George Giannakidis · Maryse Labriet
Brian Ó Gallachóir · GianCarlo Tosato
Editors

# Informing Energy and Climate Policies Using Energy Systems Models

## Insights from Scenario Analysis Increasing the Evidence Base

Springer

*Editors*
George Giannakidis
Laboratory for Energy Systems Analysis
Center for Renewable Energy Sources
Pikermi, Attiki
Greece

Brian Ó Gallachóir
Environmental Research Institute
University College Cork
Cork
Ireland

Maryse Labriet
Eneris Environment Energy Consultants
Madrid
Spain

GianCarlo Tosato
ASATREM
Rome
Italy

ISSN 2195-1284 ISSN 2195-1292 (electronic)
Lecture Notes in Energy
ISBN 978-3-319-16539-4 ISBN 978-3-319-16540-0 (eBook)
DOI 10.1007/978-3-319-16540-0

Library of Congress Control Number: 2015933834

Springer Cham Heidelberg New York Dordrecht London


Printed on acid-free paper

Springer International Publishing AG Switzerland is part of Springer Science+Business Media
(www.springer.com)

# Highly Detailed TIMES Modeling to Analyze Interactions Between Air Quality and Climate Regulations in the United States

**Evelyn Wright and Amit Kanudia**

**Abstract** This chapter describes highly detailed modeling of existing coal-fired units in the US power sector within the FACETS TIMES model. Such detailed modeling is necessary wherever the existing stock plays a key role in determining policy cost. The soon-to-be-implemented Mercury and Air Toxics (MATS) regulation imposes unit-level emissions rate constraints on nearly 1100 coal-fired units, forcing retrofit or retire decisions at a large portion of the existing fleet. Covered emissions and retrofit costs depend in a detailed way on unit configuration and coal quality, forcing development of new techniques to handle the enormous expansion in model size and detail. These retrofit/retire decisions are being made under uncertainty about future carbon policies for the sector. FACETS was used to compare "foresight" scenarios in which the model could "see" both the MATS requirements and a power sector clean energy standard (CES) to "myopic" scenarios in which the MATS decisions made in the Reference scenario are fixed in the model solution up through the MATS compliance window in model year 2018, after which the model is free to begin responding to the CES. The overall national costs of myopia were found to be small, except when the carbon policy ramps up very quickly after air quality compliance decisions are made, but significant regional heterogeneity exists. Stranded asset costs from retrofitted units that must be underutilized or abandoned later range from $2 to 8 billion in the myopic cases. Substantially fewer retrofits are undertaken in the foresight cases, reducing stranded asset costs in some regions by up to 100 %.

E. Wright (✉)
Sustainable Energy Economics, Rosendale, NY, USA
e-mail: Evelyn.L.Wright@gmail.com

A. Kanudia
KanORS-EMR, Noida, India
e-mail: amit@kanors.com



G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_13

## 1 Introduction

Carbon policy is slowly becoming a reality in many parts of the world. As this happens, analysis needs are evolving from abstract consideration of goals, timing, and high-level strategies to rigorous evaluation of the costs, incidence, and risks of specific policy designs. In the United States power sector, a key determinant of the economic impacts of carbon policy is the fate of the substantial existing stock of coal-fired units.

Over the next few years, these units are subject to implementation of historic new air emissions regulations, including a tightening of standards for sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$), as well as new standards under the Mercury and Air Toxics (MATS) rule for air toxins including acid gases, mercury, and other heavy metals (US EPA 2014a). The MATS standards differ from most major regulations recently implemented (and modeled) in an important way. These pollutants are subject to toxic hot spots, and thus the standards impose unit-level emissions rate constraints, not regional cap and trade budgets. Each of the country's nearly 1100 coal-fired units above 25 megawatts (MW) capacity faces the requirement to individually comply with these standards or retire.

At the same time, the stringency and timing of future carbon regulations for the sector remain uncertain. Although the Obama administration has recently proposed standards under the Clean Air Act (US EPA 2014b) prohibiting new coal plants without carbon capture and storage (CCS) and imposing moderate medium-term emissions rate reductions on existing plants, it remains unclear whether these proposed rules will survive legal challenge, and in any case they are expected to serve as only a prelude to eventual new, dedicated climate legislation.

The MATS compliance deadline is 2015, with possible extensions through 2017, so owners of non-compliant units will need to make costly decisions to retrofit or retire these units without certainty about how much longer these units will remain economic to operate under future carbon policy. The cost of carbon policy, in turn, depends on the decisions made regarding MATS compliance: how large is the existing stock of vulnerable units, and how significant are recent stranded investments in air compliance equipment when carbon policy becomes stringent enough to start forcing these units to retire.

Of equal importance is the *regional distribution* of carbon policy cost impacts. Previously analyses (Pizer et al. 2009; Rausch et al. 2011; Wright and Kanudia 2014) have shown that cost impacts may vary several-fold across the US, and it appears that these differences have played at least some role in the difficulty reaching consensus on a federal carbon policy (Wheeler 2008). The stock of coal-fired units, and their age, size, and existing emissions control equipment, are distributed unequally around the country, so the interactions between air quality and carbon policy can be expected to impact different regions more significantly than others.

Because air toxin emissions depend in quite a detailed way on unit configuration, coal quality, and existing emissions control equipment, it has been necessary to model the stock of existing units and their many retrofit options in a highly detailed, unit-level manner. These challenges are described in the next section. In addition to presenting this analysis, this chapter is designed as an illustration of how the TIMES platform can be used to analyze problem spaces that are much more highly detailed than has been common previously. Thus the modeling discussion in Sect. 3 assumes some familiarity with VEDA-FrontEnd[1] and interest in the details of the technique. Some new features have been developed to deal with the volume of data required, but much of the work has been done by using existing features in new ways. We hope this discussion will be useful to other modelers who are also wrestling with the need for incorporating more detail into their analyses. Other readers can feel free to scan or skip this section, as the remainder of the discussion does not depend on it.

To investigate the interaction between air quality compliance demands and carbon policy uncertainty, and demonstrate the application of these modeling techniques, the FACETS US TIMES model (Wright and Kanudia 2014) was used to compare "foresight" scenarios in which the model could "see" both the MATS requirements and a power sector clean energy standard (CES) that imposes a national cap and trade program forcing a reduction of the carbon intensity of generation over time to "myopic" scenarios in which the MATS decisions made in the Reference scenario are fixed in the model solution up through the MATS compliance window in model year 2018, after which the model is free to begin responding to the CES. Three versions of the CES policies with different stringency ramping rates were tried.

Section 4 presents this analysis, including the scenarios assessed, and the resulting system configurations, costs, and emissions results at national and regional levels. The chapter concludes with a discussion of the implications of the results, and considers the recently proposed Clean Power Plan carbon regulations for existing units in light of our findings.

## 2 Challenge of Modeling MATS Emissions and Compliance

MATS requires each unit to meet standards for several toxins. Three of the most significant were modeled here: an acid gas standard, using emissions of hydrochloric acid (HCl) as the measurement proxy; a mercury standard; and a standard for non-mercury metal toxins using filterable particulate matter (PM) as a surrogate for compliance measurement. Emissions of HCl and mercury depend on boiler type, coal quality, and emissions control equipment, and several compliance routes may be available to each unit. This section describes the rule's requirements and the emissions control retrofit options made available in the modeling.

[1]http://www.kanors-emr.org/VedaSupport/.

The acid gas standard requires emissions below approximately 0.002 pounds per million British Thermal Unit (lb/MM BTU) of coal consumed.[2] HCl emissions are a function of the chlorine content of coal and emissions control equipment for $SO_2$. The higher ash content of subbituminous and lignite coals neutralizes much HCl before emission, leading to an effective range of uncontrolled emissions among US coals ranging from 0.281 pounds per million BTU (lb/MM BTU) to 0.0015 lb/MMBTU, or more than two orders of magnitude, implying that between zero and more than 99 % reduction is necessary to comply, depending on the coal type used.

Plants can retrofit to reduce HCl emissions with either flue gas desulphurization (FGD) or direct sorbent injection (DSI). Capital and operating costs depend on unit size and existing emissions control configuration, as DSI requires a fabric filter (FF) in place, but in general, FGD is a high capital cost, low operating cost technology, whereas DSI requires a lower upfront capital cost, but three-fold higher variable operating and maintenance (O&M) cost. FGD removes a much higher percentage of the HCl (99 vs. 90 %), providing more coal type flexibility. As discussed below, FGD also makes a contribution to mercury removal, and may provide an important compliance route for the mercury standard, depending on a unit's other characteristics. Table 1 summarizes retrofit device cost and performance assumptions for all devices made available in the modeling.[3]

Mercury emissions depend on the mercury content of the coal burned along with boiler type and emissions control equipment for $SO_2$, $NO_x$, PM, and an optional dedicated activated carbon injection (ACI) for mercury removal. The latter also requires the unit to have either an electrostatic precipitator (ESP) or FF. The mercury standard requires emissions below approximately 1.2 pounds per trillion BTU of coal consumed.[4] As coal mercury contents range from 1.8 to 34.7 lb/TBTU, removal of 33–97 % of the mercury content is required.

Many different unit configurations will lead to compliant mercury control for units burning bituminous coals. For example, most boiler types will achieve 90 % reductions when equipped with FGD and selective catalytic reduction (SCR) and burning bituminous coal, and a fluidized bed unit with FF achieves a 95 % reduction. Non-ACI controls are less effective at removing mercury from subbituminous and lignite coals, but ACI will remove 90 % of incoming mercury content from any coal type. Overall, 510 units, or nearly half, achieve 90 % or greater mercury reductions under their existing configurations when burning bituminous

[2]The standards for HCl and mercury are given in mass per electricity generated for units below a heat rate threshold of 10,000 BTU per kilowatt-hour (kWh) and mass per unit of coal combusted for units above, in order to provide some flexibility for high heat rate units. Thus the precise standard is dependent on the characteristics of each unit. The threshold values are used here to provide an approximate sense of the requirements of compliance. The unit-specific standards were used in the modeling described below.

[3]Characteristics derived from US EIA (2011a) and US EPA (2010, 2011a, b).

[4]For plants burning bituminous or subbituminous coals. Plants burning lignite are subject to a different standard, which was implemented in the modeling but neglected here for simplicity of discussion.

**Table 1** Emissions control retrofit options and characteristics

| Equipment | Capital cost ($/kW)[a] | Addition to fixed O&M ($/kW years) | Addition to variable O&M (mills/kWh) | Removes | Removal rate |
|---|---|---|---|---|---|
| FGD | 378–662 | 5.9–18.0 | 1.9 | $SO_2$ | 95 % |
| | | | | HCl | 99 % |
| | | | | Hg | Depends on configuration |
| DSI alone | 30–110 | 0.4–2.0 | 5.9 | $SO_2$ | 70 % |
| | | | | HCl | 90 % |
| DSI plus FF | 154–291 | 0.4–2.0 | 5.9 | $SO_2$ | 70 % |
| | | | | HCl | 90 % |
| SCR | 154–219 | 0.5–2.3 | 1.1 | $NO_x$ | 90 % |
| | | | | Hg | Depends on configuration |
| ACI alone | 5–27 | 0.0 | 2.4 | Hg | 90 % |
| ACI plus FF | 144–228 | 0.5–0.9 | 0.5 | Hg | 90 % |

[a]All costs presented in 2004$

coal, enough for compliance burning most bituminous coals, while just over 100 achieve 90 % when burning subbituminous coal, largely through existing ACI.

The remaining plants must install some combination of retrofits, or in some cases, switch to a lower mercury coal type, in order to continue operation. Depending on their existing configuration, their HCl compliance needs, and the value of $SO_2$ and $NO_x$ reductions in their region, this may be as simple and inexpensive as adding ACI, at a relatively low capital cost, or it may be necessary or optimal to upgrade their $SO_2$, $NO_x$, or PM control equipment as well or instead, at costs up to nearly two orders of magnitude higher.

Finally, enhanced filterable PM controls are required at many units to control emissions of other toxins under MATS. US EPA (2011b) evaluated existing coal units and found that 393 units would be required to upgrade their existing ESP or install a new FF. These upgrades were exogenously imposed on each unit in the modeling described below, with capital costs imposed as an increment to annual fixed O&M charges of $5.5–20.4 $/KW, depending on the upgrade required.

Because of this great diversity in compliance costs and the unit-level nature of the MATS requirements, analysis of the regulation's impact based on average or typical plant characteristics, as would be required in a model with coarse geography, would fail to represent the very detailed supply curve for the survival of existing plants. And importantly, it would also fail to capture the regional diversity of retrofit costs and the need to build replacement capacity for those plants that retire. This geographic information is essential for the analysis of carbon regulations because the costs of implementing low carbon technologies depend on geographical relationships between low carbon resources, electricity generation and transmission infrastructure, and loads. The distribution of low carbon resources, including wind, solar, geothermal, and access to $CO_2$ sequestration sites, is highly heterogeneous, leading to significant regional differences in the costs of emission reduction (Wright and Kanudia 2014).

## 3 Modeling the Power Sector in FACETS

The Framework for Analysis of Climate-Energy-Technology Systems (FACETS) multi-region US TIMES model has been designed to enable such geographically rich analysis of the US energy system. Specifically, FACETS has been designed with unit-level detail in the power sector, including a rich set of emissions control retrofit options for coal-fired units, and a regional structure that emphasizes existing infrastructure and key geographical relationships. This section describes the FACETS power sector and associated fuel supplies, with a focus on the techniques used to handle the challenges described in the previous section. The rule-based VEDA-TIMES system was essential to handle the enormous level of detail required, and was enhanced on both the input and output sides. In particular, we describe three things: the use of VEDA rules to describe the existing control equipment at each unit and its retrofit options and resulting emissions; the use of a topology insert table to create coal input options specific to each unit, and the VedaViz system to support analyzing the correspondingly large volume of results data.

The data source for the power sector is the US EPA National Electric Energy Data System database (US EPA 2010), which provides capacity, cost, efficiency, availability, emissions, and emissions control equipment data for just over 15,000 units in the lower 48 states. Plants are grouped into 32 regions that represent regional transmission organizations (RTOs), independent system operators (ISOs) and key transmission bottlenecks. A matrix of transmission capacities and costs describes the potential flows between these regions, and data from the US Department of Energy (DOE) National Energy Modeling System (NEMS, US EIA 2009) provides capital costs for additions to this capacity.

In order to preserve this infrastructure information, the 32 power sector regions were implemented as regions within FACETS, with the transmission capacities serving as a trade matrix. Electricity demand[5] takes place in a different set of regions: the nine Census divisions that US DOE uses to track sectoral consumption data. A matrix of user constraints prescribes the share of each consumption region's electricity that must be provided by each of its corresponding electricity regions.

[5]Although FACETS contains a full representation of end use sectors, for this study, which focuses on power sector policies, only the power sector and its fuel supplies were used. The demand for electricity consumption was driven by Annual Energy Outlook projections (US DOE 2011a).

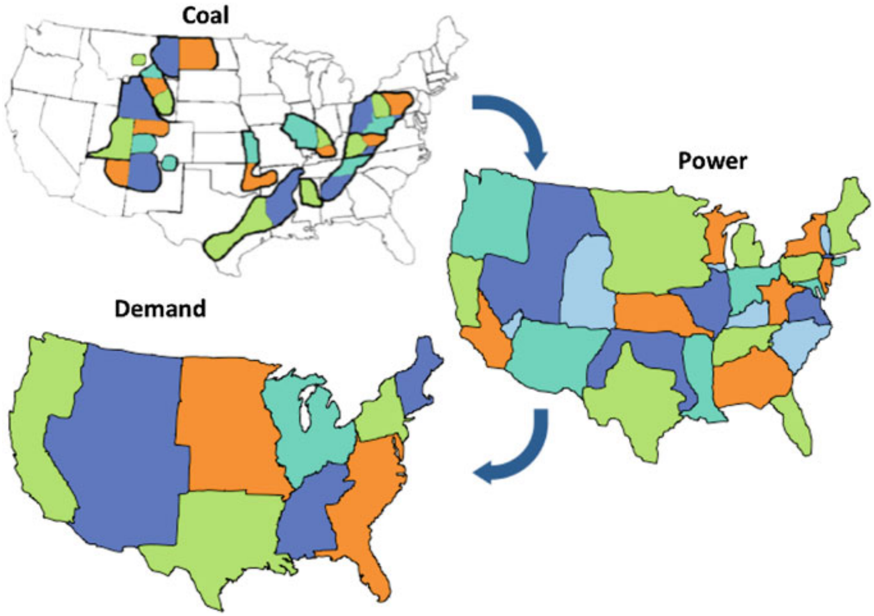


**Fig. 1** FACETS coal, power, and demand regions

This matrix is based on historical data and represents the physical location of homes, businesses, and facilities within each power region's territory.

On the input side, coal and biomass are sourced from their own sets of regions and traded to the power sector regions using trade matrices, as illustrated in Fig. 1. (Because of high cost of transport, biomass may only be traded to geographically overlapping regions.) Finally, when the model implements carbon capture and storage, the $CO_2$ flows are traded to a set of sequestration regions, each with their own "supply" cost curves for accepting $CO_2$, and again governed by a trade cost matrix from the power regions.

Within the power sector, the nearly 3800 hydroelectric units, whose production is governed by seasonal capacity factors, are aggregated by power region and state. The remaining 11,200 units are modeled individually. While much of the data for these units can be read in a single Excel table built directly around the source data, a major data handling challenge is presented by the need to describe the input fuel choice, emissions, and emissions retrofit options for the 1100 coal units.

A TIMES model is based on network topology. The inputs and output of each process must be specified in order to provide the links that "hook" the network together. FACETS includes 85 bituminous, subbituminous, and lignite coals, distinguished by rank, source region (and hence transportation cost to each unit) and sulfur level, each with its own sulfur, mercury, and chlorine content. Each unit may burn some subset of these fuels, depending on its configuration, location, equipment, and permitted sulfur emissions level. Some units are restricted to only one rank, while others are flexible. And beginning in 2017, each is subject to its individual MATS constraints. Enumerating the input fuel options for each of these 1100 units line by line in an Excel file would be a prohibitively labor intensive, error-prone process, not only to create and check, but also to update when updated data sources are available.

A second challenge arises from representing unit configurations, emissions, and retrofit options. The existing units have more than 100 different combinations of boiler type and existing emissions control equipment. As described in the previous section, each combination removes a different fraction of the content of each pollutant in the source coal, and each combination is also eligible for a different set of retrofit options, ranging from zero choices, if it already has a fully compliant combination, to eleven, if it has no pre-existing equipment, and can fully select from the options in Table 1. To minimize the model size implications of duplicating each of these processes, we wish to make only potentially improving options available.

VEDA's rule-based approach and Excel lookup tables have been heavily relied upon to build the specifications. To drive these specifications, heavy use has been made of information embedded within each process's short and long names. Unit short names consist of the federal unit ID number, followed by a seven character code that describers its boiler configuration and $NO_x$, acid, PM, and mercury emissions control equipment specifications and indicates whether it is the original (mother) unit or one of its retrofitted replacements. Unit descriptions are packed with information as follows:

> EPLT -<Plant name>.<Fuels>.<Coal transport cost category>.<County>-<State>.<Plant type>.<Plant size category>.<Optional code for retrofit equipment>

For example, *EPLT—E C Gaston.CoaB.ALR3.Shelby-Alabama.CST.SC3.EmRf C* describes a coal steam (CST) unit at E C Gaston plant in Shelby County, Alabama, that burns bituminous coal only, is approximately 300 MW in size, has been retrofitted with SCR, and receives coal according to transport cost category ALR3. The unit size categories are used to specify costs for emissions control retrofits. This information allows emissions, retrofit, and fuel choice data to be input by rules based on process name and description, rather than manual data entry.

The code in each unit's short name is used in the input template to look up from a source data table of emission modification factors the amount of each pollutant "scrubbed" from the input coal. All emissions constraints are then written in terms of the net of raw minus scrubbed emissions. Another lookup table specifies which retrofits are available to plants with each code. For example, plants with existing wet scrubbers but no post-combustion $NO_x$ or mercury controls are eligible for retrofits with SCR, ACI, or SCR + ACI. A set of process declaration tables references this table using each unit's code to declare or not declare each possible option. A set of simple update tables then references the codes in the process description to add the corresponding capital cost and modify the unit's operating costs and efficiency.

**Table 2** Topology insert table for coals to coal-fired units

| ~TFM_TOPINS | | | |
|---|---|---|---|
| PSET_SET | PSET_PD | CSET_CN | All regions |
| ELE | *.CoaB.* | ECoal-__-B* | IN |
| ELE | *.CoaB/CoaS.* | ECoal-__-B*,ECoal-__-S* | IN |
| ELE | *.CoaL.* | ECoal-__-L* | IN |
| ELE | *.CoaL/CoaS.* | ECoal-__-L*,ECoal-__-S* | IN |
| ELE | *.CoaS.* | ECoal-__-S* | IN |

User constraints limit the total capacity of each group of mother plus retrofit units to the capacity of the original unit. In principle, lumpy investment in each retrofit choice would be a more precise way to model the retrofit choice, as the current approach could lead to partial retrofits. However, with this many units, lumpy investment would be prohibitive in terms of solve time, and because of the unit-level nature of the constraints, in practice this behavior has been minor.

To manage the fuel inputs, all units that take a single input energy carrier—for example, dedicated natural gas units, and renewable units with dummy inputs—have that specification directly entered in the base year (2012) input template, reading from the source data. All other inputs have been created by means of a Topology Insert table using rules based on the process description. Table 2 shows the portion of the table for coal-fired units. The first row assigns *all* bituminous coal types as inputs to every bituminous unit. Two restrictions are then applied to limit the coals actually available to the unit. First, the coal transport cost matrix specifies the actual list of some 1200 allowable links and their costs, which range from very small costs and single links for mine-mouth plants, to high costs for cross-country rail transport. One single-line table bounds out all possible transport links, and another reads the transport matrix, releases the bounds on allowed links, and assigns them the correct cost. Finally each unit has a permitted sulfur emissions rate, which in conjunction with its scrubber efficiency (if any) will further restrict its allowable fuels. This limit is imposed via user constraint on each unit restricting the net sulfur emissions per electricity generated.

The rich detail of the model creates data handling challenges on the output side as well. In particular, the regional information and trade flows between regions are crucial to understanding the model behavior and extracting meaning from the results. But trade flows in particular are difficult to interpret in a table of numbers. The regions themselves are many and do not correspond to political, social, or cultural boundaries. Because regions are of different geographic size, viewing, for example, capacities of retrofits or retirements by model region may not give and accurate sense of how these changes are distributed in the country.

To help interpret these results, a geographic information systems (GIS) results mapping system has been developed within the VedaViz[6] online results processing

[6]http://vedaviz.com.

and visualization tool. VedaViz was developed to facilitate collaborative interpretation of model results by analysts who are not themselves TIMES modelers or VEDA users. Originally developed as part of the Energy Modeling Forum EMF-27 study (Weyant and Kriegler 2014), it begins with a set of standard high-level summary variables, including primary energy, electricity generation and capacity, final energy consumption, emissions, and cost data, which are then made available online for quickly generating summary graphs and tables using a set of flexible forms based on Google Chart tools[7] and the D3 JavaScript visualization library.[8] Dimensions including scenarios, regions, variables, years, and (for multi-model comparisons) models may be pivoted, and small multiples may be created for side-by-side comparisons.

This system makes high-level results available online to any domain-aware analyst without them needing to be experts in the model Reference Energy System (RES). The tool is designed facilitate collaborative analysis and results dissemination. One can create and save views for others to view, post and respond to comments on views, and generate links from any view to publish online. We now use VedaViz as a primary tool for a first, high-level graphical view of the patterns in the results, combined with VEDA-BE for drilling down into RES details as needed.

The GIS system is based on Google Maps components. Each region in the model is represented by a map coordinate, allowing values to be "graphed" on the map using pie or bar charts. Trade flows may be visualized using arrows, whose width corresponds to the size of the flow (example in Fig. 5). In the FACETS power sector, each unit is coded in the input data with its latitude and longitude, so that unit-level data may also be visualized to see how retirements, retrofits, and emissions "clump" geographically (Fig. 6).

To create a VedaViz online project for a set of results, the VD files[9] are read into an SQL server database, which creates the variable names, processes the raw VD results into the variable values. It can then can do further operations on them, including scenario differences, period averages, shares, capacity utilization, and so on. These variables and calculations are data driven, and customized for each application. In addition to standard charts and maps, a host of other graphical features are available, including animated bubble charts, and Sankey diagrams.

## 4 Analysis

This section describes the scenarios modeled and the national, regional, and unit level results.

[7]https://developers.google.com/chart/.

[8]http://d3js.org/.

[9]Standard results files from TIMES runs.

## 4.1 Scenarios Modeled

In addition to the MATS regulations described above, which are assumed to be fully in effect in 2017, the Reference scenario includes regional cap and trade standards for $SO_2$ and $NO_x$ under the Clean Air Interstate Rule (CAIR), and the proposed New Source Performance Standard (NSPS) for $CO_2$. The NSPS is implemented as a ban on new coal units without CCS.

The new $CO_2$ policy analyzed here is a power sector clean energy standard (CES), similar to that analyzed by US EIA (2011b). Like a renewable portfolio standard (RPS), a CES requires a minimum fraction of generation to be obtained from specified sources, in this case a range of zero and low carbon technologies. One full CES credit is awarded to generators per MWh of zero-carbon generation, and partial credit is awarded for some other types in rough proportion to their degree of carbon emissions reduction from coal steam generation (Table 3).

The percentage of CES credits as a share of total national generation ramps up from 2010 levels of roughly 42.5–90 % in 2050, the last model year, with the constraint first binding in model year 2023, after MATS compliance decisions are final. Three different CES trajectories were tested, representing a range of aggressive to delayed action, as illustrated in Fig. 2. The scenarios are named 85, 65, and

**Table 3** CES credits by generation type

| Generation type | CES credits per MWh |
|---|---|
| Biomass, geothermal, hydro, nuclear, solar, wind | 1.0 |
| Gas combined cycle | 0.5 |
| Coal or gas with CCS | 0.9 |

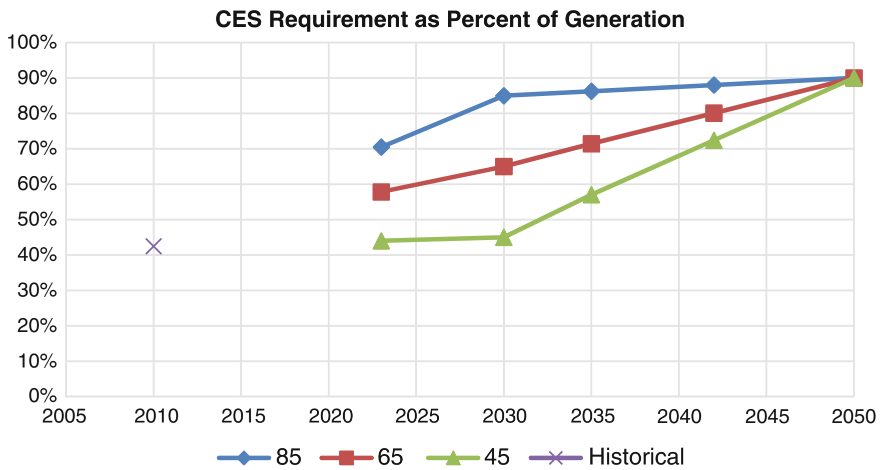


**Fig. 2** CES trajectories

**Table 4** Build rate constraints

| Plant type | Annual build limit before cost penalty incurred (GW/year) | | | |
|---|---|---|---|---|
| | 2010 | 2020 | 2035 | 2050 |
| Coal/Gas with CCS | 1.3 | 2.6 | 3.9 | 5 |
| Photovoltaic | 5 | 15 | 45 | 450 |
| Offshore wind | 0.5 | 1.5 | 10 | 100 |
| Onshore wind | 10 | 30 | 90 | 900 |

45, for the share required in 2030. The 65 trajectory increases linearly to 2050, while the 85 trajectory ramps up much more aggressively, reaching nearly the full level by 2030, and the 45 trajectory postpones most action until after 2030. Banking and borrowing are not permitted.

New power plant cost and performance characteristics are derived from AEO 2013 (US EIA 2013). All plant options face the same cost of capital. However, plants also face capital cost supply step adders that vary by plant type, representing short-term increases in costs for labor and materials when the model seeks to build new capacity faster than the rates shown in Table 4. These steps are based on a review of similar build rate adders in IPM (US EPA 2010) and NEMS (US EIA 2011c), as well as recent historical maximum annual builds (US EIA 2012) for these capacity types. Plant types with complex engineering requirements and limited recent builds (coal/gas with CCS and offshore wind) have more stringent limits that increase more slowly over time than types with simpler engineering and more rapid recent capacity additions. All supply steps relax over time to represent the potential for development of increased national construction capacity for in-demand plants.

New nuclear builds are prohibited. The cost and social acceptance of new nuclear builds in the US is highly uncertain, as no new plants have been completed for several decades. Previous analysis (Wright and Kanudia 2014) found that CES compliance strategies and cost are highly sensitive to these assumptions. At AEO 2013 costs, new nuclear was the dominant strategy in many regions. Prohibiting nuclear leads to a richer regional mix. For these runs, electricity demand was kept fixed at AEO levels, rather than responding to price changes using elastic demand, in order to keep the focus on generation technology changes.

To assess the impact of the timing of knowledge about the CES when making MATS compliance decisions, each CES scenario was analyzed in two variations. The “foresight” version is a standard TIMES run, in which the CES requirement is “seen” at the time of MATS compliance. In the “myopic” version, the Reference case solution is frozen up to the end of the compliance window (model year 2018), after which the model is free to make new decisions about CES compliance.

# 5 Results

## *5.1 National Results*

As shown in Table 5, the cost of the CES policy is very sensitive to policy ramping speed. The slow-ramping 45 scenario increases total system cost—which can be interpreted in this instance as the total net present value cost of delivering electricity to all US end users—by about eight percent. The 65 scenario roughly doubles this impact to around 15–16 %, and the fast-ramping 85 scenario increases it further. The cost impacts of myopia depend even more dramatically on CES stringency. In the 45 scenario, lack of foreknowledge about the carbon policy increases the policy's cost by only one percent, or approximately 4 billion dollars. In the 65 and 85 scenarios, these increases are far more significant, at 9 and 23 %.

Figure 3 shows how the CES compliance strategies vary with policy ramping speed and foresight versus myopia. The difference between the foresight and myopic cases derive from two factors: the relative build rates of different low carbon generation types, and the extra retrofitted coal stock in the myopic cases.

In 2018, the 65 and 85 foresight scenarios have begun to deviate significantly from the Reference case. They undertake significantly less coal retrofitting, and make up the difference with new gas combined cycle builds and, in the 85 case, small amounts of gas and coal with CCS. By scenario design, the three myopic scenarios are frozen to the reference case in this period, and the 45 foresight case requires CES compliance so far down the road that it deviates from Reference hardly at all.

By 2023, the 85 foresight scenario is generating more than 10 % of its electricity from CCS plants, and the lead over the myopic scenario in building these plants persists over the model horizon. The myopic scenario relies on quicker-to-build wind and combined cycle to meet the suddenly tightening CES. In the two 65 cases, total generation from existing coal units is similar, at around 19 % of total generation, but the myopic case is more heavily relying on the retrofits it has invested in, whereas the foresight case is splitting generation roughly evenly between retrofits and retained original equipment. The early compliance strategy for both of these scenarios is an investment in new combined cycle capacity.

**Table 5** Scenario system cost impacts

| Scenario | Increase over reference (%) | Increase due to Myopia (%) |
|---|---|---|
| 85-MY | 35.6 | 23 |
| 65-MY | 16.5 | 9 |
| 45-MY | 8.1 | 1 |
| 85-FS | 28.9 | |
| 65-FS | 15.1 | |
| 45-FS | 8.0 | |

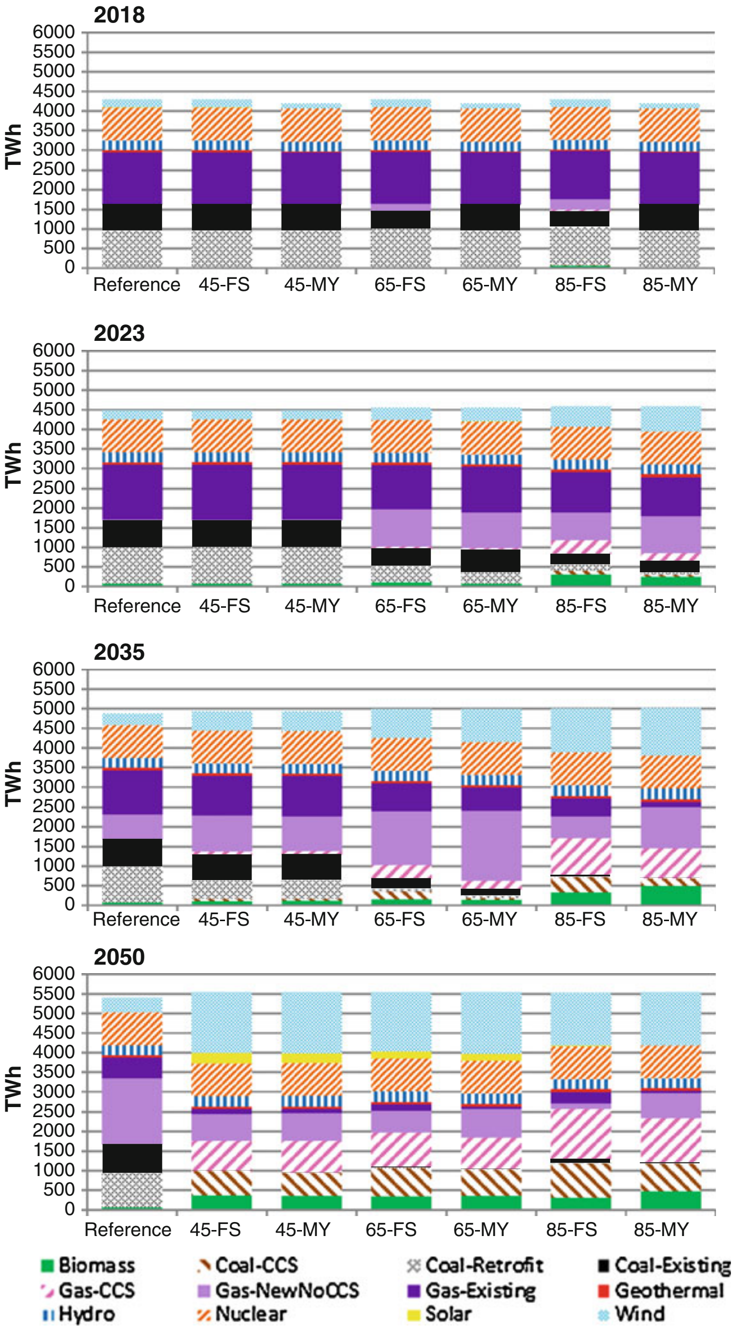


Fig. 3 National generation mix across scenarios

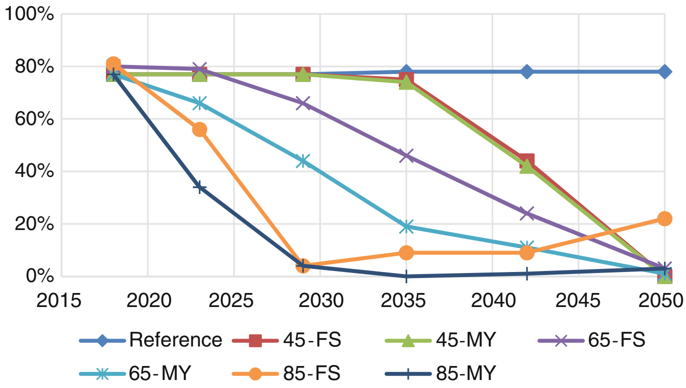


**Fig. 4** Utilization of retrofitted coal units

By 2035, the 65 foresight case is still operating nearly half of the coal capacity it retrofitted, covering this non-compliant generation with more CCS than the myopic case, which has abandoned most of its retrofits (Fig. 4). The 45 cases have begun investing in wind and combined cycle, but are still operating most of their retrofit capacity. The differences between the foresight and myopic cases are minimal.

2050 brings a convergence of all the CES policies to the same 90 % requirement, but the compliance strategies differ significantly depending on the route taken over the previous periods. The 85 foresight case relies most heavily on the CCS it has been building steadily over the entire horizon, followed closely by the 85 myopic case. The foresight case is still operating around a quarter of its retrofit capacity. The other cases include more wind and solar, whose cost has come down, and the differences between the myopic and foresight cases have largely evaporated.

Table 6 summarizes retrofits and retirements by scenario. 76 GW of capacity retires rather than retrofit in the Reference and myopic cases, with an additional 30 GW in the 65 foresight case and a further 9 GW in the 85 foresight. Most of the foregone retrofits are additions of ACI to control mercury, along with some decrease in SCR and FGD. Perhaps surprisingly, DSI retrofits, which have lower

**Table 6** Coal unit retirements and retrofits by scenario (GW)

| | 85-MY | 65-MY | 45-MY | 85-FS | 65-FS | 45-FS | Reference |
|---|---|---|---|---|---|---|---|
| Retirements | 76 | 76 | 76 | 115 | 106 | 76 | 76 |
| Retrofits—ACI | 71 | 71 | 71 | 44 | 49 | 71 | 71 |
| Retrofits—SCR | 4 | 4 | 4 | 0 | 0 | 4 | 4 |
| Retrofits—DSI | 11 | 11 | 11 | 13 | 4 | 11 | 11 |
| Retrofits—FGD | 41 | 41 | 41 | 8 | 23 | 41 | 41 |
| Retrofits—All[1] | 100 | 100 | 100 | 55 | 65 | 100 | 100 |

[1]Retrofits do not sum to totals because some units receive more than one retrofit

capital but higher operating costs, are not stimulated in the foresight cases. Overall, there are 35 GW fewer units that receive retrofits in the 65 foresight case and 45 GW in the 85 foresight. The 45 cases show no difference between myopic and foresight choices.

Figure 4 shows that, in both the 65 and 85 myopic cases, the model must precipitously abandon much of its retrofitted capacity, once the unanticipated CES kicks in, while the foresight cases are able to continue using their more modest retrofitted stock for longer. The difference is most significant and prolonged in the 65 cases, in which the moderately ramping CES allows continued utilization of retrofitted units at greater than 50 % through model year 2035.

## 5.2 Regional and Unit-Level Results

Figure 5 shows the generation mix and inter-regional trade flows in 2035 for the 85 foresight and myopic scenarios. (Pie and wedge sizes in the figure are proportional to generation, and arrow widths are proportional to interregional flows.) A mix of compliance strategies are visible, with heavy investment in wind and biomass in the resource-rich Plains and Upper Midwest. Coal and gas with CCS are concentrated in Southeast and Gulf Coast regions with good access to sequestration sites, and other regions rely on new gas combined cycle and existing nuclear and hydro.

Table 7 shows the net present value change of the costs to each region of supplying its own consumers' electricity demand, including capital, operating, and fuel costs, along with net costs/earnings for inter-regional electricity and CES permit trades. The values are then scaled by 2012 generation in order to allow impacts on regions of different sizes to be compared.

The CES hits the small, gas-dependent regions of New York City and Long Island hardest, with both higher gas prices and the need to import CES credits. Other high cost regions are those that have fewer (Kentucky) and/or more expensive (Southwest Power Pool—South) compliance options, or that have significant existing coal fleets that must be abandoned and replaced (PJM). Those regions that already have (Upstate and Downstate New York, Commonwealth Edison, and Pacific Northwest) or can relatively cheaply build (Northwest Power Pool—East, and Midwest Regional Organization) significant supplies of compliant generation experience a net benefit from the CES.

Myopia imposes costs on most regions, especially under the high-cost 85 CES. But some regions benefit under myopia from being able to export higher cost credits to regions with more constrained options. For example, regions in the Upper Midwest (Midwest Regional Organization) and Plains (Southwest Power Pool—North) with strong wind and biomass resources are able to become large exporters of power and CES credits in the myopic scenarios, and experience a net cost gain from myopia as a result (Fig. 5).

Those who are impacted most by not knowing about the CES before retrofit decisions must be made are, of course, the owners of the coal plants affected.

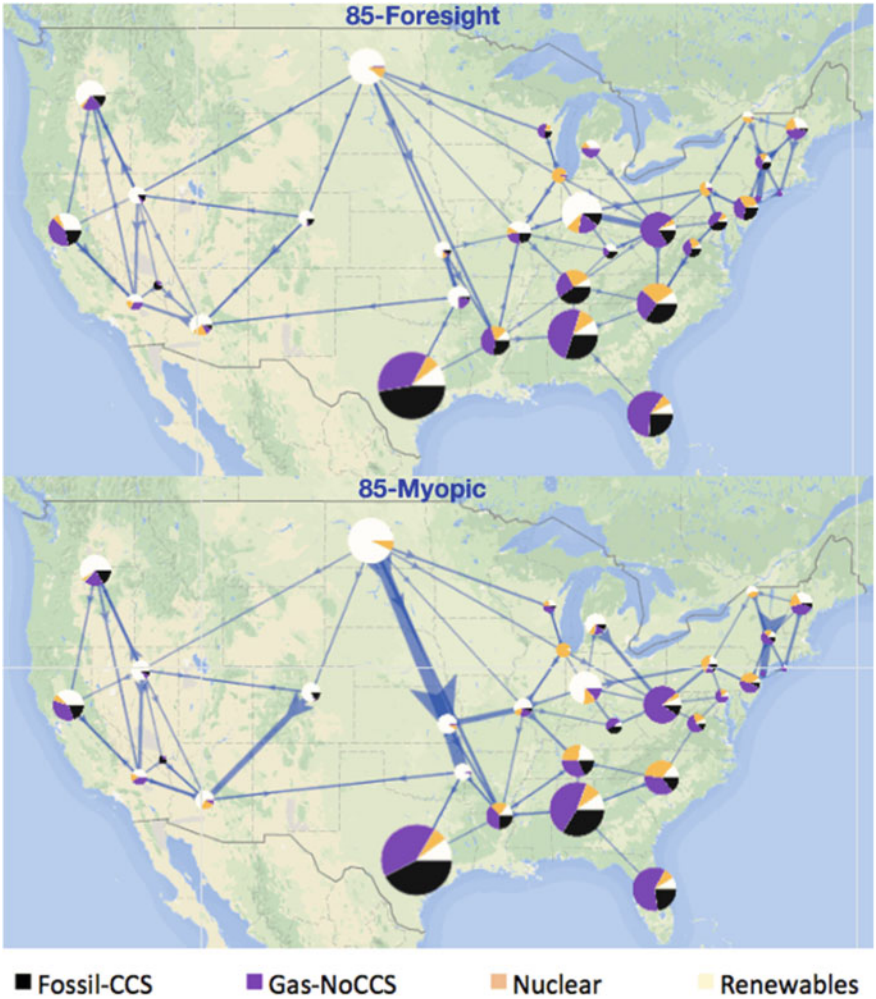


**Fig. 5** 2035 generation mix and inter-regional trade in the 85 foresight and myopic scenarios

Table 8 shows the cost of stranded retrofitted capacity, measured by regional annualized investments in retrofits multiplied by the difference in utilization between the Reference case (taken to be normal utilization rates) and each scenario's regional utilization. These costs range several orders of magnitude across regions, up to more than $1 billion in some regions. Regions with the lowest costs have little or no retrofitted capacity even in the Reference scenario, whereas the highest cost regions tend to be those with the largest retrofit capacities (Southwest Power Pool—South, Texas Regional Entity, and Midwest Regional Organization), along with those that must abandon retrofit capacity most precipitously (Southern Company and MISO).

**Table 7** Net present value regional cost of electricity supply (M2004$/MMBTU)

| Region | Cost increase over reference (scaled) | | | | | | Cost of Myopia | | |
|---|---|---|---|---|---|---|---|---|---|
| | 85-MY | 65-MY | 45-MY | 85-FS | 65-FS | 45-FS | 85 | 65 | 45 |
| Arizona—New Mexico | 72 | 6 | 42 | 58 | 25 | 36 | 13 | −19 | 6 |
| California North | 60 | 6 | 20 | 121 | 12 | 13 | −61 | −6 | 7 |
| California South | 351 | 100 | 37 | 308 | 126 | 41 | 43 | −26 | −4 |
| Commonwealth Edison | −242 | −177 | −34 | −143 | −209 | −21 | −98 | 32 | −13 |
| Downstate New York | −1190 | −681 | −200 | −948 | −645 | −190 | −241 | −35 | −9 |
| Kentucky | 403 | 202 | 147 | 240 | 203 | 104 | 162 | −1 | 43 |
| MISO | 105 | 65 | −9 | 63 | 91 | −5 | 41 | −26 | −4 |
| PJM | 501 | 254 | 89 | 313 | 242 | 89 | 187 | 13 | 0 |
| Entergy | 263 | 87 | 32 | 123 | 59 | 41 | 140 | 28 | −9 |
| Texas Regional Entity | 183 | 89 | 35 | 114 | 108 | 34 | 68 | −19 | 1 |
| Florida Reliability Coordinating Council | 321 | 134 | 45 | 227 | 125 | 45 | 94 | 9 | 0 |
| Long Island Lighting Company | 959 | 433 | 149 | 711 | 456 | 152 | 248 | −24 | −3 |
| Mid-Atlantic Area Council—East | 102 | 25 | 16 | 84 | 32 | 20 | 18 | −7 | −4 |
| Mid-Atlantic Area Council—South | 351 | 124 | 44 | 95 | 174 | 42 | 256 | −50 | 2 |
| Mid-Atlantic Area Council—West | 178 | 39 | 17 | 151 | 26 | 21 | 28 | 12 | −4 |
| Gateway (Illinois-Missouri) | 327 | 178 | 43 | 170 | 198 | 43 | 156 | −20 | 0 |
| Michigan Electric Coordination System | 110 | 78 | 18 | 116 | 29 | 26 | −5 | 49 | −8 |
| Midwest Regional Organization | −116 | 34 | 0 | −40 | 61 | −6 | −77 | −27 | 6 |
| New England Power Pool | 76 | −59 | −12 | 24 | −56 | −12 | 52 | −3 | 0 |
| Northwest Power Pool East | −271 | −58 | −35 | −190 | −48 | −50 | −81 | −11 | 15 |
| New York City | 960 | 440 | 132 | 719 | 463 | 128 | 241 | −23 | 4 |
| Pacific Northwest | −180 | −140 | −29 | −92 | −149 | −19 | −87 | 9 | −10 |
| Rocky Mountain Power Area | −67 | 89 | 10 | 26 | 99 | 11 | −92 | −9 | −2 |

(continued)

**Table 7** (continued)

| Region | Cost increase over reference (scaled) | | | | | | Cost of Myopia | | |
|---|---|---|---|---|---|---|---|---|---|
| | 85-MY | 65-MY | 45-MY | 85-FS | 65-FS | 45-FS | 85 | 65 | 45 |
| Southern Nevada | 95 | −25 | −158 | −81 | −59 | −141 | 176 | 34 | −17 |
| Southern Company | 210 | 129 | 46 | 144 | 97 | 44 | 66 | 32 | 2 |
| Southwest Power Pool—North | −445 | −13 | −28 | −123 | −14 | −39 | −321 | 1 | 11 |
| Southwest Power Pool—South | 571 | 221 | 68 | 283 | 229 | 68 | 289 | −8 | 0 |
| Tennessee Valley Authority | 192 | 66 | 27 | 82 | 67 | 28 | 109 | −1 | −2 |
| Upstate New York | −447 | −282 | −66 | −283 | −304 | −66 | −163 | 22 | 0 |
| Virginia-Carolinas | 151 | 46 | 29 | 43 | 47 | 31 | 108 | −1 | −2 |
| Dominion Virginia Power | 219 | 65 | 39 | 177 | 24 | 29 | 42 | 41 | 10 |
| Wisconsin-Upper Michigan | 265 | 101 | 39 | 312 | 103 | 42 | −47 | −2 | −3 |

**Table 8** Net present value cost of abandoned retrofit capacity (M2004$)

| Region | Cost of lost retrofit utilization | | | | | | Cost of Myopia | | |
|---|---|---|---|---|---|---|---|---|---|
| | 85-MY | 65-MY | 45-MY | 85-FS | 65-FS | 45-FS | 85 | 65 | 45 |
| Arizona—New Mexico | 209 | 99 | 42 | 107 | 53 | 40 | 102 | 46 | 2 |
| California North | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| California South | 3 | 2 | 1 | 3 | 1 | 1 | 0 | 1 | 0 |
| Commonwealth Edison | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| Downstate New York | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Kentucky | 85 | 40 | 17 | 0 | 0 | 16 | 84 | 40 | 0 |
| MISO | 878 | 563 | 174 | 330 | 152 | 156 | 548 | 411 | 18 |
| PJM | 756 | 469 | 170 | 37 | 92 | 163 | 719 | 376 | 7 |
| Entergy | 459 | 314 | 100 | 0 | 40 | 97 | 459 | 275 | 3 |
| Texas Regional Entity | 470 | 359 | 109 | 227 | 215 | 116 | 243 | 144 | −7 |
| Florida Reliability Coordinating Council | 254 | 165 | 57 | 3 | 38 | 57 | 251 | 127 | 0 |
| Long Island Lighting Company | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mid-Atlantic Area Council—East | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mid-Atlantic Area Council—South | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mid-Atlantic Area Council—West | 224 | 57 | 52 | 60 | 31 | 53 | 164 | 26 | −1 |
| Gateway (Illinois-Missouri) | 265 | 176 | 51 | 145 | 72 | 51 | 120 | 105 | −1 |
| Michigan Electric Coordination System | 95 | 68 | 23 | 15 | 25 | 21 | 80 | 44 | 2 |
| Midwest Regional Organization | 770 | 531 | 250 | 338 | 215 | 239 | 432 | 316 | 11 |
| New England Power Pool | 2 | 1 | 1 | 0 | 1 | 0 | 2 | 0 | 0 |
| Northwest Power Pool East | 205 | 128 | 57 | 146 | 53 | 59 | 58 | 74 | −1 |
| New York City | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pacific Northwest | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 0 |
| Rocky Mountain Power Area | 145 | 77 | 39 | 48 | 38 | 38 | 97 | 39 | 1 |

(continued)

**Table 8** (continued)

| Region | Cost of lost retrofit utilization | | | | | | Cost of Myopia | | |
|---|---|---|---|---|---|---|---|---|---|
| | 85-MY | 65-MY | 45-MY | 85-FS | 65-FS | 45-FS | 85 | 65 | 45 |
| Southern Nevada | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Southern Company | 1053 | 675 | 231 | 22 | 11 | 217 | 1031 | 664 | 14 |
| Southwest Power Pool—North | 372 | 217 | 104 | 122 | 101 | 102 | 249 | 115 | 2 |
| Southwest Power Pool—South | 1311 | 768 | 331 | 395 | 371 | 310 | 916 | 396 | 21 |
| Tennessee Valley Authority | 724 | 479 | 165 | 240 | 139 | 148 | 484 | 340 | 17 |
| Upstate New York | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Virginia-Carolinas | 158 | 82 | 32 | 12 | 6 | 30 | 146 | 76 | 2 |
| Dominion Virginia Power | 128 | 65 | 23 | 0 | 0 | 23 | 128 | 65 | 0 |
| Wisconsin-Upper Michigan | 106 | 93 | 30 | 0 | 0 | 32 | 106 | 93 | −3 |
| Total | 8673 | 5430 | 2057 | 2254 | 1656 | 1971 | 6335 | 3709 | 41 |

The additional costs imposed by myopia also vary greatly, even among the high cost regions, with some regions able to eliminate most or all of these costs with foresight, even in the 85 case, through reduced retrofit investments and longer utilization of the retrofitted stock. For example, the PJM region foregoes more than 5 GW of capital-intensive FGD retrofits, retaining only 0.3 GW of FGD and 1.4 GW of ACI, substantially reducing its lost investments when these units must be shut down under the increasing CES. Overall, foresight saves more than $6 billion in stranded asset costs in the 85 case and nearly $4 billion in the 65 case.

Figure 6 compares the distribution of the retrofitted units in the 85 foresight and myopic scenarios. The concentration of additional myopic retrofits—and hence the costs of myopia—in the Ohio Valley and Southeast is clearly visible.

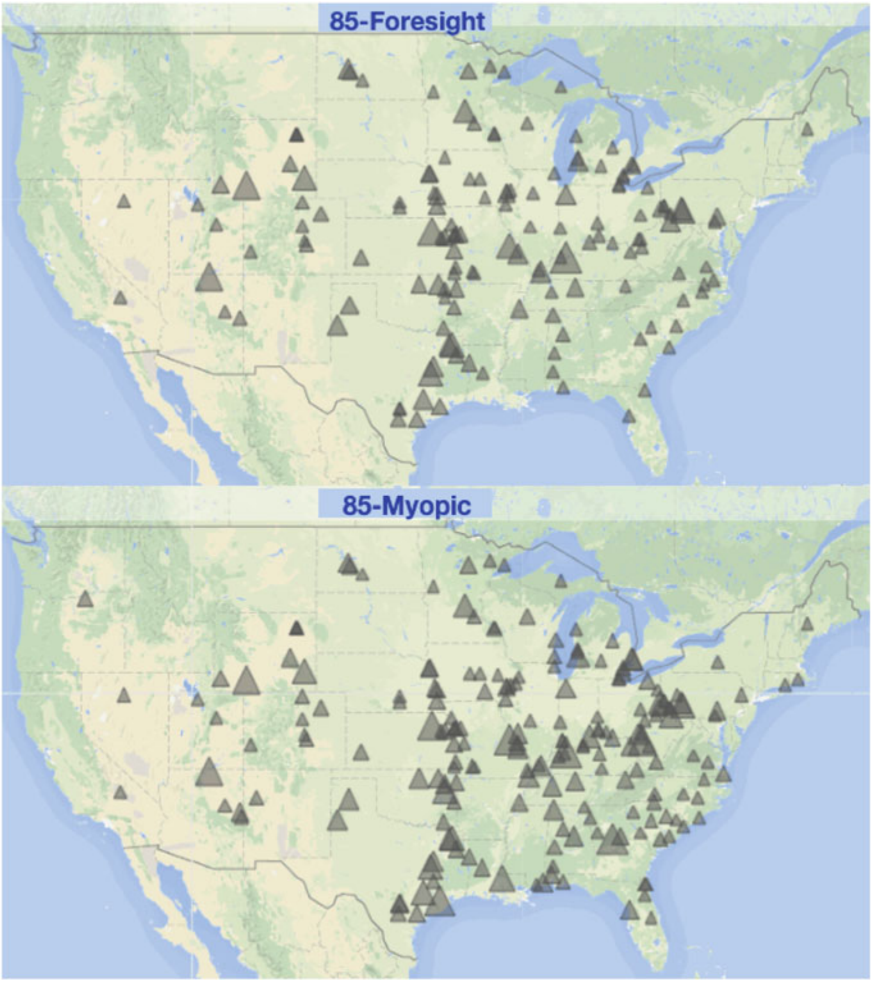


**Fig. 6** Retrofitted units in 85 foresight and myopic scenarios

## 6 Conclusions

This chapter has described and illustrated the techniques used to conduct highly detailed modeling of existing coal-fired units in the US power sector. Such detailed modeling is called for in situations where the existing stock plays a key role in determining policy cost and incidence, and will be increasingly necessary for analyzing real climate policies. It also permits the application of TIMES modeling to policies that are far nearer-term than has been commonly practiced.

In the analysis presented here, the FACETS model was used to analyze the interactions between air quality and carbon policies, when the timing and stringency of the carbon policy is uncertain. The overall national costs of myopia were found to be small (1–10 % of overall carbon policy cost), except when the carbon policy ramps up very quickly after air quality compliance decisions are made. However, these national results obscure significant regional heterogeneity. Some regions experience substantial cost increases from myopia, while others that can export valuable credits actually experience a net benefit. The cost of retrofitted units that must be underutilized or abandoned later range from $2 billion in the slow-ramping 45 cases to more than $8 billion in the 85 myopic case. Substantially fewer retrofits are undertaken in the foresight cases, reducing stranded asset costs in some regions by up to 100 %. Because elastic demand was not used for these runs, we would expect the real world cost and generation mix impacts to be somewhat muted as electricity demand responded to price changes.

Recently US EPA (2014) has released draft regulations for carbon emissions from existing power plants under section 111d of the Clean Air Act, known as the Clean Power Plan (CPP). The CPP is similar to the CES modeled here, imposing a maximum carbon emissions rate for covered generation in each state, where covered units include existing fossil plus non-hydro renewables. Existing hydro and most existing nuclear are excluded, reducing or eliminating the windfall gains found herein for regions with substantial shares of hydro and nuclear capacity in their existing mix. The CPP requirements ramp in over the period 2020–2030, reaching approximately midway in stringency between our 45 and 65 cases, and require no further reductions beyond 2030.

The analysis conducted here suggests that the overall costs of the CPP are likely to be modest, although some regions may experience substantially greater cost impacts than others. Assuming any new, additional carbon policy would not take effect until after the CPP's compliance period ends in 2030, additional costs from having taken MATS decisions more than a decade earlier without foreknowledge of the future carbon policy will be small. If, however, the need for additional carbon emissions reductions from the power sector comes to be seen as more urgent, the potential for significant costs from stranded assets rises.

Because the CPP will be implemented at the state level, each state will need to conduct its own analysis of compliance strategies, based on its own existing stock and resource base. An analysis of the CPP using FACETS is underway.

## References

Pizer W, Sanchirico JN, Batz M (2009) Regional patterns of U.S. household carbon emissions. Clim Change 99:47–63

Rausch S, Metcalf GE, Reilly JM (2011) Distributional impacts of carbon pricing: a general equilibrium approach with micro-data for households. Energy Econ 33:S20–S33

US Energy Information Administration (2009) The national energy modeling system: an overview, Washington, DC. DOE/EIA-0581(2009)

US Energy Information Administration (2011a) Assumptions to the annual energy outlook 2011, Washington, DC. DOE/EIA-0554(2011)

US Energy Information Administration (2011b) Analysis of impacts of a clean energy standard as requested by Chairman Hall, Washington, DC

US Energy Information Administration (2011c) Electricity market module of the national energy modeling system, Washington, DC. DOE/EIA-M068(2011)

US Energy Information Administration (2012) Annual energy review 2011, Washington, DC DOE/EIA-0384(2011)

US Energy Information Administration (2013) Annual energy outlook 2013, Washington, DC DOE/EIA-0383(2013)

US Environmental Protection Agency (2010) Documentation for EPA base case v.4.10 using the integrated planning model, Washington, DC. EPA #430R10010

US Environmental Protection Agency (2011a) Documentation supplement for EPA base case v4.10_PTox—updates for proposed toxics rule, Washington, DC. EPA #430-R-11-006

US Environmental Protection Agency (2011b) Documentation supplement for EPA base case v.4.10_MATS—updates for final Mercury and Air Toxics Standards (MATS) rule, Washington, DC. EPA #430-F-11-066

US Environmental Protection Agency (2014) Carbon pollution emission guidelines for existing stationary sources: electric utility generating units—proposed rule, Washington, DC. EPA-HQ-OAR-2013-0602

US Environmental Protection Agency (2014a) Mercury and Air Toxics Standard. http://www.epa.gov/mats/. Accessed 25 Nov 2014

US Environmental Protection Agency (2014b) Air pollution and the clean air act. http://www.epa.gov/air/caa/. Accessed 25 Nov 2014

Weyant J, Kriegler E (2014) Preface and introduction to EMF 27. Clim Change 123:345–352. doi:10.1007/s10584-014-1102-7

Wheeler D (2008) Why Warner-Lieberman failed and how to get America's working families behind the next cap-and-trade bill. Center for Global Development, Working Paper 149, Washington, DC

Wright E, Kanudia A (2014) Low carbon standard and transmission investment analysis in the new multi-region US power sector model FACETS. Energy Econ 46:136–150. http://dx.doi.org/10.1016/j.eneco.2014.09.013