# Reinventing Fire Electricity Sector Methodology

2317 Snowmass Creek Road | Snowmass, CO 81654

# TABLE OF CONTENTS


**Reinventing Fire ELECTRICITY Sector Methodology** ... 1

**2317 Snowmass Creek Road | Snowmass, CO 81654** ... 1

**Electricity Modeling Overview** ... 4

**ReEDS Modeling Overview** ... 4

Spatial Resolution ... 5

Temporal Resolution ... 6

**RMI's Input Assumptions for ReEDS** ... 9

**Demand** ... 13

**Generation Resources General Assumptions** ... 14

**Generation Resources Description** ... 17

Conventional Generation Resources ... 17

Coal ... 17

Natural Gas ... 17

Carbon Capture and Storage ... 17

Nuclear ... 18

Renewable Generation Resources ... 18

Geothermal ... 18

Biopower ... 19

Hydropower ... 20

Wind ... 20

Photovoltaics (PV) ... 21

Concentrated Solar Power (CSP) ... 22

**Generation Cost Assumptions** ... 23

Learning Curve Theory ... 24

Renewable Energy Generation Cost and Performance Assumptions ... 26

Conventional Generation Cost and Performance Assumptions ... 28

**Fuel Price Assumptions** ... 30

**Storage Technology** ... 30

**Demand Response and Interruptible Load** ... 31

**Financial** ... 32

**Specific Assumptions for the *Transform Case*** ........ **34**

**Regulatory Policies** ........ **36**

**System operations** ........ **38**

**Transmission** ........ **38**

**Distribution Network** ........ **39**

**Reserves** ........ **39**

Planning Reserves ........ 39

Operating Reserves ........ 40

**RMI Dispatch Model** ........ **41**

**Model Description** ........ **41**

**Dispatch Steps** ........ **41**

**Caveats** ........ **43**

# Electricity Modeling Overview

To assess the implications of possible future paths of the U.S. electricity sector in *Reinventing Fire*, RMI analyzed four scenarios or "cases" based on differing assumptions about how electricity might be generated, delivered, and used from 2010 to 2050. To do so, RMI conducted extensive analysis using a variety of tools including two primary models—the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) and RMI's electricity dispatch model. NREL's ReEDS was the principal analytic tool for RMI's evaluation of the technical feasibility and cost of the four electricity scenarios. ReEDS is a linear programming model designed to analyze the investment and operational needs of the U.S. electricity system over 40 years, from 2010 through 2050. Because ReEDS is not designed to account for distributed generation, the deployment of distributed resources was exogenously analyzed by RMI with the help of its internally developed dispatch model. The RMI dispatch model is an hourly, least-cost dispatch model primarily designed to analyze the feasibility and effects of increasing the amounts of variable resources added to the electric grid.

This document provides an overview of *Reinventing Fire*'s electricity sector analysis with a focus on the methodologies and inputs of NREL's ReEDS and RMI's dispatch model. The document is divided into two main sections. The first section provides a high-level overview of the ReEDS model and details of RMI's assumptions that served as ReEDS inputs. **Please note: This section relies heavily on NREL's forthcoming documentation, *Regional Energy Deployment System (ReEDS)*. This document will be updated when NREL makes its updated ReEDS documentation available.** NREL's documentation provides a detailed explanation of the ReEDS objective function, approach, algorithms, and common assumptions, including important information regarding generation and demand resource inputs, such as renewable resource potential. RMI's documentation details key inputs or variables that differ from those described in NREL's own documentation of ReEDS. The second section documents RMI's dispatch model.

## ReEDS Modeling Overview

ReEDS was developed by NREL's Strategic Energy Analysis Center (SEAC) to provide "a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs."[1]

Choosing among a broad portfolio of conventional generation, renewable generation, and storage technologies, ReEDs considers the net present value cost of constructing and operating new generation capacity to meet specified constraints in a least cost manner, including the:

- present value of the cost of generation and transmission capacity expansion and operational integration in each period,
- present value of the cost for operating that capacity during the next 20 years to meet load, i.e., fixed and variable operation and maintenance (O&M) and fuel costs, and
- cost of several categories of ancillary services and storage.

By minimizing these costs while meeting system constraints, the linear program determines which types of new capacity in each balancing authority are the most economical to add in each period. Simultaneously, the linear program determines the capacity that should be dispatched to provide the necessary energy over the year, which is represented by 17 different time periods—or time "slices"—to represent the variation of energy demand over the course of the year.[2]

The cost minimization that occurs within ReEDS is subject to more than 70 different types of constraints, which result in hundreds of thousands of equations in the model (due primarily to the large number of regions). These constraints fall into several main categories, including: regional resource supply limitations; transmission capacity constraints; regional electricity demand and reserve requirements, including planning and operating reserves; and state and federal policy demands.[3]

## Spatial Resolution

There are five distinct methods for segmenting the country in the ReEDS model. Each kind of regional segmentation is used for different purposes:[4]

---

[1] Forthcoming ReEDS documentation
[2] Therefore, the capacity factor for each dispatchable technology in each region is an output of the model, not an input.
[3] Forthcoming ReEDS documentation
[4] Forthcoming ReEDS documentation

**1. Grid Interconnects:** There are three major interconnects in the United States: Eastern interconnect, Western interconnect, and ERCOT (Electric Reliability Council of Texas) interconnect. These are electrically asynchronous regions, isolated from each other except for a limited number of AC-DC-AC connections. In the model, when new transmission must be built across interconnects, there is a higher associated cost due to new AC-DC-AC intertie capacity.

**2. National Electric Reliability Council (NERC) Subregions**: NERC supports 13 regional entities to improve the reliability of the bulk power system. Through its regional entities, NERC develops and enforces electricity reliability standards.[5]

**3. Reserve-sharing groups**: Reserve-sharing groups are responsible for coordinating transmission of electricity over large interstate areas. There are 21 Reserve-sharing groups used by ReEDS, many of which are existing areas while others, particularly those in the western states, are assumed for modeling purposes based on current transmission plans. Reserve-sharing groups are used to calculate reserve margin, operating reserves, and curtailment (*i.e.*, "spilling" of available but unneeded renewable generation).

**4. Balancing Authorities:** Balancing authorities, sometimes called power control areas, are responsible for matching generation with load and maintaining frequency. There are 134 balancing authorities in ReEDS. This is the spatial resolution at which demand requirements must be met. It is also the smallest resolution used for generating and storage resources, with the exception of wind and concentrated solar power (CSP).

**5. Wind/CSP Resource Regions**: There are 356 resource regions used to define the varying technical potential of wind and CSP generation resources. These are the only regions defined specifically by the ReEDS model outside of any other energy agency or operator.

## Temporal Resolution

ReEDS segments electricity demand, or load, by 17 timeslices (Table 1). Each timeslice is applied to the energy and power requirement for the 134 balancing authorities. Each season is defined by the following months: Summer = {June, July, August}, Fall = {September, October}, Winter = {November, December, January, February}, Spring = {March, April, May}. There is an additional timeslice for superpeak demand, which corresponds to the top 40 hours of summer load.[6]

[5] About NERC. North American Electric Reliability Corporation . http://www.nerc.com/page.php?cid=1. Accessed Sept 15, 2011.
[6] Forthcoming ReEDS documentation

Table 1 – ReEDS load timeslices

| Time Slice | Number of Hours Per Year | Season | Time of Day | Time Period |
|---|---|---|---|---|
| H1 | 736 | Summer | Night | 10:00 p.m. to 6:00 a.m. |
| H2 | 644 | Summer | Morning | 6:00 a.m. to 1:00 p.m. |
| H3 | 328 | Summer | Afternoon | 1:00 p.m. to 5:00 p.m. |
| H4 | 460 | Summer | Evening | 5:00 p.m. to 10:00 p.m. |
| H5 | 488 | Fall | Night | 10:00 p.m. to 6:00 a.m. |
| H6 | 427 | Fall | Morning | 6:00 a.m. to 1:00 p.m. |
| H7 | 244 | Fall | Afternoon | 1:00 p.m. to 5:00 p.m. |
| H8 | 305 | Fall | Evening | 5:00 p.m. to 10:00 p.m. |
| H9 | 960 | Winter | Night | 10:00 p.m. to 6:00 a.m. |
| H10 | 840 | Winter | Morning | 6:00 a.m. to 1:00 p.m. |
| H11 | 480 | Winter | Afternoon | 1:00 p.m. to 5:00 p.m. |
| H12 | 600 | Winter | Evening | 5:00 p.m. to 10:00 p.m. |
| H13 | 736 | Spring | Night | 10:00 p.m. to 6:00 a.m. |
| H14 | 644 | Spring | Morning | 6:00 a.m. to 1:00 p.m. |
| H15 | 368 | Spring | Afternoon | 1:00 p.m. to 5:00 p.m. |
| H16 | 460 | Spring | Evening | 5:00 p.m. to 10:00 p.m. |
| H17 | 40 | Summer | Peak | 40 highest demand hours of summer 1:00pm-5:00pm |

## Model Outputs

ReEDS provides a means of estimating the type and location of conventional and renewable resource development, the transmission infrastructure expansion requirements of those installations, the composition and location of generation, storage, and demand-side technologies needed to maintain system reliability, and the overall cost of electricity supply. Other outputs used in the RF analysis:

- **Electricity price**
  - ReEDS calculates national average electric price for every two-year increment (in 2009 $/MWh). The electricity price calculation assumes a 30-year rate base, so all investments are amortized over 30 equal annual payments. Investments include new (and replacement) generation capacity and new transmission lines.[7]

[7] Forthcoming ReEDS documentation

- **Costs**
    - ReEDS outputs biennual cashflow values for capital investment, operations and maintenance, and fuel cost. These cashflows are used to calculate the present value for each case.

- **Retirements**
    - Retirements of conventional generators can be exogenously specified as a model input or naturally result due to economic or lifetime constraints. ReEDS accounts for the retirement of generation capacity by technology over each two-year period. Retired capacity includes retirements of new capacity built after the first year of the simulation. However, note that the retirements used for the *Renew* and *Transform* cases differ from those in the ReEDS.

- **New Transmission**
    - ReEDS builds and accounts for new transmission resulting from new generation technology. This includes both intra- and inter- balancing authority transmission in million MW-miles.

- **Carbon emissions**
    - Carbon emissions from conventional generation sources are computed in million metric tons of $CO_2$.

- **Fuel consumption**
    - Both coal and natural gas consumption and cost are outputs—in quads and 2009 $/MMBTU, respectively—which are determined by input heat rates,[8] or the thermal efficiency of the generation facility.

- **Levelized Cost of Energy**
    - Levelized cost of energy (LCOE) is defined as the total cost of building and operating a generating plant over its life. LCOE is not used directly in the ReEDS's optimization function, but is a useful output used to compare generation sources over the simulation period. This includes capital cost, O&M, fuel and grid interconnection. Levelized costs assume a 5.7%/y real discount

[8] Heat rate is defined as the fuel or heat supplied to a power plant in a given period divided by the energy produced over that same time period.

rate, and incorporate a Risk Adjustment Factor and a Capital Cost Financial Multiplier, which are explained in greater detail in the Financial section below.

## RMI'S INPUT ASSUMPTIONS FOR REEDS

This section presents an overview of the ReEDS input assumptions that are common to all four cases: generation resources (conventional and renewable), demand, efficiency, storage resources, demand response, financing and electric vehicles (Table 2).

However, because the ReEDS model was designed to model the bulk power system rather than the distribution network or distributed generation, RMI modified several aspects of ReEDS inputs to approximate the distributed system envisioned in the *Transform* case. Specific areas whose inputs differed significantly from the approach taken in the first three cases included: distributed wind, distributed PV (rooftop and community scale), electric vehicles, and distributed storage, including vehicle-to-grid electric vehicles, ice storage, and batteries. RMI's dispatch model was used to estimate the impacts of a large proportion of distributed generation on balancing segments of the electric grid. Several inputs, most notably the distribution network itself and storage technologies, used a hybrid approach of both the RMI Dispatch Model and ReEDS. This is explained is greater detail in the *Transform Case* section.

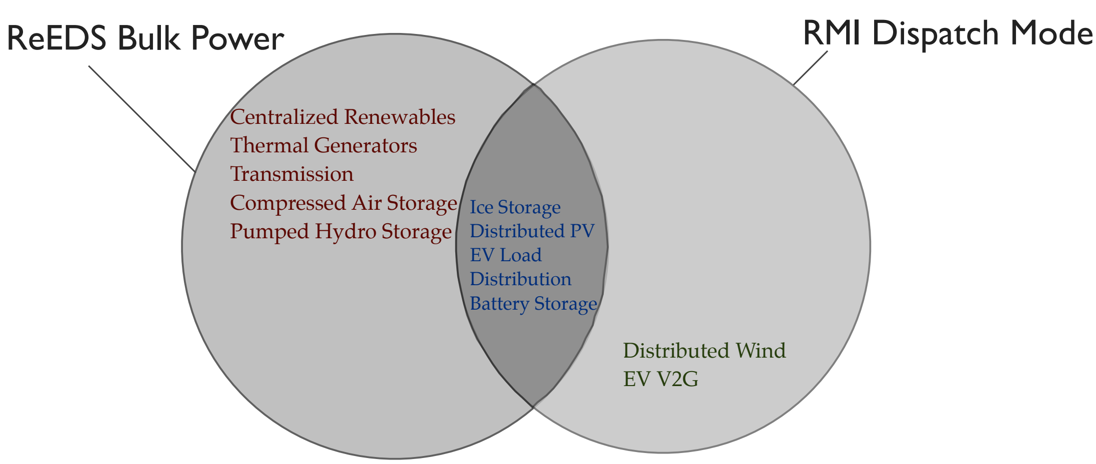
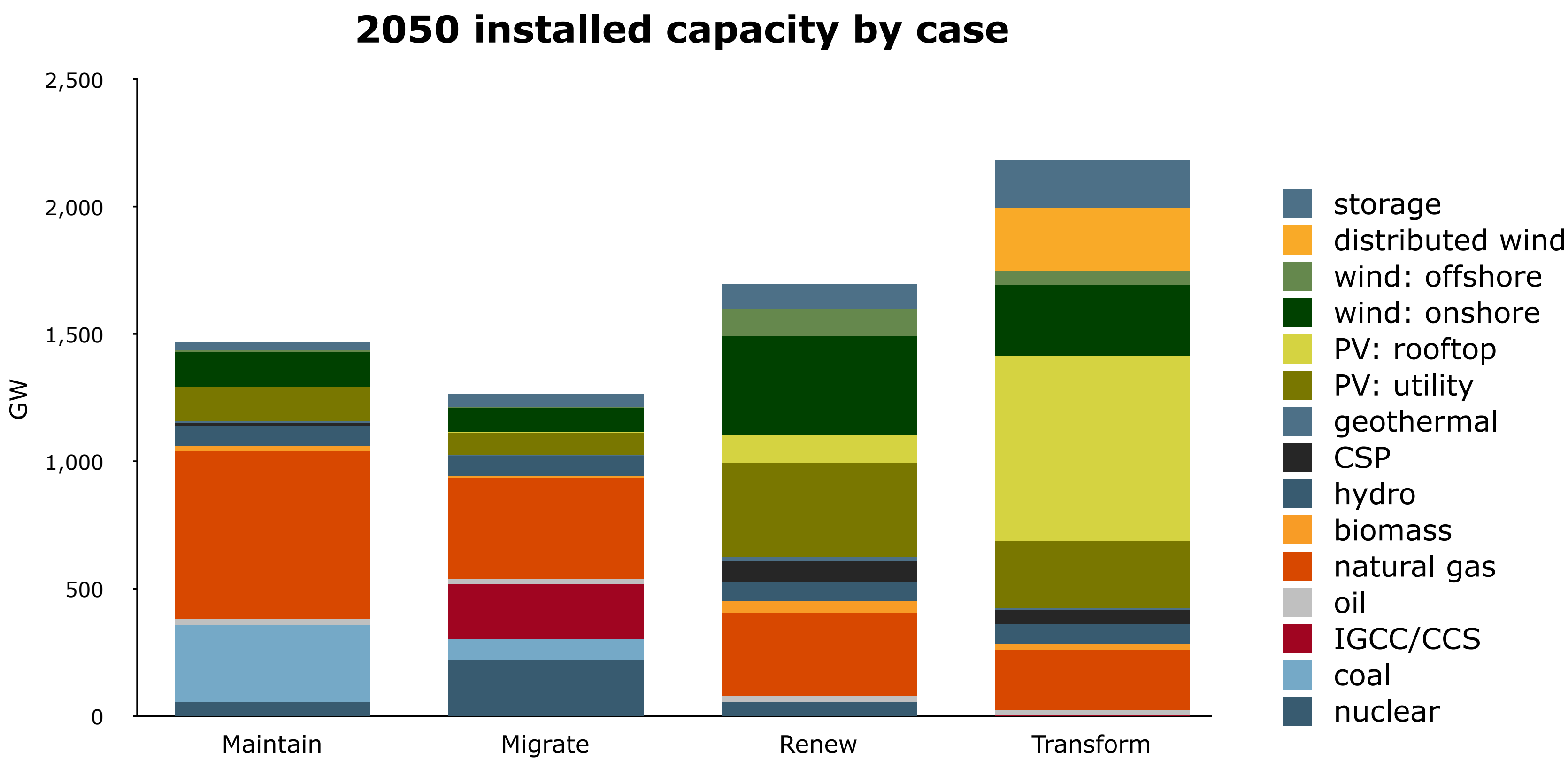
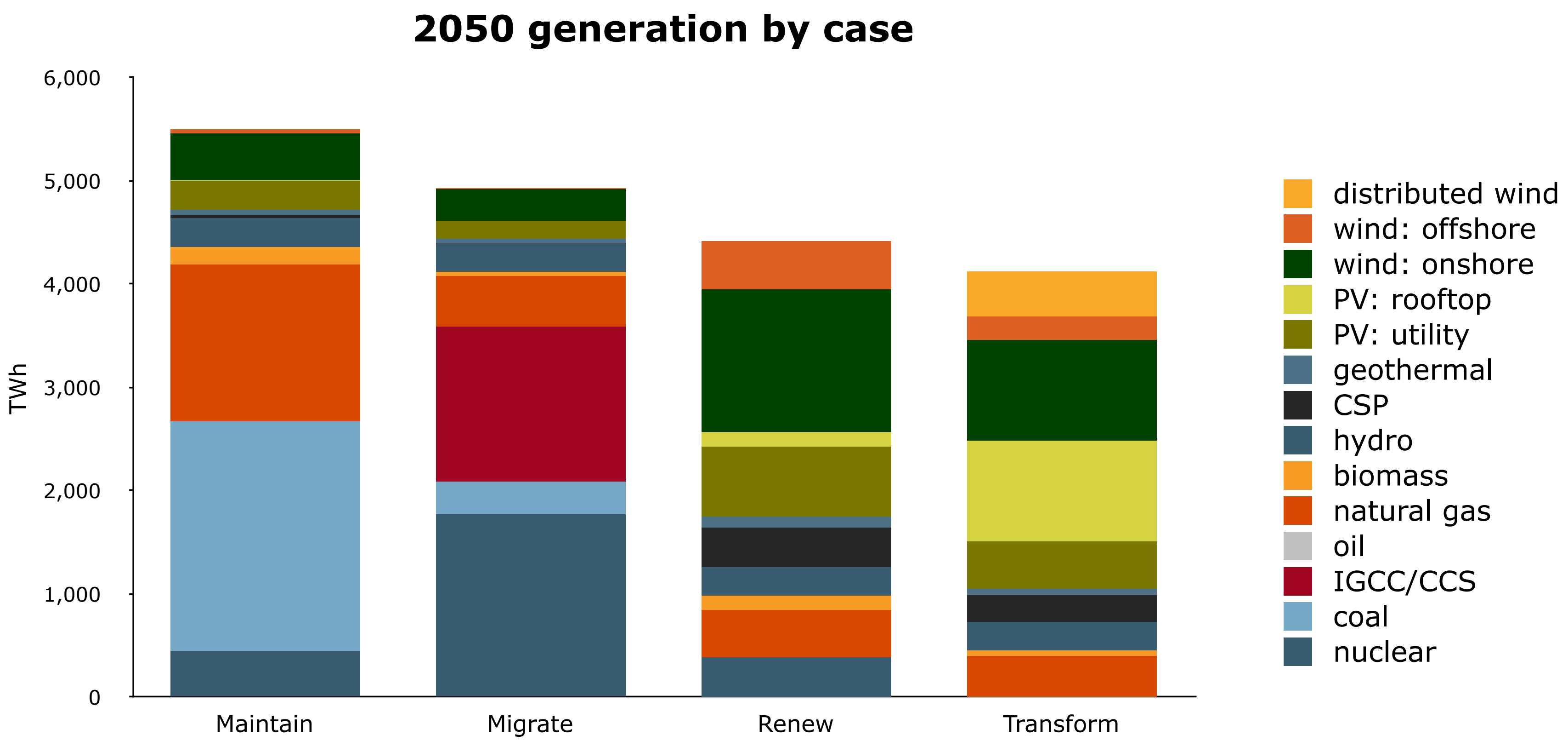


**Table 2 – RF Case characteristics**

| | *Maintain* | *Migrate* | *Renew* | *Transform* |
|---|---|---|---|---|
| Description | • *Maintain* expands an electricity system much like that of today. As such, buildout of central renewables, coal, IGCC, distributed wind, and nuclear were not constrained, while efficiency and other demand-side resources were largely business-as-usual projections (BAU) from EIA's 2010 *Annual Energy Outlook*. | • *Migrate* assumes that the anticipation of legislation to reduce greenhouse gas emissions drives a switch from conventional fossil-fueled generation to more nuclear power and new coal plants equipped with carbon capture and sequestration. | • *Renew* examines a future in which centralized renewables like solar, wind, geothermal, biomass, and small (plus existing big) hydro provide at least 80% of U.S. 2050 electricity. | • *Transform* envisions resources of varied scale but with a greater portion of supply coming from distributed sources such as rooftop solar, CHP, fuel cells, and small-scale wind. |
| Demand | • 44% total increase from 2010 by 2050 | • 28% increase in total demand from 2010 to 2050<br>• 11% decrease from 2050 BAU | • 6% total increase in total demand from 2010 to 2050<br>• 26% decrease from 2050 BAU | • 10% total decrease in total demand from 2010 to 2050<br>• 37% decrease from 2050 BAU |
| Generation Constraints (Specified to ReEDS) | • No constraints on generation type | • 31% IGCC CCS in 2050<br>• 36% nuclear generation in 2050 | • 76% Renewables in 2050<br>• 0% Coal in 2050 | • 85% Renewables, with 50% being from distributed systems<br>• 0% Coal in 2050 |
| Efficiency (Reduction in electricity demand fed to ReEDS model, assuming same delivery of end-use services) | • Business as usual EE adoption (EIA 2010 *Annual Energy Outlook*) extrapolated to 2050<br>• EE is somewhat difficult to capture due to the continuation of current implementation strategies and regulatory structures | • Slight improvement on Business as usual EE adoption (EIA 2010 *Annual Energy Outlook*)<br>• As in *Maintain*, EE is somewhat difficult to capture, but modest gains are possible | • EE potential becomes easier to capture as utilities gain more comfort with new technology (both demand- and supply-side) and see some shifts in regulatory structures to accommodate renewables that incidentally benefit efficiency | • Maximum EE potential from RF buildings group, including behavioral change but not including integrative design<br>• This potential is largely achievable due to widespread regulatory change required to support this case, the increasing role of the consumer, and greater openings in the value chain for non-utility companies to play |
| Demand Response | • Traditional DR expanded to FERC BAU scenario | • Traditional DR expanded to FERC Expanded BAU scenario | • Traditional DR expanded to FERC Achievable scenario | • Traditional DR expanded to FERC Full Participation scenario |
| Electric Vehicles (RMI dispatch model used for V2G) | • No significant PEV deployment | • Less extensive smart-grid rollout and high amount of baseload supply means that vehicle load is shifted to off-peak, but is not dynamic or bidirectional | • Scaled PEV load from RF transportation group<br>• Greater need for flexibility but less extensive customer role and regulatory change means that vehicles are predominantly V1G, meaning that vehicle load is dynamically controlled but unidirectional | • Full PEV load from RF transportation group<br>• Increasing role of the customer and more extensive regulatory change leads to and requires V2G, meaning that vehicle load is dynamically controlled and bidirectional |
| Smart Grid (RMI cost adder to each case) | • Smart grid is rolled out widely, but is focused on Automated Meter Reading and early fault detection in the grid | • Smart grid is rolled out widely, but is focused on AMR and early fault detection in the grid | • Smart grid is increasingly needed to access demand-side flexibility resources, and is rolled out widely with 2-way communication | • Smart grid is increasingly needed to access demand-side flexibility resources, and is rolled out widely with 2-way communication, self-healing, and the ability to island |




| | nuclear | coal | IGCC/CCS | oil | natural gas | biomass | hydro | CSP | geothermal | PV: utility | PV: rooftop | wind: onshore | wind: offshore | distributed wind | storage |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Maintain | 56.7 | 302.7 | .5 | 23.6 | 657.8 | 23.3 | 78.5 | 8 | 7.4 | 137.3 | 1.1 | 135.1 | 8.2 | 0 | 28.4 |
| Migrate | 224.1 | 82.6 | 212.2 | 23.6 | 394 | 7.9 | 78.5 | .5 | 5.4 | 87 | 1.1 | 96.1 | 2.9 | 0 | 52.5 |
| Renew | 56.7 | .2 | .3 | 23.6 | 328.7 | 43 | 78.5 | 81.3 | 14.9 | 368 | 109.4 | 389.1 | 108.5 | 0 | 97.3 |
| Transform | 0 | 4.4 | .5 | 23.6 | 232.9 | 25.7 | 78.5 | 52.7 | 8.6 | 262.9 | 727.3 | 279.5 | 52.2 | 249.1 | 188.2 |




| | nuclear | coal | IGCC/CCS | oil | natural gas | biomass | hydro | CSP | geothermal | PV: utility | PV: rooftop | wind: onshore | wind: offshore | distributed wind |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Maintain | 447.8 | 2225.3 | 3.8 | .1 | 1511.9 | 172.8 | 276.5 | 29.9 | 54.8 | 280.3 | 1.5 | 458.1 | 37.2 | 0 |
| Migrate | 1771.6 | 316.5 | 1504.1 | 0 | 488.5 | 40.2 | 276.5 | 1.6 | 40.3 | 174.4 | 1.5 | 304.8 | 13.3 | 0 |
| Renew | 389.6 | 0 | 0 | 0 | 455.3 | 139.9 | 276.5 | 379 | 111.1 | 674.7 | 146.4 | 1379.4 | 463.4 | 0 |
| Transform | 0 | 0 | 0 | 0 | 400.9 | 53.3 | 276.5 | 255.7 | 63.5 | 462.5 | 972.7 | 975.4 | 227.6 | 436.5 |

# DEMAND

A primary input was the demand to meet for each of the 17 timeslices in each NERC region ir each future period. Electricity is demanded from the three end-use sectors: transportation, buildings, and industry. From the perspective of the electricity system, demand from the transportation sector increases with the adoption of electric vehicles; demand from the buildi and industrial sectors decrease with the adoption of efficient technologies and combined heat and power (CHP). The relative contribution to final demand by case is shown in Figure 1.

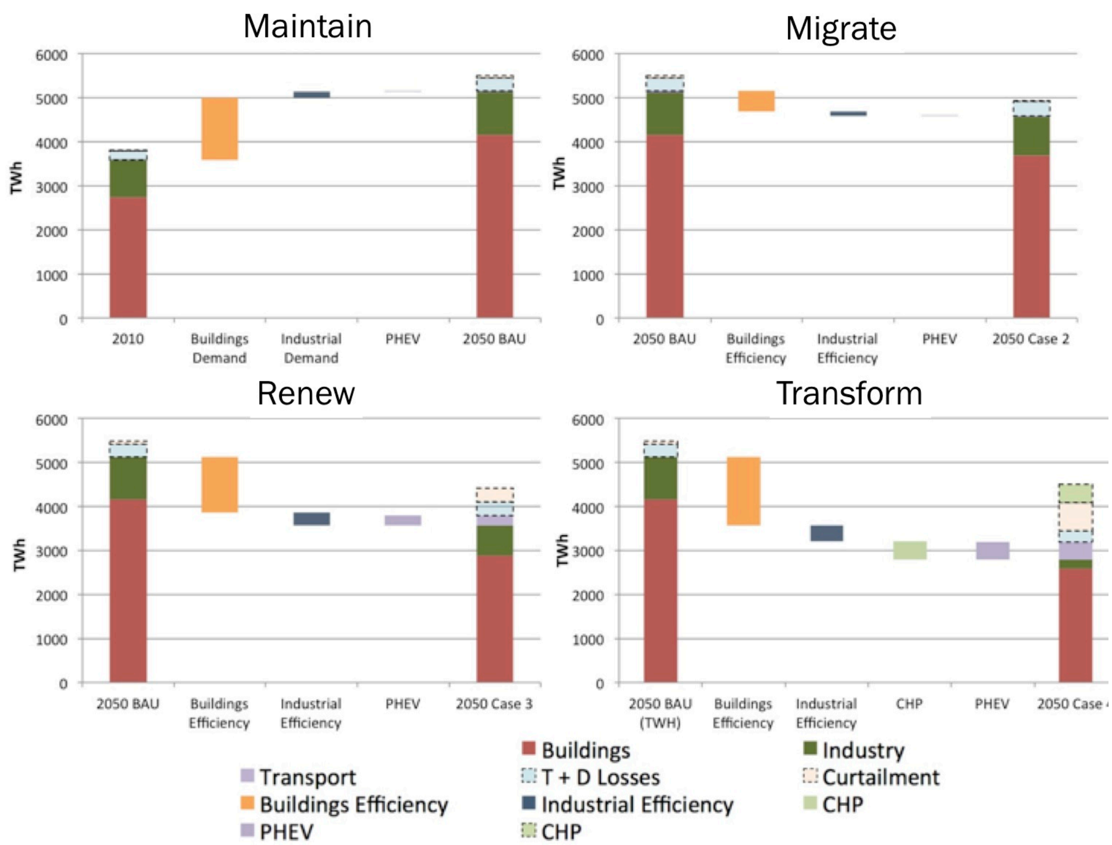



**Figure 1 – Demand to meet by RF case. Building efficiency, industrial efficiency, CHP, and PHEV load are incremental over *Maintain*.**

Table 3 – Total demand in TWh/y

| | TWh/y | | | | |
|---|---|---|---|---|---|
| | 2010 | 2020 | 2030 | 2040 | 2050 |
| ***Maintain*** | 3,584 | 4,056 | 4,438 | 4,801 | 5,152 |
| ***Migrate*** | 3,584 | 3,964 | 4,181 | 4,371 | 4,586 |
| ***Renew*** | 3,584 | 3,956 | 4,014 | 3,958 | 3,788 |
| ***Transform*** | 3,584 | 3,655 | 3,342 | 3,205 | 3,231 |

Table 3 shows the total demand to meet in each case. However, because ReEDS requires demand to be segmented by NERC region and by ReEDS timeslices, the total demand RMI projected in each year was converted to these temporal and spatial segments by applying hourly end-use load profiles for each region.

## Generation Resources General Assumptions

Generation technologies included in ReEDS include both conventional and renewable technologies. Conventional electricity generating technologies used in ReEDS analysis include: large-scale hydropower; both simple- and combined-cycle natural gas combustion turbines; several varieties of coal; oil/gas steam; and nuclear plants. Renewable technologies include several classes of wind, solar photovoltaics (PV), concentrating solar power (CSP), geothermal, and biopower. Table 4 shows general plant assumptions by technology. Characteristics for each technology include:

All generation sources:

- capital cost (2009 $/MW) – *overnight cost for capacity additions*
- fixed and variable operating costs ($/kW-yr)(2009 $/MWh) – *costs associated with energy generation*
- planned and unplanned outage rates (%) – *plant downtime percentage*
- lifetime (years) – *technical plant operation period*
- financing costs – *nominal interest rate, loan period, debt fraction, debt-service-coverage ratio*
- construction time (years) – *duration for plant construction*

If applicable:

- heat rate (million BTU/MWh) – *thermal efficiency of a power plant (following EIA's* Annual Energy Outlook, *higher heating value is assumed)*
- fuel costs (2009 $/million BTU) – *costs associated with fuel; higher heat value is assumed*
- fuel emissions (metric tons/million BTU) – *emissions from fuel combustion*
- minimum load factor (%) – *lowest allowable production level of plant*

- operating reserve capability – *ability to reduce or increase generation during generation/ load imbalances*
- risk adjustment (%) – *adder to both the return on equity and interest rate for coal generation to account for carbon risk. This is defined in further detail in the "Financial Assumptions" section.*
- capital cost financial multiplier – *adjustment factor applied to overnight capital cost for taxes, tax incentives and interest during construction. This is defined in further detail in the "Financial Assumptions" section.*

## Table 4 – General performance data for resources in ReEDS

| Technology | New installations? (Y/N) | Construction Time (years) | Lifetime (years) | Minimum load factor | Outage Rates (%) | | Emissions (lbs/MMBtu fuel) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Planned | Forced | SO2 | NOx | Hg | CO2 |
| Coal (pulverized) | Y | 6 | n/a | 40% | 6% | 10% | 0.0785 | 0.02 | 4.6e-6 | 204 |
| Coal, integrated-gasification combined-cycle (IGCC) | Y | 6 | n/a | 50% | 8% | 12% | 0.0184 | 0.02 | 4.6e-6 | 204 |
| Coal with carbon capture & sequestration (IGCC-CCS) | Y | 6 | n/a | 50% | 8% | 12% | 0.0184 | 0.02 | 4.6e-6 | 20.4 |
| Old pulverized coal (without $SO_2$ scrubber) | N | n/a | n/a | 40% | 6% | 10% | 1.57 | 0.448 | 4.6e-6 | 204 |
| Old pulverized coal (with $SO_2$ scrubber) | N | n/a | n/a | 40% | 6% | 10% | 0.157 | 0.448 | 4.6e-6 | 204 |
| Natural gas (combustion turbine, CT) | Y | 3 | 30 | 0% | 3% | 5% | 0.0006 | 0.08 | 0 | 122 |
| Natural gas (combined-cycle, CC) | Y | 3 | 30 | 0% | 4% | 6% | 0.0006 | 0.02 | 0 | 122 |
| Natural gas (CC-CCS) | Y | 3 | 30 | 0% | 4% | 6% | 0.0006 | 0.02 | 0 | 12.2 |
| Oil-gas-steam | N | n/a | n/a | 40% | 10% | 12% | 0.026 | 0.1 | 0 | 122 |
| Nuclear | Y | 6 | 60 or 80 | 100% | 4% | 6% | 0 | 0 | 0 | 0 |
| Geothermal | Y | 4 | 30 | 90% | 13% | 2% | 0 | 0 | 0 | 0 |
| Dedicated biopower | Y | 4 | 45 | 40% | 9% | 8% | 0.08 | 0 | 0 | 0 |
| Landfill-gas/municipal solid waste (MSW) | N | n/a | n/a | 0% | 5% | 5% | 0 | 0 | 0 | -157 |
| New cofire | new & retrofit | 6 | n/a | 40% | 7% | 9% | 0.0785 | 0.02 | 4.6e-6 | 204 |
| Old cofire | retrofit only | n/a | n/a | 40% | 7% | 9% | 0.157 | 0.448 | 4.6e-6 | 204 |
| Hydropower | Y | 3 | 100 | 55% | 5% | 2% | 0 | 0 | 0 | 0 |
| Wind | Y | 3 | 20 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Concentrated solar power (CSP) | Y | 3 | 30 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Utility-scale photovoltaic (PV) | Y | 3 | 30 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Pumped-storage hydro (PSH) | Y | 6 | 100 | N/A | 4% | 3% | 0 | 0 | 0 | 0 |
| Batteries | Y | 3 | N/A | N/A | 2% | 1% | 0 | 0 | 0 | 0 |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

# Generation Resources Description

This section summarizes key assumptions regarding generation resources, including performance characteristics and, in the case of renewable energy technologies, their technical potential.

## Conventional Generation Resources

ReEDS includes all forms of conventional generation. 2006 (the model start year) capacity for each technology comes from the EIA database (EIA 860 "Annual Electric Generator Report") and is segmented by balancing authority.

## Coal

There are three primary categories of coal: conventional pulverized coal, old coal without $SO_2$ scrubber, and old coal with a $SO_2$ scrubber. Plants built before 1990 are considered old coal. New coal facilities built by ReEDS are assumed to have $SO_2$ scrubbers.

Coal plants do not have a specific lifetime constraint. Any coal capacity that remains unused for energy generation or operating reserves for four consecutive years is assumed to be retired. If the capacity factor of a coal facility is less than 50% during the two-year period, sufficient capacity is retired such that the capacity factor increases to 50%.[9]

## Natural Gas

ReEDS includes two natural gas generation types: combustion turbine (CT) and combined cycle (CC), each with different cost and performance data. Both turbine types are assumed to be quick-start generation types. Gas turbines are assumed to have a 30-year service life, and automatic replacement is not assumed.

## Carbon Capture and Storage

Carbon Capture and Storage (CCS) is included for both coal and natural gas, but without geographic variation and an efficiency penalty from the separation process due to parasitic loads

[9] Forthcoming ReEDS documentation

at CCS facilities.[10] Subsequent improvement of the ReEDS model should have geographically varying costs as well as piping and sequestering constraints on the $CO_2$.[11]

## Nuclear

Assessment of resource potential and retirements for nuclear plants are treated similarly to other conventional thermal generators in ReEDS. Current capacity is defined by the EIA database and segmented by balancing authority. Nuclear plant retirements follow the same 50% minimum capacity requirements as coal facilities. However, all nuclear plants also have a forced retirement after 60 years of age.

## Renewable Generation Resources

## Geothermal

Both conventional (hydrothermal) geothermal power plants and enhanced geothermal systems (EGS) power plants are modeled. There is a wide spatial distribution in geothermal resource quality, with the largest concentrated in the WECC interconnection. Therefore, there are separate capital cost supply curves used in each balancing authority.[12] Figure 2 shows the resource potential for geothermal included in ReEDS.

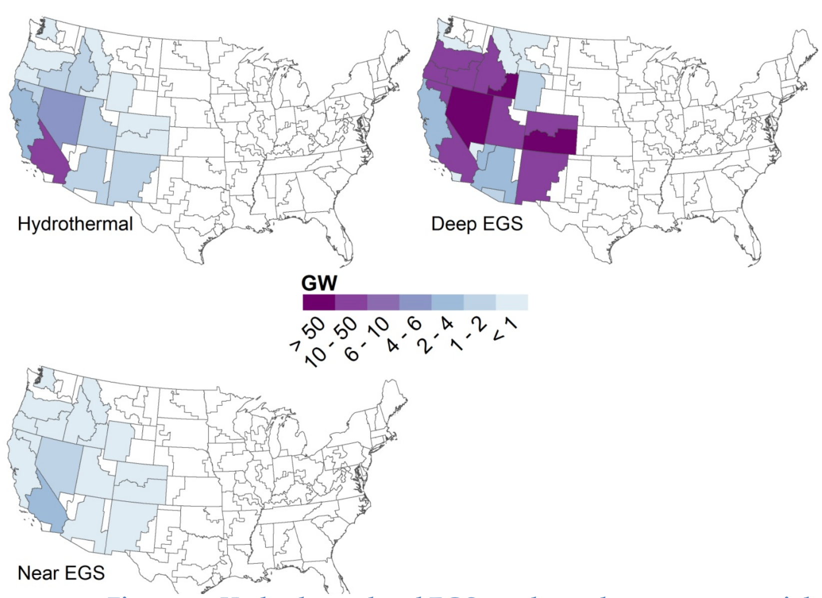



**Figure 2 – Hydrothermal and EGS geothermal resource potential**

---

[10] Forthcoming ReEDS documentation
[11] Ibid
[12] Forthcoming ReEDS documentation

## Biopower

Two biopower resources are modeled: dedicated biopower plants, and plants that co-fire both coal and biomass. ReEDS includes the option to build new co-fired plants or retrofit existing coal plants to co-fire biomass. In co-fired plants, biomass fuel is assumed to account for up to 15% of the electricity output. Dedicated biopower plants are fueled only by biomass feedstock. Availability of common feedstocks, including urban and mill waste, forest and agriculture residues, are delineated by balancing authority, but largely concentrated in central region of the country. Figure 3 shows the resource potential for biopower included in ReEDS.[13]

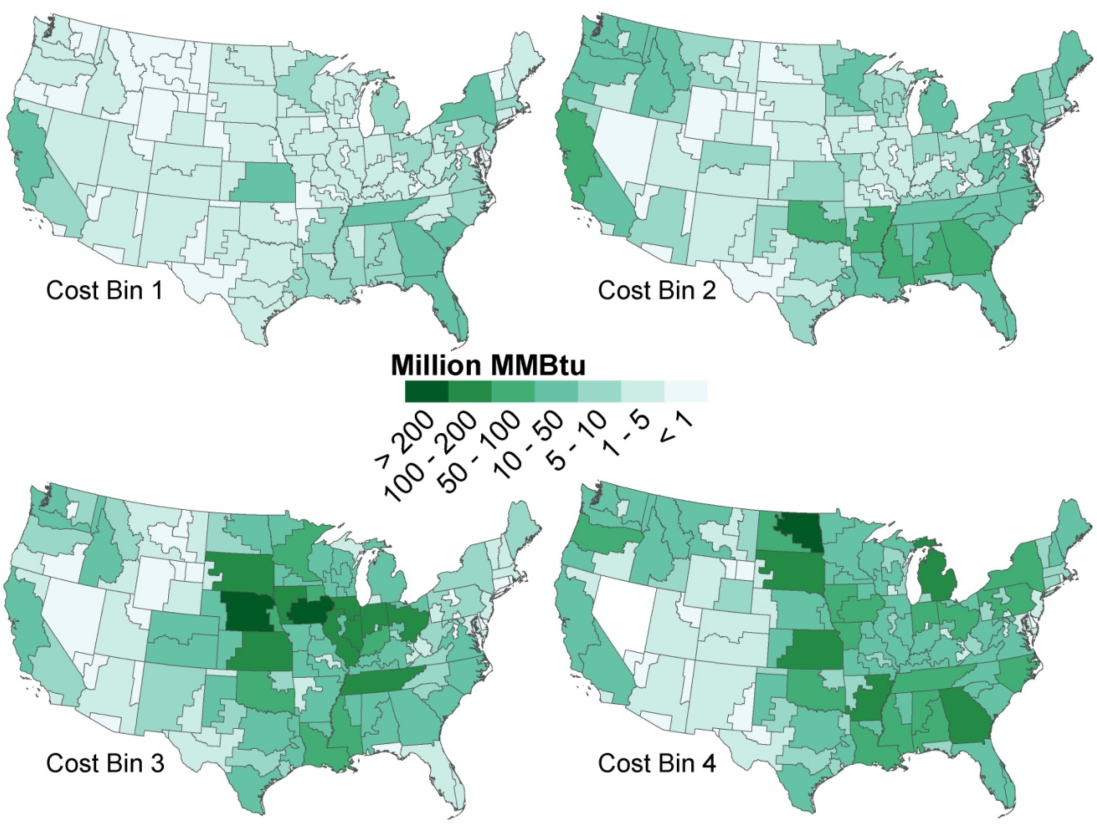



**Figure 3 – Biomass feedstock supply curve with default cost bins: $1.64/MMBtu, $2.46/MMBtu, $3.27/MMBtu, and $4.09/MMBtu**

[13] Forthcoming ReEDS documentation

## Hydropower

There is roughly 80 GW of hydropower online in 2010. Capacity factors and technical potential are segmented by balancing authority[14]. Technical potential for new hydropower resources are assumed to be only run-of-river facilities.[15] Figure 4 shows the resource potential for hydropower included in ReEDS.

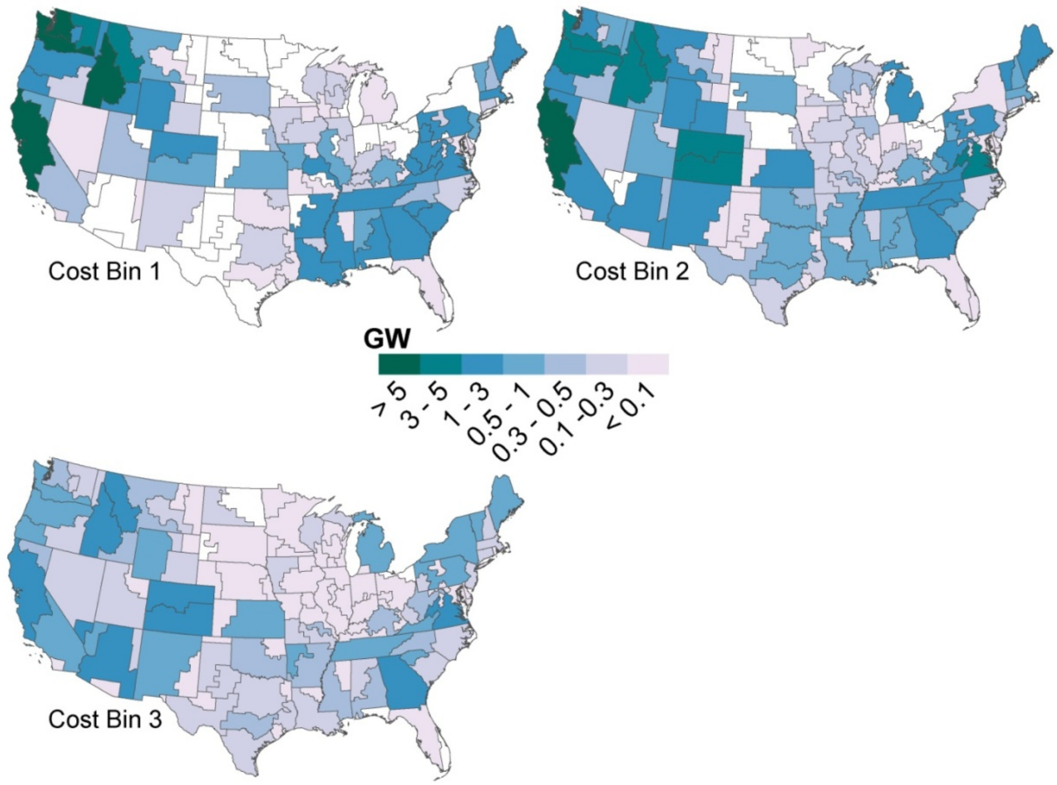



**Figure 4 – New hydropower supply curve with default cost bins of $3,500/kW, $4,500/kW, and $5,500/kW**

## Wind

Two primary categories of wind: onshore and offshore wind resources (both shallow and deep offshore) are included. Each category of wind has five resource classes based on wind power density and wind speed at 50 meters above ground. Technical potential is segmented by

[14] Forthcoming ReEDS documentation
[15] Forthcoming ReEDS documentation

resource region, rather than balancing authority for wind. Available land area of each wind class in each resource region is derived from state wind resource maps and modified for environmental and land-use exclusions, such as parks, high slope areas, wilderness, and urban areas[16]. Technical wind potential is calculated by multiplying the total available area of a particular wind resource by an assumed wind-farm density of 5 MW/km$^2$.[17] Figure 5 shows the resource potential for wind included in ReEDS.

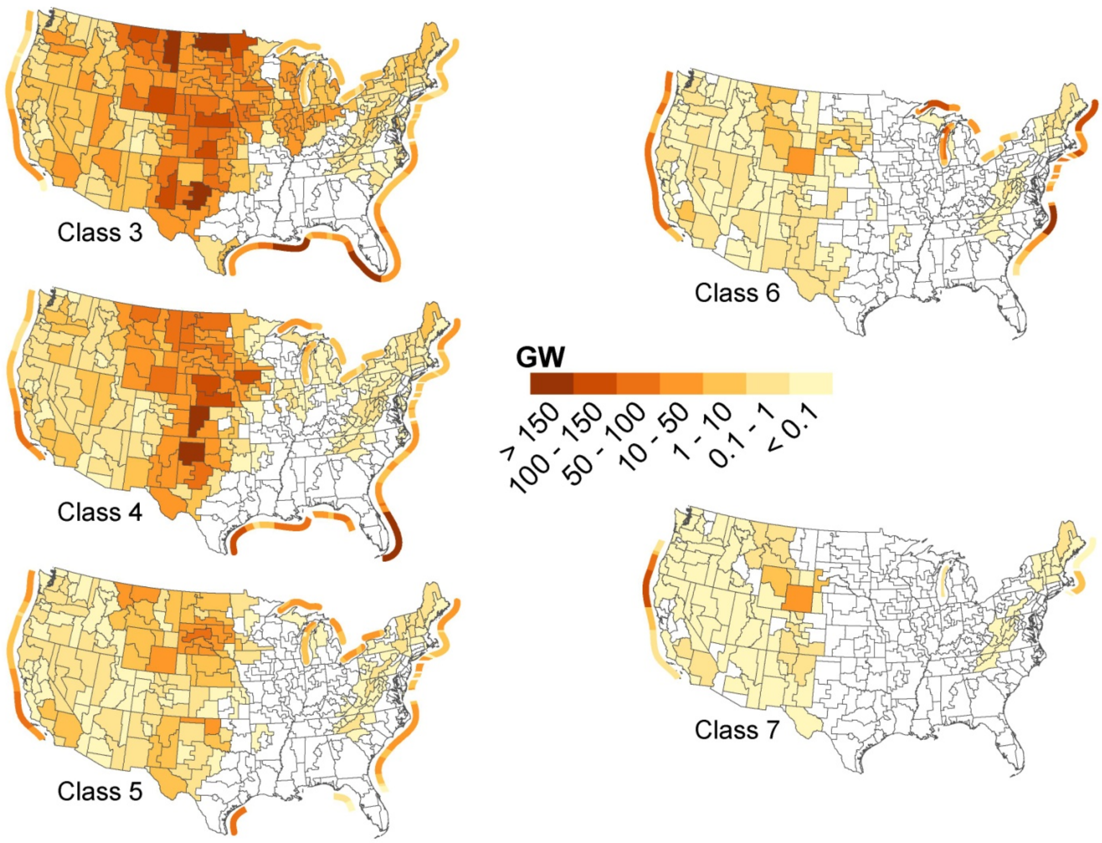



**Figure 5 – Available wind resource (onshore and offshore) by class**

---

[16] National Renewable Energy Lab. 2006. Projected Benefits of Federal Energy Efficiency and Renewable Energy Programs-FY2007 Budget Request. NREL/TP-320-39684. Golden, CO: NREL. http://www1.eere.energy.gov/ba/pdfs/39684_00.pdf.
[17] Forthcoming ReEDS documentation

## Photovoltaics (PV)

There are two primary categories of PV: utility-scale PV and distributed rooftop PV. However, distributed rooftop PV must be exogenously specified as a model input. Performance characteristics for utility-scale PV were developed by the PV module of Solar Advisor Model (SAM) using weather from typical meteorological year (TMY) files located at all TMY3 stations throughout the contiguous United States.[18] Technical potential is segmented by balancing authority and is concentrated in the Southwestern region of the country. Figure 6 shows the resource potential for PV by capacity factor included in ReEDS.

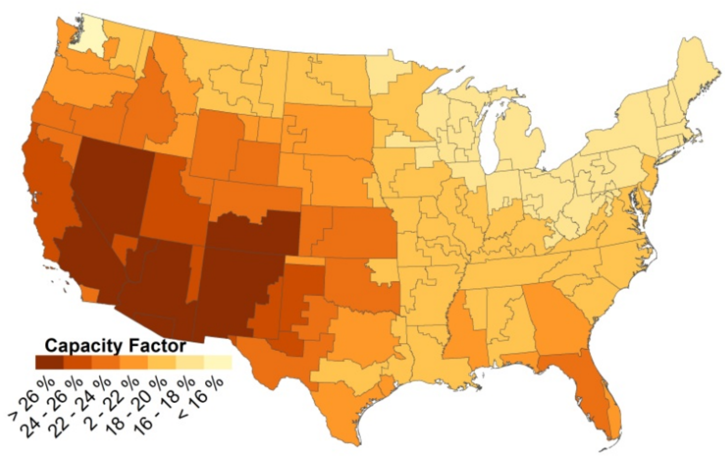



**Figure 6 – Regional capacity factor from central utility-scale PV**

## Concentrated Solar Power (CSP)

There are three CSP technologies in ReEDS: troughs without storage, troughs with at least five hours of storage, and towers with at least five hours of storage. Due to the high degree of spatial variation, technical potential is calculated at resource region resolution. There are 356 resource regions for CSP, which correspond exactly to the regions used for wind potential. CSP is assumed to be viable where the Direct Normal Irradiance (DNI) is greater than 5 kWh/m$^2$/day.

---

[18] National Renewable Energy Lab. (2010). Solar Advisor Model (SAM) version 2010.4.12. https://www.nrel.gov/analysis/sam/.

CSP sites are excluded based on land availably and slopes over 3%.[19] The total land area available for each CSP resource class is converted into GW of available capacity assuming a plant density of 31 MW/km$^2$ in applicable areas. Figure 7 shows the resource potential for CSP included in ReEDS.

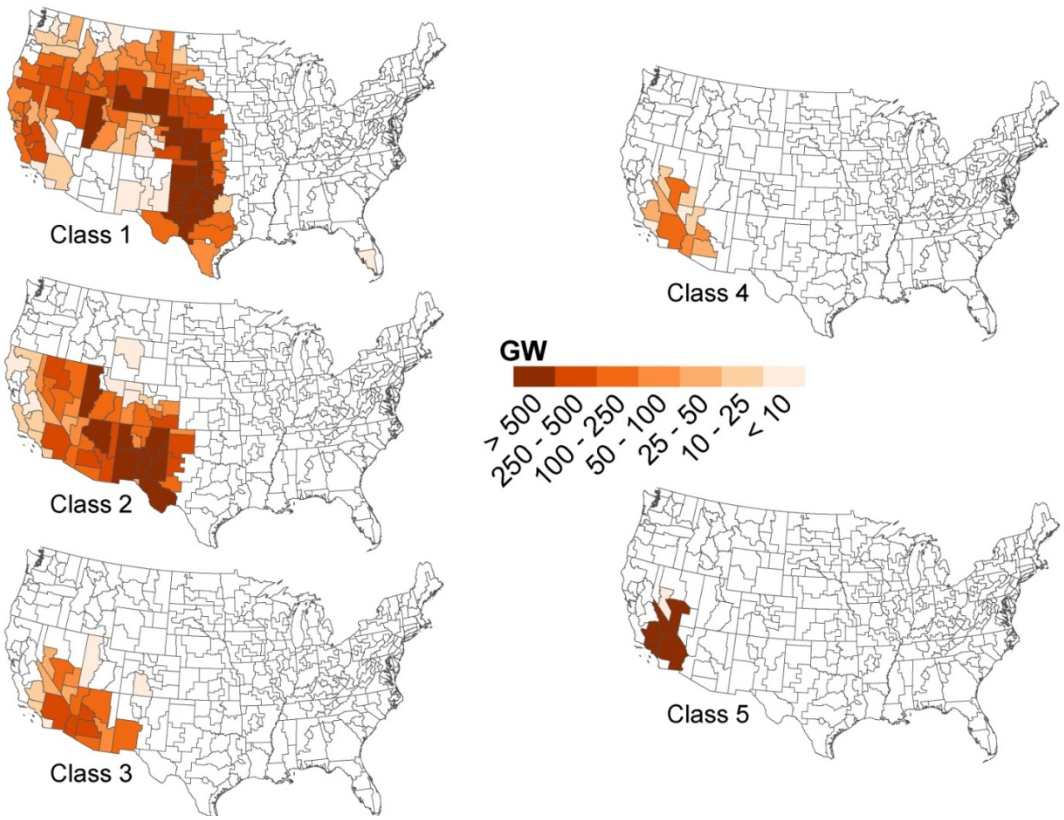



**Figure 7 – CSP resource by class**

## GENERATION COST ASSUMPTIONS

To create cost estimates for generation technologies over the 40-year study period, RMI gathered extensive data from both public and industry sources on historical, present and projected capital costs, operating costs, and performance characteristics. Base costs and operating characteristics for each technology were selected based on the validity of data sources, cost trends, and

[19] Forthcoming ReEDS documentation

convergences in the cost estimates.  Using historical empirical data, RMI applied learning curve theory to create cost projections that were calibrated with other industry projections.

## Learning Curve Theory

The concept of technology learning curves, and later experience curves, describes the phenomenon that technologies improve with cumulative experience and with manufacturing and/or deployment scale. The theory grew out of observations in shipbuilding and airplane manufacturing during the early part of the 20th century, when workers improved their productive efficiency as they produced more widgets. Although initially limited to labor in a manufacturing plant, "learning-by-doing" became a powerful concept applied across the manufacturing process of an entire industry. This broader theory, the experience curve, attempts to capture the phenomena of quality improvements and cost reductions that a technology reaps from accumulated experience of production. Empirical cost and production data of hundreds of technologies over the course of years, and even decades, correlate well with the overall expected trend.

The International Institute for Applied Systems Analysis (IIASA) characterizes the complex technological innovation process into distinct stages of evolution: invention, innovation, niche market commercialization, pervasive diffusion, saturation, and senescence.[20]

| | Stage | Mechanisms | Cost | Commercial Market Share | Learning Rate |
|---|---|---|---|---|---|
| Radical | Invention | ‣ Seeking and stumbling upon new ideas; breakthroughs; basic research | ‣ High, but difficult to attribute to a particular idea or product | 0% | ‣ Unable to express in conventional learning curve |
| Radical | Innovation | ‣ Applied research, development and demonstration (RD&D) projects | ‣ High, increasingly focused on particular promising ideas and products | 0% | ‣ Unable to express in conventional learning curve; high (perhaps >50%) in learning curves modified to include R&D (see text) |
| Incremental | Niche Market Commerciali-zation | ‣ Identification of special niche applications; investments in field projects; "learning by doing"; close relationships between suppliers and users | ‣ High, but declining with standardization of production | 0-5% | ‣ 20-40% |
| Incremental | Pervasive Diffusion | ‣ Standardization and mass production; economies of scale; building of network effects | ‣ Rapidly declining | Rapidly rising (5-50%) | ‣ 10-30% |
| Mature | Saturation | ‣ Exhaustion of improvement potentials and scale economies; arrival of more efficient competitors into market; redefinition of performance requirements | ‣ Low, sometimes declining | Maximum (up to 100%) | ‣ 0% (sometimes positive due to severe competition) |
| Mature | Senescence | ‣ Domination by superior competitors; inability to compete because of exhausted improvement potentials | ‣ Low, sometimes declining | Declining | ‣ 0% (sometimes positive due to severe competition) |

[20] McDonald, A., Schrattenholzer, L., 2001: Learning rates for energy technologies. Energy Policy 29(4):255-261.

Although experience curves can be valuable tools for testing sensitivities of potential price forecasts, the concept is perhaps most powerful for the link it illustrates between the benefits gained tomorrow from experience gained today. The curve shows the cumulative effects of a "virtuous cycle" in which the demand for technology increases as the price comes down, resulting in more production, enabling more experience and more cost reductions.

## Renewable Energy Generation Cost and Performance Assumptions

Cost data and assumptions for renewable generation are shown in Table 5.

**Table 5 – Cost data for renewables resources in ReEDS**

| | | capital costs ($2009/kW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | *Maintain* | *Migrate* | *Renew* | *Transform* | fixed O&M ($/kW-y) | variable O&M ($/MWh) | capacity factor (%) | heat rate (million BTU /MWh) |
| onshore wind | 2010 | $1,966 | $1,966 | $1,966 | $1,966 | $13.70 | $6.00 | 32%–46% | n/a |
| | 2015 | $1,851 | $1,818 | $1,789 | $1,804 | $13.70 | $6.00 | 33%–46% | n/a |
| | 2020 | $1,755 | $1,693 | $1,660 | $1,669 | $13.70 | $6.00 | 33%–46% | n/a |
| | 2025 | $1,676 | $1,631 | $1,603 | $1,615 | $13.70 | $6.00 | 34%–46% | n/a |
| | 2030 | $1,645 | $1,590 | $1,557 | $1,570 | $13.70 | $6.00 | 35%–46% | n/a |
| | 2035 | $1,621 | $1,558 | $1,522 | $1,536 | $13.70 | $6.00 | 35%–46% | n/a |
| | 2040 | $1,603 | $1,535 | $1,496 | $1,511 | $13.70 | $6.00 | 35%–46% | n/a |
| | 2045 | $1,592 | $1,520 | $1,480 | $1,495 | $13.70 | $6.00 | 35%–46% | n/a |
| | 2050 | $1,588 | $1,515 | $1,474 | $1,489 | $13.70 | $6.00 | 35%–46% | n/a |
| offshore wind | 2010 | $3,940 | $3,940 | $3,940 | $3,940 | $15.00 | $14.50 | 36%–50% | n/a |
| | 2015 | $3,267 | $3,181 | $3,128 | $3,128 | $15.00 | $14.50 | 36%–50% | n/a |
| | 2020 | $2,770 | $2,632 | $2,602 | $2,602 | $15.00 | $14.50 | 37%–50% | n/a |
| | 2025 | $2,507 | $2,431 | $2,388 | $2,388 | $15.00 | $14.50 | 37%–50% | n/a |
| | 2030 | $2,366 | $2,275 | $2,222 | $2,222 | $15.00 | $14.50 | 38%–50% | n/a |
| | 2035 | $2,260 | $2,157 | $2,098 | $2,098 | $15.00 | $14.50 | 38%–50% | n/a |
| | 2040 | $2,185 | $2,075 | $2,011 | $2,011 | $15.00 | $14.50 | 38%–50% | n/a |
| | 2045 | $2,139 | $2,024 | $1,958 | $1,958 | $15.00 | $14.50 | 38%–50% | n/a |
| | 2050 | $2,122 | $2,005 | $1,938 | $1,938 | $15.00 | $14.50 | 38%–50% | n/a |
| utility-scale (1-axis) PV | 2010 | $4,055 | $4,055 | $4,055 | $4,055 | $28.00 | $- | 16%–28% | n/a |
| | 2015 | $3,284 | $2,928 | $2,775 | $2,761 | $22.68 | $- | 16%–28% | n/a |
| | 2020 | $2,674 | $2,177 | $1,985 | $1,966 | $18.46 | $- | 16%–28% | n/a |
| | 2025 | $2,237 | $1,681 | $1,525 | $1,505 | $15.45 | $- | 16%–28% | n/a |
| | 2030 | $1,929 | $1,435 | $1,342 | $1,321 | $13.32 | $- | 16%–28% | n/a |
| | 2035 | $1,716 | $1,309 | $1,212 | $1,191 | $11.85 | $- | 16%–28% | n/a |
| | 2040 | $1,575 | $1,224 | $1,124 | $1,103 | $10.87 | $- | 16%–28% | n/a |
| | 2045 | $1,499 | $1,173 | $1,072 | $1,051 | $10.31 | $- | 16%–28% | n/a |
| | 2050 | $1,483 | $1,155 | $1,053 | $1,032 | $10.10 | $- | 16%–28% | n/a |
| distributed wind | 2010 | N/A | N/A | N/A | $3,096 | $- | $- | 25% | n/a |
| | 2015 | N/A | N/A | N/A | $3,096 | $- | $- | 25% | n/a |
| | 2020 | N/A | N/A | N/A | $3,096 | $- | $- | 25% | n/a |
| | 2025 | N/A | N/A | N/A | $3,096 | $- | $- | 25% | n/a |
| | 2030 | N/A | N/A | N/A | $2,816 | $- | $- | 25% | n/a |
| | 2035 | N/A | N/A | N/A | $2,816 | $- | $- | 25% | n/a |
| | 2040 | N/A | N/A | N/A | $2,727 | $- | $- | 25% | n/a |
| | 2045 | N/A | N/A | N/A | $2,727 | $- | $- | 25% | n/a |
| | 2050 | N/A | N/A | N/A | $2,695 | $- | $- | 25% | n/a |
| distributed rooftop PV | 2010 | $5,944 | $5,944 | $5,944 | $5,944 | $34.00 | $- | 10%–18% | n/a |
| | 2015 | $4,814 | $4,292 | $4,068 | $4,048 | $28.00 | $- | 10%–18% | n/a |
| | 2020 | $3,919 | $3,191 | $2,910 | $2,882 | $22.00 | $- | 10%–18% | n/a |
| | 2025 | $3,279 | $2,464 | $2,180 | $2,150 | $19.00 | $- | 10%–18% | n/a |
| | 2030 | $2,827 | $1,984 | $1,712 | $1,682 | $16.00 | $- | 10%–18% | n/a |
| | 2035 | $2,515 | $1,669 | $1,413 | $1,383 | $14.00 | $- | 10%–18% | n/a |
| | 2040 | $2,308 | $1,470 | $1,227 | $1,198 | $13.00 | $- | 10%–18% | n/a |
| | 2045 | $2,188 | $1,358 | $1,123 | $1,094 | $13.00 | $- | 10%–18% | n/a |
| | 2050 | $2,145 | $1,317 | $1,085 | $1,057 | $12.00 | $- | 10%–18% | n/a |
| utility PV | 2010 | $5,094 | $5,094 | $5,094 | $5,094 | $26.00 | $- | 10%–18% | n/a |
| | 2015 | $4,126 | $3,679 | $3,486 | $3,469 | $21.06 | $- | 10%–18% | n/a |
| | 2020 | $3,359 | $2,735 | $2,494 | $2,470 | $17.14 | $- | 10%–18% | n/a |
| | 2025 | $2,810 | $2,112 | $1,868 | $1,843 | $14.34 | $- | 10%–18% | n/a |
| | 2030 | $2,423 | $1,700 | $1,468 | $1,442 | $12.37 | $- | 10%–18% | n/a |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2035 | $2,155 | $1,431 | $1,211 | $1,186 | $11.00 | $- | 10%–18% | n/a |
| | 2040 | $1,978 | $1,260 | $1,051 | $1,027 | $10.10 | $- | 10%–18% | n/a |
| | 2045 | $1,876 | $1,164 | $962 | $938 | $9.57 | $- | 10%–18% | n/a |
| | 2050 | $1,838 | $1,129 | $930 | $906 | $9.38 | $- | 10%–18% | n/a |
| **concentrating solar power (w/ six-hour storage)** | 2010 | $7,000 | $7,000 | $7,000 | $7,000 | $70.00 | $- | 27%–43% | n/a |
| | 2015 | $5,403 | $5,273 | $4,275 | $4,287 | $65.00 | $- | 35%–54% | n/a |
| | 2020 | $4,684 | $4,220 | $3,558 | $3,414 | $60.00 | $- | 35%–54% | n/a |
| | 2025 | $3,601 | $3,525 | $3,364 | $3,229 | $50.00 | $- | 35%–54% | n/a |
| | 2030 | $3,415 | $3,299 | $3,176 | $3,047 | $45.00 | $- | 35%–54% | n/a |
| | 2035 | $3,264 | $3,122 | $3,014 | $2,892 | $40.00 | $- | 35%–54% | n/a |
| | 2040 | $3,154 | $2,996 | $2,893 | $2,775 | $40.00 | $- | 35%–54% | n/a |
| | 2045 | $3,086 | $2,918 | $2,816 | $2,701 | $40.00 | $- | 35%–54% | n/a |
| | 2050 | $3,060 | $2,888 | $2,787 | $2,673 | $40.00 | $- | 35%–54% | n/a |
| **geothermal (hydrothermal)** | all years | 2990 to >10000 | 2990 to >10000 | 2990 to >10000 | 2990 to >10000 | | 0.00 | up to 85% | n/a |
| **hydroelectric power** | all years | 3500-5500 | 3500-5500 | 3500-5500 | 3500-5500 | 14.85 | 5.94 | 13%–75% | n/a |
| **dedicated biopower** | 2010 | 3737 | 3737 | 3737 | 3737 | 94.06 | 14.85 | up to 84% | 14.50 |
| | 2015 | 3530 | 3535 | 3525 | 3535 | 94.06 | 14.85 | up to 84% | 14.25 |
| | 2020 | 3408 | 3400 | 3398 | 3400 | 94.06 | 14.85 | up to 84% | 14.00 |
| | 2025 | 3338 | 3333 | 3323 | 3333 | 94.06 | 14.85 | up to 84% | 13.75 |
| | 2030 | 3280 | 3278 | 3261 | 3278 | 94.06 | 14.85 | up to 84% | 13.50 |
| | 2035 | 3235 | 3235 | 3211 | 3235 | 94.06 | 14.85 | up to 84% | 13.25 |
| | 2040 | 3202 | 3205 | 3174 | 3205 | 94.06 | 14.85 | up to 84% | 13.00 |
| | 2045 | 3182 | 3186 | 3151 | 3186 | 94.06 | 14.85 | up to 84% | 12.75 |
| | 2050 | 3174 | 3179 | 3142 | 3179 | 94.06 | 14.85 | up to 84% | 12.50 |
| **landfill gas / municipal solid waste** | all years | n/a | n/a | n/a | n/a | 407.79 | 0 | up to 90% | 13.65 |
| **cofire retrofit (15% biomass)** | all years | 990 | 990 | 990 | 990 | | | | |

## Conventional Generation Cost and Performance Assumptions

Cost data for conventional generation are shown in Table 6.

**Table 6 – Cost data for conventional resources**

| | | capital costs ($/kW) | | | | fixed O&M ($/kW-y) | variable O&M ($/MWh) | heat rate (million BTU/MWh) |
|---|---|---|---|---|---|---|---|---|
| | | *Maintain* | *Migrate* | *Renew* | *Transform* | | | |
| **gas-CT** | 2010 | $714.00 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 12540 |
| | 2015 | $709.14 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2020 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2025 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2030 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2035 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2040 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2045 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| | 2050 | $707.35 | $714.00 | $714.00 | $714.00 | $8.00 | $35.40 | 10390 |
| **gas-CC** | 2010 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2015 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2020 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2025 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2030 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2035 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2040 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2045 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| | 2050 | $850.00 | $850.00 | $850.00 | $850.00 | $13.71 | $2.86 | 6870 |
| **pulverized coal** | 2010 | $2,075.00 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9200 |
| | 2015 | $2,069.23 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2020 | $2,064.05 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2025 | $2,059.54 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2030 | $2,055.77 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2035 | $2,054.48 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2040 | $2,054.48 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2045 | $2,054.48 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| | 2050 | $2,054.48 | $2,075.00 | $2,075.00 | $2,075.00 | $33.60 | $1.62 | 9000 |
| **coal-IGCC-CCS** | 2010 | $6,930.00 | $6,930.00 | $6,930.00 | $6,930.00 | $44.08 | $10.84 | 10445 |
| | 2015 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2020 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2025 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2030 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2035 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2040 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2045 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| | 2050 | $6,600.00 | $6,600.00 | $6,600.00 | $6,600.00 | $44.08 | $10.84 | 10445 |
| **nuclear** | 2010 | $5,116.00 | $5,116.00 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2015 | $5,116.00 | $5,025.03 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2020 | $5,116.00 | $4,944.61 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2025 | $5,116.00 | $4,875.53 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2030 | $5,116.00 | $4,854.30 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2035 | $5,116.00 | $4,845.37 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2040 | $5,116.00 | $4,838.85 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2045 | $5,116.00 | $4,834.80 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |
| | 2050 | $5,116.00 | $4,833.27 | $5,116.00 | $5,116.00 | $150.00 | $- | 9720 |

## Fuel Price Assumptions

Base fuel prices for natural gas and coal are derived from projections from EIA's 2010 *Annual Energy Outlook.*[21] Beyond 2035, fuel prices are assumed to increase at the same national annual average rate as projected by the AEO between 2020 and 2035. The forecasted price is increased if demand increases relative to the AEO forecasted demand, and the price is decreased if demand decreases relative to AEO forecasted demand.[22] Fossil fuel prices elasticity is 0.37 (2004$/MMBtu per Quad of electric sector consumption) for natural gas and 0.035 (2004$/MMBtu per Quad of electric sector consumption) for coal. Table 7 shows fuel price by case.

**Table 7 – Fuel prices by RF Case**

| | 2009 $/million BTU | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| **Natural Gas** | *Maintain* | $4.75 | $5.60 | $7.11 | $7.92 | $7.89 |
| | *Migrate* | $4.75 | $5.28 | $5.28 | $5.23 | $5.17 |
| | *Renew* | $4.75 | $5.25 | $4.63 | $5.93 | $4.93 |
| | *Transform* | $4.75 | $4.79 | $4.80 | $4.48 | $4.79 |
| **Coal** | *Maintain* | $2.13 | $2.07 | $2.20 | $2.37 | $2.41 |
| | *Migrate* | $2.13 | $2.06 | $2.15 | $2.15 | $2.09 |
| | *Renew* | $2.13 | $1.98 | $1.94 | $1.79 | $1.70 |
| | *Transform* | $2.13 | $1.87 | $1.70 | $1.74 | $1.75 |
| **Biomass** | All Cases | $1.64–4.09 | $1.64–4.09 | $1.64–4.09 | $1.64–4.09 | $1.64–4.09 |

## Storage Technology

Cost and performance inputs for storage technology are a combination of RMI analysis using its internal dispatch model and ReEDS base case defaults for centralized pumped hydro storage (PHS), compressed air energy storage (CAES), batteries, and thermal storage. The battery chemistry assumed in the ReEDS model is sodium-sulfur with an 8-hour discharge, based on the well-established nature of the technology and competitive costs.[23] The cost and performance parameters for storage technologies are shown in Table 8. Note that only the Transform case

[21] EIA. 2011. Annual Energy Outlook 2011. Washington, DC. http://www.eia.doe.gov/oiaf/aeo/
[22] Forthcoming ReEDS documentation
[23] Forthcoming ReEDS documentation

included distributed battery and thermal storage using the RMI dispatch model, which are shown as their own column in Table 8.

**Table 8 – ReEDS storage cost and performance data**

| | | *Maintain* | *Migrate* | *Renew* | *Transform* | Distributed | fixed O&M ($/kW-yr) | variable O&M ($/MWh) | round trip efficiency (%) | heat rate (million BTU/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| **pumped hydro-power storage (PHS)** | all years | 2230 | 2230 | 2230 | 2230 | n/a | 30.8 | 0 | 80% | n/a |
| **batteries** | 2010 | 3990 | 3990 | 3990 | 3990 | 3100 | 25.2 | 59 | 75% | n/a |
| | 2015 | 3890 | 3890 | 3890 | 3890 | 3100 | 25.2 | 59 | 75% | n/a |
| | 2020 | 3790 | 3790 | 3790 | 3790 | 1500 | 25.2 | 59 | 75% | n/a |
| | 2025 | 3690 | 3690 | 3690 | 3690 | 1500 | 25.2 | 59 | 75% | n/a |
| | 2030 | 3590 | 3590 | 3590 | 3590 | 1010 | 25.2 | 59 | 75% | n/a |
| | 2035 | 3490 | 3490 | 3490 | 3490 | 1010 | 25.2 | 59 | 75% | n/a |
| | 2040 | 3390 | 3390 | 3390 | 3390 | 1000 | 25.2 | 59 | 75% | n/a |
| | 2045 | 3290 | 3290 | 3290 | 3290 | 1000 | 25.2 | 59 | 75% | n/a |
| | 2050 | 3190 | 3190 | 3190 | 3190 | 1000 | 25.2 | 59 | 75% | n/a |
| **com-pressed air energy storage (CAES)** | all years | 900-1200 | 900-1200 | 900-1200 | 900-1200 | n/a | 11.6 | 1.55 | 125% | 4.91 |
| **thermal storage in build-ings (ICE)** | 2010 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| | 2020 | 1950–3000 | 1950–3000 | 1950–3000 | 1950–3000 | 1800 | 17.1 | 0 | 100% | n/a |
| | 2030 | 1900–2920 | 1900–2920 | 1900–2920 | 1900–2920 | 1800 | 16.7 | 0 | 100% | n/a |
| | 2040 | 1850–2850 | 1850–2850 | 1850–2850 | 1850–2850 | 1500 | 16.2 | 0 | 100% | n/a |
| | 2050 | 1810–2780 | 1810–2780 | 1810–2780 | 1810–2780 | 1500 | 15.8 | 0 | 100% | n/a |

## Demand Response and Interruptible Load

In ReEDS, interruptible load can be used to satisfy operating reserve requirements and count towards contingency and forecast error reserve requirements. Interruptible load is not counted towards frequency regulation reserve requirements. Due to the coarse time slices of the ReEDS model, the frequency with which interruptible loads (and any other reserve services) are called upon is unknown. Table 9 shows the percent that can be deployed in terms of peak load reduction from an interruptible load contract agreement reached between a utility and a load entity for planning purposes.[24] Variations in availability of interruptible load for a given year reflect the ranges between NERC subregions.

**Table 9 – Interruptible load by RF case**

| | | Percent of Peak Load | |
|---|---|---|---|
| | | Min | Max |
| 2010 | Maintain | 1% | 8% |
| 2020 | | 1% | 8% |
| 2030 | | 1% | 8% |
| 2040 | | 1% | 8% |
| 2050 | | 1% | 8% |
| 2010 | Migrate | 1% | 8% |
| 2020 | | 9% | 16% |
| 2030 | | 9% | 16% |
| 2040 | | 9% | 16% |
| 2050 | | 9% | 16% |
| 2010 | Renew | 1% | 8% |
| 2020 | | 11% | 17% |
| 2030 | | 11% | 17% |
| 2040 | | 11% | 17% |
| 2050 | | 11% | 17% |
| 2010 | Transform | 1% | 8% |
| 2020 | | 11% | 17% |
| 2030 | | 11% | 17% |
| 2040 | | 16% | 24% |
| 2050 | | 16% | 24% |

## FINANCIAL

The default financial assumptions used in ReEDs were adopted for the RMI analysis. These assumptions reflect the cost of capital and financial structure used to finance generation resources. The cost of capital and financial structure will differ depending upon how a project is financed and the perceived risk and required return. For example, the cost of capital for public financing, such as municipal bonds, would be lower than the cost of capital of an investor-owned utility and much lower than the project financing received by a private developer. For

[24] Forthcoming ReEDS documentation

simplicity, RMI assumes all projects are utility financed. Table 10 provides a summary of the financial values used to produce the net capital and operating costs.[25]

**Table 10 – General financial assumption for all RF cases**

| Assumption | Value |
|---|---|
| Inflation rate | 3% |
| Evaluation period | 20 years |
| Rate of return on equity—RROE (nominal) | 13% |
| Debt interest rate (nominal) | 8% |
| Interest rate during construction (nominal) | 8% |
| Debt fraction | 50% |
| WACC discount rate (nominal) | 8.9% |
| WACC discount rate (real) | 5.7% |
| Corporate tax rate (combined federal and state) | 40% |
| Modified Accelerated Cost Recovery System (MACRS) (non-hydropower renewables) | 5 years |
| MACRS ("conventionals" and hydropower) | 15 years |

Two other important financial inputs are the risk adjustment factor and capital cost financial multiplier for each technology (Table 11). The risk adjustment is applied to all coal-fired technologies to account for the perceived risk of potential carbon regulation, and is added to both the cost of equity and debt. The capital cost financial multiplier represents the impact to the cost of capital that would result based on debt/equity financing, taxes (and depreciation), interest during construction, risk adjustments, and any tax incentives (*e.g.*, the wind production tax credit [PTC] or solar investment tax credit [ITC]).

[25] Forthcoming ReEDS documentation

Table 11 – Risk and capital cost adjustment factor by technology

| | Risk Adjustment Factor | Capital Cost Financial Multiplier |
|---|---|---|
| Coal (pulverized) | 3% | 1.8 |
| Coal (IGCC) | 3% | 1.8 |
| Coal (IGCC-CCS) | 0% | 1.49 |
| Old pulverized coal (w/o $SO_2$ scrubber) | N/A | N/A |
| Old pulverized coal (with $SO_2$ scrubber) | N/A | N/A |
| Natural gas (CT) | 0% | 1.34 |
| Natural gas (CC) | 0% | 1.35 |
| Natural gas (CC-CCS) | 0% | 1.35 |
| Oil-gas-steam | N/A | N/A |
| Nuclear | 0% | 1.49 |
| Geothermal | 0% | 1.22 |
| Dedicated biopower | 0% | 1.22 |
| Landfill-gas/MSW | N/A | N/A |
| New cofire | 3% | 1.8 |
| Old cofire | N/A | N/A |
| Hydropower | 0% | 1.34 |
| Wind | 0% | 1.18 |
| CSP | 0% | 1.18 |
| Utility-scale PV | 0% | 1.16 |
| PSH | 0% | 1.34 |
| Batteries | 0% | 1.32 |
| CAES | 0% | 1.35 |
| Thermal storage | 0% | 1.32 |

## SPECIFIC ASSUMPTIONS FOR THE *TRANSFORM CASE*

RMI modified several aspects of ReEDS inputs to approximate the distributed system envisioned in the *Transform* case. Note that we *did not* modify the load profiles, but rather decreased the demand met by the bulk power system using ReEDS.

- **Distributed Wind:** RMI exogenously specified the percentage of total load met using distributed wind. This scaled linearly from 0% in 2010 to 10% in 2050 and reduced the total demand that the electricity system had to meet within the ReEDS model. Total distributed wind generation is 412 TWh in 2050.

- **Combined Heat and Power (CHP):** CHP was not modeled as a specific generation resource in ReEDS. Similar to the treatment of distributed wind, CHP was integrated into the ReEDS analysis by decreasing the demand that the electricity system was required to meet. RMI exogenously specified the amount of annual electricity that could be met by CHP—from industrial facilities only, not buildings—from 2010 through 2050 based on the industrial sector analysis that RMI conducted as part of RF. Two different types of CHP were assumed: 1) CHP that captures excess waste heat from existing industrial processes and recycles that waste heat to produce electricity and 2) an electricity generation facility that recycles the waste heat from that facility for industrial processes. The estimated amount of CHP by 2050 was 415 TWh annually. The generation profile was assumed to be linear, and the demand met by CHP was removed equally from each timeslice and NERC region.

- **Electric Vehicles:** The transportation analysis that RMI conducted for RF estimated 157 million electric vehicles by 2050, equating to an annual electricity demand of 398.3 TWh. The deployment of EVs was put into ReEDS as additional annual demand for electricity in each of the 17 temporal timeslices. Only a subset of those electric vehicles—26 million—was assumed to be a V2G storage resource that could supply power back to the grid. Each V2G vehicle was assumed to have a maximum storage capacity of 8 kW and 16 kWh.

- **Distributed Solar:** For the purposes of modeling, distributed PV includes community and rooftop scale solar PV. In all cases, solar PV was exogenously specified in ReEDS. RMI estimated 26% of total load could be met by this means in 2050, ramped linearly from 2010 through 2050.

- **Distributed Storage:** Ice storage and batteries were included as a suite of distributed storage resources. The dispatch model was used to determine the amount of storage resources required to balance a portfolio of distributed PV and wind. The 99th percentile of storage output for the simulated year was exogenously input to ReEDS—44 GW of batteries and 69 GW of ice storage, with a 4hr discharge assumed. ReEDS added this to the centralized storage it built for the bulk power system.

# REGULATORY POLICIES

ReEDS accounts for regulatory policies and standards that affect the cost and generation of renewables energy deployment. In general, these policies are included in the constraints but are not extended beyond their currently legislated term. Table 12 shows a list of state and federal production and investment incentives and their expirations.[26]

**Table 12 – Renewables production and investment incentives**

| Type | Location | Technology | Production Tax Credit (nominal $/MWh) | Investment Tax Credit | Notes |
|---|---|---|---|---|---|
| Federal | Renewable Energy PTC | Wind | 18.5 (2004$) | N/A | Expires in 2012 |
| Federal | Renewable Energy ITC | CSP, UPV | N/A | 30% | Expires in 2016 |
| Federal | Renewable Energy ITC | CSP, UPV | N/A | 10% | After 2016 |
| State | Iowa | Most Renewables | N/A | 5% | |
| State | Idaho | Most Renewables | N/A | 5% | |
| State | Minnesota | Most Renewables | N/A | 7% | |
| State | New Jersey | Most Renewables | N/A | 6% | |
| State | New Mexico | Most Renewables | 10 | N/A | |
| State | Oklahoma | Most Renewables | 2.5 | N/A | |
| State | Utah | Most Renewables | N/A | 5% | |
| State | Washington | Most Renewables | N/A | 6.5% | |
| State | Wyoming | Most Renewables | N/A | 4% | |

Emissions of $CO_2$ are not constrained in each case. However, $SO_2$ emissions are capped at a level that corresponds roughly to the 2005 Clean Air Interstate Rule[27].

Renewable Portfolio Standards (RPS) are also a constraint in ReEDS. Table 13[28] shows the fraction of renewables generation mandated by state and date of implementation. While ReEDS has the capability to mandate a federal RPS, there is no federal standard at present. There are, however, resource constraints on maximum generation for coal and nuclear for each RF case.

[26] Forthcoming ReEDS documentation
[27] EPA. 2005a. Clean Air Interstate Rule, Charts and Tables. Washington, DC: US Environmental Protection Agency. http://www.epa.gov/cair/charts_files/cair_ emissions_costs.pdf.
[28] Forthcoming ReEDS documentation

**Table 13 – State Renewable Portfolio Standards**

| State | RPS Start | Full Implementation | Penalty ($/MWh) | Assumed RPS (%) | Legislated RPS (%) | Load Fraction |
|---|---|---|---|---|---|---|
| Arizona | 2001 | 2025 | 5 | 15 | 15 | 0.59 |
| California | 2003 | 2011 | 50 | 20 | 20 | 0.75 |
| Colorado | 2007 | 2015 | 5 | 30 | 30 | 0.51 |
| Connecticut | 2004 | 2020 | 55 | 23 | 27 | 0.93 |
| Delaware | 2007 | 2020 | 5 | 36 | 40 | 0.36 |
| Illinois | 2004 | 2025 | 5 | 25 | 25 | 0.46 |
| Iowa | 1999 | 1999 | 5 | 105 MW | 105 MW | 1 |
| Massachusetts | 2003 | 2020 | 59 | 15 | 15 | 0.85 |
| Maryland | 2006 | 2022 | 20 | 20 | 20 | 0.97 |
| Michigan | 2007 | 2015 | 5 | 10 | 10 | 1 |
| Minnesota | 2002 | 2025 | 5 | 55 | 55 | 0.5 |
| Missouri | 2007 | 2021 | 5 | 15 | 15 | 0.7 |
| Montana | 2008 | 2015 | 10 | 15 | 15 | 0.67 |
| Nevada | 2003 | 2015 | 5 | 20 | 20 | 0.88 |
| New Hampshire | 2008 | 2025 | 54 | 23.8 | 23.8 | 1 |
| New Jersey | 2005 | 2021 | 50 | 22.5 | 22.5 | 0.98 |
| New Mexico | 2006 | 2020 | 5 | 29.4 | 30 | 0.52 |
| New York | 2006 | 2013 | 5 | 23.7 | 23.8 | 0.73 |
| North Carolina | 2007 | 2021 | 5 | 21 | 22.5 | 0.53 |
| Ohio | 2007 | 2024 | 45 | 12.5 | 12.5 | 0.89 |
| Oregon | 2003 | 2025 | 5 | 40 | 40 | 0.51 |
| Pennsylvania | 2007 | 2021 | 45 | 17.5 | 18 | 0.97 |
| Rhode Island | 2007 | 2019 | 59 | 16 | 16 | 0.99 |
| Texas | 2003 | 2015 | 50 | 5880 MW | 5880 MW | 1 |
| Washington | 2007 | 2020 | 50 | 15 | 15 | 0.85 |
| Wisconsin | 2001 | 2015 | 10 | 10.1 | 10.1 | 1 |

# SYSTEM OPERATIONS

## TRANSMISSION

As a simplifying assumption that matches the scope of an expansion model, rather than a dispatch or hourly unit commitment simulation, the ReEDS model assumes transmission is constrained only by the size of the transmission lines and not by other characteristics of electrical power flow. This excludes the topology of the transmission network and the interactive effect of flows between regions.[29]

The following excerpt from the forthcoming ReEDS documentation describes transmission assumptions:

ReEDS uses a reduced network with 134 nodes (center-to-center of ReEDS balancing areas) and roughly 300 aggregate lines that connect contiguous balancing areas. Each line has a nominal carrying capacity limit determined for the start-year (2006) based on power-flow analysis using ABB's GridView model and NERC reported limits.[30] In later years, ReEDS is able to build additional capacity to increase these carrying capacities. Transmission expansion is limited before 2020 to lines for which new construction is already planned.[31] After 2020, that limitation is dropped. ReEDS considers transmission flow limits when dispatching generation in each of the 17 time-slices and in planning firm transmission capacity contracts between reserve-sharing groups. In all cases, the transmission capacity required to carry variable-resource generation from wind and PV is assumed to be the nameplate capacity of the wind and PV.

ReEDS does not address AC-power-flow issues of voltage, frequency, or phase angle. Intra-BA transmission and distribution networks are similarly ignored, effectively assuming away transmission congestion within each region.
Transmission power losses are characterized by a factor of 1%/100 miles. Distribution losses are not considered endogenously in ReEDS; they are estimated at 5.3% of end-use demand and do not apply to distributed utility-scale and rooftop PV, as these technologies are assumed to be located within distribution networks.

Grid interconnection costs are applied to most generation and storage technologies upon construction. Since concentrating solar power (CSP) and wind resource quality depends heavily

[29] Forthcoming ReEDS documentation
[30] NERC Model Validation Task Force of the Transmission Issues Subcommittee. *Power System Model Validation*. North American Electric Reliability Corporation. May 2010.
[31] Edison Electric Institute. *Transmission Projects: At A Glance*. Februrary 2010.

on location, supply curves for each wind/CSP resource region (of which there are 356) in the United States were developed to account for the additional transmission line construction for connecting these resources to the grid as well as to local demand centers.

## Distribution Network

The cost of the distribution network is not included in ReEDS analysis. Several assumptions were made to account for distribution network investments for *Reinventing Fire*. To provide an estimate of base distribution investment costs per year, EIA's *Electric Power Annual 2008* and EEI's *Statistical Yearbook 2009* were used to review the historical empirical data since 1997. Performing a regression, RMI estimated that the cost of distribution infrastructure investments was $41.76 per kW of new generation capacity added to the system. To account for the net investments required for the distributed intelligence and operational control that increases in the *Renew* and *Transform* cases, an additional "Smart Grid" cost was estimated. Using EPRI's recent study[32], Smart Grid investments were estimated at $1.5 billion per year through 2030 and $0.9 billion per year during 2030–2050 in the *Maintain* and *Migrate* cases. The *Transform* case has an adder of $3.7 billion per year through 2030 and $2.2 billion per year from 2030-2050. The *Transform* case has the largest adder, with $7.4 billion per year through 2030 and $4.3 billion per year 2030-2050.

## Reserves

### Planning Reserves

Planning reserves account for the required capacity that must be carried on the system above estimated peak demand. Reserve margins by NERC region are shown in Table 14. However, these reserve requirements are further divided by RTO area. All dispatchable generator-types, including CSP systems with storage, count their full (nameplate) capacity toward the planning reserve requirement.[33]

---

[32] EPRI. 2011. *Estimating the Costs and Benefits of the Smart Grid. A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid.* Final Report, March 2011. 1022519.
[33] Forthcoming ReEDS documentation

Table 14 – Required reserve margin by NERC region.

| NERC Subregion | Reserve Margin |
|---|---|
| ECAR | 15% |
| CA | 17% |
| ERCOT | 12.5% |
| FL | 15.8% |
| MAAC | 15% |
| MAIN | 15% |
| MAPP | 15% |
| NE | 15% |
| NWP | 17.2% |
| NY | 15% |
| RA | 17% |
| SERC | 13% |
| SPP | 12% |

## Operating Reserves

Operating reserve requirements provide the daily system flexibility to ensure that generation and demand are balanced at all times.

### There are three reserve requirements in ReEDS:

- Contingency reserve requirements ensure that unplanned outages do not alter power delivery. In ReEDS, the contingency reserve requirement is 6% of demand in each time slice. Spinning reserves or interruptible load must make up half of this requirement, while the rest can be met with quick-start generators.

- Frequency regulation reserve requirements ensure demand and generation deviations are minimized at a sub-hourly time scale. In ReEDS, this is set at 1.5% of average demand in each time slice and is only met with spinning reserves.

- Variable resource renewable energy (VRRE) forecast error reserve requirements ensure wind and PV do not destabilize the power system. ReEDS uses two standard deviations of hour-ahead persistence forecast errors in each reserve-sharing groups.

# RMI Dispatch Model

## Model Description

The RMI dispatch model is an hourly, least-cost dispatch model primarily designed to analyze the feasibility and effects of increasing the amounts of variable resources onto the electric grid. The model incorporates user-inputted factors such as generation plant operating costs, $CO_2$ emissions, fuel costs, and forced and planned outage rates.

The generator mix is fully customizable, allowing resources to be added and electricity demand to be defined in any existing or hypothetical grid. In general, generators fall into three categories: *variable* generators (such as wind or solar PV), *dispatchable* generators (coal, gas, etc.), and *storage* generators (such as pumped hydro or an electric vehicle fleet). For all resources, the capacity, ramp rate, minimum allowable output, capital cost, variable (fuel, O&M, and $CO_2$) costs, and rates of forced outages and maintenance are user inputs to the model.

Variable generators, for example a windfarm, also require data for the capacity factor of the resource in each hour of the year. These data are site and year specific, and a different dataset is required for each variable generator. For simple storage resources, such as thermal energy storage or pumped hydro, the user also inputs charging and discharging costs and efficiencies, and maximum allowed level of discharge. For more complicated storage resources, such as EVs/PHEVs, the drivetrain efficiency and driving and charging behavior patterns are fully customizable.

## Dispatch Steps

In dispatching generating resources for each hour, the RMI Dispatch Model "forecasts" both demand and variable supply 36 hours ahead and determines the lowest-cost generating mix to meet demand, following four main steps.

First, any energy efficiency measures are applied to reduce the projected electricity demand. The RMI Dispatch Model incorporates efficiency measures estimated to apply broadly to specific end-uses. For example, a specific model run may include a lighting efficiency measure that reduces electricity demand for residential lighting by 15% and has 80% adoption. Another measure could reduce electricity for commercial space cooling by 20% with 50% adoption. For each energy efficiency measure, the portion of original demand attributable to that end-use is reduced by the corresponding amount (reduction × penetration) at all hours of the year. Because many end-use-specific demands (for example, space cooling) are significantly higher during peak demand hours, this application of efficiency measures usually results in more savings at peak hours, reducing fluctuations in overall demand.

After energy efficiency measures are applied, the model dispatches required power supplies of two types: 1) minimum generation from dispatchable plants, and 2) available power from variable generators. In the first set, all dispatchable generators have a minimum output in any hour of the year. This output level is fixed at either the minimum allowable output from the plant (as set by operational and safety requirements—typically 20–40% of nameplate capacity), or at the previous hour's output minus the plant's ramp rate. For example, if a 450 MW coal plant is operating at 320 MW, and has a ramp rate of ±50 MW/h, its minimum output in the next hour is 270 MW.  (Similarly, its maximum output in the next hour is 370 MW.) Most peaking plants are modeled as having the ability to ramp up their full capacity in any hour. The second set of required supplies is output from variable generators. Variable generators (such as wind or solar PV) have essentially zero operating cost, so it is assumed that the grid always takes their power when it is available. These outputs are calculated for each hour from the gross resource capacities and hourly availabilities, and along with minimum dispatchable output levels, are applied to meet a portion of the demand. The remaining demand, or *net load*, is what must be met with the remaining capacity of dispatchable generators, demand response and storage resources. Depending on the shape of the post-efficiency demand and the variable generation profiles, the *net load* may in fact be negative in some hours of the year.

In the third main step of the model, hydropower and demand-shifting resources are applied to flatten the peaks of demand as much as possible. Hydropower, a fully dispatchable and essentially free resource, is dispatched first to meet the peaks of the net load, taking into account two important limits. First, the hourly generation from any hydro facility cannot exceed its nameplate capacity, and second, the amount of energy available from hydropower is subject to daily and weekly budgets that are based on real generation patterns from these facilities. In practice, these budgets are the result of water availability (which in small reservoirs is highly variable throughout the year), downstream agricultural and municipal demand, and ecosystem management requirements. After partially flattening the load with hydropower, storage and demand response resources are used to shift energy demand from peaks to valleys. In applying storage resources to shift loads, each type of resource is modeled slightly differently to include technology-specific requirements. In all cases, storage facilities can take excess energy from the grid at a specified cost per MWh and charging efficiency. Storage facilities can return this energy to the grid at a later time, again at some cost and efficiency, but subject to their limits of maximum discharge rate and discharge level.

The remaining load after energy efficiency measures, variable generators, and load shifting must be met with dispatchable resources. Taking into account fuel, $CO_2$, and O&M costs, the available dispatchable resources are sorted by their marginal cost. At this point, some generators are randomly taken offline to reflect their specified forced outage rates. With these sorted costs and the set of offline generators defined, the model then dispatches, in order of increasing cost, each generator up to its maximum allowable output in that hour until the net load is met. Similar to the minimum allowed output detailed above, each generator has a maximum output level at any hour that is the minimum of its nameplate capacity and its output in the previous hour plus its ramp rate. The model records any remaining unmet demand.

## CAVEATS

Following the four main steps outlined above, the RMI Dispatch Model determines the least-cost generation mix at every hour of the year, charging and discharging schedules for storage resources, and demand response load shifting. The RMI Dispatch Model is not intended to replace operational and unit commitment power models. While the model includes many detailed operational parameters, it also makes several simplifying assumptions, three of which are:

- *The variable cost of generation from a given resource is a linear function of its output.* There are certainly more complicated cases where this would not be true; one example is a tiered cost structure for $CO_2$ emissions, where the generator pays one rate for $CO_2$ emissions up to a baseline level, a higher rate for emissions exceeding the baseline up to the next threshold, and so on. Such variable cost structures are not included in this model.

- *The transmission network is sufficient to balance all the generators and loads on the grid without congestion or connection issues.* In effect, the model has only one transmission region. This is a more realistic assumption when modeling smaller, regional grids. However, with a grid of widely distributed, smaller generators, it is expected that these generators will perform some amount of self-balancing with local loads and rely less on arterial transmission networks. Characteristics of power quality, such as voltage magnitude and harmonic content in the waveforms, are not included in the dispatch model.

- *The dispatcher has a perfect forecast of both demand and variable supply when dispatching 36 hours in advance.* In reality, wind generation can be predicted with only around 50% accuracy 36 hours ahead, but with greater than 90% accuracy one hour ahead. The 36-h forecast of wind and solar generation allows the grid operator to make a good guess at how much reserve peaking capacity is necessary, and roughly when to charge/discharge storage resources. Continually revising these demand and supply forecasts as the dispatch hour approaches, and using these forecasts to refine the generation mix, can allow the operator to approach the efficiency of this perfect-forecast scenario.