Additional Information Regarding the Economic Assessment of RTO Policy Report released February 27, 2002

Prepared by:

ICF Consulting

March 21, 2002

Contents

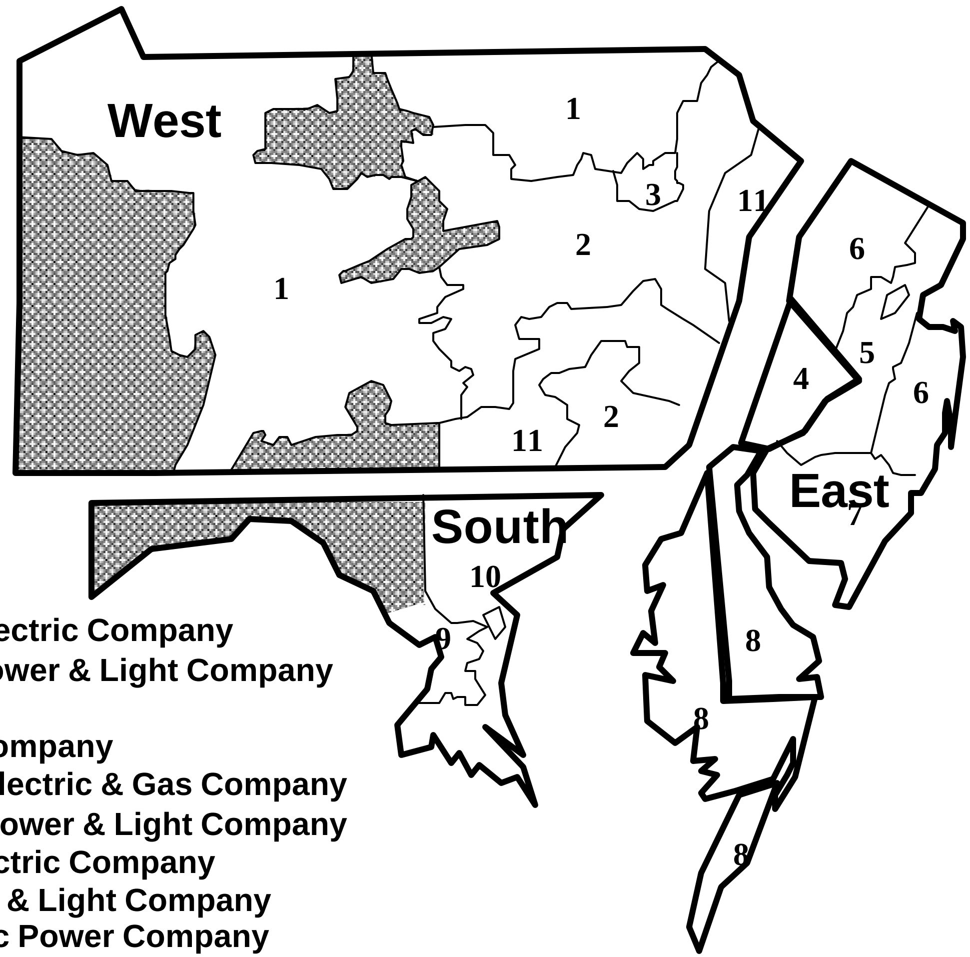
- Northeast Regional Detail
- Modeling Assumptions

Northeast Regional Detail

Determining RTO Regional Configurations

- The RTO configurations for all of the scenarios were based on ICF's judgment in consultation with FERC staff.
- Based on public filings with the Commission, trade press reports and discussion with industry participants as to the likely participation of various entities in RTOs.
- Not based on any FERC order.

PJM Regional Overview

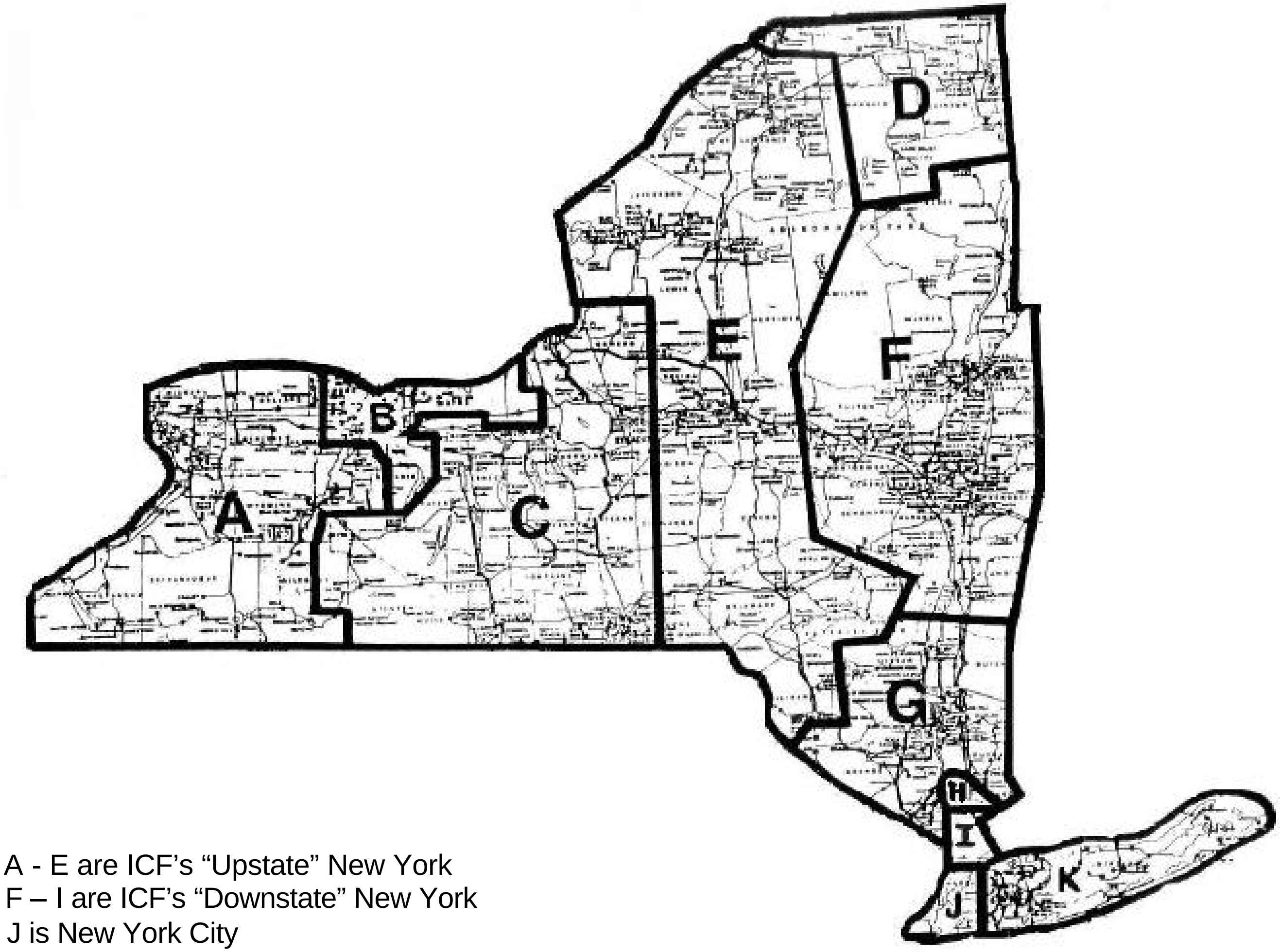


Non-PJM Territory

Service Territory Boundary

1. Pennsylvania Electric Company
2. Pennsylvania Power & Light Company
3. UGI Corporation
4. PECO Energy Company
5. Public Service Electric & Gas Company
6. Jersey Central Power & Light Company
7. Atlantic City Electric Company
8. Delmarva Power & Light Company
9. Potomac Electric Power Company
10. Baltimore Gas & Electric Company
11. Metropolitan Edison Company

Market Structure in New York – PX
The Energy Market – NYISO Load Zones



Zones A - E are ICF's "Upstate" New York
Zones F – I are ICF's "Downstate" New York
Zones J is New York City
Zone K is Long Island
Source: NYPP

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Market Structure in New York – PX
The Energy Market – NYISO Load Zones

- The New York ISO marketplace is broken into 11 zones. The market utilizes Locational Based Marginal Pricing (LBMP), and prices are reported for these eleven zones.
- The Bowline Unit #3 expansion will reside in Rockland County located on the eastern border of Zone G.
- For modeling purposes, ICF aggregates the zones into four regions: Zones A-E comprise ICF's "Upstate" region, Zones F-I make up ICF's "Downstate" region, Zone J remains ICF's New York City, and Zone K is ICF's Long Island subregion.

Northeast RTO Sub-region Transfer Capability (GW)

Transmission Link	Transfer Capability (GW)
PJM-W to PJM-E	6.2
PJM-W to PJM-S	4.1
PJM-W to Upstate NY	1.98
PJM-E to PJM-W	2.0
PJM-E to Downstate NY	1.7
PJM-S to PJM-W	2.4
PJM-S to VIEP	3.78
Upstate NY to PJM-W	2.74
Upstate NY to Downstate NY	5.0
Downstate NY to PJM-E	0.6
Downstate NY to NEPOOL	1.4
Downstate NY to Upstate NY	5.0
Downstate NY to LILCO	1.05
Downstate NY to NYC	5.0

Northeast RTO Sub-region Transfer Capability (GW) *(continued)*

Transmission Link	Transfer Capability (GW)
NEPOOL to Downstate NY	1.6
NYC to Downstate NY	5.0
NYC to LILCO	1.05
LILCO to NYC	1.05
LILCO to Downstate NY	1.25
VIEP to PJM-S	3.85

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Modeling Assumptions

Outline

I. Scenario Overview

II. Analytic Approach

III. Assumptions

- Macroeconomic Drivers, Power Market Drivers, & Variable O&M
- Fuel Prices
- Environmental Assumptions
- New Power Plants
  - Coal and Gas Technologies
  - Renewable/Advanced Technologies
- Scenario Assumptions

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I. Scenario Overview

Context for Assumptions Document

- ICF Consulting has been conducting an economic cost/benefit study of Regional Transmission Organization (RTO) policy for the FERC. A central element of this study is a set of computer model simulations of the US electric power sector, performed using ICF's Integrated Planning Model (IPM®) framework.

- The purpose of an Assumptions Document is to facilitate development of Base Case and policy scenarios. In addition, the Assumptions Document can assist in discussion of the IPM® model, the overall analytic framework, and the underlying assumptions that drive this portion of the analysis.

- This version of the Assumptions Document adopts scenario nomenclature and other elements from the final report ("Economic Assessment of RTO Policy") released by the Commission on February 27, 2002.

Overview of Scenario Development Approach

- In order to estimate the potential costs and benefits of a regulatory policy, an approach known as scenario analysis is often employed. This approach posits a series of assumed conditions and varies them systematically in order to create one or more alternative scenarios, defined as complete, internally consistent sets of assumptions. The results of each scenario are then compared in order to capture the changes in relevant elements of the power system (costs, output, power flows, etc.).

- A starting point for comparison is required to estimate changes in the power system that might result from a given set of policy steps. This starting point is referred to as the Base Case. In general this Base Case represents the current status quo in terms of power market and regulatory assumptions. Policy scenarios are then developed by making changes to the assumptions in the Base Case.

- For this analysis of RTO policy, a limited set of model scenarios is used to estimate a range of potential changes to the power system under changing regulatory conditions. Sensitivity analysis can also be employed to vary specific assumptions in order to assess their effects, or new sets of assumptions can be varied together to simulate alternative assessments of the likely results of the policy.

Framing Scenarios

RTO Configuration		No RTOs; 32-region structure	4 RTOs and ERCOT			2 RTOs and ERCOT	9 RTOs and ERCOT
Type of RTO-Related Economic Benefit	**Specific Model Assumption**	**Base Case**	**RTO Policy Scenarios**			**Sensitivity Cases**	
			Transmission Only	**Transmission/ Generation**	**Demand Response**	**Sensitivity I: Larger RTOs**	**Sensitivity II: Smaller RTOs**
Transmission	**Reduced Inter-Regional Barriers to Trade**	Base Case assumption	No transmission hurdle rates within RTOs; hurdle rates converge to $2 per MWh between RTOs beginning in 2004				
	Transmission Capability Expansion	Base Case assumption	Increased by 5% from 2004 onward				
	Capacity Sharing	75% of energy transfer capability	100% of electricity transfer capability				
	Reserve Margins	Decline over time to system-wide average of 15% by 2020	Decline over time to system-wide average of 13% by 2020				
Generation	**Efficiency Improvements**	Base Case assumption		Fossil-fired Units: Heat rate improves by 6% by 2010 and availability increases by 2.5%			
Demand Response	**Demand Response**	Not analyzed			3.5% reduction in peak beginning in 2006	Not analyzed	

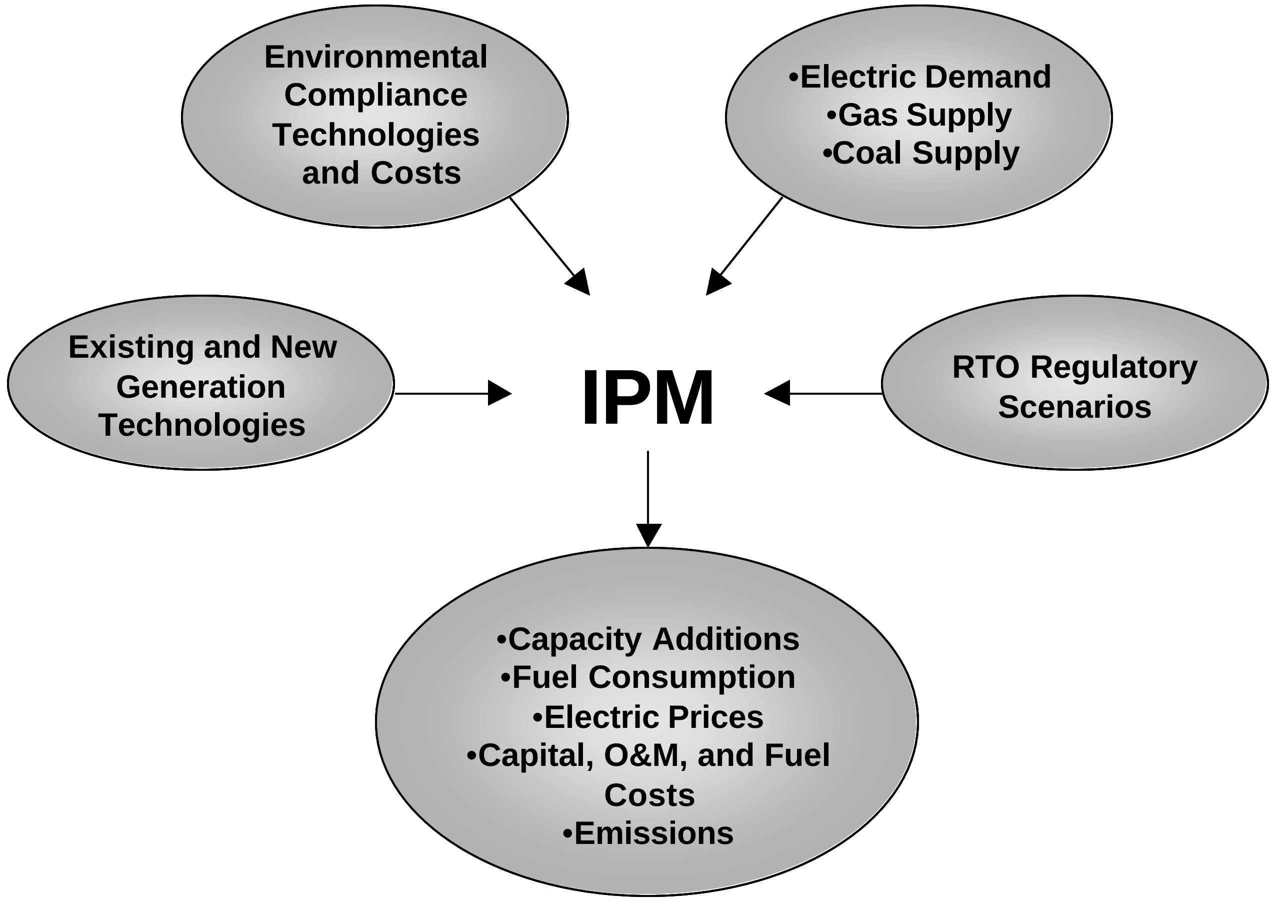
Framing Scenarios

- Scenarios combine specific modeling assumptions into complete sets of parameters that are intended to represent alternative potential outcomes, or to clarify the effects of particular factors on analytic results. Both regulatory assumptions and market assumptions must be specified to develop a complete modeling scenario.

- For this analysis, three main policy scenarios and two sensitivity scenarios have been analyzed and reported. Results are compared to a Base Case that represents the status quo or no-action regulatory alternative (Order No. 888 without the subsequent RTO Initiative as embodied in Order No. 2000).

II. Analytic Approach

Analytic Framework



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The IPM® Modeling Framework

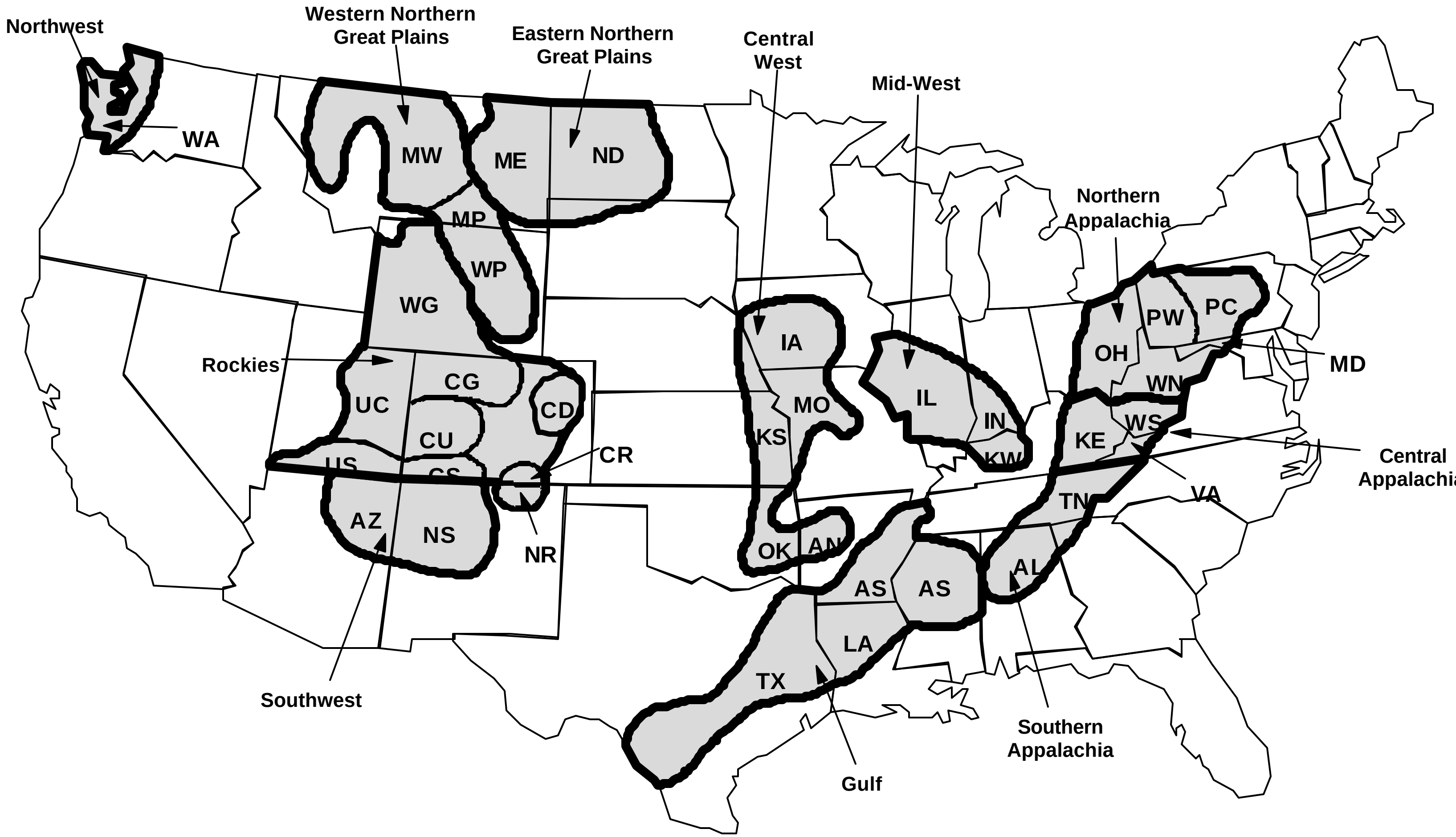
- ICF Consulting uses a proprietary, national Integrated Planning Model (IPM®) to analyze the impacts of RTOs on power markets, regional generation, and the transmission system.
- IPM® is a linear programming model with a detailed representation of every boiler and generator operating in the United States. The model determines the least cost means of meeting electric energy and capacity requirements, while complying with specified regulatory scenarios.
- In addition to optimizing wholesale and environmental markets, IPM® simultaneously optimizes coal production, transportation and consumption.
  - IPM® contains 40 coal producing regions and has over 10 coal types defined by rank and sulfur content.
  - Each coal plant is assigned to one of over 40 coal demand regions characterized by location and mode of delivery including rail, barge, and truck.
- Natural gas prices are derived within IPM® using a similar supply curve and transportation network.

IPM® Regional Map (32 Base case model regions)

IPM® Model Regions

- National IPM® divides the United States into model regions, closely resembling NERC regions. ICF divides NERC regions based on known transmission bottlenecks (i.e. sub-regions in which spot prices are expected to diverge significantly), or when clients request specific regional breakouts.
- All IPM® regions have a representation of the electric transmission system that connects neighboring regions. The inter-regional transmission connections allow for the transfer of both capacity and energy and allow for broad price equilibration when transmission capacity is available. These transmission links are aggregated from line-specific data and form a transportation-type network, which is not intended to assess engineering or reliability limits on a short-term basis but rather to represent a reasonable estimate of long-term net transfer capabilities.
- For this study, ICF begins with a total of 32 model regions in order to best capture the effects of RTOs on the national grid.

IPM® Coal Supply Regions



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Representation of Coal Supply, Demand, and Transportation in IPM®

- IPM® forecasts coal production from over 40 supply regions:
  - Bituminous, sub-bituminous, lignite
  - 12 different sulfur grades
- Each coal power plant is assigned to one of 41 coal demand regions based on location and mode of delivery.
- Coal transportation network links coal supply and demand regions.
- Coal consumption by sulfur grade is a function of electricity generation levels, air pollution regulations, and oil and gas prices.

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NANGAS Supply Regions

POF:	Pacific Offshore
PON:	Pacific Onshore
SJ:	San Juan
RF:	Rockies Foreland
WI:	Williston
P:	Permian
MC:	Mid-Continent
AET:	Arkla-East Texas
TGC:	Texas Gulf Coast
GMW:	Gulf of Mexico-West
GMC:	Gulf of Mexico-Central
NP:	Norphlet
SL:	South Louisiana
WF:	West Florida
MF:	MAFLA Onshore
MW:	Mid-West
AP:	Appalachia
ANS:	Alaska North Slope
MD:	MacKenzie Delta
AB:	Alberta
BC:	British Columbia
SI:	Sable Island
DI:	Distrigas
CP:	Cove Point
EI:	Elba Island
LC:	Lake Charles

Wyoming, Colorado and parts of Utah, Arizona, New Mexico, South Dakota and Montana constitute Rockies in NANGAS

Gas Market Approach

- ICF's natural gas price forecasts are derived from results from ICF's North American Natural Gas Analysis System (NANGAS). The NANGAS model has descriptive and analytic capability that allows assessment of gas resources and markets from reservoir to burner-tip, working from a database of more than 17,000 U.S. and Canadian reservoirs.

- The NANGAS model also contains: explicit characterizations of the performance and market penetration rate of E&P technologies; detailed regional/sectoral/seasonal demand criteria; site-specific investment, operating and environmental compliance cost; and a pipeline network simulation that analyzes supply, demand, and transportation interactions consistently and comprehensively.

- Natural gas commodity and transportation prices are assumed to vary with demand on a seasonal basis in accordance with historical trends -- higher commodity and transportation prices in winter and lower prices in other seasons.

- Increased demand as a result of a carbon policy is endogenously handled within IPM® using supply curves generated from NANGAS. These curves are described in greater detail in the Assumptions section.

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III. Assumptions

Macroeconomic and Power Market Drivers

ICF's Base Case Includes Market and Regulatory Assumptions

- The purpose of a Base Case is to establish points of comparison for policy analysis, and to show how underlying trends in power markets play out in the IPM framework.
- For any modeling scenario, both regulatory policies and economic/technical assumptions must be defined.
- The Base Case also includes a full set of assumptions regarding economic trends, power market fundamentals, and future technological options. These assumptions can be varied in policy scenarios, or they can be left 'as is' to facilitate comparisons that isolate the effects of regulatory changes.

2000 Peak Demand and Total Energy Consumption, by Region

Region	Peak Demand (Summer) in MW	Net Internal Demand (Summer) in MW	Energy in MWh
AZNM	17,048	16,805	87,892,147
CAPO	10,907	10,424	58,320,854
COMED	21,973	20,575	96,469,380
DNSNY	6,439	6,439	34,628,844
DUKE	18,971	18,132	101,434,721
MECS	17,294	16,700	94,985,848
ECAO	74,739	72,171	450,972,152
ENTERGY	27,714	26,332	137,300,000
ERCOT	57,606	54,450	286,313,000
FRCC	37,194	34,476	196,561,000
ILMO	18,885	17,683	98,037,916
LILCO	4,200	4,200	18,609,888
MAPP	28,605	26,870	145,981,000
MONTANA	2,105	2,072	12,462,467
NYC	8,891	8,891	47,819,391
NOCAL	21,726	16,013	113,379,141
NWPPE	5,369	5,284	36,731,416
NEPOOL	21,919	21,919	124,886,000
PACNW	28,061	27,617	191,898,117
PJME	25,184	24,414	133,521,628

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2000 Peak Demand and Total Energy Consumption, by Region *(continued)*

Region	Peak Demand (Summer) in MW	Net Internal Demand (Summer) in MW	Energy in MWh
PJMS	11,874	11,511	62,954,546
PJMW	12,419	12,039	65,843,826
ROCKIES	8,589	8,470	51,481,000
SCEG	9,740	9,309	52,071,145
SOCAL	32,588	24,020	170,068,712
SOCO	43,692	41,621	210,023,000
MOKAN	14,446	13,923	66,560,835
SPPW	25,753	24,822	127,100,165
TVA	29,446	27,128	160,549,000
UPSNY	8,608	8,608	55,573,878
VIEP	15,618	14,926	83,512,281
WUMS	11,694	10,950	65,100,704

Electricity Demand Growth Will Remain Strong

- In the 1960's, electricity demand grew at about twice the rate of growth in GDP. The ratio of electricity growth to GDP growth has slowly declined over the past 30 years so that in the 1990's the rate of electricity growth has been approximately the same as the rate of growth in GDP. This trend is expected to continue.

- The Base Case forecast assumes that electricity demand will grow at about the rate of growth in GDP through 2005 and then will slowly decline to average about 80 percent of the growth in GDP through 2020. These electric demand growth rates are higher than those forecast by the North America Electric Reliability Council (NERC), and are derived by adjusting NERC forecasts based on recent actual demand growth.

- The Base Case uses the NERC estimates of regional variation in electricity demand growth.

- Peak demand projections were developed using our forecast of annual electricity demand and the NERC's projected load factors (the ratio of average load to peak load).

Projected Reserve Margins

Region	2005	2010	2015+
AZNM	15%	15%	15%
CAPO	15%	15%	15%
COMED	15%	15%	15%
DNSNY	18%	18%	15%
DUKE	15%	15%	15%
MECS	15%	15%	15%
ECAO	15%	15%	15%
ENTERGY	15%	15%	15%
ERCOT	15%	15%	15%
FRCC	17%	23%	18%
ILMO	15%	15%	15%
LILCO	18%	18%	15%
MAPP	15%	15%	15%
MONTANA	15%	15%	15%
NYC	18%	18%	15%
NOCAL	15%	15%	15%
NWPPE	15%	15%	15%
NEPOOL	17%	15%	15%
PACNW	15%	15%	15%
PJME	18%	15%	15%

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Projected Reserve Margins *(continued)*

Region	2005	2010	2015+
PJMS	18%	15%	15%
PJMW	18%	15%	15%
ROCKIES	15%	15%	15%
SCEG	15%	15%	15%
SOCAL	15%	15%	15%
SOCO	15%	15%	15%
MOKAN	15%	15%	15%
SPPW	15%	15%	15%
TVA	15%	15%	15%
UPSNY	18%	18%	15%
VIEP	15%	15%	15%
WUMS	15%	15%	15%

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Reserve Margins Drop Over Time

- ICF models reserve margin requirements in order to capture ongoing reliability standards. These reserve margins require the model to build economic capacity additions to meet peak demand plus a specified percentage in each model region.

- Historically, reserve margins have been declining as more inter-regional power transfers and increasing real-time response options have reduced the need for dedicated reserve capacity.

- Each model region has a specific trajectory of projected reserve margin requirements. These assumptions are based on a number of sources, primarily NERC projections and regional reliability council estimates.

- RTOs may provide significant decreases in reserve capacity requirements in policy scenarios.

Representative Financial Assumptions for New Power Plant Investments

Input Assumptions:	
Debt Life (years)	15
Book Life (years)	30
After Tax Equity Rate (%)	14.0
Equity Ratio (%)	50.0
Debt Rate (%)	9.0
Debt Ratio (%)	50.0
Income Tax Rate (%)	41.3
Other Taxes/Insurance (%)	2.0
Inflation (%)	2.5
Output:	
Real Weighted Average After Tax Cost of Capital	6.97
Levelized Real Fixed Capital Charge Rate (%)	14.1

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Financing Capital Projects

- Financing assumptions vary by capacity type for new builds and retrofits. The major financing component that varies is the debt-equity ratio (as well as their respective rates).

- ICF considers the capital charge rate as the levelized rate of return on an investment. The components of this rate are not based on traditional utility financing, but rather focus more on how marginal merchant projects (or components of projects designed for spot sales) will be financed in a deregulated industry.

- Recently some projects intended partially for the merchant market have been financed at lower rates and higher debt shares than in the past. The merchant component, although difficult to finance relative to the utility-backed portion, is the only relevant portion for the spot short-term market prices we are forecasting.

ICF Assumes Nuclear Plants Relicense at End of 40 Year Operating Period

- ICF assumes that all nuclear plants opt to renew their nuclear licenses at the end of the original 40 year operating period if it is economic to do so.
- The model allows all plants to economically retire in 2003 onwards if they are unable to cover their going-forward fixed costs. This is determined endogenously within the model through an evaluation of the potential future revenue stream for each plant.

Segmental Variable O&M

- Segmental variable O&M captures changing costs that result from start-up and cycling. Non-fuel segmental variable O&M is an inverse function of a unit's capacity factor, with low capacity factors implying higher variable O&M and high capacity factors implying lower variable O&M.

- Base load units that cycle very little have variable O&M rates at the low end of the range shown.

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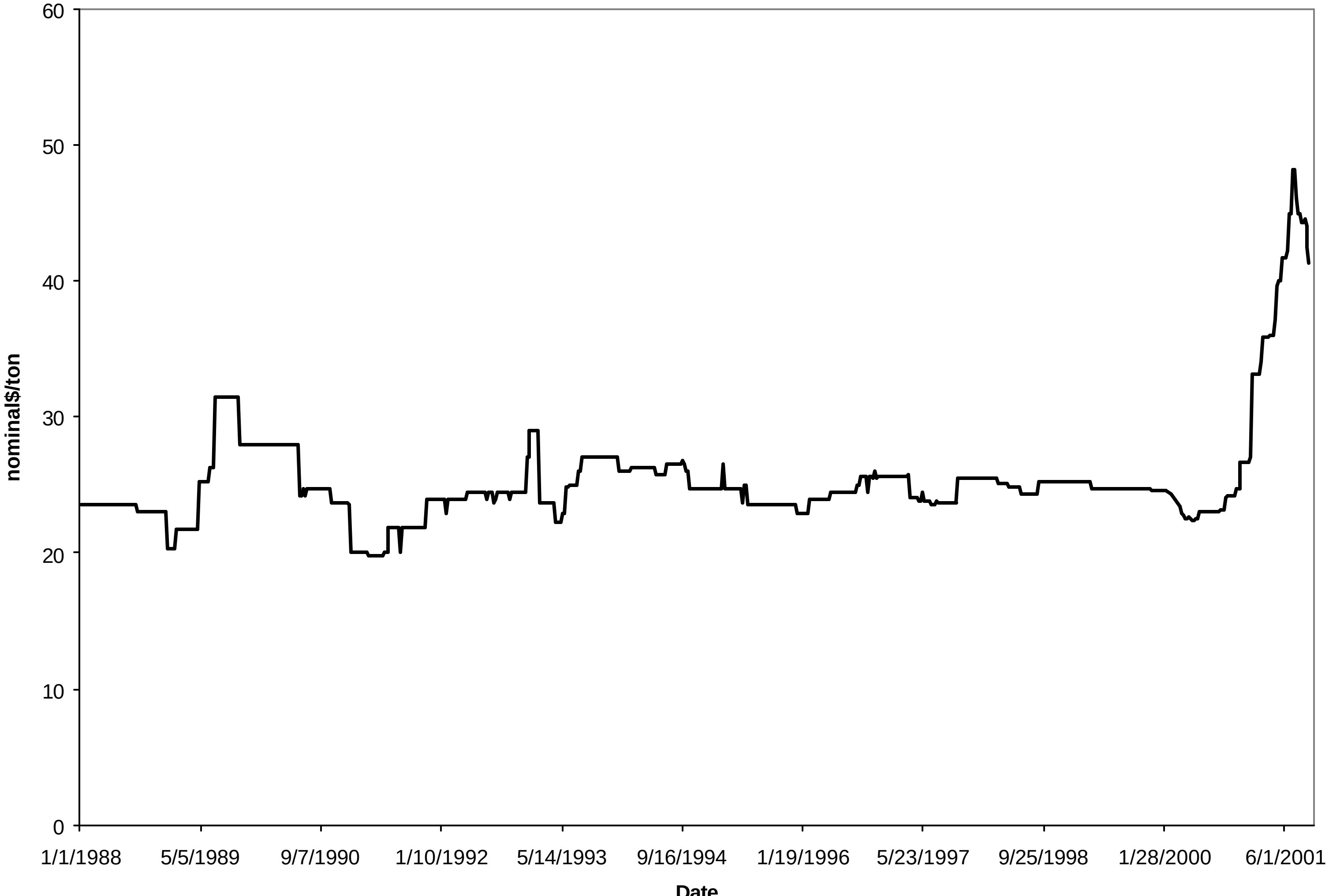
Fuel Prices

Coal Supply Assumptions

1% Sulfur Central Appalachia Coal Prices Since 1988 (nominal $)



Source: Coal Week; Central Appalachia 1.0% S, 12,500 Btu/lb

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Recent Marker Coal Price Movements

- Minemouth coal prices across the U.S. rose sharply in the summer of 2001, but are returning to previous levels.

- The most dramatic price increases were concentrated in Central Appalachia and Northern Appalachia. Central Appalachian coal prices briefly increased by between $20/ton (nominal$) and $25/ton and Northern Appalachian coal prices increased by between $10/ton and $16/ton. The price of Powder River Basin coal increased by approximately $4 to $5/ton, although in early 2001 PRB prices rose by between $8 to $10/ton.

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Recent Run-up in Coal Prices A Short-term Phenomenon

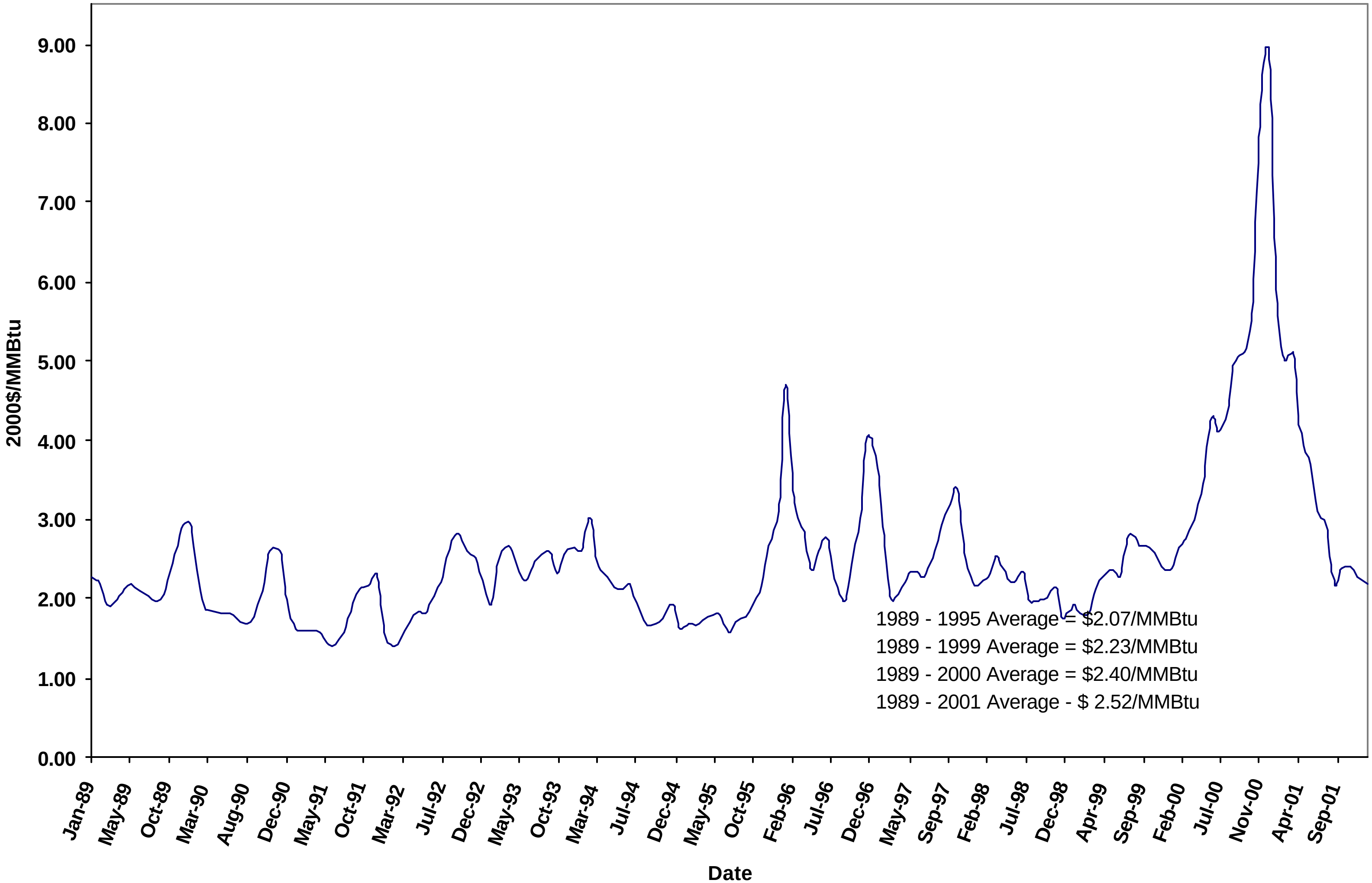
- The increase in coal prices was driven by a tight coal supply, resulting from flat coal production and higher demand.
- Increased demand was driven by several factors:
  - Severe weather conditions in winter 2000/2001
  - Increased exports resulting from high international oil and gas prices
  - Higher consumption from the electric sector in response to high natural gas prices
- Despite this increased demand, coal production increased only slightly in 2000. As a result, coal stocks in the U.S. fell in 2000 and are currently near 20-year lows.
- ICF expects coal prices to return to lower levels by 2004/5.
  - Coal prices have moderated in recent months
  - Coal futures prices indicate further declines are anticipated
  - Production will increase in response to higher price levels and low stocks
  - Demand pressures have abated as gas prices have fallen from their recent peaks. As discussed below, ICF believes that gas prices will return to long-term average levels in the mid-term

Coal Mining Productivity Improvements Will Slow Over Time

- The Base Case forecast assumes a gradual decrease in the the rate of productivity improvements over time.
- Productivity improvements have historically been higher in the West. The Base Case forecast assumes that historical regional variations in productivity improvement will continue. While Powder River Basin (PRB) productivity is expected to experience continued growth, dramatic increases in demand for PRB coal offset these improvements, leading to a stable minemouth price over time.
- The rate of mining productivity improvement is expected to slow as long-wall mining applications are exhausted. Other major breakthroughs in mining technology are not expected in the near term.
- We assume a constant 2 percent annual decrease in the cost of transportation.

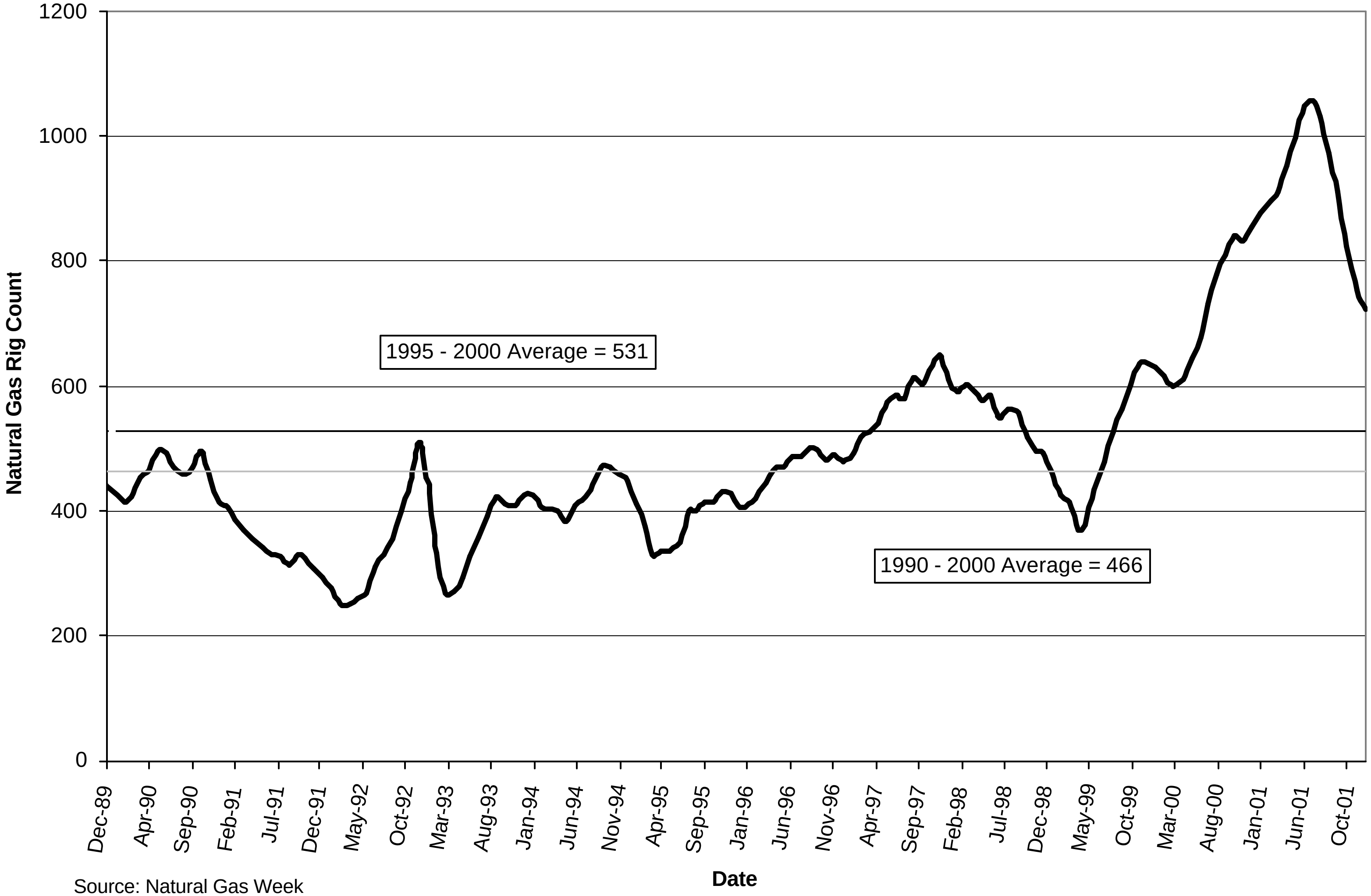
Gas Supply Assumptions

Henry Hub Historical Monthly Prices (2000$/MMBtu)



YTD - January 2002

The Drilling Rig Count Illustrates How the Gas Market Responded to High Prices



Source: Natural Gas Week
YTD -Jan 2002

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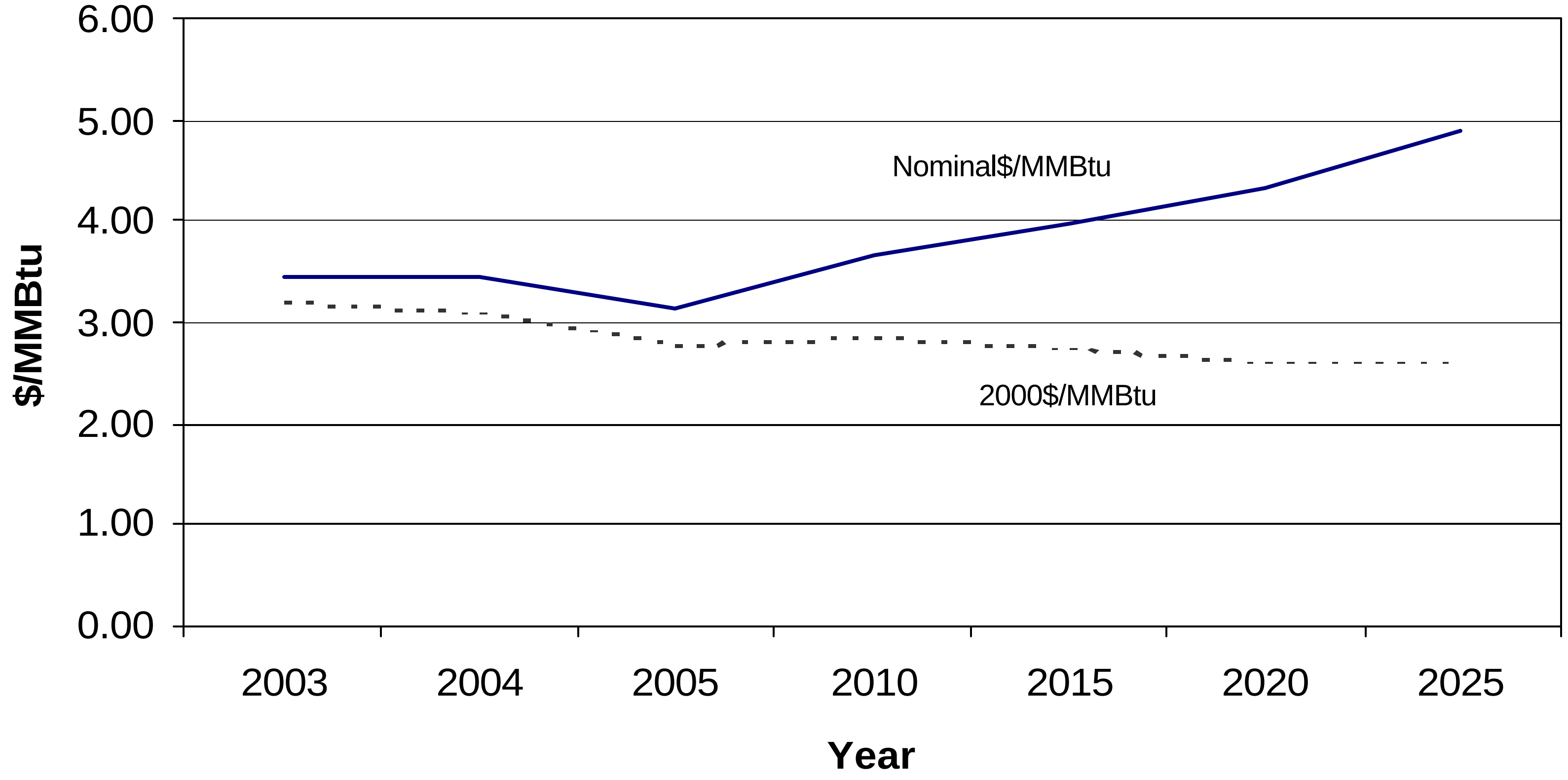
ICF Base Case Forecast



Henry Hub Forecast

	2000$/MMBtu	Nominal$/MMBtu
2003	3.20	3.45
2004	3.12	3.44
2005	2.78	3.14
2010	2.85	3.65
2015	2.74	3.96
2020	2.63	4.31
2025	2.63	4.88

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Gas Prices Have Returned to Historically Low Levels

- ICF projected that recent natural gas prices were unsustainably high and that markets would come down. In fact, the Henry Hub price has fallen from over $9.00/MMBtu to under $3.00/MMBtu. Fundamentals, i.e., a massive resource base and technological improvement, will force commodity prices to remain at these lower levels in the long term.

- ICF perspectives are based on detailed modeling of technological improvements and their impact on reservoir-level supply economics. Our modeling of technological improvements and penetration demonstrates that supply will keep pace with rapidly rising gas demand.

- Historical advances in exploration and production (E&P) technology have allowed greater volumes of reserve additions and production at lesser cost than anticipated.

- This trend in E&P technology is expected to continue (perhaps at a slower rate), supporting growth in gas production and potential reserves. Key drivers include:
  - Improved application of offshore technologies
  - Major growth in new economic supply sources not previously considered (deepwater offshore, Eastern Canada, coalbed methane, etc.)
  - Continued growth of reserves in discovered fields in traditional producing areas

- Gas prices are forecasted to be slightly higher in 2005 and 2010, and slightly lower in 2015.

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Natural Gas Supply Curves

- Natural gas resource estimates from traditional sources are taken from USGS for onshore U.S., Minerals Management Service for offshore U.S. and Geological Survey of Canada (GSC) for Canadian basins.

- The latest outlook of E&P technology such as horizontal wells, exploration success rates, drilling cost declines and regional rig capacities are incorporated.

- Frontier resource estimates are obtained from various sources and supply curves are generated for each of the frontier resource category based on ICF's view of price/supply curves for them.

- Extensive research was undertaken to develop price/supply curves for each U.S. frontier resource category
  - Alaska's North Slope supplies
  - Supplies from Mackenzie Delta
  - LNG from Distrigas, Elba Island, Cove Point, & Lake Charles
  - Other unconventional gas resource not included in the traditional resource base
  - Ultra deep water resource located primarily in Gulf of Mexico-Central and Gulf of Mexico-West regions
  - Deep gas (deeper than 15,000 ft) located in onshore locations such as Texas Gulf Coast and South Louisiana

Natural Gas Supply Curves *(continued)*

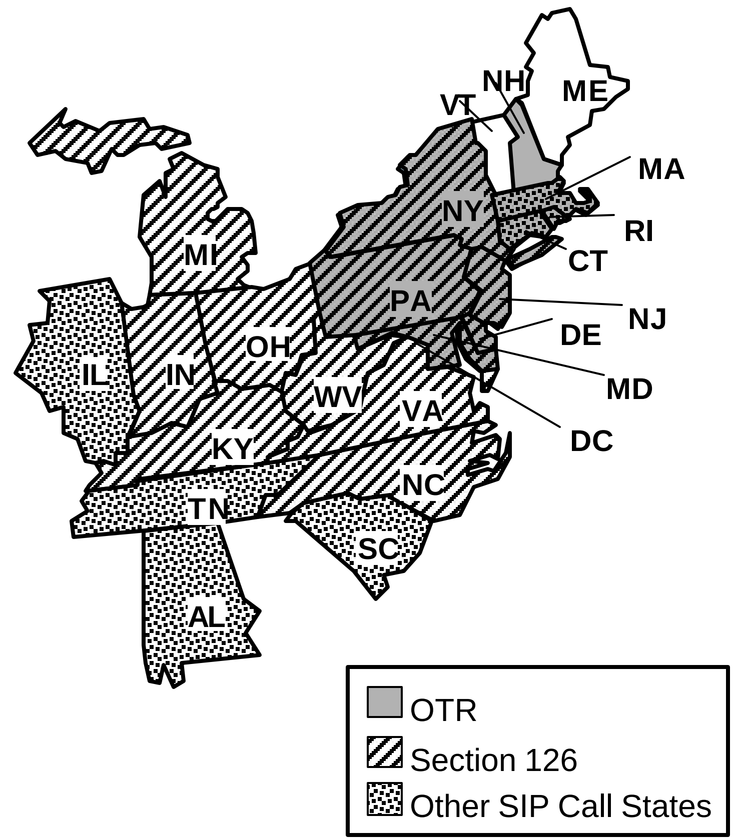
- Additional research was undertaken to develop price/supply curves for each Canadian frontier resource category
  - Canadian coal bed resource
  - Canadian tight gas resource
  - Natural gas resource located offshore Newfoundland
- ICF’s view on natural gas supplies from Northern Mexico is added.
- Supply curves for each resource category are supplied to NANGAS and are used in the supply/demand balance.

Environmental Assumptions

Emissions Regulations

Base Case Environmental Regulations

- The Base Case assumes the following existing environmental policies:
  - Phase II of the Title IV SO_2 trading program will continue unmodified
  - Phase II of the Ozone Transport Region (OTR) program implemented in 1999-2002
  - Existing New Source Review settlement with the EPA (TECO)
- The Base Case also assumes that the expanded-scope SIP Call (State Implementation Plan Call) NO_X trading program will be in place in 2003/2004, including the following stipulations:
  - 12 Northeast states and D.C. adopt SIP Call targeting 0.15 lb/mmBtu in 2003.
  - 19 states and D.C. adopt SIP Call policy targeting 0.15 lb/mmBtu in 2004.
  - Clean Air Act Section 126 requirements delayed until 2004 and assumed to be superseded by the SIP Call.



Notes: Maine and Vermont have opted out of the trading program.
All Sect. 126 states are also SIP Call States.

Existing Unit NO_x Emission Rates

- NO_X emission rates were populated based on EPA's 1999 and 2000 Emissions Scorecard data which is comprised of data based on the Continuous Emissions Monitoring System (CEMS).

- Data is provided on a unit by unit basis for Phase I and Phase II affected units based on the specific characteristics of each unit.

- These rates were modified depending on whether combustion controls are installed on the unit and on the NO_X affected status of the boilers (see below).

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NO_X Combustion Controls for Coal Units

- To simplify the modeling process, NO_X combustion controls such as Low NO_x Burners (LNB) and Overfire Air (OFA), are assumed to be the first step taken by most coal plants when affected by a NO_X regulation. Therefore, combustion controls are not a specific compliance option within IPM. Rather, combustion controls are assumed to occur on individual coal plants if they are affected by a NO_x policy and meet certain criteria based on current controls, boiler type, size, and initial NO_X rate.

- The methodology for applying combustion controls to individual coal plants is based on EPA's approach to modeling NO_X regulations in the "1998 Analyzing Electric Power Generation Under the CAAA," pages A5-4 to A5-6.

- ICF has developed a separate NO_X rate data set that is applied to existing coal units that are affected by a NO_x cap and trade regulation. These NO_X policy rates for each coal unit are adjusted to account for the installation of combustion controls due to the policy. The percent reduction is based on the coal unit's boiler type and initial NO_X rate.

- Because NO_X combustion controls are not modeled endogenously within IPM®, the cost of installing combustion controls are calculated outside of IPM®.

Modeled NO_X Control Options (2000$)

	COAL-FIRED UNITS					OIL/GAS STEAM UNITS	
	SNCR		SCR			SNCR	
Unit Size MW	200	400	200	400	800	200	400
Capital Cost ($/kW)	$17.51	$13.62	$106.02	$86.57	$70.03	$17.51	$13.62
Fixed O&M ($/kw-y)	$0.24	$0.13	$0.49	$0.24	$0.13	$0.24	$0.13
Variable O&M * ($/MWh)	$0.44	$0.44	$0.56	$0.56	$0.56	$0.44	$0.44
Catalyst Cost ($/kW)	*NA*	*NA*	*$8.81*	*$9.01*	*$9.11*	*NA*	*NA*
% Gas Usage	NA	NA	NA	NA	NA	NA	NA
% NOx removal	30%	25%	85%	85%	85%	55%	55%

* Although catalyst costs are incurred upfront, they are listed separately as a component of Variable O&M because they recur based on the performance of the unit.

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Available SO_2 Control Options Differ by Region

- All wet scrubber cost and performance data was developed from U.S. Environmental Protection Agency estimates. Lime spray dryer assumptions were taken from public testimony of the Public Service Company of Colorado.
- Additional flue gas desulfurization retrofits will likely be configured as wet limestone and forced oxidized, due to the low cost of limestone and the easy disposal of scrubber byproduct.
- Some existing scrubbed power plants are currently switching to forced oxidation so that their scrubber byproduct can be sold as commercial gypsum.
- The lime spray dryer (dry scrubber) retrofit option was given to units in WRAP* states only because of their limited water resources and access to low sulfur coal.

"WRAP" refers to the Western Regional Air Partnership, a voluntary organization of western states, tribes and federal agencies formed to improve visibility in national parks and wilderness areas on the Colorado Plateau. The participating states are: Washington, Oregon, Idaho, Montana, Wyoming, North Dakota, South Dakota, California, Utah, Colorado, Arizona, and New Mexico.

Flue Gas Desulfurization for a 500 MW Coal-Fired Generating Unit (2000$)

Control Technology	Capital ($/kW)	Fixed O&M ($/kW-y)	Variable O&M ($/MWh)	Capacity Penalty	SO_2 Removal	Mercury Removal
Wet-Limestone Forced-Oxidized Scrubber (Wet FGD)[1]	184.58	6.00	1.05	2.10%	95%	34%
Lime Spray Dryer (Dry FGD)[2]	76.42	4.43	0.57	2.10%	85%	25%

[1]Source: (1) EPA, "Analyzing Electric Power Generation Under the CAAA," March, 1998; (2) Testimony by Public Service of Colorado, Metro Emissions Reduction Air Quality Improvement Rider

[2]The LSD option is applied only to units in WRAP states (see next page).

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New Power Plants

Technology Costs – Greenfield Power Plant Characteristics (2000$)

	Advanced Coal (IGCC)	Combined Cycle	Combustion Turbine	Circulating Fluidized Bed	Pulverized Coal
	380 (MW)	250 (MW)	160 (MW)	500 (MW)	400 (MW)
2001					
Heat Rate (Btu/kWh)	N/A	6,928	10,905	10,000	9,386
Capital ($/kW)	N/A	642	390	1,243	1,558
Fixed O&M ($/kW/yr)	N/A	20.0	13.5	26.0	33.3
Variable O&M ($/MWh)	N/A	1.1	2.2	2.1	3.37
2005					
Heat Rate (Btu/kWh)	7,469	6,753	10,671	10,000	9,253
Capital ($/kW)	1,649	642	390	1,243	1,543
Fixed O&M ($/kW/yr)	32.7	20.0	13.5	26.0	33.3
Variable O&M ($/MWh)	2.2	1.1	2.2	2.1	3.37
2010					
Heat Rate (Btu/kWh)	6,968	6,583	10,443	10,000	9,087
Capital ($/kW)	1,555	610	371	1,243	1,524
Fixed O&M ($/kW/yr)	32.7	20.0	13.5	26.0	33.3
Variable O&M ($/MWh)	2.2	1.1	2.2	2.1	3.37

Greenfield Power Plant Costs and Performance

- The Base Case assumes that new power plant costs will decline and efficiency will improve.
- Capital cost assumptions account for interest during construction (IDC) and hidden or "soft" costs which occur during plant construction. Soft costs are estimated to be between 25 and 50 percent of direct plant costs.
- Coal Integrated Gasification Combined Cycle (IGCC) plant costs and heat rates are assumed to decline corresponding to projections in EIA's Annual Energy Outlook.
- Capital, fixed O&M, and variable O&M cost estimates include the costs of emission controls required to comply with New Source Performance Standards.
- Individual capital costs are adjusted by region to reflect variations in labor costs and unit capacity adjustments that result from changes in elevation and temperature.

ICF New Build Emission Profiles

- Integrated Gasification Combined Cycle
  - NO_X: SCR with an emission rate of 0.02 lb/MMBtu
  - SO_2: Emissions rate of zero
- Circulating Fluidized Bed
  - NO_X: SNCR with an emission rate of 0.12 lb/MMBtu
  - SO_2: Lime injection into combustion chamber with 95% removal efficiency
- Pulverized Coal
  - NO_X: SCR with an emission rate of 0.11 lb/MMBtu
  - SO_2: FGD with 95% removal efficiency
- Combined Cycle
  - NO_X: SCR with an emission rate of 0.02 lb/MMBtu
  - SO_2: Emissions rate of zero
- Combustion Turbine
  - NO_X: Combustion controls with an emission rate of 0.06 lb/MMBtu
  - SO_2: Emissions rate of zero

Unplanned Build Restrictions

Year	Combustion Turbine Restriction	Combined Cycle Restriction	Coal Plants
2002	Yes (only jet engines such as LM6000)	Yes (Only those under construction)	Yes (Only those under construction)
2003	No	Yes (Only those under construction)	Yes (Only those under construction)
2004-5	No	No	Yes (Only those under construction)
2006+	No	No	No

Note: Unplanned builds are those considered by IPM in addition to existing and firmly planned builds.

- A typical combined cycle or cogeneration unit requires a lead time of 18 - 20 months or more prior to coming on-line.
- Given the longer lead-time required for a combined cycle unit versus a combustion turbine unit, we assume that no new combined cycle units are possible before 2003.
- All plants currently under construction in the U.S. are assumed to come on line in the year of their projected completion

Cost and Performance of New Renewable Power Technologies (2000$)

	Wind	Landfill Gas	Solar Thermal	Photovoltaic	Fuel Cell
	30 (MW)	5 (MW)	100 (MW)	5 (MW)	10 (MW)
2000-2004					
Heat Rate (Btu/kWh)	N/A	10,000	N/A	N/A	5,361
Capital ($/kW)	977	1,243	3,155	4,481	2,224
Fixed O&M ($/kW/yr)	26.9	47.2	48.3	10.2	15.3
Variable O&M ($/MWh)	-	15.1	-	-	2.1
2005-2009					
Heat Rate (Btu/kWh)	N/A	10,000	N/A	N/A	5,361
Capital ($/kW)	977	1,243	3,003	2,526	2,105
Fixed O&M ($/kW/yr)	26.9	47.2	48.3	10.2	15.3
Variable O&M ($/MWh)	-	15.1	-	-	2.1
2010-2014					
Heat Rate (Btu/kWh)	N/A	10,000	N/A	N/A	5,361
Capital ($/kW)	977	1,243	2,852	1,881	1,687
Fixed O&M ($/kW/yr)	26.9	47.2	48.3	10.2	15.3
Variable O&M ($/MWh)	-	15.1	-	-	2.1
2015-2020					
Heat Rate (Btu/kWh)	N/A	10,000	N/A	N/A	5,361
Capital ($/kW)	977	1,243	2,700	1,784	1,516
Fixed O&M ($/kW/yr)	26.9	47.2	48.3	10.2	15.3
Variable O&M ($/MWh)	-	15.1	-	-	2.1
2020 and After					
Heat Rate (Btu/kWh)	N/A	10,000	N/A	N/A	5,361
Capital ($/kW)	977	1,243	2,513	1,724	1,435
Fixed O&M ($/kW/yr)	26.9	47.2	48.3	10.2	15.3
Variable O&M ($/MWh)	-	15.1	-	-	2.1

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Renewable Cost and Performance Assumptions

- The capital cost estimates for each renewable technology shown are regionalized using economic multipliers that account for labor and equipment cost differences across the U.S. The capital costs are also adjusted to account for interconnection costs as well as interest during construction within the model.

- Each of the cost and performance assumptions, with the exception of landfill gas, is derived from the assumptions used by DOE/EIA in their 2000 Annual Energy Outlook forecasts. Some of their assumptions have been modified slightly to match IPM's modeling structure and regions.

- Landfill gas assumptions are based on data provided from the EPA Landfill Methane Outreach Program as well as discussions ICF has had with industry professionals throughout the course of our work. As a mature technology, no incremental cost and performance improvements are assumed.

- All of the technologies listed above (except fuel cells) are considered carbon-neutral and will not contribute emissions toward a carbon cap.

Scenario Assumptions

RTO Policy Scenarios and Sensitivity Cases

<table>
<tr><td colspan="2">RTO Configuration</td><td>No RTOs; 32-region structure</td><td colspan="3">4 RTOs and ERCOT</td><td>2 RTOs and ERCOT</td><td>9 RTOs and ERCOT</td></tr>
<tr><th rowspan="2">Type of RTO-Related Economic Benefit</th><th rowspan="2">Specific Model Assumption</th><th rowspan="2">Base Case</th><th colspan="3">RTO Policy Scenarios</th><th colspan="2">Sensitivity Cases</th></tr>
<tr><th>Transmission Only</th><th>Transmission/ Generation</th><th>Demand Response</th><th>Sensitivity I: Larger RTOs</th><th>Sensitivity II: Smaller RTOs</th></tr>
<tr><td rowspan="4">Transmission</td><td>Reduced Inter-Regional Barriers to Trade</td><td>Base Case assumption</td><td colspan="5">No transmission hurdle rates within RTOs; hurdle rates converge to $2 per MWh between RTOs beginning in 2004</td></tr>
<tr><td>Transmission Capability Expansion</td><td>Base Case assumption</td><td colspan="5">Increased by 5% from 2004 onward</td></tr>
<tr><td>Capacity Sharing</td><td>75% of energy transfer capability</td><td colspan="5">100% of electricity transfer capability</td></tr>
<tr><td>Reserve Margins</td><td>Decline over time to system-wide average of 15% by 2020</td><td colspan="5">Decline over time to system-wide average of 13% by 2020</td></tr>
<tr><td>Generation</td><td>Efficiency Improvements</td><td colspan="2">Base Case assumption</td><td colspan="4">Fossil-fired Units: Heat rate improves by 6% by 2010 and availability increases by 2.5%</td></tr>
<tr><td>Demand Response</td><td>Demand Response</td><td colspan="3">Not analyzed</td><td>3.5% reduction in peak beginning in 2006</td><td colspan="2">Not analyzed</td></tr>
</table>

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Scenarios Capture Benefits as Stated in FERC Order No. 2000

- The scenarios developed for this study by FERC attempt to quantify the range of benefits described in Order No. 2000.

- The assumptions in the *Transmission Only Case* represent the first class of benefits outlined in Order No. 2000. These benefits reflect improvements to the management of the transmission infrastructure.

- The second class of benefits described in Order No. 2000 includes unit generation improvements brought about by increased competition and better flow of information within the power market. The *RTO Policy Case* incorporates these benefits in addition to those specified ion the *Transmission Only Case*.

- The *Demand Response Case* includes all of the assumptions described for the two cases above and adds improvements in customers' ability to react to price changes. A FERC Staff Paper in 2001 concluded that such improvements could result from advances in technology and practices currently under development.

- The scenarios are compared to a *Base Case* in the study that represents current estimates of underlying market conditions and regulatory policy under order No. 888.

- The following pages provide greater detail on the modeling of each of the scenario assumptions and the sources for those assumptions.

Transmission Only Case Assumptions

- The *Transmission Only Case* combines several transmission-related potential benefits into a single scenario.
- *Base Case* assumptions on transmission capability among regions are taken from the NERC 2000 Summer Assessment and 2000/2001 Winter Assessment. Where available, regional studies have been used to augment NERC data.
- Hurdle rates in the *Base Case* were developed through the calibration process described in Section 2.3.2 of the report. The hurdle rates ($ per MWh) are projected to decline at 2.5% per year until 2010 from which point they remain constant.
- *Base Case* reserve margin requirements are based on several sources, including NERC and state information.
- These assumptions serve as the bases for the changes assumed in the policy scenarios, as shown in the table below.

Transmission Transfer Capability Assumption

- In the policy scenarios, transmission transfer capabilities are increased by 5 percent with no additional costs.
- This is implemented as a one-time increase in the physical transfer limits in 2004.
- This assumption represents improvements in the operational management of the transmission system, as distinct from capital upgrades such as phase angle regulators or FACTS technology. Specifically, the Commission has stated that RTOs are expected to result in more accurate calculation of ATC and better management of congestion and parallel path flows.

Transmission Only Case Assumptions *(continued)*

Potential Benefit	Description	Timing	Regional Specificity	Source
Reduced Inter-Regional Barriers to Trade	Implicit hurdle rates WITHIN RTOs decline to $0 per MWH; Rates BETWEEN RTOs set at $2 per MWh	Fully implemented in 2004	Applied to all sub-RTO transmission links nationwide	Developed specifically for this analysis
Transmission Transfer Capability Expansion	Effective transfer capability of links WITHIN RTO increased at no cost by 5%; Capabilities BETWEEN RTOs not changed			Environmental Assessment for FERC Order No. 2000
Capacity Sharing	Capacity sharing WITHIN RTOs set equal to total energy transfer capability; Sharing BETWEEN RTOs not changed			Developed specifically for this analysis
Reserve Margins	Reserve margin requirements decline to system-average 13% (instead of 15%, as in Base Case)	Reserve margins decline linearly from 2004 values to 2020	Region-specific values; Decline applied to all RTO sub-regions	Modified from Environmental Impact Statement for FERC Order No. 888

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RTO Policy Case Generation Assumptions

- The *RTO Policy Case* incorporates all of the transmission-related potential benefits outlined above and adds cost and performance improvements for fossil-fired units.
- The *Base Case* includes unit-specific assumptions on heat rates and availability that serve as the basis for the changes described in the table below.

Potential Benefit	Description	Timing	Regional Specificity	Source
Heat Rate Improvement	Full-load heat rate decreases by 1% per year	Improvement from 2004 to 2010; constant thereafter	Applied to all fossil-fired units nationwide	Environmental Assessment for FERC Order No. 2000 ^
Fossil-fired Unit Availability Improvement	Availability for fossil-fired units increases by 2.5% in 2004 and remains at higher level through 2020	Fully implemented in 2004		Environmental Assessment for FERC Order No. 2000*

^ An annual average increase of 1% between 2004 and 2010 results in just over the 6% improvement used in the Environmental Assessment.
* The Environmental Assessment assumed an increase of 3% in availability. For the purpose of this study, the 3% increase was applied to unit seasonal availability. In cases for which the increase resulted in seasonal availabilities exceeding 100%, availability was limited to 100% for that season. Over the range of units and seasons, the resulting average availability increase was the 2.5% improvement reported here.

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Sources for Heat Rate Improvement Assumptions

- The heat rate improvements implemented to represent generator efficiency are based on previous work on competitive electric power markets.
- The specific 6% heat rate improvement used in this study was taken from the Environmental Assessment for FERC Order No. 2000. Similar assumptions were used in the Environmental Impact Statement for FERC Order No. 888 and the Department of Energy's Supporting Analysis for the Comprehensive Electricity Competition Act.
- The methodology supporting these heat rate improvement assumptions is based on best practice analysis, an analytic method often employed in engineering and corporate finance contexts. The approach relies upon statistical analysis of performance indicators.
- A complete report that documents the basis for the Department of Energy's heat rate improvement assumptions can be obtained from www.onlocationinc.com/hreport.htm. The report is titled Efficient Heat Rate Benchmarks for Coal-Fired Generating Units. The potential for heat rate improvement under competitive incentives is estimated to be 8% in this study.

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The End