RGGI Reference Case Assumptions

September 12, 2011

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Outline

Assumptions Overview

Changes from 2010 Assumptions

RGGI Reference Case Assumptions

- Electric Demand and Reserve Requirements
- New Capacity
  - Firmly Planned Additions
  - Cost and Performance of New Capacity
- Transmission Capability
- Fuel Prices
- Regulatory Environment
  - Federal Air Regulations
  - State Air Regulations
  - Offsets
  - Renewable Portfolio Standards
- Pollution Controls
  - Firmly Planned Controls
  - Cost and Performance of New Controls

Appendix A: State Energy Efficiency Assumptions

Assumptions Overview

What are Reference Case Assumptions?

- IPM relies on several user-defined parameters to set the overall requirements and boundaries for its projections. For example, the user must tell IPM what level of energy demand it must meet by year for each model region.
- Most of these parameters are not known with certainty, so users must make assumptions about their values going forward over the time horizon of the analysis.
- We use the term “assumptions” to describe the collection of input parameters that will go into the model.
- The model’s projections are developed using market fundamentals informed by the assumptions.
- This document provides the assumptions used for key input parameters for the RGGI Reference Case, as agreed to by the RGGI States.

Sources of Assumptions

Parameter	Sources				
	ISOs	States	EPA	EIA	Other
Electric Demand	X	X			
Reserve Requirements	X				
Firmly Planned Capacity Additions	X	X			
Coal and Nuclear Capacity Limits		X			
Cost and Performance of New Capacity				X	
Transmission Capability	X				
Firmly Planned Transmission Additions	X	X			
Fuel Prices				X	
Federal Air Regulations		X			
State Air Regulations		X			
Offsets		X	X		
Renewable Portfolio Standards		X			
Firmly Planned Controls		X	X		
Cost and Performance of New Controls			X		

Data Sources for RGGI Reference Case Assumptions

- **U.S. Energy Information Administration's (EIA) 2011 Annual Energy Outlook**: http://www.eia.gov/forecasts/aeo/

- **ISOs**:
  - 2010 Regional Transmission Expansion Plan (RTEP) – http://pjm.com/documents/reports/rtep-report.aspx
  - PJM 2011 Load Forecast – http://pjm.com/documents/~/media/documents/reports/2011-pjm-load-report.ashx
  - ISO-NE 2011 Capacity, Energy, Loads and Transmission report (CELT) – http://www.iso-ne.com/trans/celt/fsct_detail/2011/isone_fcst_data_2011.xls
  - NYISO 2010 Reliability Needs Assessment (RNA) – http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/2010_Reliability_Needs_Assessment_Final_09212010.pdf
  - NYSIO 2011 Load & Capacity Data (Gold Book) – http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2011_GoldBook_Public_Final.pdf

- **EPA:**
  - EPA Base Case v.4.10: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html
  - Offsets: "EPA S.280 mitigation cost schedules for capped sectors and domestic and international offsets." EPA memo to the Energy Information Administration (EIA), March 2007. Available at: www.epa.gov/climatechange/economics/economicanalyses.html

Changes from 2010 Assumptions

Updated Assumptions for September 2011 Projections

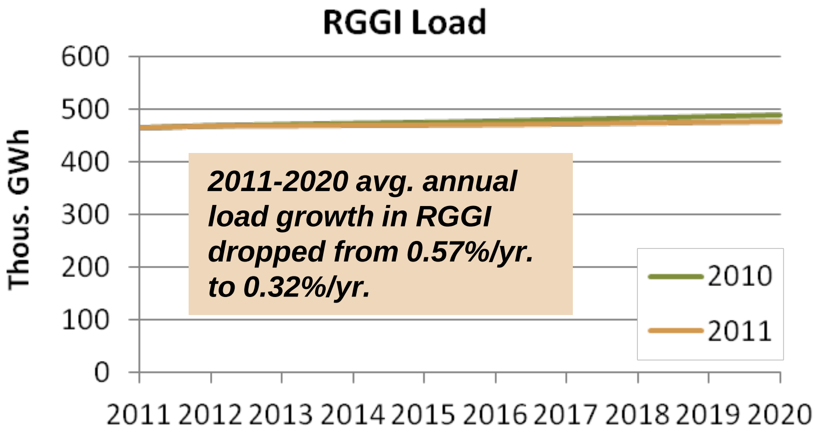
Overview

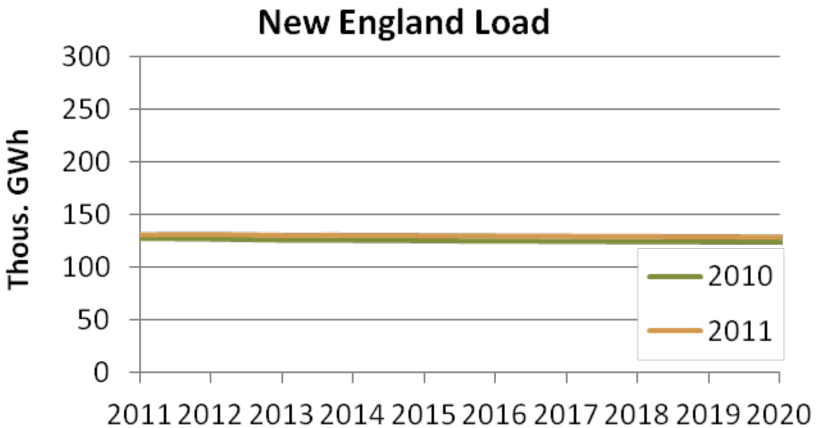
- The table below summarizes the sources for key assumptions in the new 2011 analysis as compared to the 2010 analysis.
- The following slides compare electric demand by ISO and then gas prices for the 2010 and 2011 analyses.

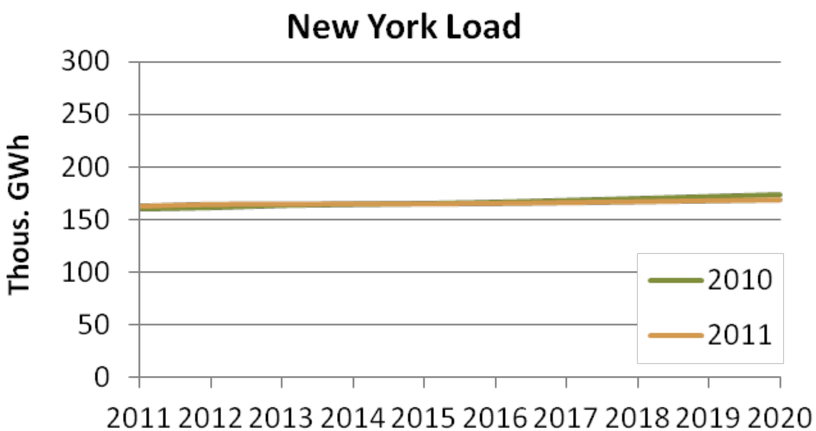
Assumption	2010 Analysis	2011 Analysis
Electric load growth	RGGI states – ISOs 2010 Other states – AEO 2010	RGGI states – ISOs 2011 Other states – AEO 2011
Reserve margin requirements	ISOs 2010	ISOs 2011
Natural gas prices	Combination of NYMEX and AEO 2010	AEO 2011
Base costs of new generating capacity	AEO 2010	AEO 2011
Costs of pollution controls	EPA Base Case v4.10	EPA Base Case v4.10
SO_2 and NO_X regulation	Clean Air Transport Rule (CATR, as proposed)	Cross-State Air Pollution Rule (CSAPR)
Firm capacity additions and retirements	RGGI states	RGGI states

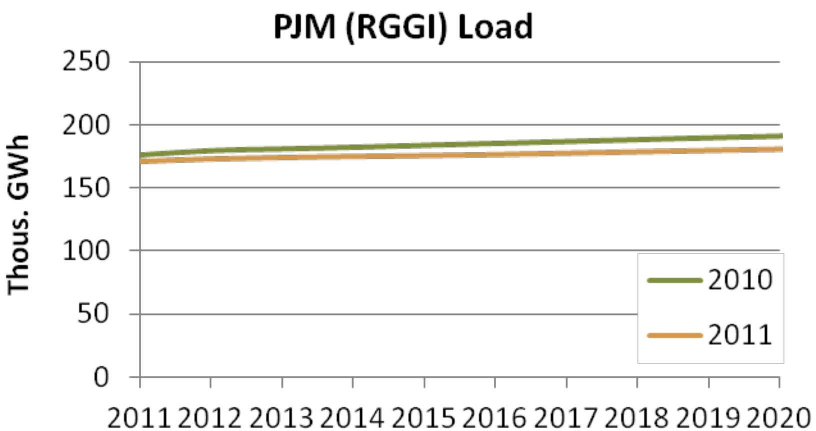
Updated Assumptions for September 2011 Projections

Load Growth in the RGGI Region



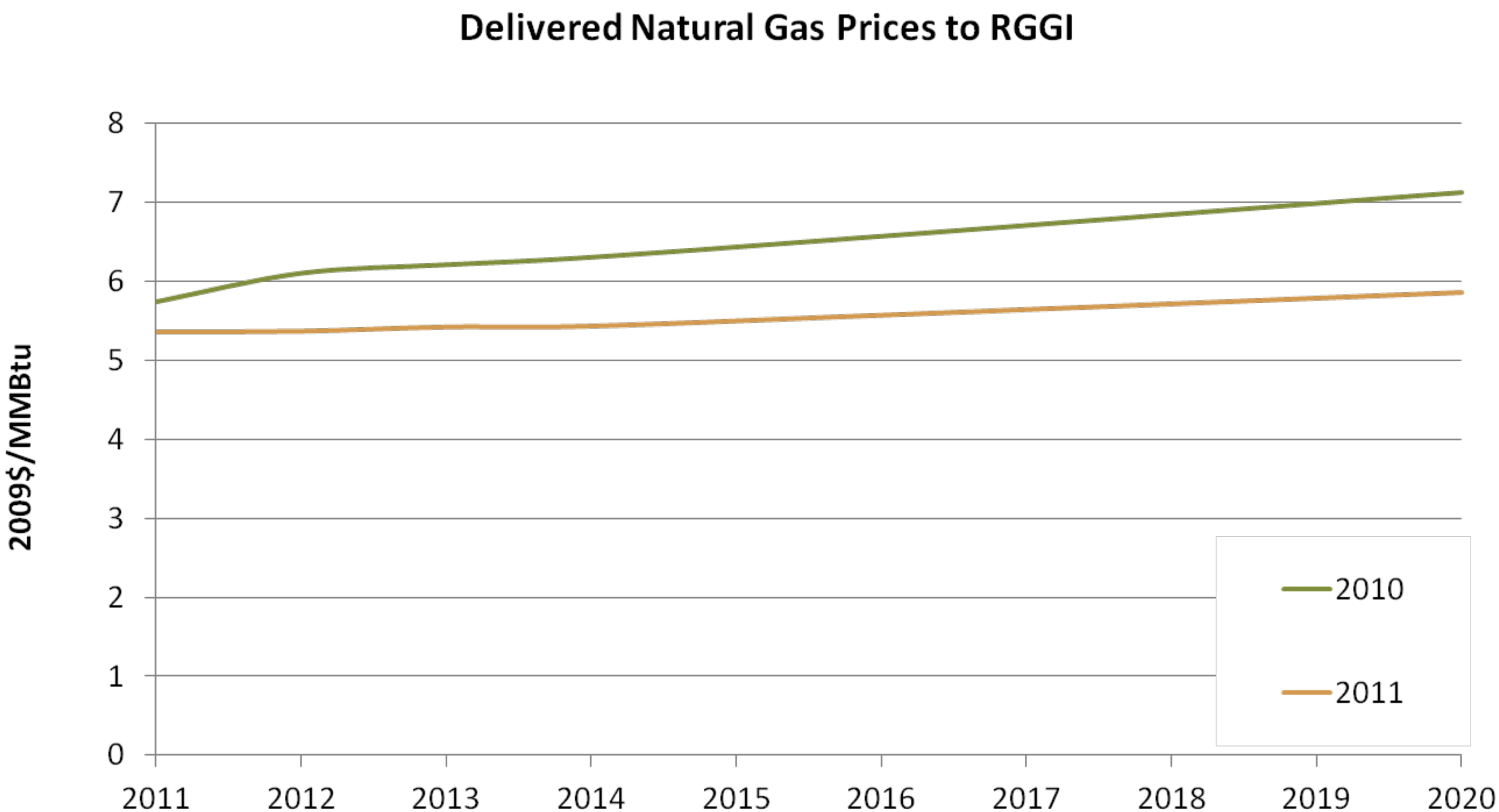






Updated Assumptions for September 2011 Projections

Natural Gas Prices



RGGI Program and Modeling Changes for 2011

Overview

- The Reference Case projections assume that New Jersey leaves the RGGI program at the beginning of 2012.
- The timeframe for the modeling analysis has been adjusted to 2020 rather than 2030. Unlike actual market participants, the model has "perfect foresight" about all market parameters (e.g., fuel prices, allowance scarcity, electricity load). As a result, the model may over-compensate in the short-term for a condition that it observes far in the future. The revised timeframe is being selected in order to have the model provide results that are more consistent with market participant decision making time horizons.

Reference Case Assumptions

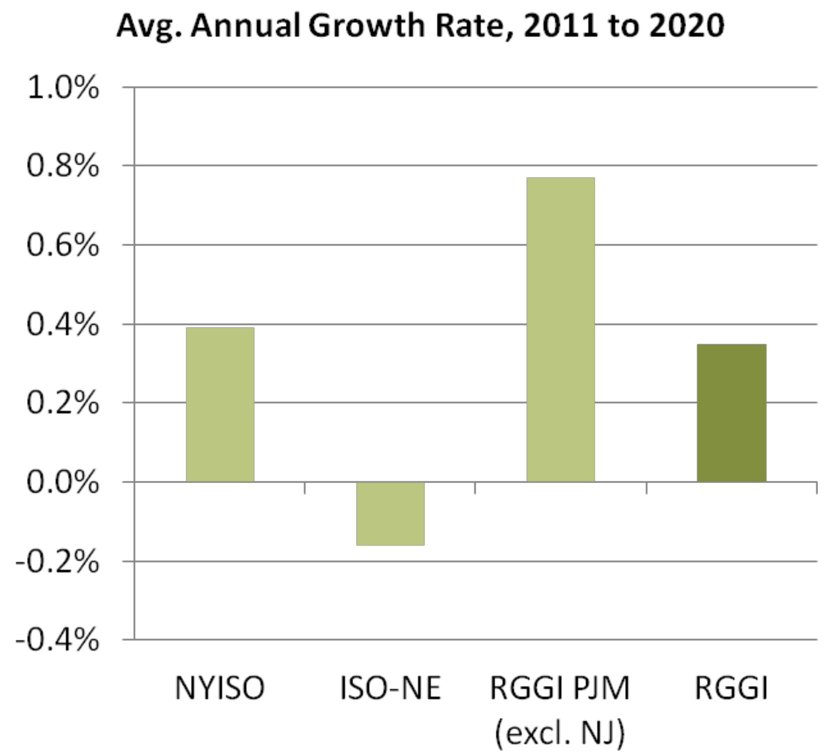
Regional Energy and Peak Demand

Overview

- DESCRIPTION
  - Energy (MWh) and peak (MW) demand requirements by state for the period 2011 to 2020
  - IPM meets regional energy needs by running existing plants, building new plants and using transmission resources

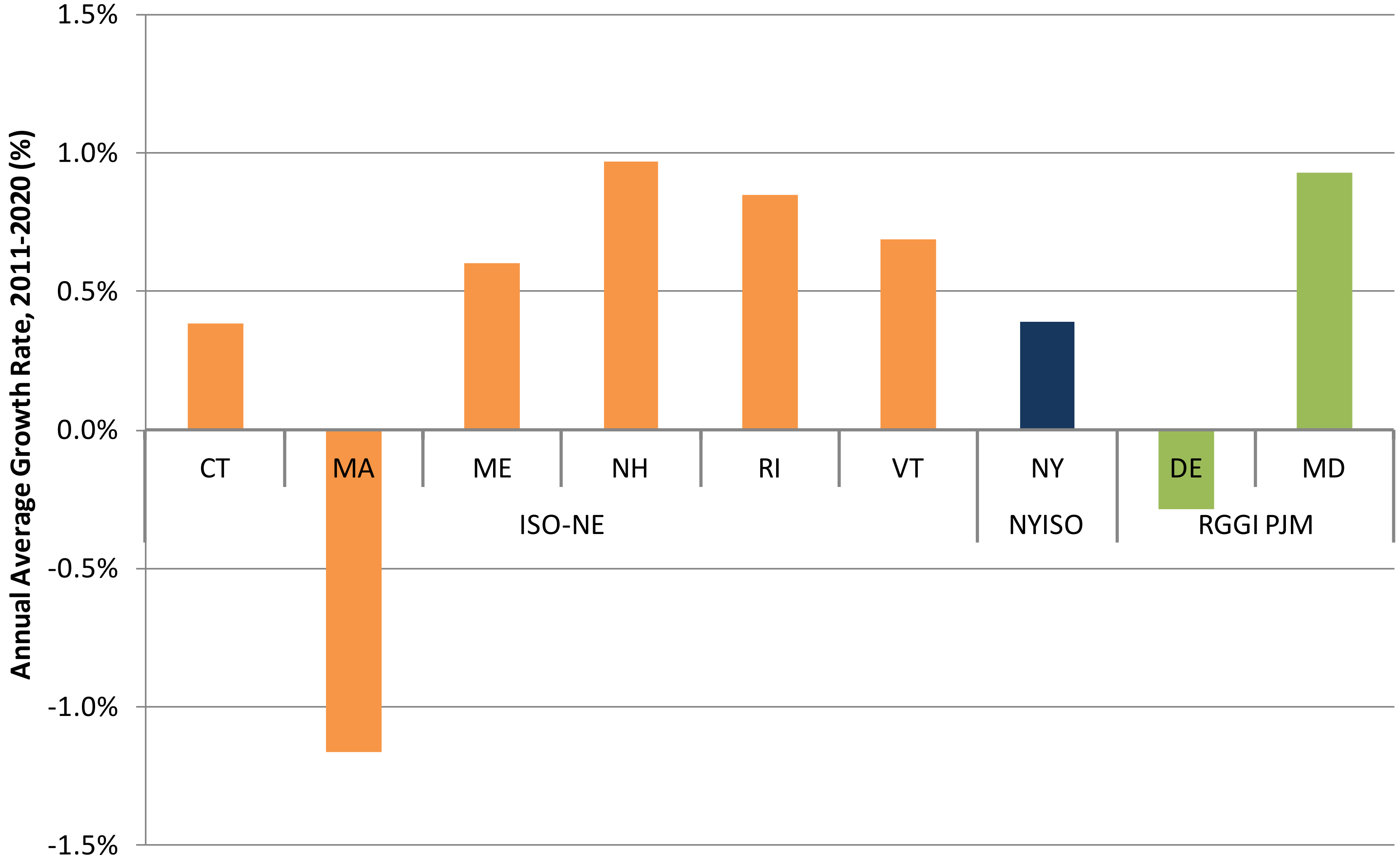
- RGGI REFERENCE CASE ASSUMPTION
  - ISO projections, adjusted for efficiency as provided by the States
  - See Appendix A for state-specific efficiency assumptions

- NOTES
  - The chart at right shows the average annual growth rates for the RGGI states, grouped by ISO.
  - The chart on the following page shows average annual growth rates over the 2011-2020 period by state.



Regional Energy and Peak Demand

Annual Average Growth Rates by State, 2011 to 2020



Reserve Margins and Local Reserve Requirements

Overview

- DESCRIPTION
  - Backup capacity required above peak demand to maintain system reliability, expressed as a percentage of peak demand
  - NYISO locational minimum installed capacity requirements for Zones J and K specify the percentage of peak load that must be met with in-zone resources
  - IPM must use existing capacity and build new capacity to meet reserve requirements in each region
- RGGI REFERENCE CASE ASSUMPTION
  - Latest ISO projections for PJM and ISO-NE
  - Projected 2011 reserve margin for NYISO, held constant
  - NYISO local reserve requirements for Zones J and K (80% and 104.5%, respectively)
- NOTES
  - The table below shows reserve margin requirements as a percentage of peak demand by year for each ISO.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020+
ISO-NE	14.5%	13.6%	12.6%	14.6%	14.4%	14.4%	14.4%	14.3%	14.2%	14.2%
NYISO	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
PJM	15.6%	15.5%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%

Firmly Planned Generation and Retirements

Overview

- DESCRIPTION
  - Firmly planned capacity additions and retirements are those that are far enough along in the process to be included in the Reference Case
  - IPM will take firm capacity additions and retirements into account in making projections

- RGGI REFERENCE CASE ASSUMPTION
  - Firmly planned capacity based on ISO studies and queues, supplemented with additions by States (including additions for Cape Wind, Bluewater Wind, and retirement of Vermont Yankee and Indian Point)
  - ISO studies and data
    - NYISO – 2010 RNA
    - ISO-NE – 2011 CELT
    - PJM – Interconnection Request Queues, filtered for units under construction

- NOTES
  - The following slides list the assumed firmly planned additions and retirements in the RGGI region

Firmly Planned Generation and Retirements

Unit-specific Additions in ISO-NE

State	Plant Name	Generating Type	Net Summer Dependable Capacity (MW)	Year
CT	Devon: 15	Combustion Turbine	48.5	2010
CT	Devon: 16	Combustion Turbine	48.5	2010
CT	Devon: 17	Combustion Turbine	48.5	2010
CT	Devon: 18	Combustion Turbine	48.5	2010
CT	Middletown: 12	Combustion Turbine	48.5	2011
CT	Middletown: 13	Combustion Turbine	48.5	2011
CT	Middletown: 14	Combustion Turbine	48.5	2011
CT	Middletown: 15	Combustion Turbine	48.5	2011
CT	Mashantucket Pequot Tribal Cogeneration: GT1	Combustion Turbine	7.5	2010
CT	Mashantucket Pequot Tribal Cogeneration: GT2	Combustion Turbine	7.5	2010
CT	Millstone Point 3 Expansion	Nuclear	80	2010
CT	Plainfield Renewable Energy	Biomass/Biofuels	37.5	2014
CT	Kleen Energy Project: CC	Combined Cycle	560	2012
CT	New Haven Harbor	Combustion Turbine	130	2012
MA	Indian River Hydro (MA): HY1	Hydro	0.76	2010
MA	Indian River Hydro (MA): HY2	Hydro	0.76	2010
MA	Berkshire Wind Power: WT1 10	Wind	15	2010
MA	Sugar River: 2	Hydro	0.2	2010
MA	Templeton Wind Turbine: 1	Wind	1	2010
MA	Town_of_Falmouth_Wind_Turbine: 1	Wind	1.65	2010
MA	Cape Wind: 1	Wind	468	2013
MA	Stony Brook (MA): CC2	Combined Cycle	280	2013

Firmly Planned Generation and Retirements

Unit-specific Additions in ISO-NE *continued*

State	Plant Name	Generating Type	Net Summer Dependable Capacity (MW)	Year
ME	Kibby Wind Power: WT23 44	Wind	66	2010
ME	Stetson Wind: WT39 55	Wind	25.5	2010
ME	Record Hill Wind: WT1 22	Wind	50.6	2011
ME	First Wind-Rollins Mountain	Wind	60	2011
ME	Oakfield Wind, LLC (First Wind) Oakfield	Wind	51	2011
NH	Clean Power Berlin	Biomass	20	2013
NH	Granite Reliable Wind	Wind	99	2013
RI	Ridgewood Providence: GEN16	Landfill Gas	32	2013
VT	Project 10: GT1	Combustion Turbine	20	2010
VT	Project 10: GT2	Combustion Turbine	20	2010
VT	Sheffield Wind Project: WT1 16	Wind	40	2011
VT	Deerfield Wind Project	Wind	30	2012
VT	Georgia Mountain Wind	Wind	12	2013
VT	Lowell Mountain Wind	Wind	60	2013

Firmly Planned Generation and Retirements

Unit-specific Additions in NYISO

State	Plant Name	Generating Type	Net Summer Dependable Capacity (MW)	Year
NY	Blenheim-Gilboa Unit 4 uprate	Pumped Storage Uprate	30	2010
NY	Chautauqua Landfill	Landfill Gas	6.4	2010
NY	Empire Generating	Combined Cycle	635	2010
NY	Steel Winds II	Wind	15	2010
NY	Astoria Energy II	Combined Cycle	550	2011
NJ	Bayonne Energy	Combustion Turbine	512.5	2011
NY	Nine Mile Point II	Nuclear Uprate	115	2012
NY	Nine Mile Point II	Nuclear Uprate	53	2014
NY	Munnsville Wind Power	Wind	6	2013
NY	Seneca Energy II - Ontario	LFG	5.6	2012

Firmly Planned Generation and Retirements

Unit-specific Additions in PJM

State	Plant Name	Generating Type	Net Summer Dependable Capacity (MW)	Year
DE	AMERESCO (Laurel)	Landfill gas	1	2010
DE	Hayroad Expansion	Combustion Turbine	13	2010
DE	W1-062 -DMEC addition	Combustion Turbine	67	2012
DE	Bluewater (R-36)	Wind	250 (20% capacity)	2016
MD	Criterion Wind Power Generating Facility: WT 1 28	Wind	70	2011
MD	Roth Rock Wind Power: WT1 20	Wind	50	2011
NJ	PSE&G Area solar project	Solar	52	2010
NJ	Dynamic Energy Resources (Farmingdale, NJ)	Solar	0.5	2010
NJ	New Jersey Medowlands Commission (Kearny, NJ)	Solar	1.9	2010
NJ	Recurrent Energy Development Holdings (5 locations Cranbury, NJ)	Solar	7.498	2010
NJ	PSE&G Barringer Highschool Project	Solar	0.549	2010
NJ	PSE&G Park Elementary School Project	Solar	0.432	2010
NJ	PSE&G Central Highschool Project	Solar	0.773	2010
NJ	PSE&G Camden Street School Project	Solar	0.425	2010
NJ	PSE&G (2 buildings Perth Amboy	Solar	2.308	2010
NJ	PPL Renewable Energy LLC (locatation White Township, New Jersey)	Solar	2	2011
NJ	Britten Road (U3-32) solar generation project	Solar	20	2011
NJ	Paradise Road	Solar	5.1	2011
NJ	Recurrent Energy Development Holdings (8 locatations Cranbury, NJ)	Solar	16	2011
NJ	Vineland Municipal Electric Utility	Natural Gas	63	2012
NJ	Mt. Hope Waterpower Project	Biomass	30	2013

Firmly Planned Generation and Retirements

Unit-specific Retirements in RGGI

State	Plant Name	Generating Type	Net Summer Dependable Capacity (MW)	Year
MA	Somerset Station: 6	Coal	109	2012
MA	Salem Harbor 1 & 2	Coal	160.2	2012
MA	Salem Harbor 3 & 4	Coal & Oil/Gas	587.3	2015
VT	Vermont Yankee	Nuclear	604.25	2012
NY	Charles Poletti: 6	Oil/Gas Steam	890	2010
NY	Green Island: 1	Hydro	0.868	2011
NY	Green Island: 2	Hydro	0.868	2011
NY	Green Island: 3	Hydro	0.868	2011
NY	Green Island: 4	Hydro	0.868	2011
NY	Project Orange	Gas	80	2011
NY	AES Greenidge 4	Coal	106.1	2011
NY	AES Westover 8	Coal	81.5	2011
NY	Indian Point 2	Nuclear	1027	2013
NY	Indian Point 3	Nuclear	1040	2015
PA	Energy Systems North East, LLC unit	Combined Cycle	88	2011
DE	Indian River Generating Station (DE): 2	Coal	91	2010
DE	Indian River Generating Station (DE): 1	Coal	91	2011
DE	Indian River Generating Station (DE): 3	Coal	165	2014
NJ	Howard Down: 10	Coal	17	2010
NJ	Hudson Generating Station: 1	Oil/Gas Steam	383	2011
NJ	Kearny Generating Station: 10	Combustion Turbine	122	2012
NJ	Kearny Generating Station: 11	Combustion Turbine	128	2012
NJ	Kearny Generating Station: 9	Combustion Turbine	21	2013
NJ	Oyster Creek	Nuclear	619	2020

Cost and Performance of New Generation

Overview

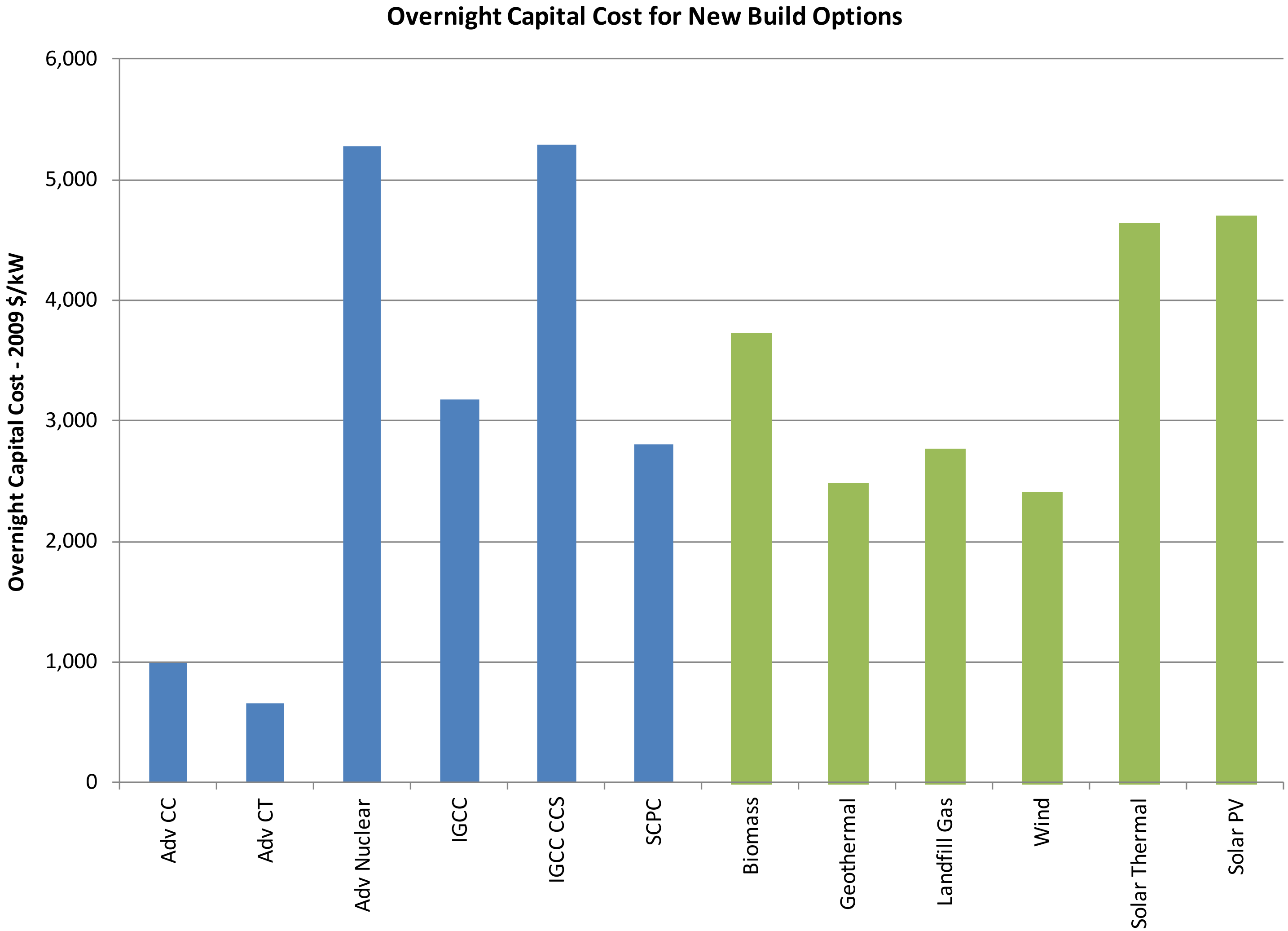
- DESCRIPTION
  - Capital and operating costs, heat rates, and emission rates for new generating capacity options, including combined cycle gas, coal, nuclear and renewable types
  - IPM builds new capacity to meet energy and peak needs based on relative economics

- RGGI REFERENCE CASE ASSUMPTION
  - EIA AEO 2011 build cost and performance assumptions

- NOTES
  - The following page shows the assumed capital costs by technology based on EIA's latest assumptions.

Cost and Performance of New Generation

Overnight Capital Cost of New Capacity Options



Coal Plant Construction in RGGI

Overview

- DESCRIPTION
  - Limits on the amount and type of new coal capacity that can be built within the RGGI region
  - In IPM, such limits supersede decisions based on market fundamentals

- RGGI REFERENCE CASE ASSUMPTION
  - New coal capacity is allowed to be built only if it is equipped with carbon capture and storage capabilities

- NOTES
  - None

Nuclear Plant Construction in RGGI

Overview

- DESCRIPTION
  - Limits on the amount and type of new nuclear capacity that can be built within the RGGI region
  - In IPM, such limits supersede decisions based on market fundamentals

- RGGI REFERENCE CASE ASSUMPTION
  - Nuclear can be built on an economic basis at existing plant sites that have space available for an additional unit or at plant sites with license applications in process

- NOTES
  - In the RGGI region, 5 unit sites meet these criteria: Pilgrim (MA), Seabrook (NH), Oswego (NY), Calvert Cliffs (MD), and Hope Creek/Salem (NJ)
  - Economic additions of nuclear capacity are limited to these 5 units in the Reference Case

Firmly Planned Transmission Additions

Overview

- DESCRIPTION
  - Additions to existing capacity in planning or construction stages and assumed to be firm
  - IPM relies on transmission capability to help meet regional electricity demand

- RGGI REFERENCE CASE ASSUMPTION
  - Use PJM timing for capability expansion in that ISO:
    - TrAIL in 2011
    - MAPP in 2015
    - Susquehanna-Roseland by 2014
  - Include 660 MW Hudson Line from New Jersey to New York in 2013

- NOTES
  - None

Transmission Capability

Overview

- DESCRIPTION
  - Existing interregional transmission capacity for use in moving energy across regional boundaries
  - IPM relies on transmission capability to help meet regional electricity demand

- RGGI REFERENCE CASE ASSUMPTION
  - Capabilities based on ISO reports and modeling
    - ISO-NE: Planning Advisory Committee, Preliminary Assumptions for Economic Studies
    - NYISO: 2010 RNA
    - PJM: 2011 RTEP and ICF analysis

- NOTES
  - The tables on the following slides show the assumed transfer capability among RGGI states/regions, including the firmly planned additions discussed on the previous page.
    - "Zonal" limits are those that constrain a single link between two model regions.
    - "Interface" limits are those that constrain one or more links across model regions.

Transmission Capability

Total Transfer Capabilities

ISO-New England

Source: ISO-NE 2009 Regional System Plan

Interface Limit Assumptions (MW)(1)										
Interface	2009	2010	2011	2012	2013	2014	2015	2016	2017	Affected IPM regions
New Brunswick–New England	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	NB-BHE
Orrington–South Export	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	ME-BHE
Surowiec–South	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	SME-ME
Maine–New Hampshire	1,600	1,600	1575(2)	1,550	1,525	1,500	1,475	1,450	1,450	NB-BHE
North–South	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	North: VT, NH, SME, ME, BHE; South: WMA, CT, SWCT, NOR, CMA/NEMA, Boston, RI, SEMA
Boston Import	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	Boston
SEMA Export	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	SEMA
SEMA/RI Export	3,000	3,000	3,000	3,000	3300(3)	3,300	3,300	3,300	3,300	2009-12: RI, SEMA 2013+: East CMA/NEMA, RI, SEMA, Boston, NH, SME, ME, BHE, NB; West VT, WMA, CT, SWCT, NOR
East–West	2,800	2,800	2,800	2,800	3500(3)	3,500	3,500	3,500	3,500	
Connecticut Import	2,500	2,500	2,500	2,500	3600(3)	3,600	3,600	3,600	3,600	CT, SWCT, NOR
Southwest Connecticut Import	2,350	3650(4)	3,650	3,650	3,650	3,650	3,650	3,650	3,650	SWCT, NOR
Norwalk–Stamford	1,300	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	NOR
Cross-Sound Cable (Export)	330	330	330	330	330	330	330	330	330	NY-CT
Cross-Sound Cable (Import)	346	346	346	346	346	346	346	346	346	
NY–NE Summer	1,525	1,525	1,525	1,525	1,525	1,525	1,525	1,525	1,525	NY-VT, WMA, CT, NOR
NY–NE Winter	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	
NE–NY Summer	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	
NE–NY Winter	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	
HQ–NE (Highgate)	200	200	200	200	200	200	200	200	200	VT-HQ
HQ–NE (Phase II)	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	CMA/NEMA-HQ

Transmission Capability

Total Transfer Capabilities

New York

Source: NYISO and 2009 NY State Energy Plan

Zonal Limits		2010+		2013+	
Sending Region	Receiving Region	Capacity (MW)	Energy (MW)	Capacity (MW)	Energy (MW)
Ontario	Zones A-E	800	800	-	-
Quebec	Zones A-E	1,200	1,500	-	-
CT	Zones G-I	500	500	-	-
CT	Zone K	530	530	-	-
VT	Zones A-E	-	-	-	-
Western MA	Zone F	500	500	-	-
Zones G-I	Zones A-E	1,600	1,600	-	-
Zones G-I	Zone F	2,000	2,000	-	-
Zones G-I	CT	800	800	-	-
Zones G-I	PSEG	2,400	2,400	-	-
Zones G-I	Zone K	1,200	1,200	-	-
Zones G-I	Zone J	3,200	3,200	-	-
Zone K	Zones G-I	350	350	-	-
Zone K	Zone J	270	270	-	-
Zone K	JCPL	660	660	-	-
Zone K	CT	350	350	-	-
Zone J	Zones G-I	3,500	3,500	-	-
Zone J	PSEG	500	500	-	-
Zone J	Zone K	-	-	-	-

Zonal Limits		2010+		2013+	
Sending Region	Receiving Region	Capacity (MW)	Energy (MW)	Capacity (MW)	Energy (MW)
Zones A-E	Quebec	1,000	1,000	-	-
Zones A-E	Ontario	1,325	1,325	-	-
Zones A-E	VT	175	175	-	-
Zones A-E	PJM West	600	600	-	-
Zones A-E	Zones G-I	1,600	1,600	-	-
Zones A-E	Zone F	3,000	3,000	-	-
Zone F	Zones A-E	2,000	2,000	-	-
Zone F	Western MA	800	800	-	-
Zone F	Zones G-I	3,200	3,200	-	-
JCPL	Zone K	660	660	-	-
PSEG	Zones G-I	-	-	-	-
PSEG	Zone J	1,000	1,000	320	660
PJM West	Zones A-E	1,320	1,320	-	-

Interface Limits - 2010+		
Interface Name	Capacity (MW)	Energy (MW)
PJM to NYISO	3,600	2,600
NYISO to PJM	2,175	2,175
Into Zones G-I	4,800	4,800
ISONE to NYISO	1,400	1,400
NYISO to ISONE	1,600	1,600

Transmission Capability

Total Transfer Capabilities

RGGI PJM (1)

Source: RTEP and ICF Analysis

Zonal Limits	Current (2010)		2011-2013 (with TrAIL)		2015+ (with MAPP)	
	Capacity (MW)	Energy (MW)	Capacity (MW)	Energy (MW)	Capacity (MW)	Energy (MW)
DPL to PSEG	-	-	-	-	-	-
PSEG to DPL	-	-	-	-	-	-
BGE to DPL	-	-	-	-	793	1,793
DPL to BGE	-	-	-	-	793	1,793
DPL to PSEG	-	1,265	-	-		
PSEG to DPL	-	1,099	-	-		
JCPL to PSEG	428	473	-	-	-	-
PSEG to JCPL	276	464	-	-	-	-
JCPL to PSEG	1,710	2,641	-	-	-	-
PSEG to JCPL	1,714	2,017	-	-	-	-
JCPL to PSEG	1,481	2,170	-	-	-	-
PSEG to JCPL	1,748	2,170	-	-	-	-
PEPCO to DOM	1,502	3,652	-	-	1,293	263
DOM to PEPCO	1,514	2,547	-	-	670	1,368
BGE to PECO	-	1,095	-	-	-	-
PECO to BGE	609	609	-	-	-	-
BGE to WEST CENTRAL	1,858	3,352	-	-	-	-
WEST CENTRAL to BGE	2,088	2,221	-	-	-	-
BGE to PEPCO	2,975	4,207	200	200	835	1,238
PEPCO to BGE	3,129	4,200	200	200	1,158	981
APS to PEPCO	1,170	3,189	500	500	-	-
PEPCO to APS	1,139	3,695	500	500	-	-
APS to BGE	-	-	-	-	-	-
BGE to APS	-	-	-	-	-	-

Transmission Capability

Total Transfer Capabilities

RGGI PJM (2)

Source: RTEP and ICF Analysis

Interface Limits	Current (2010)		TrAIL Limits (2011-2013)		MAPP Limits (2015+)	
	Capacity (MW)	Energy (MW)	Capacity (MW)	Energy (MW)	Capacity (MW)	Energy (MW)
BGE to neighbors	5,432	7,788	200	200	381	540
neighbors to BGE	4,306	4,643	200	200	377	465
PEPCO to neighbors	4,359	8,400	500	500	-	-
neighbors to PEPCO	4,711	6,829	500	500	-	-

Fuel Prices

Overview

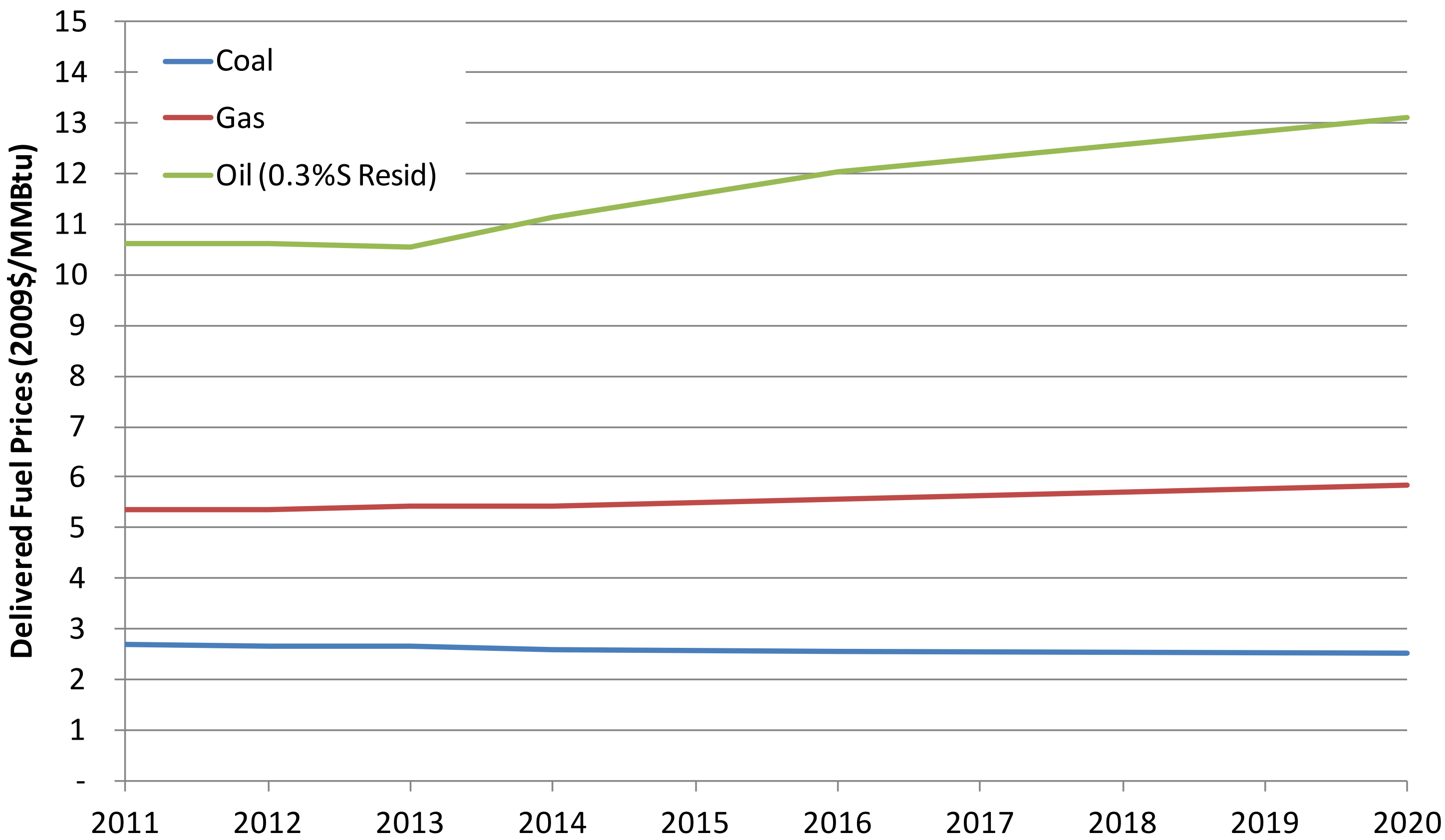
- DESCRIPTION
  - Commodity and delivered prices for natural gas, oil products and coal
  - Delivered fuel prices are included in unit operation and investment decisions

- RGGI REFERENCE CASE ASSUMPTION
  - (Oil and Gas) EIA AEO 2011
  - (Oil and Gas) Transportation and seasonal cost adjustments based on 10-year historical averages
  - (Coal) ICF supply curves calibrated in near-term to EIA AEO 2011

- NOTES
  - The following slide shows average delivered fuel prices to the RGGI region for natural gas, a representative basket of coals, and low sulfur resid.

Fuel Prices

Average Delivered Fuel Prices to RGGI Region



Federal Environmental Policies

Overview

- DESCRIPTION
  - Federal air pollution requirements for SO_2, NO_X and mercury under Clean Air Act
  - IPM must comply with assumed regulations as it operates units to meet demand
- RGGI REFERENCE CASE ASSUMPTION
  - Cross-State Air Pollution Rule for SO_2 and NO_X
  - National Mercury MACT (90% removal from input)
- NOTES
  - None

State Environmental Policies

Overview

- DESCRIPTION
  - State emission limits for SO_2, NO_X, and mercury, either as statewide cap and trade programs or unit-specific requirements
  - IPM must comply with state requirements in making operation and investment decisions
- RGGI REFERENCE CASE ASSUMPTION
  - Existing requirements as provided by state agencies
- NOTES
  - None

Offsets for Use in RGGI Program

Overview

- DESCRIPTION
  - Offsets are CO_2-equivalent emission reductions generated by eligible projects in sectors not affected by the RGGI program. They may come from domestic or international sources.
  - In determining the least-cost means of compliance with RGGI and the CO_2 allowance price, IPM will utilize offsets to the extent that they are cost-effective relative to on-system reductions and subject to program limitations

- RGGI REFERENCE CASE ASSUMPTION
  - (Domestic) EPA U.S. marginal abatement cost curves (MACCs) by source category (e.g., landfill gas), scaled to RGGI region based on relevant data (e.g., RGGI landfill capacity as percentage of U.S. landfill capacity)
  - (International) EPA international MACCs, as used in EPA Waxman-Markey analysis, with prices adjusted to reflect recent activity in U.S. and international markets

- NOTES
  - None

Renewable Portfolio Standards (RPSs)

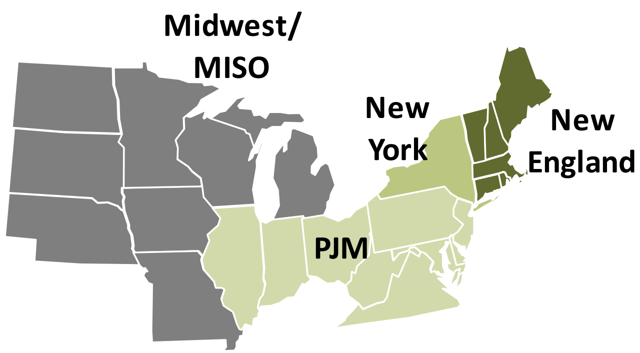
Overview

- DESCRIPTION
  - RPS programs require that a portion of retail sales be met with generation from qualifying sources
  - IPM will comply with RPS requirements in making operation and investment decisions, up to assumed alternative compliance payments (ACP)

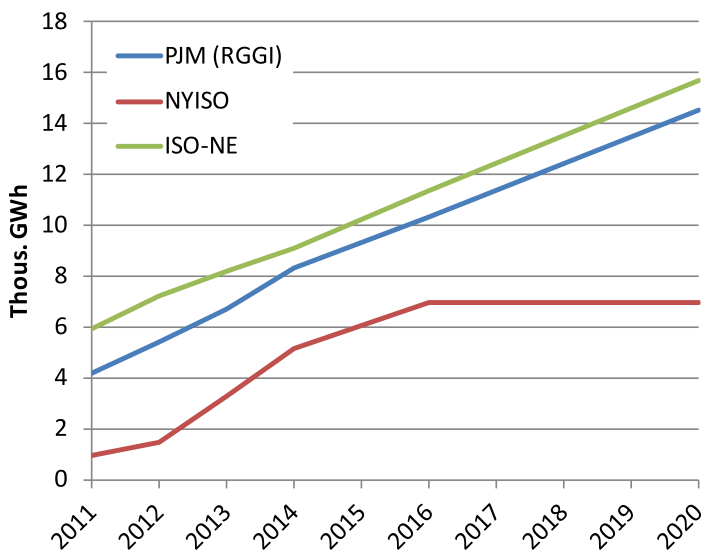
- RGGI REFERENCE CASE ASSUMPTION
  - Three regional markets, by ISO, with regional ACPs specified by States
  - Technology-specific (solar, offshore wind) tiers where applicable

- NOTES
  - The chart at right shows the main tier RPS requirements by ISO.
    - The PJM (RGGI) line reflects the contribution of the MD and DE RPS programs to the total PJM market requirement.
  - The Reference Case does not include a federal RPS requirement.

Reference Case Renewable Markets



Reference Case RPS Requirements



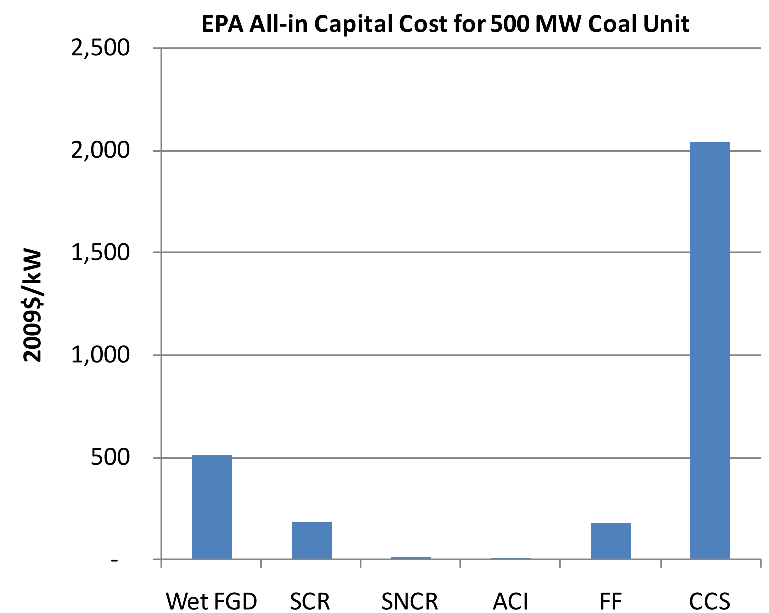
Cost of Pollution Controls; Firmly Planned Controls

Overview

- DESCRIPTION
  - Capital and operating costs of controls to control emissions of SO_2, NO_X and mercury, along with assumed percentage reduction in emissions
  - Firmly planned installations are those that are far enough along in development (planning or installation) that they are included in the model
  - IPM projects other control installations on an economic basis in response to regulatory requirements

- RGGI REFERENCE CASE ASSUMPTION
  - Control costs from EPA Base Case v. 4.10
  - Firmly planned controls based on public announcements, EPA NEEDS database and review by States.

- NOTES
  - The chart at right shows EPA's capital costs for controlling a 500 MW coal unit, by control type.
  - The following slide shows the firmly planned control installations.



Cost of Pollution Controls; Firmly Planned Controls

Firmly Planned Control Installations

State	Plant	Unit	Type	Online Year
DE	Indian River Generating Station	3	ACI	2011
		4	ACI	2011
			LSD	2012
MD	Brandon Shores	1	ACI	2010
		2	ACI	2010
			FGD	2010
	Chalk Point	1	FGD	2010
		2	FGD	2010
	Dickerson	1	FGD	2010
			SNCR	2010
		2	FGD	2010
			SNCR	2010
		3	FGD	2010
			SNCR	2010
	Morgantown Generating Station	1	FGD	2010
		2	FGD	2010

State	Plant	Unit	Type	Online Year
NJ	Hudson Generating Station	2	ACI	2010
			LSD	2011
			SCR	2011
	Mercer Generating Station	1	ACI	2010
			LSD	2010
		2	ACI	2010
			LSD	2010
	B.L. England	1	ACI	2012
			SCR	2013
			FGD	2013
		2	ACI	2012
			SCR	2012
			FGD	2012
NY	Dunkirk Generating Station	1	ACI	2011
			SNCR	2010
		2	ACI	2011
			SNCR	2010
		3	ACI	2011
			FGD	2011
			SNCR	2011
		4	ACI	2011
			FGD	2011
			SNCR	2011
	Huntley Generating	67	FGD	2011
		68	FGD	2011
NH	Merrimack	1	FGD	2013
		2	FGD	2013

Appendix A
State Energy Efficiency Assumptions

New England Energy Efficiency Assumptions

Connecticut

Based on the ISO-NE baseline modified by the New England States Committee on Electricity (NESCOE) 7/1/10 proposal of an additional 234 MW per year EE under BAU for ISO-NE modeling assumptions (www.nescoe.com/uploads/Memo_to_ISO_on_Assumtions__7.1.10.pdf pp. 3-4), Connecticut reduced the load and peak demand proportionate to the regional estimate.

Maine

Based on the New England States Committee on Electricity (NESCOE) 7/1/10 proposal of an additional 234 MW per year EE for ISO-NE modeling assumptions (www.nescoe.com/uploads/Memo_to_ISO_on_Assumtions__7.1.10.pdf pp. 3-4) , Maine reduced their peak demand by a proportional 20MW annually and applied the annual ISO NE load factor to the peak numbers to derive the energy load forecast.

New England Energy Efficiency Assumptions Cont'd

Massachusetts

Assumptions for development of MA loads and usage with EE to 2030 reflect the aggressive energy efficiency investments required of investor owned utilities in MA (funded in part by RGGI Auction proceeds). DPU has approved a mechanism for funding the efficiency programs.

- Each year's incremental improvements are calculated as a percentage of that year's baseline w/o EE
- Municipal Light Plants supply 14% of each zone's baseline w/o EE
- Municipal Light Plants make no energy efficiency improvements
- Efficiency Improvements have the same effect on peak load as on energy usage
- Efficiency Improvements at Investor Owned Utilities (IOUs) are 1.31% in 2010, 1.87% in 2011, 2.29% in 2012 based on 3-year plans.
- Efficiency Improvements are thereafter constant as a percent of the baseline at 2.4%. The Green Communities Act (Acts of 2008 Chapter 169 Section 116(a)) sets a goal of meeting 25% of load through energy efficiency by 2020. The Energy Efficiency Advisory Council (EEAC) has set 2.4% as a goal for 2012 (see page 168 of http://www.ma-eeac.org/docs/DPU-filing/1-28-10%20DPU%20Order%20Electric%20PAs.pdf as well as attachment I of http://www.ma-eeac.org/docs/091027-Resolution.pdf). The EEAC expects to maintain that 2.4% goal going forward to 2020.
- 0.9% Efficiency Improvement Case included because that has been rate in recent years
- Includes any assumptions that are part of the baseline w/o EE

New England Energy Efficiency Assumptions Cont'd

New Hampshire

Based on the ISO-NE baseline modified by the New England States Committee on Electricity (NESCOE) 7/1/10 proposal of an additional 234 MW per year EE under BAU for ISO-NE modeling assumptions (www.nescoe.com/uploads/Memo_to_ISO_on_Assumtions___7.1.10.pdf pp. 3-4), New Hampshire reduced the load and peak demand proportionate to the regional estimate, which is approximately the same as the annual projected (and historically experienced) reduction in load and peak demand from continuation of current utility energy efficiency programs plus RGGI funded energy efficiency programs.

Rhode Island

Based on the ISO-NE baseline modified by the New England States Committee on Electricity (NESCOE) 7/1/10 proposal of an additional 234 MW per year EE under BAU for ISO-NE modeling assumptions (www.nescoe.com/uploads/Memo_to_ISO_on_Assumtions___7.1.10.pdf pp. 3-4), Rhode Island reduced the load and peak demand proportionate to the regional estimate.

Vermont

Vermont demand assumptions are based on the load forecast prepared by the Vermont System Planning Committee (VSPC). The VSPC is composed of stakeholders, including all utilities, public representatives, DPS, the Energy Efficiency Utility (EEU), and the Sustainably Priced Energy Enterprise Development (SPEED) Facilitator. The VSPC forecasts a 20 year load forecast and an adjusted forecast with energy efficiency based on what VT expects to spend on efficiency. http://www.vermontspc.com/VSPC%20Reports%20%20Correspondence/Forms/AllItems.aspx

New York Energy Efficiency Assumptions

New York

New York used NYISO baseline with EE. This is the forecast that the NYISO is using for its Reliability Needs Assessment. It represents the achievement of 36% of the State's energy efficiency goal by 2015 and approximately 50% of the goal by 2018.

PJM Energy Efficiency Assumptions

Delaware

- The DPL Zone consists of 9 Maryland counties, 3 Delaware counties and 2 Virginia Counties and the EE forecast was assembled using each of the individual state goals for consumption (energy) reductions and peak demand reduction.
    - The Delaware forecast was based on a hard 15% reduction from 2007 numbers by 2015. Delaware assumed an additional 5% over the period 2016-2025 for a maximum 20% efficiency and stable to 2030
    - The Maryland forecast was based on an estimated 15% per capita reduction from a 2007 base year and included the same 5% additional beyond the 2015 time frame, stable 2025 thru 2030.
    - The Virginia forecast was based on the state's voluntary goal of 10% use reduction by 2022 with continuing moderate increase to 2025 and stable to 2030.While Virginia may not have intended its goal to apply to peak demand, the Virginia portion was only 47 MWs at maximum contribution.

- Individual State starting points were established based on an allocation of the PJM forecast by population which assumes a similar diversity of customer classes. Actual state forecasts are not available.

- Maryland population was estimated from historic growth patterns and reductions were applied on a per capita basis, consistent with their legislation.

- Each of the states will take the actions necessary to achieve their stated goals and EE will not suddenly stop at 2015, but is anticipated to slow dramatically as less opportunity will be available.

- The state goals are separate from the EE that PJM has qualified in its base capacity auctions since the PJM forecast does not yet include public policy goals.

PJM Energy Efficiency Assumptions Cont’d

Maryland

Based on data for the Empower Maryland 15% by 2015 energy efficiency and DSM goals, Maryland assumed a factor of 35% for energy savings and a factor of 100% for the Empower Maryland peak demand goal.

New Jersey

New Jersey assumes the continuation of NJ Clean Energy Program (CEP) EE savings performance at 2009 levels and average measure lifetime of 15 years, and incorporates the recent enactment of updated building energy codes.

Sources: New Jersey's Clean Energy Program Report (Reporting Period: Year-to-Date through Fourth Quarter 2009); New Jersey Clean Energy Program Protocols (2009 Revisions).

Building Codes: Assumes energy savings for IECC 2006/ASHRAE 90.1-2004 building energy code updates promulgated by DCA in 2007; GWh savings estimates from NJ EMP modeling assumptions (Rutgers CEEEP, Modeling Report for the New Jersey Energy Master Plan - Appendix A, October 2008).