Bonneville Power Administration
Power Business Line

2002 Final Power Rate Proposal
Marginal Cost Analysis Study

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BONNEVILLE
POWER ADMINISTRATION

MARGINAL COST ANALYSIS STUDY
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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
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
Alcoa	Alcoa, Inc.
Alcoa/Vanalco	Joint Alcoa and Vanalco
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CRITFC	Columbia River Inter-Tribal Fish Commission
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CTPP	Conditional TPP
CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones

DMP	Data Management Procedures
DOE	Department of Energy
DROD	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
Energy Services	Energy Services, Inc.
Enron	Enron Corporation
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth 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)
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
HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
IPC	Idaho Power Company
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IJC	International Joint Commission

IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
ISC	Investment Service Coverage
ISO	Independent System Operator
Joint DSI	Alcoa, Vanalco, and DSI
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	Kilowatthour
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
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 C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
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
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Principles	Fish and Wildlife Funding Principles
Project Act	Bonneville Project Act
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People's Utility District
Puget	Puget Sound Energy, Inc.
PURPA	Public Utilities Regulatory Policies Act
RAM	Rate Analysis Model (computer model)

RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
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 Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
SPG	Slice Purchasers Group
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
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
USFWS	U.S. Fish and Wildlife Service
Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
VI	Variable Industrial Power rate
VOR	Value of Reserves
WAPA	Western Area Power Administration
WEFA	WEFA Group (Wharton Econometric Forecasting Associates)

WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System 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 study presents Bonneville Power Administration's (BPA) Marginal Cost Analysis (MCA) for its 2002 wholesale power rate case. The MCA estimates the variable cost of the marginal resource in a competitively priced energy market. In this study the terms 'marginal cost' and 'market clearing price' refer to the variable cost of the marginal resource for energy traded at the Mid-Columbia hub. When the monetary values are denominated in real dollars, real dollars are defined as 1997 inflation adjusted dollars.

In competitive market pricing, the marginal cost of production is equivalent to the market clearing price. Market clearing prices are important factors in determining BPA's bulk power revenues. Therefore, the marginal cost estimates inform BPA's bulk power revenues in the rate case. The Risk Analysis Study, WP-02-FS-BPA-03, provides an explanation for the use of the MCA in the bulk power revenue forecast.

The MCA is also used to inform the seasonal and daily pattern for BPA's rates. Rates patterned after market clearing prices send a signal to consumers about the marginal cost BPA sees in the energy market and will encourage economic efficiency. The Wholesale Power Rate Development Study, WP-02-FS-BPA-05, provides an explanation of how the MCA informs the seasonal and daily pattern of rates.

1.2 Marginal Cost Analysis Framework

This study 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.

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 up to the quantity where the amount consumers are willing to pay for marginal consumption 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 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. The assumptions that are especially important to the level of long-term costs (costs of a CCCT and the load forecast) are detailed in the "Assumptions" section of this study.

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 where capacity has relatively less surplus; the peak pricing months and heavy load hour (HLH) periods. The average levels of monthly prices and the HLH and light load hour (LLH) prices for each month are given in the "Results" section of this study.

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. 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 demand forecast implicitly includes the effect of price elasticity over time. 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 places two restrictions on the hourly operation of generating plants. First, AURORA simulates the 'must run' status of certain units. Second, AURORA recognizes that costs associated with ramping generation levels up and down will make the economic dispatch of plants on an hourly basis impractical. To account for this, AURORA commits generating plants to operate at weekly intervals. AURORA uses a weekly price forecast to determine plant profitability and to model the commitment decision.

AURORA recognizes the effect that transmission capacity and prices have on the ability to move generation output between areas. AURORA recognizes 12 areas within the Western Systems Coordinating Council (WSCC), largely defined by state boundaries, with a few exceptions. California is split into northern and southern areas (N. Cal and S. Cal); Oregon and Washington (OR/WA); and British Columbia and Alberta (Canada) are each combined into single areas.

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 data base. An existing resource that is not economically profitable will be retired from the resource data base.

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 the 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; the iterative process converges to a stable solution.

3. ASSUMPTIONS

3.1 Overview

There are three primary assumptions that are relevant to the MCA: natural gas prices, the investment costs of a CCCT, and the load forecast. Natural gas prices and the investment cost of a CCCT will determine the full cost of a CCCT, which is expected to provide the bulk of economic new resource. Long-term prices will gravitate towards this cost. The third assumption, the load forecast, determines how quickly prices move to the cost of this new resources. Consequently, the assumptions on the load forecast, natural gas prices and CCCT investment costs are described in detail first.

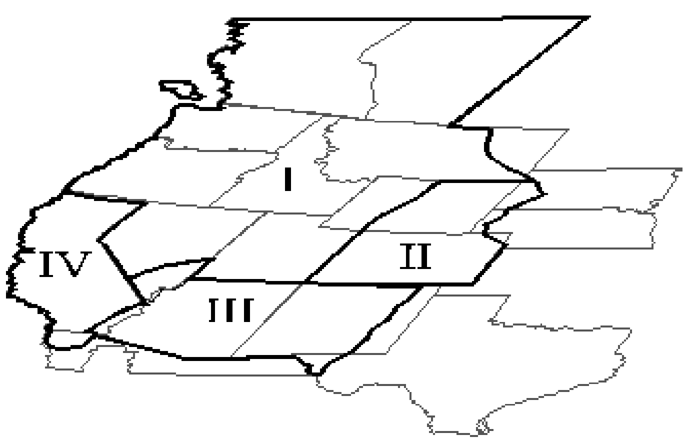
A number of other relevant assumptions are discussed in the following sections. Remaining data and assumptions that are required to run AURORA are listed in Marginal Cost Analysis Study Documentation, WP-02-FS-BPA-04A and WP-02-FS-BPA-04B.

3.2 Load Forecast

The load forecast consists of four parts: the base year load forecast; 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. BPA used the 1998 WSCC load forecast as the base year load forecast as input for AURORA. The WSCC forecasts loads for four regions: the Northwest Power Pool (NWPP) Area which is divided into United States (U.S.) and Canadian systems; the California - Mexican Power Area which is divided into U.S. and Mexican systems; the Rocky Mountain Power Area; and the Arizona - New Mexico - southern Nevada Power Area. Figure 1 represents the areas:

Figure 1: 1998 WSCC 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 WSCC regions were converted into the 12 AURORA areas for BPA's forecasts. The methodology used to convert the WSCC regional loads can be seen in the following example.

With the NWPP Area - U.S. system, the loads in the original AURORA data base for OR/WA, Idaho (ID), Montana (MT), and Utah (UT) were summed to get an aggregate total load. The loads for OR/WA, ID, MT, and UT were each divided by the aggregate total load to develop percentages. The percentages were then applied to the aggregate WSCC regional load forecast for the NWPP Area - U.S. system to get a 1998 load forecast for AURORA areas OR/WA, ID, MT, and UT. This procedure was then repeated for each of the WSCC regions to derive each AURORA area 1998 base load forecast.

3.2.2 Annual Average Growth Rate. BPA used an average annual growth rate of 1.5 percent, obtained from the Northwest Power Planning Council (NWPPC) Cost and Revenue (C&R) Analysis. This average annual growth rate is consistent with historical load growth figures. The WSCC also forecasts annual average growth rates. BPA used these WSCC regional growth rates to reflect its prediction that loads will grow at different rates in the different WSCC regions. BPA scaled the 1.5 percent average annual growth rate into the different WSCC regions. Table 1 shows the WSCC annual growth rates and the scaled growth rates used in the MCA:

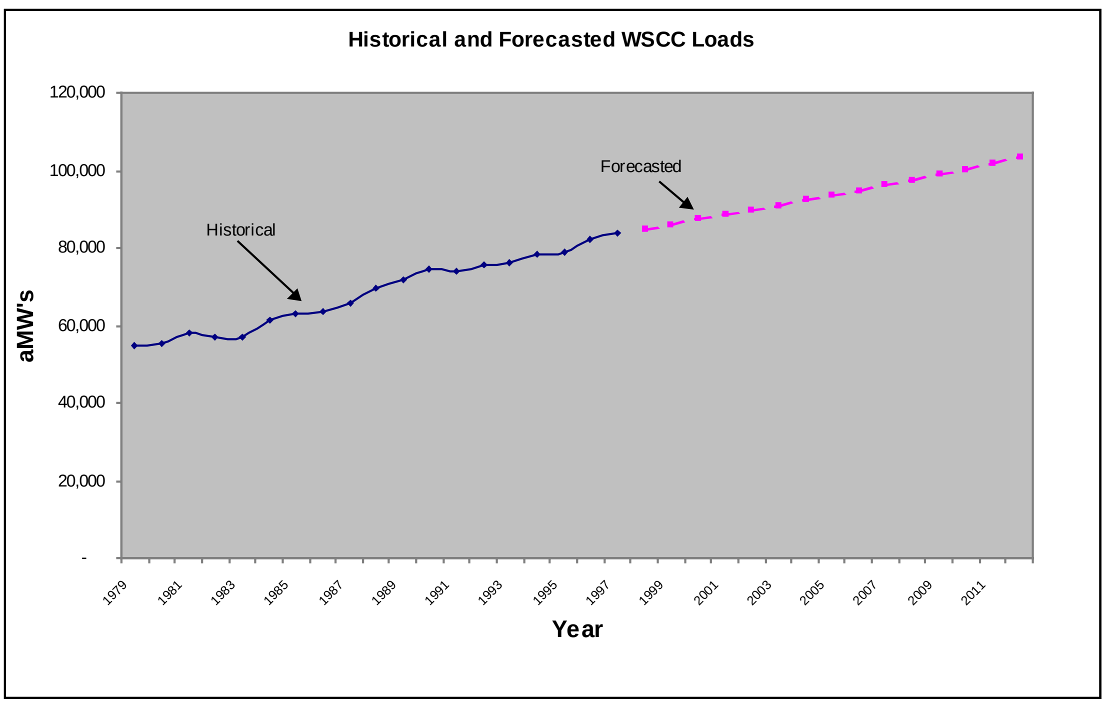
Table 1: Load Forecast Annual Average Growth Rate

Area	WSCC AAGR	Scaled AAGR
NWPA	2.00	1.52
CA	1.40	1.06
AZ/NM/NV	2.40	1.82
RMPA	2.30	1.74
CANADA	1.80	1.36
WSCC	1.98	1.50

Because the starting year for AURORA is 1997, BPA reduced the 1998 base load forecast by the average annual growth rate to obtain a 1997 starting year forecast for input into AURORA.

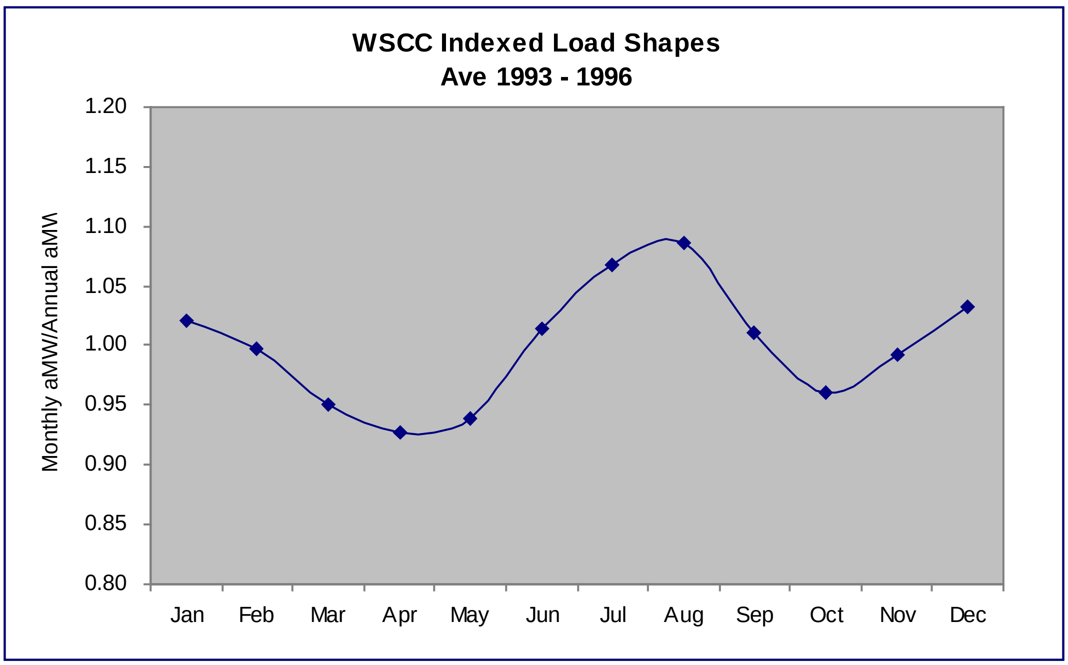
BPA applied the annual average growth rate to the base load forecast to determine the load forecast over time. The following graph illustrates historical WSCC loads and the resulting BPA load forecast:

Graph 1: Historical and Forecasted WSCC Loads



3.2.3 Monthly Load Shaping Factors. BPA developed monthly load shaping factors for converting the annual load forecast into a monthly load forecast. BPA used monthly utility-specific load data for the years 1993 through 1996 to calculate monthly shaping factors for each AURORA area. The historical monthly loads by area were divided by the annual average load in that area to develop a monthly shape factor. AURORA multiplies the monthly factor by the annual load forecast to derive the monthly load forecast. The following graph represents the monthly load factors for the entire WSCC:

Graph 2: Indexed Monthly Load Shapes



3.2.4 Hourly Load Shaping Factors. BPA developed hourly load shaping factors for converting the monthly load forecast into an hourly load forecast. The hourly load shapes were derived from historical hourly load data for 1993 through 1997. The hourly load shape factors were calculated by dividing every hourly load by the average monthly load for each of the years 1993 through 1997. This data is aligned so that the first hour of each of the first Mondays of each of the years coincides. Once this was accomplished, each hourly factor was averaged across all the years.

3.3 Natural Gas Prices

3.3.1 Methodological Overview. The natural gas price forecast is based on a demand and supply analysis. The analysis begins with a review of historical demand, supply, and price. This historical review sets the context for underlying patterns in the natural gas price forecast.

The first methodological step of the gas price forecast is to develop a price forecast for Henry Hub, Louisiana (Henry). Henry is the primary pricing point and touchstone for natural gas pricing in North America. Henry is a very common starting point for natural gas price forecasts of other organizations. Henry is also the site where natural gas futures market trading has the greatest volume.

The next several methodological steps translate the Henry price to the variable gas prices seen by electric generators in each AURORA area. The AURORA area gas prices are driven by prices in the western natural gas producing basins. To begin this translation to AURORA area prices, a correlation analysis is used to match up the primary western producing basins to the AURORA areas.

The next step estimates a price forecast for the western producing basins. This forecast is developed by estimating a regional price differential (basis) between the producing basin and Henry. The basis forecast is developed from supply and demand factors specific to the producing basins, especially changes in the natural gas transportation system that will affect the basis forecast.

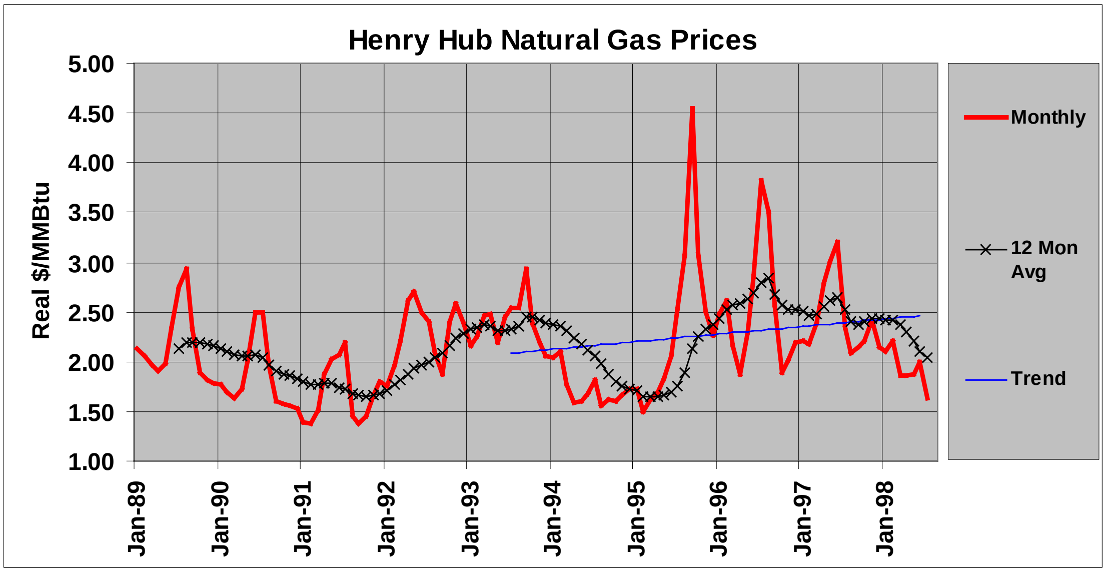
Finally, price differences between the producing basins and the AURORA areas are added to the producing basin prices to yield the AURORA area prices. A fixed gas price estimate is subtracted from this 'total' price forecast to give the variable gas cost. The fixed gas cost is added into the operation and maintenance (O&M) cost of gas-fired generators.

3.3.2 Historical Prices. Significant industry restructuring in the last several years has fundamentally altered the pricing structure of wholesale natural gas. Two of the most significant changes, the Natural Gas Wellhead Decontrol Act (Decontrol Act) and Federal Energy Regulatory Commission (FERC) order 636, have been implemented in the last ten years. An Energy Information Administration (EIA) study stated[1], "[T]he 'Decontrol Act' of 1989 (Public Law 101-60) established a schedule to remove price controls on wellhead sales of natural gas. More than 40 years of wellhead price controls on interstate supplies ended on January 1, 1993." The EIA study further stated, "[P]rice ceilings established for different categories of natural gas under the Natural Gas Policy Act had created severe distortions in the gas market and significantly influenced producers' drilling decisions." In addition, in 1992 FERC Order 636 required pipeline companies to provide open-access transportation and storage and to separate sales from transportation service completely. The prices and underlying pricing structure prior to these restructuring actions are not directly comparable to today's situation.

Since restructuring has been implemented, there has been a modest increasing trend in gas prices. Over the last three years, prices have reached some of their highest monthly values. The following graph shows the recent trend in Henry natural gas prices. In addition to the monthly prices, a 12-month average price is shown on the graph. This illustrates the cyclical pattern in gas prices. A linear trend was estimated from the 12-month average data. This illustrates the overall growth in gas prices.

[1] Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates.

Graph 3: Henry Hub Natural Gas Prices

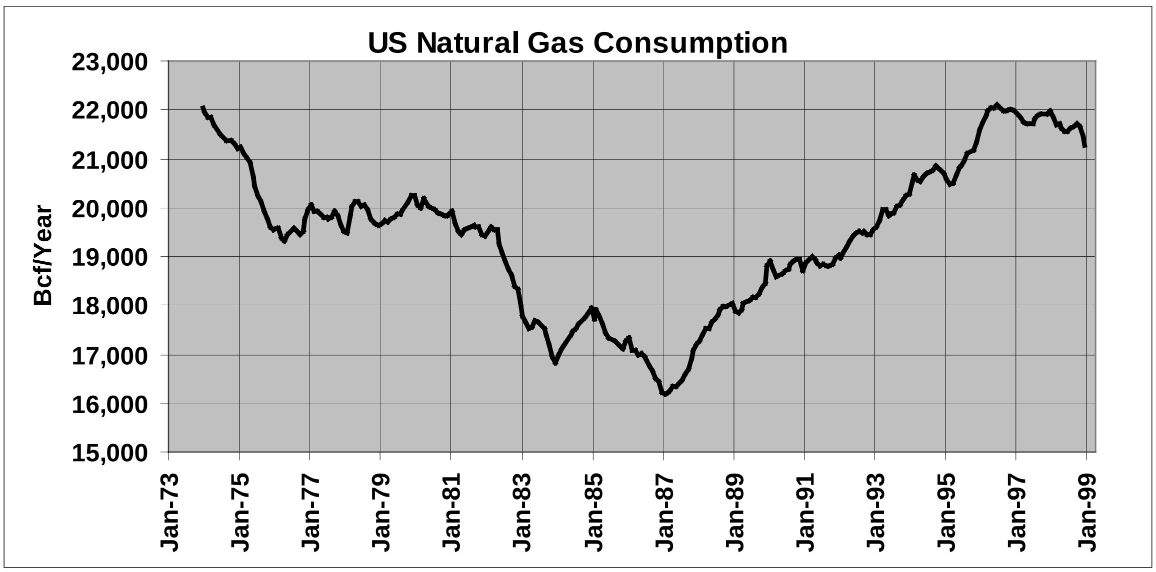


3.3.3 Historical Demand and Supply. Natural gas consumption grew rapidly from the mid-1980s to the mid-1990s. From 1986 to 1996, the compound annual growth rate in U.S. natural gas consumption was 3 percent. In 1996, consumption reached nearly 22 trillion cubic feet (tcf), a level only slightly below the record set in 1972. From 1996 to 1998, consumption declined slightly. For 1998, U.S. consumption was at 21 tcf. In forecasting, it is important to note that the natural gas industry has no experience in producing levels of consumption much higher than those that have occurred in the last few several years.

Supply has been strained to keep up with these high demand levels. While measures of natural gas productive capacity such as the rig count and well completions have grown, measures of natural gas productivity have decreased. The natural gas rig count reached a record high in 1997. Also in 1997, the number of wells completed reached the highest level since 1985. However, supply side weakness can be seen in measures of productivity. The amount of production per rig declined by 30 percent from 1988 to 1998. The amount of production per well completed has also declined substantially during this period. Production decline rates for natural gas wells, a measure of how quickly a well is depleted, rose from 14 percent in 1990 to 23 percent in 1997.[2]

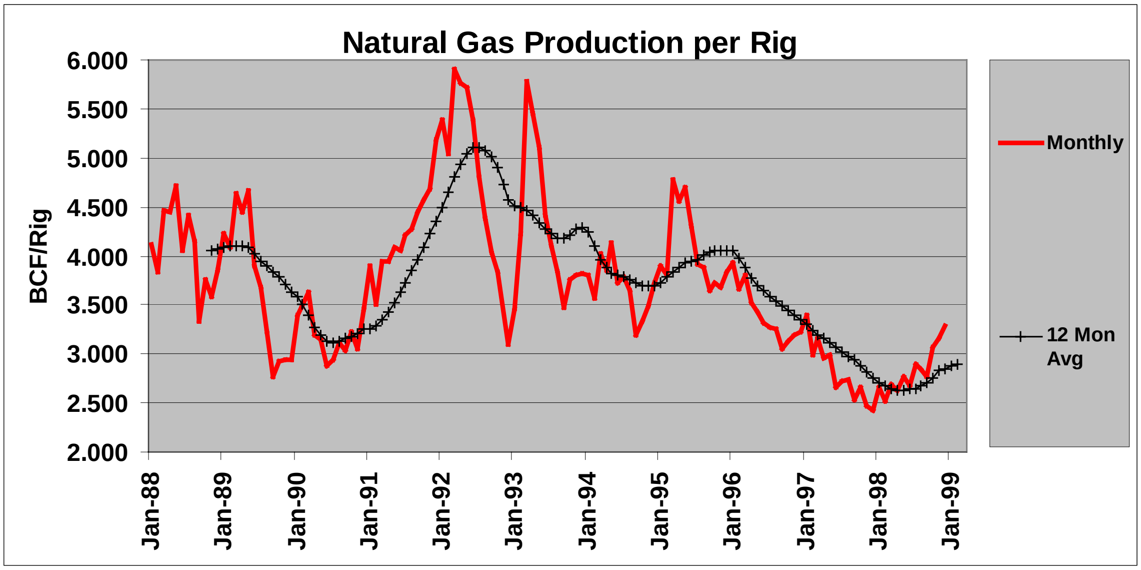
In summary, the natural gas industry at the beginning of the forecast period is characterized by demand at near record levels, declining productivity measures in supply and upward pressure on prices. Historical patterns of consumption and productivity, as measured by the ratio of production per rig, are shown in the following graphs.

Graph 4: U.S. Natural Gas Consumption



[2] Natural Gas Week. April 26, 1999.

Graph 5: U.S. Natural Gas Production Per Rig



3.3.4 Henry Hub Price Forecast. The long-term price forecast for Henry is based on a forecast of strong demand growth over the next several years and supply side pressure moderated by technological improvements that reduce production cost. The balance of demand and supply forces will lead to a modest increase in real gas prices. In the short-term, a cyclical supply tightening will lead to prices rising relatively faster.

The strong growth in demand is driven by expectations that natural gas-fired generation will provide the bulk of new electric generating supply. For power generation, natural gas has several advantages over other fuels. Natural gas generation plants are smaller in scale than typical coal, nuclear or hydro facilities. Lower capital cost and the ability to site generation near load centers are advantages for natural gas in a deregulated market. Natural gas is viewed as relatively environmentally benign, especially in comparison to coal-fired generation. Many power developers view natural gas as the most cost-effective fuel for new generation, even after accounting for future price expectations. This is reflected in the fact that the large majority of planned new generation is natural gas-fired generation.

The supply outlook is determined by the interplay of the conflicting forces of resource depletion and technological improvement. Further increases in production will be met only by increasingly costly sites. There are new areas of potential supply, most notably the deepwater Gulf of Mexico. These resources will be more costly to bring into production although technological improvements will help reduce upward cost pressures.

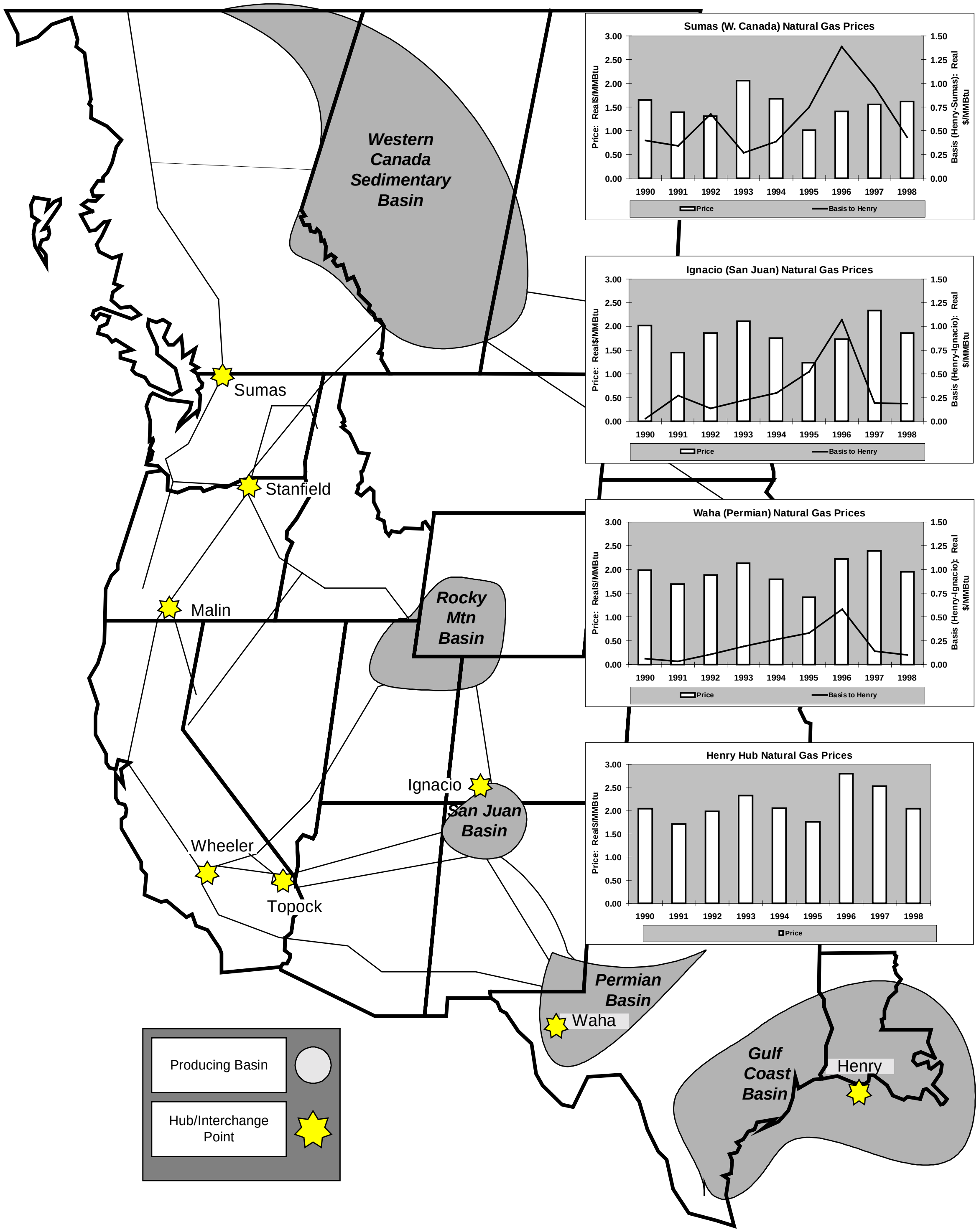
On the demand-side, the forecast predicts robust growth in consumption. On the supply side, there will be pressures to replace production from existing fields and to meet demand growth. Therefore, prices are forecast to increase in real dollars over the forecast time horizon. In the short-term, the current downturn in rigs and other production measures will lead to a short-term tightening of supply and a relatively faster growth in prices.

Table 2: Henry Hub Natural Gas Price Forecast (Real $/MMBtu)

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Price	1.86	2.10	2.15	2.19	2.23	2.27	2.30	2.33	2.36	2.38	2.40	2.42

3.3.5 Western Natural Gas Pricing Patterns. Natural gas supply and demand balances are more surplus in western North America than in the east. Thus, western natural gas prices are generally lower than those at Henry. The following map shows the main production basins and pipelines in western North America. The graphs seen on this map show historical prices at these basins and the basis differential to Henry.

Figure 2: Western Natural Gas System



AURORA requires a gas price forecast for each AURORA area to estimate the cost of gas-fired generation in each area. Western production basins were matched to each of the AURORA areas using correlation analysis. Correlation coefficients between production basin prices and prices in several consuming areas proximate to AURORA areas were computed from historical data. AURORA areas were matched to the production basin with the highest correlation coefficient.

Sumas prices, representing the western Canada production basin, were used for the AURORA areas of OR/WA, N. Cal, Canada, MT, and Wyoming (WY). Ignacio prices, representing the San Juan production basin, were used for the AURORA areas of S. Cal, Nevada (NV), UT, Colorado (CO), Arizona (AZ), and New Mexico (NM).

3.3.6 Western Production Basin Forecasts. Sumas and Ignacio price forecasts were estimated by subtracting a basis differential from Henry. The basis will be affected by the supply and demand within areas and by available pipeline capacity between areas. The basis forecast is drawn from historical data and projected future pipeline capacity additions.
From 1995 through 1997 the average Sumas to Henry basis was $1.03/Million British Thermal Units (MMBtu). In 1998, the basis between Sumas and Henry was $0.43/MMBtu. This basis decline is due to the Northern Border expansion that recently added about 7 million cubic feet/day capacity out of western Canada to the U.S. Midwest.

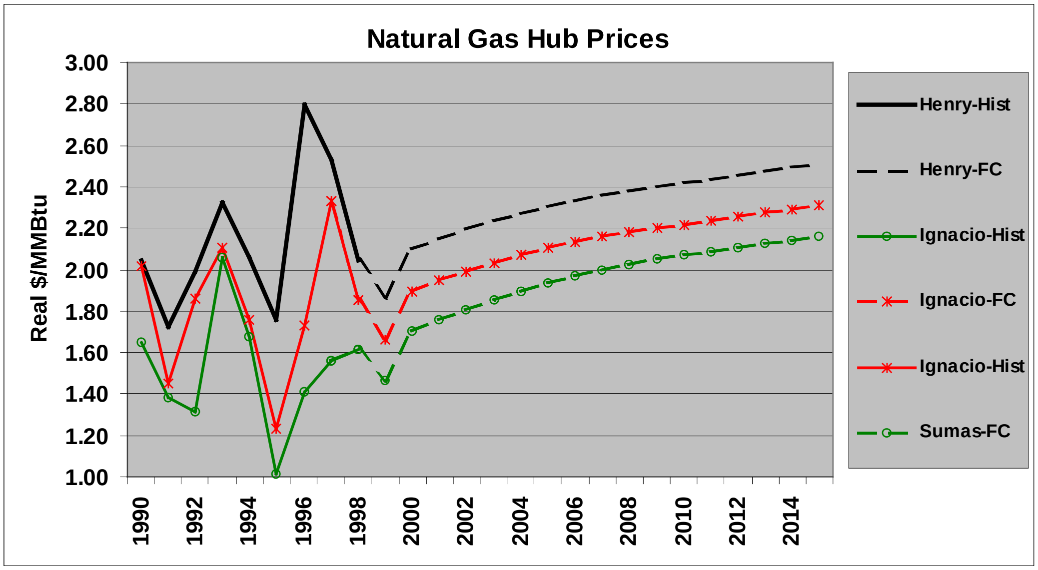
The Sumas to Henry basis is forecast to decline further over the forecast horizon because more pipeline capacity is expected. The most visible potential expansion is the Alliance project that is expected to add about 1 billion cubic feet/day of capacity from western Canada to the U.S. Midwest. This project is expected to come on line in the near future. Alliance’s online date is not certain and the date and amount of additional capacity can change with time. To account for these uncertainties, a continuous decline in the basis is forecast over several years rather than a discreet decline in a particular year that would be associated with a specific online date.

In 1998, the basis between Ignacio and Henry was $0.19/MMBtu. While there may be relatively small changes in the demand, supply, and transportation situation in the U.S. Southwest, there is no clear evidence of future significant basis changes. The basis for the San Juan basin is forecast to remain constant at $0.20/MMBtu.

Table 3: Western Natural Gas Hub Price Forecasts

	Western Natural Gas Hub Prices (Real$/MMBtu)			
	Basis to Henry		Price	
Year	Ignacio	Sumas	Ignacio	Sumas
1999	0.200	0.400	1.66	1.46
2000	0.200	0.395	1.90	1.70
2001	0.200	0.390	1.95	1.76
2002	0.200	0.385	1.99	1.81
2003	0.200	0.380	2.03	1.85
2004	0.200	0.375	2.07	1.89
2005	0.200	0.370	2.10	1.93
2006	0.200	0.365	2.13	1.97
2007	0.200	0.360	2.16	2.00
2008	0.200	0.355	2.18	2.03
2009	0.200	0.350	2.20	2.05
2010	0.200	0.350	2.22	2.07

Graph 6: Historical and Forecast Natural Gas Prices



3.3.7 AURORA Area Price Forecasts. The AURORA area natural gas price forecasts are derived by adding an estimate of the price differences between the relevant production basin (Sumas or Ignacio) and the delivered natural gas cost in each consuming area. These estimates were derived from historical data. The differences in price between production basins and consuming areas are forecast to decline slightly over time due to declining real margins for natural gas transportation.

Table 4: Western Natural Gas Area Price Differentials

Area	Or/Wa	N.Cal	S.Cal	Can	Id	Mt	Wy	Co	NM	Az	Ut	Nv
	Producing Basin to AURORA Area Differntial (Real$/MMBtu)											
1999	0.25	0.55	0.40	0.20	0.25	0.25	0.30	0.30	0.30	0.35	0.30	0.30
2000	0.25	0.55	0.40	0.20	0.25	0.25	0.30	0.30	0.30	0.35	0.30	0.30
2001	0.24	0.54	0.39	0.19	0.24	0.24	0.29	0.29	0.29	0.34	0.29	0.29
2002	0.24	0.54	0.39	0.19	0.24	0.24	0.29	0.29	0.29	0.34	0.29	0.29
2003	0.24	0.54	0.39	0.19	0.24	0.24	0.29	0.29	0.29	0.34	0.29	0.29
2004	0.24	0.54	0.39	0.19	0.24	0.24	0.29	0.29	0.29	0.34	0.29	0.29
2005	0.23	0.53	0.38	0.18	0.23	0.23	0.28	0.28	0.28	0.33	0.28	0.28
2006	0.23	0.53	0.38	0.18	0.23	0.23	0.28	0.28	0.28	0.33	0.28	0.28
2007	0.23	0.53	0.38	0.18	0.23	0.23	0.28	0.28	0.28	0.33	0.28	0.28
2008	0.22	0.52	0.37	0.17	0.22	0.22	0.27	0.27	0.27	0.32	0.27	0.27
2009	0.22	0.52	0.37	0.17	0.22	0.22	0.27	0.27	0.27	0.32	0.27	0.27
2010	0.22	0.52	0.37	0.17	0.22	0.22	0.27	0.27	0.27	0.32	0.27	0.27

The final step in determining the AURORA area gas price forecasts subtracts $0.18/MMBtu from each AURORA area to account for the fixed cost of gas. The result is a forecast for the variable cost of natural gas delivered to electric generators in each of the 12 AURORA areas. The fixed cost of natural gas was added into the fixed cost for gas-fired generation. The monthly shape of natural gas prices was estimated to incorporate the effects increased electric generation from natural gas. In addition, new pipeline capacity will cause the monthly pattern of gas prices in different basins to equilibrate.

Table 5: Western Natural Gas Variable Cost Forecasts

Area	Or/Wa	N.Cal	S.Cal	Can	Id	Mt	Wy	Co	NM	Az	Ut	Nv
Consuming Area Variable Costs (Real$/MMBtu)												
1999	1.53	1.83	1.88	1.48	1.53	1.53	1.58	1.78	1.78	1.83	1.78	1.78
2000	1.77	2.07	2.11	1.72	1.77	1.77	1.82	2.01	2.01	2.06	2.01	2.01
2001	1.82	2.12	2.16	1.77	1.82	1.82	1.87	2.06	2.06	2.11	2.06	2.06
2002	1.87	2.17	2.20	1.82	1.87	1.87	1.92	2.10	2.10	2.15	2.10	2.10
2003	1.91	2.21	2.24	1.86	1.91	1.91	1.96	2.14	2.14	2.19	2.14	2.14
2004	1.95	2.25	2.27	1.90	1.95	1.95	2.00	2.17	2.17	2.22	2.17	2.17
2005	1.99	2.29	2.31	1.94	1.99	1.99	2.04	2.21	2.21	2.26	2.21	2.21
2006	2.02	2.32	2.33	1.97	2.02	2.02	2.07	2.23	2.23	2.28	2.23	2.23
2007	2.05	2.35	2.36	2.00	2.05	2.05	2.10	2.26	2.26	2.31	2.26	2.26
2008	2.07	2.37	2.37	2.02	2.07	2.07	2.12	2.27	2.27	2.32	2.27	2.27
2009	2.09	2.39	2.39	2.04	2.09	2.09	2.14	2.29	2.29	2.34	2.29	2.29
2010	2.11	2.41	2.41	2.06	2.11	2.11	2.16	2.31	2.31	2.36	2.31	2.31

3.4 Fixed Costs of Combined-Cycle Combustion Turbines

The data for cost and efficiency on potential new resources was drawn from the NWPPC's study, Analysis of the BPA's Potential Future C&R study. The source for several of these assumptions was the NWPPC's Fourth Northwest Conservation and Electric Power Plan (Fourth Power Plan).

3.4.1 Technology. The CCCT powerplant study assumptions are based on 250 megawatt (MW) class industrial units. The 250 MW class unit is the predominant combined-cycle unit currently employed in powerplant development.

3.4.2 Capital Cost. The Clark Public Utilities River Road powerplant provides the starting point for the capital cost estimates of a new combined-cycle plant. River Road, a 248 MW General Electric 107FA combined-cycle powerplant, entered service in late 1997. The River Road construction cost was adjusted to arrive at a representative plant cost for each of the AURORA areas.

The River Road construction costs were first adjusted by a factor representing the estimated difference between the development cost of a single-unit combined-cycle powerplant at the River Road Vancouver site and the average plant development cost for a large group of potential combined-cycle powerplant sites in the Northwest.[3] This factor normalizes for site-specific development costs and captures possible economies at sites capable of accommodating multiple units. The resulting "average Northwest" development cost was then increased by 2.7 percent to represent the estimated average degradation of capacity over the life of the plant. The resulting cost is assumed to be the average cost of developing new combined cycle plants in the OR/WA area under current market conditions.

However, because of the weak market conditions prevailing for the past several years, the average Northwest cost is assumed to represent a depressed price. The estimate was increased by 10 percent to represent a market equilibrium condition thought more typical of the study period.

Further adjustments for regional price differentials and elevation effects were made to arrive at combined-cycle capital cost estimates for specific AURORA areas. These adjustments use index

[3] The development of this factor is further described in Appendix F of the *Fourth Northwest Conservation and Electric Power Plan*. The factor used here is the difference between the estimated cost of developing a single unit combined-cycle powerplant at a Vancouver, Washington, site (the location of the actual River Road plant) and the average estimated cost of developing units at the "Group 1" set of sites identified in the Fourth Plan. The Group 1 sites are those sites for which construction permits were currently held or being sought at the time the Fourth Plan was in preparation. Group 1 sites could accommodate from one to four 250 MW class units.

values where a value of 100 is equivalent to a multiplication factor of 1.00. The regional price indices shown in Table 6 are assumed to decline linearly from the 1997 values to a uniform index level of 100 by 2015. Because the output of a gas turbine decreases with the ambient atmospheric density, AURORA area capital costs were further adjusted for the effect of elevation on atmospheric density as shown in the third column of Table 6.

Table 6: Resource Area Cost Adjustments

Loads & Resources Area	Regional price Indices (1997, declines to Zero by 2015)	Elevation-related Cost Indices (Gas and wind turbine technologies)
Oregon and Washington	100	102
Northern California	105	102
Southern California	105	102
BC and Alberta	105	110
Idaho	100	110
Montana	100	119
Wyoming	102	119
Colorado	102	119
New Mexico	102	119
Arizona	102	110
Utah	100	119
Nevada	105	110

Commercially available gas turbine powerplants have not approached practical limits of cost or thermodynamic efficiency. The cost of future plants is expected to decline over time as design, materials, and manufacturing processes improve. A forecast of the future improvements in the specific power of gas turbine combined-cycle plants was used as a proxy for cost reductions through technology improvements.[4] When other factors are equal, increases in specific power increase the power available from a machine of given physical size. This will reduce cost, though not in direct proportion to improvements in specific power because of the probability that the advanced materials and manufacturing processes needed to increase specific power will be

[4] Specific power is the power output of a turbine per unit mass of working fluid passing through the machine (*e.g.*, kW/lb).

more expensive than conventional materials and processes. For this study, 30 percent of the forecast increases in specific power are assumed to translate into capital cost reductions.

3.4.3 Operation and Maintenance Cost. Fixed and variable O&M cost assumptions are based on those developed for the Fourth Power Plan. The Fourth Power Plan values were adjusted to 1997 dollars, then deescalated by 2.5 percent per year to reflect the effect of competitive pressure in the generation sector on plant O&M costs. This deescalator is used by the EIA in preparing its Annual Energy Outlook.

O&M costs for specific AURORA areas are obtained by adjusting the base values by the regional price indices. In addition, fixed O&M costs are adjusted by the elevation index.

The fixed O&M costs of future plants are assumed to decline in proportion to the capital cost technology improvement indices. Furthermore, future fixed and variable O&M costs of both new and existing plants are assumed to continue to decline at 2.5 percent per year through 2004 in response to the expected effects of an increasingly competitive wholesale power market.

3.4.4 Heat Rate. Combined-cycle plant heat rates are based on the measured "new and clean" performance of the River Road plant. This value was reduced slightly to account for performance degradation during plant operation. Commercially available gas turbine combined-cycle plants have not approached feasible thermodynamic efficiency limits and continued improvement in heat rate is expected. A forecast of heat rate improvements was developed based on historic efficiency improvements and theoretically achievable efficiency.

3.4.5 Financing. New capacity is assumed to be merchant plants that will not have long-term power sales agreements when built. Developers are assumed to be nonregulated private generating companies. The “Unregulated Independent” financing assumptions of the NWPPC C&R study were used. These were based on Fourth Power Plan values, modified as described below. Estimated future general inflation rates were reduced from 3.5 percent annually to 2.5 percent annually to reflect continuing low rates of general inflation. Concurrently, nominal debt interest rate and return on equity assumptions were lowered by 1 percent, consistent with the reduction in the general inflation rate. The resulting annual long-term debt interest and return on equity rates are 8.7 percent and 17.3 percent, respectively. The discount rate was adjusted from the 8.5 percent annual “societal” rate (nominal) of the Fourth Power Plan to the after-tax cost of capital rate of 9 percent annual (nominal). This adjustment was made to simulate the expected actual cost of the developing merchant powerplants. Finally, the Fourth Power Plan “Unregulated Independent” debt/equity ratio of 80/20 was adjusted to 70/30, consistent with recent merchant plant financing experience.

3.4.6 Other Assumptions. Fourth Power Plan assumptions were used for development and construction lead times, plant availability, construction cash-flows and operating life.

3.5 Data Base Updates

Several very useful comments were received in the public workshops that led BPA to alter some assumptions from the original AURORA data base. Updates to the original AURORA data base drawn from these comments are described below.

3.5.1 Generating Resource Update. BPA added and deleted generating resources to be consistent with the most current data available from the WSCC.

3.5.2 Redefinition of Generation Capacity. BPA determined that the available capacity is a more accurate measure of resource capacity than nameplate capacity. Available capacity was used in AURORA.

3.5.3 Western Systems Coordinating Council Boundary Definition. BPA added or deleted generating resources from the data base to be consistent with the boundary definition of the WSCC. These changes were made so that the loads and resources would be consistent and based on the same source, the WSCC.

3.5.4 Non-Utility Generation. BPA updated non-utility generating resource data to include individual plant-specific data. BPA also updated the overall amount of capacity for non-utility generation. This change made the amount of generation and load consistent with WSCC definitions.

3.5.5 Minimum Generation Percentage. AURORA models the costs for generating units to start up and shutdown operations by defining some units as "committed units." It also assumes that all committed units can vary their generation levels to a minimum of 50 percent of capacity. However, many units may actually have minimum generation levels different than 50 percent. BPA updated AURORA's generic minimum generation percentages based on data from the 1996 MCA and BPA's discussions with energy experts in the Pacific Northwest (PNW). The following data list the percentage level of minimum generation for units by the fuel type: coal - 40 percent, oil - 25 percent, natural gas - 40 percent, uranium - 90 percent, and peaking fuel - 10 percent.

3.5.6 Transmission Capacities and Wheeling Rates. BPA incorporated recent data on transmission capacities between areas. In addition to updating existing transmission capacity, BPA adjusted transmission capacity in AURORA to account for the Alturas line from OR/WA to

NV. BPA also corrected an inconsistency in transmission wheeling rates. BPA updated the AURORA data base so that the rate in both directions between OR/WA and S. Cal. is consistent.

3.5.7 Curtailment Escalation Rates. BPA changed the escalation assumption so that the curtailment prices remained constant in real dollars.

3.6 Other Assumptions

3.6.1 Hydroelectric Capacity and Generation. BPA used different sources of data to determine monthly hydroelectric generation for the various AURORA areas. For the PNW (OR/WA, ID, and MT), the hydroelectric regulation study that was used for the Loads and Resources Study, WP-02-FS-BPA-01 was also used for the MCA. For the State of California, California Energy Commission (CEC) data were used. For the remaining areas, WSCC data were used. These raw data were reformatted for use suitable to AURORA.

The hydroelectric regulation study for the PNW consists of monthly generation levels for 50 different historical water years (1929-1978). For each month, BPA used the average of these 50 historical water years as the hydro generation forecast for AURORA. The average historical hydroelectric generation data from CEC for the years 1980-1997 was used for California. WSCC data was used for the rest of the areas.

3.6.2 Data for New Resources Other Than CCCTs

3.6.2.1 Single-Cycle Combustion Turbines. The data on single-cycle combustion turbines (SCCT) were taken from NWPPC analysis completed subsequent to the NWPPC C&R study. The models used in this analysis were the General Electric 7FA and the Siemans V84-3A.

The capital costs of new SCCTs are based on equipment-only gas turbine generator set budgetary prices appearing in the Gas Turbine World 1997 Handbook. Similar to the market adjustment for CCCTs, the SCCT prices were increased by a 10 percent market equilibrium adjustment to account for the weak market conditions of the past several years.

The equipment-only package prices are FOB factory and include a gas turbine, electric generator, starting system, skid, enclosure, inlet filter, silencer, and controls. Not included are substations, switchyards, gas supply facilities, backup fuel storage facilities, administrative buildings, special emission controls, foundations, and civil works. Also not included are engineering, construction management, and owner's costs.

Gas Turbine World estimates that the balance-of-plant costs range from 60 to 100 percent of gas turbine generator set costs. The balance-of-plant costs were assumed to average 80 percent of equipment costs. Single-cycle units are assumed to be constructed in pairs to obtain additional operating flexibility and economies of scale. The cost of a second unit is assumed to be 75 percent of a first unit. Net plant costs are reduced by 2.6 percent to account for inlet, exhaust and auxiliary equipment losses. Because the cost assumptions are used for long-term market studies, this "new and clean" net cost was reduced by an additional 2.7 percent to account for average lifetime degradation in plant output. SCCT costs for the various AURORA areas were estimated by adjusting the general capital cost values by regional price indices and by the effect of elevation on plant output as described for CCCTs.

The cost of future plants is assumed to decline over time with improvements to design, materials, and manufacturing. As with CCCTs, 30 percent of the forecast of future improvements in combustion turbine specific power was used to estimate future costs.

O&M cost estimates are based on estimates prepared for the Fourth Power Plan. These were originally derived for a 1995 base-year using an Electric Power Research Institute model. All routine and periodic O&M costs except fuel are included. The fixed O&M cost is adjusted by the regional price and elevation indices and the technology improvement cost indices as described earlier. The variable O&M cost is adjusted by the regional price and the technology improvement cost indices. In addition, the EIA general O&M cost deescalator is applied through 2004 to both fixed and variable O&M costs.

SCCT heat rates are based on values reported in the Gas Turbine World 1997 Handbook. These values were increased by 1.11 to convert from a lower fuel heating value to the higher heating value basis. This heat rate was reduced for inlet, exhaust, and auxiliary losses. This “new and clean” value was further reduced by 2.1 percent.

Retrofits to improve heat rate are assumed not to be installed during the operating life of a plant, consistent with O&M cost estimates. However, plants delivered at future dates are assumed to benefit from improved technology. The improvement factor is based on the forecast of CCCT efficiency improvements.

Fourth Power Plan assumptions were used for the development and construction lead times, plant availability, construction cash-flows and operating life of SCCT. Financing assumptions are the same as those used for the CCCT. Fuel costs were the same as for combined-cycle gas plants except that $0.60/MMBtu is added to the cost of gas to account for startup costs.

3.6.2.2 Coal-Fired Generation. Data for the fixed costs of new coal-fired generation was taken from the NWPPC C&R study. Coal-fired electric power generating technologies considered for resource additions in the NWPPC C&R study included pulverized coal-fired steam-electric plants and pressurized fluidized bed combustion powerplants.

The pulverized coal-fired steam-electric plant is a mature power generating technology in use throughout the west. It is a pure steam cycle and has attained its maximum practical efficiency without a substantial increase in steam pressure that would require the use of costly materials to ensure reliable operation. The NWPPC C&R study assumed that it would be more economical to develop alternative coal-fired technologies using combined gas turbine steam cycles than to attempt to improve the efficiency of steam-electric technology. The representative coal steam-electric technology used for the NWPPC C&R study is a single 300 MW unit.

A promising alternative to steam-electric coal technology is the pressurized fluidized bed combustion (PFBC) combined-cycle powerplant. In this technology, coal is combusted in a pressurized furnace. The pressurized gaseous products of combustion are cleaned and used to power a gas turbine-generator. Steam, produced both in the pressurized boiler and from the hot exhaust of the gas turbine, powers a steam turbine-generator. PFBC technology offers the advantages of higher thermodynamic efficiency, more compact size, more opportunity for factory fabrication and lower cost compliance with air emission criteria. PFBC technology is being demonstrated at several plants and is expected to be commercially available in the first part of the next decade. The representative PFBC technology used for the NWPPC C&R study is a single 340 MW unit, available for commercial service in 2005.

The NWPPC C&R initial study runs suggested that new coal resources would not be selected in the early years of the study. Once commercially available, PFBC plants would be economically superior to conventional coal-fired steam powerplants. For this reason, conventional coal-fired powerplants were removed from the set of new resource options used for subsequent NWPPC C&R study runs.

Overnight capital cost of conventional and advanced coal technologies are based on the values developed for the Fourth Power Plan. These costs were $1,650/kilowatt (kW) for the steam-electric unit and $1,340 for the PFBC unit, in 1995 dollars. Following selection of the PFBC unit as the representative coal-fired technology, the costs were inflated to 1997 dollars, resulting in a base capital cost of $1,395/kW. Capital costs for the various load and resource areas were obtained by adjusting the general capital cost values by regional price indices. AURORA area capital costs were further adjusted for the effects of elevation (through atmospheric density) on plant output because the output of the open gas turbine cycle used in a PFBC plant decreases with the ambient atmospheric density.

The technology improvement cost indices developed for CCCT plants were applied to the cost of future PFBC coal plants.

O&M cost assumptions for coal technologies are based on those developed for the Fourth Power Plan. The Fourth Power Plan estimates were inflated to 1997 dollars, and deescalated to the 1997 base year using the general annual O&M cost deescalator of 2.5 percent.

Both fixed and variable O&M were further deescalated through 2004 at 2.5 percent per year to represent the expected effects of an increasingly competitive wholesale power market.
In addition, the technology improvement cost indices developed for CCCT plants were applied to the fixed O&M costs of the PFBC plant.

Heat rate assumptions for coal technologies are based on those developed for the Fourth Power Plan. The heat rate of conventional coal plants is assumed to remain at current values, whereas the heat rate of PFBC plants is assumed to improve over time from technological improvements. The heat rate improvement factors developed for combined-cycle powerplants were used to estimate the heat rate of future PFBC plants. The base year heat rate assumptions of conventional and PFBC coal plants are 10,070 British Thermal Unit (Btu)/kilowatthour (kWh) and 8,425 Btu/kWh, respectively.

Fourth Power Plan assumptions were used for development and construction lead times, plant availability, construction cash-flows, and operating life. Financing assumptions are the same as those used for CCCTs. Coal prices are assumed to decline by 1 percent per year in real terms.

3.6.2.3 Wind Generation. Base year overnight capital costs for wind generation are drawn from estimates prepared for the Fourth Power Plan. These were adjusted to 1997 dollars. In the Fourth Power Plan, wind power development costs were estimated for 48 promising wind resource areas in the Northwest, for which adequate wind resource and geographic data is available. The Fourth Power Plan estimates include permitting, engineering, equipment, erection, commissioning and overhead costs for wind farm development and interconnection to the main grid. A representative development cost for each of the three types of wind resources (Pacific Coast, Basin and Range, and High Plains) was obtained by averaging the development cost estimates for several Northwest resource areas of the respective type. The resulting capital cost estimates are adjusted by the regional price indices used elsewhere in the NWPPC C&R study and technology improvement indices developed for the Fourth Power Plan.

The base year fixed and variable O&M costs are based on estimates prepared for the Fourth Power Plan, adjusted to 1997 dollars, using the approach described for capital costs. The Fourth

Power Plan operating costs include operating, maintenance and royalty costs, and transmission costs to the main grid. Fixed and variable O&M costs are adjusted by the regional price and technology improvement cost indices as described for capital cost. In addition, a general O&M cost deescalator, based on EIA work, is applied through 2004. This deescalator represents the anticipated general effect of competitive market pressures on powerplant operating costs. Fourth Power Plan assumptions were used for development and construction lead times, construction cash-flows and operating life.

3.6.3 Retirement Restrictions. In the original AURORA data base and in the NWPPC C&R study, a constraint is placed on the amount of capacity that may be retired in any one year. This assumption captures the effect that some generating units may receive regulatory rate support and will not be retired even though they have become uneconomic. The basic assumption for the constraint used in this analysis follows from the NWPPC C&R study. The NWPPC C&R study assumed that the retirement restriction grew by 500 MW every other year. BPA slightly modified this assumption so that the retirement restriction increases by 250 MW every year.

4. RESULTS

The complete results of the MCA are in terms of hourly prices. BPA’s energy rates are in monthly blocks of HLH and LLH. The results of the MCA in these time period blocks are shown in the following table and graph. An additional block, “Wgt Avg Energy,” is a weighted average of HLH and LLH prices. The weights are 57 percent HLH and 43 percent LLH. This is based on the amount of HLH and LLH in an average month.

Table 7: Marginal Cost Estimates

Nominal $/MWH

Marginal Cost Analysis

	Heavy Load Hour Energy							Light Load Hour Energy							Wgt Avg Energy							FY02-FY06 Avg.		
	FY00	FY01	FY02	FY03	FY04	FY05	FY06	FY00	FY01	FY02	FY03	FY04	FY05	FY06	FY00	FY01	FY02	FY03	FY04	FY05	FY06	hlh	llh	avg
Oct	24.1	28.7	30.6	32.9	32.8	32.6	33.3	15.2	18.5	19.4	21.6	21.0	21.0	20.7	20.3	24.3	25.8	28.0	27.7	27.6	27.9	32.4	20.8	27.4
Nov	31.5	37.0	40.3	42.9	43.4	44.0	46.2	22.6	26.1	29.7	31.4	30.6	30.7	30.8	27.6	32.3	35.8	37.9	37.9	38.3	39.6	43.4	30.6	37.9
Dec	32.1	36.6	40.5	43.6	45.4	45.7	46.3	21.3	24.6	28.0	29.9	30.6	30.9	31.0	27.4	31.4	35.1	37.7	39.0	39.3	39.7	44.3	30.1	38.2
Jan	35.3	37.4	39.1	39.1	38.7	40.3	41.4	20.6	20.4	24.7	25.6	24.3	24.4	24.6	29.0	30.1	32.9	33.3	32.5	33.5	34.2	39.7	24.7	33.3
Feb	33.3	36.4	38.2	37.5	36.2	37.1	37.9	18.8	21.4	23.6	23.5	23.0	22.2	22.8	27.1	29.9	31.9	31.5	30.5	30.7	31.4	37.4	23.0	31.2
Mar	28.6	33.0	34.8	33.4	32.9	33.0	33.4	15.7	18.6	20.4	19.8	19.3	20.2	21.2	23.0	26.8	28.6	27.6	27.1	27.5	28.1	33.5	20.2	27.8
Apr	21.0	23.6	25.5	26.0	26.8	27.2	27.4	13.0	14.3	15.1	15.1	15.3	16.3	17.4	17.6	19.6	21.0	21.3	21.9	22.5	23.1	26.6	15.8	22.0
May	19.8	22.6	24.6	25.4	26.3	27.6	28.0	11.1	12.2	12.5	12.9	13.2	13.8	13.7	16.1	18.1	19.4	20.0	20.7	21.6	21.9	26.4	13.2	20.7
Jun	24.2	26.4	28.5	31.0	33.2	35.1	36.6	12.4	13.6	15.3	15.5	15.5	16.2	16.5	19.2	20.9	22.9	24.4	25.6	27.0	27.9	32.9	15.8	25.5
Jul	29.9	31.3	34.5	40.0	41.3	45.5	51.6	21.1	26.9	28.2	26.0	24.4	24.7	24.7	26.2	29.4	31.8	34.0	34.0	36.6	40.0	42.6	25.6	35.3
Aug	36.6	44.3	49.5	52.5	56.5	66.3	74.6	25.9	29.2	32.7	32.8	31.2	29.3	29.1	32.0	37.8	42.2	44.0	45.6	50.4	55.0	59.9	31.0	47.4
Sep	32.5	38.0	41.9	42.8	43.4	46.9	49.7	26.5	29.4	32.1	32.9	33.2	32.5	31.5	29.9	34.3	37.7	38.6	39.0	40.7	41.9	44.9	32.4	39.6
Avg	***29.1***	***32.9***	***35.7***	***37.3***	***38.1***	***40.1***	***42.2***	***18.7***	***21.3***	***23.5***	***23.9***	***23.5***	***23.5***	***23.7***	***24.6***	***27.9***	***30.4***	***31.5***	***31.8***	***33.0***	***34.2***	***38.7***	***23.6***	***32.2***

Real $/MWH

Marginal Cost Analysis

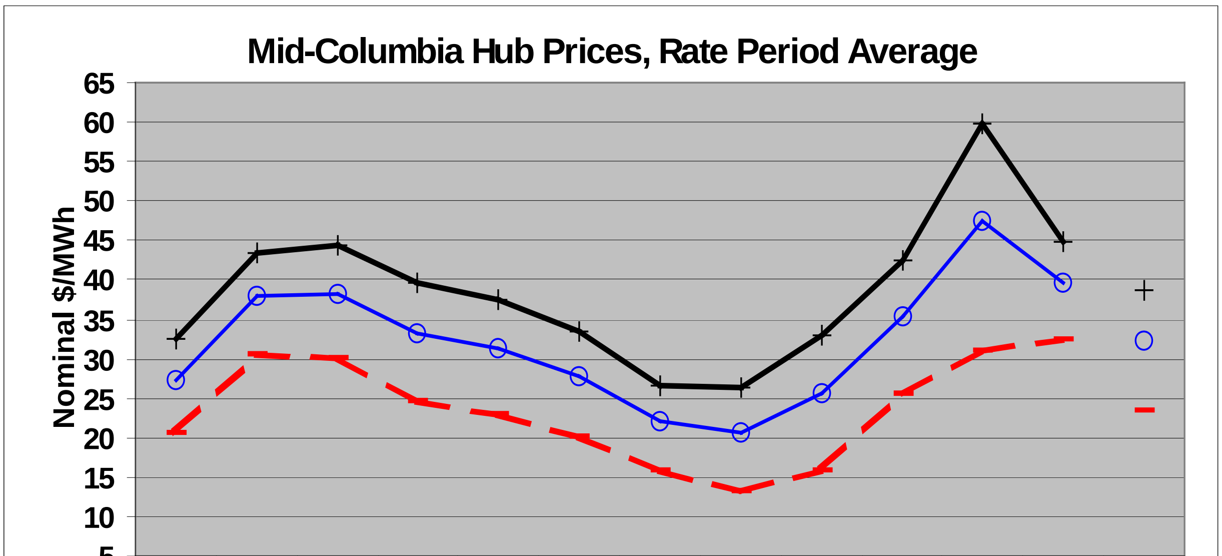
	Heavy Load Hour Energy							Light Load Hour Energy							Wgt Avg Energy							FY02-FY06 Avg.		
	FY00	FY01	FY02	FY03	FY04	FY05	FY06	FY00	FY01	FY02	FY03	FY04	FY05	FY06	FY00	FY01	FY02	FY03	FY04	FY05	FY06	hlh	llh	avg
Oct	22.9	26.6	27.6	29.0	28.1	27.3	27.1	14.4	17.1	17.5	19.1	18.0	17.6	16.8	19.2	22.5	23.3	24.7	23.8	23.1	22.7	27.8	17.8	23.5
Nov	29.8	34.2	36.4	37.7	37.2	36.7	37.5	21.4	24.2	26.8	27.6	26.2	25.6	25.0	26.2	29.9	32.3	33.4	32.5	31.9	32.1	37.1	26.2	32.4
Dec	30.3	33.7	36.5	38.2	38.7	38.0	37.5	20.1	22.7	25.2	26.2	26.1	25.7	25.2	26.0	29.0	31.6	33.0	33.3	32.7	32.2	37.8	25.7	32.6
Jan	33.3	34.5	35.2	34.2	33.0	33.4	33.5	19.4	18.8	22.2	22.4	20.7	20.2	19.9	27.3	27.7	29.6	29.1	27.7	27.8	27.6	33.9	21.1	28.4
Feb	31.3	33.4	34.2	32.7	30.8	30.7	30.6	17.7	19.7	21.2	20.5	19.5	18.4	18.4	25.5	27.5	28.6	27.5	26.0	25.4	25.4	31.8	19.6	26.6
Mar	26.9	30.3	31.1	29.1	27.9	27.2	26.9	14.7	17.0	18.2	17.3	16.4	16.7	17.0	21.6	24.6	25.6	24.0	22.9	22.7	22.6	28.4	17.1	23.6
Apr	19.7	21.6	22.8	22.6	22.7	22.4	22.0	12.2	13.1	13.4	13.2	13.0	13.4	14.0	16.5	17.9	18.8	18.5	18.5	18.6	18.6	22.5	13.4	18.6
May	18.5	20.6	21.9	22.0	22.2	22.7	22.5	10.4	11.1	11.2	11.2	11.2	11.3	11.0	15.0	16.5	17.3	17.4	17.4	17.8	17.5	22.2	11.2	17.5
Jun	22.6	24.1	25.4	26.9	28.0	28.8	29.3	11.6	12.4	13.6	13.5	13.1	13.3	13.2	17.9	19.0	20.3	21.1	21.6	22.1	22.4	27.7	13.3	21.5
Jul	27.9	28.5	30.6	34.5	34.8	37.3	41.2	19.7	24.5	25.1	22.5	20.5	20.3	19.8	24.4	26.8	28.2	29.3	28.6	29.9	32.0	35.7	21.6	29.6
Aug	34.0	40.2	43.8	45.2	47.4	54.1	59.5	24.1	26.5	28.9	28.2	26.2	23.9	23.2	29.7	34.3	37.4	37.9	38.2	41.2	43.9	50.0	26.1	39.7
Sep	30.2	34.4	37.0	36.8	36.3	38.3	39.5	24.6	26.6	28.3	28.3	27.8	26.5	25.1	27.8	31.1	33.3	33.2	32.7	33.2	33.3	37.6	27.2	33.1
Avg	***27.3***	***30.2***	***31.9***	***32.4***	***32.2***	***33.1***	***33.9***	***17.5***	***19.5***	***21.0***	***20.8***	***19.9***	***19.4***	***19.0***	***23.1***	***25.6***	***27.2***	***27.4***	***26.9***	***27.2***	***27.5***	***32.7***	***20.0***	***27.3***

These prices follow the pattern suggested in "Pricing Structure" where prices increase in the near-term, then generally level out near the price of new resources. In real terms, the weighted average price increases from $23.1/MWh in Fiscal Year (FY) 2000 to $27.2/MWh in FY 2002. From FY 2002 to FY 2006 the weighted average price varies between $26.9/MWh and $27.5/MWh.

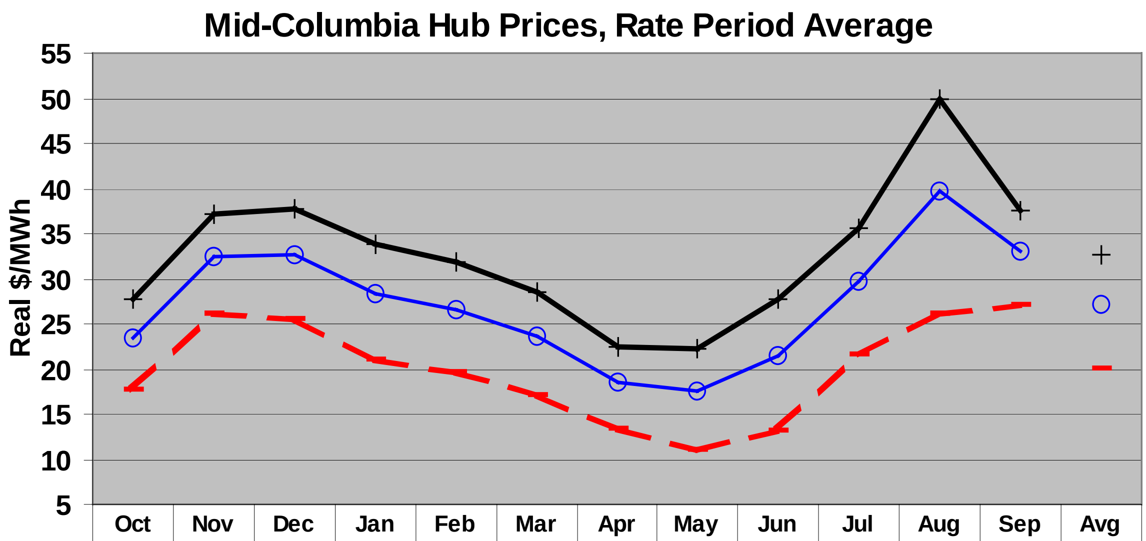
Economic theory also suggests that until prices reach a long-term equilibrium, prices in relatively capacity constrained times (peak months and HLH) will grow relatively faster. This pricing pattern is seen in the marginal cost forecast. Prices in the peak pricing month (August) grow more rapidly than prices in other months, and HLH prices increase more than LLH prices.

These marginal cost estimates are used to help shape the monthly and daily pattern of rates. Therefore, the monthly shape of HLH and LLH marginal costs during the rate case period are especially relevant. A summary of the monthly shape of the marginal costs is detailed in the figures below.

Graph 7: Marginal Cost Estimates



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
hlh	32.4	43.4	44.3	39.7	37.4	33.5	26.6	26.4	32.9	42.6	59.9	44.9	38.7
Avg	27.4	37.9	38.2	33.3	31.2	27.8	22.0	20.7	25.5	35.3	47.4	39.6	32.2
llh	20.8	30.6	30.1	24.7	23.0	20.2	15.8	13.2	15.8	25.6	31.0	32.4	23.6



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
hlh	27.8	37.1	37.8	33.9	31.8	28.4	22.5	22.2	27.7	35.7	50.0	37.6	32.7
Avg	23.5	32.4	32.6	28.4	26.6	23.6	18.6	17.5	21.5	29.6	39.7	33.1	27.3
llh	17.8	26.2	25.7	21.1	19.6	17.1	13.4	11.2	13.3	21.6	26.1	27.2	20.0