Assumption Development Document:
Regional Greenhouse Gas Initiative Analysis

Prepared by:

ICF Consulting

For:

Regional Greenhouse Gas Initiative (RGGI)

Staff Working Group and Stakeholders

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Project Overview

Introduction and Goals of the Analysis

- NYSERDA, on behalf of the Regional Greenhouse Gas Initiative (RGGI) Staff Working Group (SWG) has commissioned ICF Consulting to evaluate the impacts of implementing a CO_2 cap on the electric power sector in the northeast and mid-Atlantic region.
- The analysis that will be produced will be driven by two key issues: the **Assumptions** used and **Scenarios** examined.
- Both the technical and market assumptions that serve as inputs to the modeling analysis as well as the policy scenarios evaluated have been developed by the RGGI SWG, and are the sole responsibility of the SWG.
- The assumptions developed by the SWG contained in this document have been used by ICF in it's Integrated Planning Model® (IPM®) to analyze the policies specified by the SWG.
- This document provides an overview of the technical and market assumptions used for this analysis, together with documentation of the data sets that the SWG has chosen to use.
- This document serves as the final assumptions document that contains all of the assumptions decided upon by the SWG for the Reference Case power sector analysis that has been conducted in the course of the RGGI process.

Purpose of this Assumptions Document

- The assumptions document serves two purposes:

- **Introduce the structure and capabilities of the IPM® model.** This document provides an overview of IPM®. It is broken out in sections discussing treatment of the elements of the electric power system within the model. Each element is defined first in terms of its role in the modeling system and then in terms of datasets that are used in the analysis.

- **Provide a framework to document the required assumptions.** This document contains datasets from the sources for regional- and market-level assumptions that have been used in the analysis. For a study of this type, both regulatory policies and economic/technical assumptions must be defined.

  – Regulatory policy assumptions/specifications have been developed by the Staff Working Group.

  – Sources for economic and technical assumptions presented in this document include the Energy Information Administration's Annual Energy Outlook 2005, the regional Independent System Operators (ISOs), the US EPA, and others . The Staff Working Group has reviewed and selected the sets of assumptions it feels most comfortable with.

- This assumptions document presented the complete assumptions set that has been adopted by Staff Working Group assumptions.

Scenario Specification

The Challenge of Forecasting

- Part of the nature of forecasting is the need to address inherently uncertain issues that have definitive impacts on the future operation of the power system.
- No forecast is going to be "right" due to the fact that no one has a crystal ball regarding many of the key underlying issues, but it is extremely useful in determining directionality and cause and effect.
- Policy analysis requires two things:
  - A Reference Case on which to base comparisons; and
  - Scenarios that examine the impact of changing policy, technical and market parameters.
- The purpose of a Reference Case is twofold: 1) to understand system operations under existing – or expected – regulations and 2) to establish points of comparison for policy analysis.
- When comparing policy/technology/market scenarios to the Reference Case, the goal should be to understand the impacts of the variables being examined. In order to understand what changes are being driven by, it is often best to change one thing at a time (isolate the variables).

Establishing a Reference Case (in RGGI Context)

- “Middle-of-the-road” estimate of what the future might look like in the absence of a carbon cap-and-trade program, against which to compare the results of scenarios that contain various carbon policies.

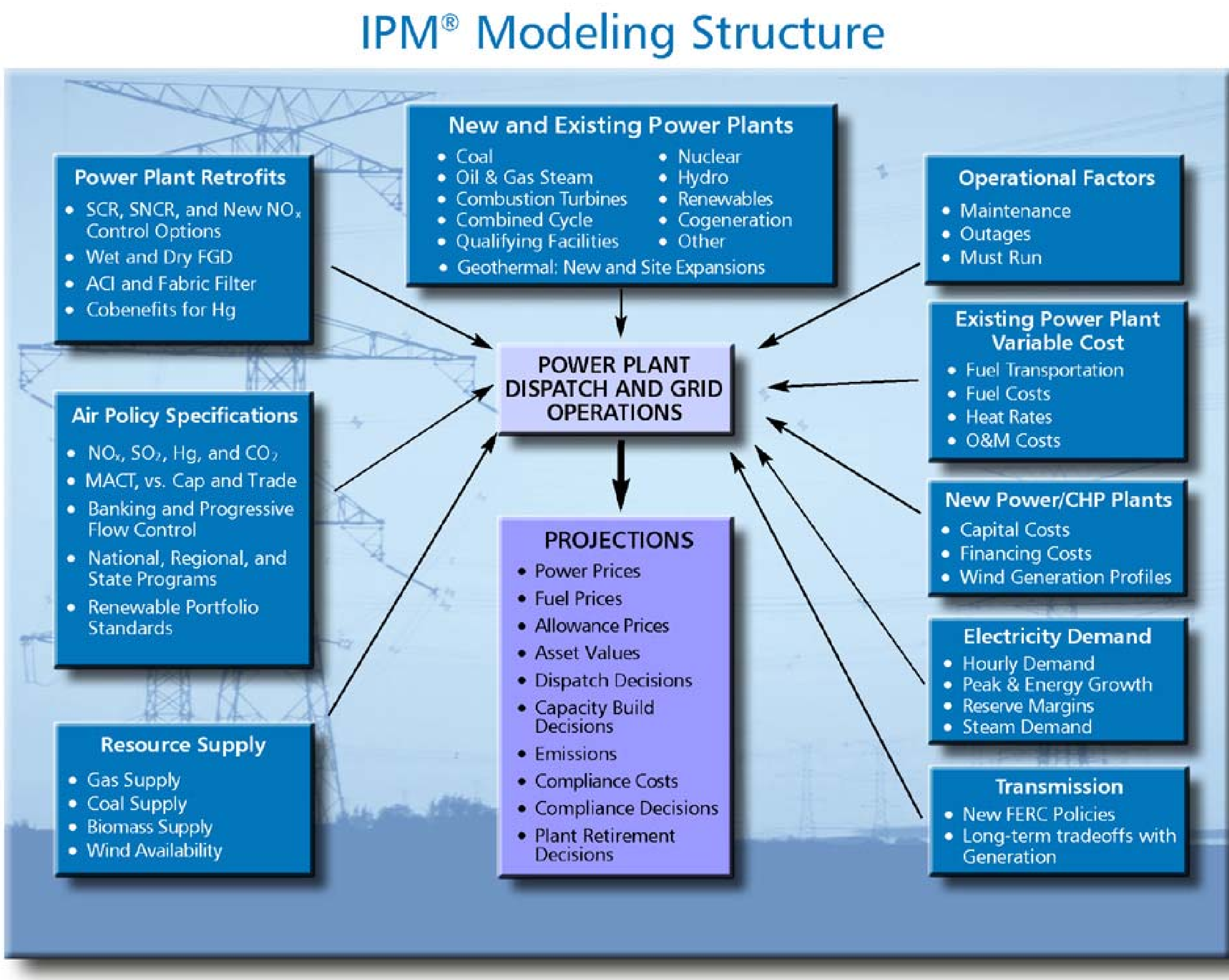
- Not a “prediction” of the future, but rather a moderate/reasonable/ plausible/ believable expectation or “best guess” for analytical purposes.

- Includes existing policies, as well as those judged to be “reasonably certain or expected.” Defined to include renewable portfolio standard (RPS) programs, state regulations, and federal 3-P.

- Based on current energy and environmental regulatory climate and public opinion; includes no new regulatory outcomes on either extreme that may or may not occur as a result of future debate on controversial issues.

Analytic Approach and IPM® Overview

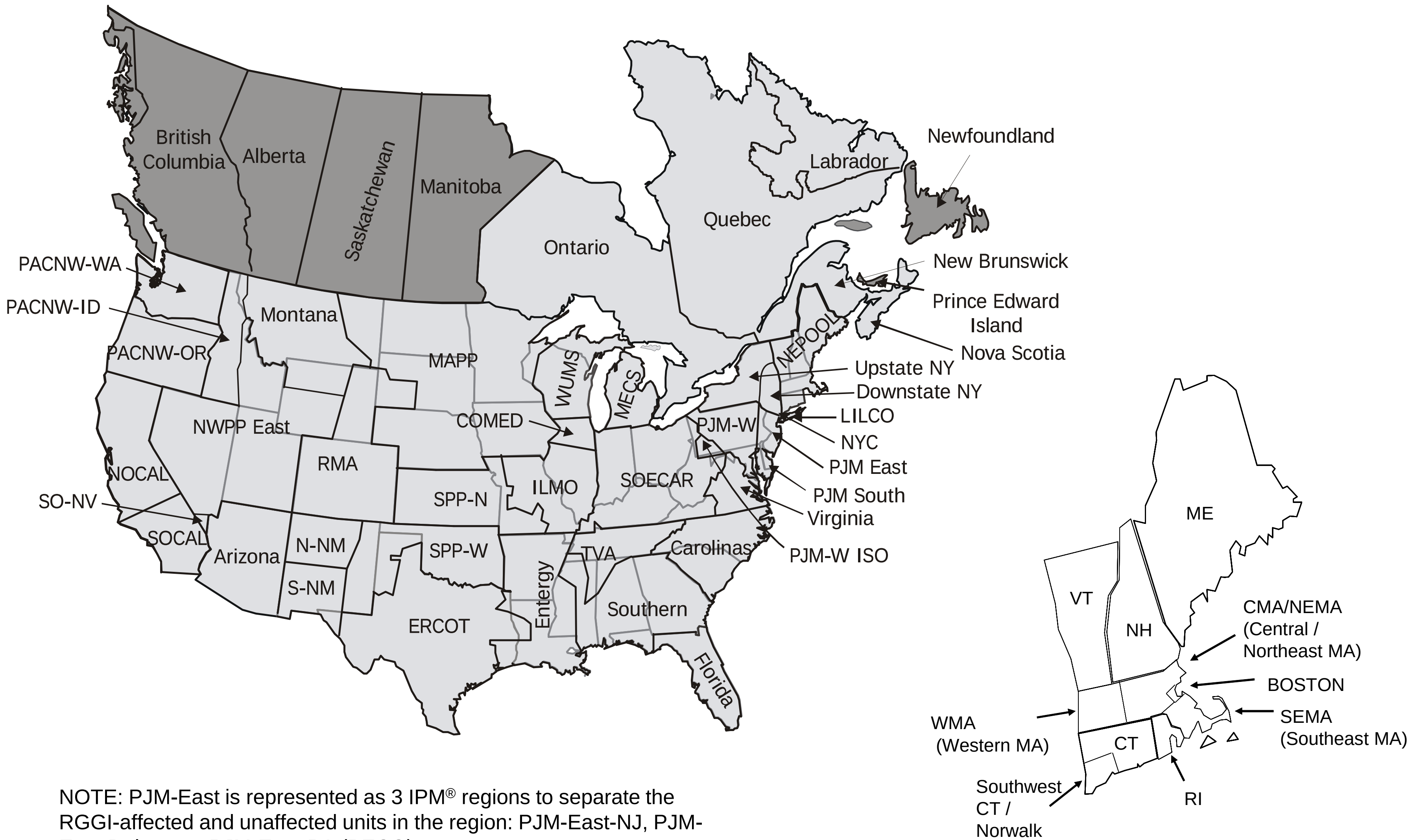
IPM® Analytic Framework



The IPM® Modeling Framework

- The Integrated Planning Model (IPM®) was used to analyze the impacts of environmental policies on allowance markets, electric markets and compliance decisions.
- 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 air 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 Henry Hub supply curve and regional and seasonal delivery adders.

IPM® North America



NOTE: PJM-East is represented as 3 IPM® regions to separate the RGGI-affected and unaffected units in the region: PJM-East-NJ, PJM-East-Delmarva, PJM-East-PA (PECO).

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Key Features of IPM®

- ICF uses a national version of IPM® specifically designed for simulating the effect of environmental regulations in the electricity sector.
- For this analysis, IPM® North America included a representation of at least 40 power market regions (depending on the final Northeast representation), including 10 New England regions, 5 New York regions, and 5 Canadian regions.
- IPM® explicitly models transmission links between those regions.
- The model includes endogenous pricing of coal supply, coal transportation and gas supply costs.
- The national model determines the least cost means of complying with the specified air pollution regulations:
  - Multiple environmental compliance requirements are evaluated simultaneously - e.g., SO_2 , NO_X, CO_2, Hg.
  - Determines optimal compliance for the system from a comprehensive range of choices including: new investment in capacity and/or pollution controls, fuel switching, repowering, retirement, and dispatch adjustments.

The IPM® Optimization Process

- IPM® combines peak power demand, total energy demand, and hourly load profiles to create load duration curves for each season and region.
- To meet demand, IPM® selects units to create a stack of generators dispatched by variable cost, subject to availability and other operating constraints. The last unit to be dispatched (i.e., the unit with the highest variable costs to operate) is the marginal unit and sets the energy price for that demand period.
- IPM® will choose to endogenously bring to market new capacity where it is economically feasible, in order to minimize the *present value* costs over the lifetime of the forecast period. For example, saving 1$ in 2003 is equivalent to saving $1.60 in 2010, assuming a 7% discount rate.
- All costs are prices in IPM® are represented in real 2003 dollars.

Run Years and Model Size

- The high level of detail in national IPM® creates computing limitations on the overall size of the run. As a part of any modeling project, IPM® must be scoped to provide maximum resolution on the areas of interest to the client.

- Various elements affect model size, but the most crucial is the number of ***run years***. A run year is a calendar year chosen to represent a single year or a group of years that face similar electric and fuel markets and environmental policies. An IPM® run is generally limited to generating results for a maximum of 6 run years.

- Because it impacts future revenue streams for generators, an updating allowance allocation mechanism requires that run years be assigned as blocks of a fixed number of calendar years, with that number corresponding to the number of years used to determine the updating allocations.

- To incorporate the flexibility to run an updating allocation scenario for CO_2 and to maintain the same reporting years across all scenarios and sensitivities, the run year schedule on the following slide will be adopted for the RGGI analysis.
  - This schedule accommodates a 3-year updating mechanism, meaning that the average generation over each 3-year block of years will be used to determine the allocation in the following 3-year block.

- Due to the requirement to run the model in 3-year blocks, the start dates for some policies may need to be shifted up or back one year. The national 3-pollutant policy, for example, will be assumed to start in 2011 rather than in 2010.
  - Second phase cap adjustments, such as those for the 3-pollutant policy, are handled by averaging the caps over the calendar years covered by the 3-year run year block. So, that national NO_X cap in the 2015 run year will be equivalent to one times the Phase I annual cap in 2014 plus 2 times the Phase II annual cap in 2015 (to represent the 2015 and 2016 caps), averaged over the 3 years.

Run Years and Model Size
continued

Calendar Year	Run/Reporting Year	Policies to Begin in Run Year
2005 2006 2007	2006	New York and New England state regulations, where appropriate; Northern and Southern Tier RPSs
2008 2009 2010	2009	NJ MACT constraint
2011 2012 2013	2012	National 3-pollutant -- Phase I SO_2, NO_X, Hg
2014 2015 2016	2015	National 3-pollutant -- Phase II SO_2, NO_X
2017 2018 2019	2018	National 3-pollutant -- Phase II Hg
2020 2021 2022	2021	

Air Regulatory Compliance in IPM®

- IPM® incorporates constraints on emissions of NO_X, SO_2, mercury, and CO_2 into its optimization process. Constraints are specified on the basis of target-rates, cap-and-trade policies, $/ton emitted tariffs, or command-and-control policies, and applied to individual generating units or groups of units.

- Units subject to constraints have a variety of compliance options:

  1) **Reduce Running Regime**. In order to comply with non-command-and-control polices, a unit can limit its operational hours to more lucrative non-baseload segments.

  2) **Fuel Switch**. In the case of SO_2 regulations, coal and oil units can choose to burn more costly low sulfur fuels.

  3) **Retrofit**. For the three current criteria pollutants (NO_X, SO_2, and mercury), a variety of retrofit technologies are available to reduce emissions. In the case of CO_2, ICF will also model potential carbon capture-and-sequestration technologies. The cost and performance assumptions of all retrofit technologies are detailed in the *Emissions Controls* section below.

  4) **Retire**. As with the unconstrained model, if a unit cannot cover its operating costs going forward, it is allowed to retire.

- Note that units can also comply using any combination of the first three options.

Air Regulatory Treatment in IPM®

- IPM® applies air emissions regulations to various classes of fossil fuel-fired generators. Regulations can vary by pollutant, structure, scope (geographic and technological), timing, and stringency. Several regulations may affect the same geographic area and, therefore, the same units.

- The most common among these regulations are of the **cap-and-trade** type structure. Under a cap-and-trade policy, a group of units must collectively reduce their emissions to a mandated region-wide cap. For every ton of emissions up to the cap level there is a corresponding emissions allowance that can be bought or sold among affected units. Each generator complies with the program by reducing its emissions or buying allowances at the market rate, depending on the relative economics it faces. These Include the NO_X SIP Call trading program and the CAAA Title IV SO_2 trading program.

- The other most prominent type of control policy is the **Maximum Achievable Control Technology (MACT)**. A MACT policy requires each generator (or sometimes power plant) to control its emissions to a certain guaranteed standard rate OR install a specified control technology. The federal government is currently working on a possible MACT standard to control mercury.

- IPM® can simultaneously apply a number of existing and potential future regulations restricting emissions of a variety of pollutants, including CO_2.

Assumptions

Market, Technical and Policy Assumptions

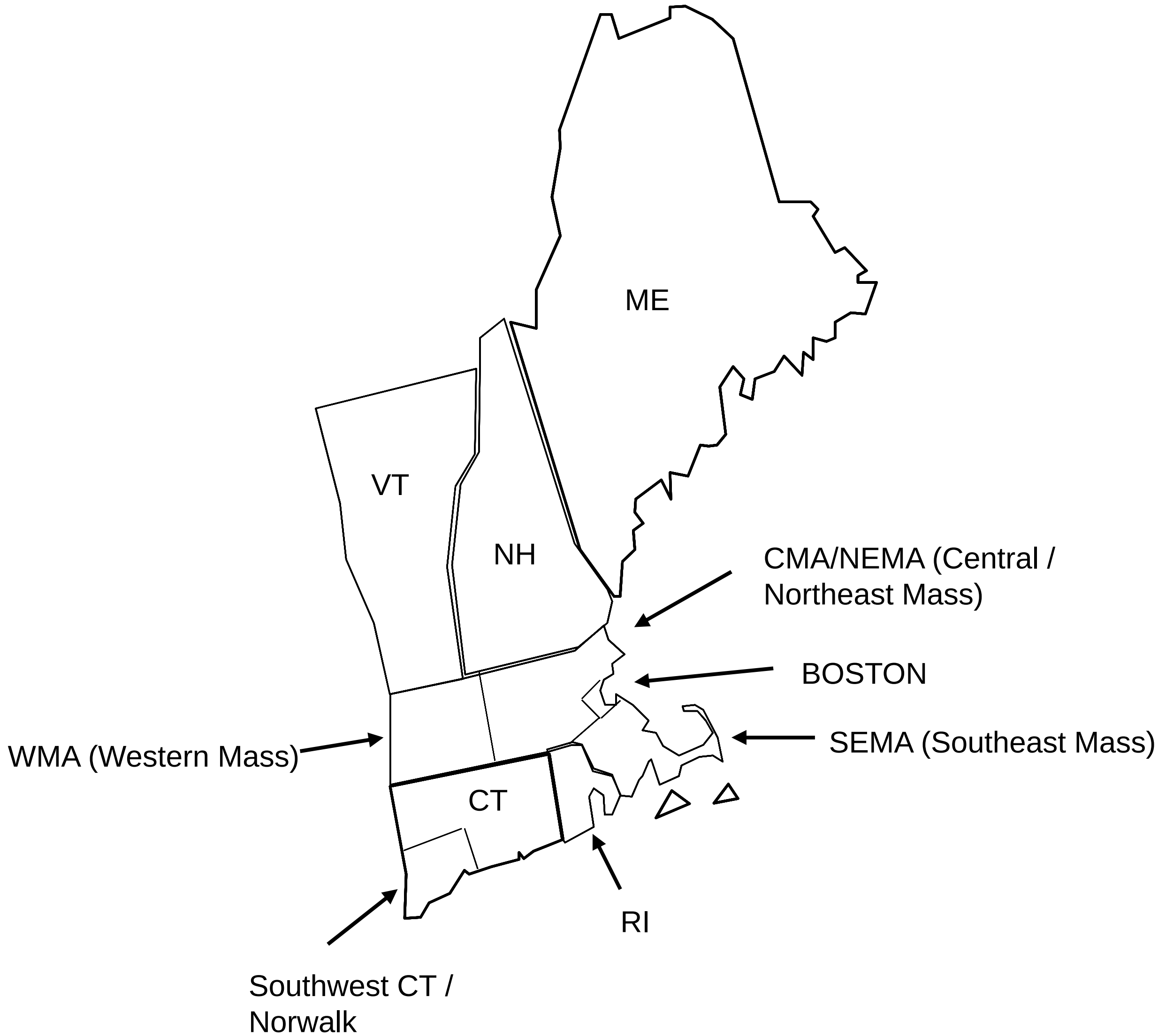
Status of Assumptions Development

Assumption	Proposed Data Source					Status of Assumptions Development
	AEO (EIA)	EPA	ICF	ISOs/ States	Other	
Market Assumptions						
National Electricity and Peak Demand	X					Complete
Regional Electricity and Demand Breakout				X		Complete
Gas Supply and Price Forecast (wellhead and regional)	X	X			X	Complete
Oil Price Forecast	X				X	Complete
Coal Supply and Price Forecast	X		X			Complete
Financial Assumptions					X	Complete
Technical Assumptions						
Firmly Planned Capacity Additions				X		Complete
New Conventional Capacity Cost and Performance	X				X	Complete
New Conventional Capacity Emissions Profiles	X				X	Complete
Pollution Control Retrofit Cost and Performance	X	X				Complete
Renewable Power Technology Cost and Performance					X	Complete
Renewable Power Resource Availability and Cost					X	Complete
Nuclear Unit Relicensing and Uprate Assumptions		X (Rel.)			X (Up.)	Complete
Existing Transmission Total Transfer Capabilities				X		Complete
RTO Structure & Transmission Tariffs				X		Complete
Policy Assumptions						
Renewable Portfolio Standards				X	X	Complete
3-pollutant Federal Program Specification					X	Complete

Market Assumptions

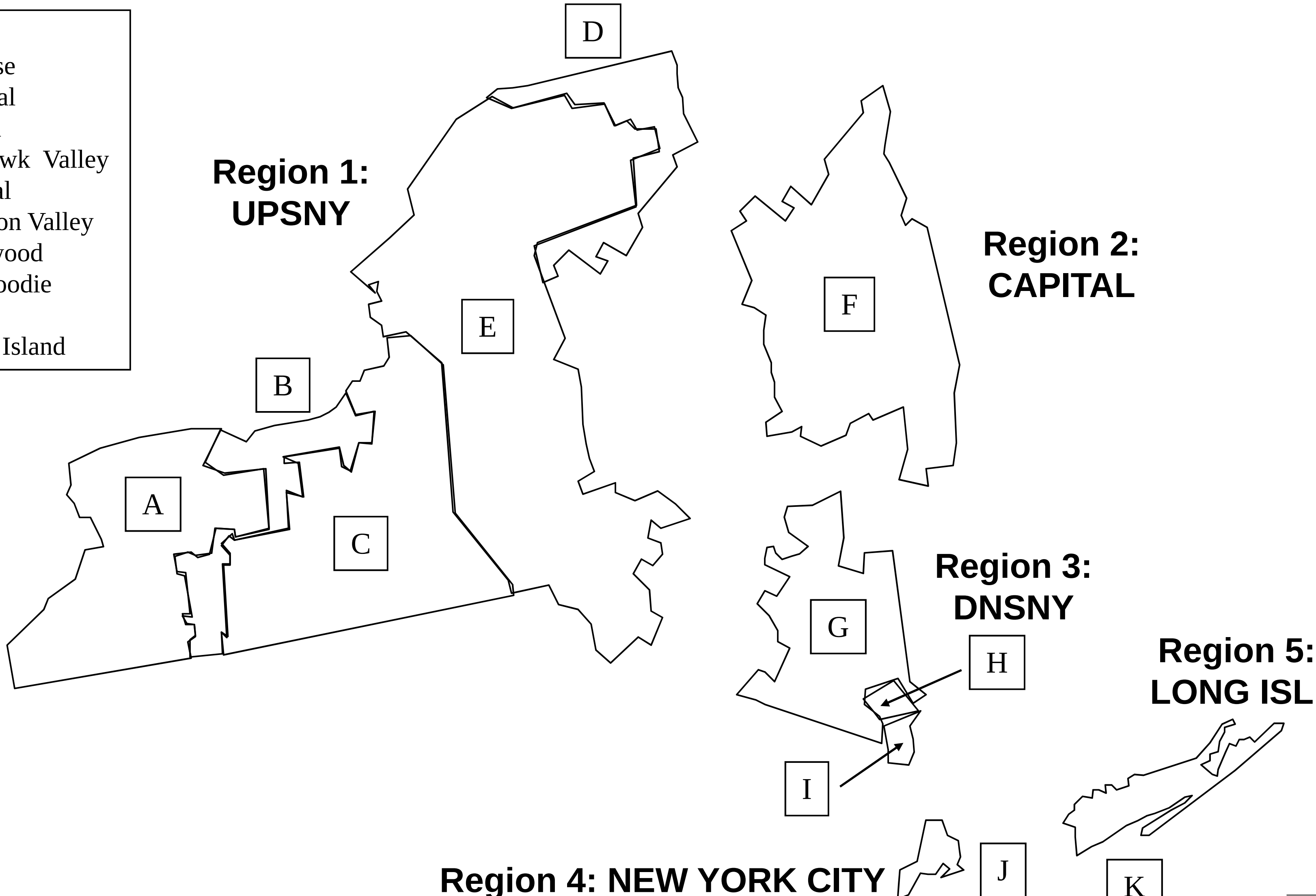
Electricity Demand

IPM® New England – 10 Model Regions Based on ISO-NE RTEP Definitions



IPM® Regional Breakdown of the New York

A – West
B – Genese
C – Central
D – North
E – Mohawk Valley
F – Capital
G – Hudson Valley
H – Millwood
I – Dunwoodie
J – NYC
K – Long Island



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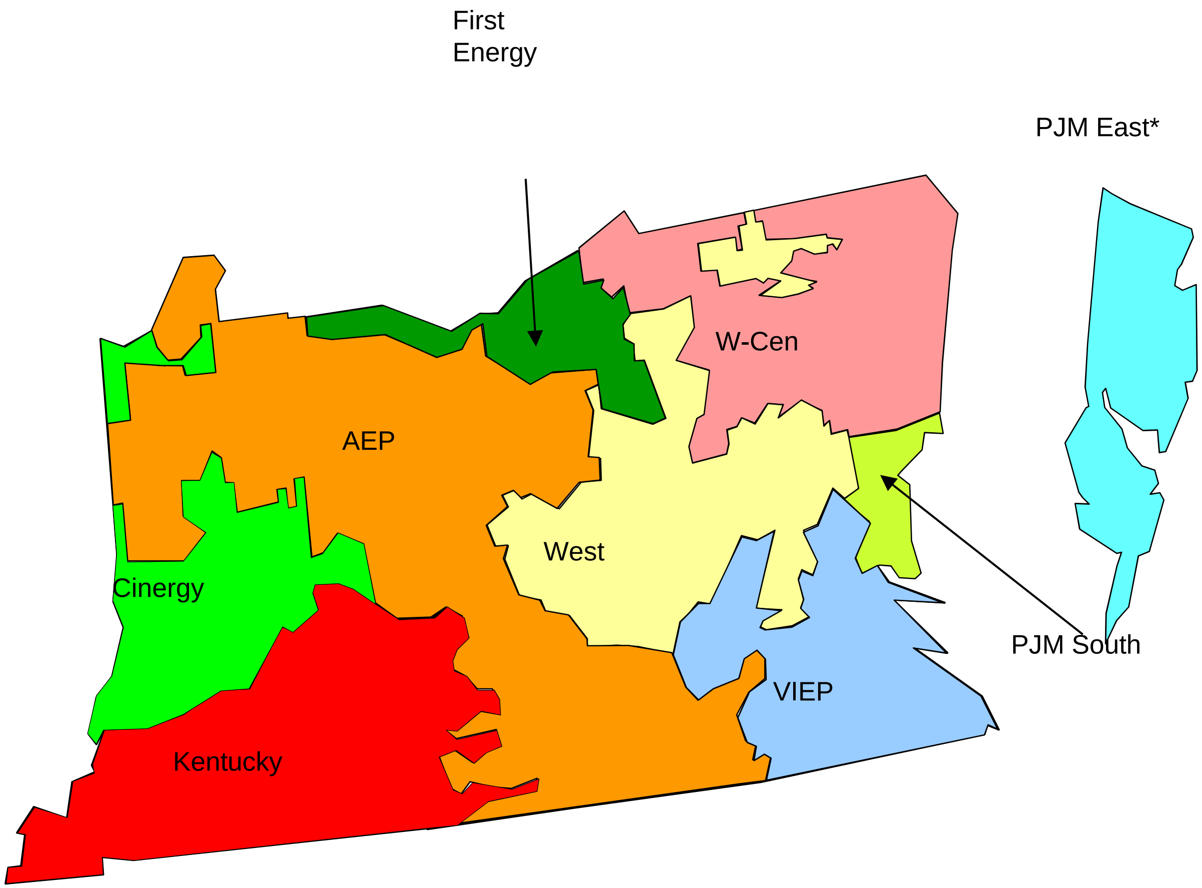
IPM® Breakdown of PJM and Neighboring Regions



* PJM-East is represented as 3 IPM® regions to separate the RGGI-affected and unaffected units in the region: PJM-East-NJ, PJM-East-Delmarva, PJM-East-PA (PECO)

Demand in IPM®

- Demand is represented in IPM® by a combination of the following variables:
  - **Model Demand Regions** – The geographic level at which demand and supply are equilibrated to determine dispatch and prices. Each demand region acts as a power pool with a supply stack of units and a market clearing price. The proposed regional break-out for the RGGI-affected region is shown above.
  - **Peak Demand** – The maximum power load (MW) requirement for a demand region, defined by the top Demand Segment of each Season.
  - **Energy Demand** – The total energy requirement (MWh) for a demand region, defined annually.
  - **Hourly Load Profiles** – The 24-hour shape of demand level, defined for 8760 hours of a base year, for each demand region, scaled to meet peak and energy demand. Hourly load files are created from the historical load data filed by each region's utilities (FERC Form 714) for a weather normal year.
  - **Seasons and Segments** – IPM® maps annual demand, defined by hourly load profiles scaled to peak and energy demand, then breaks it into seasonal loads, defined by month. Seasonal load is further subdivided by segment. IPM® creates a dispatch stack and solves for the market clearing-price for each segment of each season in each region for each year -- 5 segments, 2 seasons, 40+ regions, and 6 “run” years will be modeled for this analysis.

Reserve Margin Assumptions

- To maintain system stability and reliability, each IPM® demand region must make sure a certain amount of backup capacity is available relative to its projected peak demand. This capacity level is known as the reserve margin requirement. It is defined by a percentage of the annual peak demand.
- Demand regions can meet their internal reserve margin requirements through either native supply, power imports from adjacent regions (where transmission capacity is available), or any combination of the two.
  - Note that the locational capacity requirements for New York City (80%) and LIPA (99%) will be imposed for this analysis.
- The NYISO capacity demand curve structure will not be integrated into this analysis.
  - Given the focus of the RGGI analysis on mid- to long-term CO_2 emissions and regulations, the demand curve is not assumed to be a critical driver in the modelled outcomes.
- Because of the uncertainties facing future electric markets, including the addition of intermittent renewable capacity to the mix, growing reliance on gas, etc., the following reserve margin requirements are assumed to remain constant throughout the study period:
  - New York: 18%
  - ISO-NE: 16%
  - PJM: 15%
- The requirements and the assumption to hold them constant were developed with the respective ISOs.

Demand and Reserve Margin Assumptions for the RGGI Analysis

- The datasets chosen by the SWG for this analysis focus on the Northeast/Mid-Atlantic region that will fall under or be directly impacted by a RGGI CO_2 policy, as consistent with the currently proposed geographic scope.
- Because IPM® is a national model however, similar datasets must be developed for all regions in the North American system, including the Canadian regions, that are consistent with those used for the focus region.
- Fuel and energy market interactions as represented in IPM® will allow behavior in the RGGI-affected regions to impact energy markets well outside the Northeast and vice-versa. Therefore, demand growth assumptions that are wholly different in the RGGI region than they are outside the RGGI region could lead to unrealistic projections.
  - For this reason, demand assumptions used in the RGGI regions, as taken from EIA, the relevant ISOs, or other sources, should be consistent with the growth projections to be used in the remainder of the country.
- The SWG Modeling Subgroup has chosen to use ISO projections for the RGGI regions and EIA projections from AEO 2004 for the rest of the country. The following slides show the ISO projections for the RGGI-affected regions.
  - Because the ISOs projections do not extend past 2013 (2014 for PJM), EIA's long-term projected growth rates, scaled to be consistent with near-term ISO growth rates, will be applied to extend the projections through the time horizon of this analysis.
  - The resulting scaled long-term growth rates are shown in the following slides, along with the load projections.

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New York Demand Forecasts by IPM® Region

New York IPM Regions - Average Annual Growth Rates						
Year	Zones A-E	Zone F	Zone G-I	Zone J	Zone K	EIA (for ISO)
2005-2013	0.33%	0.36%	1.21%	1.51%	1.26%	1.43%
2014-2025	0.16%	0.17%	0.57%	0.71%	0.59%	0.67%

Forecasted Energy Demand (GWh)					
Year	Zones A-E	Zone F	Zone G-I	Zone J	Zone K
2005	58,964	11,892	19,908	54,456	22,783
2006	59,444	11,954	20,307	55,757	23,175
2007	59,852	12,007	20,673	56,991	23,576
2008	60,089	12,066	20,941	57,919	23,939
2009	60,150	12,080	21,131	58,651	24,104
2010	60,405	12,152	21,383	59,484	24,407
2011	60,579	12,213	21,601	60,221	24,680
2012	60,495	12,213	21,737	60,710	24,967
2013	60,544	12,243	21,919	61,375	25,176
2014	60,638	12,264	22,044	61,809	25,325
2015	60,732	12,285	22,169	62,247	25,474
2016	60,827	12,306	22,295	62,687	25,624
2017	60,922	12,327	22,422	63,131	25,776
2018	61,016	12,348	22,549	63,578	25,928
2019	61,111	12,369	22,677	64,028	26,081
2020	61,206	12,390	22,806	64,481	26,235
2021	61,302	12,412	22,936	64,937	26,390
2022	61,397	12,433	23,066	65,397	26,545
2023	61,492	12,454	23,198	65,859	26,702
2024	61,588	12,475	23,329	66,325	26,860
2025	61,684	12,497	23,462	66,795	27,018

Source: NYISO "2004 Load and Capacity Data" – Gold Book

EIA growth rate provided as point of reference only

New England Demand Forecasts by IPM® Region

New England IPM Regions - Average Annual Growth Rates											
Year	**ME**	**NH**	**VT**	**Boston**	**Central MA**	**Western MA**	**SE MA**	**RI**	**Central CT**	**SW CT**	**EIA (for ISO)**
2005-2013	1.13%	1.76%	1.29%	1.10%	1.01%	1.11%	0.92%	1.26%	1.13%	1.24%	1.55%
2014-2025	0.96%	1.49%	1.09%	0.93%	0.85%	0.93%	0.78%	1.06%	0.95%	1.05%	1.31%

Forecasted Energy Demand (GWh)										
Year	**ME**	**NH**	**VT**	**Boston**	**Central MA**	**Western MA**	**SE MA**	**RI**	**Central CT**	**SW CT**
2005	11,950	8,810	7,470	26,625	8,570	10,760	12,900	11,500	17,040	17,155
2006	12,035	8,960	7,545	26,925	8,645	10,880	12,995	11,640	17,205	17,365
2007	12,125	9,105	7,635	27,210	8,720	11,000	13,085	11,790	17,320	17,520
2008	12,275	9,260	7,730	27,500	8,790	11,120	13,180	11,935	17,480	17,715
2009	12,420	9,415	7,820	27,810	8,865	11,240	13,280	12,100	17,660	17,940
2010	12,555	9,580	7,920	28,135	8,975	11,375	13,435	12,260	17,880	18,165
2011	12,725	9,750	8,025	28,490	9,090	11,520	13,610	12,440	18,150	18,440
2012	12,910	9,950	8,155	28,795	9,195	11,640	13,750	12,585	18,415	18,710
2013	13,075	10,130	8,275	29,070	9,285	11,750	13,880	12,710	18,640	18,935
2014	13,200	10,281	8,365	29,341	9,364	11,860	13,988	12,845	18,818	19,134
2015	13,326	10,434	8,456	29,615	9,444	11,971	14,096	12,982	18,997	19,334
2016	13,453	10,589	8,548	29,891	9,524	12,083	14,206	13,120	19,178	19,537
2017	13,582	10,746	8,641	30,170	9,605	12,195	14,316	13,259	19,361	19,742
2018	13,712	10,906	8,735	30,451	9,687	12,309	14,427	13,400	19,545	19,949
2019	13,843	11,068	8,830	30,735	9,769	12,424	14,540	13,542	19,732	20,158
2020	13,975	11,233	8,926	31,022	9,852	12,541	14,652	13,686	19,920	20,370
2021	14,108	11,400	9,023	31,311	9,936	12,658	14,766	13,832	20,109	20,583
2022	14,243	11,569	9,121	31,604	10,020	12,776	14,881	13,979	20,301	20,799
2023	14,379	11,741	9,220	31,898	10,105	12,895	14,997	14,128	20,494	21,017
2024	14,517	11,916	9,321	32,196	10,191	13,016	15,113	14,278	20,690	21,238
2025	14,655	12,093	9,422	32,496	10,278	13,138	15,230	14,429	20,887	21,461

Source: ISO-NE Forecast Report of Capacity, Energy, Loads and Transmission (CELT) 2004 - 2013

EIA growth rate provided as point of reference only

PJM Demand Forecasts by IPM® Region

PJM - Average Annual Growth Rates							
Year	PECO	New Jersey	Delmarva	MD/DC	Central PA	Allegheny	EIA (for Mid-A)
2005-2014	1.03%	1.39%	2.00%	1.73%	1.53%	1.01%	1.70%
2015-2030	0.74%	1.04%	1.44%	1.26%	1.11%	0.72%	1.22%

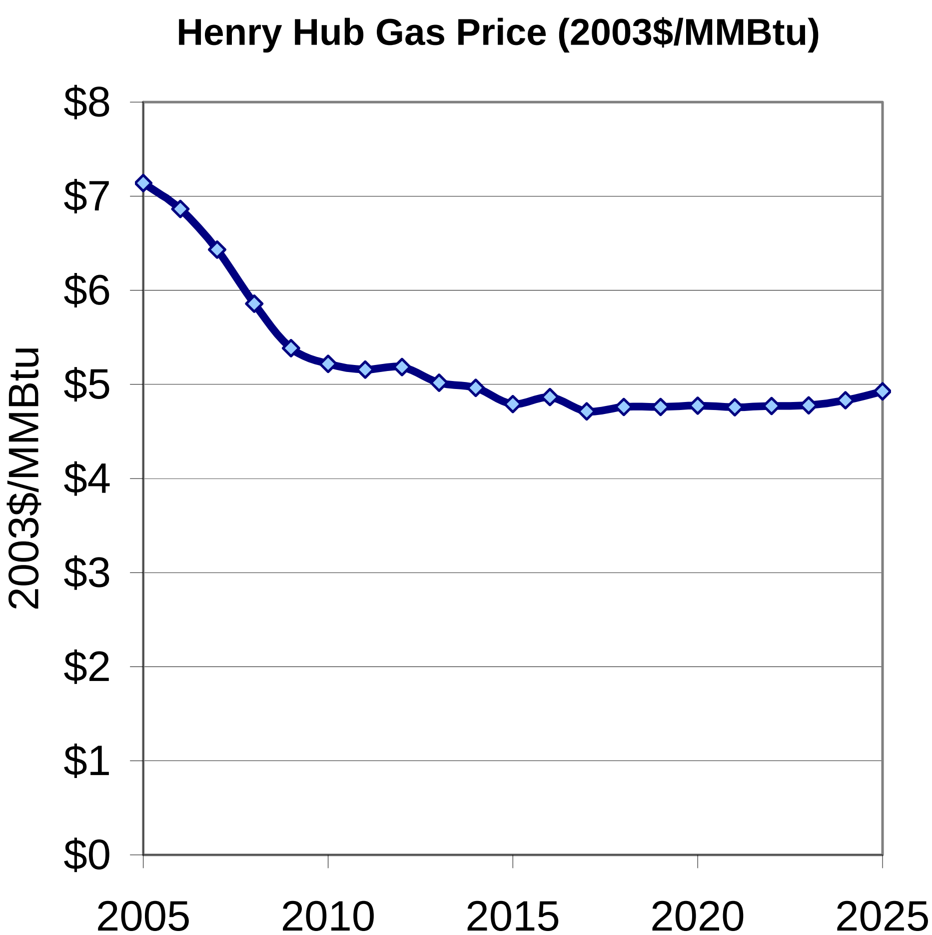
PJM - Forecasted Energy Demand (GWh)						
Year	PECO	New Jersey	Delmarva	MD/DC	Central PA	Allegheny
2004	39,495	82,524	18,486	65,756	73,272	51,365
2005	39,778	83,644	18,905	66,950	74,567	51,948
2006	40,176	84,971	19,329	68,128	75,857	52,622
2007	40,579	86,238	19,767	69,308	77,126	53,181
2008	41,088	87,687	20,217	70,496	78,344	53,887
2009	41,393	88,808	20,705	71,717	79,569	53,950
2010	41,811	90,112	21,157	72,958	80,815	54,453
2011	42,227	91,336	21,609	74,219	82,029	55,056
2012	42,751	92,700	21,937	75,507	83,193	55,864
2013	43,179	93,930	22,265	76,818	84,346	56,348
2014	43,610	94,669	22,593	78,155	85,511	56,844
2015	43,932	95,631	22,918	79,136	86,455	57,255
2016	44,257	96,605	23,248	80,130	87,410	57,669
2017	44,584	97,591	23,582	81,137	88,376	58,086
2018	44,913	98,591	23,921	82,158	89,352	58,507
2019	45,245	99,603	24,265	83,193	90,339	58,930
2020	45,579	100,629	24,614	84,241	91,338	59,356
2021	45,916	101,668	24,968	85,304	92,348	59,785
2022	46,255	102,721	25,327	86,381	93,369	60,218
2023	46,596	103,787	25,692	87,473	94,401	60,653
2024	46,941	104,868	26,061	88,580	95,446	61,092
2025	47,287	105,962	26,436	89,701	96,502	61,534

Source: PJM “2004 PJM Load Forecast Report”, Table C-1

EIA growth rate provided as point of reference only

Fuel Supply

Reference Case Natural Gas Price Forecast



- The State Working Group has adopted a gas price trajectory phasing from a 3-year moving trend of EEA's trajectory in the near to mid-term to a long-term EIA trajectory.
- To be consistent with the proposed oil price trajectory (discussed next), the EEA trend phases into an average of EIA's natural gas projections under its AEO 2005 Reference and High Oil cases.
- These commodity prices are converted into delivered prices on the following slide, based on EPA seasonal and regional transportation adders.
  - These adders are for the Reference Case(s).
  - The adders are not assumed to change over time.

Delivered Natural Gas Prices to RGGI Regions

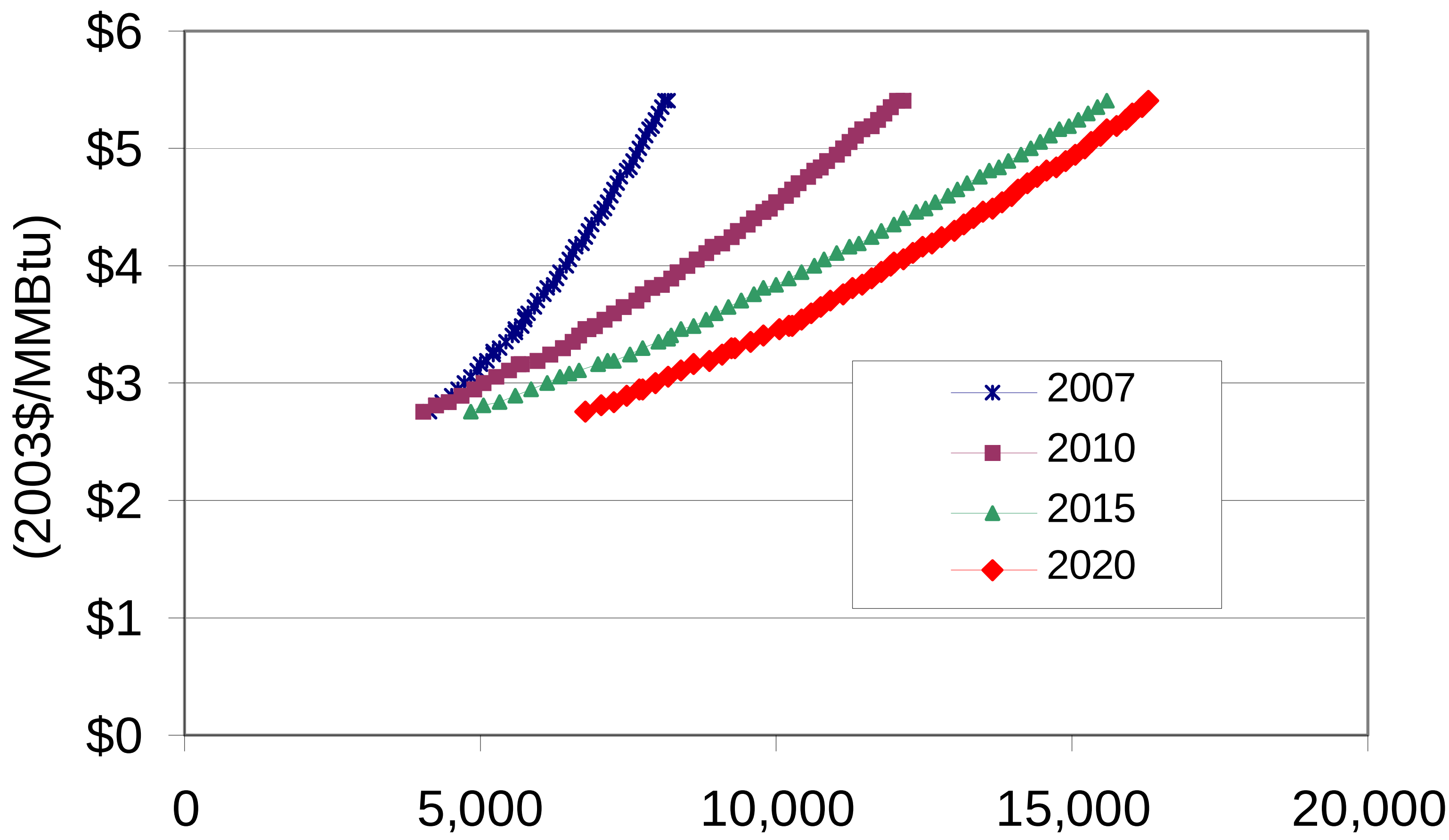
(2003$/MMBtu, Based on RGGI Year 2010 Henry Hub with EPA Base Case v.2.1.6 Transportation and Seasonality Adders)

Region	2010 Henry Hub Price (from RGGI Trajectory)	EPA Base Case Transportation Adder	EPA Base Case Seasonal Adders		Delivered Price to IPM® Region	
			Winter	Summer	Winter	Summer
APS-DUQ						
APS-DUQ	5.22	0.39	0.06	-0.08	5.67	5.53
PJM - EAST						
PJM-E	5.22	0.34	0.06	-0.08	5.62	5.48
PJM - WEST						
PJM-W	5.22	0.39	0.06	-0.08	5.67	5.53
PJM - SOUTH						
PJM-S	5.22	0.34	0.05	-0.07	5.61	5.49
New York						
Zones A thru E	5.22	0.19	0.04	-0.06	5.45	5.34
Zone F	5.22	0.19	0.04	-0.06	5.45	5.34
Zones G thru I	5.22	0.35	0.08	-0.08	5.65	5.49
Zone J (New York City)	5.22	0.71	0.08	-0.11	6.02	5.82
Zone K (Long Island)	5.22	0.43	0.10	-0.11	5.76	5.54
NEPOOL						
Southwest Connecticut/Norwalk	5.22	0.39	0.08	-0.08	5.70	5.53
Other Connecticut	5.22	0.39	0.08	-0.08	5.70	5.53
Rhode Island	5.22	0.39	0.08	-0.08	5.70	5.53
Southeastern Massachusetts	5.22	0.39	0.08	-0.08	5.70	5.53
Western Massachusetts	5.22	0.39	0.08	-0.08	5.70	5.53
Boston	5.22	0.39	0.08	-0.08	5.70	5.53
Central and Northeastern Massachusetts	5.22	0.39	0.08	-0.08	5.70	5.53
Vermont	5.22	0.39	0.08	-0.08	5.70	5.53
New Hampshire	5.22	0.39	0.08	-0.08	5.70	5.53
Maine	5.22	0.39	0.08	-0.08	5.70	5.53

EPA Gas Supply Curves

- The ability to model natural gas price sensitivity to growing demand for gas is critical to reasonable analysis of an electric sector carbon cap.
- EPA developed natural gas supply curves for use in its IPM® modeling. The curves (shown on the following page) specify annual price-volume relationships at Henry Hub wellhead and are documented on EPA's IPM® website.
  - The curves were developed based on analysis using ICF's North American Natural gas Assessment System (NANGAS) model in conjunction with electric sector gas demand generated in IPM®.
- This curve structure will capture within IPM® shifts in the commodity price resulting from changes to the supply and demand of gas brought about by environmental regulation.
- The EPA curves as shown, however, are likely not consistent with the price-volume relationship realized in EEA or AEO 2005. To simulate curves for this analysis based on the RGGI gas price trajectory, the slope of the EPA curves will be applied to the RGGI price projection.
  - The combination of the EPA curves and RGGI price projection will be made based on gas consumption results from the Reference Case for this analysis. Using this method, curves are developed that are internally consistent with the market and technical assumptions used in this analysis.

EPA Gas Supply Curves (2003$)

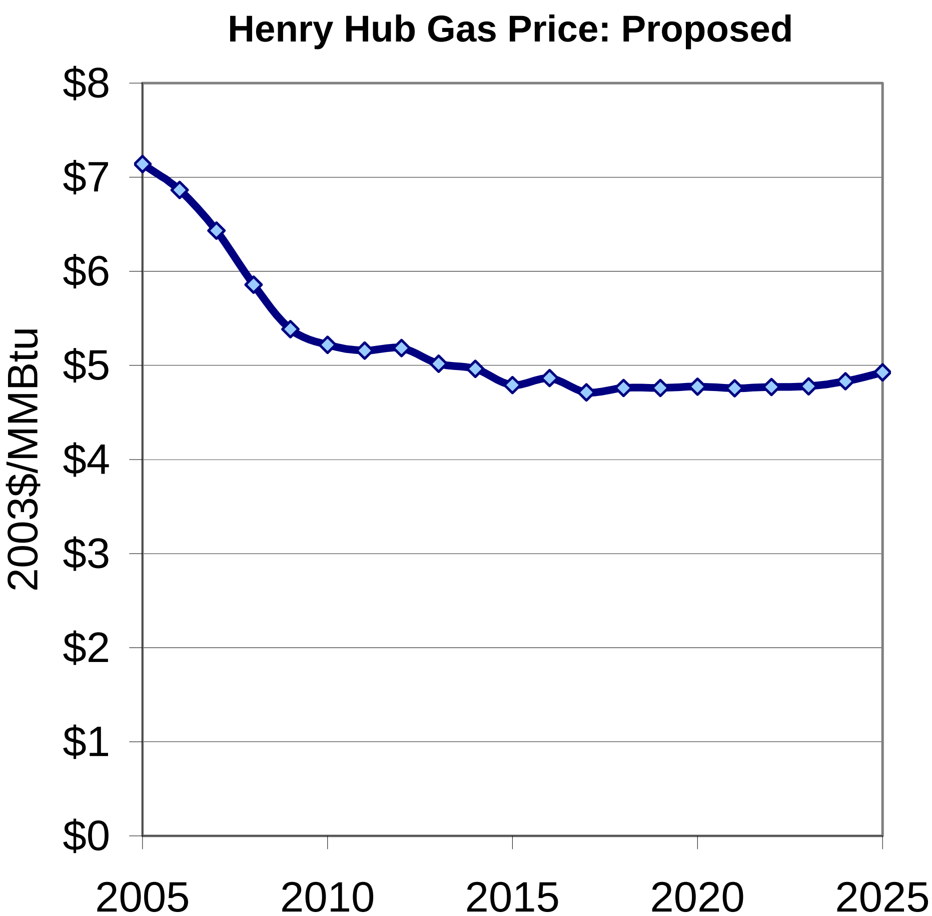


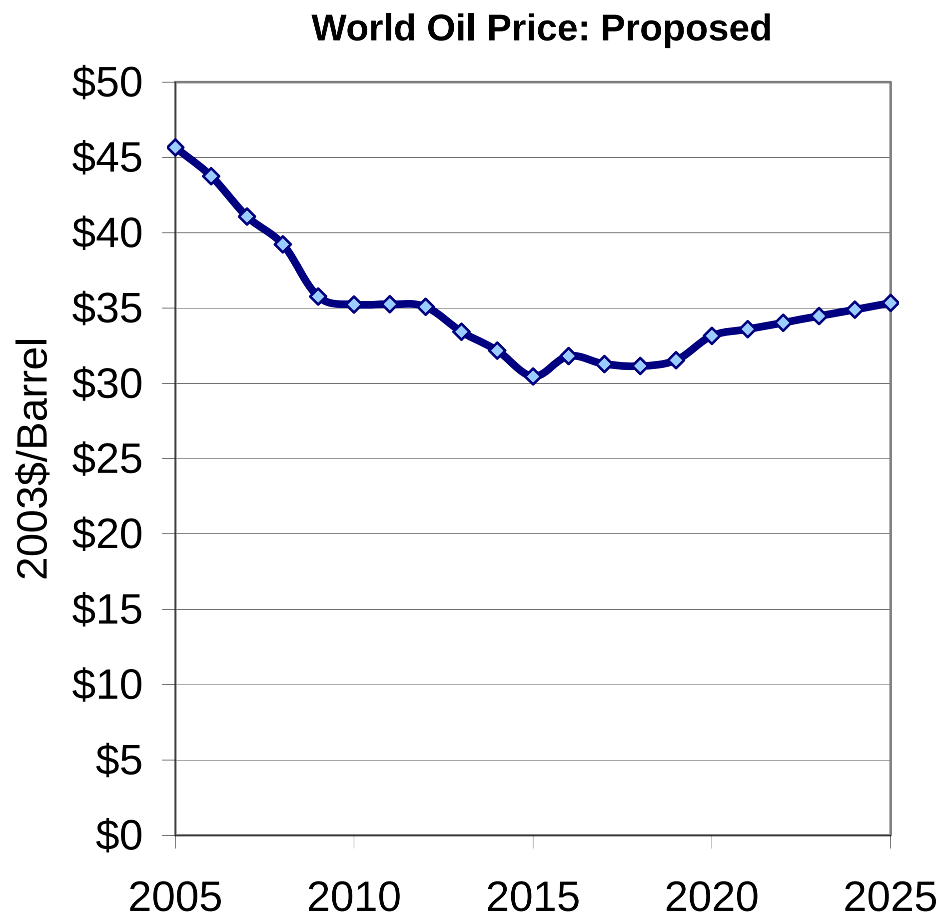
Source: EPA Assumptions Document V.2.1.9

World Oil Price Assumptions

- Oil price assumptions were developed to adequately reflect the cost of fuel switching for units that are oil- and gas-capable.
- The oil price projection for the RGGI analysis is based on EIA AEO 2005 projections and adjusted as follows:
  - In the near-term, EIA's AEO 2005 world oil price forecast is scaled by the relative gas prices (AEO as compared to the RGGI trajectory) to arrive at a modified EIA trajectory.
  - In the long-term (2015 and later), the trajectory is equal to the average of EIA's Reference Case and High Oil Case projections.
  - EIA's world oil price is the annual average U.S. refiner's acquisition cost of imported crude oil.
- The outcome of this adjustment is shown on the following slide and compared to the proposed gas price trajectory.

World Oil Price Assumptions continued





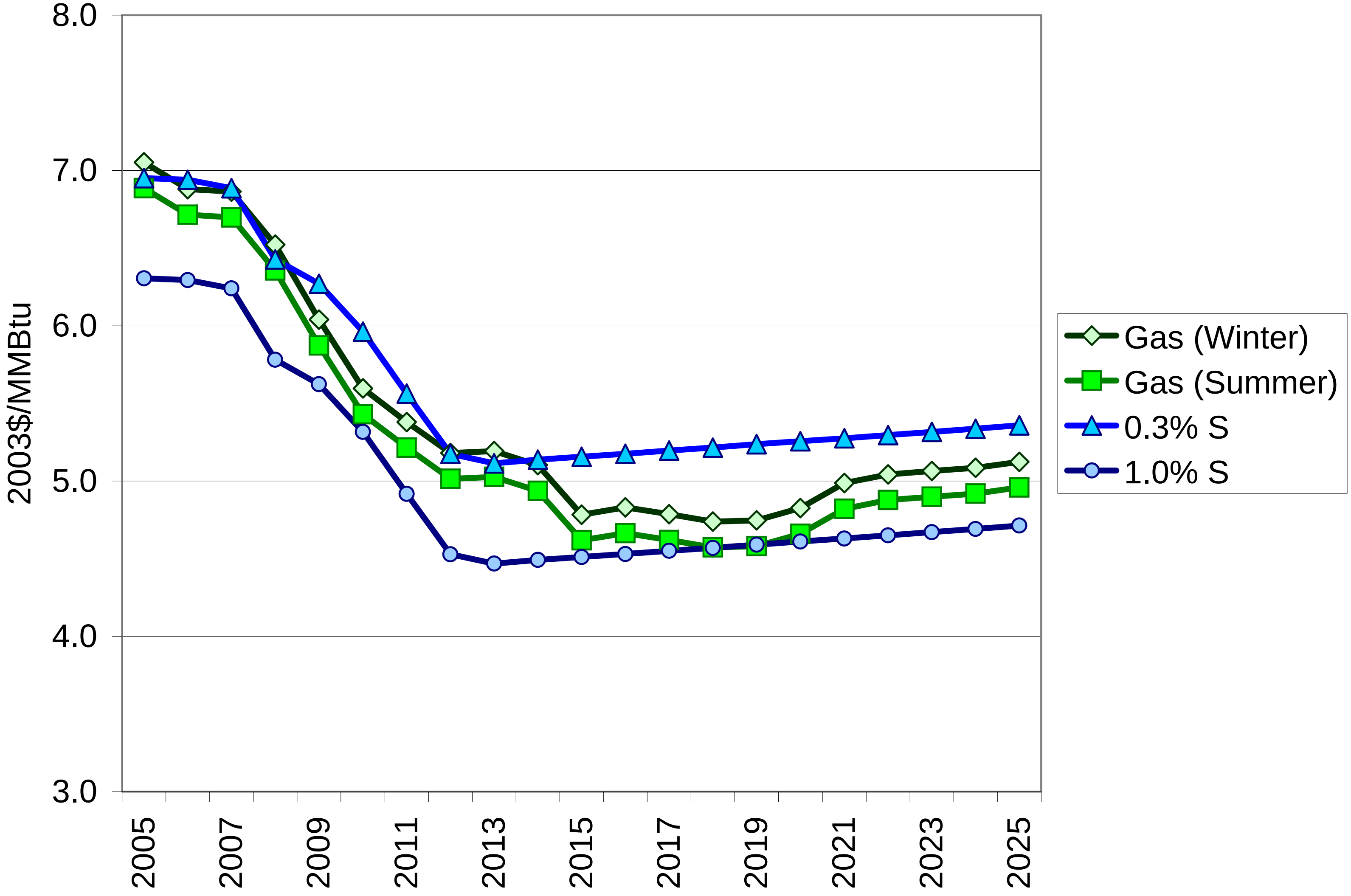
Delivered Oil Price Assumptions

- Delivered product prices are derived from the assumed world oil price shown on the previous slide and an analysis of historical price relationships and delivered prices.
- The 0.3%S price trajectory was derived based on a regression of product prices to world crude prices over 6 years (1998 through 2003).
- The price differential between 0.3%S and 1.0%S is assumed to remain constant over time and is equal to the 6-year average historical differential between the two products.
- Delivered prices for both products are based on historical data for select cities.
- The following slide compares delivered oil and gas prices in 2010 for the RGGI region. The two following slides show time series projections for two select regions.

Delivered Gas and Oil Price Comparison for RGGI Regions

Region	2010 Delivered Winter Gas Price (2003$/MMBtu)	2010 Delivered Summer Gas Price (2003$/MMBtu)	2010 Delivered Oil Prices	
			0.3% Resid	1.0% Resid
PJM - EAST				
PJM-E	5.53	5.38	5.68	5.04
PJM - WEST				
PJM-W	5.58	5.44	5.68	5.04
PJM - SOUTH				
PJM-S	5.52	5.40	5.68	5.04
New York				
Zones A thru E	5.35	5.25	5.74	5.09
Zone F	5.35	5.25	5.74	5.09
Zones G thru I	5.56	5.39	5.67	5.02
Zone J (New York City)	5.92	5.73	5.67	5.02
Zone K (Long Island)	5.66	5.45	5.67	5.02
NEPOOL				
Southwest Connecticut/Norwalk	5.60	5.44	5.78	5.14
Other Connecticut	5.60	5.44	5.78	5.14
Rhode Island	5.60	5.44	5.78	5.14
Southeastern Massachusetts	5.60	5.44	5.90	5.25
Western Massachusetts	5.60	5.44	5.90	5.25
Boston	5.60	5.44	5.90	5.25
Central and Northeastern Massachusetts	5.60	5.44	5.90	5.25
Vermont	5.60	5.44	5.90	5.25
New Hampshire	5.60	5.44	5.90	5.25
Maine	5.60	5.44	5.90	5.25

Delivered Gas and Oil Price Comparison
MA, VT, ME & NH



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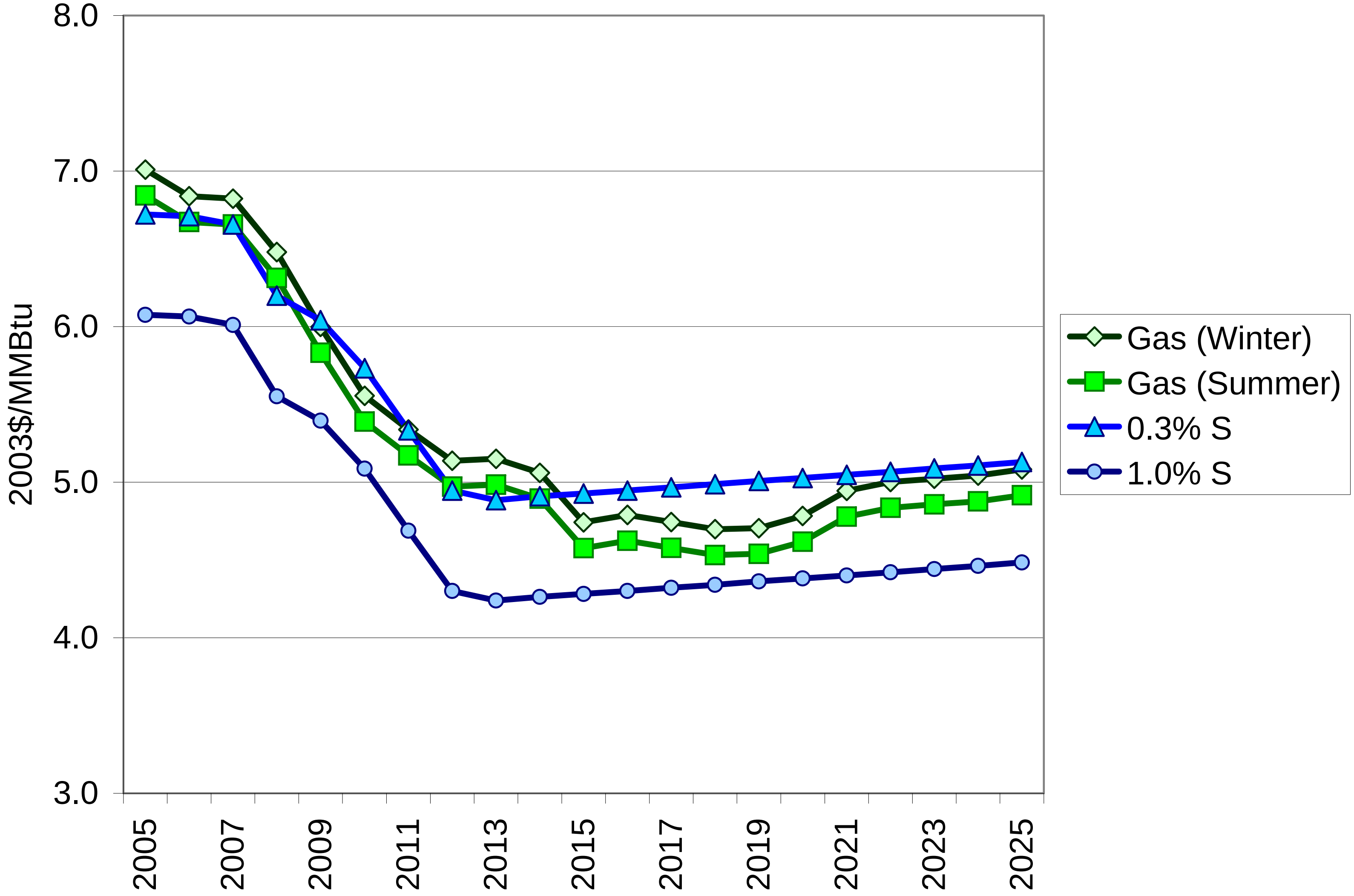
Delivered Gas and Oil Price Comparison
Downstate New York



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Coal Supply and Demand Analytic Approach

Overview

- Coal supply curves are used in IPM® to capture price and production responses from fuel switching for environmental compliance.
- ICF has developed supply curves (described later in this section) for use in its analyses. To be consistent with the long-term gas and oil prices in this analysis, the SWG chose to calibrate these curves to EIA's AEO 2004 coal price and production results.
- Like gas and oil prices, near-term (2005 and 2006) coal prices have also been calibrated to current future markets to reflect present market conditions not captured in EIA's projections.
  - Current commodity price premiums and transportation bottlenecks are assumed to ease over time as export markets for U.S. coal come into balance and domestic production increases.
- The tables at right show the price projections for key coals that the supply curves have been calibrated to. The actual prices realized in the modeling will depend on the assumed environmental regulations and other market conditions.
  - Delivered prices of these coals to New York, New England and Pennsylvania are shown on the following slide, along with the emissions and energy characteristics of each coal.
- Because reliable spot pricing and characteristics are not readily available, international coals will not be represented in this process.

Central Appalachia Low Sulfur Bituminous	
Minemouth (2003$/Ton)	
2005	$66.00
2010	$29.18
2015	$30.48
2020	$29.90

Northern Appalachia Medium Sulfur Bituminous	
Minemouth (2003$/Ton)	
2005	$54.00
2010	$27.55
2015	$26.23
2020	$26.54

PRB Low Sulfur Sub-bituminous	
Minemouth (2003$/Ton)	
2005	$7.30
2010	$6.65
2015	$7.41
2020	$7.47

Ohio High Sulfur Bituminous	
Minemouth (2003$/Ton)	
2005	$34.50
2010	$24.65
2015	$23.57
2020	$24.60

Coal Supply and Demand Analytic Approach
Delivered Prices

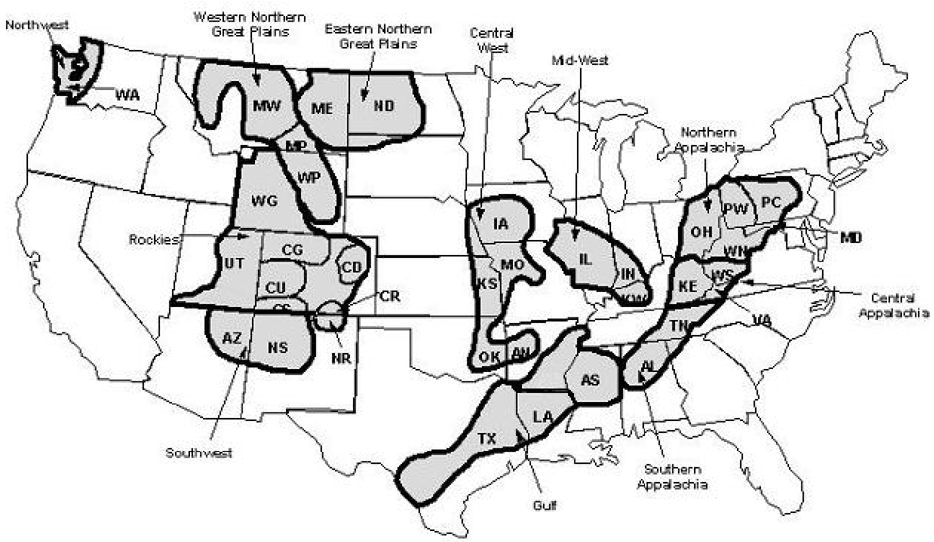
	Delivered Cost (2003$/MMBtu)											
Supply Region	**Central Appalachia**			**Northern Appalachia**			**PRB**			**Ohio**		
SO_2 Content (Lb./MMBtu)	1.0			2.2			0.8			5.0		
*Hg Content (Lb./TBtu)**	4.3			7.6			5.7			7.0		
*Heat Content (Btu/Lb.)**	12,500			13,100			8,800			11,500		
Delivered To	**NY**	**NE**	**PA**	**NY**	**NE**	**PA**	**NY**	**NE**	**PA**	**NY**	**NE**	**PA**
2005	3.06	3.23	2.71	2.23	2.55	2.29	2.22	2.41	1.94	1.96	1.91	1.67
2010	1.61	1.78	1.25	1.22	1.54	1.28	2.19	2.37	1.90	1.47	1.42	1.18
2015	1.66	1.83	1.30	1.17	1.49	1.23	2.23	2.41	1.95	1.45	1.39	1.16
2020	1.64	1.81	1.28	1.18	1.50	1.24	2.23	2.42	1.95	1.41	1.36	1.12

* As described in the coal methodology section, the coal supply curves in IPM® represent 40 supply regions. The broader Central Appalachia production region, for example, is composed of 3 IPM® supply regions. The Hg and heat contents shown reflect those for coals from particular IPM® coal supply regions within the broader supply region shown (e.g., "Central Appalachia"). These coals are representative of other supply regions.

Coal Supply and Demand Analytic Approach

IPM® Coal Market Structure

IPM® Coal Supply Regions



- Coal resources for each of 40 coal supply basins are disaggregated into the following categories:
  - Rank
  - Sulfur content
  - Existing and new
  - Surface: Overburden Ratio, Size, Mining Method
  - Underground: Depth, Seam Thickness, Mining Method
- Mercury contents are assigned to coals by rank and production region based on EPA's 1999 ICR shipment data.
- Coal supply curves for each of the 40 supply basins are created by applying disaggregated coal resources assigned to one of 16 prototype coal costing models.
- The coal supply curves are then used as inputs to IPM®.
- Coal plants in IPM® are assigned to one of 41 different coal demand regions that are defined by location and mode of delivery.
- A coal transportation matrix links supply and demand regions in IPM®, which determines the least cost means to meet power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.

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Financial Assumptions

Discount Rate

- IPM® is a linear programming model that optimizes system performance in a least cost manner to meet any number of market and policy requirements (constraints) defined in the analysis.

- All costs in the model are represented in real 2003$, and are then discounted back on a present value basis to determine the least cost way to meet the market and policy requirements defined. The discount rate then becomes important in evaluating the tradeoffs of making investments and incurring costs in the near-term vs. incurring expenses over the longer-term.
  - For this analysis, the SWG chose to use a 6.86% (real) discount rate on a system-wide basis to evaluate revenues and costs and to make investment decisions.

Financial Assumptions

- Capital investments in IPM® are annualized using a capital charge rate that takes into account the ratio of debt and equity and their respective rates, taxes, depreciation schedule, book life and debt life. Capital charge rates are assigned to each technology type as shown on the next slide.
- The assumptions shown on the following page are intended to reflect financial conditions characteristic of merchant investments, or those investments likely to be the marginal decisions that IPM® relies on to forecast energy and capacity prices.
- New gas- and coal-fired capacity options are assumed to face similar debt rate and return-on-equity requirements. Investments in new nuclear capacity are assumed to require higher rates to account for a higher risk profile. Pollution control options, because they will be installed on existing units with available historical generation and cost profiles, are assumed to be financed at lower rates.

Financial Assumptions For Potential Builds and Retrofits

	Nuclear	Combined Cycles*	Combustion Turbines	Pulverized Coal	IGCC	Retrofits
Input:						
Debt Life (years)	20	20	20	20	20	15
Book Life (years)	40	30	30	40	40	20
Nominal After Tax Equity Rate (%)	14.0	13.0	13.0	13.0	13.0	12.0
Equity Ratio (%)	50	50	50	50	50	50
Nominal Debt Rate (%)	9.0	8.0	8.0	8.0	8.0	7.0
Debt Ratio (%)	50	50	50	50	50	50
Income Tax Rate (%)	41.2	41.2	41.2	41.2	41.2	41.2
Other Taxes/Insurance (%)	2.2	2.2	2.2	2.2	2.2	2.2
Inflation (%)	2.25	2.25	2.25	2.25	2.25	2.25
Output:						
Levelized Real Fixed Capital Charge Rate (%)	14.0	13.3	13.3	12.9	12.9	13.6

* Also applies to repowering options from coal and oil/gas steam units to new combined cycle units.

NOTE: Income tax and other tax/insurance rates updated as of July 2003.

Technical Assumptions
Supply

Supply in IPM®

- Supply in IPM® is defined by a combination of the following variables:
  - **Existing Capacity** – The amount of MW generating capacity currently available to the grid.
  - **Unit Types, and Characteristics** – The classification of different generator types by fuel use, heat rate, operating costs, availability, environmental performance, and so on.
  - **Firmly Planned Vs. Potential Capacity** – The two options for brining new capacity to the system within the model.
  - **New Build Cost and Performance** – The specifications for new potential capacity types, including assumptions about technology improvement over time.
  - **Financing** – The financial backing a new power project can support, based on equity costs, book life, tax rates, debt to equity ratios, and so on.
  - **Renewable Power** – Renewable power generators, along with special specifications for their costs and operational characteristics.
  - **Nuclear Power** – The primary issues that affect nuclear power, such as relicensing and uprates.
  - **Transmission** – The representation of the transmission system linkages, costs, line losses in IPM®.

Existing and New Capacity

Existing Capacity

- IPM® contains a database of all existing grid-connected generators and boilers in the continental US and Canada based on publicly available information from FERC, EIA, EPA, Statistics Canada and other public sources. This data is periodically updated by ICF based on data in the public domain.
- In order to limit mode size, individual units may be aggregated into model plants based on a strict set of aggregation criteria.
- Existing capacity is given the option to undertake multiple types of pollution control retrofits in order to comply with current and future air regulations. Specific retrofit assumptions are presented later in this document.
- Existing nuclear units are offered the option to relicense and/or uprate. Assumptions for these options are presented later in this section.
- Some units specified by ISO-NE will be modelled as “must run” in the first run year of the analysis (2005-2007) to capture generators required for transmission support, etc. This must-run requirement will be removed in 2008.

Existing Capacity
Capital Expenses

- Existing units may be required to incur annual expenses to mitigate the effects of aging, undertake major repairs, etc. These capital expenses are incorporated into the fixed costs of existing units.

- For plants beyond 30 years of age, EIA adds an additional $37/kW-yr. for nuclear plants. This capital expense escalation will be incorporated into the analysis.

Existing Capacity
Oil/Gas Steam Generation

- Generation from oil-fired and gas-fired steam units was calibrated to approximate recent historical levels in New York and the RGGI region in accordance with discussions with the ISOs and stakeholders.

- 5-year average historical levels were used as a starting point and prorated for the 2006, 2009 and 2012 run years.

- In 2015 and beyond specific units are required to run at minimum levels during summer to meet specific reliability requirements (New York State Reliability Council I-R3 (Loss of Generator Gas Supply in New York City and Long Island)), and all oil/gas units are required to run for the equivalent of a minimum of 2 months during the winter to approximate historical levels.

New Capacity Additions – Firm Build Vs. Potential Build

- There are two types of new capacity additions implemented in IPM®, "**Firm Build**" and "**Potential Build**"

- **Firm Build –** Firm build, short for firmly planned capacity additions, are plants currently under construction or expansion plans at existing sites.

  – From a modeling perspective, firm builds are treated as existing capacity that generally comes online in the next 1-3 years. Since firm build units are considered "done deals" in the model, they incur no capital costs in the optimization process. Their operating costs, however, are treated the same as any other unit.

  – Generally, only those plants that have begun construction as firm.

- **Potential Build -** IPM® adds capacity necessary to meet net peak demand and reliability/reserve requirements. The mix of new builds is endogenously determined based on the economics of the system and the costs of new capacity.

  – Potential build units are brought online where:

  1) They are the least cost option for meeting demand given all costs and constraints over time; and

  2) Their capital and operating costs are covered by energy and capacity revenues, assuming pre-specified financial hurdle rates.

Firm Build and Retirement Assumptions for RGGI Region

- The table on the following slide shows the units to be considered “firm” for the RGGI analysis, including capacity additions and retirement decisions.
  - Units listed in italics are assumed to be retired when the unit listed at the top of each box enters into service.
- New York units were developed from the Article X unit list based on units under construction as of September 30, 2004.
- New England units were taken from the RTEP04 list provided by ISO-NE and then filtered for those units found to be currently under construction or very far along in the permitting process.
- PJM units were developed based on information provided in the PJM Generation Interconnection Request Queues (through Queue N) and filtered based on construction status. Retirements were taken from the “PJM Generator Retirement Requests” list (dated 09/28/04) and assumed for all units listed in the years requested.

Firm Build and Retirement Assumptions for RGGI Region
continued

Unit	IPM Model Region	Capacity Type	Online Year	Capacity Summer Dependable (MW)
Milford	NE-ISO - Southwest CT	CC	2004	544
Devon 7 & 8			2004	-214
Mystic 4 - 6			2004	-388
Bethleham Energy	NY - Zone F	CC	2005	750
Albany 1				*-86.7*
Albany 2				*-87.2*
Albany 3				*-90.2*
Albany 4				*-92.2*
Poletti Station Expansion	NY - Zone J	CC	2006	500
Poletti 1				*-882*
Astoria Energy	NY - Zone J	CC	2006	500
East River 8	NY - Zone J	CC	2006	360
Waterside 6				*-69.6*
Waterside 8				*-48.5*
Waterside 9				*-48.5*
Freeport	NY - Zone K	CT	2004	47
Eqqus Freeport	NY - Zone K	CT	2004	44
Bethpage	NY - Zone K	CT	2005	79
Babylon	NY - Zone K	CT	2005	79
Russell 1	NY - Zone B	Coal	2008	-43.2
Russell 2	NY - Zone B	Coal	2008	-61.9
Russell 3	NY - Zone B	Coal	2008	-61.9
Russell 4	NY - Zone B	Coal	2008	-72.9
Fairless Energy Center	PJM - East	Cogen/CC	2004	1200
Bethlehem	PJM - East	Cogen/CC	2004	1100
Marcus Hook Refinery Cogen	PJM - East	Cogen/CC	2004	725
Linden	PJM - East	Cogen/CC	2005	1186
Linden 1		*Oil/Gas Steam*	*2005*	*-180*
Linden 2		*Oil/Gas Steam*	*2005*	*-250*
Linden CT 3		*CT*	*2005*	*-15*

Firm Build and Retirement Assumptions for RGGI Region

continued

Unit	IPM Model Region	Capacity Type	Online Year	Capacity Summer Dependable (MW)
Seward	PJM - West	Coal	2004	521
Bear Creek Wind Farm	PJM - West	Wind	2004	34
Hudson 3	PJM	CT	2003	-129
Sayreville 4 & 5			2004	-229
Gould Street			2003	-101
Seward 4&5			2003	-196
Deleware 7 & 8			2004	-250
Burlington 10			2004	-261
VCLP NUG			2004	-46.6
Wayne			2004	-56
Warren 3		CT	2004	-57
Blossburg		CT	2004	-19
Gilbert 1 & 4		CT	2006	-48
Glen Gardner 1 & 5			2006	-40
Shawnee		CT	2006	-20
Riegel Paper			2004	-27
Martins Creek 1 & 2			2007	-280
Collins 1-5 (NICA)			2004	-2,698
Sewaren 1-4			2004	-453
Hudson 1			2004	-383
Kearny 7			2004	-150
Kearny 8			2007	-150
B L England 1-3			2007	-439
B L England IC1-IC4			2007	-8

Treatment of NRG & AES Settlements with New York

- NRG settlement
  - Retire Huntley units 63-66 in 2006 run year
  - SO_2 and NO_X caps on remaining Huntley and Dunkirk units
  - Remaining units at Dunkirk and Huntley will be assumed to burn PRB coal to maintain a 0.6 lb SO_2 per MMBtu rate and, with the addition of new low NO_X burners, 0.15 lb NO_X per MMBtu from 2005 through 2011.
- AES settlement
  - Impose Greenidge 4 SO_2 & NO_X caps of

    SO_2 -- 11800 tons in 2006, 11475 in '07, 11150 in '08, 10825 in '09 and later

    NO_X – 0.15 lb./MMBtu beginning in 2006
  - Impose Westover 8 SO_2 & NO_X caps of

    SO_2 -- 9250 tons in 2006, 9000 in '07, 8750 in '08, 8500 in '09 and later

    NO_X – 0.15 lb./MMBtu beginning in 2006
  - Impose on Greenidge 3 and Westover 7

    Beginning in 2007, 1400 hour run-time limitation

    Beginning in 2007, 3 lb./MMBtu SO_2 limit

New Capacity Additions – General Assumptions

- New coal capacity of any type will not be allowed to be built within the RGGI-affected region over the time horizon of the analysis, unless otherwise specified in sensitivity scenarios.
  - The same is true for the modeled Canadian provinces, reflecting Canada's commitment to the Kyoto Protocol and recent policy statements in Ontario calling for the retirement of all existing coal in the province.
- In calculating the capital cost of new greenfield capacity, the project lead (construction) time is accounted for by calculating the interest during construction and adding that carrying cost to the capital cost of the new unit.
- Permitting time in addition to the project lead time is explicitly accounted for in the earliest year the unit is allowed to be built. Beyond these online year restrictions, IPM® decides the optimal timing and location to add new capacity over the timeframe of the analysis.

Potential Build Cost and Performance

- The SWG has chosen to use as a basis for the new capacity cost and performance assumptions the inputs from EIA AEO 2004.
  - Cost and performance values are provided for multiple years. These values will be reflected in IPM® through the use of vintaged technology options.
- These costs reflect those for a new unit in an area of average labor, materials and construction costs in the U.S.
- Capital costs include interest during construction based on EIA's construction schedule. They do not include transmission interconnection adders or regional multipliers, which are addressed in later slides.
- A capital cost of $40/kW will be added to combustion turbine investments in IPM® RGGI sub-regions containing non-attainment areas to reflect the cost of a hot side SCR.
  - The addition of the SCR reduces the NO_X rate of a new CT to 0.01 lb./MMBtu.
  - The cost of the SCR was derived from testimony to FERC on behalf of ISO-NE.[1]

[1] Testimony of John J. Reed to FERC on behalf of ISO-NE. Docket ER03-563-030. August 31, 2004.

Potential Build Cost and Performance From EIA AEO 2004

<table>
<tr><th>Parameter</th><th>Nuclear</th><th>Conv. Combined Cycle</th><th>Adv. Combustion Turbine</th><th>Pulverized Coal</th><th>IGCC</th></tr>
<tr><td>Earliest Online Year</td><td>2013</td><td>2008</td><td>2007</td><td>2010</td><td>2010</td></tr>
<tr><td>Construction Leadtime (Years)</td><td>6</td><td>3</td><td>2</td><td>4</td><td>4</td></tr>
<tr><td>Fixed O&M (2003$/kW-year)</td><td>60.14</td><td>12.61</td><td>8.41</td><td>25.22</td><td>34.67</td></tr>
<tr><td>Variable O&M (2003$/MWh)</td><td>0.44</td><td>2.10</td><td>3.28</td><td>3.15</td><td>2.10</td></tr>
<tr><td colspan="6">Total Capital Cost, Including IDC (2003$/kW)</td></tr>
<tr><td>Earliest Online Year</td><td>2,374</td><td>583</td><td>491</td><td>1,364</td><td>1,592</td></tr>
<tr><td>2010</td><td>--</td><td>574</td><td>476</td><td>1,364</td><td>1,592</td></tr>
<tr><td>2015</td><td>2,244</td><td>568</td><td>439</td><td>1,340</td><td>1,533</td></tr>
<tr><td>2020</td><td>2,191</td><td>561</td><td>420</td><td>1,321</td><td>1,473</td></tr>
<tr><td>2025</td><td>2,138</td><td>555</td><td>407</td><td>1,306</td><td>1,401</td></tr>
<tr><td colspan="6">Heat Rate (Btu/kWh)</td></tr>
<tr><td>Earliest Online Year</td><td rowspan="3">10,400</td><td>7,444</td><td>9,289</td><td>8,689</td><td>7,378</td></tr>
<tr><td>2010</td><td>7,056</td><td rowspan="2">8,550</td><td>8,689</td><td>7,378</td></tr>
<tr><td>2015 and later</td><td>7,000</td><td>8,600</td><td>7,200</td></tr>
</table>

Regional Cost Adjustments Applied to Potential Build Options

- Regional cost multipliers are applied to the capital costs presented above to reflect regional differences in labor, material and construction costs.
  - An interconnection cost of $65/kW will be added to new capacity capital costs after the application of the regional adjustment factors based on John Reed's testimony to FERC.
- These adjustments will be applied for all regions within IPM®, including those outside the RGGI region. Therefore, multipliers must be used that reflect consistent treatment of premiums across the U.S. For this reason, the multipliers outside the RGGI region and the "Rest of State" (for New York), "Rest of Pool" (for New England) and "Other PJM" values are set equal to EIA's regional multiplier assumptions for those respective regions.
  - The 1.043 multiplier for Rest of State New York and rest of Pool ISO-NE and the 0.996 multiplier for Other PJM shown in the regional adjustment factor table are taken directly from EIA.
- To adequately reflect geographic cost differences within the RGGI region, further adjustments were made to EIA's regional multipliers where additional information was available.
  - For ISO-NE, adjustment factors were derived based on testimony by John Reed on behalf of ISO-NE to FERC in August 2004 (Exhibit ISO-8)[1].
  - For NYISO, the regional multipliers were derived from relative costs presented in the Levitan study[2] and calculations made by the NY DPS in its comments on the Levitan study.
  - For PJM, the New Jersey IPM® region was assigned the same multiplier as "Rest of State" New York because of its proximity to New York.

[1] Testimony of John J. Reed to FERC on behalf of ISO-NE. Docket ER03-563-030. August 31, 2004.

[2] Levitan's Independent Study to Establish Parameters of the ICAP Demand Curves for the NYISO, August 16, 2004.

[3] "Comments of the Staff of the Department of Public Service of the State of New York"

Regional Cost Adjustments Applied to Potential Build Options
continued

- Adjustment factors for the regions provided in each source were derived by dividing the cost provided for a specific region (e.g., Northeast MA/Boston) by the cost provided for Rest of Pool (or Rest of State in the case of New York).
  - For example, the testimony to FERC on behalf of ISO-NE presented a cost for a CT of $554.91/kW for Northeast MA/Boston and a Rest of Pool cost of $505.32/kW.
  - The Northeast MA/Boston adjustment factor, therefore, is equal to 1.098 (554.91/505.32) times the Rest of Pool cost.
- These relative regional adjustments were then scaled to the EIA values to maintain consistency across the IPM® regions.
  - For example, the multiplier for the Northeast MA/Boston area equal to 1.098 (see above) from the FERC testimony for ISO-NE is assumed relative to a Rest of Pool value of 1.000.
  - To maintain the EIA 1.043 Rest of Pool regional adjustment consistent with other regions outside of RGGI, the 1.098 value for Boston is multiplied by the ratio of the EIA Rest of Pool value to the ISO-NE Rest of Pool value, or 1.043/1.000.
  - The revised adjustment factor of 1.145 (1.098 * 1.043) is now consistent with the EIA value used for Rest of Pool and, therefore, with the regions being modeled outside of RGGI.

Regional Cost Adjustments Applied to Potential Build Options
continued

RGGI Regions

Region	Regional Multiplier
ISO-NE "Rest of Pool"	**1.043**
Southwest CT	1.137
Other CT	1.107
Maine	1.021
Northeast MA/Boston	1.145
NYISO "Rest of State"	**1.043**
New York City	1.989
Long Island	1.879
Other PJM	**0.996**
New Jersey	1.043

Other Regions

Region	Regional Multiplier
MAPP, ECAR, MAIN	1.004
SPP	0.997
SERC & TVA	0.960
Rockies	1.003
Northwest	1.026
Florida	0.961
California & Nevada	1.058
ERCOT	0.986

Sample All-In Cost Calculation

- As noted in the previous slides, the all-in cost of new capacity includes the base capital cost (from EIA), interest during construction (IDC, based on EIA's build schedules), regional multipliers (calibrated to NYISO and ISO-NE estimates) and interconnection costs. The example below shows the calculation of all-in cost with all of these factors for new combined cycle units in two RGGI regions in 2010.

	New York - Zone F	New England - Boston
Base Capital Cost with IDC (2003$/kW)	$574	$574
+ Interconnection Cost (2003$/kW)	$65	$65
= Regionally Adjusted Cost (2003$/kW)	$639	$639
* Regional Adjustment Factor	1.043	1.145
= All-in Capital Cost (2003$/kW)	**$666**	**$732**

Potential Build Environmental Performance

- The table below shows the assumptions for the environmental performance of new capacity by pollutant.

Pollutant	Nuclear	Combined Cycle	Combustion Turbine	Pulverized Coal	IGCC
SO_2	No Emissions	No Emissions	No Emissions	95% reduction from fuel content	100% Removal
NO_X		0.01 lb/MMBtu rate	0.10 lb/MMBtu rate	0.07 lb/MMBtu rate	0.02 lb/MMBtu rate
Hg		No Emissions	No Emissions	90% reduction from fuel content	95% reduction from fuel content

- To address needs for lower NO_X rate CTs in non-attainment areas in the RGGI region, the CT option offered in those regions will include an SCR to reduce the rate to 0.01 Lb./MMBtu.
  - Achieving this lower rate would require the addition of a hot SCR to the unit, resulting in a capital cost adder of $40/kW as described earlier in this section.

Existing Nuclear Unit Assumptions

- For existing nuclear units, two critical assumptions must be defined:
  - **Uprates** – How much new nuclear capacity is available to the system through uprating existing capacity in the future?
  - **Relicensing** – Do existing nuclear units stay online past the end of their current operating licenses?
- The Nuclear Regulatory Commission (NRC) has approved over 4 GW of power uprates at existing nuclear facilities over the past 25 years.
- The NRC has also granted several license renewals for nuclear units and is expected to approve others.

Nuclear Uprate Definitions

- There are three categories of nuclear power uprates:
  - *Measurement Uncertainty Uprates:* This type of uprate will typically increase a unit's capacity by 2% or less. The increase in capacity is achieved by installing improved sensors and state-of-the-art devices used to measure reactor power.
  - *Stretch Power Uprates:* A stretch power uprate will typically increase unit capacity by up to 7%. The increase in capacity is not achieved by major plant modifications but can be attributed to changes and refinements in instrument settings.
  - *Extended Power Uprates:* Extended power uprates, which can increase unit capacity by as much as 15% or more, require extensive plant modifications and upgrades, such as the replacement of steam turbines and/or modifications to generators, transformers, and feedwater pumps.

Source:

Peltier, Dr. Robert. *Platts Power.* "Nuclear Renaissance Continues." June 2004.

U.S. Nuclear Regulatory Commission. *Fact Sheet on Power Uprates for Nuclear Plants.* http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html

Nuclear Uprates in the RGGI Region

- The SWG Modeling Subgroup has recommended that units be given the option to uprate on an economic basis.
- Nuclear uprate opportunities will be apportioned based on company ownership between 2005 and 2012.
- The table on the following page shows the uprate potential and associated cost for each of the nuclear units in the RGGI region and neighboring states. It also shows EPA's capacity change and timing assumptions for each unit.
  - Uprate potential and type by unit is taken from "U.S. Commercial Nuclear Power Industry Assessment for Department of Energy, Energy Information Agency", October 2001.
  - Uprate cost by type assumed to be the middle of the range published in Power magazine article, July/August 2001.

Nuclear Uprate Potential in the RGGI Region

Unit	State	Nuclear Energy Institute		EIA Analysis		Power Magazine
		Capacity (MW)	License Expiration Date	Uprate Potential (MW)	Uprate Option Type	Uprate Option Cost (2003$/kW)
Millstone: 3	CT	1,120	Nov. 2025	57	Stretch	$268
Millstone: 2	CT	923	Jul. 2015	43	Stretch	$268
Pilgrim: 1	MA	669	Jun. 2012	60	Stretch	$268
Seabrook: 1	NH	1,155	Oct. 2026	57	Stretch	$268
Vermont Yankee: 1	VT	496	Mar. 2012	110	Extended	$575
Calvert Cliffs: 1	MD	850	Jul. 2034	42	Stretch	$268
Calvert Cliffs: 2	MD	850	Aug. 2036	42	Stretch	$268
Hope Creek	NJ	1031	Apr. 2026	100	Extended	$575
Oyster Creek	NJ	650	Apr. 2009	32	Stretch	$268
Salem: 1	NJ	1106	Aug. 2016	55	Stretch	$268
Salem: 2	NJ	1106	Apr. 2020	55	Stretch	$268
Fitzpatrick	NY	825	Oct. 2014	25	Stretch	$268
Ginna	NY	490	Sept. 2009	25	Stretch	$268
Indian Point: 2	NY	975	Sept. 2013	97	Extended	$575
Indian Point: 3	NY	980	Dec. 2015	50	Stretch	$268
Nine Mile Point: 1	NY	609	Aug. 2009	60	Extended	$575
Nine Mile Point: 2	NY	1148	Oct. 2026	57	Stretch	$268
Beaver Valley: 1	PA	810	Jan. 2016	60	Extended	$575
Beaver Valley: 2	PA	833	Mar. 2027	62	Extended	$575
Peach Bottom: 2	PA	1160	Aug. 2033	116	Extended	$575
Peach Bottom: 3	PA	1160	Jul. 2034	116	Extended	$575
Susquehanna: 1	PA	1100	Jul. 2022	110	Extended	$575
Susquehanna: 2	PA	1100	Mar. 2024	110	Extended	$575
Three Mile Island: 1	PA	875	Apr. 2014	45	Stretch	$268

Nuclear Plant Relicensing

- Nuclear relicensing is likely to have an impact on the cost of CO_2 policy compliance in the RGGI region and on electric prices.
- Units will be given the option to economically relicense at the end of their 40-year lifetimes for a one-time capital cost of $350/kW.
  - The cost is taken from "Documentation of EPA Modeling Applications (V.2.1) Using The Integrated Planning Model", March 2002.
  - In its latest Base Case, EPA assumes that nuclear units relicense and does not assign a cost.
- Regardless of exogenous relicensing decisions, all nuclear plants are allowed to economically retire 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 revenues stream for each plant.

Transmission

Transmission in IPM®

- Transmission between demand regions allows for broad price equilibration and reserve sharing across the US grid.
- IPM® represents transmission between demand regions with four variables:
  - Wheeling charges (mills/kWh) – The average annual wheeling tariff to send power in one direction over a line.
  - Capacity Transfer Capability (Peak Capacity) -- The maximum line capacity available during peak hours.
  - Energy Transfer Capability (Energy Capacity) – The average energy flow capable of being passed from one region to another over the course of the year. The total energy transmission available to the system in each year is equal to the energy capacity in MW terms multiplied by 8760 hours.
  - Line Losses (%) – Percentage of power lost due to line efficiency limitations.
- Note that transmission linkage characteristics are defined in each direction for a given line. This allows IPM® to capture the actual energy market dynamics between regions, especially where load flows demonstrate consistent directionality over time.
- Energy transfer capability levels are higher than capacity transfer capabilities on some lines. Whereas capacity transfer capability figures represent MW transfer capacities during peak hours, when the lines are most heavily loaded, energy transfer capabilities provide the average capacity of the line over peak and non-peak segments when the lines are generally less constrained.

Existing Transmission Assumptions – Line Losses

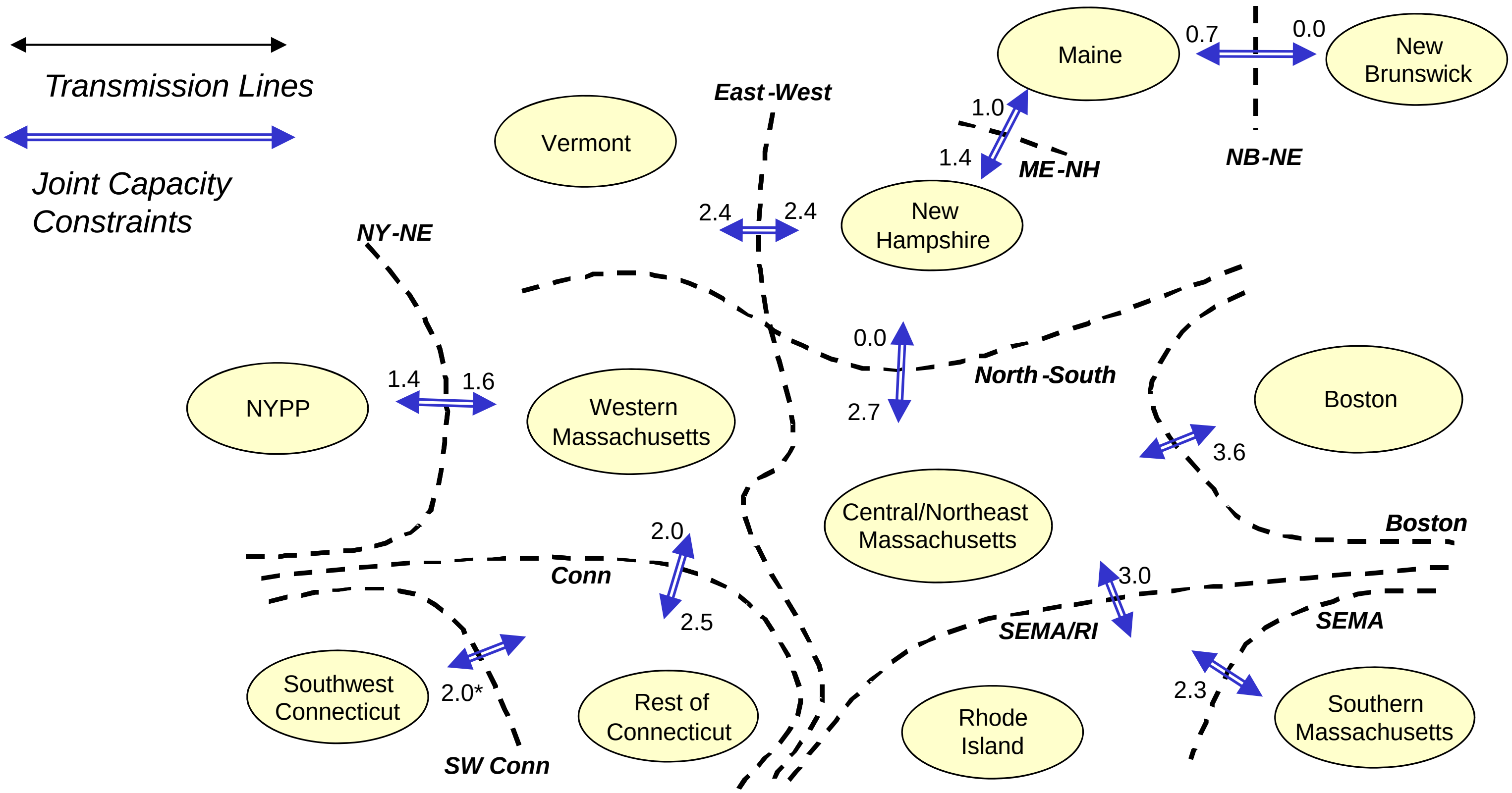
- Although transmission losses vary with line loading and line length, it is impractical to estimate the exact loss factors for each interconnecting transmission path. Therefore, based on industry rules of thumb, transmission losses of between 2% to 3% are assumed for wholesale-level transfers. Where precise data is otherwise unavailable, we have used an average of 2.5%.

- Note that these losses are intended to capture only bulk power transmission losses. Distribution losses are not included.

Regional Transmission Assumptions

- The following slides show the transmission capability assumptions for the RGGI-affected regions for the RGGI analysis. These assumptions have been developed by the SWG and respective ISOs – ISO New England, NY ISO, and PJM.
  - Capabilities within Canada were taken from NERC, Canada's National Energy Board, Natural Resources Canada and the Canadian Electricity Association.
- Power transported across power pools is assumed to incur a cost of $2.60/MWh (2003$).
  - Within a power pool, no charge is assumed to be incurred due to postage stamp pricing.
  - As per guidance by ISO-NE, no charge will be imposed on flows between ISO-NE and New York.
- The expansion of PJM westward is explicitly accounted for in the pricing of transmission across power pools.
- The following assumptions were adjusted in the near-term to more closely represent 5-year average historical levels.
  - Flows were calibrated for flows from Canada and PJM West into RGGI.
  - The constraints affect only the 2006 and 2009 run years and are phased out by 2012.

Joint Transfer Capacity Constraints New England (GW)

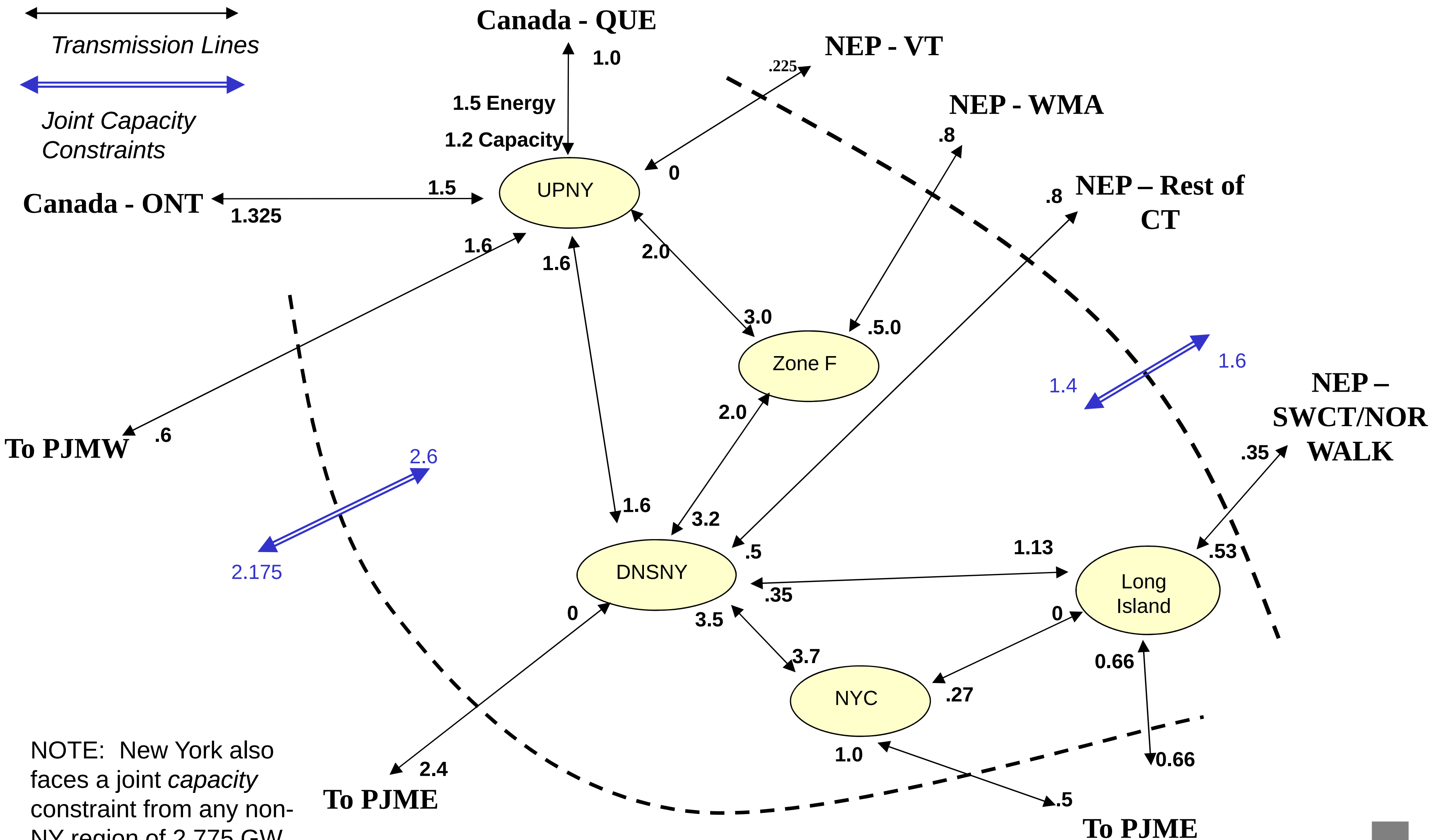


* Constraint increases to 2.6 in 2006 and 3.4 in 2008.

- Joint capacity limits constrain the ISO-NE system. These constraints are applied to transfer capabilities over multiple lines such that the total transmission into or out of a region is limited to an amount less than the sum of all of the transfer capability linked to the region.

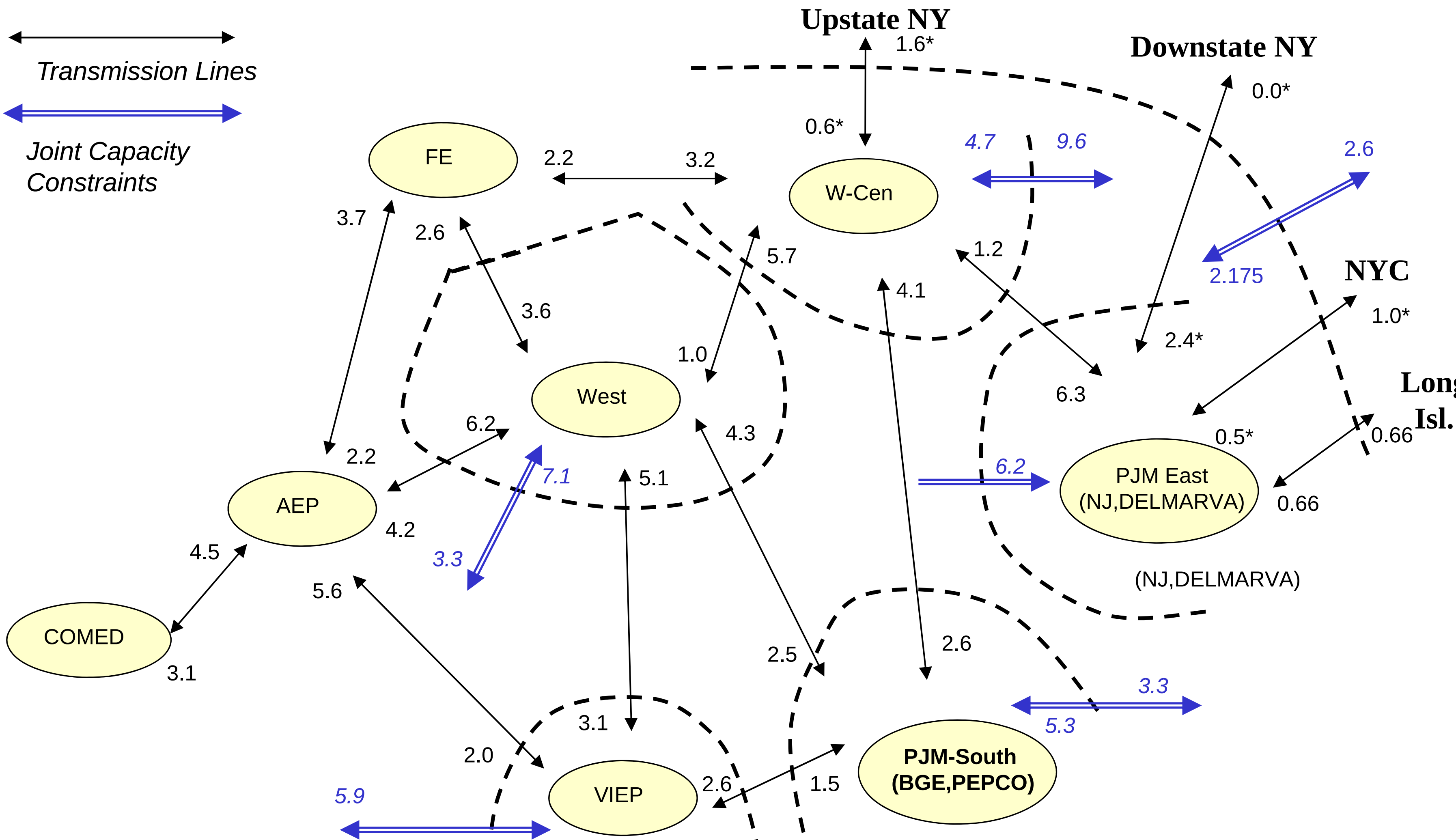
- The joint limits used in this analysis are based on RTEP 2004, as provided by Jim Platts at ISO-NE, except NY-NE to NY limit provided by NYISO.

Transmission Capability -- Energy New York (GW)



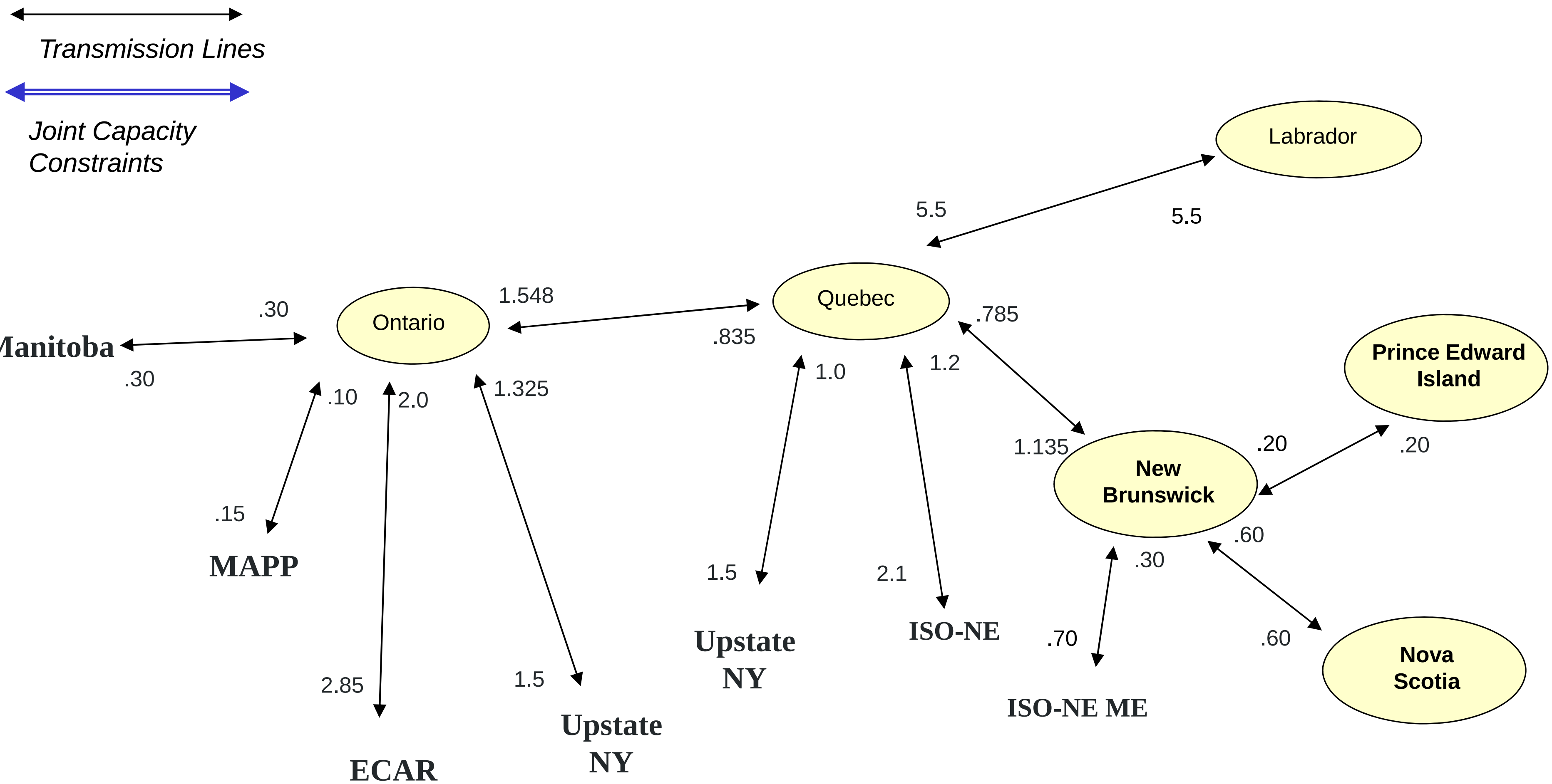
NOTE: New York also faces a joint *capacity* constraint from any non-NY region of 2.775 GW.

Transmission Capability -- Energy PJM (GW)



* *Inputs from NYISO*

Transmission -- Energy Eastern Canada (GW)



Emissions Control Technologies/Retrofits

Emissions Control Technologies/Retrofits

- Within the IPM® framework, units affected by air emissions regulations can comply by fuel-switching, buying allowances if the policy is market-based, reducing dispatch/shutting down, or installing emissions control technologies.

- IPM® explicitly models the most common existing control technologies, each of which impact the emissions rate for one or more regulated pollutants, SO_2, NO_X, mercury, and in some cases CO_2. Emissions rates are actually emissions reduction factors applied to the input content of the fuel.

- For this analysis, the SWG has chosen to use EIA's assumptions for SCR and ACI controls and EPA's v.2.1.6 assumptions for SO_2 scrubber controls.
  - Because EIA does not model an intermediate NO_X control option, an SNCR option based on EPA assumptions is also being included.

Combustion Control Assumptions

- EPA assumes that NO_X combustion controls are an initial step to comply with a NO_X control program.
- Baseline NO_X rates in affected areas are assumed to capture the implementation of combustion controls.
- The baseline rates serve as the starting NO_X rate to which emission rate reductions from endogenously selected post combustion environmental controls are applied.

Assumptions for SCR Cost and Performance for Coal Units (2003$)

Unit Size (MW)	300	500	700
Capital ($/kW)	112.8	98.6	89.4
Fixed O&M ($/kW-yr)	1.6	1.3	1.1
Variable O&M (mills/kWh)	1.6	1.6	1.6
NO_X Removal	90%	90%	90%

- The SWG has chosen to use EIA's cost and performance assumptions for SCR controls.
- EIA assumes that combined FGD and SCR controls result in a 90% reduction (from input) in Hg emissions from bituminous coals.

Source: EIA AEO 2004 assumptions

SO_2 Control Assumptions for Coal Units (2003$)

	All Costs are Based on a 500 MW Unit
SO_2 Option	LSFO
Capital ($/kW)	236.1
Fixed O&M ($/kW-yr)	9.16
Variable O&M (mills/kWh)	1.08
SO_2 Removal	95%

- The SWG has chosen to use EPA's cost and performance assumptions for SO_2 controls.
- SO_2 Control Notes
  - LSFO = Limestone Forced Oxidation, applied to boilers ≥ 100 MW
  - Option assumes a 2.1% capacity and heat rate penalty
  - EPA assumes a SCR and scrubber combination results in a 90% Hg removal (from input). With the scrubber alone, we assume EPA will use their previous 34% Hg reduction co-benefit.

Source: "Documentation of EPA Modeling Applications (V.2.1) Using The Integrated Planning Model", March 2002

Scrubber Technologies on Coal Units
Cost Scalars (2003$)

- LSFO
  - Capital = 5,232.8*(1/MW)^0.4986
  - Fixed O&M = 135.5*(1/MW)^0.4336
  - Variable O&M = Fixed at 1.08
- ICF calculated the EPA scalars based on the cost numbers for a 10,000 Btu/kWh heat rate unit presented in the *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model*.

Source: “Documentation of EPA Modeling Applications (V.2.1) Using The Integrated Planning Model”, March 2002

Mercury Assumptions

- There are three types of mercury assumptions used in IPM®
  - Mercury content of coal
  - Mercury removal rates for each unit
  - Cost and performance for Activated Carbon Injection (ACI), the pollution control technology that, when installed with a fabric filter, is typically considered the most effective control for mercury emissions.
- Data sets regarding the mercury content of coal and the mercury removal rates for existing units were developed using EPA's Mercury Information Collection Request (ICR) process.

Mercury Content of Coal Assumptions

- As part of EPA's mercury ICR, generation plant owners were required to provide data on the mercury content of coal for every sixth shipment delivered to their plant. EPA processed this data to develop estimates of the weighted average mercury content for each coal type in each coal supply region used in IPM®.
  - These contents are reflected in the content clusters shown on the following page.
- The results of this analysis show that western sub-bituminous coals have much lower mercury content than eastern bituminous coals.
- However, emissions from these sub-bituminous coals have much higher elemental mercury concentrations and eastern bituminous coals emissions have higher oxidized mercury concentrations. Because oxidized mercury is readily removed by ESP's and other particulate devices and elemental mercury is not, the effective emission rate for units burning western coals is not as low as the mercury concentrations would suggest.
- When analyzing a mercury MACT policy, IPM® can switch to lower mercury content coals as one of the compliance options.
- ICF adjusts the mercury removal rates downward if a unit switches to subbituminous coal and adjusts removal rates upward if units switch to bituminous coal. This accounts for the lower effective removal rate when burning subbituminous coals.
- A second part of EPA's mercury ICR consisted of reporting stack emissions of mercury.

Mercury Content of Coal (lbs/TBtu)

- Mercury contents of coals will be applied as shown in the table below. The "clusters" are used by EPA to capture variations in the mercury contents of coal types by supply region. In IPM®, units have the option, if the transportation links allow, of switching among coal types and bins to control mercury emissions.

Coal Type by Sulfur Grade	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	3.69	5.14	---
Low Sulfur Western Bituminous (BB)	3.41	4.1	7.85
Low Medium Sulfur Bituminous (BD)	5.07	12.54	21.95
Medium Sulfur Bituminous (BE)	6.08	10.45	18.42
Medium High Sulfur Bituminous (BF)	6.83	11.09	18.69
High Sulfur Bituminous (BG)	8.04	17.43	28.73
Low Sulfur Subbituminous (SB)	4.55	6.48	---
Low Medium Sulfur Subbituminous (SD)	4.4	6.7	---
Medium Sulfur Subbituminous (SE)	5.53	10.71	---
Low Medium Sulfur Lignite (LD)	8.45	---	---
Medium High Sulfur Lignite (LF)	5.88	9.79	---

Source: "Documentation of EPA Modeling Applications (V.2.1) Using The Integrated Planning Model", March 2002

Assumptions for ACI Cost and Performance (2003$)

- The table below shows EIA's cost and performance assumptions for mercury control using activated carbon injection (ACI) that will be used for this analysis. The cost of the control depends on the existence of a fabric filter on the unit. Units without a fabric filter must install a fabric filter to get the full 90% reduction with the ACI.

Unit Size	EIA AEO 2004	
	For Units without preexisting Fabric Filter	For Units with preexisting Fabric Filter
Capital ($/kW)	62.00	4.07
Fixed O&M ($/kW-yr)	1.52	1.52
Variable O&M (mills/kWh)	0.66	0.13
Hg Removal	90%	90%

Repowering Assumptions (2003$)

- The following repowering options will be offered to existing coal- and oil/gas-fired capacity in the RGGI region.

	Repower Coal to Super-critical Controlled Coal	Repower Coal to Gas Combined Cycle	Repower Oil/Gas to Combined Cycle
Capital ($/kW)	675	515	515
Fixed O&M ($/kW-yr)	25.22	13.70	13.70
Variable O&M	3.15	1.16	1.16
Heat Rate	8,600	7,700	7,700

Source: Costs for repowering to combined cycle taken from “Documentation of EPA Modeling Applications (V.2.1) Using The Integrated Planning Model”, March 2002. Heat rates scaled to combined cycle build performance assumptions. Super-critical coal option estimated at roughly half of the cost of a new coal plant, or the portion of a new plant associated with constructing the boiler.

Treatment of Announced Pollution Control Equipment Installations

- ICF regularly tracks announced pollution control retrofit installations and makes a determination regarding whether the announced retrofit should be considered “firm” and therefore “hardwired” into the analysis, or not.

- Since IPM® will retrofit units as it deems appropriate, given the market and air regulatory environment being analyzed, only those retrofits that are judged to be relatively certain are included in the analysis.

Renewable Capacity and Markets

Modeling Renewable Resources in IPM®

- Renewable resources are endogenously modeled in IPM® and include wind, landfill gas, solar (thermal and photovoltaic), hydro and geothermal technologies.
- Representation of renewable resources in IPM® requires that several assumptions be specified, including the demand for renewable resources and the supply characteristics of renewable capacity technologies.
- The demand side is specified through grassroots demand and RPS policies.
  - In addition to specifying generation requirements, the RPS programs will specify the resources that qualify in meeting specific state and/or regional policies.
- Renewable generation supply options are specified in the same way as conventional generation options, with cost and performance assumptions, but must also include limits on renewable resource availability.
- This section describes the key renewable market demand and supply assumptions used for the RGGI analysis. These assumptions and the following slides were developed by the SWG with the assistance of Bob Grace and LaCapra Associates.
  - The RPS program and demand assumptions are described first, followed by technology option and supply assumptions.

Renewable Market Demand

Renewable Market Demand Overview

- Purpose:
  - Provide a reasonable set of modeling input assumptions for IPM® renewable energy (RE) supply, cost and demand to enable policy analysis of greenhouse gas initiative measures.
- Perspective:
  - "Middle of the Road" estimates, neither conservative nor aggressive.
- Constraints:
  - Use most recent available studies and sources to the maximum extent possible, while seeking reasonable consistency across the modeling region
  - Accommodating state or regional studies of different qualities, assumptions, and biases, and filling numerous data gaps
  - Simplifications required to model unique state RPS requirements on a regional basis
- Analysis years – 2005, 2010, 2015, 2020
  - RE assumptions are not further evolved after 2020 due to data limitations

Expected RPS Mandates Driving Demand for Incremental RE

- The following state renewable programs are included for the RGGI analysis:
  - Connecticut Class 1
  - Massachusetts
  - New Jersey Class 1 (main & solar tier)
  - Rhode Island
  - Maryland Tier 1
  - New York: Treat as reflected in Order, main tier and customer-sited tier
  - Pennsylvania Tier 1
- Others are not considered relevant to driving material incremental RE demand:
  - Maine
  - Connecticut Class 2
  - New Jersey Class 2
  - Pennsylvania Tier 2

Renewable Portfolio Standard Representation

- The RPS-driven demand driving incremental renewables will be represented in the RGGI analysis by simulating 2 “Standard” RPS policies
- Why?
  - Modeling requires simplification v. depicting 7 distinct RPSs and green power
- How?
  - Approximate differing eligible resources and geographic requirements across RGGI states while relaxing the fewest possible program-specific constraints.
  - Challenges: differing eligibility, geographical and vintage requirements
- The demand and supply specifics of each Standard RPS are outlined on next slide.

“Standard” RPS Definitions

	RPS 1: RGGI Northern Tier	RPS 2: RGGI Southern Tier
Simulated RPS Requirement derived from Existing/Proposed State RPS Policies	MA & RI	NY, NJ Class 1, MD Tier 1, CT Class 1, PA Tier 1
Eligible to Supply RECs without Energy Delivery	New England	New England (incl. MA & RI) NYISO, PJM
Eligible to Supply RECs only with energy delivery	NY, Quebec,	Ontario & Quebec
Eligible Resource Types	Wind, LFG (post 97 only) Incremental hydro <30 MW (only after 2006) All post-1997 biomass [retrofits will be addressed thru adjustments to targets] Biomass co-firing @ coal plants 2010 and later only	Wind (all); LFG (all) Incremental hydro <30 MW All post-2002 biomass Biomass co-firing @ coal plants

Determining RE Demand

- The following steps were followed to develop the minimum generation requirements for the two RPS programs:

  1. Determine Unadjusted RPS Targets
  2. Apply to Applicable Load and Exemptions (see slide 104)
  3. Apply RPS Demand “Adjustments” (see slides 105-106)
  4. Add Other Regional Demands for New RE
     - Voluntary (Green Power) & SBC-Driven
     - Canadian

Unadjusted Target RPS Targets Driving Incremental RE (as a percentage of state load)

State Program	2005	2010	2015	2020
CT Class 1	1.50%	7.00%	7.00%	7.00%
NJ- Class 1 Main Tier	0.74%	4.30%	6.59%	8.88%
NY- Main Tier *		4.05%	6.43%	6.43%
MD Tier 1		3.00%	5.00%	7.50%
PA Tier 1		3.48%	5.75%	7.50%
MA	2.00%	4.50%	7.00%	9.50%
RI	0.00%	2.50%	8.00%	14.00%
To be modeled separately:				
NJ- Solar Tier	0.01%	0.20%	0.41%	0.62%
PA- Solar Tier	0.00%	0.02%	0.25%	0.50%

***** = This percentage applicable to entire state load, from NY RPS Order. The percentage applicable to the 6 obligated LSEs is higher.

Unadjusted RPS Targets: Key Assumptions

- Massachusetts
  - After 2009, the minimum standard increases by 1%/year, or is suspended for any given year, at the discretion of DOER.
  - ➔ Assume 0.5%/year escalation as a middle ground assumption.
- New Jersey Class 1
  - After 2008, BPU will revisit future targets.
  - ➔Assume continue to increase at 0.5%/yr (50% of the last step 2007->2008) from 2009 through 2020, resulting in 9.5% total by 2020.

    For context: RE Task Force Goals of 20% new by 2020.
- Rhode Island
  - 2% of target can be met by existing resources.
  - ➔ Subtracted 2% from statutory targets,
- New York:
  - 2% of total RPS Increment set aside for Customer-sited Resource Tier and green power demand

RPS Applicable Load and Exemptions Reduce Impact

- Total state load to which targets are applied adjusted downward to reflect exemptions:
  - Connecticut Class 1, Massachusetts, New Jersey all exempt public power
  - Rhode Island exempts Pascoag Utility District & Block Island
  - Maryland: Extensive exclusions for sales to:

    customers in excess of 300,000,000 kWh/yr of industrial process load;

    residential customers subject to a settlement agreement price freeze or cap, until the expiration of that cap; and

    customers of an Electric Cooperative under a pre-October 2004 supply agreement until the expiration of that agreement.

    Info on impact of specific assumptions from: Maryland's Renewable Portfolio Legislation: Issues, Options and Recommendations Report, August 13, 2004
- New York exempts public power, NYPA, LIPA, and large end-users on economic development FlexRates
  - Targets on previous slide apply to entire state load, no adjustment needed
- ➔ ICF to adjust applicable load accordingly, consistent with load forecasts used in IPM

Additional Adjustments to Incremental RE Demand

- CT:
  - Reduce RPS demand to account for estimated generation being met by existing eligible hydro, wind and landfill methane RPS-eligible (primarily pre-1998, not MA-eligible)
  - ICF will force SBC-driven fuel cell quantities and tag them as eligible for Southern Tier RPS, rather than subtracting from RPS incremental energy requirement
- NJ:
  - Reduce RPS demand to account for estimated generation being met by existing eligible wind and landfill methane known to be RPS-eligible
- MD
  - Reduce targets to account for a portion of RPS being met by existing eligible resources. Assumed RECs from all PJM hydro < 30 MW chase MD RPS revenue. While NY small hydro is eligible it is in NY RPS baseline, so not considered. (if used for MD, NY RPS would increase)
  - No need to reduce targets to reflect bonus credit for solar, wind and methane, as they only apply through 2008.
- MA:
  - Reduce RPS demand to reflect estimated 50% of existing (currently ineligible) biomass generators retrofitting to qualify as new/vintage with zero baseline
  - Reduce RPS demand to account for estimated generation being met by existing RPS-eligible post-97 renewables

Additional Adjustments to Incremental RE Demand
continued

- Banking and Flexibility Mechanisms provisions allow obligated entities to deal with year-to-year variations in REC output in meeting their requirements.
  - While the effect of all banking and flexibility mechanisms may have a significant near term effect on the year-to-year supply of renewable resources, they are likely to have a negligible effect over a 20 year period, and were therefore ignored for the purposes of a 20 year study.

Additional Adjustments to Incremental RE Demand Required for Alternative Compliance Payments

- Maryland has very low ACP:
  - for industrial process load, compliance fees will be assessed at rates between 0.8 cents per kWh and 0.2 cents per kWh for Tier 1 shortfalls
  - Tier 1 shortfalls for other load = 2.0 cents per kWh
  - Low Alternative Compliance Payment suggests that full RPS will not be met. We assume only 50% of RE Demand after exemptions and adjustments is met with new RE, the remainder resulting in ACP payments that are assumed to be reinvested in acquiring only 50% of the RECs demanded, resulting in 75% demand after exemptions and adjustments being met
- Massachusetts expecting non-compliance in 2005, leading to payment of ACP
  - Insufficient supply situation driven primarily by lead-time, expected to be transitory
  - Since intent is to reinvest ACP payments in new RE, with ~2 year lag between collection and investment coming on-line, this situation represents only a moderate timing influence on the analysis, in only the 2005 modeling year
  - Propose to ignore this effect as immaterial to the overall analysis

Other Regional Demands for New RE: including Voluntary (Green Power)

- Projections for new RE resulting from voluntary commitments (Green Power, GP) to be projected based on level of GP activity observed
- For NY, ramping from current penetration to 1% of total NY sales by 2013, from RPS order goals
- Additional demand considered:
  - NY: added Executive Order 111 (state facilities) commitments above RPS levels, from NY RPS Order

State	New RE Penetration Level from GP
Connecticut	Moderate
Delaware	Low
Maine	Low
Maryland	Low
Massachusetts	Moderate
New Hampshire	Low
New Jersey	Moderate
New York	reach 1% by 2013, moderate thereafter
Pennsylvania	Low
Rhode Island	High
Vermont	Low
West Virginia	Low

New RE Penetration	2005	2010	2015	2020
Low	0.01%	0.07%	0.19%	0.37%
Moderate	0.02%	0.18%	0.49%	0.99%
High	0.04%	0.36%	1.01%	2.06%

Green Power Penetration Assumptions

- 2004 unpublished projections by R. Grace, E. Holt for NYSERDA
- Low-end: consistent with the following suite of SBC-supported activities: a sustained education and awareness campaign based on best practices, associated promotional events; co-marketing with green power providers.
- High-end: Consistent with all low-end activities, plus… additional very aggressive programs:
  - a coordinated state-wide green power campaign for all customer classes based on best-practices in program structure
  - substantial level of SBC support
  - marketing incentives to help reduce the cost of customer acquisition or customer credits to reduce ultimate cost of green power to customers.

Key Assumptions (in 2013) for statewide averages	**Low-end**	**High-end**
Residential		
Customer penetration	2.0%	5.0%
Total RE as a % of customer's load	60%	80%
New Renewables as a % of total product RE content	33%	50%
Non-Residential (Commercial, Industrial, Institutional, Transportation)		
Customer penetration	0.1%	1.0%
Total RE as a % of customer's load	3%	10%
New Renewables as a % of total product RE content	20%	80%

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Canadian Renewable Demand

- Canadian renewable demand was not addressed directly in this analysis.
  - Instead, the SWG assumed that lowest cost resources “stay at home”; and identify resources for export only well in excess of potential domestic demand.

Renewable Market Supply – Technology Cost, Performance and Resources

Resource Cost Characteristics

For each technology, the following assumptions were developed for input into IPM®:

- **Capital Costs,** $/kW
  - Initial costs to purchase and install the renewable generating plant and associated equipment including capitalized labor costs
  - We assume differences in capital costs within the RGGI region are generally negligible
- **Fixed O&M**, $/kW-year
  - The non-fuel operations and maintenance costs that do not vary with the amount of electricity generated. These costs typically comprise labor, materials and supplies
- **Variable O&M**, $/MWh
  - The routine and necessary non-fuel costs and expenses incurred by the operator that vary with the amount of electricity generated
- **Heat Rate,** Btu/kWh
  - Measure of how efficiently an electric generator converts thermal energy into electricity
  - Applicable to biomass technologies, and fuel cells.
- **Capacity Factor**
  - For wind, varies by block based on wind speed
  - Hourly production profiles developed for wind, hydro, and solar/PV.
  - Biomass dispatchable, so no capacity factors explicitly modeled
  - Landfill methane and fuel cells are treated as baseload (same production in all hours)

Renewables Financing Assumptions

- Debt: Equity Ratio 60:40
- Debt Cost 8%
- Equity Cost (after tax) 14%-19%
  - Benchmarked to IPM®'s conventional power plants equity rate of 13%
  - Perceived risk of renewables decline over time, as technologies mature and become more "mainstream"
  - Offshore wind higher cost than other renewable technologies
- Debt Life 15 years, 20 years for hydro
- Accelerated Depreciation (5 year MACRS) for wind and landfill gas
- Marginal tax rate 41%
- Canadian Wind: Canadian depreciation schedule (declining balance method at 8%), lower marginal tax rate (37%)

Federal Renewable Production Tax Credit (PTC)

- Background:
  - PTC has been major cost factor for wind, providing 10 years of tax credits values at 1.8 cents/kWh (in 2003) for projects achieving commercial operation before expiration
  - Expired at end of 2003; new law just extended through 2005 (although EPACT05 extended the PTC to 2007, this was not included because the extension occurred after this analysis was underway)
  - Was available to wind and closed-loop biomass plants (there have been none of the latter)
  - Bill passed this week extends PTC to open-loop biomass, solar, landfill gas and others
- Approach:
  - Assume extended through 12/31/05 with new eligibility and inflation adjustment intact
  - Thereafter, assume static at 50% of 2005 level, with no change in eligibility through 2010
  - Applied this to all U.S. eligible resources (e.g. did not assume any municipal financing)
- Rationale:
  - Assumption represents a “middle ground” between further PTC extension after 2005 and no PTC extension

PTC Modeling Summary

Resource/Installation	2004-05	2006-10	2011 +
Wind, Closed Loop Biomass[1], Solar	1.8 cents/kWh + CPI for first 10 years of operation	0.9 cents/kWh + CPI for first 10 years of operation	0
Open-loop biomass, Landfill gas	0.9 cents/kWh + CPI for first 5 yrs. of operation	0.45 cents/kWh + CPI for first 5 yrs. of operation	0

[1] A comparison of the tax incentives for closed and open loop biomass vis-à-vis their relative fuel costs indicates that even with the greater PTC incentive, closed loop biomass is more costly. We have therefore assumed that all new construction in the study period is open-loop biomass, i.e. no need to model closed-loop biomass.

Resource Cost and Performance Characteristics

Interconnection and Transmission Costs

- We added the costs of interconnecting renewable generators to utility transmission or distribution systems to cost assumptions that appeared to omit these costs
- Where we felt that the capital costs do not allow for sufficient local and/or upstream transmission investments, we added an estimate to reflect these additional costs. (e.g. wind)

Transmission extension costs added for wind farms greater than 5 miles from transmission

- $500,000/mi for 115kV and $160,000/mi for 60kV times:
  - For 5-20 miles from transmission, weighted average distance for each block
  - Beyond 20 miles, assumed avg. distance from transmission = 35 miles
- The size of line selected was based on the MW in each block (the lower voltage and cost was used for wind farm blocks of 50 MW and less)
- Ignore costs for clusters that can interconnect at distribution voltages if > 5 miles from transmission

Exports of RE from Ontario and Quebec to the US

- We added ICF’s standard flat transmission charge of $2.60/MWh ($2003) for imports from Canada into the US.

Resource Cost and Performance Characteristics
continued

Wind Integration Costs

- Due to the operational impacts of wind (effects on unit commitment or regulation requirements), there may be additional system costs associated with wind resources. Capital investments to improve the transmission grid may also be necessary.
  - IPM® does not add transmission investments (beyond basic interconnection costs) for other resources, so we recommend excluding those costs from our integration inputs.
- Our analysis of available studies of such costs concluded:
  - For NYISO, additional operational costs on the order of $1/MWh may be imposed for incremental additions when wind penetration levels are low, increasing to $10/MWh when wind penetration levels reach 20%.
  - No "hard cap" on the amount of wind power in NY was identified.
  - These NY-specific results can be applied to the costs of wind generation additions in neighboring control areas.
- For the purpose of this analysis, the same operating cost estimates were applied to all RGGI regions.

Sources: *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations,* NYISO/NYSERDA, February 2004; Utility Wind Interest Group study, November 2003, Group, *Grid Impacts of Wind Power: A Summary of Recent Studies in the United States*, Brian Parsons, June 2003; various reports by Eric Hirst.

Wind Performance Assumptions:
U.S. Onshore wind

Forecast of Wind Net Capacity Factors

	Class 3	Class 4	Class 5	Class 6
2005	28%	33%	37%	40.5%
2010	29%	34%	38%	41%
2015	30%	35%	39%	42%
2020	31%	36%	40%	43%

Performance based on wind speed and assumed to improve over time due to improved efficiency of wind turbines.

Sources: Professional judgment after reviewing Navigant, The Changing Face of Renewable Energy (June 2003) (E.g., Class 4 is 31% trending to 37% in 2013); New Jersey Renewable Energy Market Assessment (August 2004) (p. 221 80 m hub height) (Class 4 is 35% in 2005 trending to 38.2% in 2020); Black and Veatch, Economic Impact of Renewable Energy in Pennsylvania (March 2004) (p. D-11) (Class 4 is 31%), AEO 2003, App. L, p. L-2 (Class 4 is 32.5% in 2005 trending to 33.8% in 2020). New Jersey study adjusted down to reflect greater impact of icing in most of the region. AEO 2003 adjusted up to reflect general consensus on continued improvement as shown in recent studies particularly regarding lower wind sites.

Note: Some studies show greater increase in capacity factors over time than exhibited by the data above. The data above reflects a downward adjustment to those numbers to reflect icing conditions in the Northeastern U.S. which reduce annual capacity factors.

Canadian On-shore Wind Performance Assumptions:
Forecast of Net Capacity Factors

Year	All Classes
2005	31%
2010	32%
2015	33%
2020	34%

- *Performance based on the average performance of class 3 and 4 US on-shore wind sites.*
- *Performance assumed to improve over time due to improved efficiency of wind turbines.*

Off-shore Wind Performance Assumptions:

Forecast of Net Capacity Factors

	Class 5	Class 6	Class 7
2005	33%	37%	40%
2010	34.5%	38.5%	41.5%
2015	36%	40%	43%
2020	38%	42%	45%

Sources: New Jersey Renewable Energy Market Assessment (p.221) (showing class 6 and trend over time); e-mail from B. Bailey (AWS Scientific) showing current relative capacity factors by class.

Onshore Wind Resource Potential Assumptions (MW)

Onshore Wind	Cost Step 1				Cost Step 2				Cost Step 3			
	"Near" = 0-5 Miles from Transmission				**"Far" = 5-20 Miles from Transmission**				**"Distant" >20 Miles from Transmission**			
Zone	**Class 3**	**Class 4**	**Class 5**	**Class 6+**	**Class 3**	**Class 4**	**Class 5**	**Class 6+**	**Class 3**	**Class 4**	**Class 5**	**Class 6+**
Quebec	-	-	-	-	-	-	-	-	-	-	-	-
Ontario	-	-	-	-	-	-	-	-	-	-	-	-
NS	-	-	-	-	-	-	-	-	-	-	-	-
NB	-	-	-	-	-	-	-	-	-	-	-	-
ME	442	85	35	54	1,593	525	254	348	-	231	102	73
NH	487	193	104	150	585	269	139	235	-	75	-	-
Vt	646	212	88	68	886	337	158	156	-	-	-	-
WMA	619	71	-	-	216	29	-	-	-	85	-	-
CMA/NEMA	-	-	-	-	-	-	-	-	-	-	-	-
Boston	-	-	-	-	-	-	-	-	-	-	-	-
SEMA	100	-	-	-	35	-	-	-	-	-	-	-
RI	-	-	-	-	-	-	-	-	-	-	-	-
Southwest CT	-	-	-	-	-	-	-	-	-	-	-	-
Other CT	-	-	-	-	-	-	-	-	-	-	-	-
UPSNY	2,431	182	43	-	1,953	186	38	-	-	65	-	-
CAPITAL	145	-	-	-	123	-	-	-	-	-	-	-
DNSNY	60	-	-	-	51	-	-	-	-	-	-	-
NYC	-	-	-	-	-	-	-	-	-	-	-	-
LI	-	-	-	-	-	-	-	-	-	-	-	-
PJM East NJ	-	-	-	-	-	-	-	-	-	-	-	-
PJM APS	1,575	380	116	94	1,085	289	131	151	-	-	-	-
PJM West-Central	982	135	45	-	374	60	18	-	-	-	-	-
PJM South	-	-	-	-	-	-	-	-	-	-	-	-
PJM East Delmarva	25	-	-	-	-	-	-	-	-	-	-	-
Total Available	**7,512**	**1,258**	**431**	**367**	**6,902**	**1,695**	**738**	**889**	**-**	**456**	**102**	**73**

Vermont wind builds were limited to 80 MW due to siting constraints

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Offshore Wind Resource Assumptions (MW)

Onshore Wind				
Zone	**Class 3**	**Class 4**	**Class 5**	**Class 6+**
Quebec	-	-	-	-
Ontario	-	-	-	-
NS	-	-	-	-
NB	-	-	-	-
ME	107	37	17	24
NH	85	36	19	29
Vt	190	71	44	40
WMA	147	18	18	12
CMA/NEMA	164	34	-	-
Boston	82	17	-	-
SEMA	274	79	5	-
RI	82	22	-	-
Southwest CT	-	-	-	-
Other CT	41	-	-	-
UPSNY	345	41	9	35
CAPITAL	47	27	-	-
DNSNY	20	-	-	-
NYC	-	-	-	-
LI	79	8	-	-
PJM East NJ	100	-	-	-
PJM APS	444	116	82	82
PJM West-Central	176	65	21	30
PJM South	-	-	-	-
PJM East Delmarva	43	-	-	-
Total Available	**2,427**	**571**	**215**	**252**

NJ Wind Supply Subsidies

- NJ Clean Energy Program is expected to support some amount of wind in-state, that would be available for RPS compliance (or GP), that would not otherwise occur. We estimate discounts to NJ Wind, as shown in the table below, that are sufficient to make some NJ wind competitive.
  - These adjustments were implemented as lower capital costs for all Class 4 and some Class 3 NJ on-shore wind.

Estimated total of 2005-2008 investment in NJ wind ($6m/yr for 4 yrs)	**$ 24,000,000**
Estimated MW of on-shore supply curve to support (all Class 4, clusters)	**60 MW**
Average on-shore cost reduction ($/kW)	**$ 400/kW**

Biomass Resource Availability and Quality

Background

- Biomass fuel availability will likely be the constraint on most new biomass generation construction
- Goals: 1) estimate the amount of biomass fuel available for incremental power generation 2) Based on total cost of energy, determine which technologies will likely be built.

Approach: Co-firing

- Assumed to be limited by current coal capacity, not fuel.
- Co-firing in 25% of existing coal facilities. We assume maximum of 15% of total energy output in each co-fire facility, as a proxy for local fuel limitations.

Biomass Resource Availability and Quality

Approach: Fuel Availability and Cost

- Midpoints of cost blocks used to characterize costs. Available fuel described by 4 cost blocks (Mid-points of cost blocks):
  - $.70/Mmbtu
  - $1.70/Mmbtu
  - $2.40/Mmbtu
  - $3.15/MMbtu
- Total available biomass feedstock must be reduced by fuel used in existing biomass power generation
- All remaining fuel assumed available for incremental power generation.
- Fuel currently used in power generation assumed to be lower cost. *(total: 93 million MMBtus)*

Biomass Feedstock Considered

- Agricultural Residues
- Forest Residues
- Mill Wastes
- Urban Wastes
- Dedicated Crops (potential)

Total feedstock in region available for electric generation:

394 million MMBtu

Data from *Biomass Feedstock Availability in the US: 1999 State Level Analysis*, Oak Ridge National Laboratory

Biomass Resource Availability and Quality

	\$.70/Mmbtu	\$1.70/Mmbtu	\$2.40/Mmbtu	\$3.15/Mmbtu	Total
Estimated biomass feedstock available for electricity generation, *million mmbtu*	49.6	110.9	36.3	197.1	393.8
Used in current electricity generation, *million mmbtu*	(26.9)	(34.9)	(7.5)	(23.3)	(92.6)*
Net remaining biomass feedstock	**76.4**	**145.8**	**43.8**	**220.4**	**301.2**

Notes

Estimated biomass feedstock data from 1999 ORNL state by state study. Biomass currently used in electricity generation based on estimate from EIA.

* EIA estimates that current electricity generation with biomass fuel in the RGGI footprint to be about 101 million MMBtu annually. We assume some portion of Maine's current biomass-powered generation utilizes feedstock from Canada, and thus reduce current feedstock available in U.S. by less than the amount estimated by EIA.

Biomass Resource Availability and Quality

Approach: New Construction of Biomass Technologies

- All co-firing assumed to be operational in 2006 or thereafter. Assumed to utilize lowest cost fuel.
- Gasification, direct-fire and fluidized bed total energy costs compared in various years (2010, 2015, and 2020).
  - New build in each year assumed to be exclusively the more economic technology.
  - Remaining fuel allocated to these technologies.

Biomass Resource Availability and Quality

Approach: Allocation of Fuel Availability to Modeling Zones

- Fuels designated as "rural" or "urban". Rural fuels allocated to zones based on area statistics, urban fuels based on population statistics.

Approach: Transportation Limitations

- Transportation is costly and therefore usually not practical to transport > 50 miles.
- Assume all new facilities will be built close to fuel sources.

Approach: Sustainable biomass RPS requirements

- No adjustments made for NJ and CT fuel restrictions. We assume NY and MD, which have minimal restrictions, can absorb RECs generated by such fuel by displacement.

Urban Wood Waste Biomass - Spatial Distribution

- Issue: While data shows a large amounts of urban waste in NYC & LI, there would likely be little if any new facilities built in such congested areas.
- Resolution: Fuel available in these areas could be transported to neighboring, less congested areas. We have allocated the fuel in NYC and LI as follows:
  - 1/3 of the fuel transported to New Jersey (primary use in co-firing)
  - 1/3 of the fuel transported to Downstate New York
  - 1/3 of the fuel transported to Connecticut
    - ½ of this fuel to Southwest Connecticut
    - ½ of this fuel to rest of Connecticut, with an increase of one cost block ($.70-$1.00/mmbtu) to reflect transportation over greater distance

Resource Specific Cost Assumptions: Biomass ($2003)

	Capital costs assumed in 2005 ($/kW)	Variable O&M ($/Mwh)	Fixed O&M assumed in 2005 ($/kW-yr)	Assumed Fuel Cost ($/MWH)[1]	Heat Rate (Btu/kWh)
Co-firing	239	4.6	10	0+/- *	11000
Direct Fire with RSCR	2100	5	225	35	14000
Gasification	2890	3	250	24	9750

•Offset by coal savings.
[1]For illustrative purposes only, based on an assumed fuel cost of $2.50/MMbtu
• **Source Data: Renewable Energy Technology Characterizations (1997), DOE/EPRI, adjusted per communication with John Irving, McNeil Generating Station.**
•**Communication with manufacturers and developers for fluidized bed costs.**

Landfill Gas Availability and Quality

Approach

- We began with a forecast from EPA's Landfill Methane Outreach Program database of all potential sources of LFG
  - Candidate landfills
  - Under construction projects
  - Shut-down projects
- Assumed 25% of the MWs with collections in place could be realized by 2005 if economic; remaining phased-in by 2010
- Estimated impact of increased new sources of waste offset (in part) by degradation of methane available in existing sources; resulted in 3.1% CAGR in MW available through 2020.
  - CAGR based on detailed NY-specific analysis in NYSERDA Technology Assessment
- Considered separately LFG with and without collection systems

Resource Specific Cost Assumptions: Landfill Gas

- Cost data developed for sites with and without collection systems.
- No change in capital and fixed O&M costs over time assumed.
- Estimated fuel costs to be included in fixed O&M costs
- Sources: NY RPS Cost Study for LFG system costs and NYSERDA Technology Assessment for collection system costs

	Site Without Existing Collection System	Site Has Collection System in Place
Capital Cost ($/kW)	**2,100**	**1,450**
Fixed O&M ($/kW-yr)	**295**	**205**
Variable O&M ($/MWh)	**0**	**0**

Landfill Gas Availability and Quality

LFG With Collection System - MW					
State	Max MW Potential	2005	2010	2015	2020
CT	16.3	2.6	12.0	14.0	16.3
MA	27.0	4.3	19.9	23.2	27.0
ME	6.7	1.1	4.9	5.8	6.7
NH	13.4	2.1	9.8	11.4	13.4
RI	4.4	0.7	3.2	3.8	4.4
VT	0.4	0.1	0.3	0.4	0.4
NY	110.3	17.4	81.0	94.5	110.3
NJ	201.2	31.7	147.7	172.4	201.2
PA	169.6	26.7	124.6	145.3	169.6
DE	46.8	7.4	34.4	40.1	46.8
MD	22.8	3.6	16.7	19.5	22.8
Total	618.9	97.4	454.5	530.4	618.9

LFG Without Collection System - MW					
State	Max MW Potential	2005	2010	2015	2020
CT	5.2	0	3.8	4.4	5.2
MA	6.3	0	4.6	5.4	6.3
ME	1.8	0	1.3	1.5	1.8
NH	0.0	0	0.0	0.0	0.0
RI	0.0	0	0.0	0.0	0.0
VT	7.5	0	5.5	6.4	7.5
NY	10.8	0	7.9	9.3	10.8
NJ	12.0	0	8.8	10.3	12.0
PA	4.1	0	3.0	3.5	4.1
DE	28.5	0.0	20.9	24.4	28.5
MD	0.0	0.0	0.0	0.0	0.0
Total	76.1	0.0	55.9	65.2	76.1

Hydroelectric New Facilities & Upgrades

Approach

- Assume no new dams built during term of study period.
- Assume 30 MW cutoff (based on NY proposed, and RI RPS limitations)
- Source: “U.S. Hydropower Resource Assessment Final Report,” Idaho National Engineering and Environmental Laboratory (INEEL), 1998.
- Used quantities in INEEL, applying INEEL probability factors
- Allocation to modeling zones based on location of dams considered
- Without Power = existing dams with no existing power generation
- With Power = existing dams with existing power generation

Hydro Potential by State, MW

State	Without Power	With Power
Connecticut	14	11
Massachusetts	45	14
Rhode Island	10	0
Maine	127	47
New Hampshire	25	0
Vermont	58	32
New York	399	98
New Jersey	5	0
Delaware	0	0
Maryland	10	0
Pennsylvania	170	4
Total	863	206

Resource Specific Cost Assumptions: Hydro Capital Costs ($2003/kW)

- Region-specific costs derived from DOE's Hydropower Program database (operated by the Idaho National Engineering and Environmental Laboratory, INEEL)

Zone	Upgrades to Dams w/ Existing Generation		New Generation at Existing Dams	
	Group 1	Group 2	Group 1	Group2
CT - Southwest	$1,419	$3,010	$3,753	$5,383
CT - Other	$4,484	na	$3,810	$5,508
MA - Boston	na	na	$4,995	na
MA - CMA/NEMA	$2,946	$4,859	$2,124	$5,443
MA - SEMA	na	na	$6,220	$6,699
MA - WMA	$1,353	$4,151	$3,713	$5,313
ME	$1,402	$2,449	$2,417	$4,211
NH	na	na	$3,033	$4,661
RI	na	na	$4,367	$5,854
VT	$1,750	$3,188	$2,343	$3,844
NY - Zones G - I	na	na	$3,054	$4,668
NY - Zones A - E	$1,709	$2,741	$2,249	$3,603
NY - Zone F	$1,586	$2,061	$2,292	$3,261
PJM East NJ	na	na	$4,238	$5,794
PJM East Delmarva	na	na	$6,706	na

Resource Specific Cost Assumptions: Canadian Hydro ($2003)

- Cost data based on NY RPS Cost Study.
- No change in capital and variable O&M costs over time assumed and no PTC.
- Imports from Quebec and Ontario to NY as well as Quebec to New England subject to transmission charges of $2.60/MWh.[1]

	Ontario	Ontario	Quebec	Quebec
	Upgrade	New Low Impact	Upgrade	New Low Impact
Capital Cost ($/kW)	**$1,000**	**$1,861**	**$1,000**	**$1,500**
Fixed O&M ($/kW-yr)	**$0**	**$0**	**$0**	**$0**
Variable O&M ($/MWh)	**$5**	**$5**	**$5**	**$5**

[1]Imports from NY to New England not subject to transmission charges, consistent with recent decision on point-to-point transmission charges between the two regions.

Fuel Cells, PV, & Small Wind

- RPS requirements in some states have specific provisions for fuel cells,small wind and/or PV quantities
- Our analysis "forces" amounts of these technologies into the supply curve – regardless of economics – to reflect these provisions
- CT: ICF-developed assumptions for fuel cells driven by SBC activities
  - 50 MW total, with 15 MW on-line by 2010, 30 MW by 2015, and the full 50 MW by 2020.➔ assume all located in Connecticut
  - Assume 50% in Southwest CT region, the remainder in rest of state
- NJ and PA: PV
  - RPS solar tier as met in each year, with all PV located in-state
- NY
  - Used DPS staff cost study proportion of PV, small wind and fuel cells to total customer-sited tier (see RPS% table), with all built in NY**:**

    Solar = 2.3 MW

    Small wind = 1.4 MW

    Fuel Cells = 3.0 MW

Resource Specific Cost Assumptions: Fuel Cells

- Considered only Molton Carbonate Fuel Cells (MCFC) and Solid Oxide Fuel Cells (SOFC).
- Other potential technologies such as phosphoric acid fuel cells (PAFC) and proton exchange membrane (PEM) are not considered to be close to commercialization and hence not considered.
- Costs for a 1,000 kW project are represented. Scale economies are not great for this technology.
- Data Sources: Cost data for MCFC from *NJ Renewable Energy Market Assessment*, Navigant Consulting. Cost data for SOFC from NY RPS Cost Study.

Resource Specific Cost Assumptions: Fuel Cells ($2003)

	MCFC	SOFC
Capital Cost ($/kW)	3,500	3,600
Fixed O&M ($/kW-yr)	350	0
Variable O&M ($/MWh)	0	0

Resource Specific Cost Assumptions: Solar/Photovoltaic

- Cost data from the NY RPS Cost Study, prepared for NYSERDA.
- Illustrative costs shown below; costs decline over time for modeling inputs

Indicative Cost in 2005 (2003$)	Residential	Commercial
Capital Cost ($/kW)	6,625	5,650
Fixed O&M ($/kW-yr)	40	20
Variable O&M ($/MWh)	9	9

Capital Cost Trajectory over Time

Change in Capital Costs Over Time for Renewable Technologies $2003/kW	2005	2010	2015	2020
Onshore Wind				
Clusters	$1,461	$1,285	$1,122	$993
Farm	$1,131	$973	$835	$706
Offshore Wind	na	$1,789	$1,650	$1,602
Biomass				
Direct-Fired w RSCR	$2,100	$2,016	$1,950	$1,890
Co-Firing	$239	$229	$222	$215
Gasification	$2,890	$2,572	$2,312	$2,168
Landfill Gas				
With Collection	$1,450	$1,450	$1,450	$1,450
Without Collection	$2,100	$2,100	$2,100	$2,100
Hydro				
With Power				
Low Cost Group	$1,529	$1,529	$1,529	$1,529
High Cost Group	$2,617	$2,617	$2,617	$2,617
Without Power				
Low Cost Group	$2,369	$2,369	$2,369	$2,369
High Cost Group	$4,133	$4,133	$4,133	$4,133
Solar Photovoltaic				
Residential	$6,911	$5,482	$4,054	$4,014
Commercial	$5,874	$4,753	$3,631	$3,631
Fuel Cells				
MCFC	$3,495	$2,150	$1,456	$1,456
SOFC	$3,277	$2,705	$2,133	$2,133

Sources for cost trends:

Onshore and offshore wind cost trends based on "New Jersey Renewable Energy Market Assessment," Navigant Consulting, August 2004.

Biomass cost trends based on "Renewable Energy Technology Characterizations", EPRI, 1997.

Landfill gas cost trends based on NYSERDA NY RPS study.

Hydroelectric costs assumed to remain constant in real terms over time.

Solar PV cost trend based on NYSERDA NY RPS study.

MCFC fuel cell cost trends based on "New Jersey Renewable Energy Market Assessment," Navigant Consulting, August 2004.

SOFC fuel cell cost trends based on the NYSERDA NY RPS study.

Production Profiles

- For non-dispatchable resources, IPM® inputs require 24 hour production profiles for 2 seasons – May-Sept, Oct-April
- Key assumptions:
  - Biomass Fluidized Bed and gasification – assumed dispatchable
  - Biomass co-firing: model it as must run, flat year-round, based on expected economics when factoring in REC revenue
  - Landfill Gas – assume baseload (equal output all hours) @ 90%
  - Fuel Cells – assume baseload (equal output all hours) @ 90% (MCFC) and 85% (SOFC) c.f.
  - Photovoltaic – utilized ICF's default solar profile, scales to 17.5% c.f.
  - Hydroelectric (both categories) assumed run-of-river, reflecting same production in each hour within a month, with monthly capacity factors from INEEL state-by-state data
  - Wind – on-shore and off-shore:
    - Used data from a limited set of representative sites (simulated output using wind data, or measured output), chosen to provide good representation of all major wind regimes
    - Scaled to capacity factors assumed for each resource block
    - Capacity factors modeled as improving over time

Renewable Market Supply – Resource Timing/Availability Assumptions

On-Shore Wind Availability Phase-in

- Issue: IPM® algorithm called upon vast quantities of wind from high-wind-speed blocks in Northern New England in earliest modeling periods, to take advantage of expiring production tax credits, supplanting supply that would be build from other sources and in other locations in later years. Results are counter-intuitive

- Resolution: Incorporate availability phase-in schedule for each block, to limit to feasible development penetration over time, while attempting to reflect permitting environment in near-term availability

On-Shore Wind Phase-in Details

- On-shore wind availability is phased in according to the following:
  - Phase-in rates slightly faster for (i) Class 4 located within 20 miles from transmission, than for (ii) Class 3 and Class 4 located greater than 20 miles from transmission
  - Some locations have phase-in faster than others based on analyst categorization of current level of development and permitting environment, as follows (categories applies in similar manner for clusters & farms):

    1= accepting: Quebec, Ontario, NS, NB, UPSNY

    2 = Moderate: CAPITAL, DNSNY, PJM APS, PJM West-Central, WMA (Class 4+, < 20 miles)

    3 = Difficult: ME (Class 3, 4+>20 miles); RI, Southwest CT, Other CT, LI, PJM East NJ, PJM South, PJM East Delmarva; the following portions of MA (Class 4+, < 20 miles) (CMA/NEMA, Boston, SEMA)

    4 = Extremely Difficult:: NH; VT; the following portions of MA (Class 3, 4+>20 miles) (WMA, CMA/NEMA, Boston, SEMA); NYC, ME (Class 4+, < 20 miles)
- For NY: due to slight advantage to in-state wind versus out-of-state, due to RPS deliverability requirement, etc., a subset of Class 3 wind in NY is adjusted in cost to be selected just ahead of similar Class 3 wind elsewhere, as follows:
  - Multiply capital costs of all NY “Upstate” and NY “Capital” wind farm blocks within 5 miles of transmission by a factor of 0.99

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Off-Shore Wind Availability Phase-in

- Issue: To override the potential for IPM®'s perfect foresight algorithm to call upon off-shore wind too early

- Resolution: apply the following caps on availability to all blocks

  - 2006: 0% available – all blocks
  - 2009: 25% available – all blocks
  - 2012: 50% available – all blocks
  - 2015: 75% available – all blocks
  - 2018:100% available – all blocks

- Note: due to wind speed, model may result in off-shore wind fist being built in locations other than those locations currently under development (Long Island, Cape Cod)

Biomass Availability Phase-in

- Issue: While biomass co-firing is an economically attractive source of RE, and does not require the construction lead times of greenfield power plants, it cannot be exploited instantaneously, due to lead-times for plant conversions, permitting and fuel delivery infrastructure

- Resolution: cap each fuel curve supply block at 15% of its maximum in first modeling period (2006) only (100% of potential thereafter)

Policy Assumptions

State and Federal Air Regulatory Policies

Representative National Multi-Pollutant Policy

	Policy Stringency & Timing				Key Provisions
	Annual NO_X (million tons)	Annual SO_2 (million tons)	Annual Hg (tons)	Annual CO_2 (million tons)	
3-Pollutant	2.1 in 2011* 1.7 in 2015	4.5 in 2011* 3.0 in 2015	34 in 2011* 15 in 2018	None	• National cap and trade markets • No mercury backstop price

* Start year reflects modeled run year mapping. See slide on Run Years and Model Size earlier in presentation.

State-Specific Air Regulations

State	Notes	Status	NO_X	SO_2	Mercury	Carbon
Connecticut	Trading/facility	Promulgated on 12/28/2000	Non-Ozone Cap @ 0.15 lb/MMBtu in '02 (Trading)	0.55 lb/MMBtu in '02 0.33 lb/MMBtu in '03 (Facility)	0.6lb/TBtu or 90% from input, whichever is least stringent in '08 (Facility)	NA
Massachusetts	All policies are facility specific (i.e. No trading)	Promulgated on 5/11/2001	1.5 lb/MWhr by '04	6 lb/MWhr by '06 3 lb/MWhr by '08	85% from input by 10/1/2006; 95% from input by 10/1/2012	1800 lb/MWhr by '06
New Hampshire	Trading and Banking Allowed	Passed House Committee on 11/28/2001	Annual Cap @ 1.5 lb/MWhr in '06 3,644 tons	Annual Cap @ 3.0 lb/MWhr in '06 7,289 tons	Cap level recommended in '04 (not implemented for analysis)	5.426 million tons in '06 to '10; Phase II cap recommended in '04
New York	Trading and Banking Allowed	Passed on 3/26/03	Non-Ozone Cap @ 0.15 lb/MMBtu in '04 3:1 IP* 39,908 tons	25 % below Phase II starting '05 50% starting '08 3:1 IP*	NA	Under development
North Carolina	In-state Trading Only	Signed Into Law on 6/20/02	56,000 ton annual cap (78% reduction) by 2009	250,000 ton annual cap (49% reduction) by 2009 and a 130,000 ton cap (73% reduction) by 2013	NA	NA
Texas	Senate Bill 7 and SIP Call Rules	Promulgated on 9/1/1999	**Houston 80% from 1997 by '07 ***Dallas 45$ from 1997 by '05 East TX @ ~0.16 lb/MMBtu in '03	East TX @ 1.38 lb/MMBtu in 2003	NA	NA

*IP=Import Penalty—ratio of upwind tons redeemed for a single in-state ton.
**Houston Cap phased in over time starting in 2002.
***2/3 of Dallas reductions must be achieved by 2003.

State-Specific Air Regulations (continued)

State	Notes	Status	NO_X	SO_2	Mercury	Carbon
Wisconsin	Standards for 8 WEPCO facilities	Environmental Cooperative Agreement	Annual Cap @ 0.25 lb/MMBtu in '08 0.15 lb/MMBtu in '13	Annual Cap @ 0.70 lb/MMBtu in '08 0.45 lb/MMBtu in '13	10% reduction from 1999 levels in '08 50% reduction from 1999 levels in '13	NA
Illinois	Trading and Banking Allowed	Part of the State Implementation Plan	Annual Cap @ 0.25 lb/MMBtu in '03 and 0.15 lb/MMBtu in '04	NA	NA	NA
Missouri	Trading and Banking Allowed	Signed Into Law on 9/30/2000	Annual Cap @ 0.35 lb/MMBtu in certain counties and 0.25 lb/MMBtu in other counties starting in '03	NA	NA	NA
New Jersey	MACT	Proposed 12/12/03	NA	NA	90% reduction from coal power plants in 2007	NA