NVNo, and AB. This procedure was then repeated for each of the WECC regions to derive each AURORA area 2000 base-load forecast. For this chapter, PNW is the synonymous with the OWI, IDSo and MT areas.

3.2.2 Annual Average Growth Rate. BPA used an average annual growth rate from the WECC 10-Year Coordinated Plan Summary (2005-2014). BPA used these WECC regional growth rates to reflect its prediction that loads will grow at different rates in the different WECC regions. Table 2 shows the WECC annual growth rates used for the load forecast:

Table 2: Load Forecast Annual Average Growth Rate in Percents

Area	NWPA	RMPA	AZ/NM/SO NV	CA-MX
2005	2.0	8.1	1.9	4.1
2006	2.1	2.2	3.4	2.6
2007	2.2	2.5	3.3	2.6
2008	2.3	2.4	3.3	2.6
2009	1.3	2.1	2.8	2.6

BPA applied the annual average growth rate to the base load forecast to determine the load forecast over time.

3.2.3 Monthly and Hourly Load-Shaping Factors. BPA used the default AURORA load-shaping factors for converting the annual load forecast into a monthly load forecast. AURORA multiplies the monthly shaping factor by the annual load forecast to derive the monthly load forecast. BPA also used the default hourly load-shaping factors provided for converting the monthly load forecast into an hourly load forecast.

3.3 Natural Gas Prices

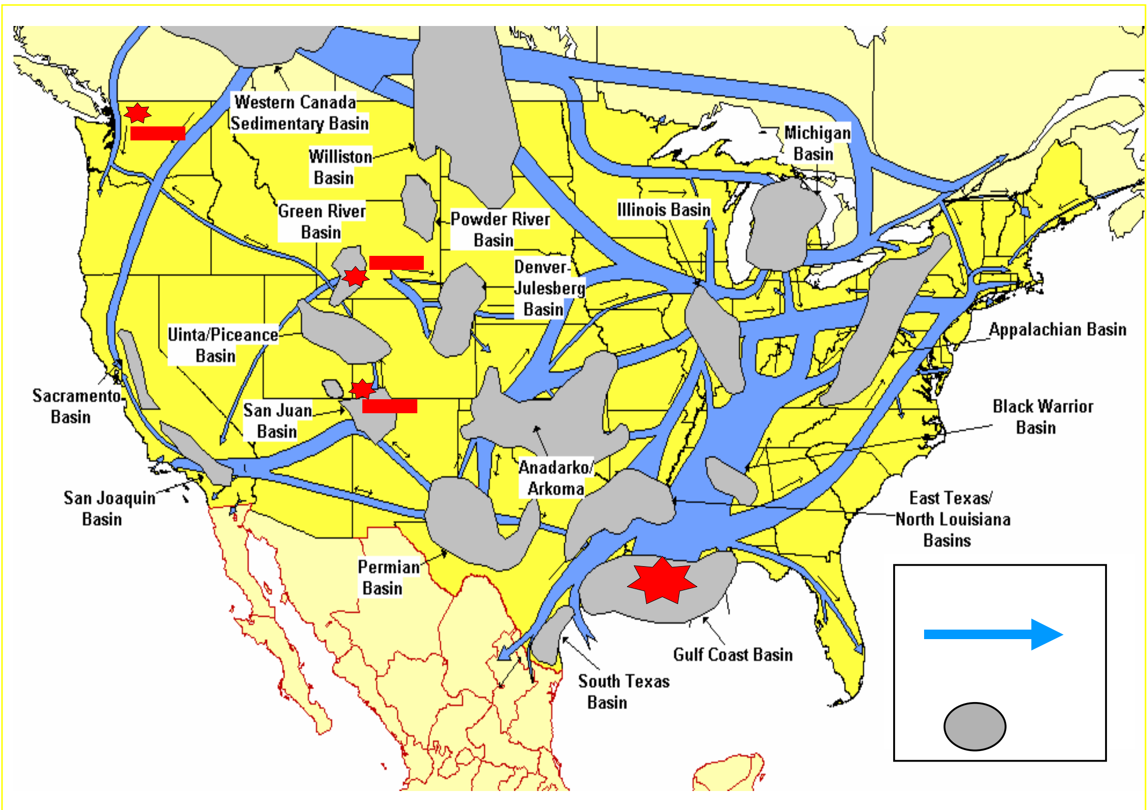
3.3.1 Methodology

This section describes the methodology used to forecast natural gas prices. The methodological description first covers the geographic aspect of the natural gas price forecast and then the temporal aspect of the forecast.

The purpose of the geographic component of the natural gas analysis is to derive a forecast for gas delivered to electric generators in each of the AURORA areas. Natural gas prices in these areas are largely determined within the interconnected North American market. However, transportation costs and local supply and demand factors also affect local prices. The methodology begins with the primary pricing hub for the North American market and then estimates the difference between this price and local prices.

The methodology begins with a forecast of natural gas prices at Henry Hub in Louisiana. This Hub is frequently referenced as a touchstone for North American gas prices and is the location of the most liquid natural gas futures market. The next step in the geographic disaggregation of gas prices estimates a price difference, or basis, between Henry Hub and three primary natural gas supply basins in the west. These basins are the source for most of the natural gas delivered in the western U.S. Market conditions in these basins are represented by pricing hubs associated with the supply basins. The Western Canada Sedimentary Basin is represented by the Sumas, Washington Hub. The collection of Rocky Mountain supply basins are represented by the Opal, Wyoming Hub. The San Juan Basin is represented by the Igancio, Colorado Hub. These three western hubs along with the supply basins and natural gas transportation flows are summarized in Figure 2.

Figure 2: North American Natural Gas Geographic Summary



The final step in the geographic disaggregation of gas prices associates each western hub with an AURORA area and estimates the price differential between the hub and the AURORA area. The hub associated with each area is the hub that tends to be the source of marginal gas supply in that area and therefore the hub that has the highest price correlation to prices in the local area. The Sumas Hub is associated with the Pacific Northwest and Northern California areas. The Opal Hub is associated with Montana, Idaho, Wyoming and Utah. The San Juan Hub is associated with Nevada, Southern California, Arizona and New Mexico. In summary, the forecast begins with a price forecast for Henry Hub. The price difference between Henry Hub and each western hub is then forecast. The final step forecasts a price difference between the western hub and its associated AURORA area. The values of the price differentials are described in the Basis section.

The temporal aspect of the natural gas price forecast differentiates between short and long-term prices. In the short-term, monthly prices for Henry Hub and the basis differentials to western hubs are forecast directly. In the long-term, annual prices and basis differentials are forecast and a monthly shaping factor is used to derive monthly prices. For the purposes of this forecast, short-term is defined as June 2005 (the preparation date of this forecast) through December 2007. The long-term is defined as January 2008 through December 2020. The natural gas price series is based on supply and demand fundamentals. These fundamentals and the resulting prices are described in the following sections.

3.3.2 Fundamentals History and Outlook: Overview

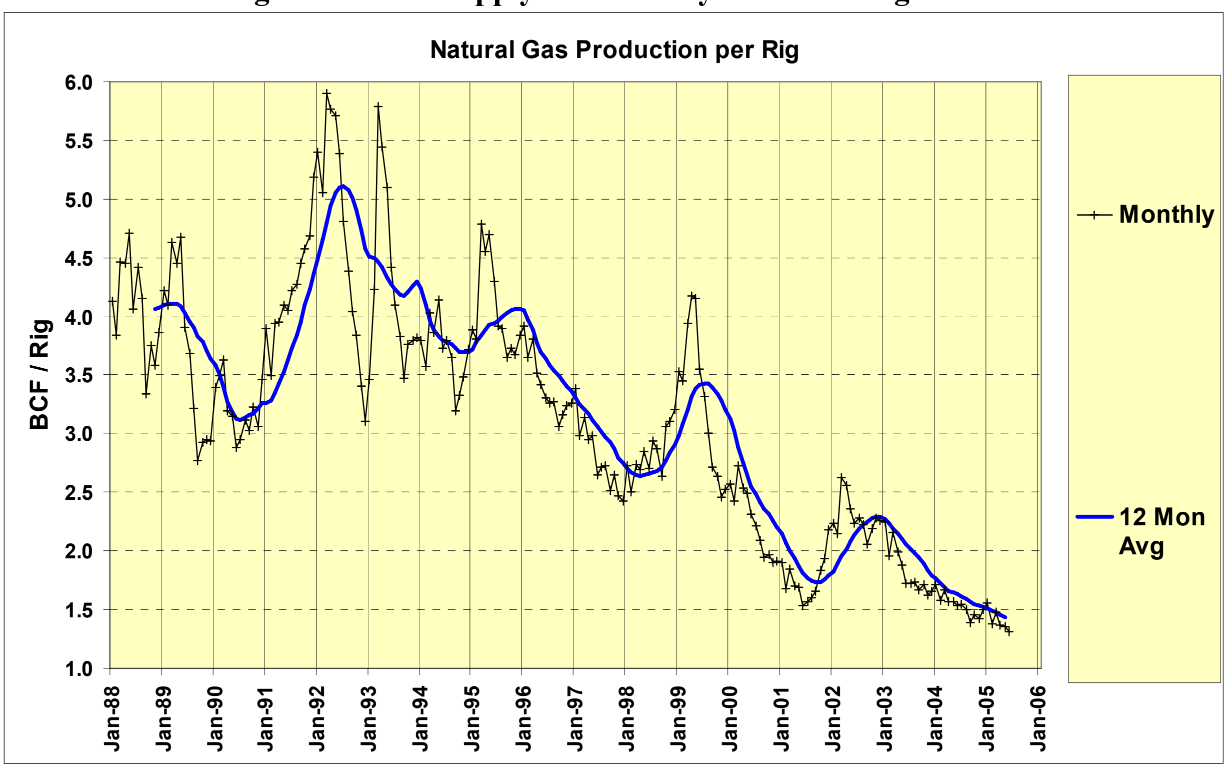
This price forecast is premised on a generally tight balance of supply and demand in the natural gas market. On the supply side, existing North American supply basins are mature and declining in productivity. New supply sources such as liquefied natural gas (LNG) and unconventional production will add to U.S. capacity, but these will not see significant growth until 2008. Natural gas demand is expected to see continued growth in the residential and commercial sector. The industrial sector is also expected to grow, but growth in this sector will be susceptible to declines from price elasticity effects and economic competitiveness. The electric power sector is also expected to increase gas consumption, although the tight gas market will encourage other sources of generation.

3.3.3 Fundamentals History and Outlook: Supply

Existing North American production basins are mature and exhibit declining productivity. The maturity of existing basins means that future conventional production will come from deeper and less accessible wells with higher marginal costs. Some of the increase in marginal costs may be offset by technological improvements in finding and development costs. However, the phenomenon of declining productivity offset by technological gain has been evident since the mid-1990s and the overall result has led to a stable level of production and increasing prices. Since 1995 production has declined by about 0.5% while prices have increased approximately 250%.

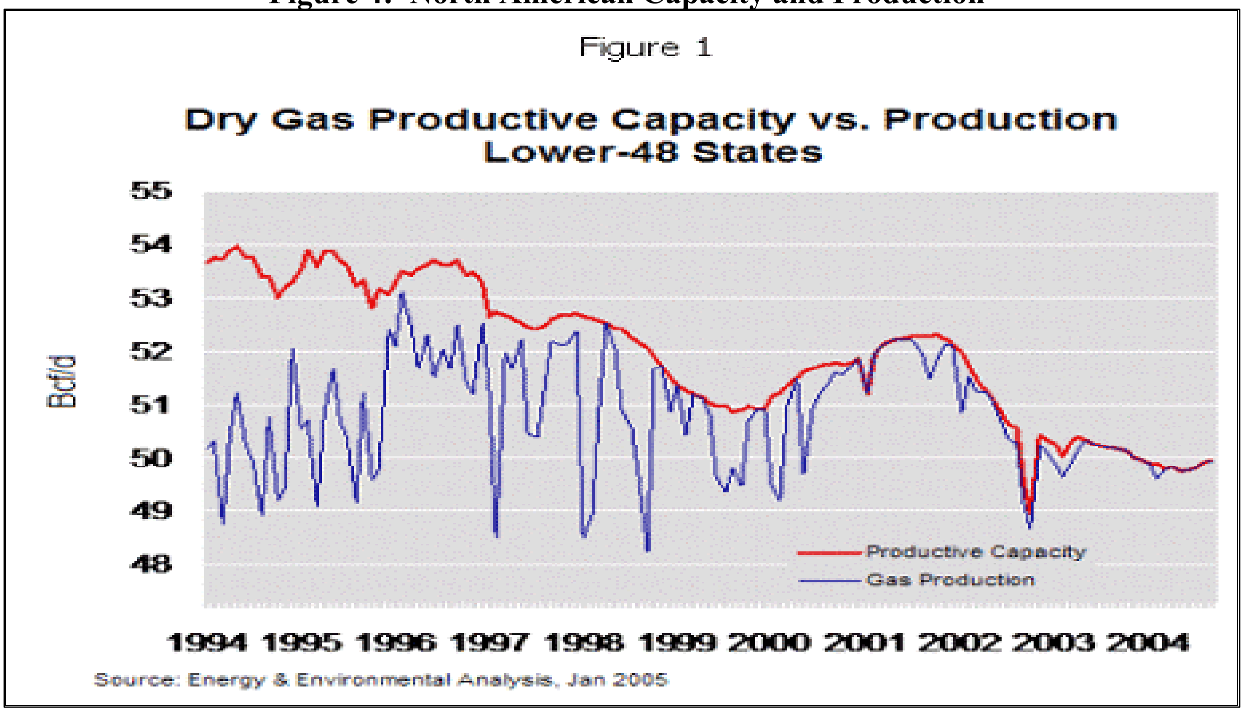
The following graph (Figure 3) shows the decline in productivity from existing basins in the U.S.

Figure 3: U.S. Supply Productivity from Existing Basins



In addition to declining productivity in existing basins, the overall productive capacity of the U.S natural gas industry has been declining since the mid-1990s. During this period of declining capacity, overall production has maintained a relatively stable level with the result that very little excess capacity exists today. Since the early part of the current decade, the natural gas industry has been producing at essentially full capacity. This factor contributes to price pressure and especially price volatility. Trends in U.S. production and capacity are shown in the following graph (Figure 4).

Figure 4: North American Capacity and Production



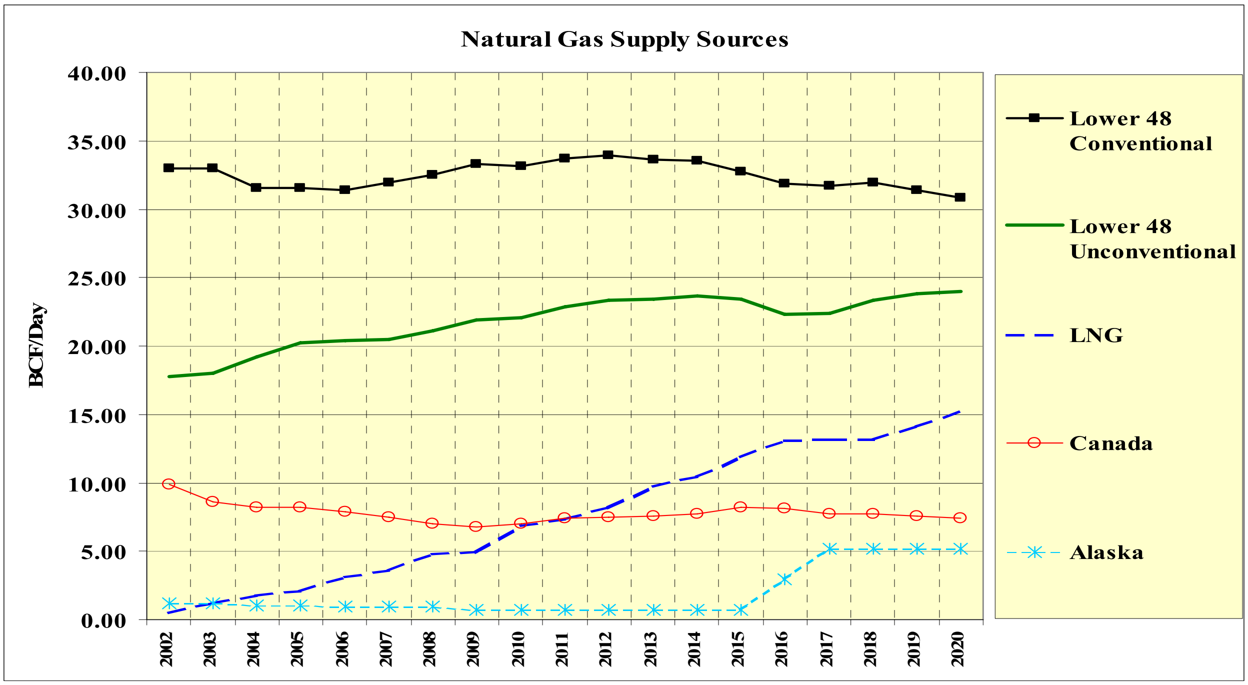
Until new sources of supply can be brought on-line, upward price pressure will continue. New supply is expected to come from unconventional sources (coal bed methane, tight sands and shale gas) and liquefied natural gas (LNG). Additional supply from these sources is expected to ramp up and eventually relieve some price pressure on natural gas. However, in the short-term (through 2007) the additional supply from unconventional gas and LNG will not lead to significant downward price relief. After 2007, these new supply sources will make an increasingly large contribution to North American production and lead to a softening of prices. Natural gas from Alaska is expected to reach the lower-48 market around 2015. The trends in natural gas supply are shown in the following table and graph, which detail the forecast from the Energy Information Administration's Annual Energy Outlook 2005 (Table 3; Figure 5).

Table 3: U.S. Natural Gas Supply

Sources of Natural Gas Supply, BCF/Day											
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Total	***63.09***	***63.77***	***64.45***	***66.35***	***67.73***	***69.86***	***71.97***	***73.69***	***75.00***	***76.18***	***76.94***
Conventional	31.53	31.39	31.95	32.49	33.32	33.18	33.68	33.97	33.62	33.56	32.78
Unconventional	20.21	20.40	20.52	21.10	21.95	22.08	22.91	23.34	23.40	23.68	23.40
Alaska	1.07	0.93	0.93	0.93	0.75	0.69	0.69	0.70	0.72	0.73	0.73
Canada	8.21	7.93	7.50	7.01	6.78	7.05	7.37	7.49	7.54	7.75	8.17
LNG	2.06	3.12	3.55	4.81	4.94	6.86	7.31	8.19	9.72	10.46	11.86

Sources of Natural Gas Supply, Annual Percent Change											
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Total		***1.1%***	***1.1%***	***2.9%***	***2.1%***	***3.1%***	***3.0%***	***2.4%***	***1.8%***	***1.6%***	***1.0%***
Conventional		-0.4%	1.8%	1.7%	2.5%	-0.4%	1.5%	0.8%	-1.0%	-0.2%	-2.3%
Unconventional		0.9%	0.6%	2.9%	4.0%	0.6%	3.7%	1.9%	0.3%	1.2%	-1.2%
Alaska		-13.0%	-0.4%	0.0%	-19.5%	-8.1%	0.9%	1.5%	1.7%	1.8%	0.4%
Canada		-3.5%	-5.4%	-6.5%	-3.3%	4.0%	4.6%	1.5%	0.8%	2.8%	5.4%
LNG		51.1%	13.8%	35.5%	2.7%	38.8%	6.6%	11.9%	18.7%	7.7%	13.4%

Figure 5: Long-Term Gas Supply Outlook; EIA



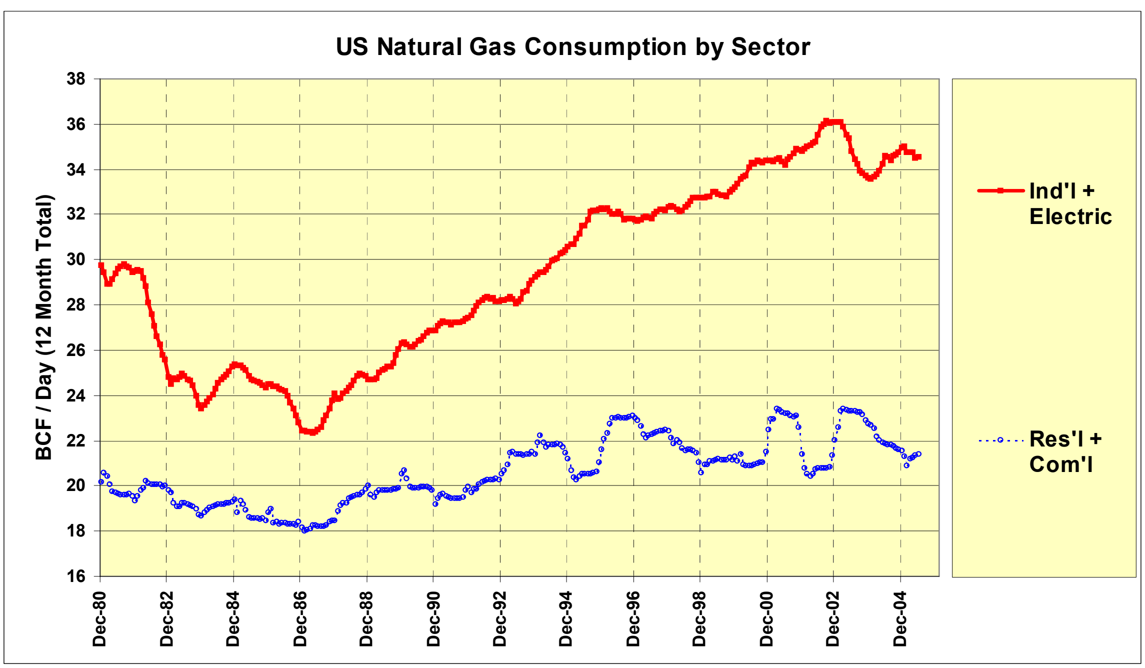
Escalating natural gas prices have led to another potential source for a supply increase: the opening of currently restricted areas in the outer continental shelves, the Rocky Mountain states and the eastern Gulf of Mexico. These areas are currently restricted through legislation, but some members of Congress have called for removal of access restrictions. Significant production from these areas is highly speculative and depends on political trends. Even if large areas were opened for production, it would be years before the supporting infrastructure would allow large quantities to reach the market. Production from these areas is not included in this forecast although it is recognized as a potential factor.

In summary, natural gas is in short supply through 2007. Short-term supply is characterized by production at full capacity and continuing declines in productive capacity and in the productivity of existing basins. The resulting high marginal costs will keep prices at historically high levels through 2007. After 2007, unconventional production and LNG will relieve some of the supply pressure and allow prices to moderate.

3.3.4 Fundamentals History and Outlook: Demand

For several years, natural gas has been "the fuel of choice." The residential and commercial sectors have seen strong and sustained growth, as natural gas has been the predominant choice, especially in new construction. In the electric generation sector, the vast majority of new generation has been fired with natural gas. The industrial sector, the largest consumer of natural gas, had several years of gas demand growth. Recently, sharply increasing gas prices have led to reductions in the industrial sector. Figure 6 shows natural gas consumption by sector. Because of data collection changes at the Energy Information Administration, the sectors are grouped into residential/commercial and electric power/industrial.

Figure 6: Consumption by Sector



Looking forward, the long-term price elasticity of natural gas consumption will be an important variable. Natural gas prices have increased by over 80% from 2002. During this time, total U.S. gas consumption declined by 3.5%. In the last year, the decline in consumption moderated. It may still be too early to gauge the long-term effect of sustained high natural gas prices, but this recent evidence suggests a fairly moderate response. A reason for the moderate decline in consumption even after sharp price increases can be traced to declining fuel substitution capability in the industrial and power generation sectors. In the industrial sector the percentage of natural gas consumption that could be readily switched to other fuels has declined from 26% in 1995 to between 5% and 10% today. In the power generation sector, fuel switching capability has declined from 35% in 1995 to between 20% and 25% today.

Given the decline in fuel switching capability and the relatively moderate response to high prices thus far, the outlook is for continued growth in natural gas demand. Demand in the residential and commercial sector is expected to be robust given the lack of substitute fuels (not correlated with gas prices) for natural applications. The power generation sector is expected to see strong growth. However, in the near-term, the large build up of generation capacity over the last few years will mean fewer new plants will be required in the short-term. In the mid- to long-term, high natural gas prices will increase the competitiveness of other generation and demand side resources. The industrial sector will see relatively slow growth. The Energy Information Administration forecasts industrial sector growth to be 1.1% from 2006 to 2020, about half the rate of total gas consumption growth. Forecasts of the industrial sector are perhaps the most unpredictable. Other analysts see a slow erosion of industrial consumption as high U.S. prices reduce the industrial sector's competitiveness and as plants relocate.

3.3.5 The Short-Term Price Forecast

The natural gas price forecast was prepared in early June 2005. Any changes in the market since this time are not reflected in this forecast. For the short-term forecast (through 2007), natural gas prices are expected to be in a $6.50 to $7.50 trading range. This price forecast is slightly lower than the NYMEX futures prices of early June 2005. In June 2005, storage balances were fairly robust, at levels near the previous five-year maximum as seen in Figure 7.

Figure 7: Natural Gas Storage Compared to the Five Year Average

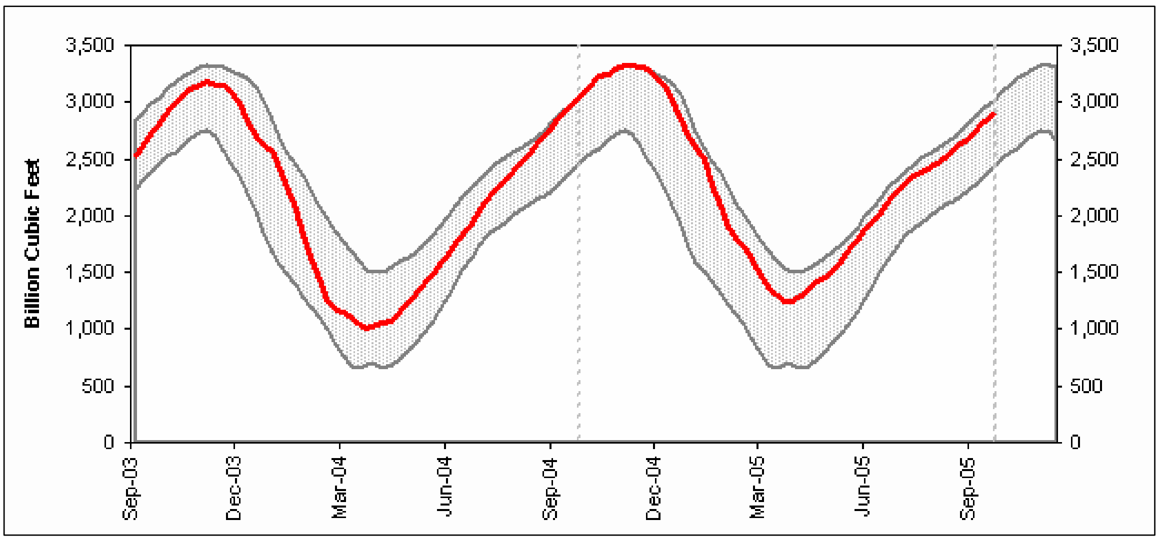
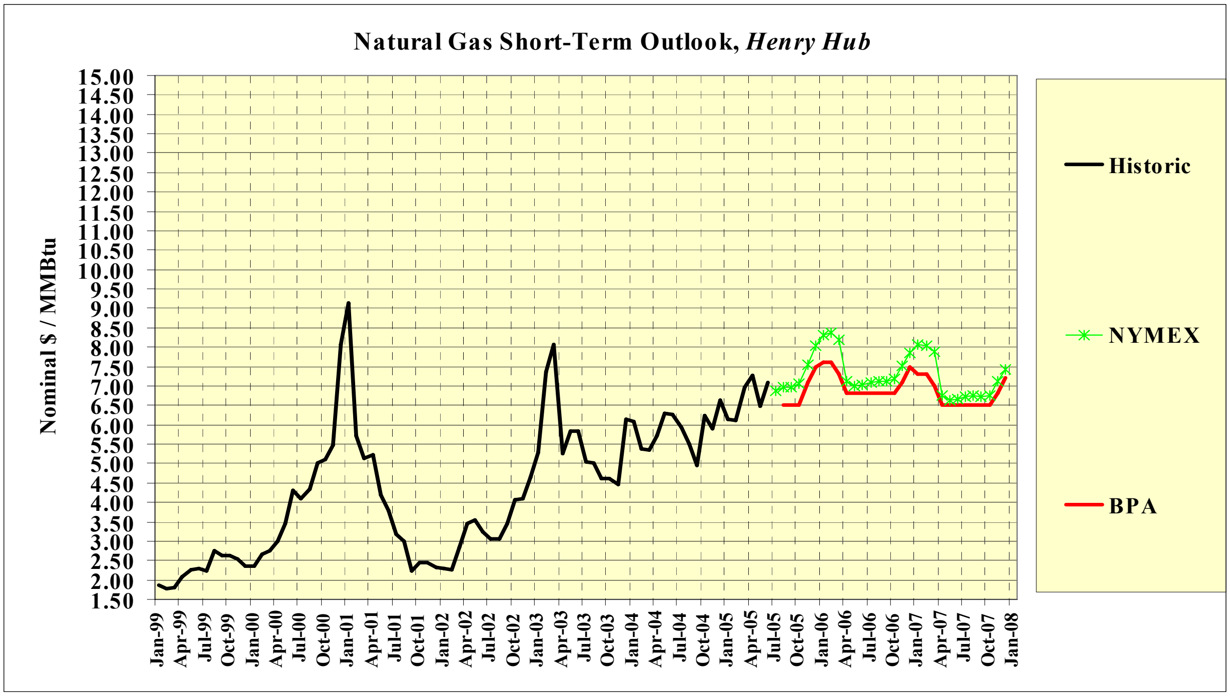


Figure 8 shows the short-term gas price forecast as compared to the NYMEX futures market at the time of the forecast. BPA's forecast is slightly lower than the NYMEX forecast based on the strong storage levels at the time the forecast was prepared.

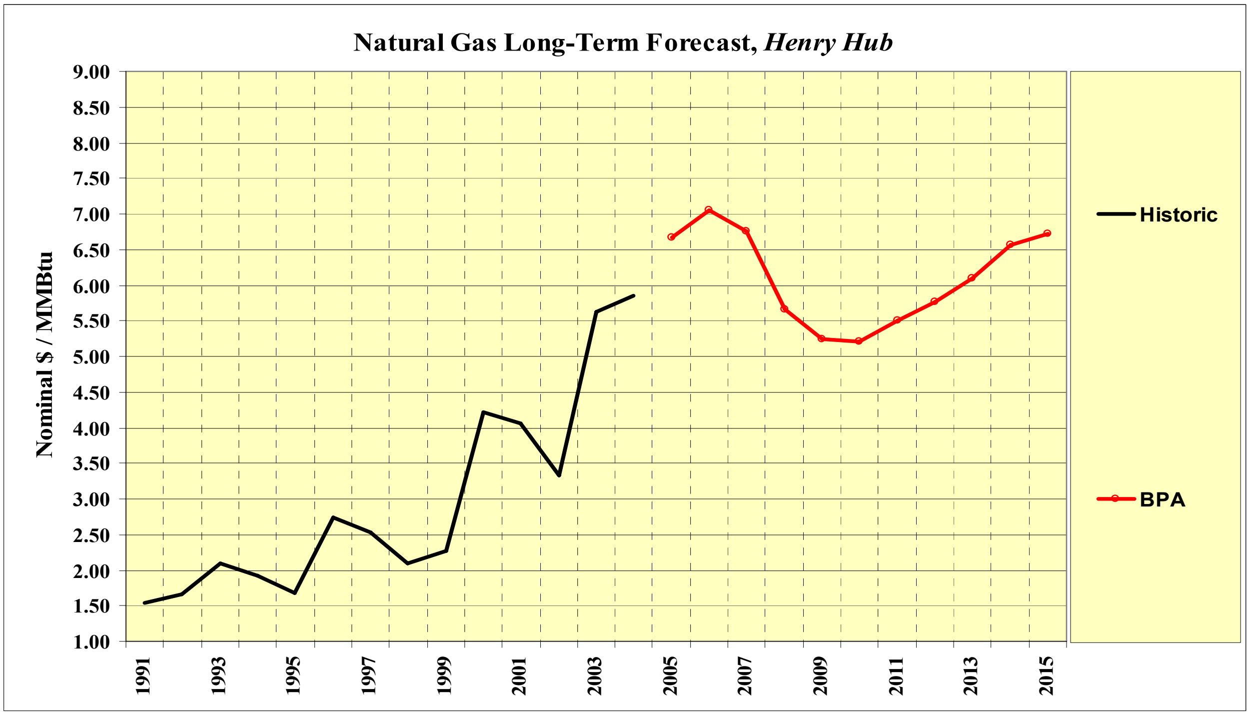
Figure 8: Short-Term Price Forecast



3.3.6 The Long-Term Price Forecast

After 2007, prices are expected to decline due to increased supply availability from unconventional sources and LNG. The pricing decline persists through 2010 when the upward price pressure from growing demand will lead to moderate price increases. The pattern of annual prices is shown on Figure 9.

Figure 9: Long-Term Price Forecast



3.3.7 Basis

This section describes the forecast of price differentials between Henry Hub and the AURORA areas. The price differentials are a result of the transportation costs of natural gas and supply and demand factors. Pipeline bottlenecks can create a supply surplus in a local area because sufficient transportation capacity does not allow local gas to flow to higher priced markets and compete in the larger North American market. When a bottleneck exists for an extended period of time, it becomes profitable to build new infrastructure to allow producers to capture the higher market prices. Absent pipeline bottlenecks the price of natural gas tends to reflect general market conditions and the basis differential is a result of transportation cost differentials. Historical average price differentials can be used to gauge the price differentials that may results without extraordinary pipeline bottlenecks. To forecast the basis spreads for the western hubs as shown in Figure 9, historic data was used in addition to any information on imminent pipeline development.

The basis forecast was adjusted to real (inflation adjusted) dollars for the year 2000 to accommodate AURORA's input requirements. In 2000 dollars, the Henry Hub to Sumas basis was forecast to decline from $0.75/MMBtu in 2005 to $0.55MMBtu in 2008 and remain constant after 2008. The Henry to Opal basis was forecast to decline from $0.74/MMBtu in 2005 to $0.50/MMBtu in 2008 and remain constant after 2008. The Henry to San Juan basis was forecast to decline from $0.79/MMBtu in 2005 to $0.45/MMBtu in 2008 and remain constant after 2008. The prices and basis differentials are shown for Henry Hub and all western hubs in the following Table 4.

Table 4: Historic and Forecast Natural Gas Prices for Hubs

	Nominal $/MMBtu				Basis to Henry		
	Henry	Sumas	Opal	San Juan	Sumas	Opal	San Juan
2005	6.66	5.91	5.92	5.87	0.76	0.75	0.80
2006	7.06	6.41	6.41	6.41	0.65	0.65	0.65
2007	6.76	6.16	6.16	6.16	0.60	0.60	0.60
2008	5.65	5.06	5.12	5.17	0.59	0.54	0.48
2009	5.24	4.64	4.69	4.75	0.61	0.55	0.50
2010	5.20	4.58	4.64	4.70	0.62	0.57	0.51
2011	5.51	4.87	4.93	4.99	0.64	0.58	0.52
2012	5.77	5.11	5.17	5.23	0.65	0.59	0.53
2013	6.09	5.42	5.48	5.54	0.67	0.61	0.55
2014	6.56	5.87	5.93	5.99	0.69	0.62	0.56
2015	6.72	6.02	6.08	6.14	0.70	0.64	0.58
2016	6.89	6.17	6.23	6.30	0.72	0.66	0.59
2017	7.06	6.32	6.39	6.46	0.74	0.67	0.61
2018	7.24	6.48	6.55	6.62	0.76	0.69	0.62
2019	7.42	6.64	6.71	6.78	0.78	0.71	0.64
2020	7.60	6.81	6.88	6.95	0.80	0.72	0.65

The next step in the natural gas price forecast is to link the western hubs to the AURORA areas. These pricing differentials are shown in the following Table 5. For AURORA's analysis, all values are shown in Real (inflation adjusted) dollars for the year 2000. Table 5 lists the three western hubs and the associated AURORA area below. The value for each AURORA area is the price differential between the western hub and the AURORA Area (Table 5).

Table 5: Price Differentials Between Hubs and AURORA Areas

Aurora Area to Western Hub Differential Price Differential (2000$/MMBtu)					
Sumas		**Opal**		**San Juan**	
PNW	0.23	**UT**	0.35	**CO**	0.36
N. Cal	0.31	**WY**	0.40	**S. CA**	0.47
		MT	0.33	**AZ**	0.41
		ID	0.35	**NM**	0.33
		N. NV	0.46	**S. NV**	

The AURORA area gas price forecast is derived by taking the western hub price and adding the differentials given in the table above. In addition, $0.25/MMBtu (Real 2000$) is added for fixed transportation costs. The final results are shown in the following Table 6.

Table 6: AURORA Area Price Forecast

Aurora Gas Price Forecast Input (2000$/MMBtu)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NW Nat Gas	5.30	5.62	5.26	4.21	3.76	3.63	3.76	3.85	3.99	4.21	4.21	4.21	4.21	4.21	4.21	4.21
N.Cal Nat Gas	5.38	5.70	5.34	4.29	3.84	3.70	3.84	3.93	4.06	4.29	4.29	4.29	4.29	4.29	4.29	4.29
S.Cal Nat Gas	5.49	5.84	5.48	4.52	4.07	3.94	4.07	4.16	4.30	4.52	4.52	4.52	4.52	4.52	4.52	4.52
Can Nat Gas	5.28	5.60	5.24	4.19	3.74	3.60	3.74	3.83	3.96	4.19	4.19	4.19	4.19	4.19	4.19	4.19
Id Nat Gas	5.43	5.73	5.38	4.37	3.92	3.78	3.92	4.01	4.14	4.37	4.37	4.37	4.37	4.37	4.37	4.37
Mt Nat Gas	5.41	5.72	5.36	4.35	3.90	3.77	3.90	3.99	4.13	4.35	4.35	4.35	4.35	4.35	4.35	4.35
Wy Nat Gas	5.47	5.78	5.42	4.41	3.96	3.83	3.96	4.05	4.19	4.41	4.41	4.41	4.41	4.41	4.41	4.41
Co Nat Gas	5.39	5.74	5.39	4.42	3.97	3.84	3.97	4.06	4.20	4.42	4.42	4.42	4.42	4.42	4.42	4.42
NM Nat Gas	5.36	5.72	5.36	4.40	3.95	3.81	3.95	4.04	4.17	4.40	4.40	4.40	4.40	4.40	4.40	4.40
Az Nat Gas	5.43	5.79	5.43	4.47	4.02	3.88	4.02	4.11	4.24	4.47	4.47	4.47	4.47	4.47	4.47	4.47
Ut Nat Gas	5.43	5.73	5.38	4.37	3.92	3.78	3.92	4.01	4.14	4.37	4.37	4.37	4.37	4.37	4.37	4.37
Nv Nat Gas	5.48	5.83	5.48	4.52	4.07	3.93	4.07	4.16	4.29	4.52	4.52	4.52	4.52	4.52	4.52	4.52

3.4 Hydroelectric Generation. For the market price forecasts, AURORA was supplied hydroelectric generation levels for the PNW area from the Loads Resources Study, WP-07-BPA-01, Section 2.1.4. For the California area, hydroelectric generation conditions were supplied from RiskMod. For the PNW, 50 water years were used for the variation in hydroelectric conditions. For the California area, 18 years of historical hydroelectric generation levels were used for determining hydroelectric generation variability. For the remaining areas, AURORA default values were used. For monthly and hourly shaping factors BPA used the default database. If BPA is provided new hydroelectric generation levels from the Load Resources Study, BPA will update the prices with these new values.

3.5 Generating Resource Update. BPA added generating resources to be consistent with the most current data available. BPA updated resources that BPA expected to be operating through the 2005 time frame. After 2005, BPA let AURORA determine which resources would be added or deleted within the AURORA database. A complete listing of all the resources can be found in the Documentation WP-07-E-BPA-03A.

3.6 Other Assumptions.

For the market price forecasts, BPA used AURORA version 5.6.33. For the assumptions not mentioned above, BPA used the default database supplied with version 5.6.33. These assumptions are contained in the Market Price Forecast Documentation WP-07-E-BPA-03A.

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