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 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2009 MARKET PRICE FORECAST STUDY

September 2008

WP-07-FS-BPA-11

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FY 2009 MARKET PRICE FORECAST STUDY
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COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	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
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con Aug	Conservation Augmentation
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
COU	Consumer-Owned Utilities
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program
DROD	Draft Record of Decision

DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
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
FERC SR	Federal Energy Regulatory Commission Special Rule
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)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party

JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
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
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
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)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
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
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWEC	Northwest Energy Coalition
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
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 Transmission
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
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
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively

UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
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 (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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1. INTRODUCTION

1.1 Definitions and Purpose

This study presents BPA's market price forecast for the WP-07 Final Supplemental Proposal, which is 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 power rates. AURORA is used as the primary tool for: (a) estimating the forward price for a portion of the DSI smelter payments; (b) estimating the uncertainty surrounding a portion of the DSI payments; (c) informing the secondary revenue forecast; and (d) providing a price input used for the risk analysis. For information about the calculation of the secondary revenues, uncertainty around a portion of the DSI payments and the price input for the risk analysis, *see* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12.

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 determination of 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 that 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 of 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 projected that the bulk of new electric power generation will be combined-cycle combustion turbines (CCCT), given the costs of current technologies. Another important factor is the load forecast. The load forecast 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 (EPIS). Production costing is a major component 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, location, and fuel price.

AURORA recognizes the effect that transmission capacity and prices have on the ability to move generation output between areas. BPA's implementation of AURORA recognizes 13 areas within the Western Electricity Coordinating Council (WECC, formally called the WSCC), defined by rated transmission paths.

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 fixed and variable costs. A potential new resource that is economically profitable will be added to the resource inventory. An existing resource that is not economically profitable will be retired from the resource inventory.

In reality, the market-clearing price (hence the profitability of a resource) and the resource inventory 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 inventory 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 inventory. 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 inventory. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource inventory 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 inventory 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 estimating the forward price for a portion of the DSI smelter payments, AURORA was run in an hourly deterministic mode, holding the natural gas price and the load forecast constant, while assuming average hydroelectric conditions. AURORA produced forecasts of hourly prices for October 1, 2008, through September 30, 2009, that were used to compute average annual prices. The prices were used to estimate the forward prices for a portion of the DSI smelter payments and can be found in the documentation for the FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11A. 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 water years from 1929 through 1978. BPA kept the load conditions and natural gas prices constant. The average prices of the 50 different games can be found in the FY 2009 Market Price Forecast Study Documentation, WP-07-FS-BPA-11A. To determine the price input for the risk run analysis, BPA altered hydro conditions, load conditions, and natural gas prices. BPA ran 3,000 different games for the risk run analysis. Both the secondary revenue forecast and the risk run analysis produced monthly HLH and LLH prices for October 2008 through September 2009. The FY 2009 Market Price Forecast Study Documentation, WP-07-FS-BPA-11A, presents the average prices of the 3,000 games. The FY 2009 Supplemental Risk Analysis Study, WP-07-FS-BPA-12, includes additional information about the secondary revenue forecast and the risk run.

As stated in Petty, *et al.*, WP-07-E-BPA-11, the loads in Oregon, Washington, and Northern Idaho were decremented by approximately 2,500 aMW to reflect the fact that BPA does not participate 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 decrement was done only in the secondary revenue forecast and the risk run.

3. MARKET PRICE FORECAST ASSUMPTIONS

3.1 Overview

Three primary drivers 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 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 price is reached. The assumptions for the load forecast, natural gas prices, and hydro conditions are described in detail below. A number of other relevant factors are also discussed. The FY 2009 Market Price Forecast Study Documentation, WP-07-FS-BPA-11A, lists additional data and assumptions used to run AURORA for this study.

3.2 Load Forecast

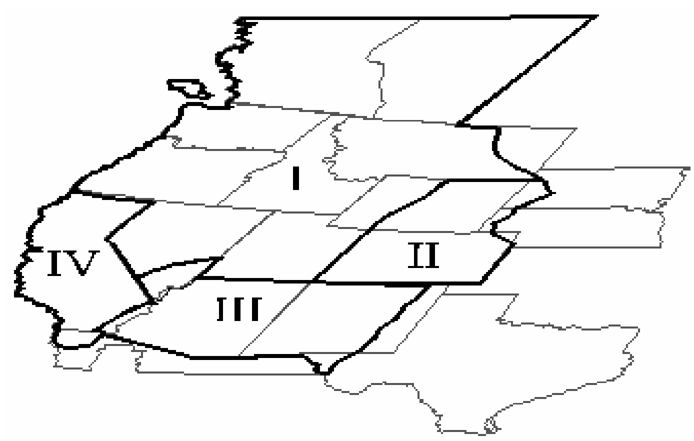
The load forecast for AURORA consists of four parts: the base-year load forecast; the annual average growth rate; monthly load-shape factors; and hourly load-shape factors. The base-year load forecast determines the starting level for the loads. The annual average growth rate increases the loads from year to year. 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 used in AURORA, BPA relied on the WECC 10-Year Coordinated Plan Summary (2006-2015) 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 regions.

Figure 1: 2006 WECC Regions



Where: I = Northwest Power Pool Area

II = Rocky Mountain Power Area

III = Arizona-New Mexico–Southern Nevada Power Area

IV = California-Mexico Power Area

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

Table 1: AURORA Areas

AREA NUMBER	AREA NAME	SHORT AREA NAME
1	Oregon/Washington/Idaho North	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/Nevada South	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 EPIS 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 2008 load forecast for AURORA areas OWI, BC, IDSo, MT, UT, NVNo, and AB. This procedure was then repeated for each of the other WECC regions to derive each of the AURORA area 2008 base-load forecasts. For this study, the PNW is synonymous with the OWI, IDSo, and MT areas.

3.2.2 Annual Average Growth Rate

BPA used the average annual growth rates from the WECC 10-Year Coordinated Plan Summary (2006-2015). 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
2009	2.2	2.3	3.1	2.1

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 EPIS default AURORA database labeled North American DB2008-01 to derive the monthly 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 used the default AURORA hourly load-shaping factors for converting the monthly load forecast into an hourly load forecast.

3.3 Natural Gas Prices

3.3.1 Methodology for Deriving AURORA Area Natural Gas Prices

In order to forecast electricity market prices, BPA forecasts natural gas prices for gas delivered to electric generators in each AURORA area. BPA first forecasts natural gas prices at Henry Hub, Louisiana. Henry Hub is frequently referenced as a touchstone for North American gas prices and is the most liquid natural gas futures market.

The next step is to forecast the basis, or price differential, between Henry Hub and three primary natural gas hubs in the west. These hubs represent production basins that are the source for most of the natural gas delivered in the western United States. The Western Canada Sedimentary Basin is represented by the Sumas, Washington Hub. The collection of Rocky Mountain supply basins is represented by the Opal, Wyoming Hub. The San Juan Basin is represented by the Ignacio, Colorado Hub.

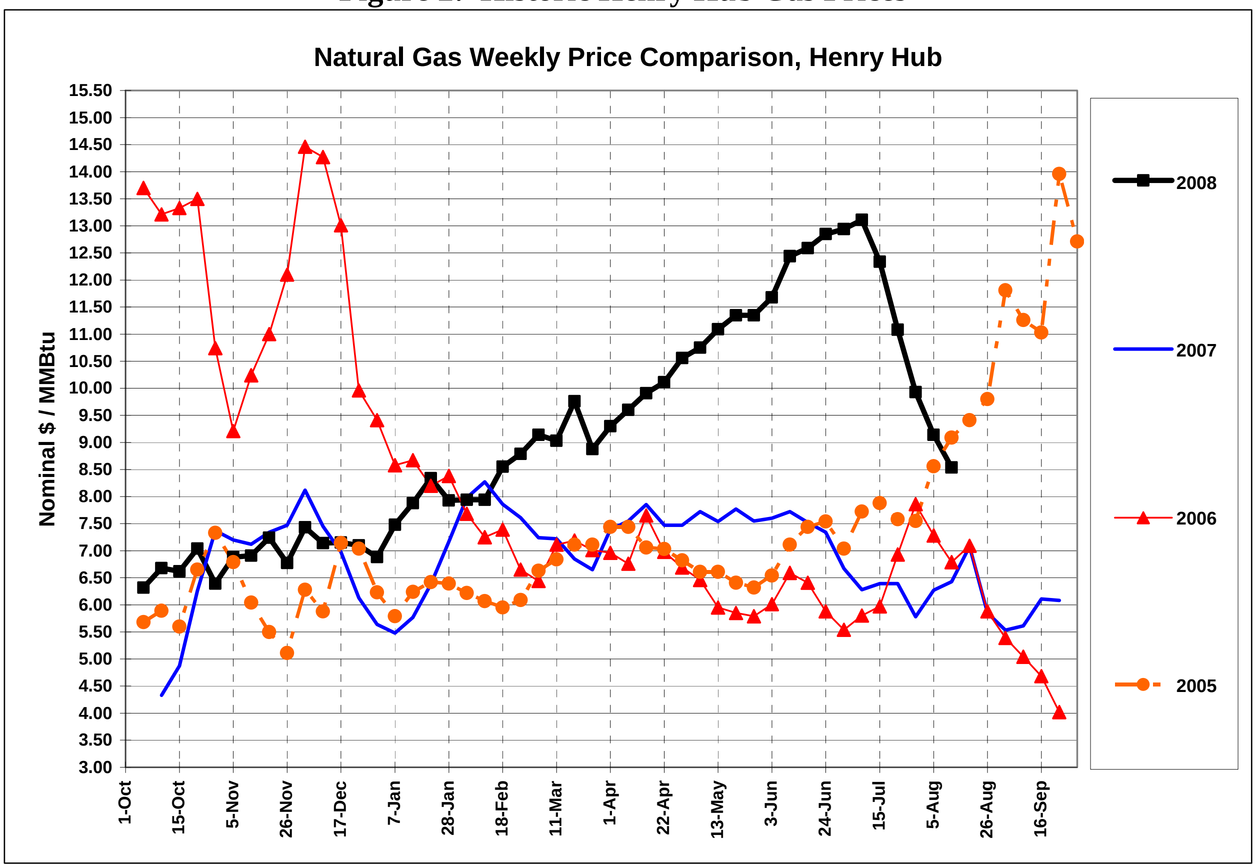
The final step is to estimate the price differential between the western trading hubs and the associated AURORA area. The hub associated with each area is the hub that tends to be the source of marginal gas supply in that area and therefore the hub that has the highest price correlation to prices in the local area. The Sumas Hub is associated with the Pacific Northwest and Northern California areas. The Opal Hub is associated with Montana, Idaho South, 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 is a basis forecast between the western hub and its associated AURORA area. The values of these price differentials are described in Section 3.3.4.

3.3.2 Current Natural Gas Market Price Trends

Natural gas prices are falling rapidly at the time of the analysis presented in this Study. From late June to mid-August, the Sumas price fell over 35%. The NYMEX futures market for FY 2009 similarly fell over 30% during this time. The sharp decline in prices is shown in Figure 2, which overlays data for four fiscal years.

Figure 2: Historic Henry Hub Gas Prices



3.3.3 Natural Gas Market Fundamentals

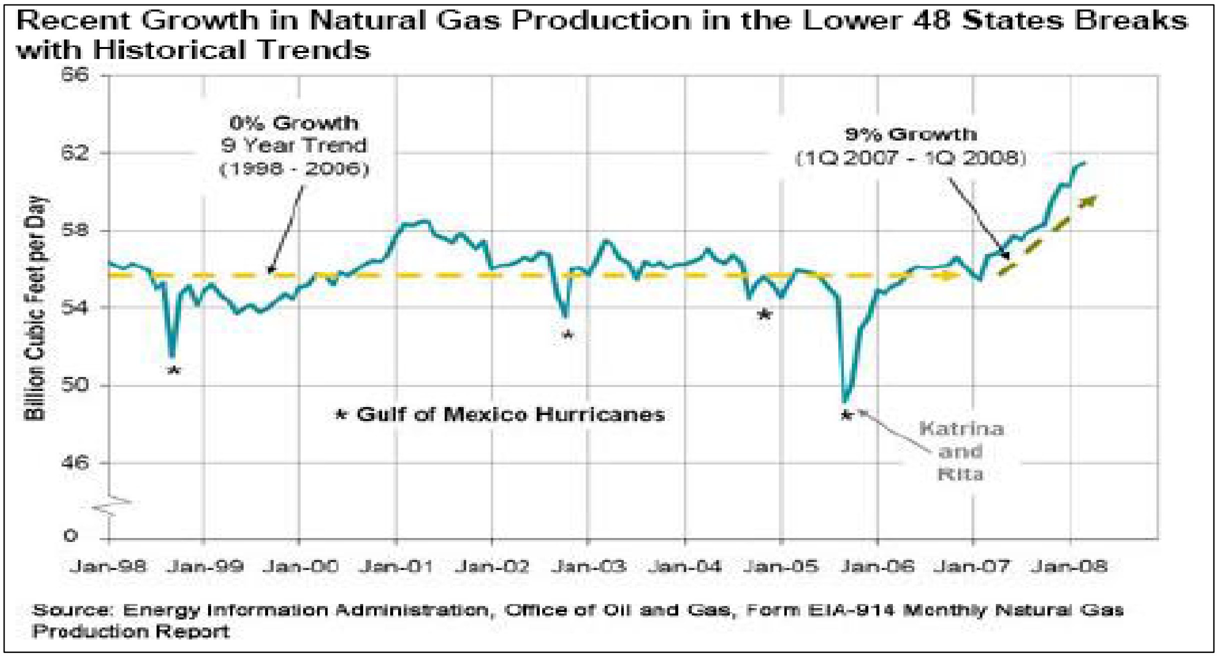
A number of factors contribute to the recent decline in natural gas prices. U.S. economic growth has slowed, depressing natural gas demand. In addition, falling oil prices have exerted downward pressure on gas prices, and natural gas production has surged.

U.S. economic growth has slowed recently, which also has depressed natural gas demand. The quarterly growth rate for the U.S. GDP (seasonally adjusted, real dollars) for the first three quarters of FY 2008 averaged only 0.9%. For FY's 2005, 2006, and 2007, the same rate ranged between 2.4% and 3.0%. Natural gas demand is relatively sensitive to economic trends as the two gas demand sectors with the highest income elasticity (*i.e*., the effect of rising or falling incomes causing consumption to rise or fall) are the industrial and electric utility sectors, which make up over half of all natural gas consumption in the U.S.

Falling oil prices have also put downward pressure on natural gas prices by affecting fuel-switching potential and some global LNG prices, which are linked to oil prices. From mid-July to mid-August, crude oil prices fell approximately 20%. As crude oil prices have fallen, so have prices for fuel oils that can be substitutes for natural gas. The decline in fuel oil prices has eased pressure on natural gas prices and has contributed to the price decline.

Natural gas production has surged recently. In May 2008, U.S. natural gas production was higher than it had been since 1980. Much of this expanded growth in production has come from unconventional production such as shale gas. The potential for unconventional production is large, and this recent growth in production is very possibly a longer-term trend. The Energy Information Administration (EIA) noted this surge in production and described this as a recent break with historical trends. Figure 3 below summarizes the information from the June 2008 EIA report, “Is U.S. Natural Gas Production Increasing?”[2]

Figure 3: Historic US Natural Gas Production



Current trends for the fundamentals of a slow economy, weakening oil prices and growing natural gas production show little evidence of reversing before the end of FY 2009. Based on the pattern of these market fundamentals, a realistic scenario exists for a continuing decline in natural gas prices from recent levels. BPA’s forecast of the Henry Hub prices for FY 2009 is $7.50/MMBtu.

A forecast of $7.50/MMBtu is at the low end of the range of recent forecasts noted in Natural Gas Week’s collection of natural gas price forecasts[3]. This range was from $7.50/MMBtu to $12.25/MMBtu for FY09 Henry Hub prices. However, this information was dated July 28, 2008

[2] http://tonto.eia.doe.gov/energy_in_brief/natural_gas_production.cfm
[3] Natural Gas Week’s Price Forecast Scoreboard. Natural Gas Week, July 28, 2008.

and forecasts published on this date have not reflected the price declines in August 2008. Therefore BPA's forecast is within a range of reasonable forecasts, and it is consistent with current market information.

3.3.4 The Forecasts of Basis Differentials

The western hub basis forecast is shown in Table 3. The values in Table 3 indicate the forecast difference between Henry Hub and the western hub. A negative number indicates that the price at the western hub is less than the price at Henry Hub. These forecasts are based on historic data, transportation cost of natural gas, and the outlook for pipeline expansions.

Table 3: Price Differentials Between Henry and the Western Hubs

FY 2009 Western Hub Basis ($/MMBtu)		
Sumas	Opal	Ignacio
-0.51	-1.03	-0.69

The next step in the natural gas price forecast is to link the western hubs to the AURORA areas. Table 4 shows these pricing differentials. For AURORA's analysis, all values are shown in real (inflation-adjusted) dollars for the year 2000. Table 4 lists the three western hubs and their associated AURORA area below. The value for each AURORA area is the basis differential between the western hub and the AURORA area.

Table 4: 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	0.46

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

3.4 Hydroelectric Generation

For the market price forecasts, AURORA was supplied hydroelectric generation levels for the PNW area from the FY 2009 Load Resource Study, WP-07-FS-BPA-09. 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.

3.5 Generating Resource Update

BPA added generating resources to be consistent with the most current data available. BPA updated actual resources that BPA expected to be operating through the end of 2009. For 2008 and beyond, BPA also let AURORA determine which generic resources would be added or deleted within the AURORA database. A complete listing of all the resources can be found in the FY 2009 Market Price Forecast Study Documentation, WP-07-FS-BPA-11A.

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 data supplied with version 5.6.33.

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