A Guide to Clean Power Plan Modeling Tools

Analytical Approaches for State Plan CO_2 Performance Projections

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Synapse Energy Economics
Jeremy Fisher, Ph.D.
Nidhi R. Santen, Ph.D.
Patrick Luckow

Argonne National Laboratory
Fernando de Sisternes, Ph.D.
Todd Levin, Ph.D.
Audun Botterud, Ph.D.

Argonne NATIONAL LABORATORY

Center for Energy, Environmental, and
Economic Systems Analysis (CEEESA)

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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1. INTRODUCTION

The Clean Power Plan introduces new challenges and opportunities for coordination between state regulators, utilities, and stakeholders. States must determine not only a best path to compliance from amongst a myriad of options, but in some cases also demonstrate that their plans will be successful. Effective modeling tools will be key to facilitating this process, yet the complexity of the rule means that the choice of compliance modeling tools is far from clear. To add to the challenge, utilities and utility regulators have a long history of using complex modeling and forecasting tools. In contrast, the state environmental regulators that are ultimately charged with preparing State Plans, as well as stakeholders who may not have previously engaged in utility planning, are less familiar these processes. In this report, Synapse and ANL together review the range of analytical tools available to help states find cost-effective means of reducing carbon dioxide (CO_2) emissions from the electricity sector, and to demonstrate performance for EPA requirements when necessary. This paper dissects and discusses a spectrum of compliance modeling tools in the context of modeling Clean Power Plan-related decisions.

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) finalized the Clean Power Plan—its plan to regulate CO_2 pollution from the electricity sector by setting the first-ever national standards limiting CO_2 emissions from electricity generation at power plants built before 2012. Under the Clean Power Plan, each state with affected sources (electric generating units, or EGUs) must comply with either a state-specific mass-based CO_2 emissions goal (tons CO_2) or emission performance rate target (pounds CO_2 per MWh) beginning in the year 2022. EPA estimates that in 2030 when Clean Power Plan targets are fully in place, total electricity sector CO_2 emissions will be 32 percent below 2005 levels.[1]

The Clean Power Plan requires each state to submit a compliance plan (State Plan) for meeting its prescribed CO_2 mass or rate targets, or alternatively to request an extension, by September 6, 2016.[2] There are seven different compliance pathways that a state may choose for compliance (see Figure 1, below),[3] some of which require performance demonstrations or projections. While EPA requires performance demonstrations for specific compliance pathways, there are a number of reasons that states and stakeholders may want to exercise one or more compliance modeling tools, including finding least-cost pathways, exploring the costs and benefits of various policy constructs, understanding equity considerations, examining possible impacts on state economies, and planning for any significant changes to the electricity grid.

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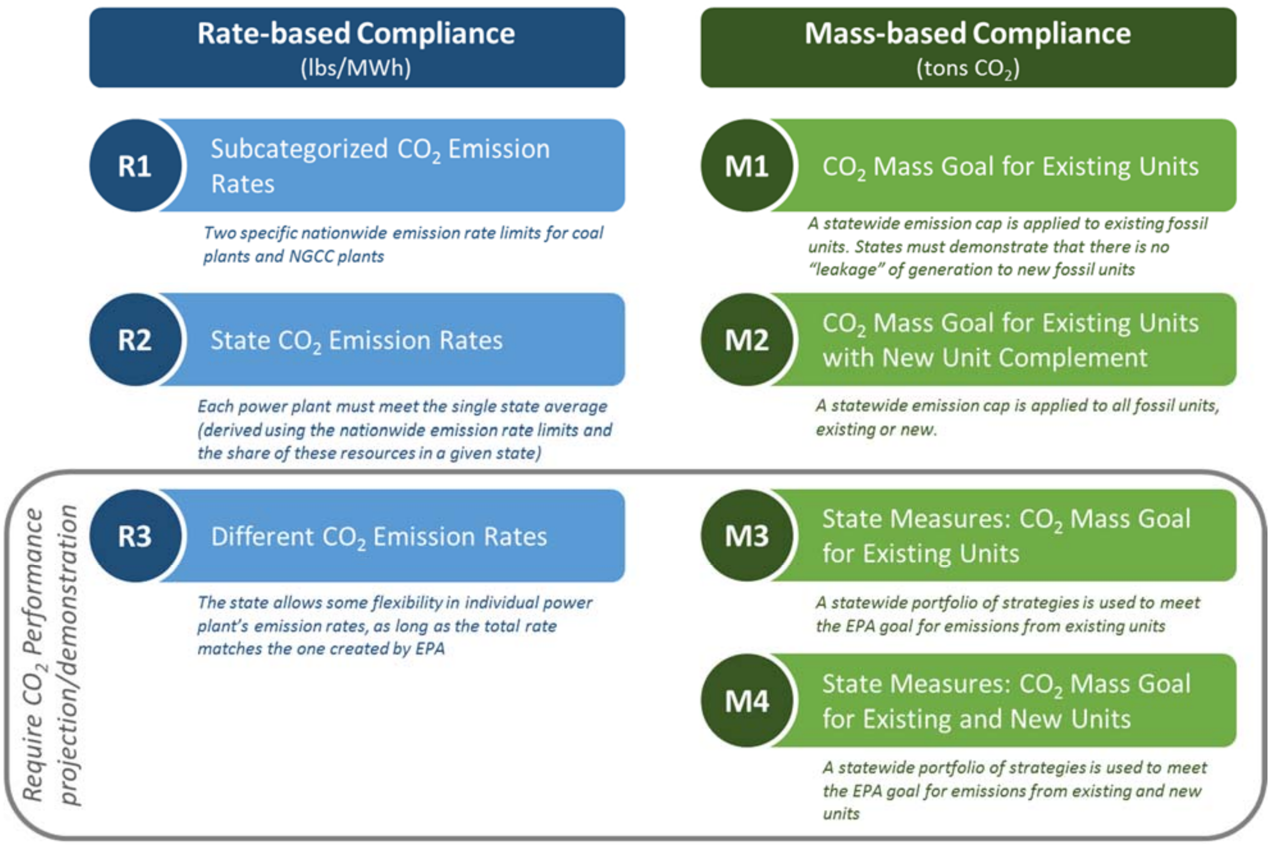
[1] EPA (2015) Factsheet: "Overview of the Clean Power Plan." Available at: http://www.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan.

[2] An extension of up to two years may be granted, but the final rule states that all compliance plans must be submitted no later than September 6, 2018.

[3] For more information about the compliance pathways, see Knight, P. (2015) "Understanding Clean Power Plan Compliance Paths." Synapse Energy Economics Blog, August 6. Available at: http://synapse-energy.com/about-us/blog/understanding-clean-power-plan-compliance-paths.

Figure 1. Clean Power Plan compliance pathways



EPA provides for several different compliance pathways, which are briefly noted here. For expediency, we denote rate-based compliance as "R" pathways, and mass-based compliance as "M" pathways. Amongst the rate-based options, states may set standards for each EGU at a specific sub-categorized rate for coal and gas (R1), apply a uniform standard of the state's average rate as determined by EPA (R2), or choose custom EGU standards that differ from EPA's determinations (R3). Alternatively, in the mass-based compliance pathways, states can opt for an EPA-designed trading mechanism covers only existing EGU (M1), a trading mechanism that covers both existing and new sources (M2), or design their own unique mechanism of meeting state mass targets for either only existing sources (M3) or both new and existing sources (M4).

States choosing either individual EGU-specific rate-based emission limits that differ from EPA guidelines (R3 in Figure 1) or a mass-based state-measures approach for compliance (M3 or M4 in Figure 1) must submit a *CO_2 performance projection* along with the rest of its State Plan filing. EPA believes that there is additional flexibility inherent in these particular compliance pathways, and greater potential for deviations from CO_2 targets. This is in contrast to other compliance pathways that have EGU-specific emission standards at levels pre-determined by EPA; EPA does not require any CO_2 performance projection for states choosing these pathways (R1, R2, M1, or M2).[4] Thus, while a state is free to choose an R3, M3, or M4 compliance pathways, it must show EPA that the measures it is adopting for emissions reduction are expected to achieve compliance at the required levels. Ongoing emissions performance checks for compliance occur throughout the implementation and final periods (2022-2029, 2030 and beyond) for all compliance pathways as well, but EPA only requires the formal CO_2 performance projection analyses during final State Plan submittal for the R3, M3, and M4 states.

The purpose of EPA's CO_2 performance projection requirement is to quantitatively show that the specific emission reduction measures in a state's chosen compliance pathway will likely result in CO_2 emissions (tons) or a CO_2 emission rate (pounds per MWh) at or below the state's mass-based emissions goal or emission performance rate. The performance projection must demonstrate compliance through 2031 (after this year, states must show that the measures they have implemented are permanent). Appendix A provides detailed requirements for compliance demonstration submittals, broken down by the compliance pathway chosen by a state.

EPA's performance projection requirement appears to be designed to prevent states that choose methods outside of EPA's default pathways from falling too far beyond targets by the time interim compliance checks are completed. States that take M3, M4, and R3 pathways also have a motive to prevent taking a direction that diverges from targets to prevent the onset of either corrective measures or backstop provisions. Regardless of a state's pathway decision, modeling can be used to understand the economic and technical impacts of *all* compliance pathways, irrespective of whether or not EPA requires a performance projection.

Emissions reduction measures can include heat rate improvements at EGUs, re-dispatch (increasing the utilization rate of existing gas-fired power plants and reducing the utilization of coal EGUs), switching existing EGUs to lower carbon fuel sources, implementing demand-side energy efficiency programs that can verifiably reduce the total demand for electricity, new renewable energy, and new nuclear power plants. States may also choose to implement different regulatory or market-based structures for achieving these emission reduction measures, such as introducing a carbon tax, imposing emission limits with EGU permits and/or establishing an intra-state or interstate emission trading program inclusive or exclusive of non-electricity sectors.[5]

In this report, we review the suite of analytical approaches available for conducting CO_2 performance projections, dissecting and discussing each of them in the context of modeling Clean Power Plan-related decisions and constraints. EPA provides some tools to states to help design compliance pathways assess

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[4] Note, the labeling convention for the compliance pathways in Figure 1 (e.g., R1, R2, M1, M2) are used for organizational purposes only; EPA does not recognize or use these labels.

[5] For an extensive discussion of emission reduction measures available to states, see *Implementing EPA's Clean Power Plan: A Menu of Options*. National Association of Clean Air Agencies. May, 2015. Available at: http://www.4cleanair.org/NACAA_Menu_of_Options

the impacts of the Clean Power Plan,[6] but does not explicitly require or endorse the use of a particular method or tool by name. It is not clear what types of methods would be acceptable to EPA in creating a performance demonstration, including the possibility of spreadsheet-based tools that incorporate historical generation and emissions, to formal statistical analysis, or comprehensive electric energy system dispatch modeling. This paper attempts to shed light on mechanisms that might be appropriate for CO_2 performance projections in different states, and weighs the benefits of different tools for states conducting compliance planning, even in the absence of a regulatory requirement.

The specific modeling tool that should be used will depend on many factors, including but not limited to:

a) the compliance pathway (emission standards or state measures) and specific measures considered in State Plan design;

b) the characteristics of the affected EGUs in a state (e.g., age, retirement plans, heat-rate improvement potential, fuel, and technology type);

c) the state's underlying physical energy system (e.g., degree of electric interconnectedness with neighbors, known transmission constraints, growth potential);

d) the level of engagement the state seeks with stakeholders.[7]

The objective of this report is to distill the main features of some key classes of models and modeling approaches, as they relate to the emission reducing actions states may take to respond to the Clean Power Plan.

2. THE SUITE OF CLEAN POWER PLAN MODELING TOOLS: AN OVERVIEW

EPA has provided states with a considerable amount of flexibility in choosing an appropriate tool to perform CO_2 emissions performance projections for Clean Power Plan compliance. Each state is expected to choose a methodology that is appropriate for representing the unique circumstances within that state. It is expected that the methodology chosen will generate the specific information that EPA requires for compliance demonstrations (See Appendix A).

This section provides an overview of five analytical approaches for CO_2 compliance demonstrations, and a description of the strengths and weaknesses of each approach in capturing the impacts of various

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[6] See *Clean Power Plan Toolbox for States*. U.S. EPA. http://www.epa.gov/cleanpowerplantoolbox

[7] For a brief discussion of some of these issues, see FERC's *Staff White Paper on Guidance Principles for Clean Power Plan Modeling.* Docket No. AD16-14-000. January, 2016. http://www.ferc.gov/legal/staff-reports/2016/modelingwhitepaperAD16-14.pdf

emission reduction measures. These broad classifications are presented to provide an overview of different methods and tools.[8]

1. **Production Cost Models.** Tools that determine the optimal output of the EGUs over a given timeframe (one day, one week, one month, one year, etc.) for a given time resolution (sub-hourly to hourly).[9] These models generally include a high level of detail on the unit commitment and economic dispatch of EGUs, as well as on their physical operating limitations. They are not, however, designed to determine the optimal addition of new EGUs to meet future capacity requirements or the retirement of non-economic EGUs.

2. **Utility-Scale Capacity Expansion and Dispatch Models**. Tools that determine the optimal[10] generation capacity and/or transmission network expansion in order to meet an expected future demand level and comply with a set of regional/state specifications (reliability requirements, renewable portfolio standards, CO_2 emissions limits, etc.). These models operate at the resolution of individual EGUs.

3. **National-Scale Capacity Expansion and Dispatch Models.** Tools that determine the optimal generation capacity and/or transmission network expansion in order to meet an expected future demand level at a national (or large regional) scale. As a result of the higher dimensionality, these models typically exhibit a lower resolution than utility-scale models (e.g., demand represented in "blocks" as opposed to using an hourly resolution; aggregation of similar EGUs into model plants).

4. **Multi-Sector Models.** Tools that explore the interaction between different sectors of the energy system, as well as macroeconomic factors, using either a general equilibrium or partial equilibrium approach.[11] These models typically include transportation, industry, commercial, and residential sectors, in addition to electricity production. These models generally operate at an aggregate level of model plants or technology types, similar to the national-scale capacity expansion models.

5. **Non-Optimization Approaches.** Tools that develop approximate predictions of future production and/or investment decisions, or provide detailed bookkeeping of user-based

[8] These categories are not necessarily mutually exclusive. Individual models or techniques may contain elements or capabilities that span two or more of these categories.

[9] Optimal outputs in production cost models typically refer to least-cost operation, inclusive of reliability and other security constraints.

[10] Optimal outputs in capacity expansion models typically refer to "minimum total system cost;" total system cost can either be total generation costs or the sum of total generation and transmission expansion costs, depending on the "decision" variables the model represents.

[11] General equilibrium models assume that all markets have an effect on every other market, and model all markets simultaneously. Partial equilibrium models assume that changes in one market (or the segment of markets explicitly represented in the model) do not affect other markets; the assumption is that neither the price of every other good (outside the modeled markets) nor income changes.

decisions. These tools may make decisions based on expert judgement, heuristic rules,[12] scenario analysis, or statistical analysis). These tools often rely on external projections of supply, demand, and other economic conditions; and they do not explicitly optimize the operation of a power system or simulate economic equilibrium conditions.

Table 1 provides a summary of the key features of each method; these individual features will be referred to in the chapters that follow. Appendix B includes a list of popular models in each category and websites for information on accessing them.

[12] Heuristics refer to "rules of thumb" and other computationally non-exhaustive methods that allow models to be solved more efficiently.

Table 1. Summary of modeling capabilities for five model classifications

		Features represented			
		Generation	**Transmission**	**Demand and Renewable Resources**	**Geographic scope**
Production Cost Models *e.g., PROSYM (ABB), PLEXOS (Energy Exemplar), PCI Gentrader, AURORAxmp (EPIS), and GE-MAPS*		Output decision at the individual EGU level	Major transmission lines and nodes represented	Chronological, hourly resolution or less	Regional to interconnect
Utility-Scale Capacity Expansion Models *e.g., System Optimizer (ABB), Strategist (ABB), PLEXOS-LT, AURORAxmp, RPMI (NREL)*		Investment and dispatch decisions at the individual EGU level	Discrete/selected transmission lines represented	Non-chronological, Hourly (typical week) or coarser resolution	Utility, state or discrete region
National-Scale Capacity Expansion Models *e.g., IPM (ICF), ReEDS (NREL), NEMS EMM (EIA), HAIKU (RFF), POM (Navigant)*		Aggregated capacity buildout by technologies (generally does not incorporate individual EGU granularity)	Representation of transmission capacity limits between major zones	Non-chronological, demand in multi-hour blocks Poor representation of extreme events	Interconnect to national
Multi-Sector Models *e.g., MARKAL (IEA ETSAP), NE-MARKAL (NESCAUM), NEMS (EIA), EPPA (MIT), NewERA (NERA)*	*General equilibrium*	Model plants representing individual technologies.	No representation of transmission	Large demand blocks	Regional to national
	Partial equilibrium	Model plants representing individual technologies.	No representation of transmission	Demand blocks/hourly resolution	Varies
Non-Optimization Approaches *e.g., EGU Growth Tool (ERTAC), AVERT (EPA), CP3T (Synapse), CPP Planning Tool (MJ Bradley), CPP Evaluation Model (Energy Strategies)* *SUPR (ACEEE), STEER (AEEI), LEAP (SEI)*	*Screening curves-based heuristics*	Model plants representing individual technologies.	No representation of transmission	Demand blocks/hourly resolution	Varies
	Net present value (NPV) calculations [13]	EGUs are price takers Simulation of the cash-flows of an individual EGU	Representation of transmission congestion through historical locational marginal prices	Hourly resolution	Varies
	Merit order-based heuristics	Variable cost-based dispatch of the EGUs in the system	No representation of transmission	Hourly resolution	Varies

Note: Many models listed here by name can span more than one classification, depending on the features selected in a particular model run or the "mode" the model is run in. For ease of exposition, the model has been classified using its most commonly designated category. Therefore, the listed features do not necessarily perfectly apply to each individual model in that is provided as an example for a given model classification. The list of specific models show here is representative and non-exhaustive.

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[13] NPV (Net Present Value) is the difference between the present value of cash inflows and outflows, often used to assess economic feasibility of long-term capital budgeting/investment projects.

A key distinction among the approaches above is that the first four *generally* utilize "optimization" methods, whereas the fifth category can include non-optimization approaches such as simulation.

Optimization models are prescriptive—i.e. they seek a specific goal (called an "objective function")—while abiding by a set of constraints that represent the limitations of the. The usual objective function in these models is least cost, or maximum benefit. Constraints can include system requirements (e.g., compliance with emissions limits, reserve margins) and individual EGU operational constraints (e.g., ramping limits, minimum output of the EGUs, minimum "on" and "off" times). For example, a production cost model uses a computational method to find least-cost dispatch while obeying physical constraints such as generator ramp rates, minimum "on" and "off" times, transmission limits, system reserve margins, and emissions limitations. This paper will discuss optimization models that solve for optimal dispatch (production cost models), as well as least-cost buildout and portfolio development at local and national scales.

Non-optimization approaches for compliance planning span a gamut of models and non-models, including simulation models, statistical analyses, bookkeeping methods, and complex spreadsheet-based tools that seek to help stakeholders, researchers, and policymakers answer specific questions. They are distinguished in that they do not necessarily find an optimal set of decisions subject to system constraints; instead, they follow a prescribed set of rules and relationships to simulate the behavior of the system under certain conditions.[14] For example, some screening models that test the cost effectiveness of different resources against each other or seek to construct a user-specified buildout are versions of simulation models.

Challenges Inherent in Electricity Modeling

- *Limited ability to handle uncertainty over long planning horizons*
- *Typically assumes rational decisions with perfect information. Difficulty in accounting for more realistic behavioral assumptions, including strategic interactions and market power*
- *Typically assume highly efficient, centralized dispatch. Difficulty accounting for market inefficiencies.*
- *Limited ability to predict future electricity prices, which are driven by a very complex set of underlying market dynamics.*

It is important to recognize that *all* models are reduced-form representations of real world systems. The inherent complexity within, and interactions between, the electricity industry's technical, economic, and regulatory systems make the CO_2 projection task very challenging for electric power systems. As such, each of these modeling approaches will display tradeoffs—often between computational tractability (i.e., reasonable run-time) and detail (e.g., time resolution, technical detail, geographic scope, characterization of uncertainty). Stakeholders will have varying needs for different modeling structures. Some will seek transparency and increased accessibility, while others will seek engineering or operational detail. These varying needs are often a point of

[14] The term "simulation" here means a type of model or tool that is descriptive in nature, following a set of rules. Confusingly, the term simulation can also be used to refer to sensitivity analyses performed on top of an optimization model to test the effect of different values of the input parameters on the solution produced by the model.

contention between optimization and other modeling approaches, and between stakeholders who are able to access and exercise more complicated models and those who are not. The resulting differing levels of engineering detail, scale, and scope means that each class of approaches ends up having strengths and weaknesses for modeling Clean Power Plan compliance, producing logically consistent CO_2 projections, and successfully engaging stakeholders.

These and other model characteristics will be important for states and other stakeholders to consider as they set forth to develop and submit State Plans. While it may be tempting to utilize an approach represented by the lowest level of effort possible, it may ultimately be in a state's best interest to create as accurate a projection as possible to understand real outcomes and potential liabilities in their plans. This can also help to avoid excessively large discrepancies between estimated CO_2 and actual reported emissions.[15]

The remainder of this report discusses in more detail the following key Clean Power Plan compliance modeling-related features or capabilities in relation to the particular class of model:

- Capability to represent **EGU efficiency improvements** (e.g., heat rate improvements) and/or **fuel switching at individual EGUs;**
- Capability to model **generation shifting** between different EGUs (e.g., from coal to gas, or from existing gas to new gas);
- Capability to represent **individual EGU emissions restrictions.**
- Capability to estimate **market-based emission credit or allowance trading programs**, such as intra- and interstate allowance or emission rate credit (ERC) trading programs;
- Ability to represent **banking of emission credits or allowances**;
- Capability to estimate impacts of **renewable energy programs**, and ability to account for renewable energy variability and/or intermittency;
- Capability to estimate level of **cost-effective energy efficiency**, and impacts of energy efficiency programs;
- Capability to capture **transmission** constraints and plan **impacts on reliability**;
- Capability to estimate **interstate impacts** from coordinated or uncoordinated policies between neighboring states;
- **Transparency** of assumptions (a model that relies on proprietary data inputs may lack transparency); and

[15] In the event of a greater than 10 percent deviation in EGU emissions from the emission performance standards specified in a State Plan, EPA plans to apply federally enforceable emission standards at affected EGUs as a backstop measure.

- **Appropriate computational requirements** (results can be generated in a reasonable amount of time).

Note that even within each class, capabilities and model features will be different. The purpose of this document, and the sections below, is to provide an overview of model types and structures, and their general capabilities for Clean Power Plan modeling.

3. Production Cost Models

Electricity system production cost models are regularly used by utilities, grid operators, and independent power producers in day-to-day operations and decision-making. Utilities and EGU owners/operators run these models to forecast revenues and costs, assist in fuel and contract procurement, develop market intelligence, and support strategic decisions. In regulated settings, these models are used to support ratemaking filings and calculate the avoided costs for the procurement of energy efficiency[16] and renewable energy from qualifying facilities. Grid operators, including utilities and independent system operators (ISO) use "unit commitment" and economic dispatch algorithms[17] similar to the ones in production cost models for day-ahead and near real-time decision-making processes. Utility operators use these models to match demand against available generation supply and determine the least-cost feasible operating schedule for the EGUs.

Production cost models are driven by economics (i.e. the variable cost of production) and usually account for the operational limitations of the EGU such as maximum ramp rates, minimum up and down times, and minimum stable output of the generators. In addition to EGU operational constraints, these models operate within other system requirements and constraints, such as minimum reserve capacity requirements, thermal transmission limitations along specific transmission lines or aggregate "paths," and emissions costs. These models do not optimize EGU additions or retirements; changes in the electric system portfolio must be manually altered. Planners can use production cost models in conjunction with other tools that help inform what new additions are expected. An example of this would be using a capacity expansion model to plan for the optimal capacity of existing and new resources, followed by a production cost model to calculate detailed operations for individual EGU. In this case, these models can be used in the same time horizon as the capacity expansion model (i.e. decades). Often, system planners

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[16] For example, see Hornby, R., P. Chernick, D. White, et al., 2013. *Avoided Energy Supply Costs in New England: 2013 Report*. http://www.rieermc.ri.gov/documents/2013%20Evaluation%20Studies/AESC%20Report%20-%20With%20Appendices%20Attached.pdf.

[17] "Unit commitment" refers to the decisions of turning EGUs on and off, whereas economic dispatch refers to how much power is generated from each committed EGU on a system. Thermal EGUs require anywhere from minutes to hours to turn on from an off state, and cannot simply switch on and off when it is economically advantageous. Chronological dispatch models take into account this ramping time, and use unit commitment algorithms to decide when a unit should be turned on, given a forecast of economic conditions over the next hours or days.

will also use production cost models in conjunction with future buildouts of a system that are determined through other means, to verify future system capacity needs.

Examples of commercial production cost modeling tools include: PROSYM (ABB), PLEXOS (Energy Exemplar), PCI Gentrader, AURORAxmp (EPIS), and GE-MAPS.

3.1. Features

Production cost models typically utilize security constrained economic dispatch methods (SCED) or security constrained unit commitment methods (SCUC) to determine the optimal operation of EGUs on an hourly (or shorter) basis to meet demand.[18] The main difference between SCED and SCUC models is that the former determines the production of a given set of committed EGUs, while the latter also calculates the optimal commitment decisions of the EGUs together with their optimal dispatch. These models may have a broad spatial scope, covering multiple Regional Transmission Organization (RTO) regions, and often modeling entire interconnects (i.e. Western, Eastern and/or ERCOT).

Production cost models typically characterize individual EGUs in detail, including fuel and variable costs as well as operational constraints. Some production cost models treat transmission lines in aggregate to characterize the thermal constraints of links between zones, while other "nodal" models represent potential congestion on individual transmission lines. Zone-based models, which are more common, typically represent control areas or balancing authorities. Each zone contains a load (demand) profile and a set of EGUs. Dispatch and transmission are balanced to maintain reliability while providing least-cost service on a variable cost basis. The "nodal" level models characterize transmission constraints between individual EGUs. These highly detailed nodal production cost models are used to predict differences between locational marginal prices at specific EGU connection nodes, and are far more computationally intensive than zonal production cost models.

Production cost models often operate chronologically, modeling all 8,760 hours of the year, individual weeks, individual days, or

Challenges of Production Cost Models

- *Expansion/retirement decisions are exogenous inputs to the model; tradeoffs between capital resource decisions are not optimized*
- *Model easily becomes a "black box" with limited transparency for the user*
- *Requires firm system boundaries (e.g. import/export with neighboring regions)*
- *Transmission constraints relatively simplified; full representation may not be computationally feasible*
- *Regional focus required; typically cannot model entire US simultaneously*
- *Requires handling large amounts of data (input and output)*
- *Does not represent interactions with other sectors of the economy*

[18] The Energy Policy Act of 2005 (EPAct) §1234 defines economic dispatch as the "operation of generation facilities to produce energy at the lowest cost to reliable serve consumers, recognizing any operational limits of generation and transmission facilities."

periods of some other duration. Production cost models contain a finer time resolution and substantially more detail about individual EGUs than regional or national planning or capacity expansion models. These details include operational constraints such as ramp rates, minimum outages, maintenance schedules, and emissions and fuel use constraints. In addition, production cost models can characterize heat rate curves depicting expected efficiency changes at various levels of output. Many are able to model impacts of uncertainty by allowing for random variations in unknown variables, such as forced outage schedules, fuel prices, renewable availability and hourly demand (many models term this as operating in "stochastic" mode).

3.2. Application to Emissions Reduction Approaches

Production cost models are well suited to evaluate the near-term operations of a system and individual EGUs, as opposed to determining long-term portfolio solutions. Operations include changes in demand, fuel prices, emissions constraints or prices, and other economic considerations. Because production cost models do not optimize new generation or retirements, they are generally not well suited to determining the long-run impact of emissions reduction approaches without *a priori* assumptions of how the fleet will change composition over time, or in response to emissions reduction approaches. Production cost models are well suited to predict, over the near term,[19] how new energy efficiency, renewable energy, other EGUs, or EGU retrofits will impact the production from fossil generators and the overall emissions in the system. Nevertheless, it is worth highlighting that these models do not generate an optimal generation capacity expansion and retirement plan. Therefore, when using this class of model, decisions about new and retiring capacity should be pre-determined using other methods (e.g. capacity expansion models), and will be taken as input to the production cost model.

- **EGU efficiency improvements and/or fuel switching**: Production cost models explicitly track the EGU-specific and system implications of strategies such as heat rate improvements or fuel switching.[20] However, as discussed above, decisions about retrofits should be made outside of a production cost model, and the trajectory of improvement would be one of the sets of inputs.
- **Generation shifts**: Production cost models can be used to assess the effect of fuel prices and efficiency improvements on the dispatch of the EGUs in the system, including potential shifts from coal-based generation to gas-based generation.

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[19] "Near term" here refers to a reasonably short number of years (i.e. 3-5), but may vary depending on changing economic considerations, such as rapidly changing fuel prices or unit additions/retirements. Production cost models can be very useful even on a 10-year timeframe if future supply is adequately represented; they can model the impacts of energy efficiency and renewable energy on a much more detailed level than a traditional capacity expansion model.

[20] For example, fuel switching a boiler from coal to gas-fired generation will reduce the emissions rate of the EGU, but may increase the variable cost of the EGU, effectively decreasing its dispatch. To compensate for the loss of energy from this EGU, other EGUs will increase their output. Depending on that EGU's position in the loading order (i.e. its relative economics) the energy requirement may be met by boilers with greater or lesser emissions rates. In aggregate, system emissions rates may change differently than the emissions from the EGU with an improved efficiency or changed fuel.

- **Individual EGU emissions restrictions**: Most production cost models are equipped to represent individual EGU emissions restrictions. This may be important for R3 states that assign individual EGU-specific emission rates to affected EGUs, or for M3 and M4 states using a state measures compliance pathway that incorporates individual EGU mass- or rate-based limits.

- **Market-based emissions reductions**: Production cost models are well equipped to capture the effect of emissions prices on individual EGU emissions: They can assess the impact of a uniform emissions price or multiple regional prices, or calculate the clearing price for emissions based on a cap amongst the set of modeled EGUs. Production cost models can determine how signals such as emissions prices would impact operational decisions—but *not* how these signals would impact the acquisition or retirement of EGUs. The capability to endogenously estimate emissions clearing prices is relevant for all states that are required to submit a CO_2 compliance demonstration (M3, M4, and R3 states), because they will need to: (a) estimate direct emission mass or rate impacts from trading *as well as* indirect emission changes from a change in network flows in the region, and (b) estimate allowance or ERC prices (both within the state and regionally).

- **EE/RE programs**: Production cost models are EGU specific and fairly detailed, and can thus predict which EGUs will reduce generation (and subsequently emissions) when new energy efficiency or renewable energy is introduced into a system. The specific level of precision a production cost model has in estimating network and emissions impacts from EE/RE resources is unmatched in comparison to the other modeling classes described here.[21] Production cost model cannot choose a cost-effective energy efficiency or renewable energy procurement, but they can be used to evaluate the impacts of energy efficiency and renewable energy on a system. In particular, these models are well suited to assess how stochastic renewable energy changes system operations.

- **Interstate impacts:** Production cost models are typically detailed and capture large geographies. Indeed, a production cost model that fails to review large geographies may significantly misrepresent system dynamic, especially in zones that are highly interconnected. Multi-zonal production cost models that include transmission constraints between different zones can determine the optimal production schedule of the EGUs in the zones considered, while accounting for the power exchanges among different zones. A production cost model may be well equipped to assess how different compliance mechanisms and targets in different states impact the flow of electricity between states, and any adverse impacts this may have on either compliance or the efficacy of the rule.

- **Transparency and stakeholder engagement**: Production cost models require expertise to operate and interpret. The algorithms and codes can be complex, and in many cases are closed-source (some models allow users to see the underlying computer codes,

[21] However, since increasing penetrations of energy efficiency or renewable energy over long timeframes may eliminate or defer the need for new capacity or transmission, or allow existing generation to retire economically, the operational margin calculated by a production cost model becomes less relevant over longer periods of time; changes in the fleet composition cannot be captured by a production cost model.

while others do not). Most production cost models are proprietary and have hefty licensing fees. Additionally, input data with the required level of detail may be proprietary and/or considered confidential business information by utilities. Some parties have asserted that the output from these models using utility information is also confidential business information.

4. Utility-Scale Capacity Expansion and Dispatch Models

Capacity expansion models are used to inform long-run planning decisions for generation and transmission. These models are available across a spectrum of resolutions, capturing anywhere from national-scale trends to specific EGU decisions. As will be discussed, both broad-scale and fine-scale resolution have various advantages and challenges. At the finer resolution, utility-scale capacity expansion models are run by utilities and independent power producers to inform new resource procurement and, more recently, retirement decisions. These models can also be used to support long-term power and fuel procurement contracts, but are more often used for longer time scales—typically two to three decades. Utility-scale capacity expansion models feature in state electricity regulatory proceedings where long-term planning is at issue, and thus state utility commissions are often broadly familiar with these models. Multiple vertically integrated utilities use capacity expansion models to conduct forward planning, as well as to review the economics of specific retrofit decisions. Utilities that submit integrated resource plans often use a utility-scale capacity expansion model to examine long-term strategies and develop short-term action plans.

Utilities have experience using these models to examine carbon reduction strategies in integrated resource plans and pre-approval dockets. Planning scenarios often examine the cost and buildout implications, if not emissions, of increased energy efficiency or renewable energy, emissions pricing and/or trading, and/or hard emissions caps.

Examples of utility-scale capacity expansion model tools include: System Optimizer (ABB), Strategist (ABB), PLEXOS-LT (capacity expansion mode), AURORAxmp, and the Resource Planning Model (RPM, from NREL).

Challenges of Utility-Scale Capacity Expansion Models

- *Limited representation of chronological variability in renewables and load*
- *Limited representation of operational detail of EGUs*
- *Highly limited representation of transmission*
- *Some solutions may not be operationally feasible, may be verified with production cost models*
- *Solutions very sensitive to long-term cost assumptions*
- *May require firm system boundaries (e.g. import/export with neighboring regions)*
- *Model easily becomes a "black box" with limited transparency for the user*
- *Does not represent interactions with other sectors of the*

4.1. Features

Utility-scale capacity expansion models have high spatial detail with limited geographic scope that encompasses a utility service territory or a sub-regional scale, frequently with sales or purchases outside the utility system represented by a simple market price profile. These models generally have better temporal resolution than the national-scale capacity expansion models (discussed next), with each model year dispatched based on an annual hourly load duration curve.[22] Alternatively, these models may only explicitly model a representative subset of hours in a year (i.e. every 4th hour, three days per week, or peak/shoulder/trough) to reduce computational requirements. They then extrapolate results accordingly. Utility-scale capacity expansion models are designed to track individual EGUs, where each EGU has specific operational characteristics. Models are often designed to choose the optimal resource mix that meets demand using a least-cost objective function. These models can handle constraints at the EGU level (e.g. minimum operation, outage schedule), system level (e.g., emissions cap), and build options (e.g. maximum number of EGUs built for a specific technology). Alternatively, some models may require some types of expansion and retirement decisions to be made exogenously, or outside the model. For example, it is not uncommon to perform energy efficiency growth calculations outside of the model, and apply energy efficiency impacts as a modification to demand, rather than as a supply-side resource. In addition, some capacity expansion models are unable to endogenously retire EGUs, and require these decisions to be made outside of the model construct. While making decisions outside the model reduces computational requirements, it may introduce user error or bias. For example, a modeler may not review economic retirements, and thus fail to capture a cost-effective compliance mechanism.

In the case of high spatial and temporal resolution capacity expansion models, the number of technology options for generation capacity expansion may be limited to a select subset to reduce the runtime of the model. This can be done through an outside-the-model screening analysis to pre-select the resources most likely to be economic in the area of interest, or by running the model iteratively to eliminate inferior alternatives.

4.2. Application to Emissions Reduction Approaches

Utility-scale planning models are commonly used to determine optimal marginal capacity addition decisions for focused areas of interest (i.e. a specific utility's decisions). Individual EGU representation means that these models are reasonably well suited to the review of both the operating margin as well as the build margin. They can determine how signals such as emissions prices would impact operational decisions, the acquisition of new EGUs, and the retirement of existing assets on an economic basis.

The hourly load duration curve dispatch methodology, combined with EGU specificity, allows for analysis of a relatively wide range of emissions reduction approaches. The effects of additional energy efficiency,

[22] A load duration curve depicts the hourly loads for a given period (e.g. a year) in descending order. Utility-scale models may represent only a typical week per month, or other selected time period, rather than all hours in a year.

renewable energy, or fuel switching can be captured at the balancing area level, although such additions may have impacts beyond the model study area.

Economic dispatch decisions in capacity expansion models are generally far more limited than in production cost models, which can account for more detailed scheduling and unit-commitment decisions.[23] However, the added capacity expansion optimization benefits allow for broader changes in a utility's energy mix and longer-term analyses.

Capacity expansion models can be highly sensitive to input assumptions such as commodity prices, new EGU capital cost assumptions, existing EGU fixed operations and management (O&M) cost data, and restrictions on new EGU selection. Results should always be taken as contingent on the assumptions made and, when deemed appropriate, they should be accompanied by sensitivity analyses that reflect the impact of the range of possible values of the uncertain parameters on the solution.

- **EGU efficiency improvements and/or fuel switching**: These models explicitly track the EGU-specific and system impacts (e.g., emissions and costs) of direct emission reduction strategies such as heat rate improvements or fuel switching.
- **Generation shifts**: Utility-scale capacity expansion models can capture changes in the utilization of different generation technologies due to efficiency improvements or changes in fuel prices, and it uses this information to decide on the capacity investments and retirements necessary to meet demand at minimum cost. However, the use of an hourly load duration curve for dispatch instead of a chronological load time series typically ignores start-up and shut-down decisions, causing a distortion in the output from gas- and coal-based generation, ultimately affecting emissions, although usually to a fairly minor extent.[24]
- **Individual EGU emissions restrictions**: Utility-scale capacity expansion models may be able to review individual EGU emissions restrictions, depending on the capability of the specific model.
- **Market-based emissions reductions**: Utility-scale capacity expansion models are well equipped to capture the effect of emissions prices or emission caps on individual EGU output and retirement decisions, and new EGU additions.[25]
- **Renewable energy programs**: Utility capacity expansion models are able to show the acquisition path of cost-effective renewable energy programs, and explicitly track the EGU-specific and system implications of renewable energy programs. The effects of additional renewable energy programs can be captured at the balancing area level, although such additions may have wider-ranging impacts beyond the study area of

[23] See section on production cost models for discussion.

[24] Santen, N.R., Webster, M.D., Popp, D., and Perez-Arriaga, I. 2014. "Inter-temporal R&D and capital investment portfolios for the electricity industry's low carbon future." National Bureau of Economic Research (NBER Working Paper 20793). Available at: http://www.nber.org/papers/w20783.

[25] Utility-scale models do not generally see changes that occur in an EGU outside of the model's boundaries, and thus cannot estimate a regional or national emissions clearing price (unless the larger area is modeled).

these models. In addition, because these models do not handle chronological dispatch, they may inaccurately depict the operational impacts of variable renewable energy sources.

- **Energy efficiency programs:** Utility capacity expansion models are able to show an acquisition path towards cost-effective energy efficiency, although configuring the models to do so is difficult and rare. Most capacity expansion models users configure energy efficiency expectations outside the model (exogenously) and apply the efficiency pathway as a modification to load. As with renewable energy, utility capacity expansion models are able to track EGU-specific and system implications of energy efficiency programs.[26]

- **Interstate impacts**: These models are typically limited in scope to a few balancing areas, and thus may not represent measure impacts that occur outside the modeled region, or may unduly credit all measure impacts to that single balancing area. Most utilities are focused on their area of operation and as such focus their modeling efforts on that area. However, it would be feasible for a state planning agency to model a wider spatial area for Clean Power Plan modeling, at the expense of computational requirements. Impacts beyond model scope are represented by generic market assumptions, and occur externally to the model; regional impacts are not well represented without extending the model beyond the state boundary.

- **Transparency and stakeholder engagement**: Utility-scale capacity expansion models require expertise to operate and interpret. The algorithms and codes can be complex, and in many cases are closed-source (some models allow users to see the underlying computer codes, while others do not). Most utility-scale capacity-expansion models are proprietary and have significant licensure fees. Additionally, input data with the required level of detail may be proprietary and/or considered confidential business information by utilities. Some parties have asserted that the output from these models using utility information is also confidential business information.

5. National-Scale Capacity Expansion and Dispatch Models

National-scale electricity capacity expansion models are typically used for long-term policy analysis and forecasting over a period of decades. They are built with a focus on big-picture trends in energy use across large regions or the country as a whole, and capture only broad-scale information, such as changes in regional or state fuel mix, fuel consumption, emissions, and infrastructure expenditures (i.e.

[26] See, for example Fisher, JI, C James, N Hughes, et al., 2011. Emissions reductions from renewable energy and energy efficiency in California Air Quality Management Districts. Produced for the California Energy Commission Public Interest Energy Research Program. Available at http://www.energy.ca.gov/2013publications/CEC-500-2013-047/CEC-500-2013-047.pdf.

new generation and transmission). These models may be based on similar algorithm structures as utility-scale capacity expansion models but they typically operate with aggregated, and often simplified, information. Such models can be used to review trends in emissions and energy sector structure under changing regulatory and economic conditions.

This model type is used by policy analysts, by stakeholders interested in engaging in environmental policies, and by the academic community. These models are predominant in regional and national emissions policy planning. For example:

- The Eastern Interconnect Planning Collaborative (EIPC), a utility and stakeholder process funded by the U.S. Department of Energy, used a national-scale capacity expansion model to assess the costs and implications of a rigorous carbon emissions reduction scenario, and then performed more rigorous cost analyses using a production cost model.[27]

- Historically, EPA has employed the Integrated Planning Model (IPM)—a multi-regional electricity capacity expansion model—to estimate the costs and efficacy of policies and rules such as emissions trading programs, regional transport rules, and boiler emissions reductions policies (such as the Mercury and Air Toxics Standard). IPM was used to inform the Regulatory Impact Assessment (RIA) of the Clean Power Plan, and also by the Regional Greenhouse Gas Initiative (RGGI) to assess likely costs and prices of its emissions trading program.[28]

- The U.S. National Renewable Energy Laboratory (NREL) recently published the Renewable Electricity Futures Study. This study examined the opportunities and costs of increasing renewable energy penetration in the United States, and also the greenhouse gas emissions reductions from the resulting scenarios. NREL's Regional Energy Deployment System Model (ReEDS)—a national-scale capacity expansion model—was used as one of the two main models in this study to explore future long-term renewables scenarios.[29]

Utilities and electric system planners may use national-scale capacity expansion models to forecast regional market electricity and capacity prices, as well as to estimate likely regional fuel uses and emissions. However, because these models do not assess individual EGU decisions, they tend not to be reviewed with the same level of state regulatory scrutiny as the more detailed utility-scale capacity expansion models.

Examples of national-scale capacity expansion models, some discussed below, include: ICF's IPM model (as used by EPA), the National Renewable Energy Laboratory's Regional Energy Deployment System

[27] See http://www.eipconline.com/

[28] See, for example, http://www.rggi.org/docs/ProgramReview/February11/13_02_11_IPM.pdf

[29] National Renewable Energy Laboratory. (2012). Renewable Electricity Futures Study. Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/.

Model (ReEDS), U.S. EIA's NEMS Electricity Market Module EMM,[30] Resources for the Future's HAIKU model, and Navigant's Portfolio Optimization Model.

5.1. Features

National-scale electric capacity expansion models have moderate spatial detail with broad scope, generally encompassing the entire country or interconnects (i.e. Eastern, Western, and ERCOT), subdivided into smaller areas such as balancing authorities or control areas. For computational efficiency, these models almost always use "dimensionality reducing" techniques such as selecting representative hours of the year, or aggregating hours into representative bundles with similar demand (i.e. peak, shoulder, off-peak, super-peak, etc.) and/or likely generation characteristics. Utility-scale capacity expansion models also perform these aggregations, but national-scale models tend to rely on them more. In these models, existing EGUs may be clustered into broad technology types, sometimes subdivided by vintage year or emissions controls. These types of models focus on future capacity expansion decisions. They seek units that provide energy and capacity requirements while minimizing system costs, maintaining reliability criteria, and following other constraints, such as minimum build times, renewable energy availability, or emissions restrictions.

5.2. Application to Emissions Reduction Approaches

National-scale capacity expansion models can provide valuable insights at the national and regional level, as they are capable of capturing the effects of broad country-level and region-level policy decisions. Due to the aggregation of generation units into generic types, these models only roughly capture outcomes from direct control strategies such as EGU efficiency improvements or individual EGU fuel switching. The effects of additional energy efficiency, renewable energy, or fleet-wide fuel switching can be appropriately captured at a regional level, although these models are less suitable for analyzing individual EGU decisions and outcomes. EGU-specific emissions limitations (i.e., permit limits), retrofit decisions, and retirements can only approximated in these models, because they represent aggregate model plants, rather than specific EGU characteristics. For the purposes of reviewing emissions reductions approaches,

Challenges of National-Scale Electric Capacity Expansion Models

- *Limited representation of chronological variability in renewables and load*
- *Highly limited representation of transmission constraints*
- *Highly limited representation of operational detail of EGUs*
- *Some solutions may not be operationally feasible*
- *Solutions very sensitive to long-term cost assumptions*
- *Model easily becomes a "black box" with limited transparency for the user*
- *Does not represent interactions with other sectors of the economy*

[30] The Electricity Market Module (EMM) is a sub-routine of the NEMs program, designed as a regional capacity expansion model. The overall NEMs program is more appropriately categorized as a multi-sectoral model.

these models should be able to capture the aggregated retirements of existing non-economic assets.

- **EGU efficiency improvements and/or fuel switching**: Fleet-wide fuel switching can be appropriately captured at a regional level. Note, however, that any changes to heat rates or fuel switching at applicable EGUs are normally completed manually prior to operation, as these models are not setup to optimize such modifications. Such improvements and fuel switching at individual EGUs are typically not captured by these models.
- **Generation shifts**: National capacity expansion models can model generation shifts on aggregate for classes of EGUs, but may not be able to track such shifts for individual EGUs.
- **Individual EGU emissions restrictions:** As EGUs are generally aggregated in these models, national-scale models are not equipped to review individual EGU emissions restrictions.[31] However, a number of models, such as IPM, ReEDS and NEMS, maintain an external file that allows users to roughly disaggregate model plants into specific EGU outputs.[32]
- **Market-based emissions reductions**:[33] National- and regional-scale models are able to capture economic tradeoffs between aggregate EGU categories (e.g. fuel and EGU types), and thus can either capture the effect of emissions prices, or calculate emissions prices based on a regional or national emissions cap.
- **Renewable energy programs**: The effects of renewable energy can be roughly captured at a regional level, although marginal changes due to renewable energy may be "lumpy" in nature, affecting one aggregate class of EGU at a time. In addition, these models do not capture the variability inherent in some renewable energy programs, except at a very rough estimation. These models are equipped to acquire cost-effective renewable energy.
- **Energy efficiency programs**: The effects of additional energy efficiency can be roughly captured in national capacity expansion models, although similar to renewable energy modeling, the marginal changes due to demand reductions may be lumpy and ill-defined. Some of the models of this class are able to procure cost-effective energy

[31] Individual unit emissions restrictions for units with a fixed (or nearly fixed) emissions rate are modeled similarly to energy-limited units (i.e. units that can only deliver a certain amount of energy over a period of time, such as hydrologic reservoirs). To model individual unit restrictions, models must co-optimize for least cost dispatch at all hours, as well as total energy availability for units with restrictions. Such modeling generally requires the review of tradeoffs between individual units to ensure that energy and capacity requirements are met at all hours while still meeting total emissions limits. This analysis is generally beyond the capability of models that aggregate units or hours.

[32] For example, since EPA Base Case v.5.13 results are presented at the model plant level, EPA has developed a post-processor "parsing" tool designed to translate results at the model plant level into generating unit-specific results. The parsing tool produces unit-specific emissions, fuel use, emission control retrofit and capacity projections based on model plant results. For details see: http://www.epa.gov/powersectormodeling/docs/v513/Chapter_2.pdf.

[33] Market-based emissions reductions include direct emissions prices as well as the realized or opportunity cost of emissions credits realized from a trading program.

efficiency, modify load as a response to simulated spending on energy efficiency programs or other price signals, roughly simulating energy efficiency programs.

- **Interstate impacts**: These models may not identify a precise location for new emitting or non-emitting resources within a region or sub-region, rendering it difficult to determine state vs. out-of-state impacts.[34] This problem may be exacerbated by the fact that many interconnects are operated without regard for state borders and therefore national system models may include aggregation zones that themselves span multiple states.
- **Transparency**: Capacity expansion models require expertise to operate and interpret. Many of the models used for this purpose are proprietary, with licensure fees (or are exclusively run on behalf of customers by the model owner) and detailed input data may be proprietary. However, some of these models, such as the ReEDS model, have broader accessibility and do not rely as heavily on proprietary input data. The level of aggregation in these models means that their outputs are often considered non-confidential business information, although this varies by vendor and operator.

6. MULTI-SECTOR MODELS

Multi-sector models are typically used to examine broad-scale emissions markets and similar federal policy initiatives, including clean energy standards, carbon taxes, and renewable energy portfolio standards. They are used to review trends in emissions, expected broad-scale resource consumption, and energy sector structural changes under changing regulatory and economic conditions. They often review changes over a period of decades and form the basis of many long-term fuel price and availability forecasts. For example, the U.S. Energy Information Administration (EIA) runs the National Energy Modeling System (NEMS) for the purposes of forecasting fuel prices, production and demand, and evaluating the energy sector impact of federal energy and environmental policies.

Examples of multi-sector modeling tools include: MARKAL, NE-MARKAL, NEMS, EPPA (MIT), and NewERA.

[34] For example, even if a model respects state boundaries, within an electrically contiguous area, a new resource may be equally likely to be put in place on either side of a political boundary. State and other political boundaries are generally not meaningful in electric system modeling, except for state policies and constraints.

6.1. Features

Multi-sector models cover a broad range of energy sectors beyond electricity and feature detailed representations of end-use demands and technology choices, but operate at a highly aggregated scale. The range of national capacity expansion, utility planning, and chronological dispatch models discussed previously focus on detailed characterizations of the electric sector to address sector-specific questions. Multi-sector models, in contrast, attempt to include many other energy-consuming sectors of the economy in order to understand interactions between these sectors. The broader scope of coverage necessarily entails a more aggregate representation of the electricity sector both spatially and temporally, and thus these models have limited use in examining outcomes in detail. Multi-sector models generally encompass the entire country, subdivided into somewhere from one to 30 regions. Technologies are typically aggregated into a few broad types with general characteristics. Finally, these models simplify the dispatch problem with a highly aggregated representation of time that may use very few time blocks. For example, a multi-sector model may seek only to ensure that there is enough generation capacity to meet the peak demand hour in a given year, as opposed to modeling actual operations throughout the year or even a suite of typical hours.

Challenges of Multi-Sector Models

- *Limited representation of chronological variability in renewables and load*
- *Limited representation of capacity expansion decisions*
- *Highly limited representation of transmission constraints*
- *Highly limited representation of operational detail of EGUs*
- *Some solutions may not be operationally feasible*
- *Models may be computationally intense, or difficult to solve*
- *Solutions very sensitive to long-term cost assumptions*
- *Model easily becomes a "black box" with limited transparency for the user*

The value of these models is in understanding feedbacks between load and supply, interactions between sectors, and changes in prices on a macro scale. A key strength of this type of model is the ability to provide multi-sectoral feedback between resource consumption and prices. For example, many of these models track fuel supplies and adjust fuel prices to account for changing demand. The Annual Energy Outlook (AEO) that results from EIA's NEMS model is one of the most relied-upon energy price forecasts. It undergoes significant review and seeks to characterize recent and expected changes across the energy sector comprehensively.

6.2. Application to Emissions Reduction Approaches

Multi-sectoral models are best used to understand the national-scale impacts resulting from potential policies across energy sectors with particular attention to emissions impacts, total fuel consumption, changes in fuel price, and other resource concerns. They can be valuable tools for understanding the national energy system impacts of changes to the electricity sector, and as such can provide inputs based on internally consistent scenarios of multi-sector energy use to more detailed analyses. Multi-sector models are useful in examining cross-sectoral policies where tradeoffs between sectors play critical roles. Such policies may include multi-sector emissions policies (i.e. a fee on carbon emissions from electricity, transportation and end-uses) or technology-forcing regulations, such as fuel standards.

Their limited spatial and temporal detail combined with limited treatment of EGU technology types significantly limits their use in addressing EGU-specific emissions reduction approaches. Due to their level of spatial aggregation, these models cannot be used to represent output or outcomes in individual state without significant simplifying assumptions. Furthermore, they typically do not represent utility structures or energy markets that would affect resource decisions at the state level.

Outputs from multi-sector models would be useful to provide inputs to a more detailed analysis. For example, results from U.S. EIA's Annual Energy Outlook, produced with the NEMS model, could be used to provide fuel prices and load forecasts for a production cost model or capacity expansion model.

- **EGU efficiency improvements and/or fuel switching**: These models are not well suited to address heat rate improvements, EGU-specific fuel switching, or EGU-specific emissions limitations in anything but a very simplified representation.

- **Generation shifts:** These models are well equipped to identify potential aggregated fuel switching between broad classifications (i.e. coal to natural gas) over long timescales, but not for individual units. In addition, they may capture fuel price implications associated with generation shifts.

- **Individual EGU emissions restrictions**: As EGUs are generally highly aggregated in these models, multi-sector models are not equipped to review individual EGU emissions restrictions.

- **Market-based emissions reductions**: Multi-sector models are able to capture economic tradeoffs between aggregate EGU categories (e.g. fuel and EGU types) and even non-electric sector emissions sources, and thus can either capture the effect of emissions prices, or calculate emissions prices based on a regional or national emissions cap, including multi-sector caps.

- **EE/RE programs**: The effects of additional energy efficiency and/or renewable energy can be roughly captured at a regional level, although marginal changes due to demand reductions may result in unrealistically "lumpy" responses in these models.

- **Interstate impacts:** These models may use a region representation that does not explicitly model individual states. For example, the NEMS Electricity Market Module used by EIA to prepare the AEO considers 22 regions that are not precisely aligned with state borders.

- **Transparency:** Many multi-sector models require subject matter expertise to operate and interpret. Some multi-sector models are proprietary and include licensure fees (or are run on behalf of customers by the model owner) and detailed input data may be proprietary. However, more models in this category are accessible to segments of the academic and research consulting modeling community (at low or no cost), and rely on publicly available data.

7. NON-OPTIMIZATION APPROACHES

Numerous parties have developed non-optimization approaches to estimate the impact of energy and emissions policies in the electric sector. Analytical frameworks based on non-optimization approaches have been used to evaluate the impact of clean energy programs and policies at the federal[35] and state levels,[36] estimate future emissions inventories for state and regional air quality modeling,[37] estimate the impact of load reduction measures (energy efficiency and renewable energy) on individual EGU fossil emissions at the county or state level,[38] and estimate regional emissions rates.[39]

This category includes a wide range of approaches, including analysis of historical data, decision rules based on heuristics or expert judgement, screening curves, and the selective use of modeling outcomes from national/regional scale modeling and/or utility scale modeling. The class of models developed specifically for Clean Power Plan compliance planning effectively fall into a class of "bookkeeping" analyses that allow users the option to manually build a system, while tracking generation, emissions, compliance, and in some cases, cost. These approaches generally use publicly available data, do not rely on economic data or proprietary information regarding individual EGUs, and are often built to be accessible to both expert and non-expert users with few restrictions. They provide a low-cost, simple, and often transparent framework to allow stakeholders to engage with complex energy policy decisions at a simplified but indicative level.

Examples of these tools include: ERTAC's EGU Growth Tool, EPA's Avoided Emissions and Generation Tool (AVERT), Synapse Energy Economics' CP3T, MJ Bradley's CPP Planning Tool, Energy Strategies' CPP Evaluation Model, ACEEE's SUPR model, STEER, and Stockholm Environment Institute's LEAP Model.

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[35] See "Beyond Business as Usual" Synapse Energy Economics, 2010. Available at: http://www.americancleanenergyagenda.org/wp-content/uploads/2012/09/beyond_bau_may_2010.pdf and Energy Innovation Energy Policy Simulator, 2015. Available at: https://www.energypolicy.solutions/.

[36] Synapse Energy Economics CP3T (2014-2016), available at: http://www.synapse-energy.com/tools/clean-power-plan-planning-tool-cp3t; MJ Bradley CPP Evaluation Tool (2015-2016), available at: http://www.mjbradley.com/about-us/case-studies/clean-power-plan-evaluation-tools; Energy Strategies CPP Evaluation Model (2016), available at: http://www.westernstatecppmodeling.org/; Advanced Energy Economy State Tool for Electricity Emissions Reduction (STEER), available at: http://info.aee.net/steer.

[37] See, for example the ERTAC Electric Generating Utility Growth Model. Available at: http://www.ertac.us/index_egu.html.

[38] See EPA's AVERT (Avoided Emissions and Generation Tool). Available at: http://www.epa.gov/avert.

[39] See Flexibility Weighted Hourly Average Emissions Rate (FW-HAER) in Hausman, E., J. Fisher, and B. Biewald. 2008. "Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation." EPA ORD. Available at: http://nepis.epa.gov/Adobe/PDF/P1002UQO.pdf; see EPA eGRID non-baseload emissions rate (2009). Available at: http://www3.epa.gov/ttnchie1/conference/ei18/session5/rothschild.pdf; see Time Matched Marginal (TMM) emissions tool, a proprietary algorithm used to estimate avoided emissions. D. Jacobson and C. High. 2010. "U.S. Policy Action Necessary to Ensure Accurate Assessment of the Air Emission Reduction Benefits of Increased Use of Energy Efficiency and Renewable Energy Technologies." *Journal of Energy & Environmental Law*.

7.1. Features

Many of these approaches are purpose-built and designed to answer specific questions about the impact of new policies or programs. They are generally not designed to be comprehensive, and are often considered indicative rather than precise. These approaches do not optimize economic dispatch or new capacity additions. Instead, they use demand growth rates, electricity production trends and/or data from other energy models to understand heuristically the result of power system installations and operation decisions.

Non-optimization approaches generally assume that power plant behaviors follow basic rules, and in the absence of significant shifts in commodity prices, can be expected to behave similarly in the future as today. Several features held in common amongst these methods are that they (1) generally build on historical generation and emissions output from individual EGUs, (2) are insensitive to fuel and emissions price forecasts, (3) do not solve for optimal economic dispatch or new EGU expansion, (4) do not capture transmission constraints or limits, and (5) generally take electricity prices as a given. These tools generally divide the contiguous United States[40] into regional power markets, following ISO boundaries, eGRID boundaries, NERC regional boundaries, or state lines. They generally seek to examine how emissions and generation from individual units could be expected to change with shifts in fleet composition, changes in electric demand, emissions restrictions, and/or retrofits at existing units. Some algorithms use the observed historical behavior of EGUs to approximate future behavior, while others add steps of differentiating units into fuel groups and EGU types, with implicit differentiation of economic outcomes for these different groups. Some of these algorithms may contain subroutines to add new generation automatically to meet load requirements. The approaches vary in effective temporal resolution, from hourly[41] to annual,[42] depending on the analytical goal.

Challenges of Non-Optimization Approaches

- *Does not provide an optimal, or near optimal (i.e. least cost) solution*
- *Limited representation of capacity expansion decisions*
- *Typically no representation of transmission constraints*
- *Typically no representation of operational detail of EGUs*
- *Some solutions may not be operationally feasible*
- *Typically no representation of dispatch*
- *Typically no representation of binary decisions (e.g. operational unit commitment decisions and capacity expansion decisions)*
- *Typically does not represent interactions with other sectors of the economy*

[40] Hawaii and Alaska do not report hourly generation and emissions from individual EGUs to EPA, and are thus generally excluded from these models.

[41] See EPA's AVERT and ERTAC's Electric Generating Utility Growth Model.

[42] See CP3T, MJ Bradley's CPP Planning Tool.

7.2. Application to Emissions Reduction Approaches

Non-optimization analyses are usually designed to answer specific questions about the shape, structure, and operations of the electric sector. Some of the methods are appropriately used to understand broad trends and screen the effectiveness of emissions reductions approaches, while other are designed to explore the near-term operational impacts of clean energy programs. Non-optimization approaches may have narrow design specifications that are implicitly embedded in the tools, or explicitly changed by the user. These approaches generally have a distinct advantage in their transparency, ease of use, availability, and even flexibility, but in turn are subject to significant simplifications and assumptions.

All modeling approaches require a user to carefully assess embedded assumptions in the structure of a tool or model; however, non-optimization approaches require an additional level of care to understand how simplifications or underlying structural assumptions impact outcomes. For example, one area that is handled only roughly in non-optimization approaches are how individual EGUs respond to incremental energy efficiency or renewable energy, or emissions pricing signals. Differing tools use different assumptions or mechanisms, which may or may not be either explicitly discussed or caveated. In other cases, non-optimization approaches rely on explicit user, or model designer, assumptions about long-term economics and short-term dispatch (or make these decisions implicitly, without user input or transparency), and may not appropriately characterize economic decisions, EGU behaviors, or expected market outcomes.

It may be the case that, due to their simplifying assumptions, non-optimization approaches are inappropriate to use for establishing firm policies without additional economically driven modeling. Long-term and large-scale emissions reductions strategies impact economic dispatch decisions, operations, and resource decisions in ways that may differ from simplified assumptions. In addition, these approaches may not correctly capture geographic patterns (i.e. in-state versus out-of-state emissions reductions).

Non-optimization approaches, however, provide high value screening-level input into more rigorous model assessments, and allow the engagement and involvement of non-technical stakeholders and decision-makers. The ease of use of these models typically allows users to readily explore a wide range of strategies and/or policies, and understand the general dynamics of the system and the implications of new policies or other economic changes.

- **EGU efficiency improvements and/or fuel switching:** Non-optimization approaches only capture emissions changes due to efficiency improvements or fuel switching based on user-specified input parameters.
- **Generation shifts:** Fuel switching and efficiency improvements fundamentally change variable costs for EGUs, and consequently their dispatch position. However, because non-optimization approaches generally cannot consider economic dispatch, it is unlikely that they can capture how changing generation at one EGU will impact generation (and thus emissions) from another EGU on the system.
- **Individual EGU emissions restrictions:** In electricity systems, individual EGU emissions restrictions are met either through trading programs or by limiting output of specific EGU,

usually as the result of an optimized process. Non-optimizing tools are generally unable to capture EGU or system-wide responses to specific EGU emissions limits; rather these approaches may roughly characterize the impact of such restrictions.

- **Market-based emissions reductions:** Because non-optimization approaches do not consider economic dispatch, they are unlikely to be able to capture the impact of emissions markets on EGU dispatch.
- **EE/RE programs**: Some of the non-optimization approaches characterized here are designed specifically to estimate how either individual units or a broader generation fleet would respond to changes in demand, assuming no change in economic forcing (i.e. commodity prices or emissions costs). Given generic assumptions about what categories of generation are most likely to be the marginal categories, these models can approximate emissions impacts of new EE/RE programs. These assumptions can be particularly risky in the long term, when power system operations may differ from historical behavior.
- **Interstate impacts:** Non-optimization approaches could easily be organized with state level geographic resolution and could therefore identify interstate impacts, however the results would be subject to the previously discussed limitations.
- **Transparency:** These are often simple and transparent frameworks for estimating how EGUs will respond to changes conditions. Some of these tools are designed to be operated by non-expert users, while others are made available for interested parties. These approaches are based on generally publicly available data,[43] and do not rely on economic data or proprietary information regarding individual EGUs.

8. Compliance Modeling Pathways

Each of the approaches discussed in this report can play an important role in Clean Power Plan state compliance planning, particularly when used in combination with each other. Given the differences in level of technical detail represented, temporal and geographic scope, level of expertise required to run the models, and different ability of states and stakeholders to access them, there may be no single best modeling approach for demonstrating compliance in all situations. Nevertheless, there are methods and analytical approaches that will produce more reliable solutions than others. For example, while non-optimization approaches may certainly provide useful information, they generally cannot guarantee an optimal solution for a given set of assumptions, and representing technical considerations in these models might prove much harder than in pure optimization models. Similarly, broad regional models may capture expected shifts in energy systems, but may produce inaccurate information at the scale of a single state, and even more so at the scale of specific power plants. At the other end of the spectrum,

[43] For example, hourly emissions and generation data for all fossil EGUs greater than 25 MW are available from EPA's Clean Air Markets Division (CAMD) in Air Markets Program Data (AMPD); annual generation, capacity, ownership, fuel consumption, fuel cost, retail demand, and retail rates available from Energy Information Administration forms 860, 861, and 923.

optimization-based production cost models can easily incorporate most of the technical details that characterize different electricity generation technologies, but require a greater effort to interpret the results. In general, all energy modelers should recognize that modeling exercises are meant to be indicative and their outputs are not fixed in time; as economic, technological, policy, and even political realities change, models must be updated and re-calibrated. Nonetheless, models are meant to inform planners and policymakers in their decisions in light of potential and/or likely futures as represented in a set of assumptions, and their value should be taken as such.

The modeling choice for a particular compliance pathway will depend on multiple factors, including the purpose of the exercise, the resources of the entity sponsoring or conducting the modeling, and the availability of data to inform the modeling process. The purpose of the modeling exercise may range across a variety of needs: informing a stakeholder process or informing an advocacy position, determining the least cost compliance pathway for a state, providing a performance demonstration to EPA, or determining equitable allowance distribution systems.

8.1. Screening analysis

Screening Analysis

Screening analyses may be useful tools for stakeholders involved in early compliance plan development, as well as starting points for more in-depth modeling studies. These non-optimization approaches are broadly accessible to non-experts, transparent, and provide an aggregate view of potential emissions reduction opportunities. The main advantage of non-optimization approaches is that the relationships between the different variables in the system are made explicit through a set of rules. This makes the models more transparent and facilitates the interpretation of the results.

Several parties have developed specific Clean Power Plan compliance tools that track affected units and allow users to review the impact of selected emission reduction strategies, such as the re-dispatch of natural gas units, the deployment of energy efficiency and renewable energy, and retirement of selected units.[44] Users are able to examine tradeoffs between strategies and estimate the rough degree to which different strategies should be employed to reach specific targets. Some of these models are able to incorporate rough cost estimates for different compliance strategies.

The purpose-built Clean Power Plan compliance screening analyses are all designed to engage stakeholders in productive and informed discussions about potential strategies, the depth of emissions

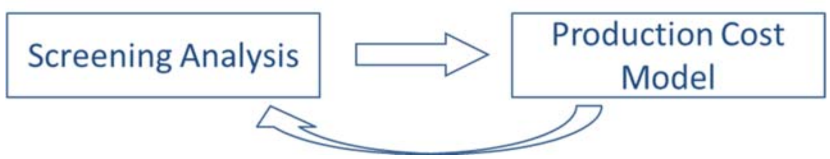
[44] See CP3T from Synapse Energy Economics (http://www.synapse-energy.com/tools/clean-power-plan-planning-tool-cp3t), MJ Bradley Clean Power Plan Evaluation Tool (http://www.mjbradley.com/about-us/case-studies/clean-power-plan-evaluation-tools), and Energy Strategies CPP Evaluation Model Tool (http://www.westernstatecppmodeling.org/).

reductions required, and even the costs of compliance. They serve as educational tools and provide the opportunity to rapidly review multiple scenarios at very low computational cost.

However, because these purpose-built screening-level analyses are not economically driven, they cannot account for changing economic drivers (i.e. fuel prices and/or emissions costs), or capture how new resources impact dispatch. Further, because they are not based on optimization algorithms, the solution provided is not necessarily least cost, or otherwise optimal. This can make it very difficult to accurately characterize the effects of particular emissions policies that individual states might adopt. Dispatch decisions (including the displacement from energy efficiency and renewable energy) and economic tradeoffs (such as how units respond to different emissions prices, or other short-term opportunity costs) must generally be input based on simple rough merit order assumptions or estimated from other optimized models. Decisions to retire existing units or build new units require a set of heuristic rules, or are manually determined. Finally, screening analyses have difficulty taking into account the impact of cross-state electricity and emissions trading. Nonetheless, these types of analyses can produce useful and indicative results.

Screening models alone would likely be insufficient to provide a performance demonstration to EPA for either mass-based state measures plans (M3/M4) or rate-based plans with non-subcategory or non-state average rates (R3).

8.2. Screening analysis with dispatch optimization



One of the disadvantages of a screening-level analysis is the difficulty of representing the technical operational detail of the EGUs, emissions caps, or the decision to develop new clean energy resources. Therefore, the results produced by a screening-level analysis may not always be technically feasible, due to various constraints that are not fully captured by the model. This can be addressed by coupling the screening analysis with a production cost model that captures all the technical operating limits of the EGUs, as well as the uncertainty and variability in demand and renewable resource availability over an appropriate time horizon. This would guarantee that the solution produced by the screening analysis is operationally feasible and generates a more accurate assessment of the results. This approach might employ the screening analysis and production cost model in an iterative cycle, where the production cost model informs the expected dispatch of units in the screening analysis, and the screening analysis informs the buildout of units utilized in the production cost model.

This type of framework could be directly applied using models that are readily available to almost all electric utilities, and still allow stakeholders and non-experts to utilize the user-friendly interface of a screening model. Production cost models still require a great deal of EGU-specific input information, much of which may be proprietary. These models generally require significant expertise to operate, interpret and adjust, but are in common usage by electric utilities.

The combination of a screening model with a production cost model might be sufficient to provide a performance demonstration to EPA for either mass-based state measures plans (M3/M4) or rate-based plans with non-subcategory or non-state average rates (R3). This type of analysis, however, cannot guarantee that a state will follow the delineated capacity buildout path (i.e. new EE/RE, or expected retirements), unless such a buildout is required by state law.

8.3. Downscaling national models

National-scale capacity-expansion models may make an appearance in many state compliance planning exercises, either as the backdrop for national commodity price forecasts, or in the foreground as a primary modeling tool in the analysis of Clean Power Plan compliance. Many state air quality managers have broad familiarity with the Integrated Planning Model (IPM), used by EPA for policymaking and by some states for air quality compliance planning. Broad-scale tools have the advantage of both reasonable familiarity, and the ability to capture interstate interactions, but may not fully capture the details of individual EGUs or specific state actions. In general, these models aggregate individual EGUs into “typical” or “representative” plants, which carry common characteristics but not individual EGU features.

Federal policymakers currently rely on national-scale models for policy analysis, long-term energy assessments, and commodity price forecasting. For example, over the last decade, EPA has relied on IPM[45] and the Energy Information Administration (EIA) runs the National Energy Modeling System (NEMS). In recent years, the National Renewable Energy Laboratory (NREL) has developed the Renewable Energy Deployment System (ReEDS) model, similar in scope to IPM. By virtue of their regional scale, these models are not EGU specific, but they do contain substantial information about existing units and the potential for new units. They are also currently the most accessible selection of optimization models available to states – either through use of pre-fabricated runs produced by using IPM runs from EPA regulatory assessments, NEMS runs from EIA, or via the publicly sponsored ReEDS model.[46]

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[45] http://www.epa.gov/airmarkets/documentation-base-case-v513-using-integrated-planning-model

[46] EIA’’s NEMS model is also publicly sponsored and is freely available.

One possible compliance modeling pathway uses these models to examine a range of regional and/or national policies, and then "downscale" the results at the state level by estimating individual state EGUs outcomes using the aggregate representative plants. The national-scale model could be preceded by a screening-level analysis to narrow the range of possible compliance pathways, and an iterative process might be used to then re-calibrate the screening model with outcomes from the national-scale model. This would provide a fair amount of detail, flexibility to users of the screening analysis, and the advantages of an optimization framework. Similarly, capacity results from the regional model could be used in a production cost model to assess if the resulting generation capacity mix is operationally feasible.

States interested in exploring how changes in the electric sector might impact other sectors might choose to use a multi-sectoral model in conjunction with the capacity expansion framework. Yet, this analysis should not be strictly necessary to prove compliance with the Clean Power Plan.

A downscaled regional model might be sufficient to provide a performance demonstration to EPA for either mass-based state measures plans (M3/M4) or rate-based plans with non-subcategory or non-state average rates (R3).[47] The state would have to be able to show that its assumptions about individual units were valid even after taking into account model plant aggregations.

8.4. EGU-specific capacity expansion

States with a history of performing Integrated Resource Planning (IRP) are broadly familiar with a class of capacity expansion models used to perform planning for individual utilities, or at the state scale. These models provide an opportunity for states to engage in detailed compliance planning, with a suite of industry-standard tools. Some of these tools are able to examine cost-effective EGU retirements, accounting for other capital requirements, system reliability constraints, and transmission constraints. All of them are able to build an optimized portfolio given an estimate of future commodity prices, expected capital expenses, and maintenance requirements for individual units and new EGU types.

These models require detailed inputs about each individual EGU, and may require otherwise proprietary data. However, if a state is able to coordinate with its utilities, much of this data may be readily available and part of existing analysis frameworks. Utility-scale capacity expansion models sometimes portray their area of concern (i.e. a utility, or group of utilities) in isolation to their surrounding region. For the

[47] States that choose mass-based (M1/M2) or rate-based (R1/R2) emission standard plans do not need to provide a performance demonstration to EPA.

purposes of compliance planning, it is important to ensure that a model takes into account the actions of surrounding states. For example, if the model assumes that no other states comply with the Clean Power Plan, it might underestimate wholesale market prices at state borders, and misrepresent future imports, exports, and other interstate interactions.

One likely compliance modeling pathway draws primarily on utility-scale capacity expansion models, but narrows the range of compliance scenarios through the use of a screening analysis. Similarly to the regional downscaled capacity expansion model, this modeling pathway might iterate with the screening analysis to provide stakeholders more detailed model results. Moreover, the outputs of this model might also be integrated into a multi-sectoral model to examine how policies impact non-electric sector participants.

A utility-scale capacity expansion model would likely be sufficient to provide a performance demonstration to EPA for either mass-based state measures plans (M3/M4) or rate-based plans with non-subcategory or non-state average rates (R3). However, states would have to demonstrate the mechanism used to generate allowance trading prices if used for M3/M4 demonstrations. Regulators should be aware that some of these models are operated with the assumption of state or utility isolation from wholesale markets. This assumption, sometimes seen in utility use of capacity expansion models may prevent a state from realizing likely compliance outcomes. These models do provide EGU-specificity as required for state demonstrations.

8.5. Comprehensive integrated planning

One of the most comprehensive mechanisms of compliance modeling utilizes a full suite of models to capture a range of scales and dynamics simultaneously. The mechanism first employs a national-scale model to capture interstate interactions, wholesale market electric prices, allowance and/or emission rate credit (ERC) trading prices, and possibly other commodity prices (depending on the scope of the model). The regional and state prices are then used as boundary conditions on a utility-scale capacity expansion model, which is used to simulate individual EGU build and retirement decisions that meet compliance requirements in the state, given allowance and/or ERC trading prices and dynamics in other states. The capacity choices made by the utility-scale capacity expansion model are then used directly in a production cost model that simulates hourly chronological dispatch to arrive at an estimated annual cost and identify any operational constraints imposed by the compliance plan. This mechanism is used in some IRPs for normal planning purposes, but can also be employed for compliance planning purposes.

The comprehensive integrated planning mechanism requires a number of models and a significant degree of modeling expertise. The process, however, is familiar to utilities that perform integrated planning for regulatory filing purposes.

The advantages of this mechanism are its comprehensive treatment of regional and state resources, its ability to balance both long-term planning considerations and operational considerations, and the rigor of the modeling entailed. However, the utilization of multiple models creates a framework that is inaccessible to many stakeholders. Aside from participation in screening analyses and review of outcomes, it is difficult for even highly informed stakeholders to participate in a process dominated by proprietary and highly complex models.

This modeling pathway would likely be sufficient to provide a performance demonstration to EPA for either mass-based state measures plans (M3/M4) or rate-based plans with non-subcategory or non-state average rates (R3).

9. Conclusions and Recommendations

A wide range of models and analysis frameworks exist for states to examine least-cost compliance pathways for the Clean Power Plan.

Several freely available and open-access screening level tools have been designed to assist states and stakeholders in exploring a variety of compliance plans. These screening models, tuned to the specific requirements of the Clean Power Plan, provide a useful stakeholder engagement mechanism, are readily available, and are generally user-friendly.[48] States should consider encouraging stakeholders to begin engaging with these analysis tools to understand the state's targets and options towards meeting Clean Power Plan requirements. However, states will probably not want to rely on these tools as their sole mechanism of determining a final compliance pathway: these tools cannot capture interstate impacts, adequately model economic decisions, or represent operational constraints. One risk in using these tools alone is that states may substantially over- or underestimate compliance requirements and costs. Therefore, in many cases it may be in a state's best interest to ultimately use more detailed, industry-standard models, populated with accurate data, to ensure that a compliance plan is cost-effective, equitable, and achievable.

One concern often posed by states is that industry-standard tools are expensive and require significant expert use. State environmental and utility regulators often have shallow budgets and many do not have

[48] See Synapse Energy Economics Clean Power Plan Planning Tool (CP3T) (http://www.synapse-energy.com/tools/clean-power-plan-planning-tool-cp3t), MJ Bradley Clean Power Plan Evaluation Tool (http://www.mjbradley.com/about-us/case-studies/clean-power-plan-evaluation-tools), Energy Strategies' CPP Evaluation Model (http://www.westernstatecppmodeling.org/) and State and Utility Pollution Reduction Calculator (SUPR) (http://aceee.org/research-report/e1601)

the in-house expertise to operate, or even evaluate or audit, proprietary models. However, utilities, state utility regulators, independent power producers, consumer advocates, and other regular participants in electric sector proceedings also have awareness and expertise in the practical use of energy systems models. Furthermore, the decisions made during this regulatory process will generate significant revenues and/or losses for different parties, including generation owners, clean energy providers, and consumers. Even if the cost of compliance is fairly low, there will be significant revenue transfers between parties. In 2014, the U.S. electric sector generated nearly $400 billion in revenues. A single power plant can consume tens of millions of dollars in labor and maintenance expenses, and hundreds of millions in fuel expenses per year. The cost of performing a credible and defensible optimization-driven analysis is relatively small when considered in this context.

Some states may have the opportunity to leverage utility models and/or expertise without relying on the regulated entities to generate the compliance plan or regulatory policy. States may be able to access utility models, or work with utilities to license models, or share costs in providing detailed modeling. In almost all cases, it is in participants' best interests to have accurate representations of the electric sector for regulatory purposes.

Over the course of 2016 and 2017, states will begin structuring compliance plans, and will likely seek additional guidance from EPA on which planning mechanisms are sufficient or expected. Some early action states have already begun intensive stakeholder-engaged compliance analyses, and may be able to share important lessons learned with states just beginning to engage in the process.

APPENDIX A: CLEAN POWER PLAN CO_2 PERFORMANCE PROJECTION REQUIREMENTS

General Requirements

States that are required to submit a formal CO_2 performance projection (those choosing the R3, M3, or M4 pathways described on page 2) need to demonstrate that the emission standards and/or state measures included in its plan will lead to CO_2 emission rates or emission goals that are at or below the designated goals. This demonstration will involve a quantitative analysis that appropriately links the effects of the standards and measures in a State Plan to actual CO_2 emissions in the state.

Instead of prescribing a specific methodology or tool, EPA has designated a set of features a satisfactory CO_2 projection would embody, followed by a list of specific projection requirements based on State Plan type. EPA plans to review and assess states' CO_2 projection methodologies for reasonableness, and will take the following into consideration in doing so:

- ✓ The emissions projection must use technically sound *methods* that are reliable and replicable.
- ✓ The State Plan submittal must explain *why* the projection method or tool is appropriate for assessing the emission performance of the particular State Plan in question.
- ✓ The State Plan submittal must explain *how* the emissions projection method or tool it has chosen works.
- ✓ The State Plan submittal must explicitly document all assumptions used by the state in preparing its emissions projection such that the results of the analysis are reproducible, *and* the assumptions themselves represent a "logically consistent future outlook" of the electric power system.
- ✓ The geographic area used for the emissions projection must be appropriate for capturing impacts and/or changes in the electric power system.

Specifically, documentation for emissions projections during final State Plan submittal must include, when applicable, the following:[49]

- Geographic domain considered in the analysis, and its representation
- Time period of analysis (must extend through 2031, at a minimum)

[49] Federal Register, FR 80 64865.

- Electricity demand forecast (MWh load and MW peak demand) at the state and regional level, with supporting documentation if not from a standard publicly available source (e.g., EIA, NERC, ISO/RTO)
- Planning reserve margins
- Electricity generation capacity, including planned new capacity, and analytic treatment for making capacity expansion decisions
- Wholesale electricity prices
- Fuel prices and fuel CO_2 content
- EGU-level fixed O&M costs, variable O&M costs, capacity, and heat rates
- EGU-level (EGU-specific) actions (e.g., heat rate improvements) that are being used to meet CO_2 emission reduction goals
- Assigned federally enforceable emission standard for each affected EGU
- EGU-level annual electricity generation (MWh) by fuel type and CO_2 emission levels
- Written explanations about the features and capabilities of the modeling tool used, and why it was chosen for emissions projection in this context.

Beyond these general documentation requirements, there are several additional requirements dependent on the compliance pathway chosen.

Additional Requirements for R3 States

States with plans that have unique emission standards for affected units (R3), must demonstrate that the average CO_2 emission rate of affected units, when weighted by their generation (in MWh) will be equal to or less than the subcategory-specific CO_2 emission performance rates or the state's rate-based CO_2 emission goal during the interim and final compliance periods. States can also be awarded Emissions Reduction Credits (ERCs) for electricity generated by new renewable and new nuclear capacity, as well as through verifiable reductions in electricity demand as a result of energy efficiency programs. Accordingly, the achieved average CO_2 emissions rate that will be compared against the Clean Power Plan state-specific targeted rate can be obtained by the following formula:

$$Avg. emissions\ rate = \frac{Total\ CO_2\ emissions\ from\ existing\ fossil\ fueled\ plants}{Total\ gen. from\ existing\ fossil\ fueled\ plants + Emissions\ Reduction\ Credits}$$

EPA specifies that for these states:

> **The projection will involve an analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a state. It must accurately represent the emission standards in a plan, including the use of market-based aspects of the emission standard (if applicable), such as use of ERCs or emission allowances as compliance instrument.**[50]

In addition to the general requirements above, projection documentation for emission standards plans should include, when applicable:[51]

(continued from the General Requirements lists above)

- A projection of how generation shifts between affected EGUs and between affected and non-affected EGUs over time
- Assumptions about the availability and expected use of ERCs (intra-state only is allowed under an R3 compliance pathway)
- The precise calculation or assumption being used to determine how affected EGU CO_2 emission rates are being adjusted using ERCs
- Intra-state market ERC prices
- Inter-state ERC market prices, regional and national, and assumptions about wholesale energy price interactions (and imports and exports) with ERC market prices
- Power purchase agreements and related documentation about the use of renewable energy resources in mass-based states for adjusting the CO_2 emission rate of its affected units
- Any other applicable assumptions and documentation used

Additional Requirements for M3 and M4 States

For state measures plans, a state will need to demonstrate that its emission reduction measures, as well as any federally enforceable emission limits that may be part of its plan, will achieve the state's mass-based CO_2 goals for the interim and final compliance periods.

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50 Federal Register, FR 80 64846.

51 Ibid.

EPA specifies that for these states:

> **Because different types of state measures could have varying degrees of impact on reducing or avoiding CO_2 emissions from affected EGUs, and different state measures may interact with one another in terms of CO_2 emission reduction impacts, the method and tools a state uses to project CO_2 emissions impacts must have the capability to project how the combined set of state-enforceable measures are likely to impact CO_2 emissions at affected EGUs.**[52]

In addition to those listed in the general requirements above, projections and submittal documentation for state measures State Plans must include, when applicable:[53]

(…continued from the General Requirements lists above)

- Individual state measures, including timing of their implementation and their impacts over time
- Assumptions about the availability and expected use of mass-based allowances (through intra- and/or interstate trading program)
- Intra-state allowance prices
- Inter-state allowance prices, regional and national, and assumptions about wholesale energy price interactions (and imports and exports) with allowance market prices
- Impacts of eligible renewable energy and demand-side energy efficiency measures[54]
- All other applicable assumptions and documentation used, including but not limited to, documentation about alternative "flexibilities" such as out-of-sector greenhouse gas offsets and cost-containment mechanisms

52 Ibid.

53 Ibid.

54 The final rule technical support document (TSD), "Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations" provides guidance on quantifying the impact of eligible renewable energy and demand-side energy efficiency programs.

Appendix B: Modeling Tools Reference List

Model Classification	Model/Tool Name	Website
Production Cost Models	PROSYM (ABB)	http://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis
	PLEXOS (Energy Exemplar)	http://energyexemplar.com/software/plexos-desktop-edition/
	Gentrader (PCI)	http://www.powercosts.com/solutions-products/gentrader/
	AURORAxmp (EPIS)	http://epis.com/aurora_xmp/
	MAPS (GE)	http://www.geenergyconsulting.com/practice-area/software-products/maps
Utility-Scale Capacity Expansion Models	System Optimizer (ABB)	http://new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/system-optimizer-strategist
	Strategist (ABB)	
	PLEXOS cap expansion (Energy Exemplar)	http://energyexemplar.com/software/plexos-desktop-edition/
	AURORAxmp (EPIS)	http://epis.com/aurora_xmp/
	Resource Planning Model (NREL)	http://www.nrel.gov/analysis/models_rpm.html
National-Scale Capacity Expansion Models	IPM (ICF)	http://www.icfi.com/insights/products-and-tools/ipm
	ReEDS (NREL)	http://www.nrel.gov/analysis/reeds/
	NEMS Electricity Market Module (EIA)	http://www.eia.gov/forecasts/aeo/assumptions/
	HAIKU (Resources for the Future)	http://www.rff.org/research/publications/rff-haiku-electricity-market-model
	POM (Navigant Consulting)	https://www.navigantresearch.com/
Multi-sector models	MARKAL (IEA ETSAP)	http://www.iea-etsap.org/web/Markal.asp
	NE-MARKAL (NESCAUM)	http://www.nescaum.org/topics/ne-markal-model
	NEMS (EIA)	https://www.eia.gov/forecasts/aeo/info_nems_archive.cfm
	EPPA (MIT)	http://globalchange.mit.edu/research/IGSM/eppadl
	NewERA (NERA Economic Consulting)	http://www.nera.com/practice-areas/energy/newera-model.html
Non-Optimization Approaches	EGU Growth Tool (ERTAC)	http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation
	AVERT (EPA)	http://www3.epa.gov/avert/
	CP3T (Synapse)	http://www.cp3t.com
	CPP Planning Tool (MJ Bradley)	http://www.mjbradley.com/about-us/case-studies/clean-power-plan-evaluation-tools
	SUPR (ACEEE)	http://aceee.org/state-and-utility-pollution-reduction-supr
	CPP Evaluation Model (Energy Strategies)	http://www.westernstatecppmodeling.org/
	STEER (AEEI)	http://info.aee.net/steer
	LEAP (Stockholm Environment Institute)	http://www.energycommunity.org/default.asp?action=47