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Renewable Energy and Efficiency Modeling Analysis Partnership (REMAP):

An Analysis of How Different Energy Models Addressed a Common High Renewable Energy Penetration Scenario in 2025

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Technical Report
NREL/TP-6A2-45656
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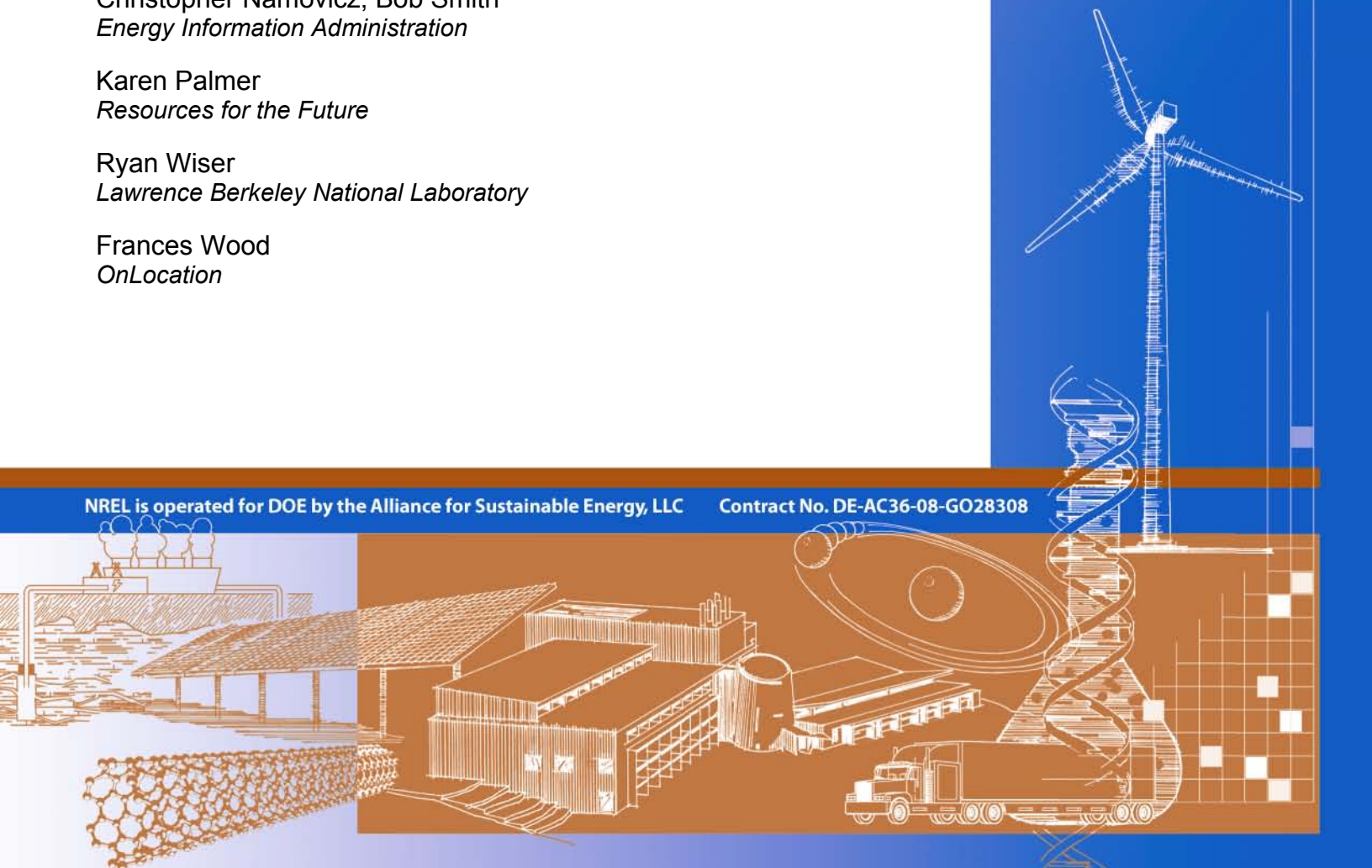

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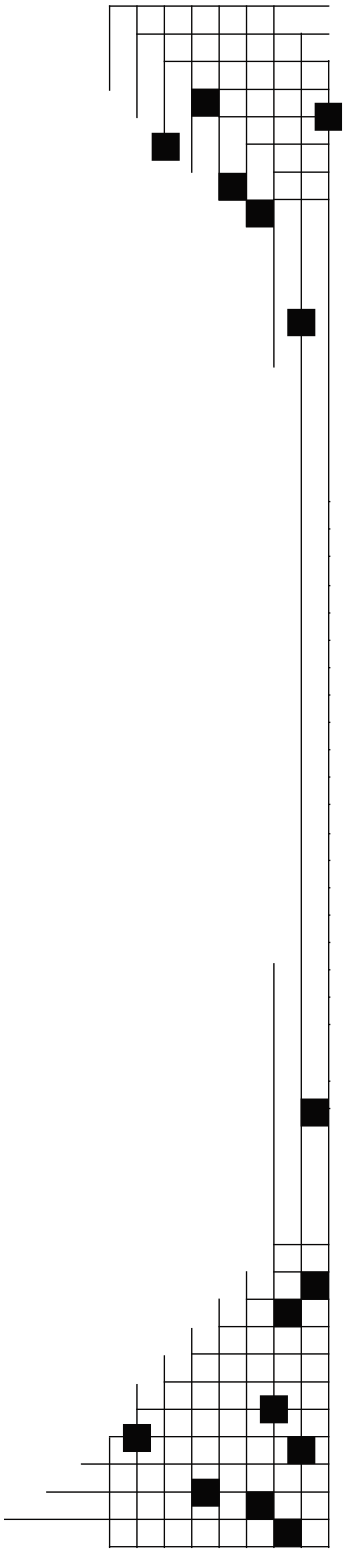

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Finally, we would like to thank our co-authors and other participants for their extensive contributions and engagement over a lengthy period of time; many participated without specific funding support. See the table of participants on Page 4 for a complete list.

List of Acronyms

ACEEE	American Council for an Energy-Efficient Economy
ACORE	American Council on Renewable Energy
AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
BNL	Brookhaven National Laboratory
CCS	carbon capture and sequestration
DOE	Department of Energy (U.S.)
EERE	Energy Efficiency and Renewable Energy (Office of)
EIA	Energy Information Administration
EMF	Energy Modeling Forum
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IGCC	integrated gasification combined cycle
IPM	Integrated Planning Model
ITC	investment tax credit
LBNL	Lawrence Berkeley National Laboratory
MACRS	Modified Accelerated Cost Recovery System
MARKAL	Market Allocation for New England
MIT	Massachusetts Institute of Technology
MSW	municipal solid waste
NEMS	National Energy Modeling System
NESCAUM	Northeast States for Coordinated Air Use Management
NREL	National Renewable Energy Laboratory
PTC	production tax credit
PV	photovoltaics
RE	renewable energy
REC	renewable energy certificate
ReEDS	Regional Energy Deployment System model
REMAP	Renewable Energy and Efficiency Modeling Analysis Partnership
REMI	Regional Economic Models Inc.
REMS	Renewable Energy Modeling Series
RFF	Resources for the Future
RPS	renewable portfolio standard
SEDS	Stochastic Energy Deployment System model
UCS	Union of Concerned Scientists
WACC	weighted average cost of capital
WinDS	Wind Deployment System model

Executive Summary

Energy system modeling can be intentionally or unintentionally misused by decision-makers. This report describes how both can be minimized through careful use of models and thorough understanding of their underlying approaches and assumptions. The analysis summarized here assesses the impact that model and data choices have on forecasting energy systems by comparing seven different electric-sector models.[1] This analysis was coordinated by the Renewable Energy and Efficiency Modeling Analysis Partnership (REMAP), a collaboration among governmental, academic, and nongovernmental participants.

The study demonstrates that:

- Different models and different technology and market assumptions can lead to widely different predictions of system outputs.
- Even when technology and market assumptions are aligned as closely as possible, substantive differences still remain.

To enable a comparison among various energy models, the group decided on a common scenario that all of the models could address. The group selected a penetration goal of 20% renewable energy generation in the electric sector by 2025, and conducted two broad sets of model runs:[2]

- A group of unaligned **Base Case** runs where modelers were allowed to use their own standard input assumptions including those for technology costs, fuels costs, and physical resources to achieve the target.
- A group of aligned **Tier 1 Case** runs, where future technology and fuel costs, financial assumptions, and even resource supply curves were aligned to the extent possible to achieve the goal. This was done to separate the impact of inputs from structural differences in the models. This alignment will likely not happen in typical model use.

We found that in both the aligned and unaligned cases, there was significant difference in the estimated output metrics, although the difference in predicted outcomes narrowed in the aligned case. Our analysis suggests that:

- Due diligence needs to be exercised by policy- and decision-makers when presented with findings from a single model. Assumptions and model choices can lead to significantly different outcomes. For example, simple choices in future capital costs may result in a particular technology appearing dominant or marginal. Similarly, different models using identical technology and market assumptions might predict substantively different outcomes due to their structural differences.
- Where possible, a variety of models using similar assumptions should be used to give the decision-maker a sense of differences in outcomes that reflect inherent uncertainties in the models, recognizing that some models are better suited to resolving certain questions than others. For example, if the policy goal is to understand the role of transmission to facilitate variable renewable energy supplies, a geospatial, disaggregated model, such as the Regional Energy Deployment System (ReEDS) model, would likely provide more informed results. At a

[1] These models are IPM, HAIKU, NEMS-EIA, NEMS-GPRA, WinDS, NE-MARKAL as well as a stochastic model SEDS (see Page 4 for full names).

[2] Because this RE scenario did not include hydroelectric power, which makes it an approximately tenfold increase over RE energy in 2008 in terms of new build (compared with overall generation), the proportion is much greater.

minimum, there needs to be thoughtful selection of the single model that is most appropriate for the question at hand.

- Sensitivity analysis must be considered. Whether using one or multiple models, scenarios with varying assumptions about technology cost and market assumptions is desirable to understand how resilient model outcomes and predictions are to such underlying assumptions.

Figure ES-1 illustrates how aligning common assumptions can tighten output ranges. It shows the percentage reduction in carbon emissions relative to the reference cases for both the Base Case and the Tier 1 Case.[3] This figure shows:

- The variation in carbon savings among models for the Base Case is significant.
- The variation among the models for the Tier 1 Case is also significant, although notably smaller. This is expected because penetration differences among technologies are expected to be smaller due to closer alignment of technology, capital, O&M costs, fuel costs, and other factors.

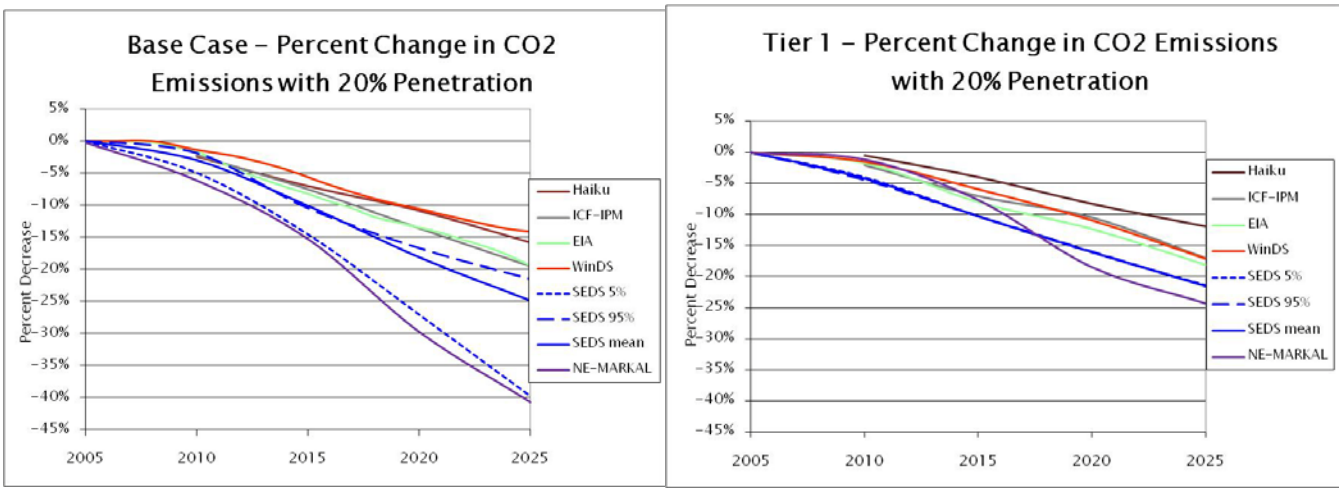

Figure ES-1. The percentage reduction in carbon emissions relative to the reference cases for both the Base Case and the Tier 1 Case

This report details the process, participants, and technical results associated with the REMAP activity. It is intended to provide guidance to both policymakers and modelers when evaluating the inputs to and outputs from modeling.

[3] This report remains neutral on policy recommendations and does not necessarily support an RPS.

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Introduction

The Renewable Energy and Efficiency Modeling and Analysis Partnership (REMAP) sponsors ongoing workshops to discuss individual "renewable" technologies, energy/economic modeling, and—to some extent—policy issues related to renewable energy. Since 2002, the group has organized seven workshops, each focusing on a different renewable technology (geothermal, solar, wind, etc.). These workshops originated and continue to be run under an informal partnership of the Environmental Protection Agency (EPA), the Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), the National Renewable Energy Laboratory (NREL), and the American Council on Renewable Energy (ACORE). EPA originally funded the activities, but support is now shared between EPA and EERE.

REMAP has a wide range of participating analysts and models/modelers that come from government, the private sector, and academia. Modelers include staff from the Energy Information Administration (EIA), the American Council for an Energy-Efficient Economy (ACEEE), NREL, EPA, Resources for the Future (RFF), Argonne National Laboratory (ANL), Northeast States for Coordinated Air Use Management (NESCAUM), Regional Economic Models Inc. (REMI), ICF International, OnLocation Inc., and Boston University. The working group has more than 40 members, which also includes representatives from DOE, Lawrence Berkeley National Laboratory (LBNL), Union of Concerned Scientists (UCS), Massachusetts Renewable Energy Trust, Federal Energy Regulatory Commission (FERC), and ACORE.

This report summarizes the activities and findings of the REMAP activity that started in late 2006 with a kickoff meeting, and concluded in mid-2008 with presentations of final results. As the project evolved, the group compared results across models and across technologies rather than just examining a specific technology or activity.[4] The overall goal was to better understand how and why different energy models give similar and/or different answers in response to a set of focused energy-related questions. The focus was on understanding reasons for model differences, not on policy implications, even though a policy of high renewable penetration was used for the analysis.

A group process was used to identify the potential question (or questions) to be addressed through the project. In late 2006, increasing renewable energy penetration in the electricity sector was chosen from among several options as the general policy to model. From this framework, the analysts chose a renewable portfolio standard (RPS) as the way to implement the required renewable energy market penetration in the models. An RPS was chosen because it was (i) of interest and represented the group's consensus choice, and (ii) tractable and not too burdensome for the modelers. Because the modelers and analysts were largely using their own resources, it was important to consider the degree of effort required. In fact, several of the modelers who started this process had to discontinue participation because of other demands on their time.

Federal and state RPS policy is an area of active political interest and debate. Recognizing this, participants used this exercise to gain insight into energy model structure and performance. The results are not intended to provide any particular insight into policy design or be used for policy advocacy, and participants are not expected to form a policy stance based on the outcomes of the modeling.

[4] The title of the series was changed to REMAP from the Renewable Energy Modeling Series (REMS) to reflect that.

The goals of this REMAP project—in terms of the main topic of renewable penetration—were to:

- Compare models and understand why they may give different results to the same question,
- Improve the rigor and consistency of assumptions used across models, and
- Evaluate the ability of models to measure the impacts of high renewable-penetration scenarios.

Once the general topic had been determined, the group formed three teams with overlapping members to develop the structure and implement the activity. The teams covered:

- Technology Assumptions (Lead: Chris Namovicz, EIA),
- Policy Assumptions (Lead: Ryan Wiser, LBNL), and
- Coordination and Planning (Leads: Nate Blair and Thomas Jenkin, NREL).

This report describes the process and participants, the structure of the analysis, and the overall results comparing the different models. The report is structured as follows:

- A description of the general process, timing, and participants
- The Base Case: Methodology and Runs
- The Tier 1 Case: Methodology and Runs
- Base Case Results – Overview
- Tier 1 Results – Overview
- Summary Findings and Concluding Thoughts

The report also includes PowerPoint slides with each model's individual results in the Appendix.
A recent related study of interest by the Pew Center on Global Climate Change in May 2008 reviewed the analysis of six studies that modeled the Lieberman-Warner Climate Security Act (S. 2191). Large differences were observed in which technologies were used to meet the carbon cap, as well as the associated price of carbon. In many ways, this review is similar to our Base Case analysis because many of the differences reflect different, or unaligned, views on technological change and other factors.[5]

Several other organizations have also employed a model comparison strategy to examine potential future scenarios for renewable energy and other energy issues. The Stanford Energy Modeling Forum (EMF) is one of these groups. As of publication, they have two active studies related to renewable energy including "Study 22: Climate Change Control Scenarios" and "Study 25: Efficiency and the Shape of the Future Energy Demand." More about EMF and their studies can be found at:
http://www.stanford.edu/group/EMF/

[5] In this study, EIA was much more optimistic about the role of nuclear than the 2003 Massachusetts Institute of Technology (MIT) study, whereas MIT was much more optimistic about the penetration of carbon capture and sequestration (CCS). See the May 2008 presentation "Insights from modeling analyses of the Lieberman-Warner Climate Security Act (S. 2191)," by Janet Peace, and similarly titled Pew Center "In Brief" report.

Process and Participants

The following outlines the process structure and implementation activities:

1. The group decided by consensus on questions to address, and identified modelers (and their models) and analysts willing to participate. They formed three subgroups that focused on (1) technology, (2) policy, and (3) coordination, although many of these subgroups had common members (fall 2006).

2. The subgroups on policy and technology met to refine questions and the common technology and policy assumptions for different model runs (late 2006). NREL led the activity, but it involved a variety of the participants listed below.

3. The group held its first in-person meeting at the Department of Energy in Washington, D.C., to agree on refined questions, scenarios to be treated, and common assumptions (November 2006). At this time, the modelers presented an overview of each model, discussed the process and assumptions for the analysis, and determined a plan of action. In this meeting, the group envisioned two sets of high-penetration renewable energy runs (in addition, "natural" penetration reference cases). These cases included:

    - **Base Case runs,** where the models were all forced to achieve 20% RE penetration in 2025 by using their existing inputs for most parameters (e.g., technology costs, fuel prices). Guidelines on the RPS were provided to ensure some degree of consistency (e.g., annual rate of growth of RE).

    - **Tier 1 Case runs,** where the model inputs were aligned as closely as possible.

In this way, outputs from Base Case runs were anticipated to have significant differences for a variety of reasons. In contrast, the differences identified in Tier 1 Case runs would primarily reflect how different models gave different results when addressing a common question, and with mostly aligned common inputs and assumptions. In other words, the Tier 1 Case attempted to isolate the structural differences between the models and thus provide "deconstructive" insights.

The Base Case model runs were conducted in spring 2007, and resulted in an intermediate reporting activity for all the models involved. NREL consolidated these results into a preliminary document that was shared with all of the modeling teams.

The groups conducted analysis on Tier 1 runs. This also was done in 2007 and resulted in much greater agreement in model outputs due to the nature of Tier 1 process described below. Methodology and guidance were provided by the subgroups for policy, technology, and coordination.

The participants held a second in-person meeting in 2008 to present results of the analysis. After receiving the results from different models, NREL consolidated the information and used a variety of metrics to show how model results differed.

This final report focuses on the outputs of Base Case results and Tier 1 Case results, and presents the overall activity in a consolidated document.

REMAP Key Participants

The following participants ran models or contributed significantly to activity planning.

The REMAP exercise involved a much broader range of participants

EPA
- Eric Smith
- Joseph DeCarolis
- David Evans
- Elliot Lieberman

U.S. EIA
- Christopher Namovicz
- Bob Smith
- Susan Holte

NREL
- Nate Blair
- Thomas Jenkin
- James Milford
- Walter Short
- Patrick Sullivan

RFF
- Karen Palmer
- David Evans (now with EPA)
- Rich Sweeney

Redefining Progress
- James Barrett

ICF
- Boddu Venkatesh
- Kamala R. Jayaraman

OnLocation
- Frances Wood
- Mark Ditmer

International Resources Group
- Gary Goldstein
- Evelyn Wright

NESCAUM
- Gary Kleiman

ACEEE
- Skip Laitner

ACORE
- Michael Eckhart

U.S. DOE
- Michael Leifman
- Darrell Beschen
- Sam Baldwin

BNL
- Chip Friley

LBNL
- Ryan Wiser

Models/modelers used for both Round 1 and Tier 1 are listed below. Their individual presentations describing an overview of their models are located online at: http://www.nrel.gov/analysis/remap/meeting.html

ICF's Integrated Planning Model (IPM) (Elliot Leiberman – EPA)
HAIKU (Karen Palmer – RFF, David Evans – now EPA)
National Energy Modeling System (NEMS) (Chris Namovicz and Bob Smith – U.S. Energy Information Agency)
NEMS-GPRA (EIA's version of NEMS) (Frances Wood – OnLocation Inc.). Used for Round 1 only, because Tier 1 would replicate NEMS results from EIA.
Wind Deployment System (WinDS) (Walter Short, Patrick Sullivan, and Nate Blair – NREL)
Stochastic Energy Deployment System (SEDS) (Walter Short, Tom Ferguson, and James Milford – NREL)
Top-D, Bottom U CGE (Ian Sue Wing – Boston University). Round 1 only.
Market Allocation for New England (NE-MARKAL) (Evelyn Wright/Gary Goldstein – IRG/NESCAUM)

The Base Case: Methodology and Runs

An Introduction

The first set of runs completed by the modeling participants were known as the "Base Case" runs. These runs showed how similar—or different—the model outputs (such as capacity or generation by technology, carbon savings, the cost of electricity) would be without trying to do any deliberate alignment of the various inputs or assumptions. In essence, the differences between these runs reflected the combination of the inherent characteristics of the models and the variance in inputs. In contrast, the Tier 1 Case runs (discussed in the next section) attempted to align as many major input assumptions as possible so as to leave only the inherent characteristics of the models reflected in the outputs from the different models.

The Base Case activity consisted of three runs:

- A "current laws" business-as-usual case (in which each model runs to 2025 or later without any special modifications).
- A 20% national renewable energy target (again, without any special calibration other than imposing the 20% national target together with specified annual targets, and assumed to be implemented with national REC trade).
- A 10% national renewable energy target (again, without any special calibration other than imposing the 10% national target, assumed to be implemented with national REC trade).

The 10% run was added to the Base Case runs because the group thought that the results would be of interest—and because running a 10% case directly following the 20% case should be relatively efficient (rather than running this case later as part of the Tier 1 runs). It was later decided to drop the 10% penetration analysis for the Tier 1 analysis so that the results in this report are simplified between a "natural" penetration and 20% penetration scenario under the Base Case and Tier 1 Case.

For most models, it was reasonably apparent how to run these cases; but for some models (e.g., SEDS, the stochastic model), further discussion was required among modelers and subgroup members.

The coordination and planning subgroup provided specific guidance on implementing these runs, including information on outputs to be forecast and reported, along with an Excel form to be filled in with outputs from the Base Case runs. The Excel spreadsheet contained the following tabs:

- **Reference**: Contains structure for reporting outputs desired by the REMAP group and sample data from NEMS and REMI where available.
- **20% Renewable Energy**: Contains output structure and the renewable fraction desired for each year.
- **10% Renewable Energy**: Contains output structure and the renewable fraction desired for each year.
- **MACRS calculations**: Contains specific data for models that do not already implement a five-year renewable MACRS (Modified Accelerated Cost Recovery System) depreciation option.

- **AEO 2006 data**: Relevant electric-sector data from NEMS for the 2006 *Annual Energy Outlook* (AEO).

(Note: The desired outputs structure reflects data to be completed to the extent that the model already does it. It was not intended that the models would be modified to estimate outputs that they do not currently estimate. For example, the majority of the macroeconomic parameters will not be estimated by many models, and that was expected).

Detailed Assumptions for each Base Case Run

This section adds more detail regarding what was assumed in the Base Case runs as described briefly above.

Reference Case: Nonpolicy Case

As mentioned above, the modelers were allowed to use "native" assumptions. Within this framework, they were asked to assume "current laws" (including sunsets where applicable), recognizing that different models may interpret this differently. To reduce variations in critical inputs, NREL provided specific guidance. The modelers were asked to be consistent, if possible, in the following areas; and, in any case, to specify their assumptions:

Federal Production Tax Credit (PTC) duration – available for eligible projects built in 2007 and earlier; one-half PTC value for certain eligible technologies

- The PTC at the time of the analysis provided a tax credit of 1.9¢/kWh for wind, closed-loop biomass, and geothermal; and half that rate (0.95¢/kWh) for open-loop biomass, eligible hydropower, landfill gas, and municipal solid waste. Biomass projects built in the United States during this timeframe were likely to be open loop, so the half-PTC would apply. As of November 2006, projects had to be in service by January 2008 to be eligible for the current PTC. For those projects that came online before January 2008, the credit lasts for 10 years, and will increase on an annual basis at the rate of inflation. Modelers were told to assume that the PTC was not extended beyond the then-current December 2007 expiration date.[6]
- For models not able to represent the PTC and/or the 2007 expiration date, an exogenous accounting for its near-term impact on renewable capacity was acceptable. Year 2007 renewable installed capacity from the AEO 06**,** or the modeler's own estimate of near-term capacity additions, was (if possible) used as the starting point for affected capacity and/or forced into the model.
- It was also assumed that a PTC is also available to 6 GW of new nuclear capacity entering service through 2020. AEO 06 estimates that this will result in an additional 6 GW of nuclear capacity entering between 2010 and 2020.

Federal Investment Tax Credit (ITC) duration – 30% ITC available for commercial/utility and residential solar systems ($2,000 per system cap for residential systems) through 2007; 10% ITC for commercial/utility solar systems after 2007, as well as for geothermal projects (no residential ITC exists

[6] The American Recovery and Reinvestment Act extended the PTC through 2012 for wind power and 2013 for many other renewable energy suppliers.

after 2007). ITCs apply to photovoltaic (PV) and solar thermal electric projects of any size, and the 10% ITC applies to geothermal after 2007.

- For those unable to model the ITC directly, several options were suggested:
  - Through 2007
    - Reduce capital cost of commercial/utility PV and solar thermal electric by 30%
    - Reduce capital cost of residential PV by $670/kW or 7.5% (the $2,000 cap is assumed to be binding for systems that average 3 kW)
  - After 2007(for duration of model run)
    - Reduce capital cost of commercial/utility PV, solar thermal electric, and geothermal by 10%
  - If the modelers were able to model the long-term ITC for solar and geothermal after 2007, but not the short-term ITC available through 2007, they were asked to consider a forced-build approach similar to that recommended for the PTC above.

Accelerated Depreciation – The five-year Modified Accelerated Cost Recovery System (MACRS) was used for eligible renewable technologies. This allows affected plant owners to depreciate their renewable generation assets faster than allowed for most conventional generation assets (five years compared to 15 or 20 years). Guidance for using the MACRS depreciation and examples of its use were provided to the modelers.

Base Case – 20% Penetration by 2025

The key difference between the Base Case Nonpolicy run and the 20% Penetration by 2025 run was the added requirement of a 20% national renewable energy target by 2025. The modelers were given a trajectory of 3% in 2008, increasing by 1% each year to reach 20% by 2025. The RPS target represents a requirement of total renewable energy generation (at wholesale) as a percentage of "all sales" (at retail). The RPS requirement was achieved nationally through mandatory renewable energy targets on *all sales* in the United States, with national trade in renewable energy certificates (RECs), which presumably allows the target to be achieved in least-cost fashion on a national basis. The target applies to all electricity sales in the lower 48 or in all 50 states, depending on the resolution of the individual models. By "all sales," it was meant to include all retail electricity sales in the United States, *excluding* customer-sited self-generation. If possible, modelers should have assumed that eligible renewable self-generation (e.g., PV, biomass used on-site, etc.) does count toward the renewable energy target (i.e., they create RECs); however, the generation from these projects does not add to "all sales."[7] Also, note that by defining the generation standard as a percent of sales, transmission losses associated with renewable generation were ignored. Actual renewable energy use at retail as a fraction of retail sales will therefore be somewhat below 20%.

To meet the 20% penetration level, existing and new non-hydropower renewable resources were eligible including wind, geothermal, biomass, landfill gas, solar, ocean, and the fraction of biomass co-firing or any other multi-fuel facility. Both sides of the customer were counted, and thus self-generation was included. In contrast, hydropower and municipal solid waste (MSW), whether new or existing, were not eligible for renewable energy target.

[7] In some sense, then, these projects actually are worth more than utility supply projects, because they earn RECs and reduce retail sales.

No multipliers, set-asides, tiers, cost caps, or load exemptions were included in the 20% (so no preference for PV, for example). Additionally, there are no sunset dates for the requirement, so it must continue to be achieved after 2025, which is an important consideration even for those models that only run through 2025.[8]

Base Case – 10% Penetration by 2025

This 10% Penetration by 2025 run is identical to the 20% penetration run, but with a final 10% national renewable energy target by 2025. This is achieved by, again, starting at 3% in 2008 with an increase of 0.412% each year to reach 10% by 2025.

[8] A sunset date means that costs cannot be recovered by REC sales beyond the expiration date. Therefore, in the later years of the program, REC prices would be increased as project owners attempted to recover any above-market costs of new renewable generation within the allotted time.

The Tier 1 Case: Methodology and Runs

Following the Base Case runs, the modelers wanted to examine how their models would behave with as many of the model inputs aligned as possible. This activity required more work than the Base Case results, but allowed a separation of the intrinsic model characteristics and the model inputs. These can vary dramatically among different models and are a primary driver for the variation in outputs seen in the Base Case results. The primary guidance (described in detail below) was to use the NEMS inputs or *Annual Energy Outlook* (AEO) results (sometimes in combination) from the AEO 2006 volume. This data set was chosen for its breadth of data and the fact that it was already collated and easily presentable to the modelers. In fact, many were already using a variety of data from this source. A few key points need to be made before providing the specific guidance below.

- The REMAP group recognized that most teams were doing these runs with other activities. Therefore, even though the group was trying to calibrate inputs and factors as described below, it did not expect that all models would be able to follow all the guidance without, in some cases, significant changes to their model—and such changes were outside the scope of this project. It is important to note that the group was not asking the modelers to make such changes where they were burdensome and/or fundamentally changed the nature of the model. However, the coordinators asked the modelers to offer a detailed explanation of how their model and/or assumptions differed from the guidance, which was necessary to better understand differences among models when comparing the outputs of Tier 1 (and earlier) runs.
- The group discussed whether to use AEO 2006 or AEO 2007 assumptions and/or outputs as the basis for the Tier 1 analysis. Because AEO 2007 was newer, the coordinators originally thought it would be the better choice. However, based on feedback, it was decided to continue using AEO 2006 (with some modifications to the wind and geothermal resource) for both the Reference Case and the 20% Renewables Case. This decision was based on concern for the additional work required to change to the 2007 data, but also allowed modelers to better compare Tier 1 results to the previously concluded (in most cases) Base Case runs that had used 2006 data.
- The coordinators encouraged modelers to use the "input assumptions" to the AEO 2006 where possible. However, because of the variety of model structures, some models required the use of "output data" from the AEO 2006 *or* the EIA 20% run to be used as their input. For example, natural gas prices are determined endogenously within NEMS/AEO, based on assumptions such as drilling cost and resource availability. Most other models either use a different approach to determining natural gas prices, or use a fixed schedule of natural gas prices. In these cases, the preference was toward using the AEO 2006/EIA 20% run output for natural gas. It was important that output be used from the matching run because gas prices (or other key outputs/inputs) may change from the Reference Case to the 20% Case.

As mentioned above, the group decided to use primarily EIA values from the AEO 2006 reference case and a 20% renewables scenario generously run by Chris Namovicz at EIA. Also, because of the extra effort involved to calibrate models to the appropriate EIA inputs, we did not ask modelers to report results for a 10% renewables scenario (only a baseline case and a 20% scenario). Further details for the Tier 1 Case include:

- **Appropriate Scenario Use –** In all calibration recommendations, EIA provided the appropriate inputs as described below for the AEO reference case and 20% renewables case. The coordinators instructed modelers to use the appropriate demands, prices, etc. for *both* the reference scenario and the 20% renewables scenario.

- **Technology Costs/Performance** – The group instructed modelers to use the provided EIA data for current and future costs and performance of all conventional power and renewable energy sources.
    - If the model included technology learning, modelers were instructed to try to match the technology-specific learning assumptions from EIA (and not just take costs/performance data).
    - If the model did not have the capacity to model technology learning, modelers were instructed to try to match the outcomes of NEMS in the appropriate case in terms of cost/performance of technologies.
    - Investment assumptions: Weighted average cost of capital (WACC) over time and other finance-based assumptions were provided by EIA. Modelers were instructed to use a simplifying approximation so that all technologies have the same WACC.

- **Electric Loads** – The modelers were instructed to use provided EIA data to calibrate the current electricity load and future load growth in their model.
    - If the model calculates the electric loads endogenously, then the modelers were instructed to attempt to match the actual load growth of each scenario from the EIA. If this is not possible, modelers were instructed to report electric loads and an explanation of the electric load calculation methodology.

- **Fuel Prices** – The modelers were instructed to use provided EIA data for fuel prices (gas, coal, nuclear, oil).
    - If possible, the modelers were instructed to use EIA values for fuels. If not, they were instructed to use similar fuel price trajectories over time. If this was not possible, they were instructed to report fuel prices and an explanation of the fuel price calculation methodology.

- **Resource Supply Curves –** EIA provided resource supply data for geothermal, biomass, and wind (using data recently provided by NREL) plus some explanation of how solar resources are handled. To facilitate different models' geographic resolution, this was done at both a national and regional level. Modelers were asked to calibrate their model to those inputs, if possible, or report any differences. Many modelers thought that their resource data was a unique characteristic of their model and were not willing to align on the EIA resource data set.

- **Macroeconomic Inputs** – EIA provided some data regarding macroeconomic inputs. Modelers were asked to calibrate to these values as much as possible, and to report inputs and methods that would significantly affect the outputs in this area.

- **Inputs Submittal Request** – In addition to the reporting document from the Base Case runs, the modelers were requested to provide the model inputs, over time, in a spreadsheet. Many of these

inputs were the EIA inputs themselves repeated back; but, in certain areas, individual models were unable to match the EIA inputs, and modelers were asked to explain their differences. Such items included:

- Capital costs for all technologies
- Performance (heat rates, capacity factors) for all technologies
- Fuel costs (current and future)
- Demand growth rate and demand
- Any elasticities in the model
- Cost of new transmission/transmission wheeling
- Resource data sources and any exclusions

Modelers were asked to follow all other guidance from the Base Case runs (renewable fraction ramp-in rates, for example).

The details of key assumptions and differences for both the implementation of RPS and Tier 1 alignment is contained at a model level in the individual presentations, which are included as part of this report.

The Base Case Results – Overview

This section presents results from the Base Case runs (for the reference, 10% RPS, and 20% RPS cases) where the models had not been explicitly aligned. One of the participating models, NE-MARKAL, was a regional model covering the nine northeastern states. Thus, some model results (such as total generation and capacity) are not directly comparable to those of the national models. Others, such as the relative contribution of various renewable technologies to meeting the RPS, are also heavily influenced by regional factors. Because of this, NE-MARKAL results are included only on those graphs where results can be meaningfully compared.

Figures 1 and 2 show the total renewable generation for the 20% Renewables Penetration Case in 2010 (Figure 1) and 2025 (Figure 2). Obviously, the renewables generation in 2025 is much higher than in 2010, which also leads to greater divergence among the models during the intervening years. The 20% penetration case for 2025 broadly corresponds to 900-1,200 terawatt-hours (TWhs) of renewable generation—although the RE technology split varies markedly by model. Some of this variance is obvious with the WinDS model needing to meet the 20% requirement only with wind capacity, but the variance is quite significant even in geothermal and biomass. More generally, this raises the issue that the ability to represent relevant potential technologies is important.

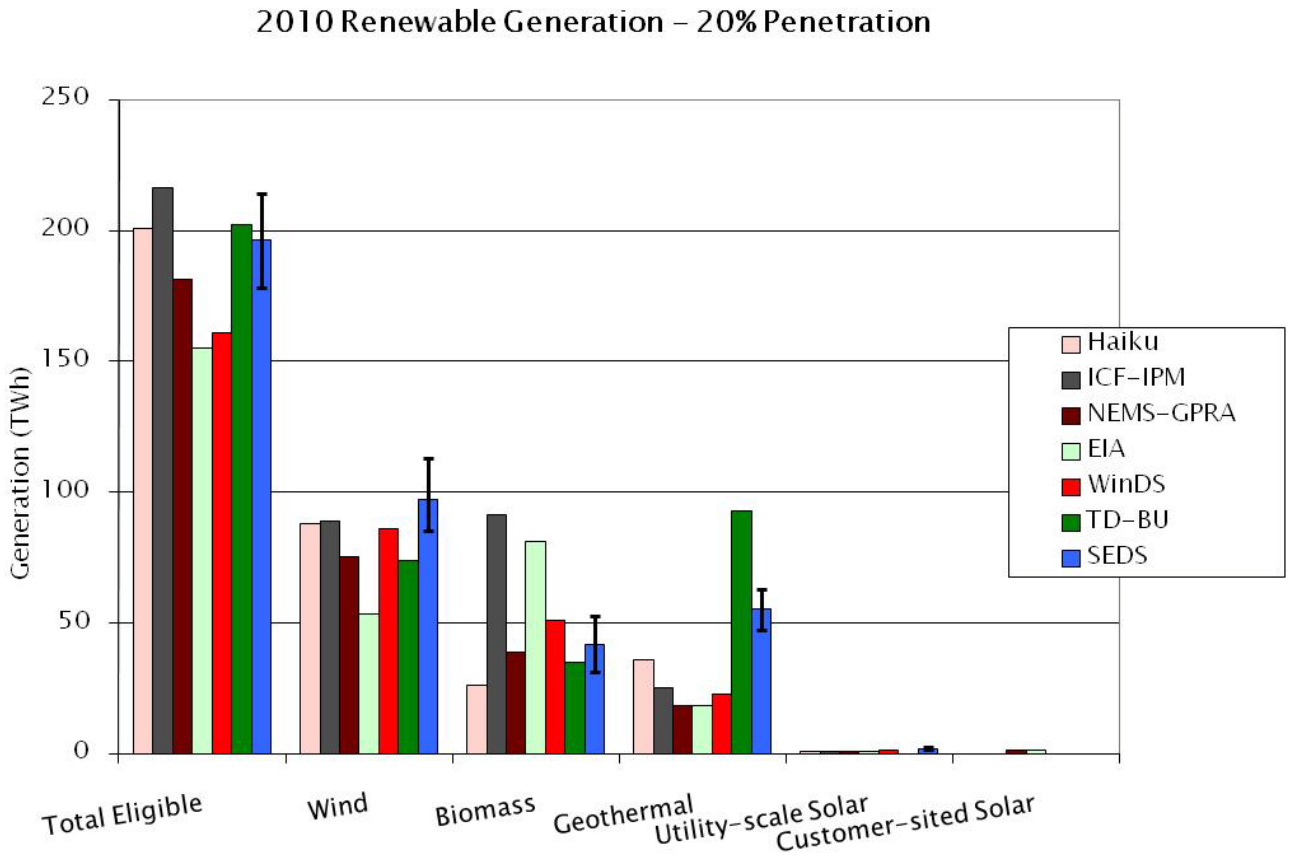


Figure 1. Base Case runs – 2010 renewable generation with 20% RE penetration

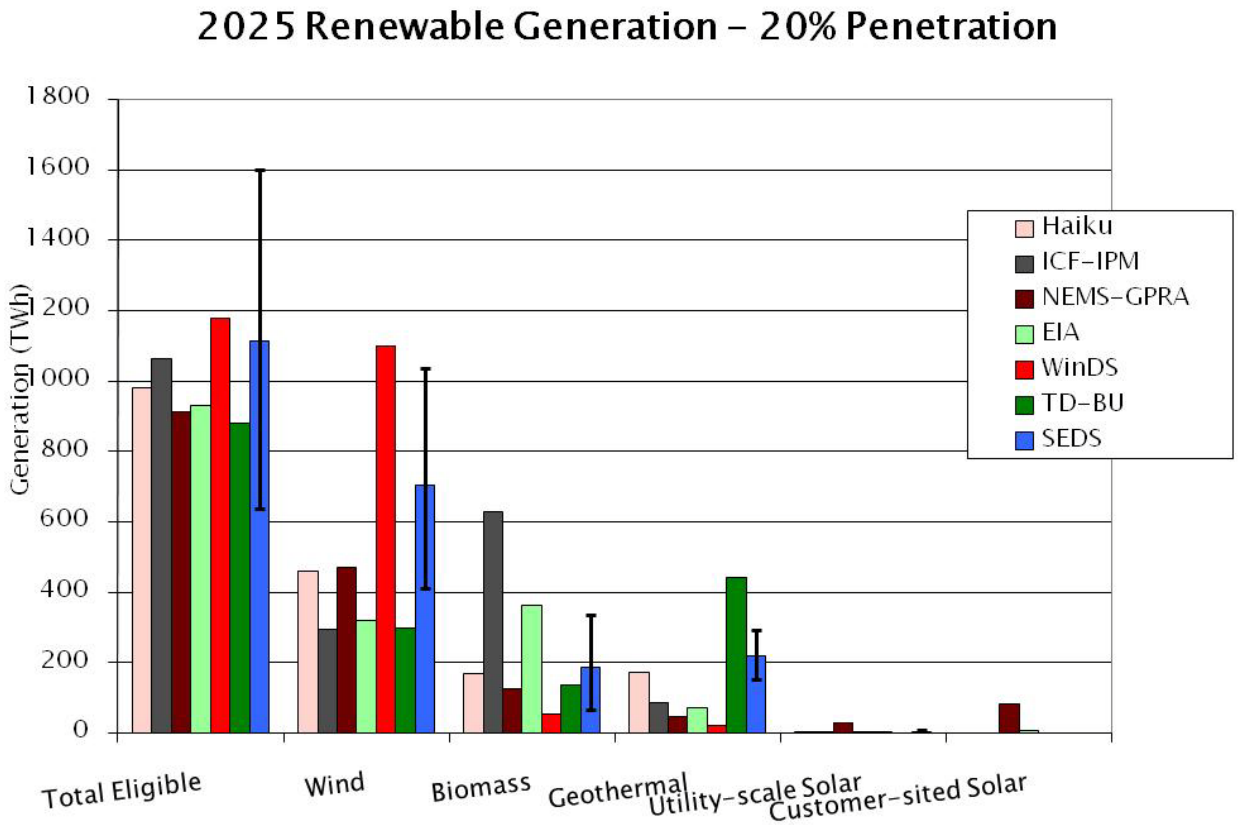


Figure 2. Base Case runs – 2025 renewable generation with 20% RE penetration

Figure 2 also shows uncertainty bands corresponding to the SEDS runs. SEDS is a stochastic model where distributions are used instead of point estimates of key variables (such as fuel costs and technology costs), as well as "if and when" specific technologies get implemented. The group could see that this factor can have a big effect. While the mean/expected generation is "in line" with the other technologies, the potential variation is large (from 600 to 1,600 TWh). However, it should be noted that the representation and magnitude of uncertainty parameters in SEDS is still under development. Nevertheless, it is important to note that with exception of SEDS, the various models are not fully representing technology, market, and future policy risk and uncertainty. If such factors were included, the range of potential outcomes would be much wider. However, such risk and uncertainty considerations were not the focus of this report.

Because models vary in the total future and incremental load required by 2025, total renewable generation varies among models. Figure 3 shows the relative contribution to meeting the RPS from different renewable technologies. The large role for wind in NE-MARKAL is due, in part, to the relative attractiveness of wind in that region and the lack of other resources for meeting the RPS on a regional basis. EIA and NEMS-GPRA show a significant role for biomass cofiring, which is not represented in all of the models.

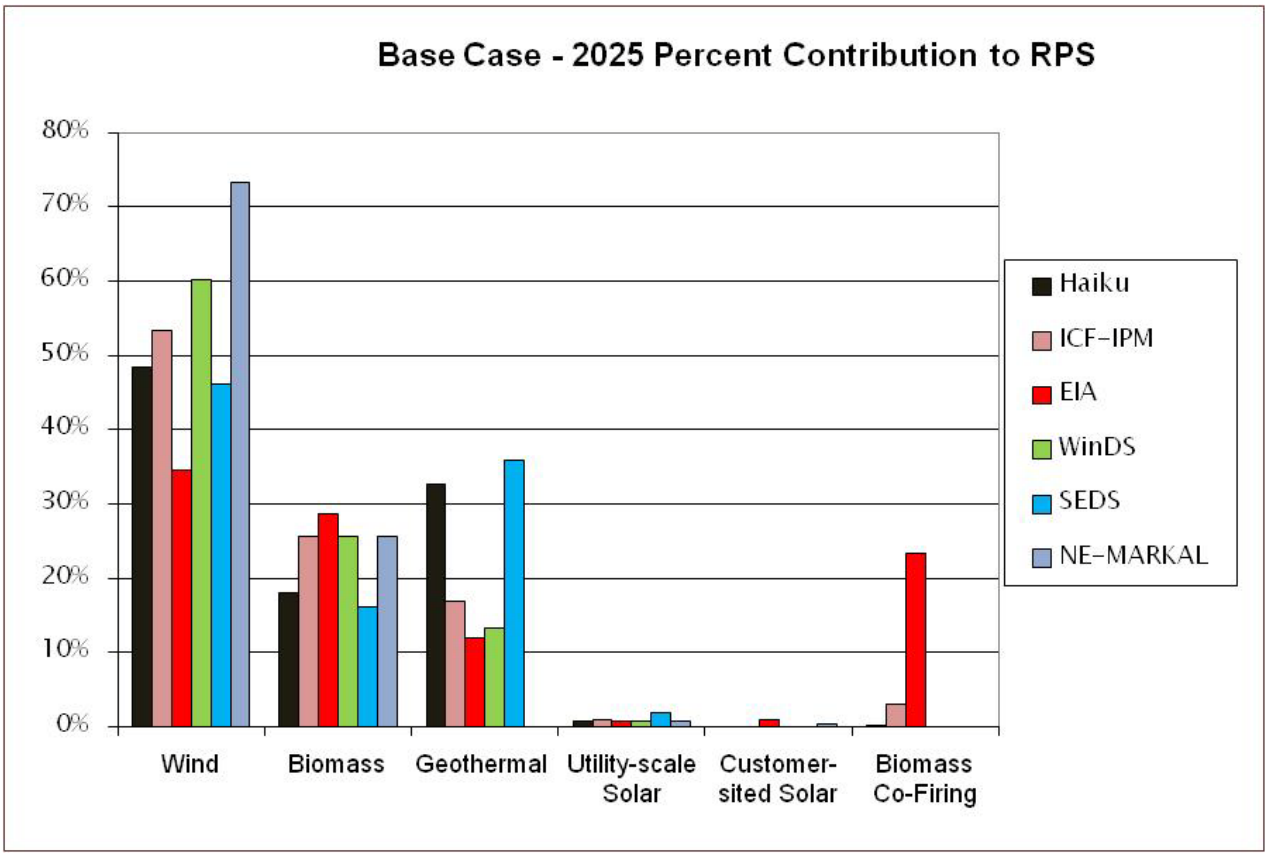


Figure 3. Base Case runs – 2025 percent contribution to RPS

Figures 4 and 5A show the renewable energy capacity values for the 20% RE penetration case. Although similar in distribution to the generation graphs above, the differences are somewhat greater because of the variance in capacity factors across different models. This is particularly true for wind, which has a lower utilization than base load plants by a factor of 2 or more. Even absent wind, we see it is common to see differences in capacity growth of more than 100% for specific technologies. This is not surprising given the freedom in the Base Case for modelers to select future technology costs, performance, and other factors. Again, some of these differences are model-driven, while others may be due to differences in assumptions.

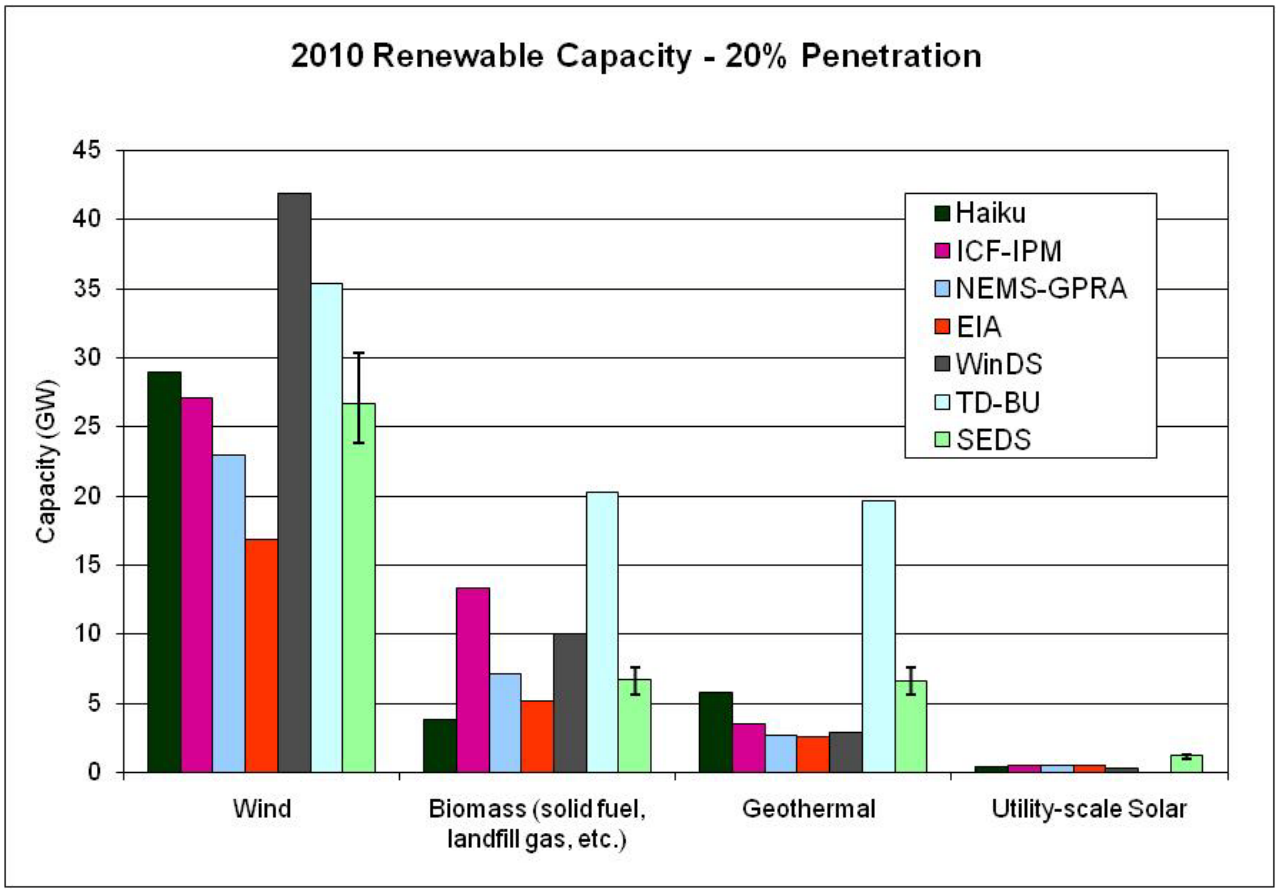


Figure 4. Base Case runs – 2010 renewable capacity with 20% RE penetration

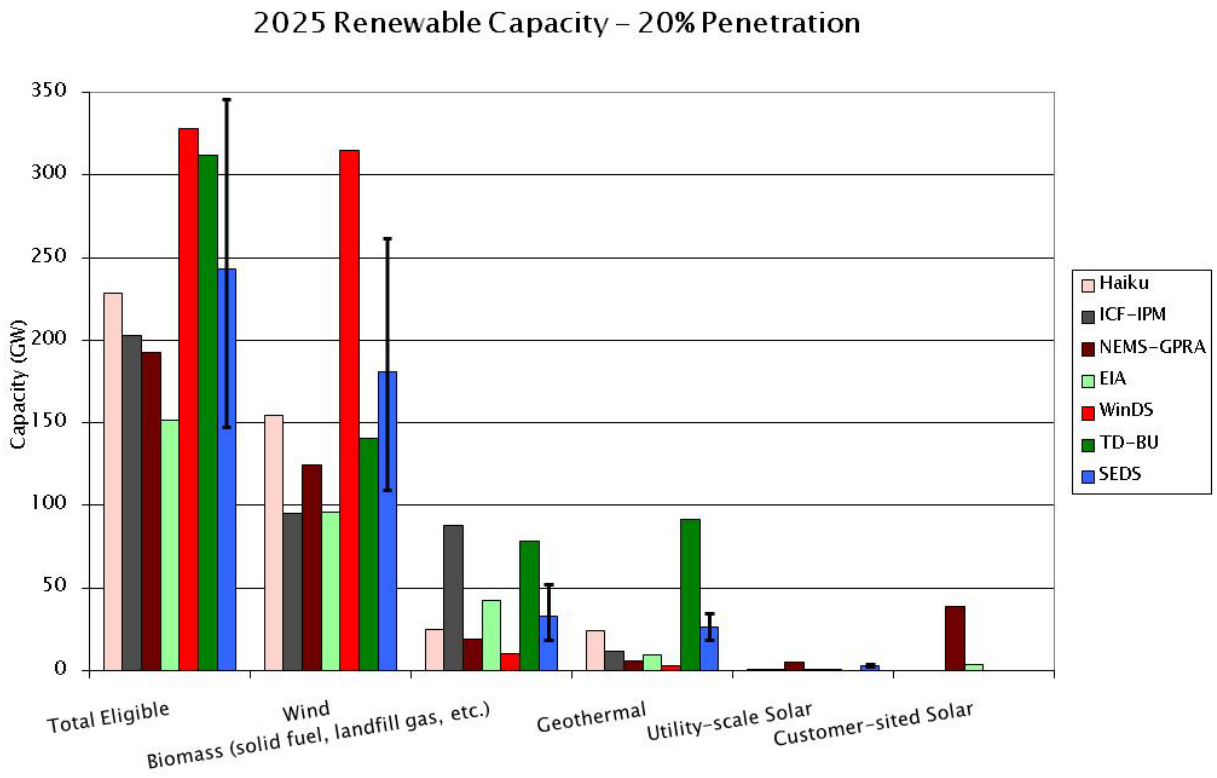


Figure 5A. Base Case runs – 2025 renewable capacity with 20% RE penetration

The group also evaluated how much of the difference among results at 20% renewable penetration is due to the fact that the models handle "high" RE penetration differently. Figure 5B shows that even in the reference case (both in 2010 and 2025), the amount of installed renewable capacity differs significantly among models. This indicates that the level of required renewables (i.e., 10% or 20%) is not a significant driver for these differences.

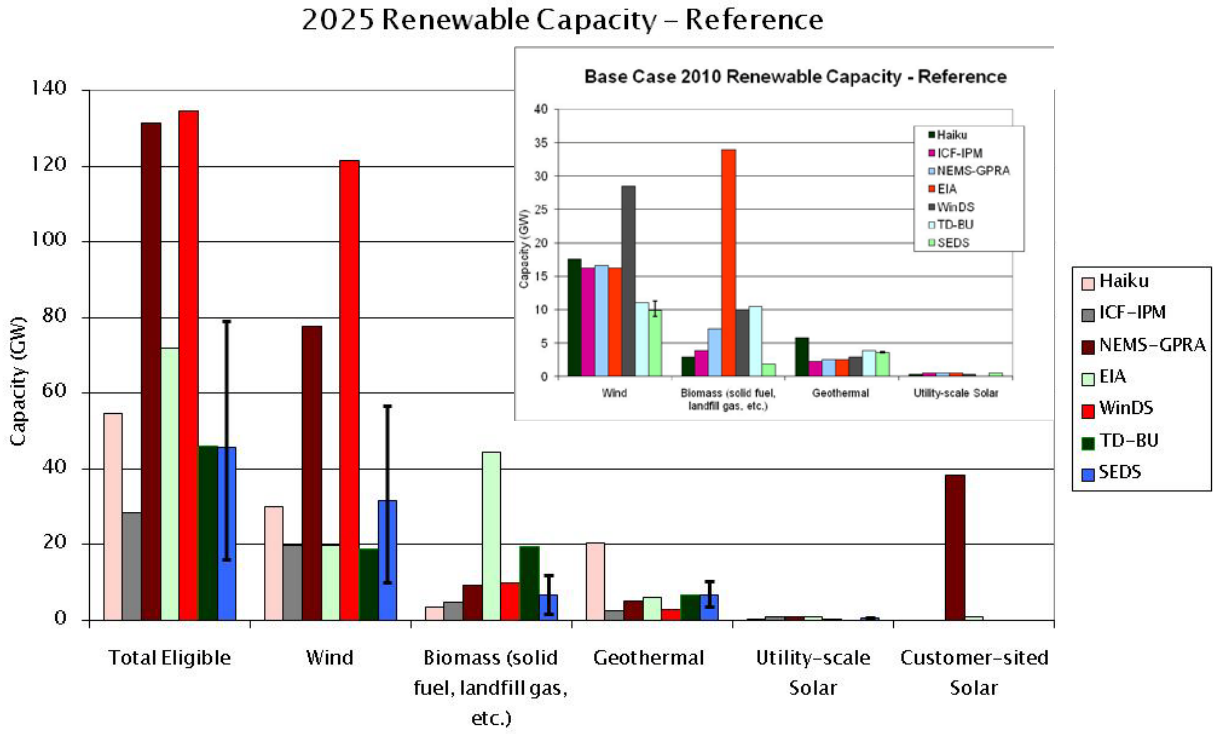


Figure 5B. Base Case reference run – renewable energy capacity in 2010 and 2025

Figures 6 and 7 show the variance in total CO_2 emissions among models (Figure 6) as well as the change in CO_2 emissions with 20% Renewables vs. the Reference Case. In Figure 6, note that the SEDS "spread" brackets all the other models;[9] note also that several models start at different points for today, indicating an incompatibility in either their existing mix of conventional technologies or the rates that those technologies emit CO_2. There are two primary reasons why CO_2 would fall: direct displacement of high-CO_2 generation by nonemitting technologies, and an overall reduction in generation due to the cost of achieving the RPS. Therefore, aligning the current electric-sector inputs is critical to getting more comparable outputs in the future. Also, some models do not capture on-site generation while some do, which also causes some of the observed discrepancies.

[9] This is not unexpected because the impact of market and technology risk and uncertainty can be expected to have a very significant effect on model parameter outputs. At the same time, it should be emphasized that the parameters chosen to represent such uncertainty within SEDS was illustrative rather than definitive (e.g., the impact of risk and uncertainty of fuel prices is likely to be significantly higher than was represented in the runs).

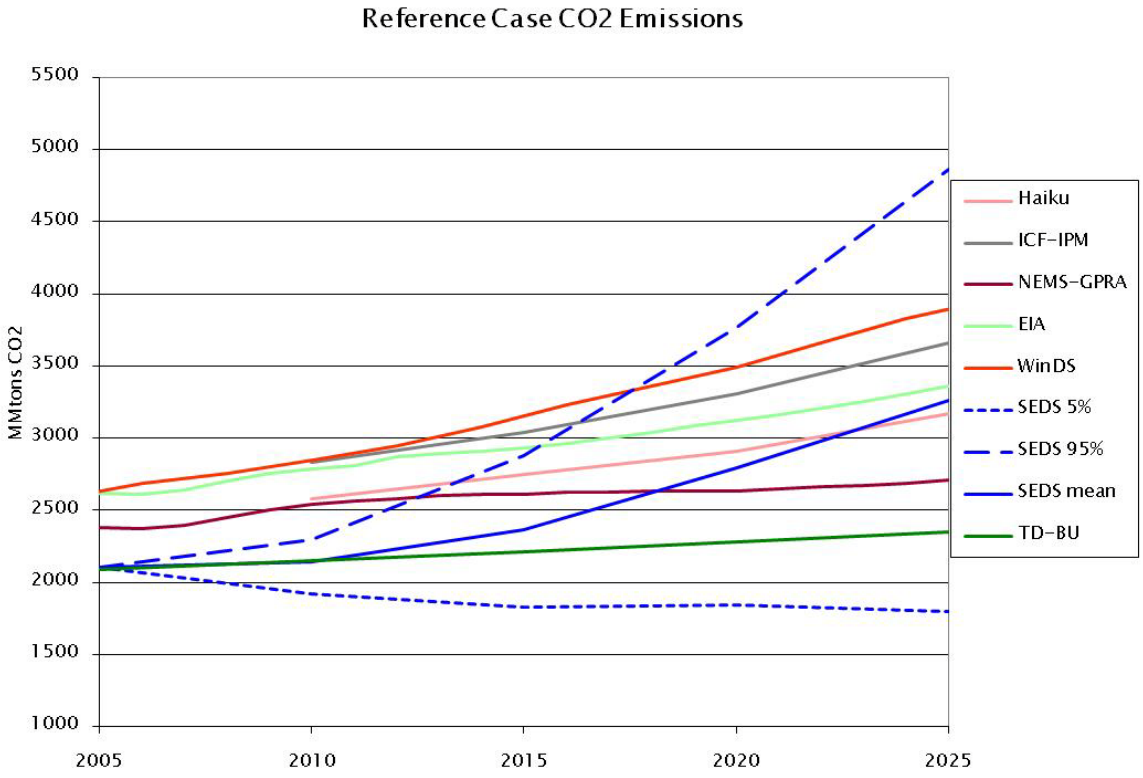


Figure 6. Base Case runs – Reference Case CO_2 emission levels for the electric sector

Partly to correct for the initial deviation in CO_2 production, Figure 7 was created to show the percentage reduction in CO_2 levels with 20% renewables vs. the reference case. Again, there is still significant spread with a range in reduction of 12% to 40% (or 300 to 1,000 million tons of CO_2 per year by 2025), partly due to variations in reference case RE penetration. In the case of NE-MARKAL, the reductions on the large end of the range occur because the required renewables displace coal almost entirely.

The benefit, or perhaps the need, for stochastic models—or at least a clear statement of technology and cost assumptions—becomes clear at this point. Normally, in an analysis of this type, there might be just one set of deterministic results shown, which could lead to overconfidence in the results. Multiple models, or at least multiple sensitivity cases with alternative assumptions when using a single model, provide a better measure of the range of possible results.

It is also worth considering why the reduction in savings in the NEMS-GPRA run is significantly lower than the cases for the other models. This is because the NEMS-GPRA reference case includes better conventional technologies resulting from governmental R&D efforts, which leads to greater energy efficiency and RE penetration even without the 20% mandate. Thus, the 20% mandate provides lower incremental carbon emissions reductions.

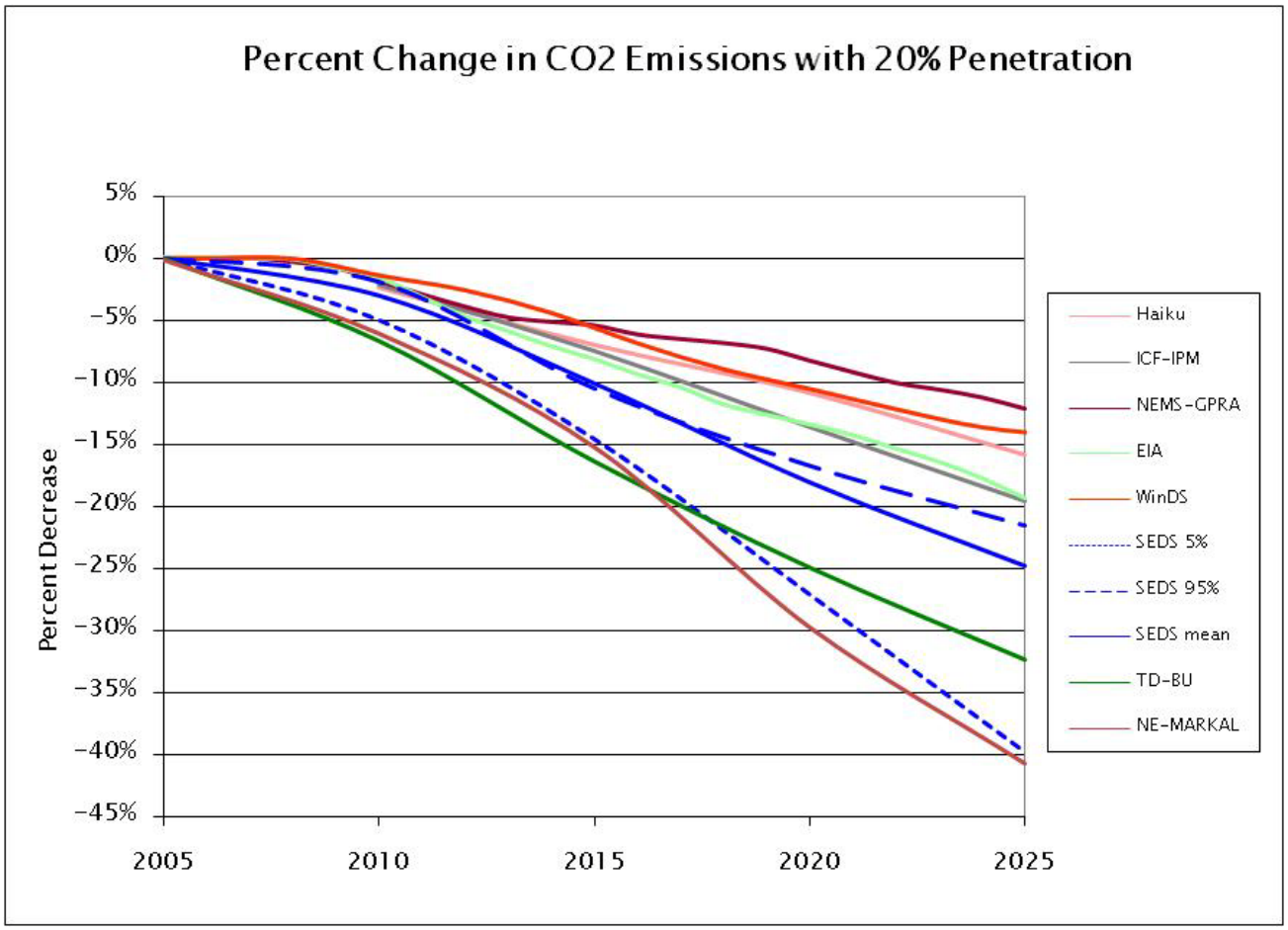


Figure 7. Base Case runs – percentage change in CO_2 emissions from the Reference Case to the 20% Renewables Case

As shown in Figure 8, electricity prices are expected to fall in all base cases. In most (but not all) models, the cases with a higher level of renewable energy penetration have relatively higher prices. However, these national average prices are not higher than even the national variance in all cases. Also note that, generally, the delta of the results between the Reference Case and 10% renewables is similar to the results delta between the 10% and 20% Renewables Cases.

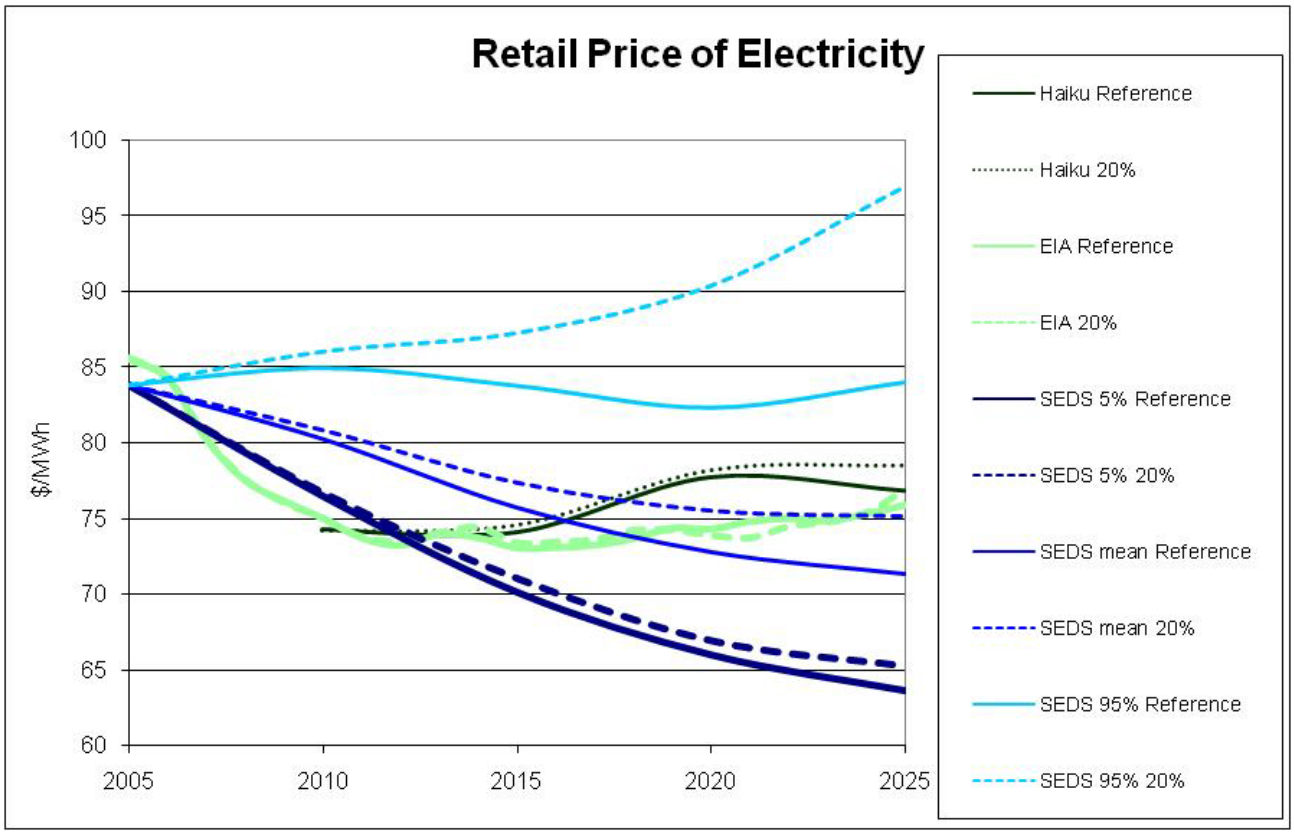


Figure 8. Retail price of electricity across models and across Base Case runs

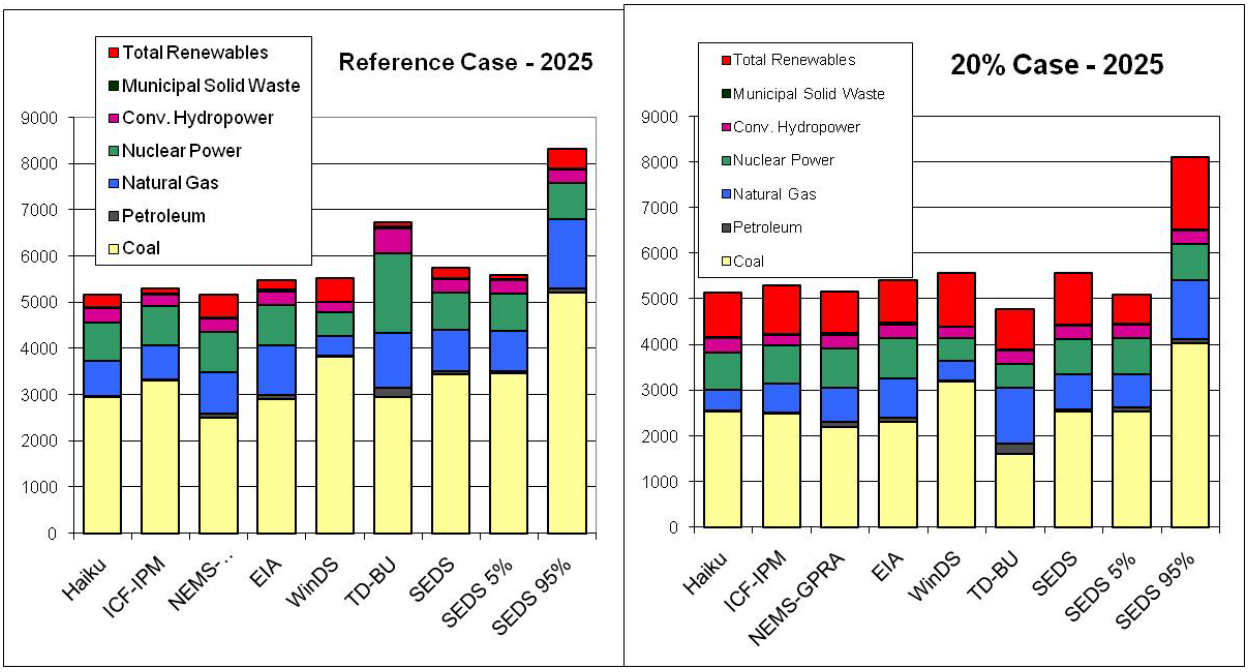


Figure 9. Comparison of generation mix for both Reference Case and 20% Renewables Case in 2025

The generation mix for conventional technologies in the Base Case runs is almost as varied as the mix of the renewable capacity. This will impact all the other metrics, including CO_2 emissions and price—often

more so than the renewable generation levels. So, even though the primary focus of this activity is to examine the variation of renewable energy results, the variance in conventional capacities and generation is likely to be an equally significant factor for these models. One of the goals of the Tier 1 Case runs was to help determine the degree to which differences are due to inherent modeling variations or to the inputs used by each model.

After examining the Base Case results, several conclusions can be drawn:

- Differences may occur because some models emphasize some renewable energy technologies over other RE technologies.
    - This can be important to the results (e.g., biomass may have a different utilization and carbon footprint than wind).
    - Limited or no representation of technologies obviously biases the results in favor of those technologies represented—and may overbuild them relative to what would likely occur if the excluded technology were cost-competitive in the scenario.
- Some models may assume different demand (and hence generation needs) over time.
- Characterization of reference cases for renewable and conventional technologies may be very different (e.g., capital costs over time, learning curves, RE capacity factors, heat rates).
- Differences in treatment (or lack of treatment) of regional differences can also generate significant differences in nationwide results. Restriction of the average technology cost to the entire United States can be problematic because there are significant variations in costs of fuels and resource availability across the United States. The NE-MARKAL results show the impact of restricting the RPS to a single region where the resource characteristics are very different from the national average.[10]

Because of such differences, the generation mix of conventional and renewable energy varies markedly, and this can impact prices and carbon emissions significantly.

[10] Even though a number of these single region models try to represent some of the effects of regionalilty by building a supply curve that considers the costs and resources on a more locational level.

The Tier 1 Case Results – Overview

This section of the report discusses the results from Tier 1, which was (as described above) essentially a repeat of the Base Case runs but used a common set of key assumptions (from AEO 2006). Again, this should allow examination of how differences in modeling methodology affect output forecasts and reduce the differences among models due to differences in inputs. Note that only the reference and 20% renewables cases were run. The results of the Tier 1 Case are best viewed in conjunction with the Base Case runs to determine the impact of aligning the inputs with the results—that is done in this section. Some models also made other minor modifications based on the Base Case results comparison (and general model improvements during this period) that might also modify the results. Additionally, fewer models participated in Tier 1 than in the Base Case scenarios. Therefore, unlike in the previous section, this section presents only the models that participated in both the Base Case and Tier 1 Case.

Figure 10 shows that the introduction of "aligned" inputs aligns the electricity price; although, even in this case, not all of the values are aligned initially. However, the final electricity price is in a much narrower band. Part of this is due to the SEDS model having removed significant amounts of the uncertainty allowed in the Base Case runs—although, of course, the elimination of such market and technology risk and uncertainty in SEDS is not possible in practice.

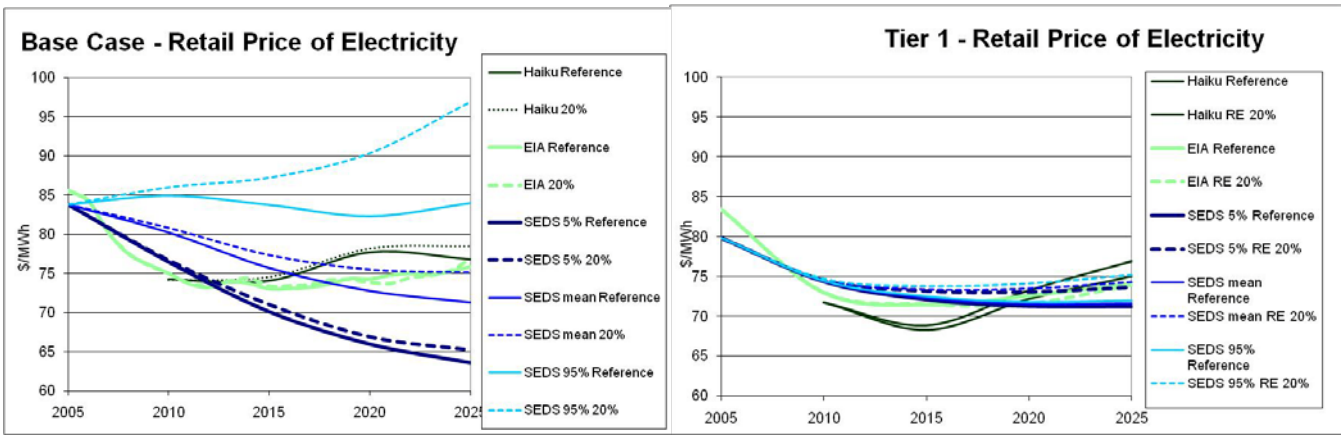


Figure 10. Base Case and Tier 1 Case price of electricity for different renewable penetration levels

Another important electric sector-wide metric is the CO_2 emission. In the Base Case runs, the variation in reductions across models was significant (shown in the left side of Figure 11 as varying from a 10% to a 40% reduction by 2025 for models that participated in both sets of runs) compared to the Tier 1 Case results, which were contained within a narrower band (30% range reduced to about 15% range).

The Tier 1 alignment of inputs also leads to a dramatic improvement in agreement of the renewable capacity penetration by 2025 without any RPS requirement. With aligned inputs, the model projections of wind capacity are more similar to each other (see Figure 12). Biomass and geothermal also show good agreement when compared with the Base Case results for this reference case (except in Haiku).

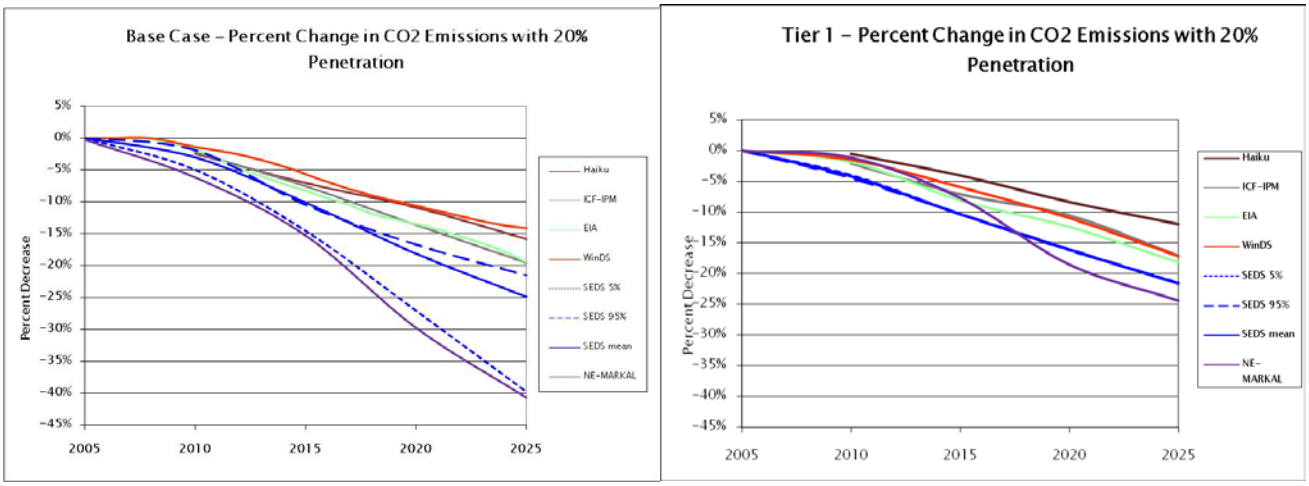


Figure 11. Base Case and Tier 1 Case run results for CO_2 emission reductions

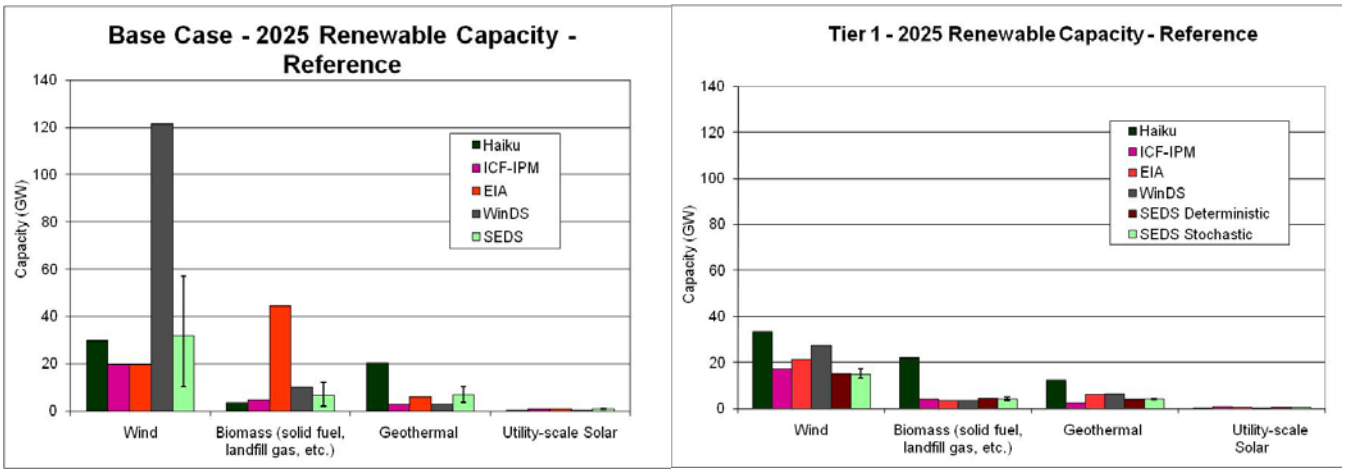


Figure 12. Base Case and Tier 1 Case run results for 2025 renewable capacity in the reference scenario

After comparing the level of renewables in the reference case (low penetration), the group examined what would happen to renewables penetration at a higher level of penetration (the 20% scenario) when aligning the inputs. As Figure 13 shows, at higher levels of renewable penetration, aligning the inputs does improve agreement. However, structural differences are more evident at this higher level of penetration. Wind capacity, for example, varies from 100 GW to 150 GW by 2025 in the Tier 1 Case, which is still a 50% variation. Of course, this is still much smaller than the Base Case, which varied from about 90 GW to 310 GW. The Haiku results for Tier 1 at this higher level of penetration are much more inline with the other models.[11]

Figure 14 shows the contribution by renewable technology to meeting the RPS. The Tier 1 Case input adjustments have reduced the spread in model results, although differences remain, particularly in the set of technologies represented—a feature of model design that was not adjusted. In general, the Tier 1 changes seem to have reduced wind and geothermal contribution, but increased biomass.

[11] The variance with the WinDS model in the Tier 1 Case was reduced significantly by the inclusion of prescribed biomass and geothermal capacity offsets for these runs.

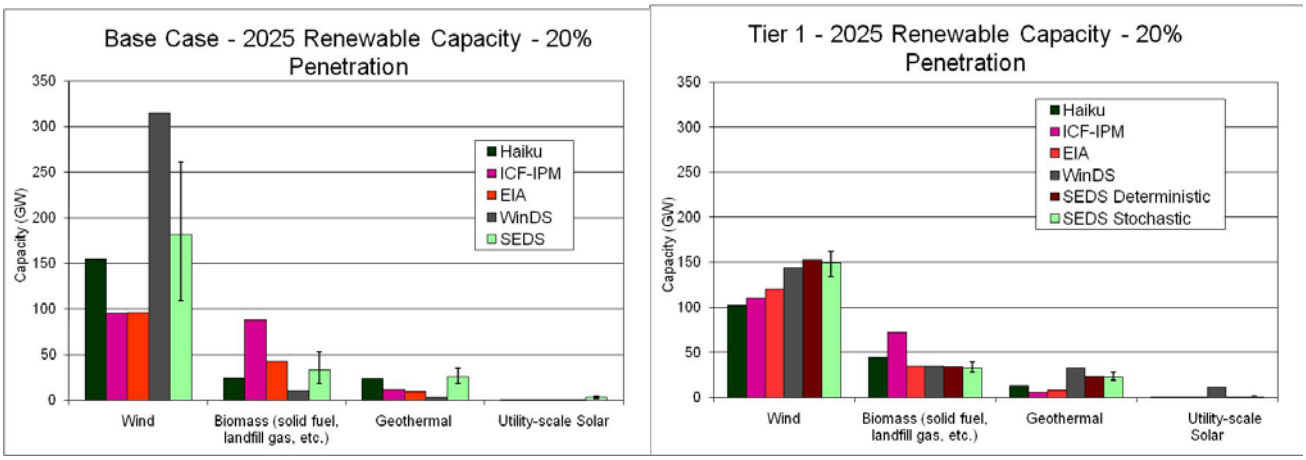


Figure 13. Base Case and Tier 1 Case run results for 2025 renewable capacity in the 20% renewables scenario

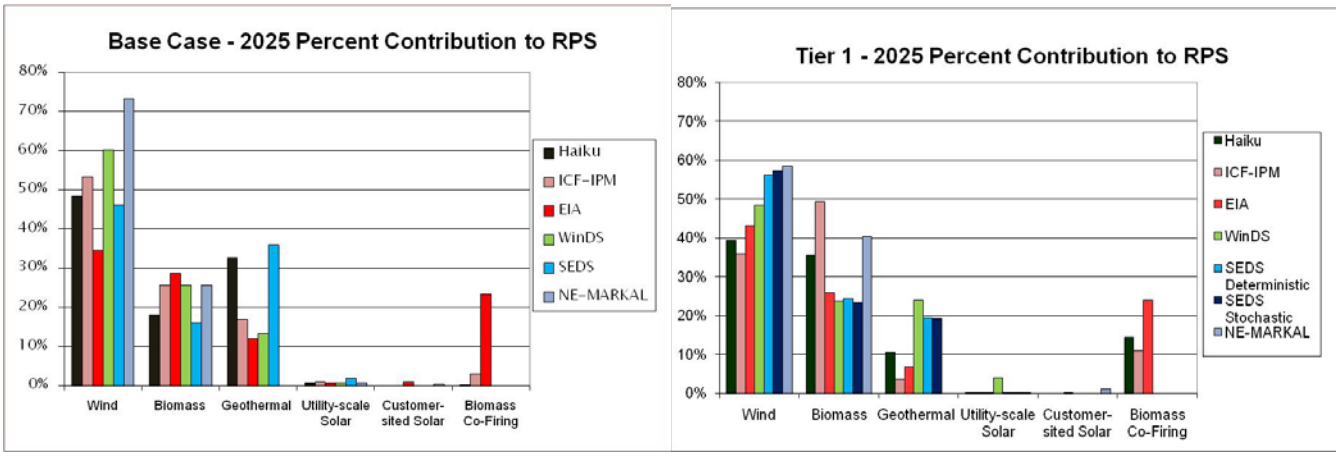


Figure 14. 2025 percent contribution to RPS by technology for Base Case and Tier 1 Case

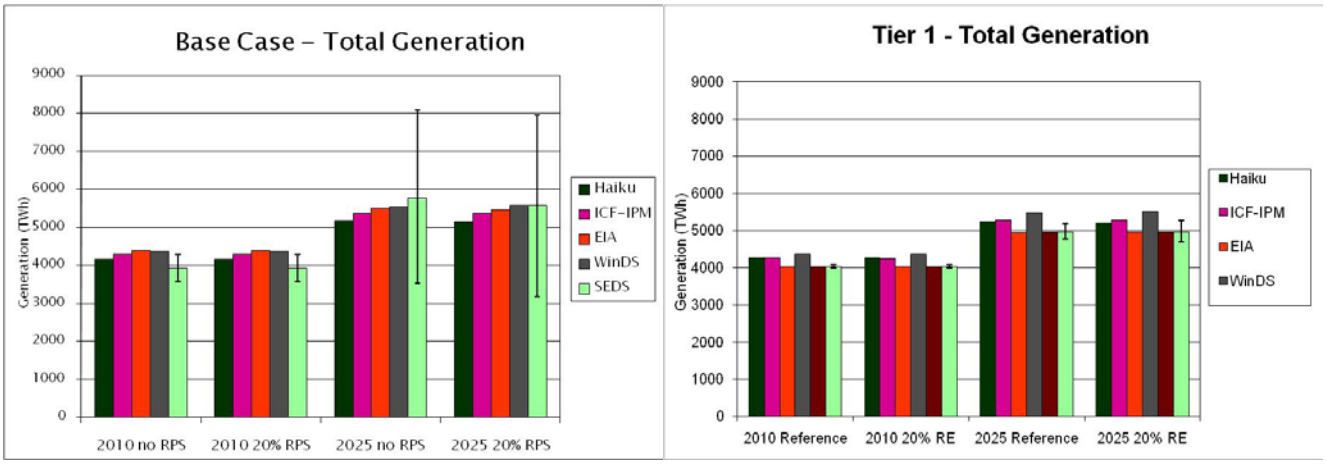


Figure 15. Base Case and Tier 1 Case run results for national generation totals for all scenarios

The assumptions made by each model regarding future electric load growth, as well as any energy efficiency or demand reduction technologies, can affect the projected RE generation in 2025. Several models take their basic electric load growth from the EIA NEMS outputs, so the group expected general alignment among those models—however, that wasn't the case. In the Base Case, there was even more extreme variation among the models, especially in the "2025 no RPS" data, which directly affects the total amount of renewables required to reach 20%.

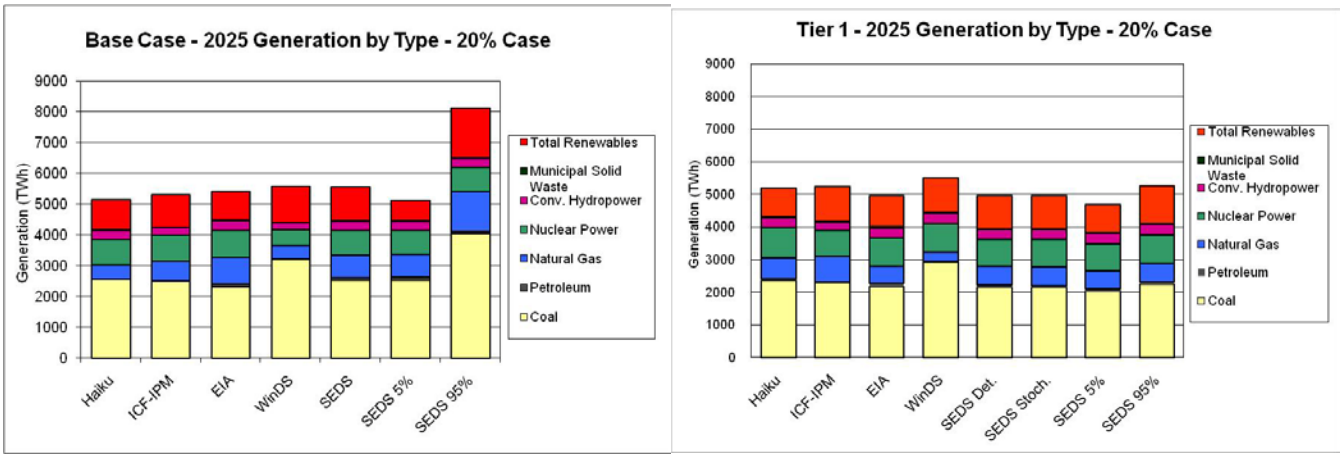


Figure 16. Base Case and Tier 1 Case run results for generation by type in 2025 with 20% renewables

Figure 16 indicates that across these models, there is as much variation in conventional generation as there is in renewable generation. Note that coal, in particular, shows an unexpectedly high level of variation across the models in the Base Case. This is improved, but not eliminated, in the Tier 1 scenario. Part of this variation comes from the projected future costs of fuel and how that factor is handled in the capacity decision process. For example, the assumed discount rate in the model directly impacts the present value of future fuel payments. SEDS includes uncertainty with the future price of fuel and electricity demand and, as a result, reports a significant variation in the type and amount of conventional power being used in the Base Case. The assumptions made about future nuclear power generation is also a major modeling issue for conventional technologies—from the issue of delayed retirements of nuclear plants to the uncertainty of getting new nuclear plants permitted, even if they are the economical optimum. Determining the cost of nuclear waste disposal is another major modeling issue as the models look to 2025 and beyond.

Another issue related to the conventional penetration has to do with the initial (2006) value for conventional capacity by type (that is, the existing capacity stock). Although this issue may seem trivial, various databases and references have different values and they classify the capacity differently, which results in nontrivial variations of capacity. This is especially true at a regional level. For example, the data that WinDS was originally using for existing capacity stock differed significantly from what EIA uses for their stock (especially with regard to the gas combined-cycle capacity around the country).

Conclusions

The primary conclusion of this REMAP activity is that the results of the models vary significantly—especially when they use their own input assumptions. This variation among models diminishes significantly once the inputs are better aligned as in the Tier 1 Case runs discussed above. This conclusion suggests that a common set of vetted inputs for key parameters across the energy modeling community would improve consistency among model results. On the other hand, policymakers need to be aware of the importance of diverse assumptions—and modelers should discuss these differences explicitly.

It's also possible that some differences in assumptions among the models are intrinsically tied to the organizational mission of a particular model's sponsors. In this case, it may not be possible to align assumptions to some consensus standard; but this does suggest that adequate disclosure of key assumptions will be critical to understanding the results. More broadly, even when common assumptions are introduced, several (aligned) sensitivity cases need to be done to reflect the very real and significant uncertainty about the future cost of technology, fuel and other factors, such as demand.

In spite of improved alignment in Tier 1, there is still significant variation in results. This is due to several factors including structural differences among the models such as in the representation of capacity-planning decisions within the model (optimization algorithms, probabilistic choice, or other factors) or in the regional or temporal resolution of the model (such as how many regions, ranging from 1 to more than 300; or how many years in each model cycle, ranging from 1 to 5). However, several more subtle issues can also cause differences. One of these is the fact that several of the models are still using different resource data sets. This variation in resource data and resource supply curves can alter the amount of renewables built and can change the geographic location of the renewables installed. In the future, a greater degree of resource data availability (and in different forms and formats) will improve agreement among the models as they all obtain better data. However, emerging technologies—such as integrated gasification combined cycle (IGCC) and carbon sequestration, and wave power—will continually require the generation of new resource data.

Another subtle issue causing continuing differences among the model results is the "starting point" characterization. One would assume that determining the amount and location of existing generating capacity would be simple compared to predicting the future. However, there are enough differences among existing databases and references that this can lead to nontrivial variation among the models. Differences in policies in the baseline versions (especially state policies) also can cause significant regional differences.

Another issue that impacts the alignment of the model outputs in the Base Case runs is that many of the models already use a variety of NEMS/EIA data as inputs to their models. If the NEMS data was not so widely known and treated as a "standard" of the industry, there would be even greater variation among the Base Case results. This use of EIA data (especially for items such as discount rates and resource data, more than for actual capital costs or policy assumptions) doesn't necessarily imply acceptance by the modelers, but rather demonstrates the lack of a viable alternative source. Many modelers also use NEMS inputs and results to help validate their model, again making the algorithms and inputs used by NEMS more widespread.

Some of the differences among the models are due to obvious modeling differences. For example, the WinDS model generally only simulated wind[12] as the renewable technology that can take on the vast majority of reaching 20% renewable energy by 2025. Therefore, this would likely lead to a much higher level of wind penetration than models that contain other renewable sources (solar, geothermal, bio-power, etc.). Additionally, it is intuitive that small variations in load growth, compounded to 2025, can result in a significant variation in the total generation required and, therefore, the amount of renewable generation and capacity required. Another obvious difference among these models is that several only model the United States as a single location—they don't contain any explicit geographical representation of the nation. A regional perspective is particularly important for modeling renewables, which are heavily influenced by local resources, the geographical distribution of loads and transmissions, and state and regional policies. In particular, state-level policies and local siting concerns have been among the primary drivers of renewable development in recent years. Differences in load growth assumptions across regions also are important because they drive the absolute value of renewables and other technologies.

The conclusion for decision-makers using the output from these models is that, absent a common framework, different models come up with significantly different results to the same question—in this case, achieving a 20% penetration scenario and estimating various parameters such as carbon savings and technology mix. This is important to recognize when presented with results from only one model. Based on specific assumptions, the group showed—at least for this question—that differences in model output of 30% to 40% or more were not uncommon; and for technology capacity, the differences are commonly over 100%, or more. It is important, therefore, to not be overconfident when presented with a single set of results—and to look carefully at the underlying assumptions. Common input assumptions across models can significantly narrow but do not eliminate such differences. Sensitivity analysis is also very important when using a single model.

In Tier 1, all models were calibrated to the EIA AEO 06 Reference Case. If the models were calibrated to another set of assumptions, analysts might expect similar agreement on the range of outcomes but that the values would shift—however, this has not been tested.

This paper shows the importance of using multiple models to provide results to a proposed policy or scenario, whenever possible. With only one model, the results would be similar to one of the Base Case runs (which had great variance in outputs between models), but any sense of this potential uncertainty due to underlying assumptions is difficult to determine. Secondly, some models are better than others for specific questions (e.g., a single-region model of the United States has a different focus than a model that focuses only on California)—and such potential limitations are not always made clear when relying on a single model. When evaluating modeled results, it is important to know what level of confidence is appropriate. This study shows that significant variation in forecast outcomes exists among models, and that input variations can amplify those differences.

In summary, our analysis suggests that:

- Due diligence needs to be exercised by policy and decision-makers when presented with findings from a single model. Assumptions and model choices can lead to significantly different

[12] Note that the newest version of WinDS, renamed ReEDS (Regional Energy Deployment System), contains solar, geothermal, biopower, electrical storage options, and demand elasticity. These options were not developed during this activity and solar was included in Tier 1.

outcomes. For example, simple choices in future capital costs may result in a particular technology appearing dominant or marginal. Similarly, different models using identical technology and market assumptions might predict substantively different outcomes due to their structural differences.

- Where possible, a variety of models using similar assumptions should be used to give the decision-maker a sense of differences in outcomes that reflect inherent uncertainties in the models, recognizing that some models are better suited to resolving certain questions than others. For example, if the policy goal is to understand the role of transmission to facilitate variable renewable energy supplies, a geospatial, disaggregated model, such as ReEDS, would likely provide more informed results. At a minimum, there needs to be thoughtful selection of the single model that is most appropriate for the question at hand.
- Sensitivity analysis must be considered. Whether using one or multiple models, scenarios with varying assumptions about technology cost and market assumptions is desirable to understand how resilient model outcomes and predictions are to such underlying assumptions.

Appendix

The following presentations highlight each model's individual results.

Haiku REMAP Analysis – Karen Palmer, Anthony Paul, and Rich Sweeney, Resources for the Future; and David Evans, EPA (includes written summary)

Wind Deployment System Model (WinDS) and Regional Energy Deployment System (ReEDS) for REMAP – Nate Blair, Patrick Sullivan, Walter Short, and Donna Heimiller, NREL

NE-MARKAL Tier 1 and Round 1 Comparison – Gary Goldstein, Evelyn Wright, and Pat DeLaquil, IRG; and Gary Kleiman, NESCAUM

Stochastic Energy Deployment Systems Model (SEDS) – James Milford and Walter Short, NREL

NEMS-GPRA08 Renewable Portfolio Standard Results – Frances Wood, OnLocation Inc.

Observations on NEMS Results from REMAP Tier 1 – Chris Namovicz and Bob Smith, EIA

Integrated Planning Model (IPM): Summary of Results – Elliot Lieberman, EPA; B.N. Venkatesh, ICF International

Haiku REMAP Analysis

Karen Palmer
Resources for the Future
David A. Evans
National Center for Environmental Economics, USEPA
Anthony Paul
Resources for the Future
Rich Sweeney
Resources for the Future

REMAP Workgroup Meeting
April 30, 2008

Outline of Presentation

- About Haiku
- RPS design in Haiku
- Calibrated Tier 1 assumptions
- Comparison of Base Case and Tier 1 analyses
- Tier 1 detailed findings

The Haiku Model

- Highly parameterized simulation model of U.S. electricity market.
- Price responsive demand and fuel modules.
- 3 seasons, 4 time blocks, 3 customer classes.
- 20 regions with inter-regional trading.
- About 48 model plants in each region.
- First principle is welfare measurement

Baseline Renewable Policies

Policy	Modeled Explicitly?	Alternative Representation?	Notes
Federal renewable PTC	No	2007 renewable capacity construction comparable to AEO 2006	PTC lapsed when Base Case conducted. Also, modeling sunset provision not possible
Federal nuclear PTC	No	6GW of new nuclear as projected by AEO 2006	Model builds >6GW of nuclear
Federal ITC	No for geothermal No for solar	Yes for geothermal No for solar projects	Geothermal may receive either PTC or ITC. With PTC not modeled, assume ITC claimed.
Accelerated depreciation	Yes		Capital costs adjusted to capture incentive of MACRS relative to 20-year depreciation.

Renewable Policies, Cont.

Policy	Modeled Explicitly?	Alternative Representation?	Notes
State RPS	No	Adopt AEO 2006 renewable build assumptions supplemented with projections for NY and MD RPS policies	
State tax incentives/ system benefit charges for renewables	No	Adopt AEO 2006 renewable build assumptions	Can model state-level tax credits. Can model regional RPS policies, but not simultaneously with national policy.

RPS Policy Assumptions

- Renewable Energy Credits can not be banked
- Technologies that receive credit under RPS:

Technology	Existing (2004)	New
Wind	Y	Y
Geothermal	Y	Y
Dedicated Biomass	Y	Y
Co-Fired Biomass	Not in model	Y
Landfill Gas	Y	Y
Solar	Y	Not in model
Ocean	Not in model	Not in model

Tier 1 Standardized Assumptions

- Generation Technology Cost/Performance
  - Existing: Mix of publicly available parametric and observation data.
  - New: NEMS, including learning functions and cost of capital (financing).
    - Also did in Base Case with exception of cost of capital.
  - Accelerated depreciation new for Tier 1
- Electricity Loads
  - Benchmark regional load growth to AEO 2006
  - Use constant elasticity demand functions
- Fuel Prices
  - Construct natural gas supply curve using AEO 2006
  - Coal market representation using NEMS input and results
- Macroeconomic Inputs
  - None (other than previously mentioned).

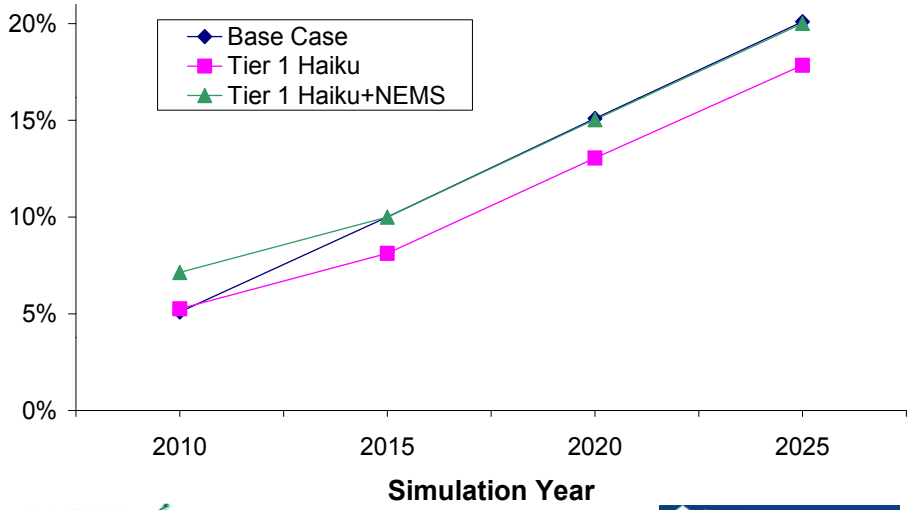
Renewable Resource Supplies

- Use NEMS geothermal, biomass and wind resource supply curves, including long term cost multipliers and interconnection costs, with a few changes:
  - Spatial aggregation different in Haiku, so need to allocate resource supplies
  - Mimic endogenous capacity factor learning for wind by increasing capacity factors over time.
  - Each wind class built in proportion (flattens supply curve).

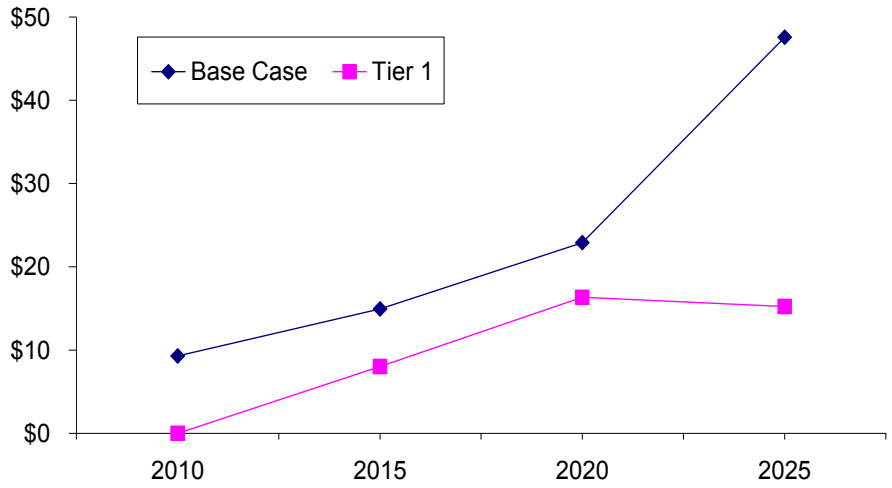
Base Case/Tier 1 Comparison

- Comparisons are Reference to 20% RPS
- Changes for Tier 1 other than standardizing assumptions:
  - Assumed NEMS on-site generation by renewables
    - Required grid servicing electricity sector renewables lower.
  - Using 20-year "economic lifetime" for all new generation technologies
  - Removed (almost all) new construction constraints
    - None of the remaining bind in Tier 1 runs.
  - Small fix to wind availability in OH/MI/IN and southeast.
- Electricity price adjustment to Tier 1 runs

Renewable % of Generation



REC Price ($/MWh)



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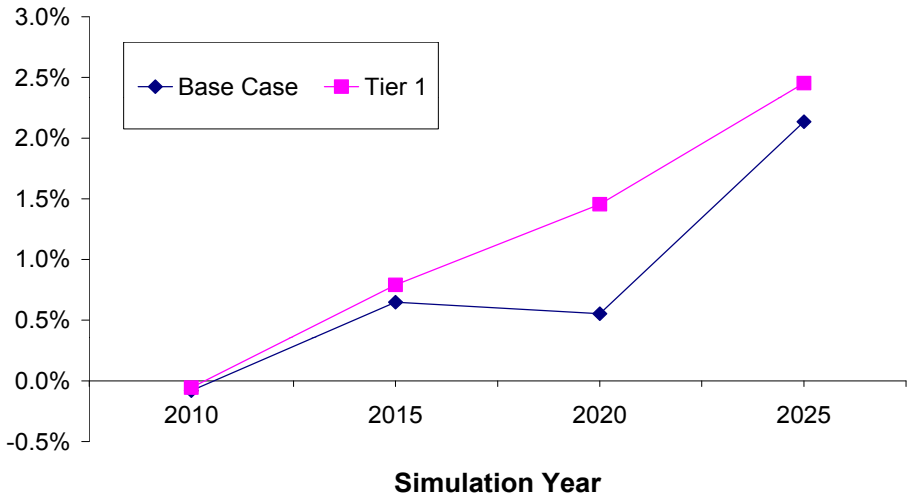
11

RESOURCES FOR THE FUTURE

% Change in Electricity Price



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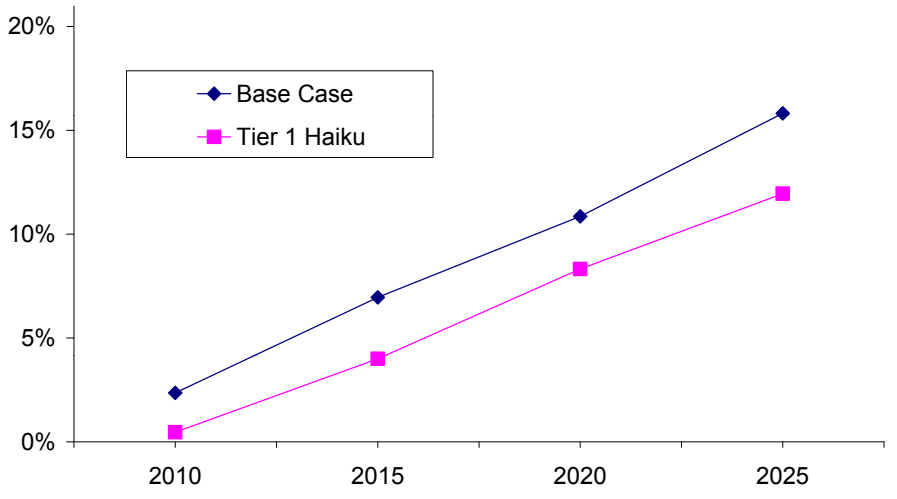
12

RESOURCES FOR THE FUTURE

% Decrease in CO_2 Emissions



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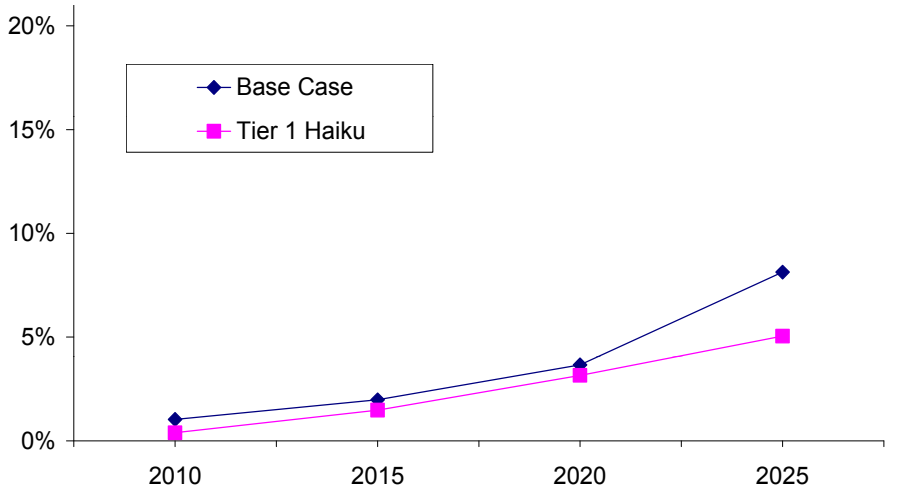
13

RESOURCES FOR THE FUTURE

% Decrease in Nat. Gas Price



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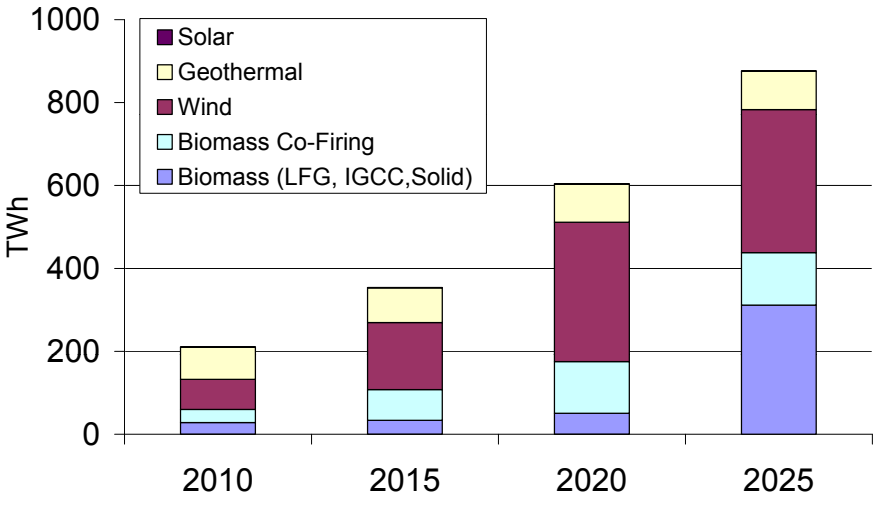
RESOURCES FOR THE FUTURE

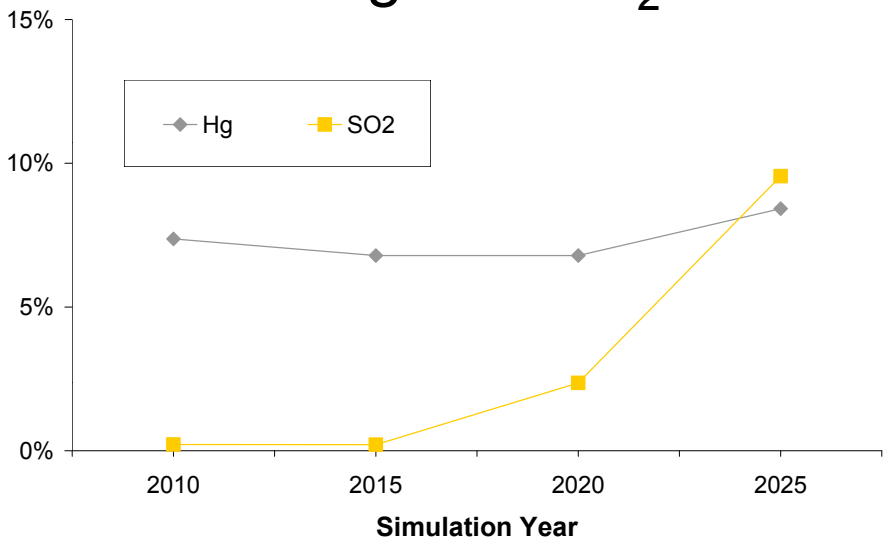
Detailed Tier 1 Findings

- Why does REC Price fall from 2020 to 2025?
  - IGCC Biomass learning
    - Construction constraint binds in Base Case.
  - Wind capacity factors falling
  - No banking of RECs
- What happens to pollution allowance prices?
  - SO_2 (Title IV/CAIR w/ banking) and Hg (CAMR w/ banking) prices behave as expected
  - Interesting behavior of NO_x prices (CAIR annual and seasonal w/ banking)

Renewable Generation with RPS



% Fall in Hg and SO_2 Price



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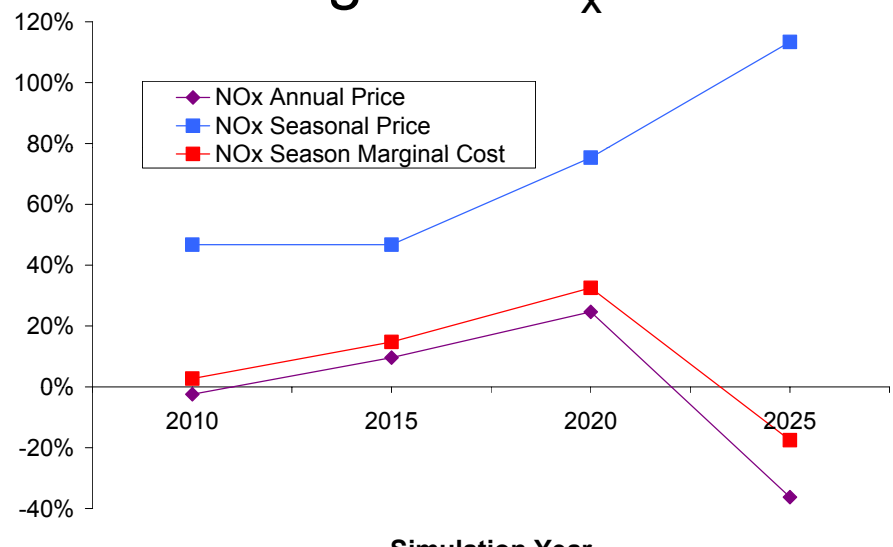
17

RESOURCES FOR THE FUTURE

% Change in NO_x Prices



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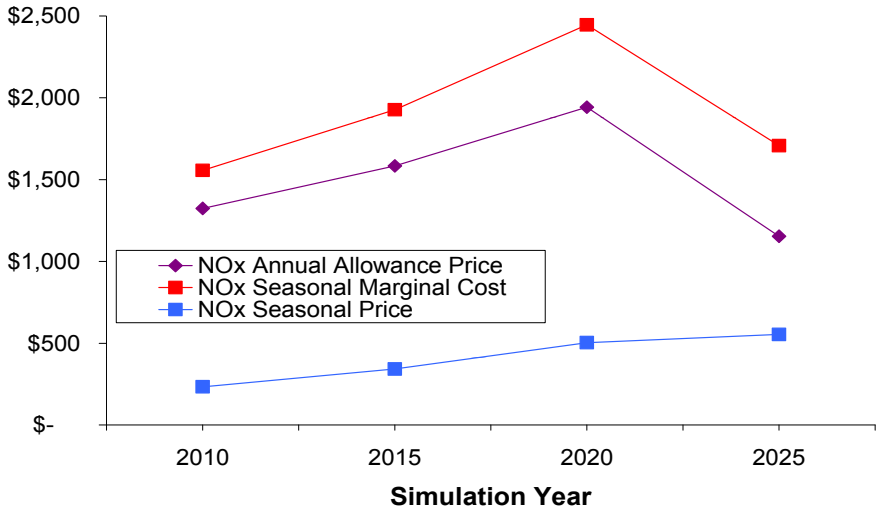
18

RESOURCES FOR THE FUTURE

NO_x Prices under RPS



Model Improvements Wish List

- (Relatively) Low Hanging Fruit
  - REC Banking
  - Off-shore wind
- High Hanging Fruit
  - Modeling multiple state/region markets where RECs can be generated out of state/region
    - Need to avoid double-counting and capture effects of differential treatment of technologies by states.
  - Wind resource on Federal lands (stated preference study)
  - Biomass opportunity costs (residual supply)

Thank You!

REMAP Tier 1 Analysis using Haiku

David A. Evans, Anthony Paul, Karen Palmer and Richard Sweeney*

12/20/2007

(With 7/15/2008 edits)

The purpose of this note is to summarize the Tier 1 reference and policy Haiku model run assumptions and results for the initial set of analyses for the Renewable Energy and Efficiency Modeling and Analysis Partnership (REMAP). The Tier 1 policy run imposes a 20% national renewable portfolio standard (RPS) policy to be achieved by 2020.

The memo begins with a brief summary of the treatment of major investment incentives, environmental and electricity pricing policies in the model. This includes a description of the policies on which information was requested in the January 16th, 2007 memo to REMAP participants as well as items that are valuable for interpreting the model results.

The second section describes how the RPS policy is modeled in Haiku. It lists those technologies that provide credit under the RPS policy and describes how the standard is adjusted to account for customer-sited self-generation from renewable technologies.

The third section describes the extent to which the Haiku model was calibrated to NEMS inputs per the goals of the Tier 1 analyses. In some cases Haiku had adopted these assumptions while for others the Haiku model has been changed for REMAP modeling. The most substantive change was to the renewable resource supply curves for wind, geothermal and biomass from NEMS. Previous versions of Haiku adopted older supply assumptions from NEMS and other sources for these resources. The fourth section lists other important differences between the version of Haiku used for these model runs and the version used for the Base Case runs. The last section presents model results aggregated to the national level. All prices and dollar figures are expressed in 2004 real dollars.

1 Baseline Assumptions

Table 1 provides a description of the major policies encouraging the use of renewable and other generation technologies and their treatment in Haiku. These policies are included in the reference case and the policy case. Table 2 provides a description of the major air quality rules affecting electricity generators and reports how these regulations are modeled in Haiku.

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* Evans is an Economist in the National Center for Environmental Economics at the U.S. Environmental Protection Agency, and Paul, Palmer and Sweeney are respectively Program Fellow, Senior Fellow and Research Assistant, Resources for the Future. Palmer is the corresponding author and can be contacted at palmer@rff.org .

The views expressed in this paper are those of the authors and do not necessarily represent those of the U.S. Environmental Protection Agency. In addition, although the research described in this report may have been funded entirely or in part by the U.S. Environmental Protection Agency, it has not been subjected to the Agency's required peer and policy review. No official Agency endorsement should be inferred.

Paul, Palmer and Sweeney received financial support from the National Renewable Energy Lab and the RFF Electricity and Environment Program, which is funded by contributions from corporations, government and foundations. The views expressed are solely the responsibility of the researchers and are not attributable to RFF, its Board of Directors or any program contributor.

Table 3 lists the 20 regions in the Haiku model and summarizes our assumptions regarding the status of electricity market regulation by region. Regions were designated as restructured if over 50% of the population in the region as a whole resided in states that have experienced electricity restructuring. Nine regions are characterized as restructured, and eleven are regulated.

Table 1. Investment Incentive Programs

Policy	Modeled Explicitly?	Alternative Method of Representing Policy?	Notes
Federal production tax credit for renewable technologies	No	Assure 2007 projects for renewable capacity comparable to AEO 2006	This policy had lapsed when the Base Case runs were conducted. Also, modeling sunset provision not possible in Haiku
Federal production tax credit for nuclear capacity	No	Force 6GW of new nuclear as projected by AEO 2006	Haiku builds more than 6GW of nuclear in the baseline anyway.
Federal investment tax credit	Yes for geothermal No for solar	No for solar projects	Geothermal is allowed to receive either the PTC or the ITC. Given that the PTC is not modeled, we assume new geothermal gets the ITC. Ability to construct new solar capacity not captured in the model.
Accelerated depreciation	Yes		Incentive of MACRS relative to 20-year depreciation is captured by adjusting capital costs
Existing state RPS policies	No	Adopt assumptions regarding renewable builds from AEO 2006 supplemented with projections as a result of NY and MD RPS policies	
State tax incentives/ system benefits charges for renewable energy	No	Adopt assumptions regarding renewable builds from AEO 2006	Haiku can model state-level renewable tax credits. It can also model regional RPS policies, but not simultaneously with a national policy.

Table 2. Environmental Regulatory Assumptions

Policy	Modeled Explicitly?	Alternative Method of Representing Policy?	Notes
State/Regional Carbon Policy	No	No	Carbon regulations can be modeled in Haiku
Federal Air Quality Regulations	Yes: CAIR, Title IV and CAMR No: BART (CAVR)		Allowances are grandfathered, SO_2, NO_X and Hg allowances may be banked
State Conventional Pollution Regulations	No	Assume control retrofits and fuel switching at certain facilities	For list of states and regulations see Appendix A of Palmer et al. 2005.[α]

α : Palmer, K.L., D. Burtraw, and J.-S. Shih. 2005. Reducing Emissions from the Electricity Sector: The Costs and Benefits Nationwide and for the Empire State. RFF Discussion Paper 05-23. http://www.rff.org/Documents/RFF-DP-05-23.pdf

Table 3. Haiku Model Regions and Regulatory Status

Region Name	States Included	Regulatory Status
NWP	Washington, Oregon, Idaho, Nevada, Utah, Montana (part), Wyoming	Regulated
CNV	California, small part of Nevada	Regulated
RA	Arizona, New Mexico, Colorado	Regulated
MAPP	North Dakota, South Dakota, Nebraska, Minnesota, Iowa and part of Wisconsin	Regulated
SPP	Kansas, Oklahoma,	Regulated
ERCOT	Most of Texas	Restructured
AMGF	Alabama, Mississippi, Georgia, part of Florida	Regulated
ENTN	Entergy, Tennessee	Regulated
VACR	Virginia (most of), North Carolina, South Carolina, DC	Regulated
OHMI	Ohio and Michigan	Restructured
KVWV	Kentucky, West Virginia and (western) Virginia	Regulated
MAIN	Most of Wisconsin, Illinois	Restructured
IN	Indiana	Regulated
PA	Pennsylvania	Restructured
MD	Maryland	Restructured
MAACR	New Jersey, Delaware	Restructured
NEO	Massachusetts, Rhode Island	Restructured
NER	Maine, New Hampshire, Vermont, Connecticut	Restructured
NY	New York	Restructured
FRCC	Florida	Regulated

2 Structure of RPS Policy

The renewable generation requirement is determined by a percentage of the total demand for electricity. The technologies that may receive credit under the RPS are listed in Table 4. Renewable generation from both the electricity sector and customer-sited self-generation, or simply "on-site" generation, from renewable technologies qualifies for credit.[1] Because Haiku does not model on-site generation and demand, the total amount of renewable generation required from the electricity sector is adjusted downward by the amount of on-site generation that is projected by the NEMS model in the NEMS Tier 1 runs. Table 5 reports the total on-site generation that qualifies for credit under the RPS. We do not think that using these values in lieu of modeling on-site generation and demand will affect comparisons of the consequences of the RPS policy between the Haiku and NEMS electricity market results as on-site generation is not very sensitive to the introduction of an RPS in the NEMS model.

The tradable credits underlying the RPS program cannot be banked and used for compliance in later years. This functionality is not available in the Haiku model.

Table 4. Technologies Eligible for Credit under RPS

	Existing as of 2004	**New**
Wind	Y	Y
Geothermal	Y	Y
Dedicated Biomass	Y	Y
Co-Fired Biomass	Not in model	Y
Landfill Gas	Y	Y
Solar	Y	Not in model
Ocean	Not in model	Not in model

Table 5: Assumed On-Site Generation Coming from Qualifying Technologies

Year	**TWh**
2010	75.2
2015	81.6
2020	91.5
2025	106.0

3 Calibrated Assumptions

On July 20, 2007, Nate Blair provided a memo to the modelers outlining the REMAP Tier 1 process. That memo contained a list of six categories of inputs that were to be calibrated across the models to the extent possible. These categories, and the extent to which Haiku was calibrated to NEMS, are described in this section.

[1] However, demand served by on-site generation does not count towards the total demand for electricity (i.e., the denominator for the RPS policy).

3.1 Technology Costs/Performance

We use our own analysis of publicly available data, such as the FERC Form 1, to identify the capital and operating cost of most (on a capacity basis) of the existing generators as of 2004 as well as their heat rate. For those primemovers where primary cost and efficiency data are not available, we draw our cost and performance assumptions for existing generators from EPRI studies, EPA's Integrated Planning Model, and the NEMS model.

For technologies that the model builds endogenously, we use the same capital and operating cost assumptions that are used in the NEMS model. The Haiku model also adopts the capital cost learning functions that are used in the NEMS model.

For financing costs Haiku uses the real cost of capital projected by NEMS as the cost of financing all new generating technologies. The capital cost projections from NEMS can be in found in the file *Tier1Bcase&20%results with financing.xls*, sheet *WACC*, which was provided to REMAP participants by Nate Blair.

3.2 Electricity Loads (Demand)

The demand functions in Haiku are constant elasticity functions:

$$Q=AP^{\varepsilon}$$

where the variables Q (quantity in kWh) and P (price in $/kWh) and the parameters A and ε (the later being the elasticity) are all indexed by consumer class, time block, and region. The elasticities are treated as constant over time and come from Dahl (1993)[2]. Haiku uses standard NEMS output data to grow the "A" parameters in the electricity demand functions. We cannot benchmark our demand curves to the NEMS output data in the *Tier1Bcase&20%results.xls* spreadsheet because the spreadsheet is not broken down by region. Instead, we use "Electricity" consumption for each of the three customer classes from Tables 1-9 (Energy Consumption by Sector and Source) from "Supplemental Tables to the AEO2006". For electricity prices by customer class, we turn to Tables 11-19 (Energy Prices by Sector and Source) from "Supplemental Tables to the AEO2006"

3.3 Fuel Prices

We use natural gas prices and quantities from the AEO 2006 reference, high and low growth cases to construct a natural gas supply curve for Haiku. Given that we do not have different growth cases for the NEMS REMAP Tier 1 reference and 20% cases, we cannot use this strategy for the Tier 1 model runs. However, we suspect that if we had this information for the Tier 1 reference runs, the resulting natural gas supply curves would not be much different than what we are using now.

Our coal supply module is also constructed entirely from NEMS data and results. We take coal production and prices from the AEO 2006 for each coal supply category. We also take from NEMS a matrix of coal transportation costs between coal supply and demand regions, a transportation price

[2] Dahl, Carol. 1993. A Survey of Energy Demand Elasticities in Support of the Development of the NEMS. October 19.

escalator, the heat and pollutant content of each coal type, and the elasticity of coal prices for underground/surface coal types.

3.4 Resource Supply Curves

We have adopted the NEMS geothermal, wind and biomass resource supply curves in the Haiku model. We emphasize that we use the resource supply curves, as opposed to electricity supply curves provided by Chris Namowicz (via Nate Blair), as Haiku uses the same primary data as NEMS uses to build up its own electricity supply curves by region for these resources. We did use NEMS projected annual capacity factors for wind, which increase over time, because Haiku does not model "capacity factor learning" for wind. Because the electricity market subregions in Haiku differ from those used in NEMS, some adjustment of the biomass and wind resource supply curves was necessary.

One important difference between the wind resource assumptions in NEMS and Haiku is that Haiku assumes that each of the three wind classes in each region are built in proportion to their availability. Otherwise the resource availability and cost assumptions such as the base capital cost, long term cost multipliers, learning, and interconnection costs are the same.

3.5 Macroeconomic Inputs

With the exception of those macroeconomic fundamentals that implicitly influence fuel prices, demand growth and the cost of capital, no NEMS macroeconomic inputs were used in the Haiku model.

3.6 Inputs Submittal Request

Nate Blair's July 20, 2007, memo also requested that each model team report its assumptions regarding technology costs/performance, the cost of capital, coal and natural gas fuel prices, and electricity demand. As described above, these components of Haiku follow the input assumptions in NEMS or are functions that are calibrated to NEMS results. Nate's memo also requested that any elasticities in the model and the cost of new transmission and wheeling.

For the capital costs, heat rates, and capacity factors for new technologies, as well as a brief description of the elasticities and transmission cost used in Haiku, see the preceding discussion as well as the spreadsheet accompanying this memo labeled *REMAP Tier 1 Inputs Tables - Haiku 071218.xls*. The construction of the fuel supply curves and electricity demand curves for Haiku is described above. The fuel prices and electricity demand forecast by the Haiku model are provided in Sections 5 and 6.

4 Other Changes to Haiku from March 2007 Base Case Runs

Other changes to the Haiku model in the Tier 1 model runs from the Base Case model runs include moving to a common economic lifetime for all new capacity (20 years), removing many of the bounds we imposed on annual and total new capacity construction across the forecast horizon.

We found two errors in the model for the Base Case analysis regarding the modeling of renewable generation potential. Both of these errors had the effect of lowering the price of renewables capacity. The first mistake is that we inadvertently expanded the wind resource potential and the available

biomass supply in the regions formally known as ECAR and STV.[3]This error is not very consequential in encouraging the construction of wind capacity given that the wind resource potential was low in these regions to begin with. However, these regions are a large source of biomass fuels in the RPS policies for the Base Case runs. The second error was to lower the geothermal capacity. While the details are complicated, the basic story is that rather than using average costs for each segment of the geothermal supply curve, the lower bound for that segment was used. All of these errors are corrected in the Tier 1 runs.

5 Haiku Tier 1 Forecasts

Table 6 provides a summary comparison of the Tier 1 reference and RPS policy Haiku runs. Table 7 breaks down generation and capacity by fuel/prime mover type for each of these runs. The choice of simulation years is the default in Haiku.

Table 6. Summary of Haiku Tier 1 Reference and Policy Runs

	Reference				20% RPS			
	2010	2015	2020	2025	2010	2015	2020	2025
Electricity Generation (BkWh)	4,256	4,618	4,918	5,239	4,256	4,608	4,895	5,206
Electricity Demand (BkWh)	4,011	4,367	4,648	4,949	4,011	4,357	4,627	4,914
Electricity Price ($/MWh)	$71.76	$68.29	$72.19	$75.03	$71.72	$68.83	$73.24	$76.87
REC Trading Price ($/MWh)	$0	$0	$0	$0	$0.00	$8.02	$16.34	$15.23

[3] These are market regions in NEMS. In Haiku, each of these two regions is divided into three separate regions. When we divided these regions up into smaller regions we inadvertently applied the wind and biomass supply curves that are appropriate for the entire region to the smaller regions.

Table 7. Haiku Tier 1 Reference and Policy Case Capacity and Generation Comparison

	Reference				20% RPS			
	2010	2015	2020	2025	2010	2015	2020	2025
Generation (BkWh)								
Coal	2,212	2,260	2,414	2,694	2,201	2,179	2,241	2,383
Natural Gas	695	975	952	835	682	893	791	661
Oil	42	43	42	37	42	41	36	31
Hydro (Conv.)	312	312	312	312	312	312	312	312
MSW	21	22	22	22	21	22	22	22
Nuclear Power	787	807	930	948	786	807	888	920
Other	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0
Total Conventional	*4,078*	*4,428*	*4,682*	*4,861*	*4,045*	*4,254*	*4,291*	*4,329*
Biomass								
Dedicated [β]	13	13	25	142	28	33	51	312
Co-firing	33	35	42	44	32	74	125	127
Geothermal	63	65	85	86	78	84	92	93
Solar	1	1	1	1	1	1	1	1
Wind	68	77	82	106	73	162	336	345
Total Renewable	*178*	*190*	*235*	*378*	*211*	*354*	*604*	*877*
Total	*4,256*	*4,618*	*4,918*	*5,239*	*4,256*	*4,608*	*4,895*	*5,206*
Capacity (GW)[α]								
Coal	339.1	344.9	351.0	381.2	337.6	334.9	332.0	346.4
Gas/Oil Steam	118.0	117.7	115.6	109.6	114.3	114.0	111.9	103.0
CCGT (Oil, Nat Gas)	178.3	178.3	178.3	177.9	165.8	164.4	163.0	159.0
GT (Oil, Nat Gas)	144.2	144.2	144.2	144.2	144.2	144.2	144.1	144.1
Nuclear Power	108.0	109.8	124.9	125.9	108.0	109.8	119.8	122.8
Hydro (Conv.)	75.7	75.7	75.7	75.7	75.7	75.7	75.7	75.7
MSW	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Other	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1
Total Conventional	*1,059*	*1,072*	*1,095*	*1,129*	*1,041*	*1,044*	*1,051*	*1,064*
Biomass								
Dedicated [β]	3.1	3.1	4.7	22.2	4.0	4.4	5.0	44.1
Co-firing	5.4	6.2	6.7	6.7	5.3	11.9	18.9	19.5
Geothermal	9.5	9.6	12.2	12.2	11.5	12.2	13.2	13.2
Solar	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Wind	21.6	24.3	25.7	33.3	22.7	49.0	101.2	102.1
Total Renewable	*39.9*	*43.5*	*49.7*	*74.9*	*43.9*	*78.0*	*138.6*	*179.2*
Total	*1,098.7*	*1,115.9*	*1,144.7*	*1,204.0*	*1,084.9*	*1,122.1*	*1,189.3*	*1243.5*

Notes α: Nameplate capacity.
β: Includes landfill gas

Wind Deployment System Model (WinDS) and Regional Energy Deployment System (ReEDS) For REMAP

Nate Blair, Patrick Sullivan, Walter Short, Donna Heimiller
National Renewable Energy Laboratory

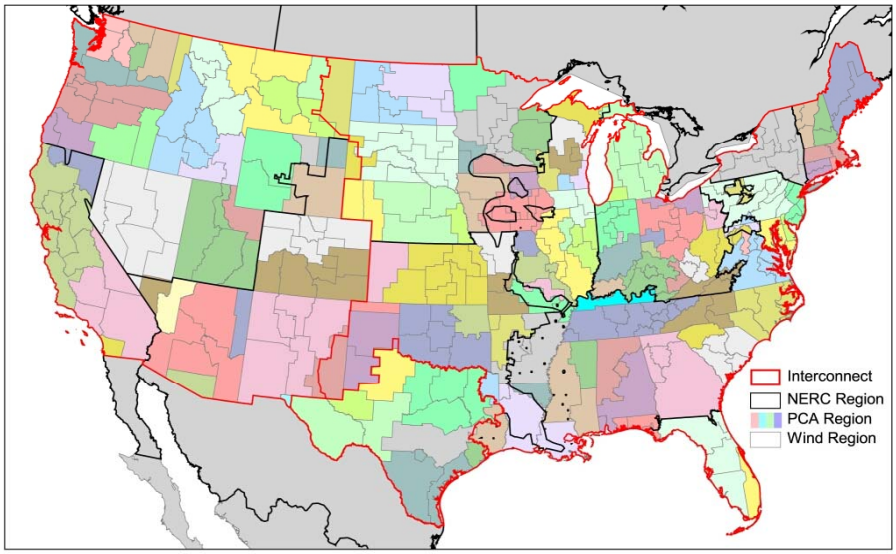
Overall Deployment System Model

Wind Deployment System Model (WinDS) and Regional Energy Deployment System (ReEDS)

- A multi-regional, multi-time-period model of capacity expansion in the electric sector of the U.S. focused on renewables.
- Designed to estimate market potential of renewable energy in the U.S. under different technology development and policy scenarios
- Linear program cost minimization every 2 years for 50 years



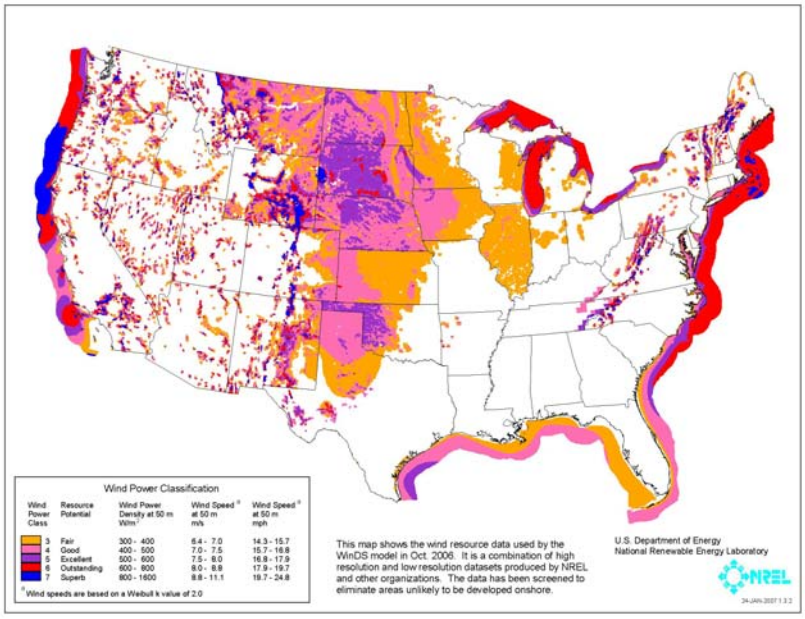
REeDS Regions – Our Unique Capability



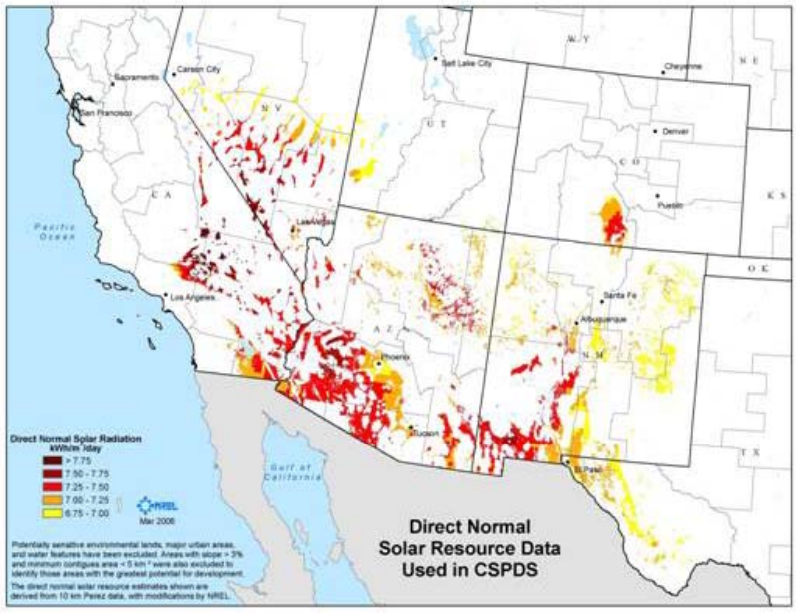
General Characteristics for Round 1

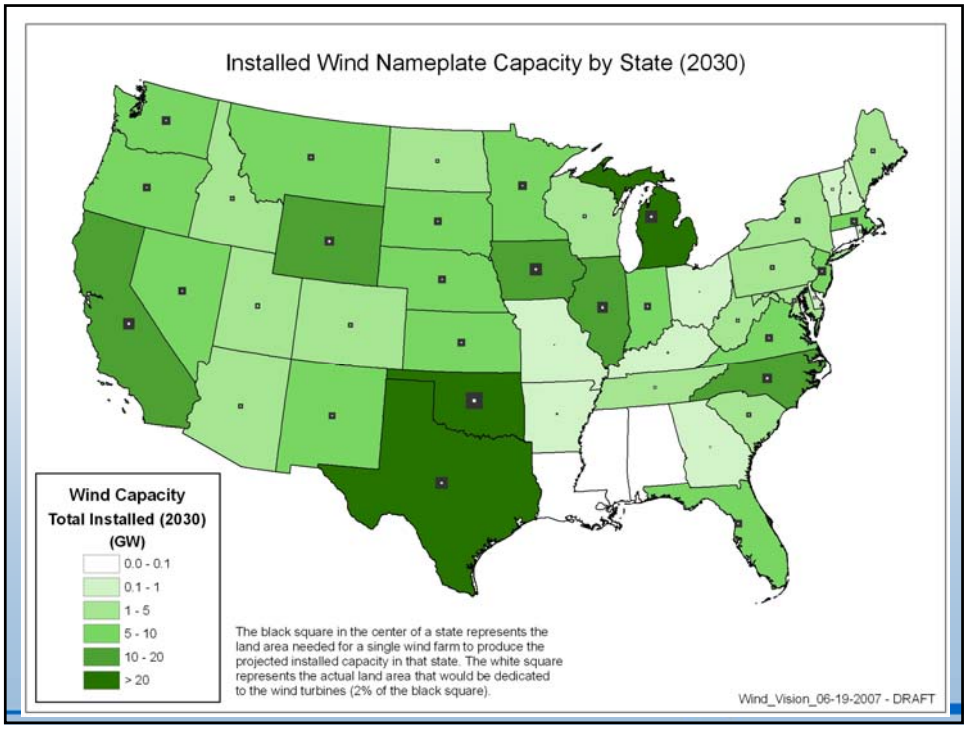
- Sixteen time slices in each year: 4 daily and 4 seasons
  - Capacity factors for each timeslice determined by hourly simulation
- 4 levels of regions – resource supply/demand, power control areas, NERC areas, Interconnection areas
- Existing and new transmission lines
- Renewable resource data from NREL:
  - 5 wind classes (3-7), onshore, offshore shallow and offshore deep
  - 5 solar classes (6.75 kW/m2/day to 8 kw/m2/day) in Southwest U.S.
- All major power technologies – hydro, gas CT, gas CC, 4 coal technologies (old w/scrubbers, old no scrubbers, adv. pulv., IGCC), nuclear, gas/oil steam
- Conventional capacity costs, performance and fuel prices taken from EIA's Annual Energy Outlook (AEO), 20% wind scenario inputs, or other sources
- Electric Loads from RDI/Platts database; Electric load growth rate based on AEO

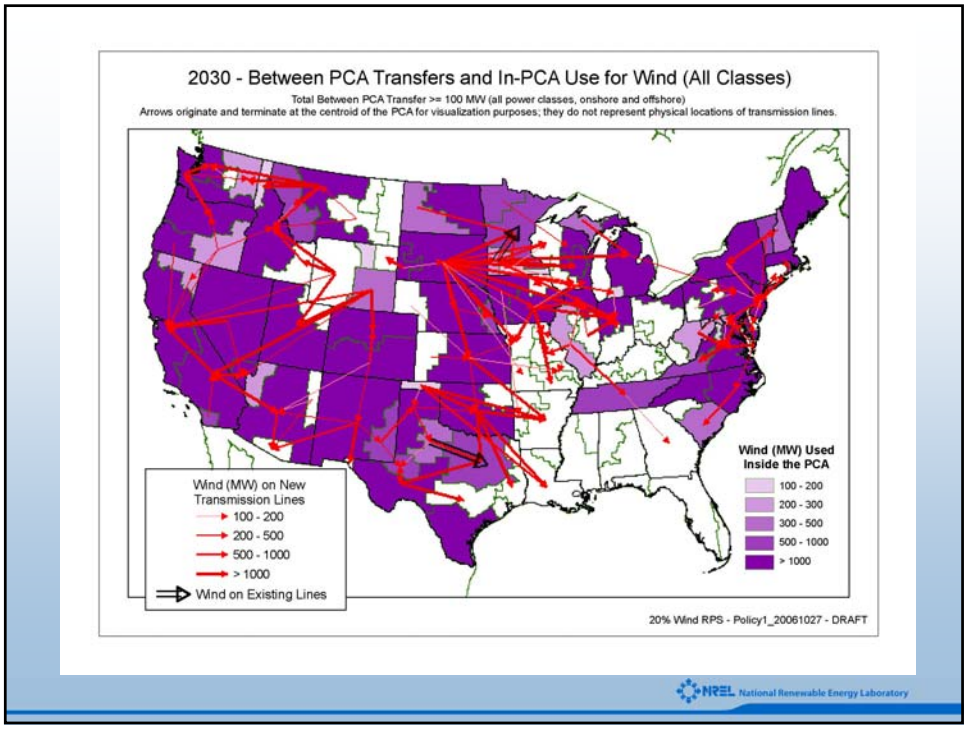
Wind Resource in ReEDS



Direct Solar Resource in ReEDS

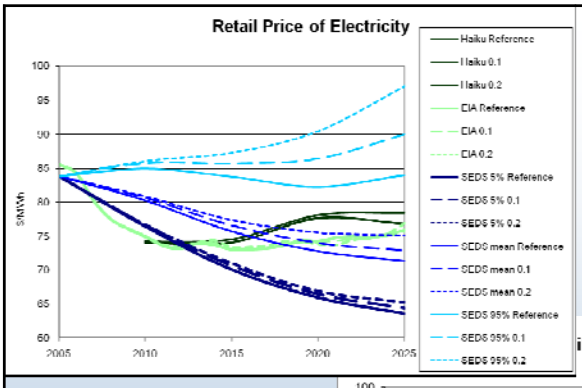



Installed Wind Nameplate Capacity by State (2030)
Wind Capacity
Total Installed (2030)
(GW)
0.0 - 0.1
0.1 - 1
1 - 5
5 - 10
10 - 20
> 20
The black square in the center of a state represents the land area needed for a single wind farm to produce the projected installed capacity in that state. The white square represents the actual land area that would be dedicated to the wind turbines (2% of the black square).
Wind_Vision_06-19-2007 - DRAFT


2030 - Between PCA Transfers and In-PCA Use for Wind (All Classes)
Total Between PCA Transfer >= 100 MW (all power classes, onshore and offshore)
Arrows originate and terminate at the centroid of the PCA for visualization purposes; they do not represent physical locations of transmission lines.
Wind (MW) Used Inside the PCA
100 - 200
200 - 300
300 - 500
500 - 1000
> 1000
Wind (MW) on New Transmission Lines
100 - 200
200 - 500
500 - 1000
> 1000
Wind on Existing Lines
20% Wind RPS - Policy1_20061027 - DRAFT
NREL National Renewable Energy Laboratory

Round 1 Renewable Input Assumptions

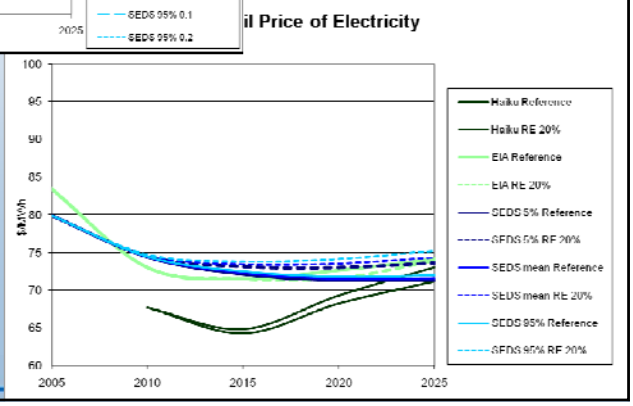
- Concentrating Solar Power
  - SEGS Type Trough Plant
  - Typical 100 MW plant with 6 hrs thermal storage
  - Prescribed capacity factor based NREL model (NREL CSP specific model)
  - Costs (capital, fixed O&M, Variable O&M) from NREL/DOE
  - Assume cost reductions in line with DOE goals
  - 8% learning rate based on national and global growth
  - Independent Power Producer (IPP) financing
- Wind Assumptions
  - Exogenous R&D improvements based on 20% wind scenario forecasts (capital costs, O&M, capacity factors by class)
  - 8% learning Rate based on national and global growth
  - Overall resource, Seasonal/Diurnal wind variation from NREL resource data

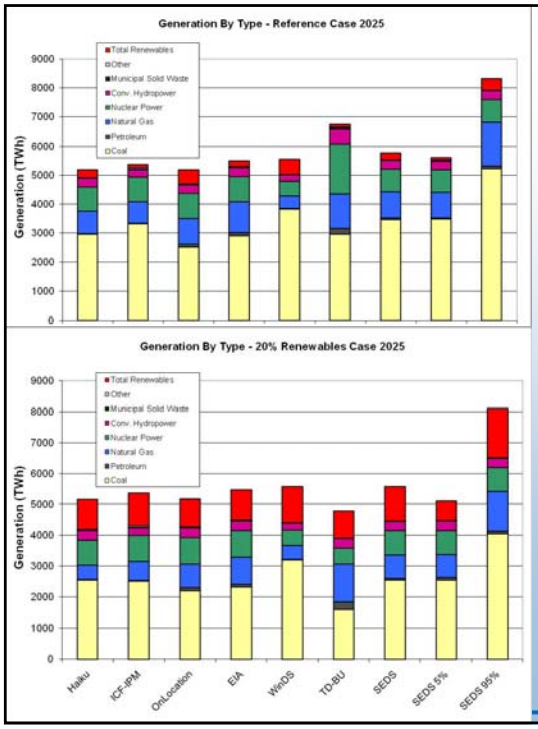


Round 1

Notice who is missing? New development version allows for output of electric price

Tier 1



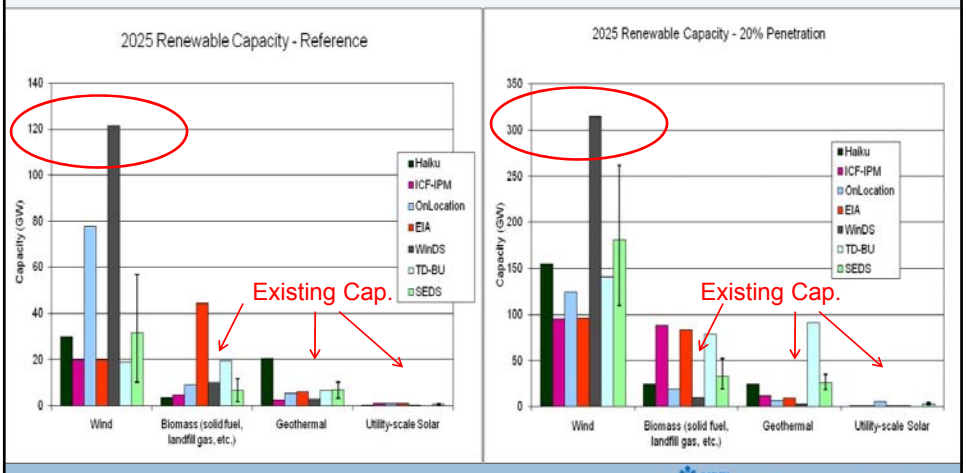


Round 1

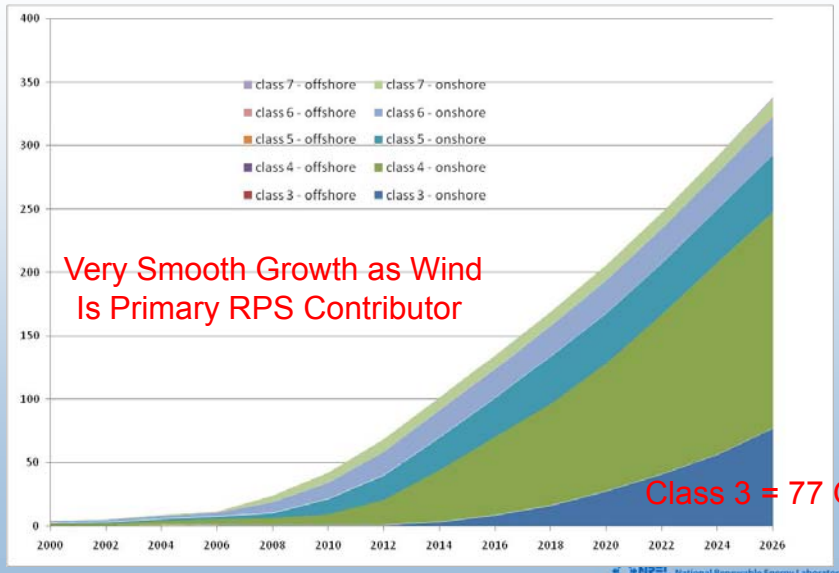
- WinDS is generally higher in coal generation and lower in gas generation
- Coal generation doesn't change too much between reference and 20%
- WinDS is higher in renewable generation in reference case

Round 1: Too Much Wind

- WinDS could only meet 20% requirement with wind and CSP (which was still too expensive in 2025)



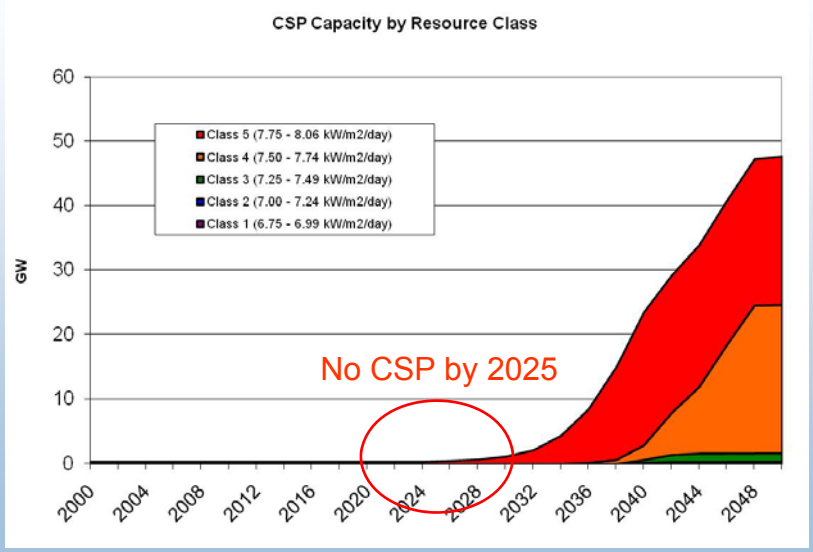
Round 1 20% Wind Capacity



Very Smooth Growth as Wind Is Primary RPS Contributor

Class 3 = 77 GW

Round 1 CSP Capacity by Class

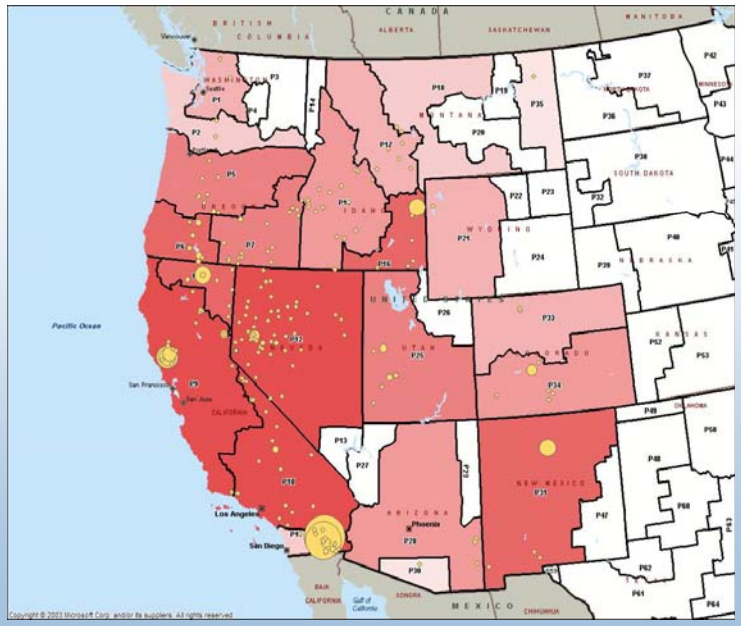


No CSP by 2025

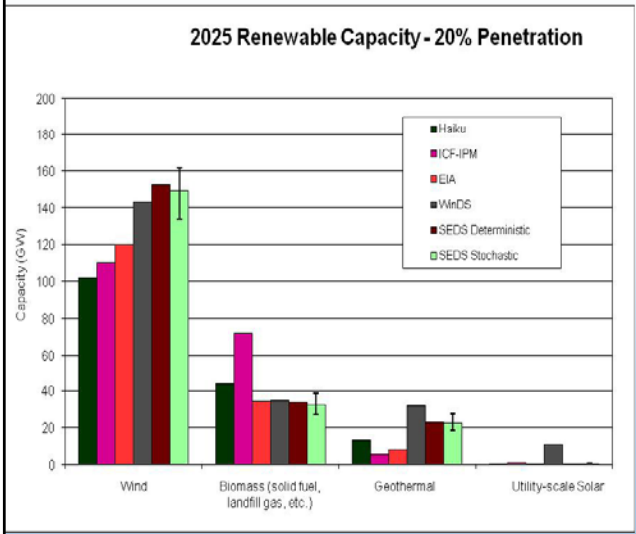
Changes to Align with Tier 1

- Changed cost structure for all inputs from current standard to EIA inputs.
- Removed Class 3 Wind Resource from Resource Pool (leaving Class 4, 5, 6 and 7).
- Did NOT adopt EIA resource curves for wind, etc.
- Class 7 grouped with Class 6 by using the same cost/performance data.
- Allowed ReEDS to use new geothermal modeling capability
- Forced builds of biomass capacity to match EIA
  - (Note that this will not be necessary in the future)

Geothermal Resource in ReEDS

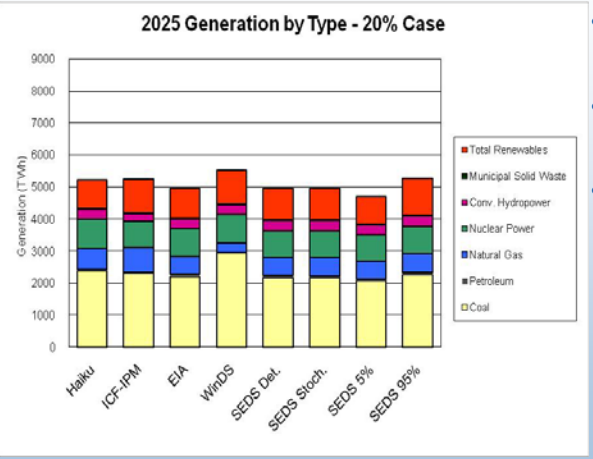


Renewable Capacity Breakdown



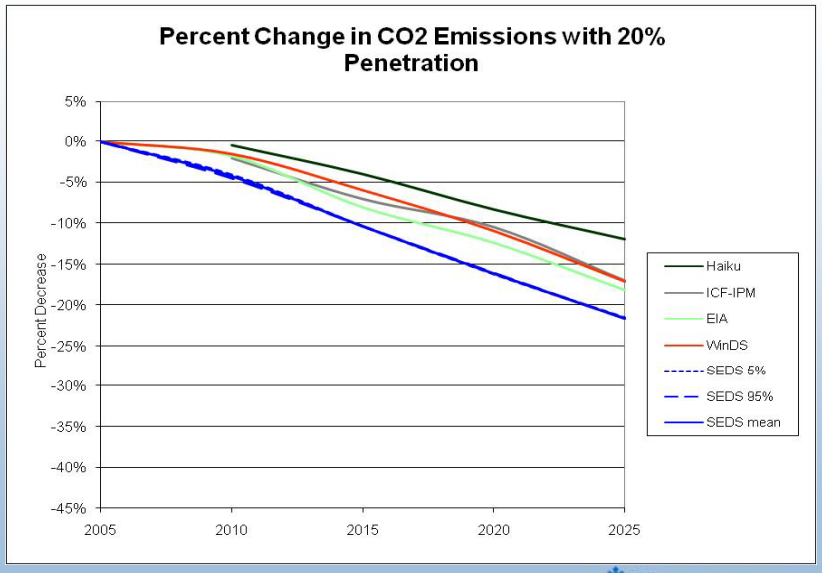
- Wind slightly higher than EIA
- Biomass forced to match EIA as planned
- Geothermal more than any other model
- CSP forms utility-scale solar contribution
- No PV in ReEDS so no distributed solar contribution

Conventional Generation Breakdown

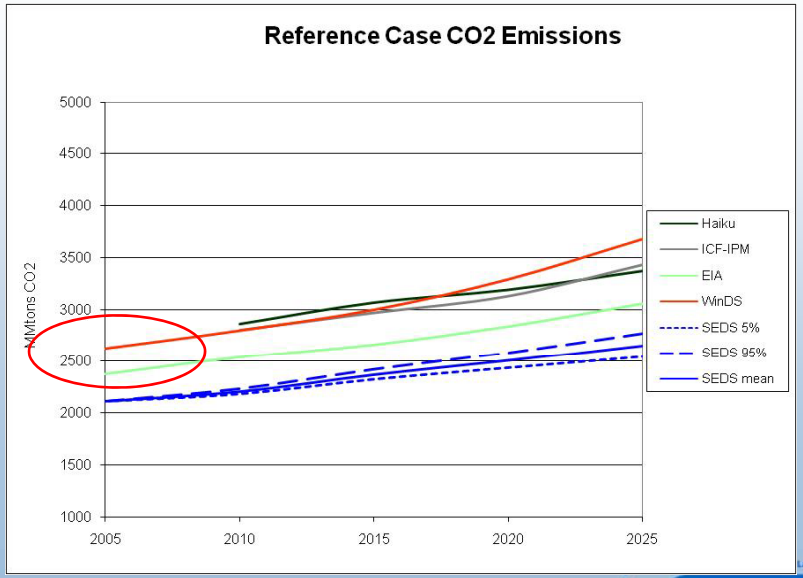


- More Coal generation than other models
- Less Gas generation than other models
- More overall generation than others
  - –Partly due to transmission losses
  - –Small level of wind surplus
  - –Load growth needs to be checked

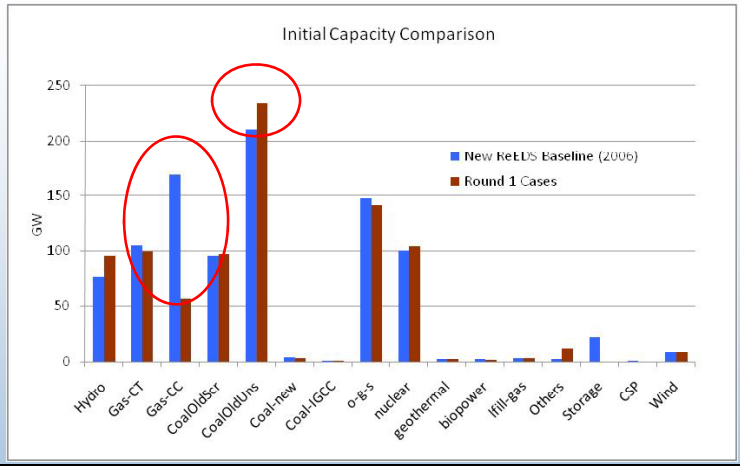
CO_2 Reduction Matches Other Models



Tier 1 WinDS initial CO2 emissions higher than EIA

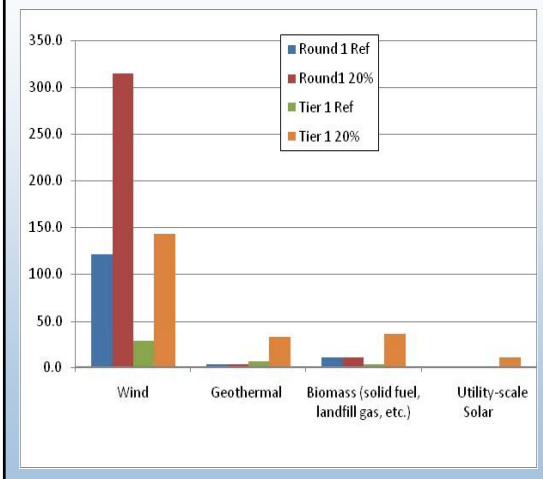


Changes to Initial Capacities



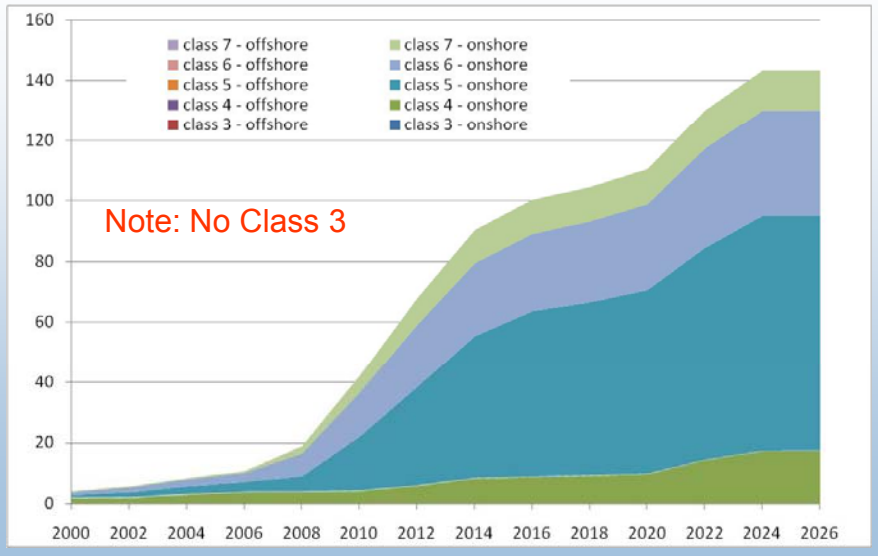
[redacted]

2025 Renewable Capacity Comparison

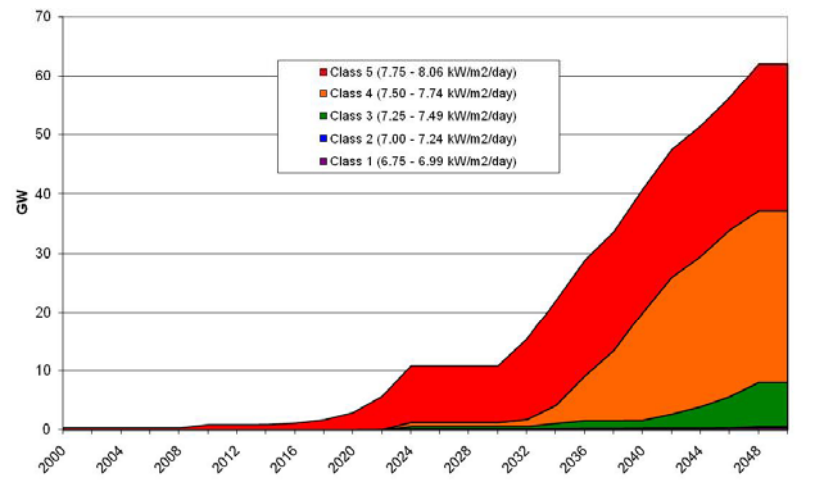


- Wind much less of 20% with forced biomass and ability to build geothermal
- Removal of class 3 wind reduces attractiveness
- CSP cost alignment with EIA results in greater penetration
- Initial biomass capacity reduced from 10 GW due to retirements

Tier 1 Wind Capacity by class



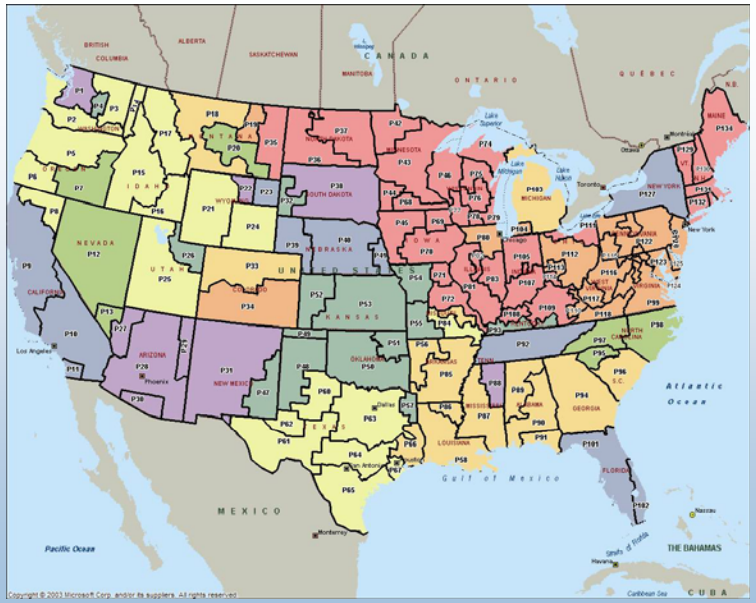
Tier 1 CSP Capacity by Class



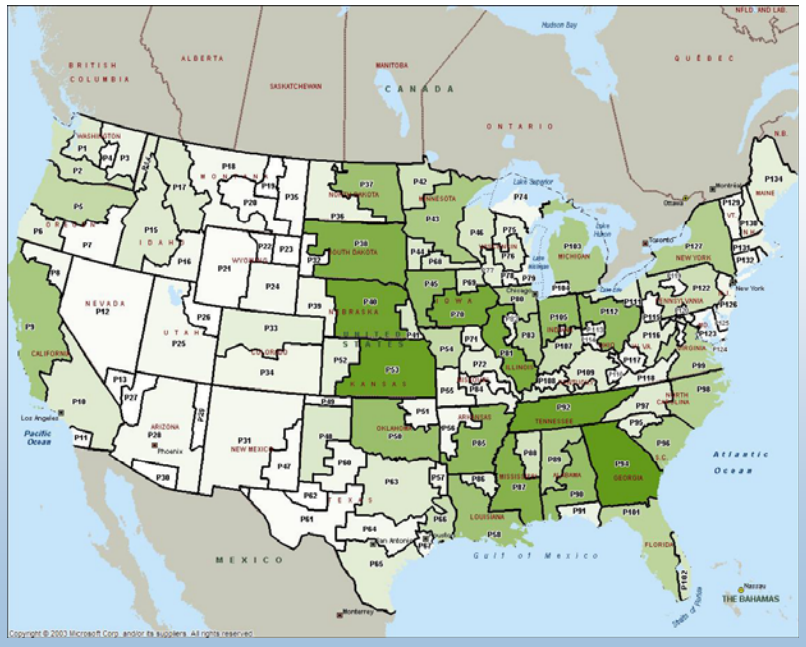
New Characteristics of ReEDS

- All major power technologies – hydro, gas CT, gas CC, 4 coal technologies (w/wo *sequestration*), nuclear, gas/oil steam, wind, CSP, biopower, geothermal
- Sixteen time slices in each year: 4 daily and 4 seasons (plus one super-peak slice)
- 5 levels of regions – RE supply, power control areas, RTOs, NERC areas, Interconnection areas
- Electricity storage – pumped hydro, batteries, CAES at grid or wind Site, H2/fuel cell at grid or wind site
- Simple elasticities provide *demand* and fossil fuel price response
- Stochastic treatment of wind and *CSP resource* variability – planning reserves, operating reserves, curtailments
- Capability to model CSP with no storage or utility-scale PV
- Electricity Price Calculation

ReEDS RTOs/ISOs



Biomass Resource in ReEDS



NREL National Renewable Energy Laboratory

Conclusions

- WinDS/ReEDS aligns much more closely to other models in Tier 1 than in Round 1
  - Wind is no longer sole source of renewables
  - Removing Class 3 wind improved agreement
  - Prescribing biomass capacity/generation did likewise
  - Future additions of other renewables should allow more precise agreement
- CSP cost and performance inputs have a major impact on CSP penetration
- Our standard cost inputs differ dramatically from the Tier 1 / EIA inputs
- Inconsistent initial capacities track through the entire scenario
- Having all RE and efficiency options present is necessary to get the correct wind or CSP answer for an RPS or other inclusive policies (like carbon tax/cap policy)

NREL National Renewable Energy Laboratory

NE-MARKAL Tier I and Round I Comparison

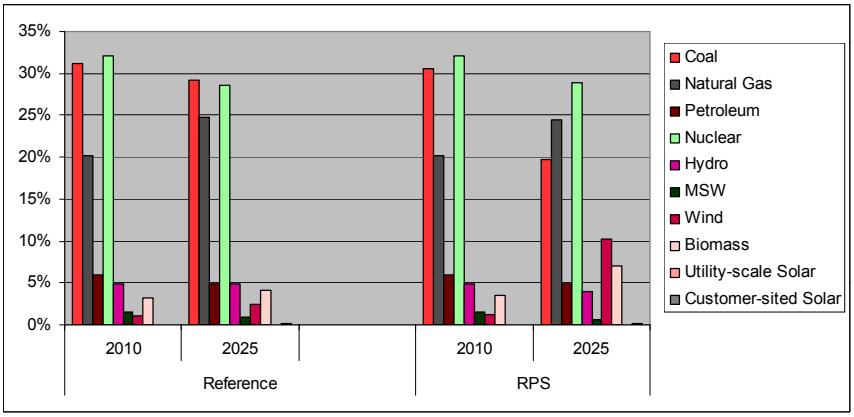
Gary Goldstein, Evelyn Wright, Pat DeLaquil, IRG
Gary Kleiman, NESCAUM

REMAP Tier I Meeting
April 30, 2008

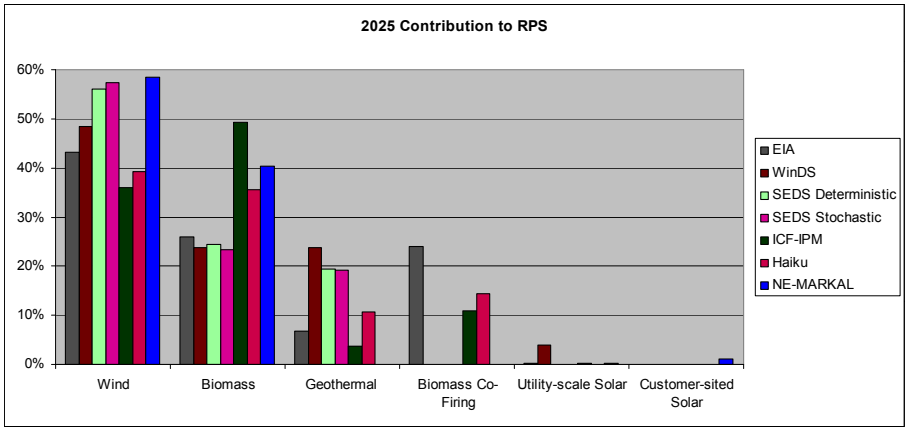
NE-MARKAL Model Characteristics

- Inter-temporal optimizing/perfect foresight engineering/economic model selects the least-cost optimized solution for meeting specified energy service demands
- Base year is 2002 and it solves in 3 year time periods (i.e. 2002, 2005, 2008...2029)
- Nine regions: ME, NH, VT, MA, RI, CT, NY, NJ, and PA (adding DE, MD, and DC)

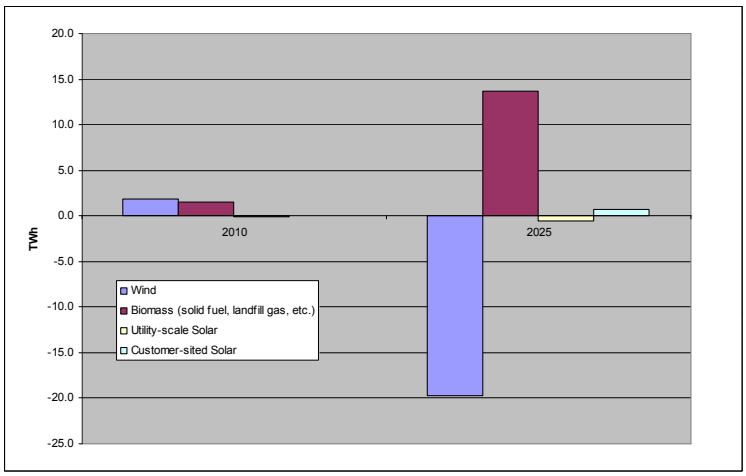
NE-MARKAL Generation Mix



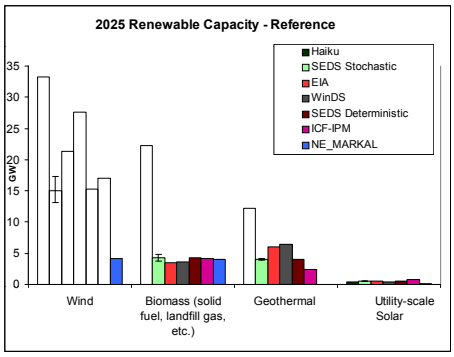
Renewable Generation Mix

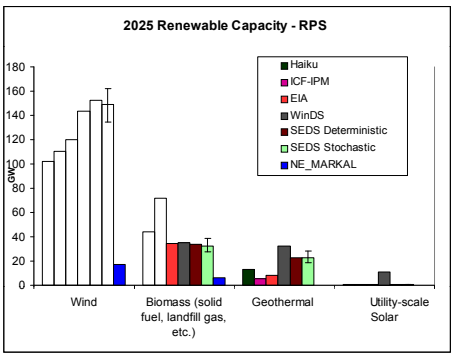


RE Generation Difference from Round I

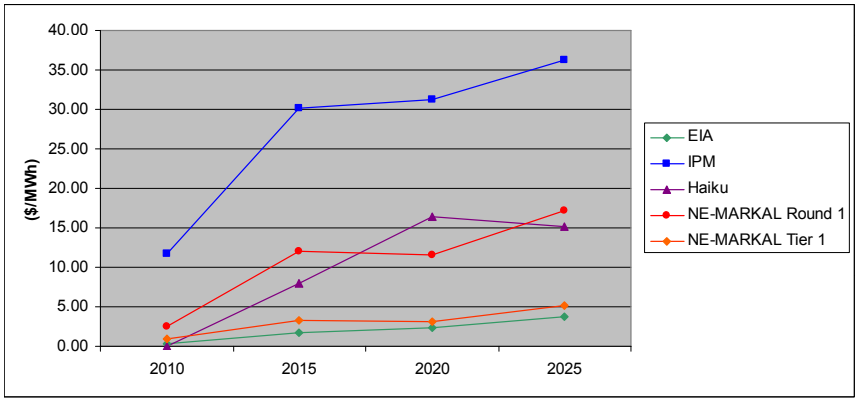


Renewable Capacity

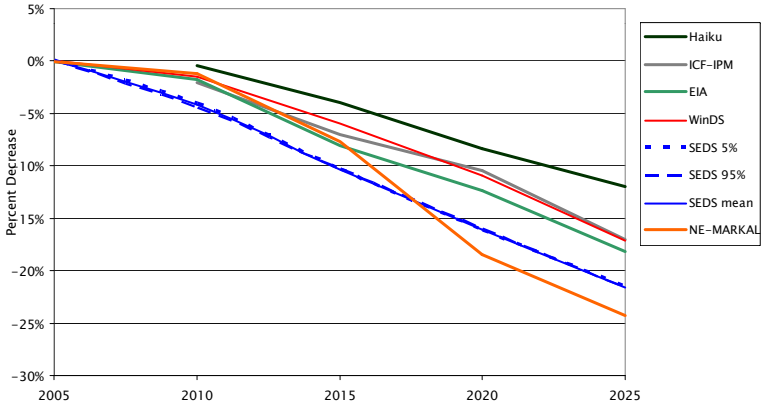




REC Trading Price Shows Wide Variation



Change in CO2 Emissions from RPS



Differences from Round I

- More biomass, less wind
- 75% lower REC price
- 50% lower ELC sector expenditures
  - May have to do with other calibration changes in the ELC sector?

Comparison to Other Tier I Models

- Differences:
  - Regional generation mix
  - Renewables available
- Similarities
  - Little demand response
    Costs within wide range of model results

What Does A Regional Model Add?

- Individual power plant representation
- State level policies and considerations
- More detailed representation of potential and constraints
  - Resource characterization
  - Distance from main power lines/demand centers
  - Siting constraints
- "Customizable" at state level; full value will be realized only with that customization

Areas for Future Work

- Sensitivity analysis on biomass supply, wind siting constraints (underway)
- Addition of biomass cofiring (underway)
- State level vetting of model assumptions and response (underway)
- Addition of local air quality precursors and Hg (underway)
- Assessment of transmission bottleneck and capacity addition representation (more difficult)
  - Break out NYC?

Stochastic Energy Deployment Systems Model (SEDS)

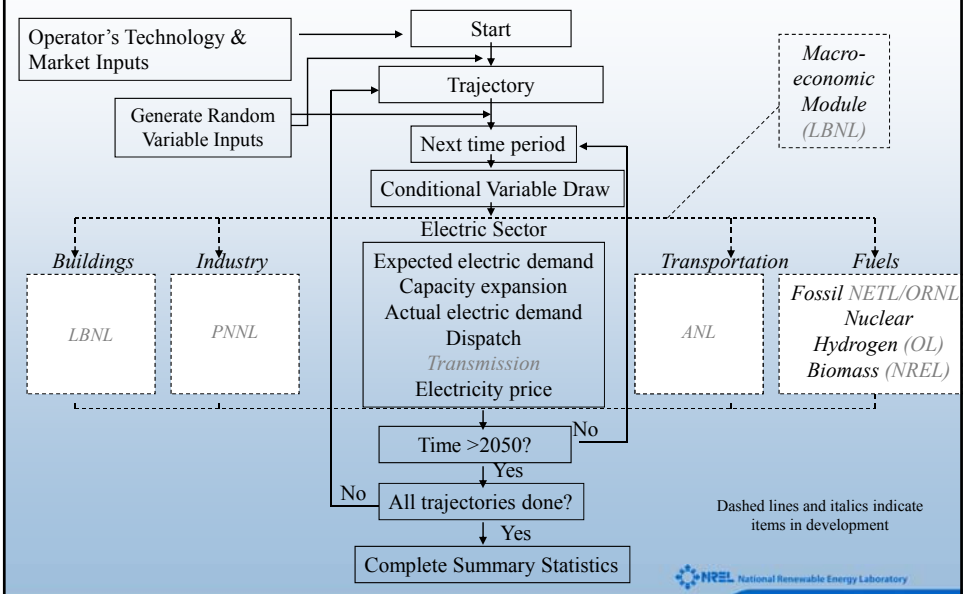
REMAP
April 30, 2008

James Milford
Walter Short

Stochastic Energy Deployment Systems Model: General Description

- Model of U.S. energy markets: Results shown today are for electric sector only
- 2010 to 2050 in 5-year increments (will be 1 year in integrated model)
- Explicit treatment of uncertainty with Monte Carlo simulations
  - actually Latin Hypercube
- Analytica software environment
- Simulation – not optimization
- Single national region
- Base, intermediate, and peak power markets
- Logit market share for new capacity
- All major electric prime mover types – coal, gas, nuclear, hydro
- Engineering/economic costs and efficiencies
- Endogenous technology change through learning curves
- Renewable energy supply curves
- Least cost dispatch
- Lack of foresight
- Planned and economic plant retirements

SEDS Modules and Routine



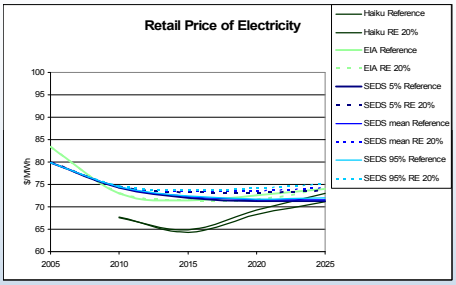
SEDS Status

- Results shown today are from a demo version of the electric sector
- Results from the integrated module can be expected to be significantly different
- We now have alpha versions of all but the transmission and LDV modules
- Expect to have the basic integrated model working this summer

Uncertain Major Market Drivers in SEDS Electric Sector Demo Module

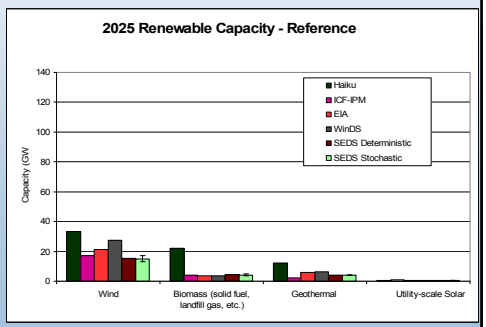
- Policy/environment
  - Climate change
  - Production Tax Credit
  - Nuclear builds = f (climate change, Yucca Mtn, etc.)
- Fossil fuel prices
  - Natural Gas, Oil and Coal
- Technological advances (e.g $/kW, capacity factor)
  - Due to R&D
    Due to learning
- The Economy
  - Electric demand
    - Growth
    - Elasticity

Tier 1 Model Comparisons



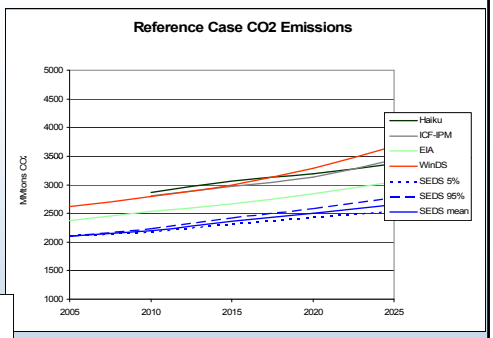
- SEDS electric price increases more due to RPS than EIA

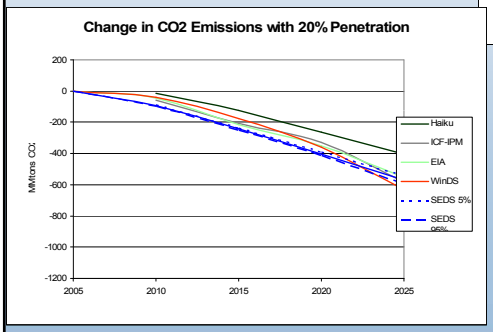
- SEDS Reference case Renewables consistent with those of other models



(2) Tier 1 Model Comparisons

- SEDS electric sector CO2 emissions inappropriately lower than other models





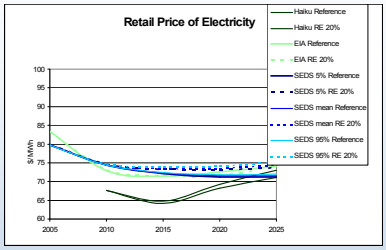
- SEDS CO2 emission reductions consistent with other models. Early year difference due to 5 year periods

SEDS Input Changes from Round 1 to Tier 1

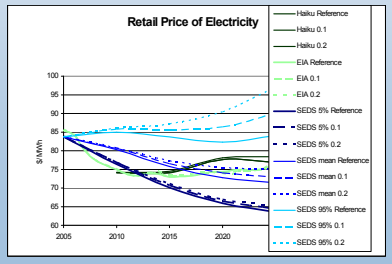
- Fossil fuel price uncertainty changed from random growth rate to uniform distribution (-5% to +15%) around AEO reference case trajectory.
- Removed correlation between oil, gas and coal prices.
- Modified representation of technology improvement uncertainty to uniform distributions around AEO values. (Costs: min=-15%, max=15%, capacity factors for wind, PV, and CSP min=0%, max=20%, capacity factors for all other technologies min=0%, max=5%)
- Removed policies and their uncertainty:
  - Carbon tax
  - PTC extension
  - Utilization of Yucca Mountain

Reference Case: Tier 1 vs Round 1

Tier 1



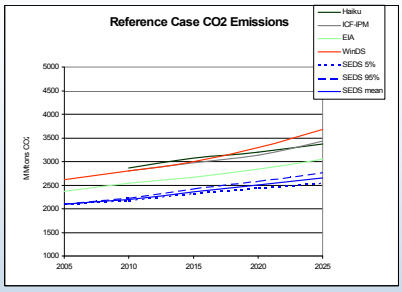
Round 1



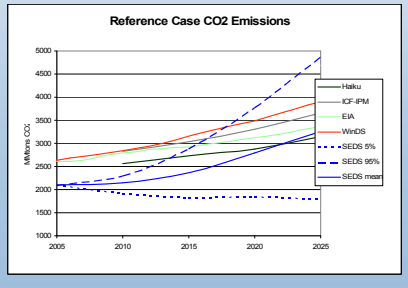
- Mean SEDS electricity price similar to other models
- Range of uncertainty much reduced in Tier 1 results

(2) Reference Case: Tier 1 vs Round 1

Tier 1



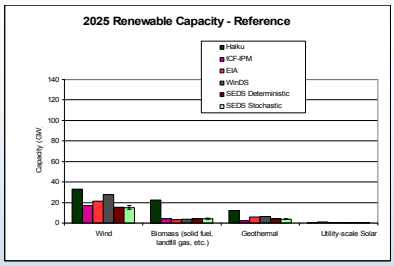
Round 1



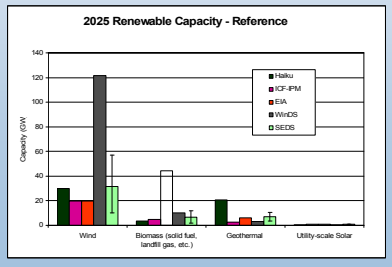
- Tier 1 uncertainty reduced
- Round 1 uncertainty very high due to prominence of carbon tax uncertainty

(3) Reference Case: Tier 1 vs Round 1

Tier 1



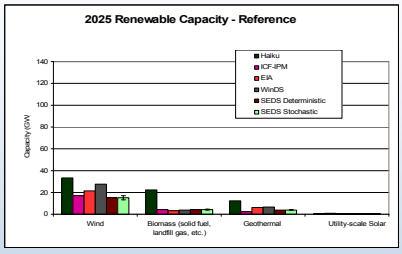
Round 1



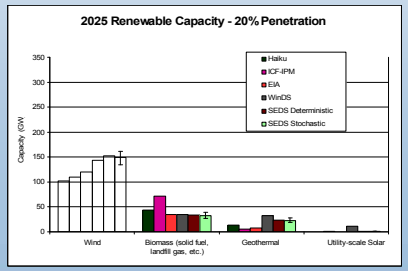
- Use of the same cost inputs as EIA in Tier 1 produced slightly less renewables than EIA
- Tier 1 has less uncertainty

Tier 1 Reference vs 20% RPS Case

Reference



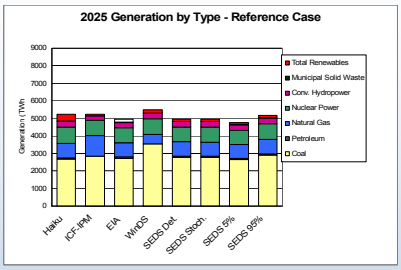
20% RPS



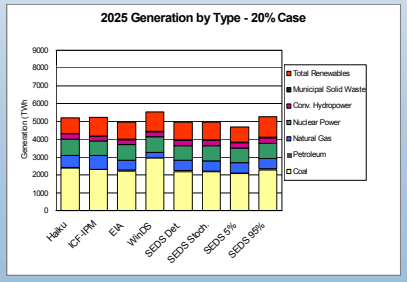
- SEDS Wind capacity higher than that of other models in the 20% case, but lower in the Reference case
- Biomass and geothermal consistent with other models
- Uncertainty slightly larger in the 20% case

(2) Tier 1 Reference vs 20% RPS Case

Reference

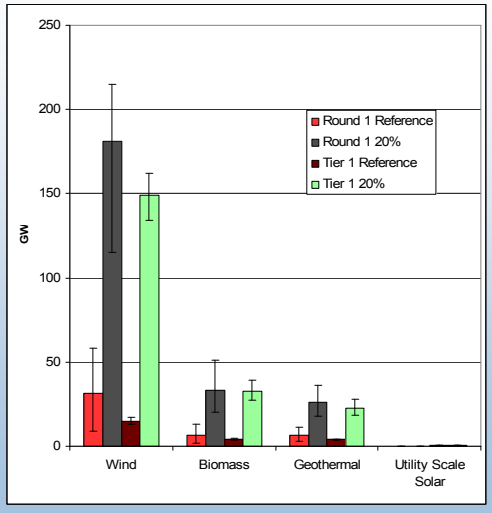


20% RPS



- SEDS Tier 1 conventional generation by type consistent with other models
- SEDS 5% and 95% renewables generation error found

2025 SEDS Renewable Capacity Chart



- RE mean capacity results not vastly different between Round 1 and Tier 1.
- Uncertainty decreased in Tier 1 results due to removal of policy uncertainties (primarily carbon tax)

Primary Differences Between SEDS and Other Models

- Uncertainties are explicit in SEDS
- SEDS Wind penetration in the 20% case is higher (based on post-busbar supply curve from the WinDS model)
- Electricity price increases more in the 20% RPS case than does NEMS (No vintaging of electric stock in SEDS)

Improvements to SEDS

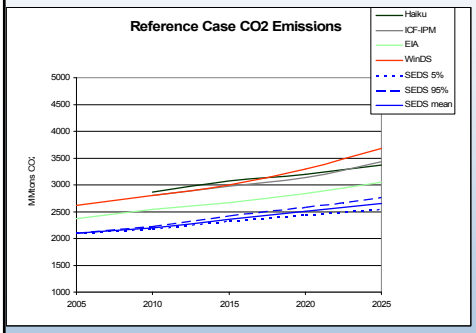
- Two improvements as a result of this REMAP exercise
  - Reestimate the heat rate of the existing electric stock (this corrected the CO2 emission discrepancy in 2005).
  - Recomputed the 5% and 95% probability bands
- Possible future improvements
  - vintaging of electric stock
  - Addition of other sectors to SEDS

Possible Future REMAP Contributions to SEDS

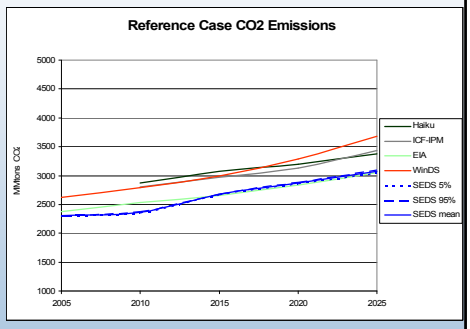
- Better supply curves for renewables
  - Wind from WinDS
  - Others from EIA and others
- Consistency in data inputs
  - Rapidly changing technology costs
  - Fuel prices

Backup

Corrected Heat Rates and Probability Bands



Before Errors Fixed



After Errors Fixed

NEMS-GPRA08 Renewable Portfolio Standard Results for REMAP

Frances Wood
OnLocation, Inc.,
Energy Systems Consulting

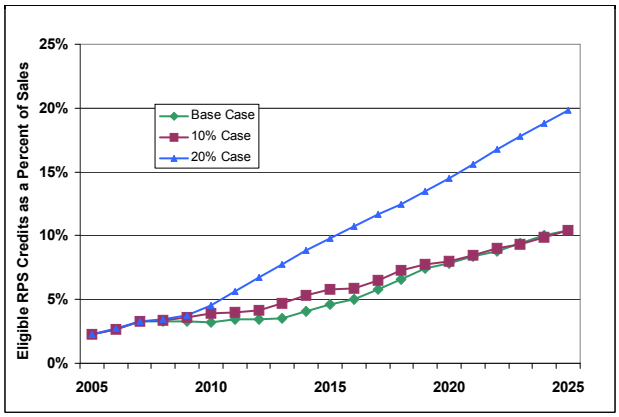
April 30, 2008

Overview

- For Round 1, three scenarios were run using NEMS-GPRA08
  - Base: GPRA08 EERE Portfolio Case
  - 10% Case: An RPS requirement starting in 2008 at 3% and reaching 10% by 2025 was added
  - 20% Case: An RPS requirement starting in 2008 at 3% and reaching 20% by 2025 was added
- Eligible generation consisted of wind, solar (PV & thermal), biomass (including biomass portion of cofiring), and geothermal
- Solar PV and biomass used on-site counted towards the RPS target and were not included in "all sales" (thus having a double benefit)
- Characteristics of the renewable and end-use energy efficiency technologies reflect the effects of the EERE Programs
- We did not run the Tier 1 case because the difference between NEMS-GPRA08 and EIA NEMS is the set of renewable technology assumptions.

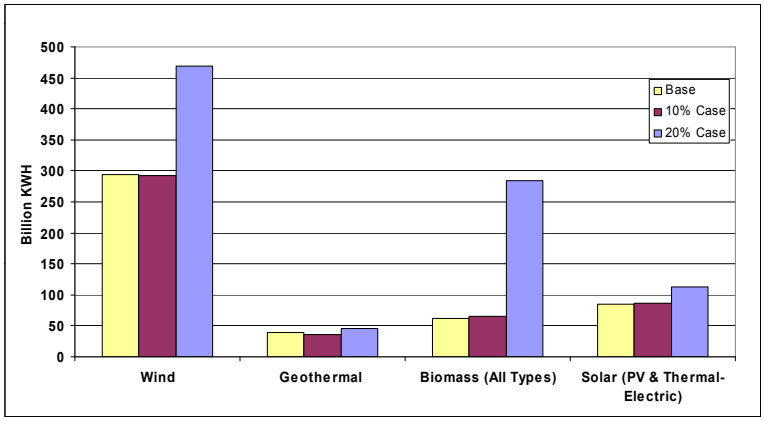
Eligible Renewable Generation as a Percent of Sales

- The EERE Portfolio Base case eligible renewable fraction is very similar to the 10% RPS requirements post 2020.



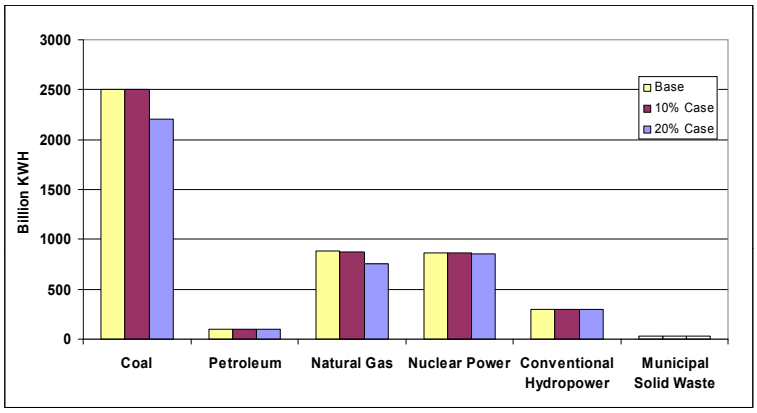
Eligible Generation in 2025

- Wind and biomass generation have the largest increases in meeting the 20% RPS requirement



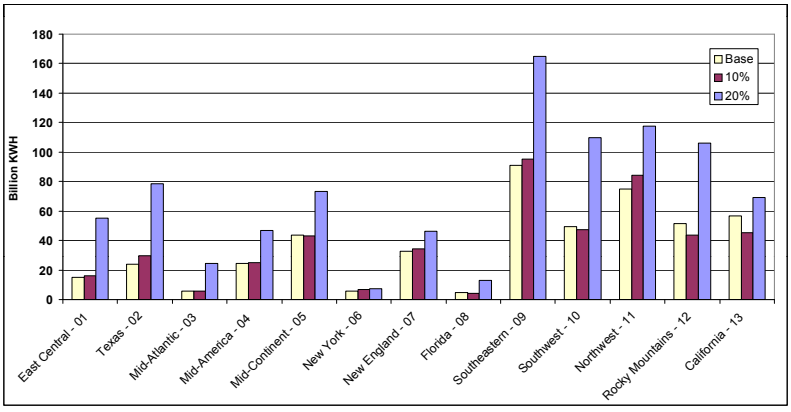
Non-Eligible Generation in 2025

- Coal generation is displaced to the greatest extent when reaching the 20% RPS requirement



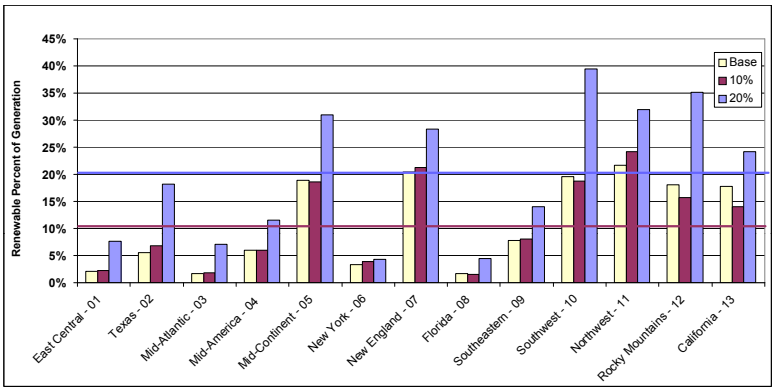
Eligible Generation in Each Region in 2025

- Eligible generation gains to meet the 20% RPS are not evenly distributed among regions



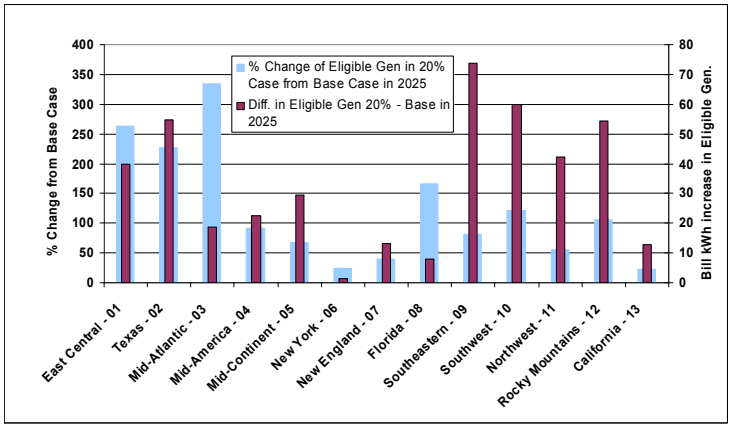
Percentage of Eligible Generation by Region in 2025

- Regions in the western part of the country contribute disproportionately to meeting the RPS targets (eligible generation/total generation within each region), along with NE and the Upper Midwest



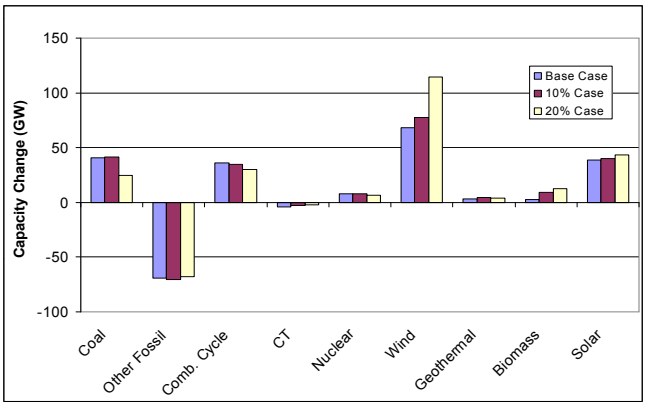
Change in Eligible Generation from Base Case by 2025 – 20% Case

- The percentage increase in eligible generation from 2005 to 2025 across the country looks very different than actual eligible generation increases



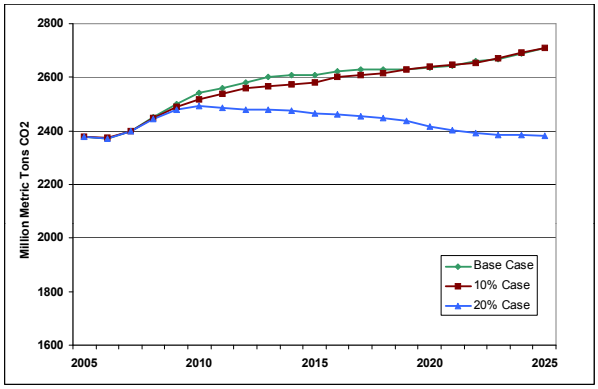
Cumulative Changes in Capacity 2005 to 2025

- Wind gains the most capacity in both RPS cases by 2025 while coal loses the greatest amount in the 20% case from the Base case



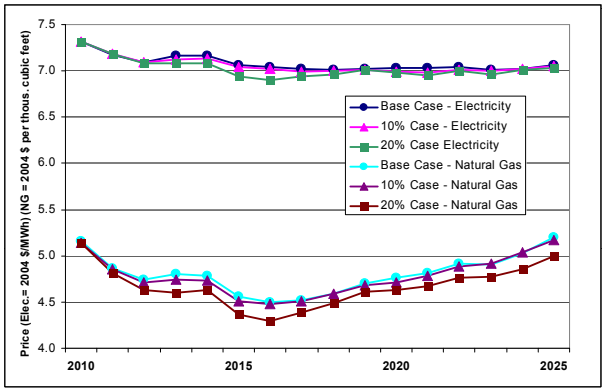
Power Sector Carbon Dioxide Emissions

- The 10% RPS does little to curb carbon emissions beyond the EERE Portfolio Base while the 20% RPS case leads to a 12% reduction in electric sector emissions in 2025



Energy Prices

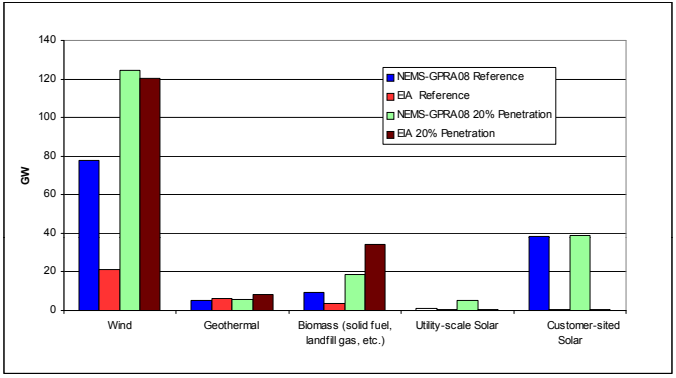
- Lower natural gas prices in the 20% RPS case lead to lower electricity prices despite the additional renewable generation requirement



Note: Prices shown are the average retail electricity price and natural gas wellhead price.

Renewable Capacity in 2025

- Our Tier 1 case would have essentially been the same as EIA's NEMS case; i.e. less wind and distributed PV capacity

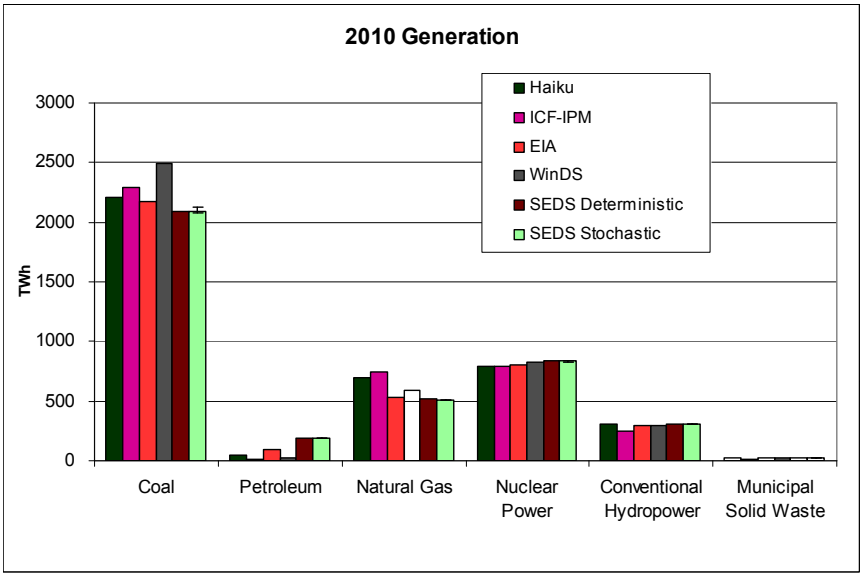


Observations on NEMS Results from REMAP Tier 1

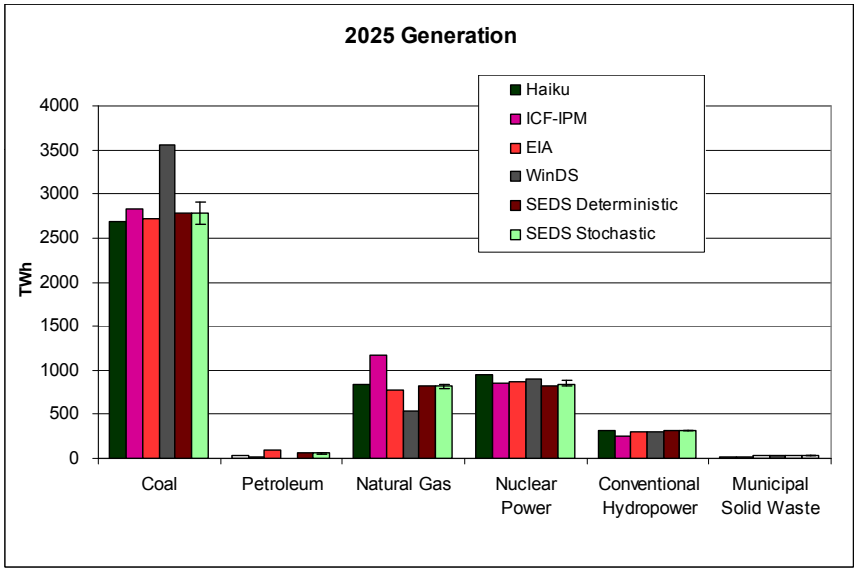
Chris Namovicz and Bob Smith

April 30, 2008

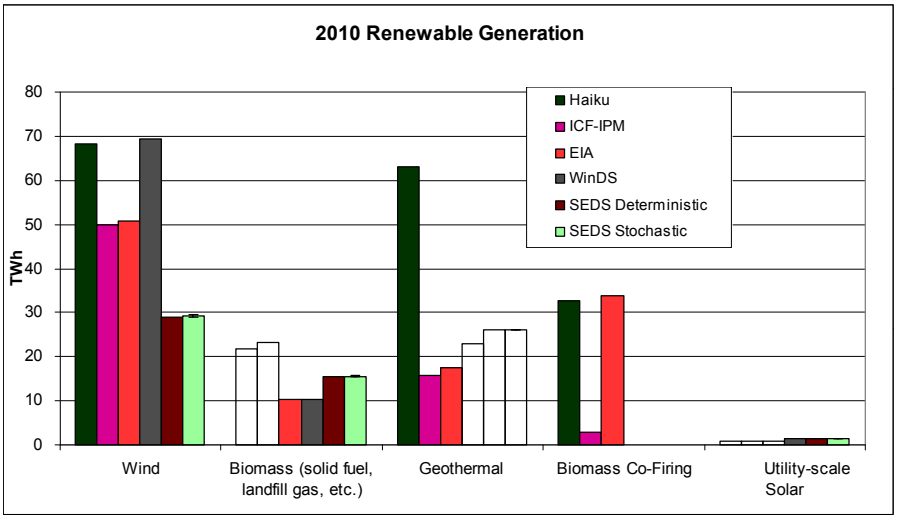
Base Case, 2010



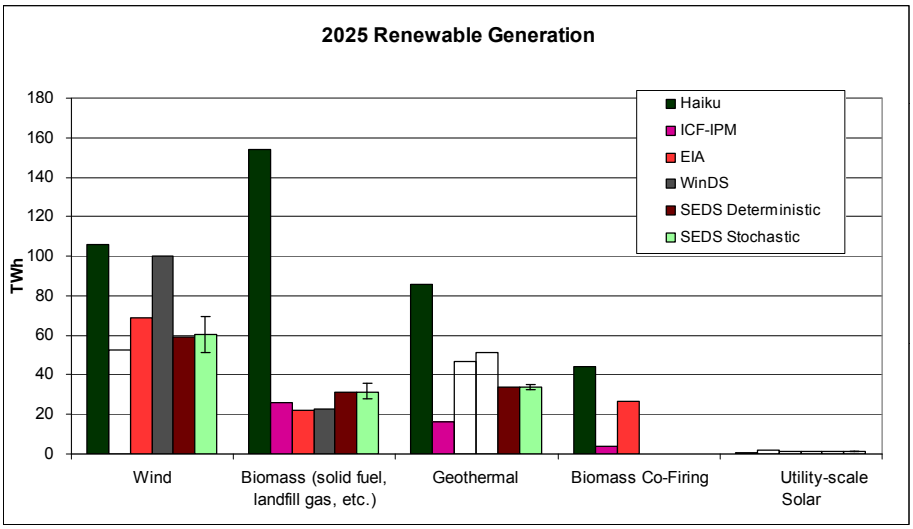
Base Case, 2025



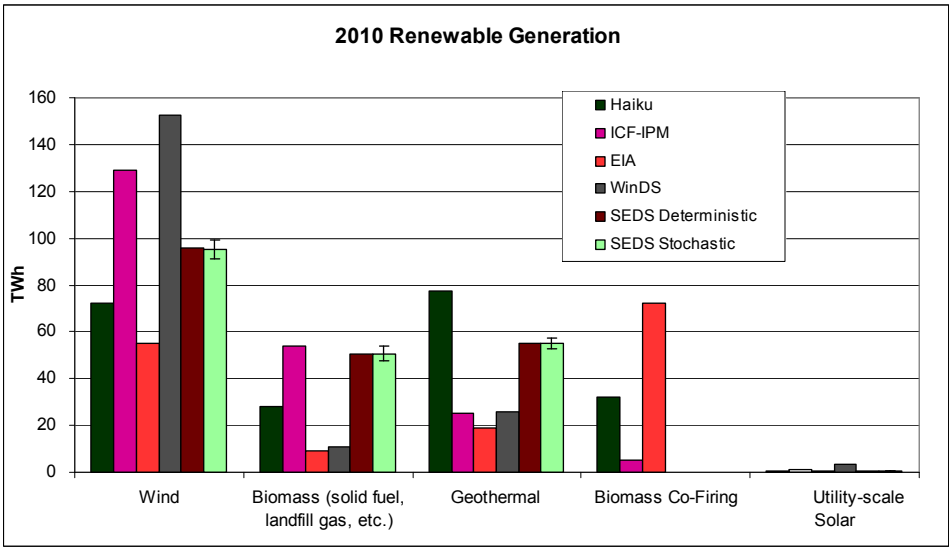
Base Case, 2010 Renewables



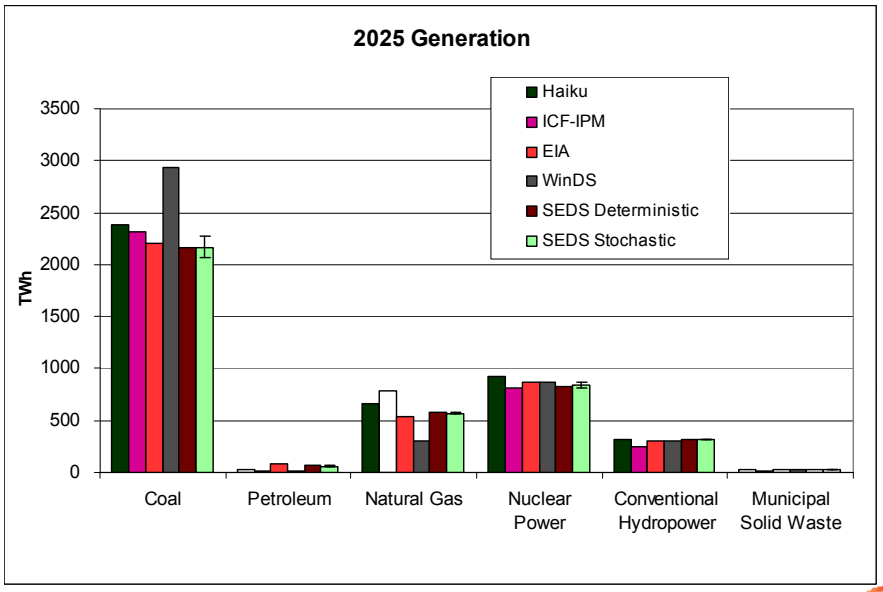
Base Case, 2025 Renewables



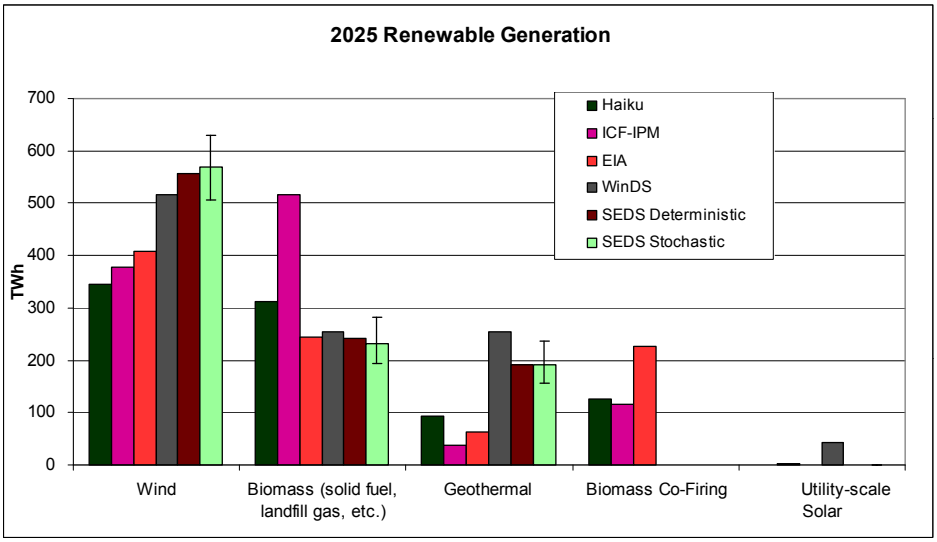
RPS 20, 2010 Renewables



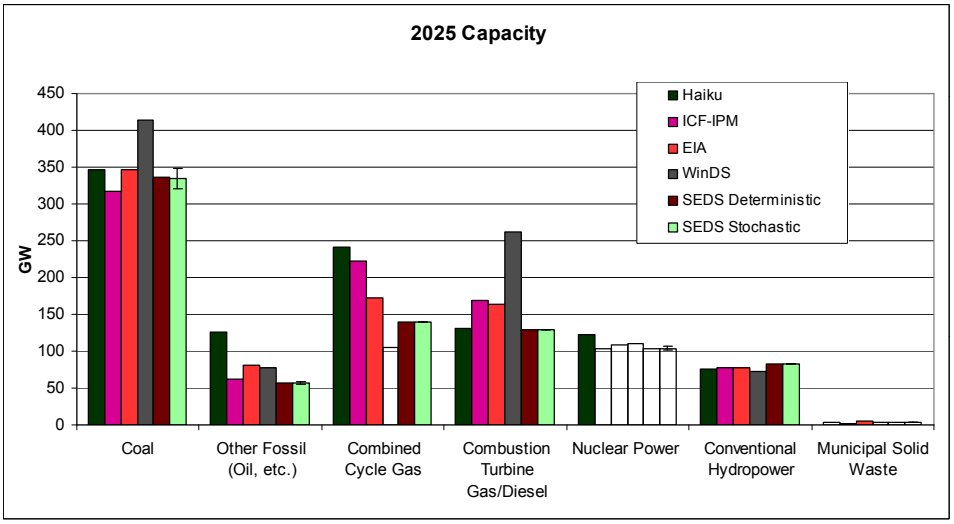
RPS 20, 2025



RPS 20, 2025 Renewables



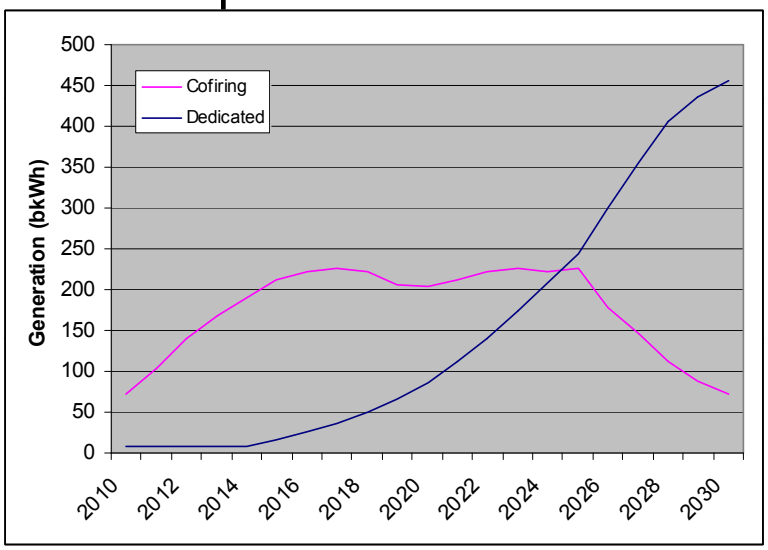
RPS 20, 2025 Capacity



Co-firing

- In the RPS case, NEMS sees co-firing as a good “swing” fuel to meet an increasing target. When the target stabilizes, it moves out of co-firing and toward dedicated biomass
  - Does temporal resolution affect early adoption of a “long-term” solution vs. using intermediate solutions?
  - What about the base case?

Co-firing as a "swing" compliance option in NEMS



CC/CT Split

- In the RPS case NEMS has a very even split between CC and CT NG capacity. WinDS is very CT-weighted, Haiku and IPM tend to favor CC over CT
  - Could this be a result of differences in intermittency algorithms for wind?
  - Could this be a result of differences in the resolution of the load duration curve?

Wind

- In the near-term RPS case, wind in NEMS is much slower to respond than in the other models
  - This is likely the result of the near-term attractiveness of co-firing
  - Not only does co-firing require a minimal investment, it can be "built" immediately
  - If co-firing isn't a viable option, wind presumably becomes the next most attractive short lead-time technology

Solar

- NEMS is not building utility solar, while WinDS is
  - Could the higher geographical resolution of WinDS be finding "niche" opportunities, where NEMS (and others) aren't?

Summary Observations

- Temporal resolution of the models could be significantly affecting differences
  - Resolution of planning cycle (annual vs. multi-year) interacts with the implementation schedule of policy
  - Resolution of diurnal/seasonal load and resource patterns may impact representation of intermittency
- Spatial resolution may also be important
- Deeper analysis of the results may be necessary to confirm/refute these observations and/or reveal other key drivers.

REMAP
Renewable Energy & Efficiency Modeling Analysis Partnership

Summary of Results

Integrated Planning Model (IPM®)

Elliot Lieberman
Clean Air Markets Division
U.S. Environmental Protection Agency

B. N. Venkatesh
ICF International, Inc.

April 30, 2008

Outline

- Introduction
- Round 1 Assumptions and Analysis
- Tier 1 Assumptions and Analysis
- Possible Future Activities

Introduction

Introduction

- In March 2007 (Round 1) and later in December 2007 (Tier 1), EPA prepared an analysis for REMAP, using ICF's Integrated Planning Model (IPM). All the runs performed were based off the EPA Base Case 2006 (v3.0).
- For both analyses, EPA executed a base case and a 20% national RPS target by 2025 case.
- The following slides describe the assumptions used in the analysis and a comparison of the results between the IPM model and other modeling platforms.

Round 1 Assumptions and Analysis

Round 1 Assumptions

- The Round 1 Base Case employed EPA Base Case 2006 (v3.0).
- **Federal Production Tax Credit (PTC), Investment Tax Credit (ITC) and Accelerated Depreciation**:
  - The Federal PTC is available for eligible projects built in 2007 and earlier. However, the first model run year in ICF's IPM is 2010. Thus, the PTC has not been explicitly modeled in the runs.
  - The Federal ITC for solar and geothermal units is implemented in IPM.
  - The 5-year MACRS (Modified Accelerated Cost Recovery System) depreciation is implemented for the new renewable technologies.
- **Biomass Cofiring option to coal plants**: All coal plants are given the biomass cofiring option. Consistent with AEO 2006, the cofiring is limited to 15% of total fuel use.

Round 1 Assumptions (Contd.)

- **Existing State RPS Policies**: The existing state RPS policies implemented in the REMAP runs are consistent with those documented in EIA's AEO 2006.
- **State Regional Carbon Policies**: The states having carbon policies implemented are as follows: Massachusetts, Washington, Oregon and New Hampshire.
- **State Tax Incentives and Renewable Energy driven by green power marketing**: These have not been explicitly modeled in the REMAP runs.
- **Utility Deregulation (cost of service vs. market clearing price):** IPM simulates the deregulated wholesale electricity market.
- **Federal Air Quality regulations**: The Federal regulations included in the REMAP runs are: CAIR (Clean Air Interstate Rule), CAMR (Clean Air Mercury Rule) and CAVR (Clean Air Visibility Rule).

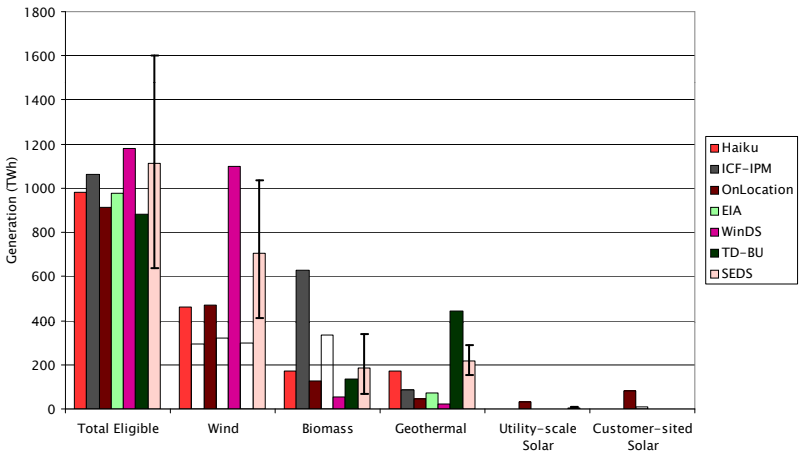
Round 1 Differences between Base Case and 20% RPS Policy Case using IPM

- Implementation of RPS results in a significant increase in wind and biomass builds. Coal builds drop to make way for increased renewable generation.
- In the 20% RPS case, the coal and gas consumption in 2025 was reduced by 21% and 15% respectively.
- Under 20% RPS, the REC price is 45 dollars in 2025. This reflects the building of wind plants in cost classes 2 and 3 and an increase in biomass fuel prices.
- Increased biomass use due to cofiring and new biomass plant builds results in an increase in biomass fuel prices.

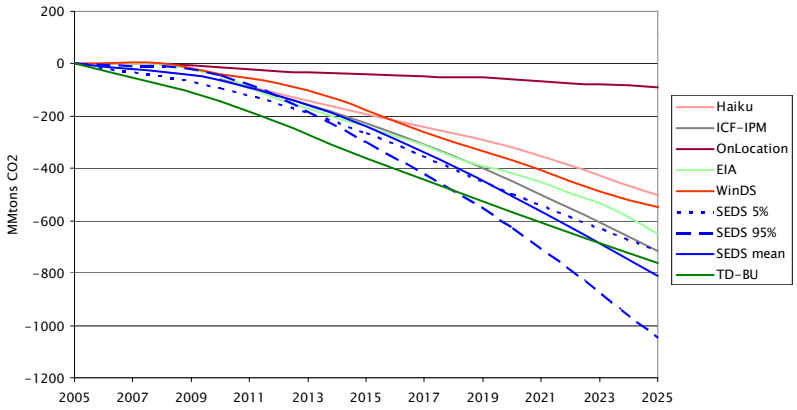
Round 1 Comparison between IPM and Other Model Results

- Base Case
  - Total generation from IPM in 2010 and 2025 is comparable to total generation from other models.
- 20% RPS Policy Case
  - Total generation from IPM in the RPS Case is same as in the Base Case due to a lack of endogenous demand response.
  - Total renewable generation from IPM (in 2025) is higher than in several other comparable models. It could be due to a lack of demand response as well as the estimation of RPS targets based on total generation as compared to total electricity sales.
  - Renewable generation from biomass units appears to be higher than in other models and generation from wind appears to be lower than in other models in 2025.
  - The reduction in projected carbon emissions in 2025 is comparable to the reductions achieved in the other models.

2025 Renewable Generation – 20% Penetration



Change in CO2 Emissions with 20% Penetration



Tier 1 Assumptions and Analysis

Tier 1 Assumptions

- The following changes were implemented in both the Base Case as well as the 20% Policy Case for Tier 1 Analysis:
  - **Technology Costs/Performance:** The capital costs for the new wind units in the Base and RPS cases were updated to be consistent with data provided by REMAP.
  - **Investment Assumptions**: The WACC (Weighted Average Cost of Capital) and Capital Charge Rate were updated to reflect REMAP inputs.
  - **Electric Loads**: The electricity load and peak demand projections for both the base and policy cases were modified based on data provided by REMAP.
  - **Fuel Prices**: The natural gas prices at the Henry Hub were changed to reflect data from REMAP. However, prices for all other fuels were unchanged (coal, nuclear and oil).
  - **Wind Resource Base**: The capacity factors and the wind resource base were updated to reflect REMAP data in the base and policy cases.
  - **Macroeconomic Inputs**: IPM does not model macroeconomic inputs explicitly.

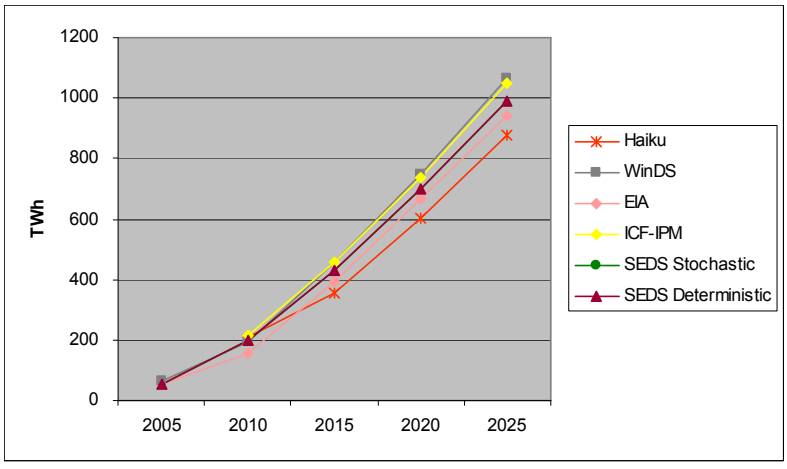
Tier 1 Differences between Base Case and 20% RPS Policy Case

- Significant increases in wind and biomass capacity and generation in the RPS case help in achieving the RPS targets. Coal and natural gas use drops to make way for increased renewable generation.
- In the 20% RPS case, the coal and gas consumption in 2025 was reduced by 16% and 31% respectively.
- The RPS case has lower (17% in 2025) carbon dioxide emissions compared to the base case.
- Under the RPS case, the REC price is $36/MWh.

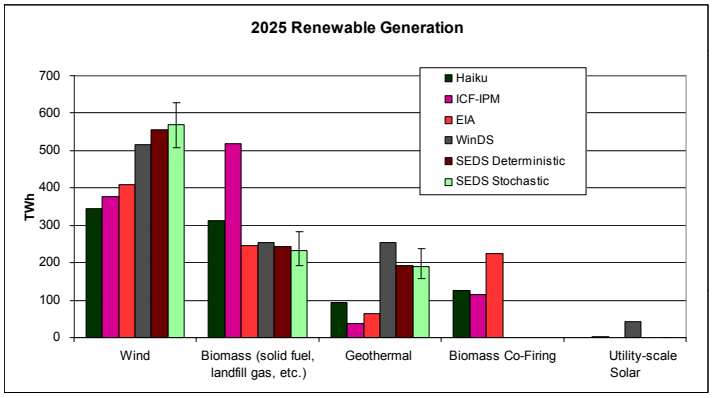
Tier 1 Comparison between IPM and Other Models

- Base Case
  - Geothermal generation is lower than in other models. It could be because geothermal assumptions were not updated to AEO 2007.
  - While generation from wind and stand alone biomass units is comparable to other models, generation from biomass cofiring is lower than in other models.
- 20% RPS Policy Case
  - IPM shows higher renewable generation compared to most of the other models. It could be based on differences in the methodology of calculating the RPS targets. There appear to be significant differences in total eligible renewable generation in 2025 across models.
  - While generation from wind and geothermal technologies is lower, generation from stand alone biomass units is higher than other models.
  - Change in CO_2 emissions from the Base Case are comparable with that of other models.

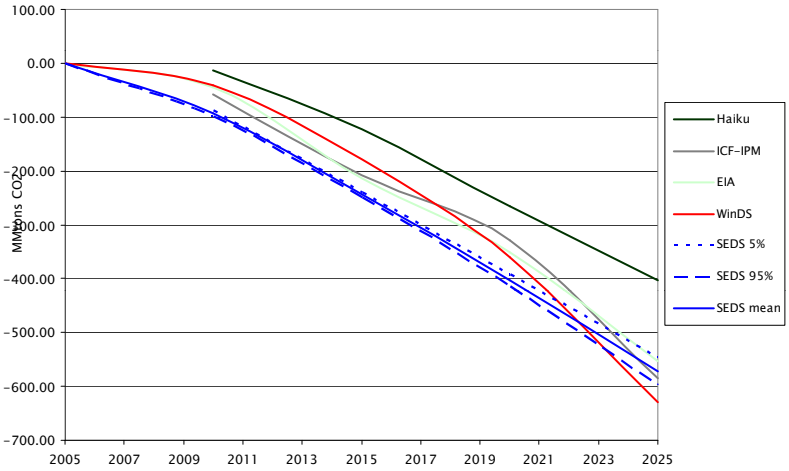
Total Eligible Renewable Generation – 20% RPS



2025 Renewable Generation – 20% RPS



Change in CO2 Emissions with 20% Penetration



Possible Future Activities

Possible Future Activities

- Low Hanging Fruit
  - Add vintages to potential wind plant options.
  - Add offshore wind plant options.
  - Update costs of new biomass options.
- Through a systematic approach, such as a Delphi process, eliciting expert assessments of the cost and performance characteristics of breakthrough renewable technologies, their timing and respective probabilities.

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14. ABSTRACT *(Maximum 200 Words)*
Energy system modeling can be intentionally or unintentionally misused by decision-makers. This report describes how both can be minimized through careful use of models and thorough understanding of their underlying approaches and assumptions. The analysis summarized here assesses the impact that model and data choices have on forecasting energy systems by comparing seven different electric-sector models. This analysis was coordinated by the Renewable Energy and Efficiency Modeling Analysis Partnership (REMAP), a collaboration among governmental, academic, and nongovernmental participants.

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