



Minnesota Pilot Project Overview of Proposed Modeling Assumptions

Presented by ICF International

September 6, 2011



Assumptions - Outline

- n Introduction and IPM Overview
- n Run Definition Assumptions
 - Run Years
 - Model Regions
- n Market Assumptions
 - Electricity Demand
 - Reserve Margin and Transmission
 - Financial Assumptions
- n Fuel Assumptions
- n Technical Assumptions
 - Supply Assumptions
 - Pollution Control Retrofits
- n CO₂ Transportation and Sequestration Assumptions
- n Air Regulatory Policies

Introduction

- n The US EPA is working with Minnesota to ensure stakeholders have the information and tools needed to meet upcoming electric utility sector rules in an integrated way. This approach will offer greater regulatory certainty to enable more informed investment decisions in the sector.
- n ICF's Integrated Planning Model (IPM®), with detailed modeling of the power sector and expanded to represent emissions and emissions reduction opportunities for a broad range of sectors, is being used for this analysis. The IPM is the tool used by US EPA's Clean Air Markets Division for analysis of proposed regulations.
- n The proposed model runs for this project are based on the US EPA's v4.10 Base Case using IPM. These proposed run specifications were developed during previous teleconferences with the Minnesota working group.
- n Detailed documentation for the US EPA v4.10 Base Case assumptions are available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html>

- n Multi-regional, deterministic, dynamic linear programming model with perfect foresight.
- n Long-term capacity expansion and production costing model for analyzing the electric power sector.
- n Comprehensive natural gas supply, demand, and pipeline modeling capability.
- n Finds the least-cost solution to meeting electricity and steam demand subject to environmental, transmission, fuel, reserve margin, and other system operating constraints.
- n IPM has evolved over 30 years after millions of dollars in development costs.
- n A core group of modelers update the tool on a continuous basis.

Run Definition Assumptions

Run Years

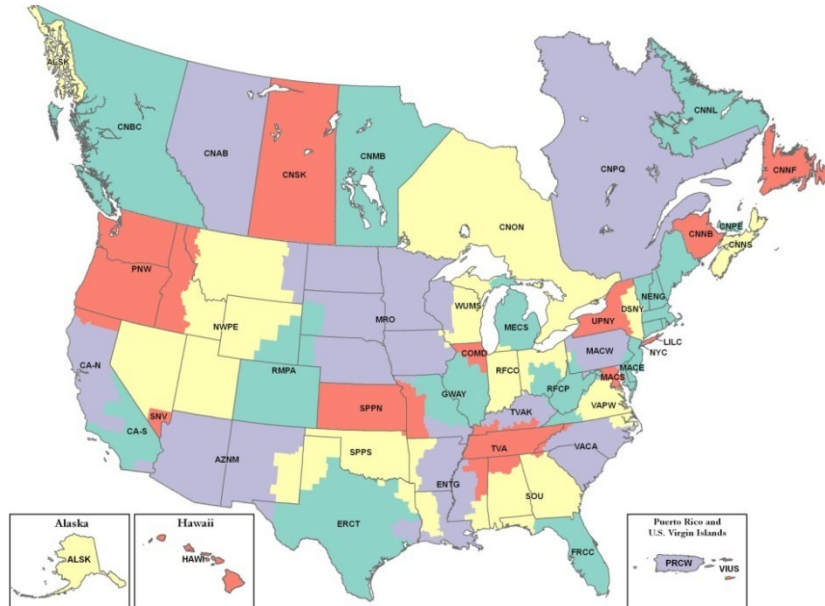
- n IPM® is equipped with a year-mapping feature that enables simulations of long time horizons.
 - Several years in the time horizon can be mapped into a single run year.
 - Generation costs for all years that are mapped to a run year are computed and included in the objective function.
- n The EPA Minnesota study will report six run years consistent with those in EPA v4.10 Base Case.

| Run Year | Years Mapped |
|----------|--------------|
| 2012 | 2012-2013 |
| 2015 | 2014-2016 |
| 2020 | 2017-2024 |
| 2030 | 2025-2034 |
| 2040 | 2035-2045 |
| 2050 | 2046-2054 |

Each run year will be modeled with two seasons: Winter (October-April) and Summer (May-September).

Model Regions

- n IPM Model regions are configured in order to:
 - Capture transmission bottlenecks.
 - Maintain consistencies with primary data sources.
 - Maintain consistency with NERC region and sub regions.
- n The EPA Base Case v4.10 models 32 model regions in the continental USA and 11 model regions in Canada.



Market Assumptions

- n Demand is represented in IPM® at a model region level by a combination of the following variables:
 - **Peak Demand** – The maximum power load (MW) requirement for a model region.
 - **Energy Demand** – The total energy requirement (MWh) for a model region, defined annually.
 - **Hourly Load Profiles** – The 24-hour shape of demand level, defined for 8760 hours of a base year, for each model 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 normal weather year.
- n EPA Base Case v4.10 uses the electricity demand assumptions from AEO 2010 Reference Case.

Reserve Margin and Transmission Assumptions

- n To maintain system stability and reliability, each IPM® model region must have a certain amount of backup capacity relative to its projected peak demand. Reserve margin is defined as the amount of capacity that needs to be built over and above the peak load.
- n IPM being a multi region model, the various power market regions are interconnected by a transmission grid. Transmission between model regions allows for broad price equilibration and reserve sharing across the North American grid

Transmission Assumptions – Selected Links

Annual Transmission Capabilities from and to the MRO Model Region

| From | To | Energy (MW) | | From | To | Energy (MW) |
|------|------|-------------|--|------|-----|-------------|
| MRO | CNMB | 0 | | CNMB | MRO | 2,175 |
| MRO | CNON | 100 | | CNON | MRO | 150 |
| MRO | CNSK | 165 | | CNSK | MRO | 215 |
| MRO | COMD | 610 | | COMD | MRO | 825 |
| MRO | ENTG | 2,000 | | ENTG | MRO | 150 |
| MRO | GWAY | 320 | | GWAY | MRO | 405 |
| MRO | NWPE | 200 | | NWPE | MRO | 150 |
| MRO | RMPA | 310 | | RMPA | MRO | 310 |
| MRO | SPPN | 2,000 | | SPPN | MRO | 600 |
| MRO | WUMS | 800 | | WUMS | MRO | 270 |

Transmission Assumptions – Selected Links Cont.

Annual Joint Capacity and Energy Limits Between MRO and Neighboring Model Regions

| Region Connections | Transmission Path | Joint Constraint Limit (MW) |
|--------------------|---|-----------------------------|
| MAIN to MAPP | COMD to MRO GWAY to MRO WUMS to MRO | 962 |
| MAPP to MAIN | MRO to COMD MRO to GWAY MRO to WUMS | 1,238 |
| WECC to MAPP | NWPE to MRO RMPA to MRO | 660 |
| MAPP to WECC | MRO to NWPE MRO to RMPA | 710 |

Financial Assumptions

n Discount Rate

- IPM® is a linear programming model that optimizes system performance in a least cost manner to meet market and policy requirements in the analysis.
- All costs in EPA Base Case v4.10 are represented in real 2007\$, 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 is important in evaluating the tradeoffs of making investments and incurring costs in the near-term vs. incurring expenses over the longer-term.

n Capital Charge Rate

- Capital investments in IPM® are annualized using a capital charge rate that takes into account the amount 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.

U.S. Discount Rates and Capital Charge Rates in EPA Base Case v4.10

| Investment Technology | Capital Charge Rate | Discount Rate | Book Life |
|--|---------------------|---------------|-----------|
| Environmental Retrofits | 11.3% | 5.5% | 30 |
| Advanced Combined Cycle | 12.1% | 6.2% | 30 |
| Advanced Combustion Turbine | 12.9% | 6.9% | 30 |
| Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture ¹ | 14.1% | 7.8% | 40 |
| Advanced Coal with Carbon Capture | 11.1% | 5.5% | 40 |
| Nuclear without Production Tax Credit (PTC) | 10.8% | 5.5% | 40 |
| Nuclear with Production Tax Credit (PTC) ² | 9.1% | 5.5% | 40 |
| Biomass with ARRA Loan Guarantees ³ | 9.3% | 4.6% | 40 |
| Biomass without ARRA Loan Guarantees | 11.1% | 6.2% | 40 |
| Wind and Landfill Gas with ARRA Loan Guarantees ² | 10.1% | 4.6% | 20 |
| Wind and Landfill Gas without ARRA Loan Guarantees | 12.2% | 6.2% | 20 |
| Solar and Geothermal with ARRA Loan Guarantees ² | 10.1% | 4.6% | 20 |
| Solar and Geothermal without ARRA Loan Guarantees | 12.2% | 6.2% | 20 |

Notes:

The discount rates appearing in the table were used in deriving these capital charge rates. However, a single U.S. discount rate of 6.15% is used across all technologies in EPA Base Case v.4.10.

¹The capital charge rate for these technologies includes a 3% climate change uncertainty adder.

²The capital charge rate for this technology reflects the impact of the PTC provided under the Energy Policy Act of 2005.

³The capital charge rate for these technologies reflects the impact of ARRA loan guarantees.

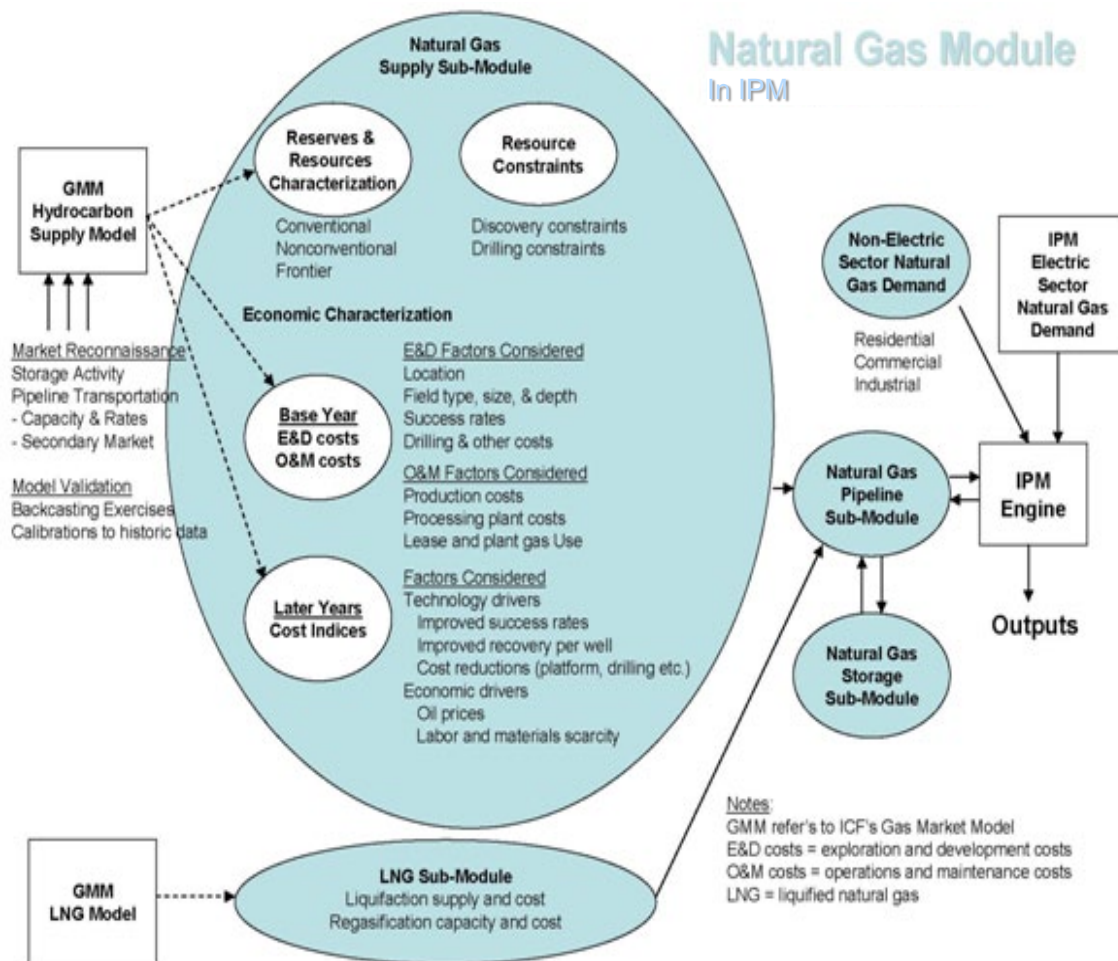
Fuel Assumptions

Gas Modeling Capabilities

§The EPA Base Case v4.10 using IPM takes advantage of the embedded comprehensive natural gas supply, demand, storage and pipeline model within IPM.

§In this system, natural gas supply curves are generated endogenously for each region, and the balance between the natural gas supply and demand is solved in all regions simultaneously. The direct interaction between the electric and the gas modules captures the overall gas supply and demand dynamic and requires no iteration.

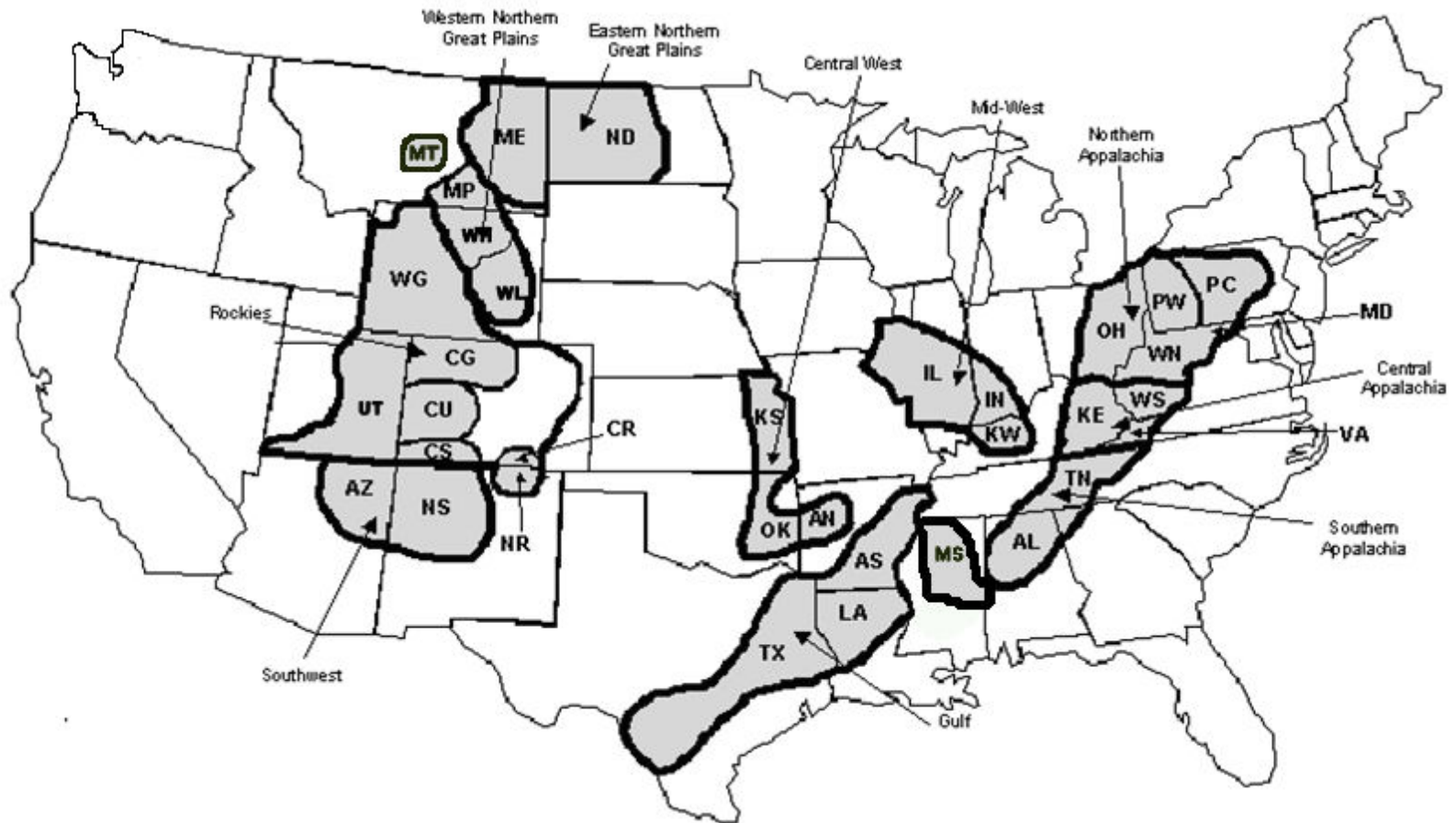
§This version of the gas model will be slightly revised to capture the AEO 2011 crude oil price projections.



Coal Market Modeling

- n EPA Base Case v4.10 relies on a supply curve structure to simulate coal markets. Having coal supply curves allows the model to simulate the price changes that would occur with substantial shifts in demand that might occur under environmental policies.
- n Coal resources for each of 34 coal supply basins are disaggregated by the following characteristics:
 - Rank (Bituminous, Subbituminous, Lignite)
 - Sulfur content ranges
 - Existing and new mines
- n Coal plants in EPA Base Case v4.10 using IPM[®] are assigned to one of 100+ different coal demand regions.
- n 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.

Coal Supply Region Map



Biomass Supply Curves

- n AEO 2010 models biomass through biomass supply curves. The biomass supply curves are defined for the 14 NEMS coal demand regions. These regions are subsets of census regions. In EPA Base Case v4.10, these regions are mapped to the IPM Regions.
- n These supply curves model the following four biomass types:
 - Urban wood waste and mill residue
 - Energy crop
 - Forestry residue
 - Agricultural residue
- n Biomass supply curves satisfy biomass demand for the electric power and the cellulosic ethanol sectors.
- n Biomass will be modeled as having a net-zero CO₂ emission factor. This is a common assumption used in power sector modeling and reflects the life cycle emissions over the materials' growth cycle and ultimate combustion.

Technical Assumptions Supply

- n Supply in IPM® is defined by a combination of the following options:
 - **Existing Capacity** – The generating capacity currently available to the grid.
 - **Firmly Planned Capacity** – The generating capacity that is firmly planned to be built.
 - **New build Cost and Performance** – The specifications for new potential capacity types, including assumptions about technology improvement over time and resource potential.

Existing Capacity – IPM® Power Plant Database

- n IPM® requires detailed information on all existing and planned and committed grid-connected electric generators and boilers in the continental U.S.
- n The IPM power plant database will be based on EPA's National Electric Energy Data System (NEEDS). NEEDS database contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units.
- n Existing and planned committed units in the database, with the exception of nuclear units, are not provided with a specific retirement year. However, IPM can endogenously retire power plants based on economics. The life extension cost estimates are based on EPA Base Case v4.10.

Existing Capacity – Power Plant Availability

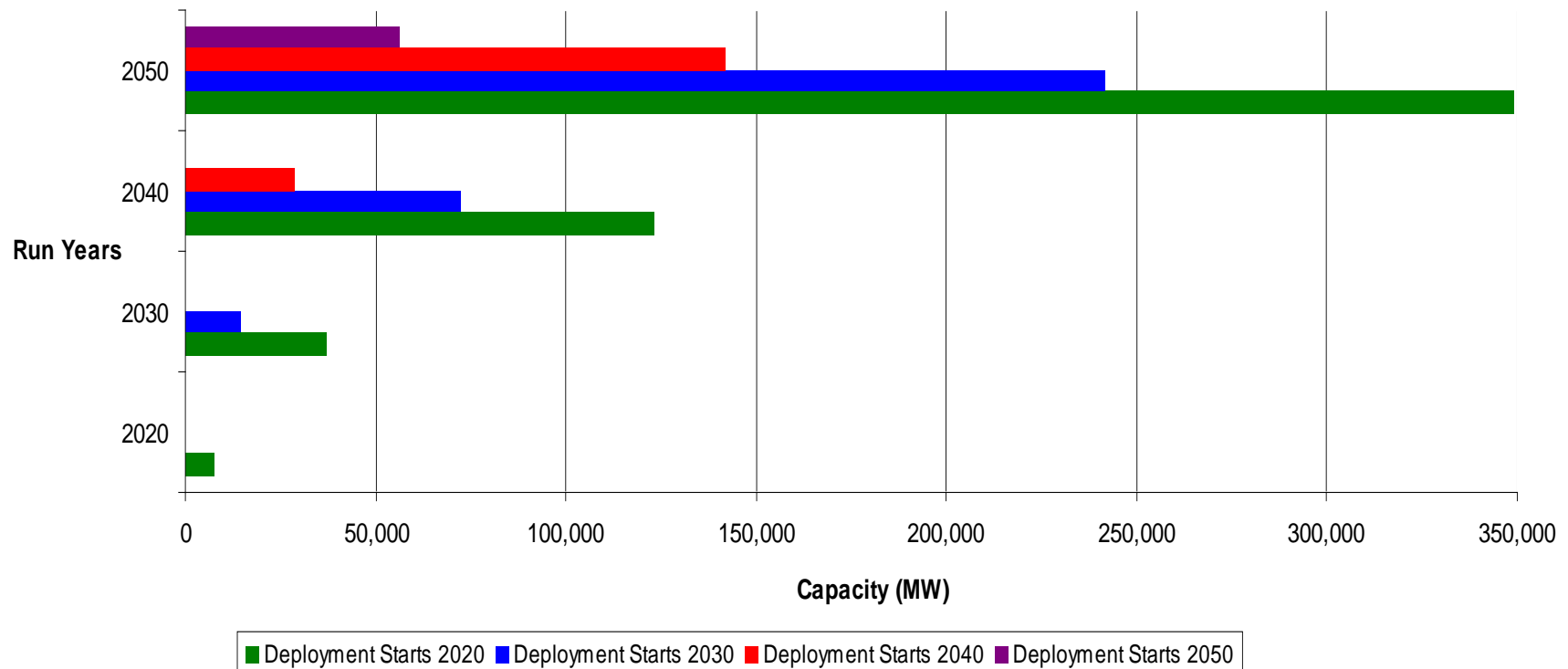
- n Power plant availabilities for non coal fossil units are based on NERC GADS and AEO.
- n For existing coal units, EPA Base Case v.4.10 adopts an approach similar to AEO 2010 of using historical capacity factors to define projected availabilities.

Performance and Unit Cost Assumptions for New Capacity from Conventional Technologies in EPA Base Case v4.10

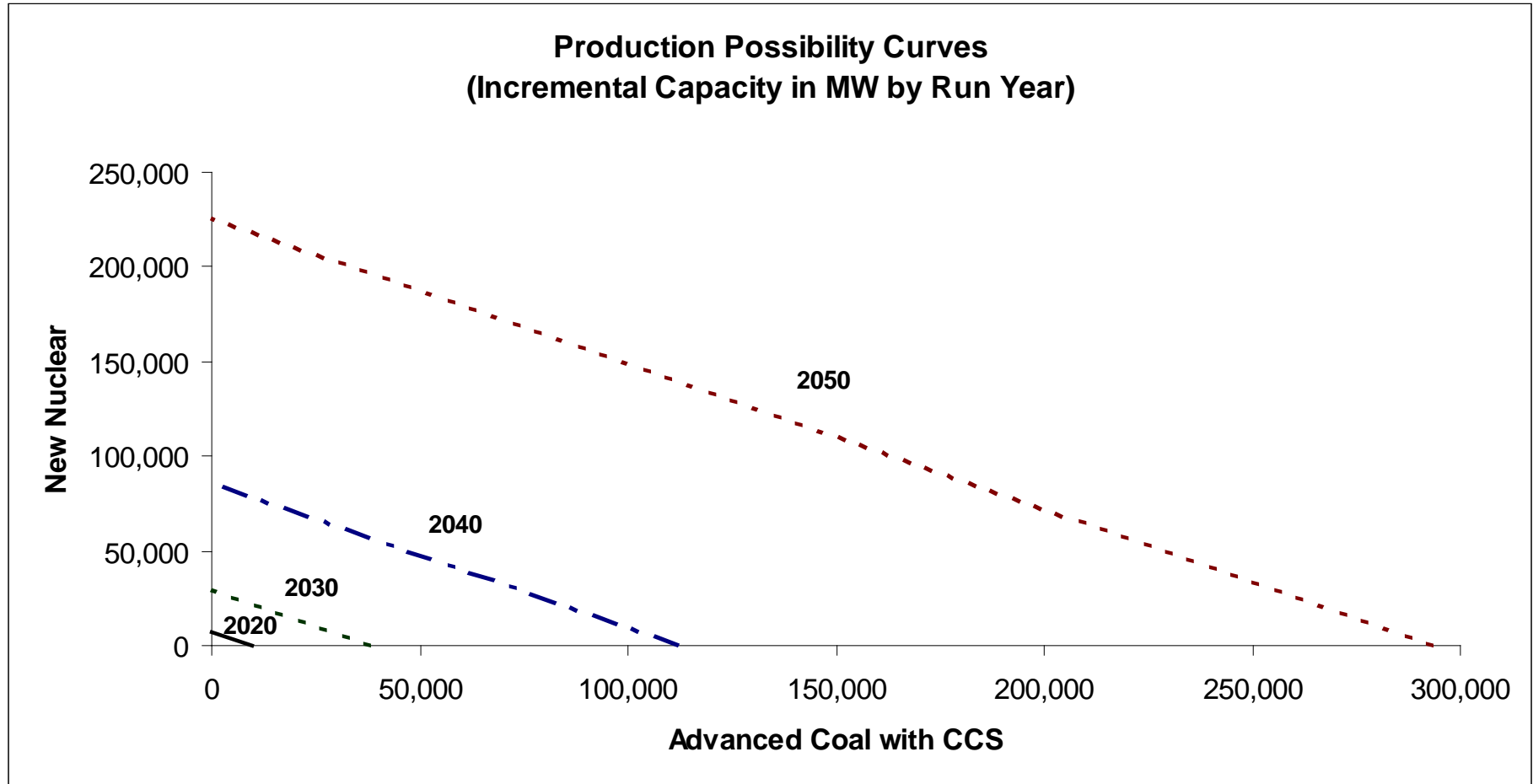
| | Advanced Combined Cycle | Advanced Combustion Turbine | Nuclear | Integrated Gasification Combined Cycle – Bituminous | Advanced Coal with Carbon Capture- Bituminous | Supercritical Pulverized Coal - Wet Bituminous |
|--------------------------------------|-------------------------|-----------------------------|---------|---|---|--|
| EPA Base Case v4.10 | | | | | | |
| Heat Rate (Btu/kWh) | 6,810 | 10,720 | 10,400 | 8,424 | 10,149 | 8,874 |
| Capital (2007\$/kW) | 976 | 698 | 4,621 | 3,265 | 4,720 | 2,918 |
| Fixed O&M (2007\$/kW/yr) | 14.4 | 12.3 | 92.4 | 47.9 | 60.5 | 28.9 |
| Variable O&M (2007\$/MWh) | 2.57 | 3.59 | 0.77 | 1.32 | 1.67 | 3.43 |

New Plant Investment Capacity Constraints - Nuclear

Maximum Possible Cumulative New Nuclear Capacity Each Run Year



New Plant Investment Capacity Constraints – Nuclear & CCS



Emissions Control Technologies/Retrofits

Emissions Control Technologies/Retrofits

- n 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.
- n EPA Base Case v4.10 using IPM explicitly models the most common existing control technologies, each of which impact the emissions rate for SO₂, NO_x, mercury, HCl and CO₂ emissions. Emission reduction factors are applied to the input content of the fuel to reflect the technology.

| Pollutant | Technology |
|-------------------------|--|
| SO ₂ and HCl | Wet Scrubber, Dry Scrubber, Dry Sorbent Injection |
| NO _x | SCR, SNCR |
| Mercury | ACI |
| CO ₂ | Carbon Capture, Biomass Cofiring, Coal-to-Gas Retrofit |

Summary of Emission Control Technology Removal Rates

| Emission Control Technology | % Reduction | Floor |
|--|----------------------------------|--|
| Limestone Forced Oxidation (LSFO) | SO ₂ - 96%, HCl – 99% | SO ₂ - 0.06 lbs/MMBtu HCl - 0.0001 lbs/MMBtu |
| Lime Spray Dryer (LSD) | SO ₂ - 92%, HCl – 99% | SO ₂ - 0.08 lbs/MMBtu HCl - 0.0001 lbs/MMBtu |
| Dry Sorbent Injection with FF (DSI) | SO ₂ - 70%, HCl – 90% | HCl - 0.0001 lbs/MMBtu |
| Selective Catalytic Reduction (SCR) - Coal | NO _x - 90% | Bit - 0.07 lbs/MMBtu Subbit - 0.05 lbs/MMBtu |
| Selective Non-Catalytic Reduction - PC (SNCR) | NO _x - 35% | -- |
| Selective Non-Catalytic Reduction – FBC (SNCR) | NO _x - 50% | -- |
| Activated Carbon Injection (ACI) | Hg - 90% | -- |
| Coal-to-Gas Retrofit | NO _x - 50% | 0.05 lbs/MMBtu |
| Carbon Capture (CCS) | CO ₂ - 90% | |

Illustrative Scrubber Costs (2007\$)

| Scrubber Technology | Capacity (MW) | Capital Cost (\$/kW) | Fixed O&M (\$/kW-yr) | Variable O&M (mills/kWh) |
|--|---------------|----------------------|----------------------|--------------------------|
| LSFO Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal SO ₂ rate: 3 lb/MMBtu Heat Rate: 10,000 Btu/kWh | 100 | 783 | 22.8 | 1.84 |
| | 300 | 573 | 10.8 | |
| | 500 | 496 | 8 | |
| | 700 | 451 | 7.4 | |
| | 1000 | 407 | 6.1 | |
| LSD Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal SO ₂ rate: 2 lbs/MMBtu Heat Rate: 10,000 Btu/kWh | 100 | 670 | 16.7 | 2.36 |
| | 300 | 491 | 8.3 | |
| | 500 | 424 | 6.3 | |
| | 700 | 403 | 5.5 | |
| | 1000 | 403 | 5.1 | |

Illustrative Post-Combustion NO_x Control Costs (2007\$)

| Control Type | Capacity (MW) | Capital Cost (\$/kW) | Fixed O&M (\$/kW-yr) | Variable O&M (mills/kWh) |
|---|---------------|----------------------|----------------------|--------------------------|
| SCR - Coal Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NO _x rate: 0.5 lb/MMBtu SO ₂ rate: 2.0 lb/MMBtu Heat Rate: 10,000 Btu/kWh | 100 | 240 | 2.5 | 1.24 |
| | 300 | 193 | 0.8 | |
| | 500 | 178 | 0.7 | |
| | 700 | 169 | 0.5 | |
| | 1000 | 162 | 0.4 | |

Illustrative Post-Combustion NO_x Control Costs Cont. (2007\$)

| Control Type | Capacity (MW) | Capital Cost (\$/kW) | Fixed O&M (\$/kW-yr) | Variable O&M (mills/kWh) |
|---|---------------|----------------------|----------------------|--------------------------|
| SNCR - Non-FBC Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NO _x rate: 0.5 lb/MMBtu SO ₂ rate: 2.0 lb/MMBtu Heat Rate: 10,000 Btu/kWh | 100 | 47 | 1 | 0.98 |
| | 300 | Size Not Modeled | | |
| | 500 | | | |
| | 700 | | | |
| | 1000 | | | |
| SNCR - Fluidized Bed Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NO _x rate: 0.5 lb/MMBtu SO ₂ rate: 2.0 lb/MMBtu Heat Rate: 10,000 Btu/kWh | 100 | 35 | 0.9 | 0.98 |
| | 300 | 19 | 0.4 | |
| | 500 | 14 | 0.2 | |
| | 700 | 12 | 0.2 | |
| | 1000 | 10 | 0.1 | |

Illustrative DSI and PM Control Costs (2007\$)

| Control Type | Capacity (MW) | Capital Cost (\$/kW) | Fixed O&M (\$/kW-yr) | Variable O&M (mills/kWh) |
|---|---------------|----------------------|----------------------|--------------------------|
| DSI - FF Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh | 100 | 125 | 2.28 | 6.72 |
| | 300 | 57 | 0.89 | |
| | 500 | 40 | 0.58 | |
| | 700 | 31 | 0.43 | |
| | 1000 | 31 | 0.38 | |
| Fabric Filter Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh | 100 | 205 | 0.9 | 0.15 |
| | 300 | 167 | 0.7 | |
| | 500 | 151 | 0.6 | |
| | 700 | 141 | 0.6 | |
| | 1000 | 132 | 0.6 | |

Illustrative ACI Control Costs (2007\$)

| Control Type | Capacity (MW) | Capital Cost (\$/kW) | Fixed O&M (\$/kW-yr) | Variable O&M (mills/kWh) |
|--|---------------|----------------------|----------------------|--------------------------|
| ACI + Full Baghouse with a Sorbent Injection Rate of 2 lbs/MMBtu Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh | 100 | 259 | 0.98 | 0.54 |
| | 300 | 197 | 0.75 | |
| | 500 | 176 | 0.67 | |
| | 700 | 163 | 0.62 | |
| | 1000 | 151 | 0.57 | |
| ACI with a Sorbent Injection Rate of 2 lbs/MMBtu Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh | 100 | 28.37 | 0.12 | 2.49 |
| | 300 | 11.16 | 0.05 | |
| | 500 | 7.23 | 0.03 | |
| | 700 | 5.43 | 0.02 | |
| | 1000 | 4.01 | 0.02 | |
| ACI with a Sorbent Injection Rate of 5 lbs/MMBtu Assuming Bituminous Coal Heat Rate: 10,000 Btu/kWh | 100 | 32.56 | 0.14 | 3.07 |
| | 300 | 12.80 | 0.05 | |
| | 500 | 8.29 | 0.03 | |
| | 700 | 6.23 | 0.03 | |
| | 1000 | 4.60 | 0.02 | |

Illustrative Coal-to-Gas Retrofit Costs (2007\$)

| Coal-to-Gas Retrofit Technology | Capacity (MW) | Incremental Capital Cost (\$/kW) | Incremental Fixed O&M (\$/kW-yr) | Incremental Variable O&M (mills/kWh) |
|--|---------------|----------------------------------|----------------------------------|--------------------------------------|
| Pulverized Coal Unit Minimum Cutoff: > 25 MW Maximum Cutoff: None | 100 | 226 | -10.0 | 0.41 |
| | 300 | 154 | -8.9 | 0.33 |
| | 500 | 129 | -8.5 | 0.30 |
| | 700 | 114 | -8.2 | 0.28 |
| | 1000 | 101 | -7.9 | 0.26 |
| Cyclone Boiler Unit Minimum Cutoff: > 25 MW Maximum Cutoff: None | 100 | 316 | -10.0 | 0.41 |
| | 300 | 215 | -8.9 | 0.33 |
| | 500 | 180 | -8.5 | 0.30 |
| | 700 | 160 | -8.2 | 0.28 |
| | 1000 | 141 | -7.9 | 0.26 |

Illustrative CCS Control Costs (2007\$)

| Applicability (Original MW Size) | 450-750 MW | > 750 MW |
|--|------------|----------|
| Incremental ¹ Capital Cost (2007 \$/kW) | 1,972 | 1,599 |
| Incremental ¹ FOM (2007 \$/kW-yr) | 3 | 1.98 |
| Incremental ¹ VOM (2007 (mills/kWh) | 2.35 | 2.35 |
| Capacity Penalty (%) | -25% | -25% |
| Heat Rate Penalty (%) | 33% | 33% |
| CO ₂ Removal (%) | 90% | 90% |

Note:

¹Incremental costs are applied to the derated (after retrofit) MW size.

CO₂ Transportation and Sequestration Modeling in IPM

CO₂ Transportation and Sequestration

- n Coal power plants with CO₂ capture capability are grouped into CO₂ production regions.
- n CO₂ storage sites are grouped into CO₂ storage regions.
- n CO₂ production regions and CO₂ storage regions are interconnected by a CO₂ transportation network.
- n The CO₂ transportation capability between production regions and storage region regions is considered unlimited and available at a constant unit cost of transportation.
- n CO₂ storage cost in each CO₂ storage region is characterized by a CO₂ storage cost curve.
- n CO₂ storage regions with enhanced oil recovery possibilities have negative costs in the CO₂ storage cost curve for that region.

Air Regulatory Policies

Federal and Regional Air Regulations

- n SO₂, NO_x and Mercury Regulations:
 - Any policy already on the books (e.g., state policies, NSR settlements) are included in the EPA Base Case v4.10.