NATIONAL RENEWABLE ENERGY LABORATORY

Volume 2 of 4

Renewable Electricity Futures Study

Renewable Electricity Generation and Storage Technologies

Volume 1 PDF
Volume 2 PDF
Volume 3 PDF
Volume 4 PDF

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Renewable Electricity Futures Study

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Renewable Electricity Futures Study

Volume 2: Renewable Electricity Generation and Storage Technologies

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Perspective

The Renewable Electricity Futures Study (RE Futures) provides an analysis of the grid integration opportunities, challenges, and implications of high levels of renewable electricity generation for the U.S. electric system. The study is not a market or policy assessment. Rather, RE Futures examines renewable energy resources and many technical issues related to the operability of the U.S. electricity grid, and provides initial answers to important questions about the integration of high penetrations of renewable electricity technologies from a national perspective. RE Futures results indicate that a future U.S. electricity system that is largely powered by renewable sources is possible and that further work is warranted to investigate this clean generation pathway. The central conclusion of the analysis is that renewable electricity generation from technologies that are commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the United States.

The renewable technologies explored in this study are components of a diverse set of clean energy solutions that also includes nuclear, efficient natural gas, clean coal, and energy efficiency. Understanding all of these technology pathways and their potential contributions to the future U.S. electric power system can inform the development of integrated portfolio scenarios. RE Futures focuses on the extent to which U.S. electricity needs can be supplied by renewable energy sources, including biomass, geothermal, hydropower, solar, and wind.

The study explores grid integration issues using models with unprecedented geographic and time resolution for the contiguous United States. The analysis (1) assesses a variety of scenarios with prescribed levels of renewable electricity generation in 2050, from 30% to 90%, with a focus on 80% (with nearly 50% from variable wind and solar photovoltaic generation); (2) identifies the characteristics of a U.S. electricity system that would be needed to accommodate such levels; and (3) describes some of the associated challenges and implications of realizing such a future. In addition to the central conclusion noted above, RE Futures finds that increased electric system flexibility, needed to enable electricity supply-demand balance with high levels of renewable generation, can come from a portfolio of supply- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations. The analysis also finds that the abundance and diversity of U.S. renewable energy resources can support multiple combinations of renewable technologies that result in deep reductions in electric sector greenhouse gas emissions and water use. The study finds that the direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Of the sensitivities examined, improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost. Assumptions reflecting the extent of this improvement are based on incremental or evolutionary improvements to currently commercial technologies and do not reflect U.S. Department of Energy activities to further lower renewable technology costs so that they achieve parity with conventional technologies.

RE Futures is an initial analysis of scenarios for high levels of renewable electricity in the United States; additional research is needed to comprehensively investigate other facets of high renewable or other clean energy futures in the U.S. power system. First, this study focuses on renewable-specific technology pathways and does not explore the full portfolio of clean technologies that could contribute to future electricity supply. Second, the analysis does not attempt a full reliability analysis of the power system that includes addressing sub-hourly, transient, and distribution system requirements. Third, although RE Futures describes the system characteristics needed to accommodate high levels of renewable generation, it does not address the institutional, market, and regulatory changes that may be needed to facilitate such a transformation. Fourth, a full cost-benefit analysis was not conducted to comprehensively evaluate the relative impacts of renewable and non-renewable electricity generation options.

Lastly, as a long-term analysis, uncertainties associated with assumptions and data, along with limitations of the modeling capabilities, contribute to significant uncertainty in the implications reported. Most of the scenario assessment was conducted in 2010 with assumptions concerning technology cost and performance and fossil energy prices generally based on data available in 2009 and early 2010. Significant changes in electricity and related markets have already occurred since the analysis was conducted, and the implications of these changes may not have been fully reflected in the study assumptions and results. For example, both the rapid development of domestic unconventional natural gas resources that has contributed to historically low natural gas prices, and the significant price declines for some renewable technologies (e.g., photovoltaics) since 2010, were not reflected in the study assumptions.

Nonetheless, as the most comprehensive analysis of U.S. high-penetration renewable electricity conducted to date, this study can inform broader discussion of the evolution of the electric system and electricity markets toward clean systems.

The RE Futures team was made up of experts in the fields of renewable technologies, grid integration, and end-use demand. The team included leadership from a core team with members from the National Renewable Energy Laboratory (NREL) and the Massachusetts Institute of Technology (MIT), and subject matter experts from U.S. Department of Energy (DOE) national laboratories, including NREL, Idaho National Laboratory (INL), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), and Sandia National Laboratories (SNL), as well as Black & Veatch and other utility, industry, university, public sector, and non-profit participants. Over the course of the project, an executive steering committee provided input from multiple perspectives to support study balance and objectivity.

RE Futures is documented in four volumes of a single report: Volume 1 describes the analysis approach and models, along with the key results and insights; This volume—Volume 2—describes the renewable generation and storage technologies included in the study; Volume 3 presents end-use demand and energy efficiency assumptions; and Volume 4 discusses operational and institutional challenges of integrating high levels of renewable energy into the electric grid.

List of Acronyms and Abbreviations

AC	alternating current
AEG	Aspen Environmental Group
AEP	American Electric Power
AFUDC	allowance for funds used during construction
ANL	Argonne National Laboratory
APS	American Physical Society
ASCE	American Society of Civil Engineers
a-Si	amorphous silicon
AWEA	American Wind Energy Association
AWST	AWS TruePower
BFB	bubbling fluidized bed
BOP	balance of plant
Btu	British thermal unit
CAES	compressed air energy storage
CBO	Congressional Budget Office
CdTe	cadmium telluride
CEC	California Energy Commission
CFB	circulating fluidized bed
CHP	combined heat and power
CIGS	copper indium gallium diselenide
CO	carbon monoxide
CO_2	carbon dioxide
CRA	Charles River Associates
CSP	concentrating solar power
dB	decibel
DC	direct current
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
Dscm	dry standard cubic meter

DSIRE	Database of State Incentives for Renewables and Efficiency
EAC	Electricity Advisory Committee
EERE	U.S. Department of Energy Office of Energy Efficiency and Renewable Energy
EGS	Enhanced Geothermal System
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EJ	exajoule
EMEC	European Marine Energy Center
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EREC	European Renewable Energy Council
ESA	Electricity Storage Association
EWEA	European Wind Energy Association
FAU	Florida Atlantic University
FERC	Federal Energy Regulatory Commission
FW	flywheel
GaAs	gallium arsenide
GAO	General Accounting Office
GEC	Global Energy Concepts
GJ	gigajoule
GPI	Greenpeace International
GTP	Geothermal Technologies Program
GW	gigawatt
GWEC	Global Wind Energy Council
HINMREC	Hawaii National Marine Renewable Energy Center
HRF	Hydropower Research Foundation
ICSG	International Copper Study Group
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IGCC	integrated gasification combined cycle

INL	Idaho National Laboratory
lb	pound
kW	kilowatt
kWh	kilowatt-hour
L/A	lead-acid
LBNL	Lawrence Berkeley National Laboratory
Li-Ion	lithium-ion
MCCS	Manomet Center for Conservation Sciences
MCF	million cubic feet
MIS	American Solar Energy Society/Management Information Services
MIT	Massachusetts Institute of Technology
MMBtu	million British thermal units
MMS	Minerals Management Service
MPa	megapascal
MSW	municipal solid waste
MW	megawatt
MW_e	megawatt electric
MW_{th}	megawatt thermal
MWh	megawatt-hour
NaS	sodium-sulfur
NAS	National Academy of Sciences
NCSU	North Carolina State University
NETL	National Energy Technology Laboratory
ng	nanogram
NHA	National Hydropower Association
Ni-Cd	nickel-cadmium
Ni-MH	nickel-metal hydride
NO_x	nitrogen oxide
NRC	National Research Council
NREL	National Renewable Energy Laboratory
NWCC	National Wind Coordinating Collaborative

NWPCC	Northwest Power and Conservation Council
NYSEG	New York State Electric and Gas
O&M	operation and maintenance
OPT	Ocean Power Technology
ORNL	Oak Ridge National Laboratory
OTEC	ocean thermal energy conversion
PG&E	Pacific Gas and Electric
PM	particulate matter
PNNL	Pacific Northwest National Laboratory
Ppm	parts per million
PSH	pumped-storage hydropower
PV	photovoltaic
RD&D	research, development, and deployment
ReEDS	Regional Energy Deployment System
RE-ETI	Renewable Electricity—Evolutionary Technology Improvement
RE-ITI	Renewable Electricity—Incremental Technology Improvement
RE-NTI	Renewable Electricity—No Technology Improvement
RFA	Renewable Fuels Agency
SDCWA	San Diego County Water Authority
SiC	silicon carbide
SNL	Sandia National Laboratories
SolarDS	Solar Deployment System
SO_x	sulfur oxide
STG	steam turbine generator
SWG	switchgrass
TES	thermal energy storage
TMI	Technology Management Inc.
TOC	total organic carbon
TSF	The Solar Foundation

TVA	Tennessee Valley Authority
TWh	terawatt-hour
USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
VOC	volatile organic compounds
VR	vanadium redox
WGA	Western Governors' Association
WPA	Wind Powering America
Zn-Br	zinc-bromine

Table of Contents

List of Figures

List of Tables

List of Text Boxes

Introduction

The United States has diverse and abundant renewable resources, including biomass, geothermal, hydropower, ocean, solar, and wind resources. These renewable resources are geographically constrained but widespread—most are distributed across all or most of the contiguous states. Within these broad resource types, a variety of commercially-available renewable electricity generation technologies have been deployed in the United States and other countries, including stand-alone biopower, co-fired biopower (in coal plants), hydrothermal geothermal, hydropower, distributed PV, utility-scale PV, CSP, onshore wind, and fixed-bottom offshore wind. Today, these resources contribute about 10% of total U.S. electricity supply. Renewable generation sources have varying degrees of variability and uncertainty, and the output characteristics of the associated technologies vary substantially. These characteristics must be considered in grid planning and operations to ensure a real-time balance of electricity supply and demand over various timescales as renewable technologies provide greater levels of electricity to the grid.

The Renewable Electricity Futures Study (RE Futures) is an initial investigation of the extent to which renewable energy supply can meet the electricity demands of the contiguous United States over the next several decades. This study includes geographic and electric system operation resolution that is unprecedented for long-term studies of the U.S. electric sector. The analysis examines the implications and challenges of renewable electricity generation levels—from 30% up to 90%, with a focus on 80%, of all U.S. electricity generation from renewable technologies—in 2050. The study focuses on some key technical implications of this environment, exploring whether the U.S. power system can supply electricity to meet customer demand with high levels of renewable electricity, including variable wind and solar generation. The study also begins to address the potential economic, environmental, and social implications of deploying and integrating high levels of renewable electricity in the United States.

The RE Futures study is documented in four volumes: Volume 1 describes the analysis approach and models along with the key results and insights from the analysis; Volume 2—this volume—documents in detail the renewable generation and storage technologies included in the study; Volume 3 describes the end-use electricity demand and efficiency assumptions; Volume 4 documents the operational and institutional challenges of integrating high levels of renewable energy into the electric grid.

This volume includes chapters discussing biopower, geothermal, hydropower, ocean, solar, wind, and storage technologies. Each chapter includes a resource availability estimate, technology cost and performance characterization, discussions of output characteristics and grid service possibilities, large-scale production and deployment issues, and barriers to high penetration along with possible responses to them. Only technologies that are currently commercially available—biomass, geothermal, hydropower, solar PV, CSP, and wind-powered systems—are included in the modeling analysis. Some of these renewable technologies—such as run-of-river hydropower, onshore wind, hydrothermal geothermal, dedicated and co-fired-with-coal biomass—are relatively mature and well-characterized. Other renewable technologies—such as fixed-bottom offshore wind, solar PV, and solar CSP—are at earlier stages of deployment with greater potential for future technology advancements over the next 40 years. Technologies such as enhanced geothermal systems, ocean energy technologies, floating platform offshore wind technology, and others that are currently under development and pilot testing were not included in the modeling analysis but are discussed in this volume.

Chapter 6. Biopower Technologies

6.1 Introduction

The major growth of the biopower industry occurred in the 1980s after passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA), which guaranteed small generators (less than 80-MW capacity) that regulated utilities would purchase electricity at a price equal to the utilities' avoided cost of electricity. In anticipation of increasing fuel prices and resulting high avoided costs, many utilities offered PURPA contracts, such as the Standard Offer 4 contracts in California, which made biopower projects economically attractive. With the deregulation of the electric industry in the early 1990s—in combination with increased natural gas supplies and reduced fuel costs—avoided costs decreased, making biopower projects less attractive. Over the past 15 years, some variation in capacity and generation has occurred as older PURPA contracts expired, resulting in idling of plants, while a few new plants came into service.

In 2010, biopower was estimated to be the third largest form of renewable electricity generation after hydropower and wind energy (EIA 2012). In 2010, 56.2 terawatt-hours (TWh) of biopower generation came from 10.7 GW of capacity (EIA 2012). Of this capacity, 7.0 GW was based on forest product industry and agricultural industry residues, and 3.7 GW was based on municipal solid waste (MSW),[1] including landfill gas. The 5.8 GW of biopower capacity in the electric power sector in 2010 represents approximately 0.56% of the total electric sector generating capacity; the 5.1 GW of end-use generation capacity represents approximately 17.0% of total end-use sector capacity. Historical growth of the biopower industry (both electric power sector and end-use sector) is shown in Figure 6-1. Details of the biopower sector from 2003–2010 are given in Table 6-1.

[1] Waste material that is not regulated as hazardous from households and businesses in a community.

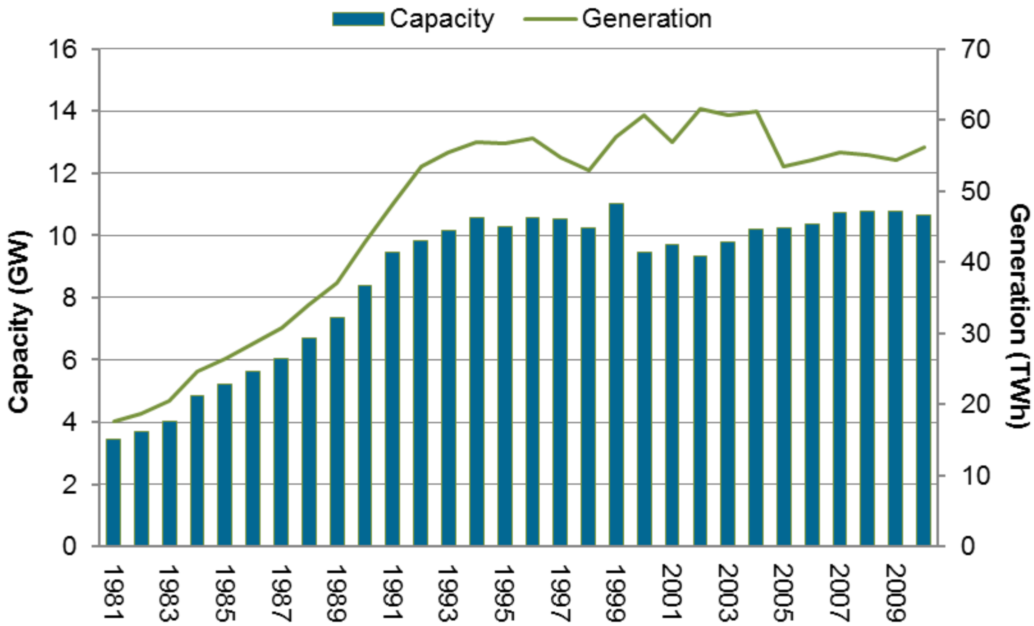

Figure 6-1. Capacity and generation of biopower in the United States, 1980–2010

The size of the U.S. biopower industry is comparable to that in the European Union (EurObserv'ER 2010). In 2009, biopower generation in the European Union was approximately 62.2 TWh, with 23.3 TWh from electricity-only plants and 38.9 TWh from combined heat and power (CHP) plants. The top four countries were Germany (11.4 TWh), Sweden (10.1 TWh), Finland (8.4 TWh), and Poland (4.9 TWh).

Table 6-1. Biopower Capacity and Generation, 2003–2010[a]

	2003	2004	2005	2006	2007	2008	2009	2010
Net Summer Capacity, GW								
Electric Power Sector [b]								
Municipal Waste	3.19	3.19	3.21	3.39	3.42	3.43	3.20	3.30
Wood and Other Biomass	2.00	2.04	1.96	2.01	2.09	2.17	2.43	2.45
Total	**5.19**	**5.23**	**5.17**	**5.40**	**5.51**	**5.60**	**5.63**	**5.75**
End-Use Generators [c]								
Municipal Waste	0.27	0.33	0.34	0.33	0.33	0.33	0.36	0.35
Biomass	4.32	4.66	4.72	4.64	4.88	4.86	4.56	4.56
Total	**4.59**	**4.99**	**5.06**	**4.97**	**5.21**	**5.19**	**4.92**	**4.91**
Total, All Sectors								
Municipal Wastes	3.46	3.52	3.55	3.72	3.75	3.76	3.56	3.65
Biomass	6.32	6.70	6.68	6.65	6.97	7.03	6.99	7.01
Total	**9.78**	**10.22**	**10.23**	**10.37**	**10.72**	**10.79**	**10.55**	**10.66**
Generation, TWh								
Electric Power Sector								
Biogenic Municipal Wastes	20.84	19.86	12.70	13.71	13.88	14.49	16.10	16.56
Wood and Other Biomass								
Dedicated Plants	9.53	8.54	8.60	8.42	8.65	9.00	9.68	10.15
Co-Firing	0.00	1.19	1.97	1.91	1.94	1.90	1.06	1.36
Total	**30.37**	**29.59**	**23.27**	**24.04**	**24.47**	**25.39**	**26.84**	**28.07**
End-Use Generators								
Municipal Wastes	2.22	2.64	1.95	1.98	2.01	2.02	2.07	2.02
Biomass	28.00	28.90	28.33	28.32	28.43	27.89	25.31	26.10
Total	**30.22**	**31.54**	**30.28**	**30.30**	**30.44**	**29.91**	**27.38**	**28.12**
Total, All Sectors								
Municipal Wastes	23.06	22.50	14.65	15.69	15.89	16.51	18.17	18.58
Biomass	37.53	38.63	38.90	38.65	39.02	38.79	36.05	37.61
Total	**60.59**	**61.13**	**53.55**	**54.34**	**54.91**	**55.30**	**54.22**	**56.19**
EIA Form 923 Actual Generation					**55.40**	**55.06**	**54.34**	

[a] In 2003, co-firing plants classified as coal, 2003 data (EIA 2006), 2004 data (EIA 2007), 2005 data (EIA 2008a), 2006 data (EIA 2009), 2007–2009 data (EIA 2010a), 2010 data (EIA 2012)
[b] Include electricity-only and combined heat and power plants whose primary business is not to sell electricity, or electricity and heat, to the public
[c] Includes combined heat and power plant and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid

Electricity produced from biomass is used as base-load or dispatchable power in the existing electric power sector and in industrial cogeneration, and this is expected to continue. In 2007, the biopower industry had revenues of $17.4 billion (2007 U.S. dollars)[2] with 67,100 industry jobs and 154,500 total direct and indirect jobs (ASES and MIS 2008). Biopower is widely distributed, with plants located in the West, Southeast, Midwest, and Northeast as shown in Figure 6-2.

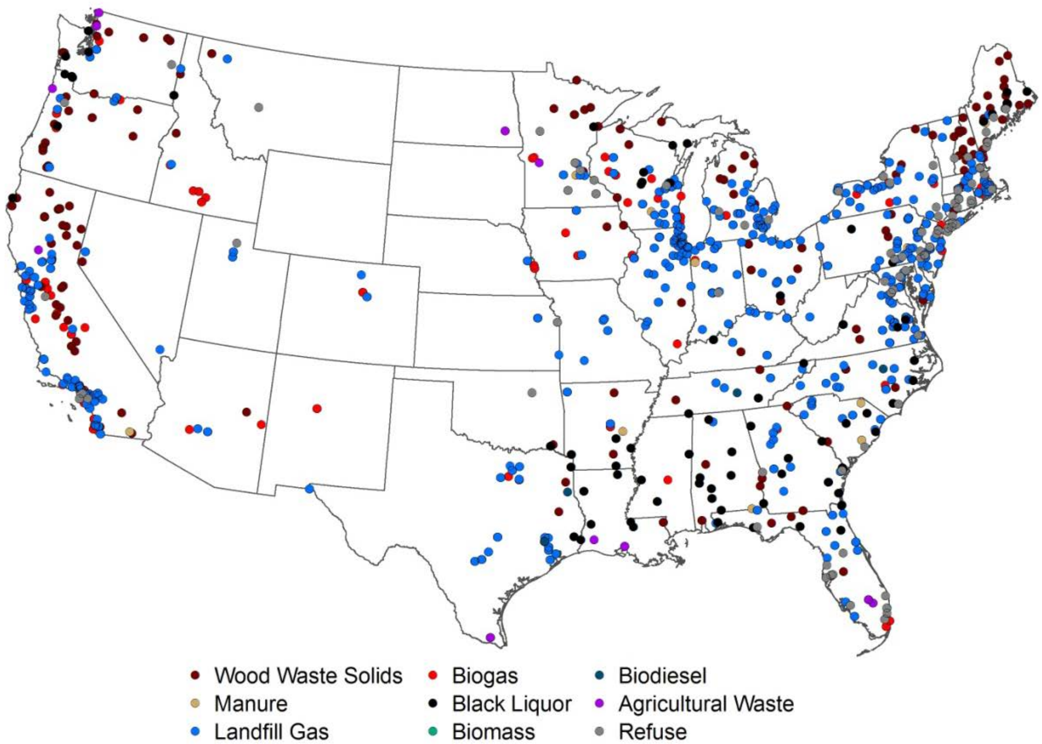

Figure 6-2. Biopower plant locations in the United States, 2010

Data source: Ventyx Energy Velocity Suite, 2012

This chapter presents an overview of biopower, including resources, technologies, costs, Regional Energy Deployment System (ReEDS) model results, environmental impacts, and possible R&D directions. To put the overview and modeling into context, limitations of the analysis include the following:

- The historical generation and capacity shown in Figure 6-1 represent both the electric sector and the end-use generator sector. In 2010, the electric power sector represented approximately 56% of biopower capacity and 50% of biopower generation. Biogenic MSW and landfill generation are included in the electric sector generation, and CHP is included in the end-use sector. The ReEDS modeled only the electric generating sector, excluding new MSW and landfill gas capacity. Although MSW generation could be based on estimates of geographic population distribution and existing per capita MSW generation, uncertainties about future composition (biogenic versus non-biogenic) and

[2] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

disposition (recycling, combusting, or landfilling) precluded detailed modeling of MSW and landfill gas. Distributed end-use anaerobic digester generation and end-use CHP generation were not modeled or included in estimates.

- The technologies chosen for inclusion in the modeling were biomass co-firing and direct generation (a mix of biomass direct combustion and biomass gasification, starting with only direct combustion, followed by a gradual introduction of gasification). Developing technologies on the horizon, such as pyrolysis oil-based generation, and synthetic natural gas from biomass (biomethane)-based generation were not included in the models as they are not yet commercial and due to lack of detailed cost data and limitations.
- Traditional woody biomass resource estimates used in RE Futures were limited to residues and did not include unexploited wood inventory not used by the pulp, paper, and forest products industries. In general, the resource estimates referenced and used as source data in RE Futures have taken a "fiber first" principle to ensure availability of resources for production of conventional forest products such as wood and paper.
- The ReEDS model requires geographical resource supply (in $/tonne) estimates in enough detail to estimate resource availability and costs for the 134 balancing areas (BAs) used in the model. Although a number of resource potential study results are shown in this chapter, only the existing inventory reports have the geographical data needed. Therefore, the biomass future resource estimate represents existing state-level inventory plus an estimate of dedicated crop potential (Walsh et al. 2000) using the county-level distribution percentages of Milbrandt (2005) and is a conservative estimate of total future biomass availability.
- Although biomass can serve a dual role in helping to meet both U.S. electricity generation needs and transportation energy needs, resource estimates were not adjusted for potential use in biofuels production. Both biopower and biofuels will play important roles in the future. The RE Futures modeling effort addresses only the utility electric sector and does not address multiple sectors of the economy.[3]
- The technical description of technologies is intentionally abbreviated due to the wide variety of commercially available technologies.[4]

[3] However, RE Futures did analyze a model scenario (Constrained Resources scenario) in which the available renewable supply for electricity generation is halved. As described in Volume 1, Chapter 1, this scenario indirectly addresses the impacts of achieving high levels of renewable electricity when the renewable supply is diminished (e.g., if the available feedstock for electricity production is reduced due to use in other sectors).
[4] Additional information about biopower technologies is available from the U.S. DOE Biomass Program (http://www1.eere.energy.gov/biomass/).

6.2 Resource Availability Estimates

Biomass is plant-derived material that stores light energy through photosynthesis (Wright et al. 2006). Depending on the type of plant matter, this energy can be stored as simple sugars, as starch, or as the more complex structural compounds cellulose,[5] hemicellulose,[6] and lignin (collectively known as lignocellulose).[7] Sugars and starches are primarily used for food, while lignocellulosic materials are used primarily as construction materials and for energy. Biomass is unique among renewable energy resources in that it can be converted to carbon-based fuels and chemicals as well as electric power.

Potential biopower resources are generally classified into five major categories: urban wood wastes, mill residues, forest residues,[8] agricultural residues, and dedicated herbaceous and woody energy crops (Table 6-2). Existing resources are widely distributed throughout much of the United States, as shown in Figure 6-4 through Figure 6-7. The availability, characteristics, and acquisition costs of each of these resources are very different, as summarized in Table 6-2.

The land base of the United States, including Alaska and Hawaii, is approximately 9.16 million square kilometers (3.537 million square miles). This area is comprised of 33% forest land, 26% grassland, pasture, and range, 20% cropland, 8% special use, and 13% urban, swamps, and deserts (Vesterby and Krupa 2001; Alig et al. 2003). Excluding Alaska and Hawaii, approximately 60% of the land in the United States could be considered for some biomass production. Generally, urban wood wastes are the least expensive biomass resource, followed by mill residues, forest residues, agricultural residues, and energy crops. This largely reflects the costs of acquisition (offsetting landfill tipping fees), collection (or production and harvesting), and processing. Finally, the uncertainty surrounding these estimates is high. A number of studies have been performed to estimate biomass availability and costs, but site-specific analyses are required to determine project estimates of available quantities at given delivered feedstock prices.

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[5] Cellulose is the carbohydrate that is the principal constituent of wood and other biomass and forms the structural framework of the wood cells.

[6] Hemicellulose consists of short, highly branched chains of sugars. In contrast to cellulose, which is a polymer of only glucose, hemicellulose is a polymer of different sugars. Hemicellulose is more easily hydrated than cellulose.

[7] Lignin is the major non-carbohydrate, polyphenolic structural constituent of wood and other native plant material that encrusts the cell walls and cements the cells together. Lignocellulose refers to plant materials made up primarily of lignin, cellulose, and hemicellulose.

[8] Forest residues include tops, limbs, and other woody material not removed in forest harvesting operations in commercial hardwood and softwood stands, as well as woody material resulting from forest management operations such as pre-commercial thinnings and removal of dead and dying trees.

Figure 6-3 compares recent estimates from the following studies:

- Oak Ridge National Laboratory (Perlack et al. 2005)
- NREL (Milbrandt 2005)
- The National Academy of Sciences (NAS 2009)
- DOE EIA (Haq and Easterly 2006)
- M&E Biomass (Walsh 2008)
- DOE (DOE 2011)

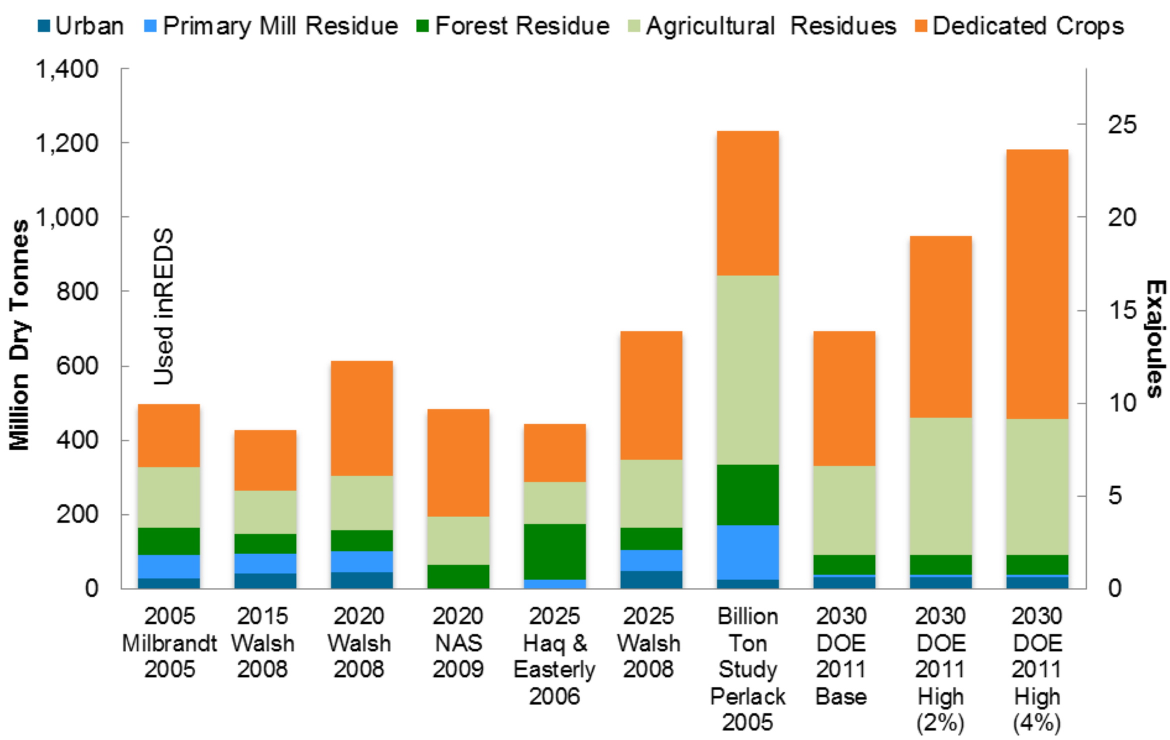


Figure 6-3. Potential biomass supply

Exajoule = 10^{18} Joule

Quadrillion Btu (quad) = 10^{15} Btu

Quad = 1.055 Exajoule

MWth = Megawatt thermal

1 MWth = 3.412 MMBtu/hr

1 MWth = 3.600 (gigajoule) GJ/hr
where 1 MM Btu = 10^6 Btu;
1 GJ = 10^9 Joule

Assumed dry biomass heating value (lower heating value basis)

Woody biomass = 18.6 GJ/tonne

Agricultural residues and biogenic MSW = 18.0 GJ/tonne where 1 tonne = 1.1023 short ton; 1 MMBtu = 1.055 GJ

The Perlack et al. (2005)[9] estimate of 1,237 million annual dry tonnes is a potential inventory of biomass in 2050. The remaining data are inventory estimates of economically available biomass believed to be available in the given years. Resources can also be estimated on an energy content basis. While the U.S. biopower community normally discusses biomass resources using tonnes, the international community uses primary energy content in exajoules. To compare resource potential to other primary energy resources in the United States (i.e., coal, petroleum, or natural gas), an energy content basis is also used. Figure 6-13 shows the available energy content (lower heating value basis) for each biomass resource as a secondary axis.

The short-term biomass supply potential range is 270–460 million dry tonnes. The long-term potential is more than 1,200 million dry tonnes. The long-term biomass primary energy potential (lower heating value) is about 22 EJ (20.8 quads).

[9] Perlack et al. (2005) has additional categories of feed. Other agriculture was combined with agricultural residues. Conservation reserve program crops were included with dedicated crops.

Table 6-2. Characteristics and Regional Distribution of Biomass Resources in United States

Biomass Resource	Characteristics	Regional Distribution	Comments
Urban waste	Woody materials, such as yard and tree trimmings, site-clearing wastes, pallets, packaging materials, clean construction, and demolition debris	See Figure 6-4	Concentrated at single source; diverted from landfills; and, possibly, composting facilities
Primary mill residues	Bark stripped from logs, coarse residues (chunks and slabs) and fine residues (shavings and sawdust) from processing of lumber, pulp, veneers, and composite wood fiber materials	See Figure 6-5	Concentrated at single source; clean; ~20% moisture; most material used as fuel or inputs in manufacture of products
Forest wood residues	Logging residues (small branches, limbs, tops, and leaves); rough, rotten, and salvable dead wood	See Figure 6-6	Much of the rough, rotten, and salvable dead material is inaccessible due to the absence of roads or access, is not economically retrievable with current technology, or is located in environmentally sensitive areas
Agricultural residues	Primarily corn stover[a] and wheat straw; other grain crops are limited in acreage or the amount of residue is small	See Figure 6-7	Approximately 30%–40% (actual amount is site-specific and the subject of studies) of corn stover and wheat straw residues may be removed to maintain soil quality (i.e., nutrients and organic matter) and limit erosion; limited collection season—usually a couple of months following grain harvest; year-round use may require storage of up to 10 months
Dedicated energy crops	Short rotation woody crops such as hybrid poplar and hybrid willow, and herbaceous crops[b] such as switchgrass	Geographically, the land that could be used for dedicated crops overlaps forest and croplands	Management practices for each crop are regionally dependent; ability to use existing on-farm equipment is a potential advantage of switchgrass[c] over tree crops

[a] Stover is the dried stalks and leaves of a crop remaining after the grain have been harvested. Corn stover is the refuse of a corn crop after the grain is harvested.
[b] Herbaceous energy crops are perennial non-woody crops that are harvested annually, though they may take 2–3 years to reach full productivity.
[c] Switchgrass is a tall North American panic grass (*Panicum virgatum*) that is used for hay and forage.

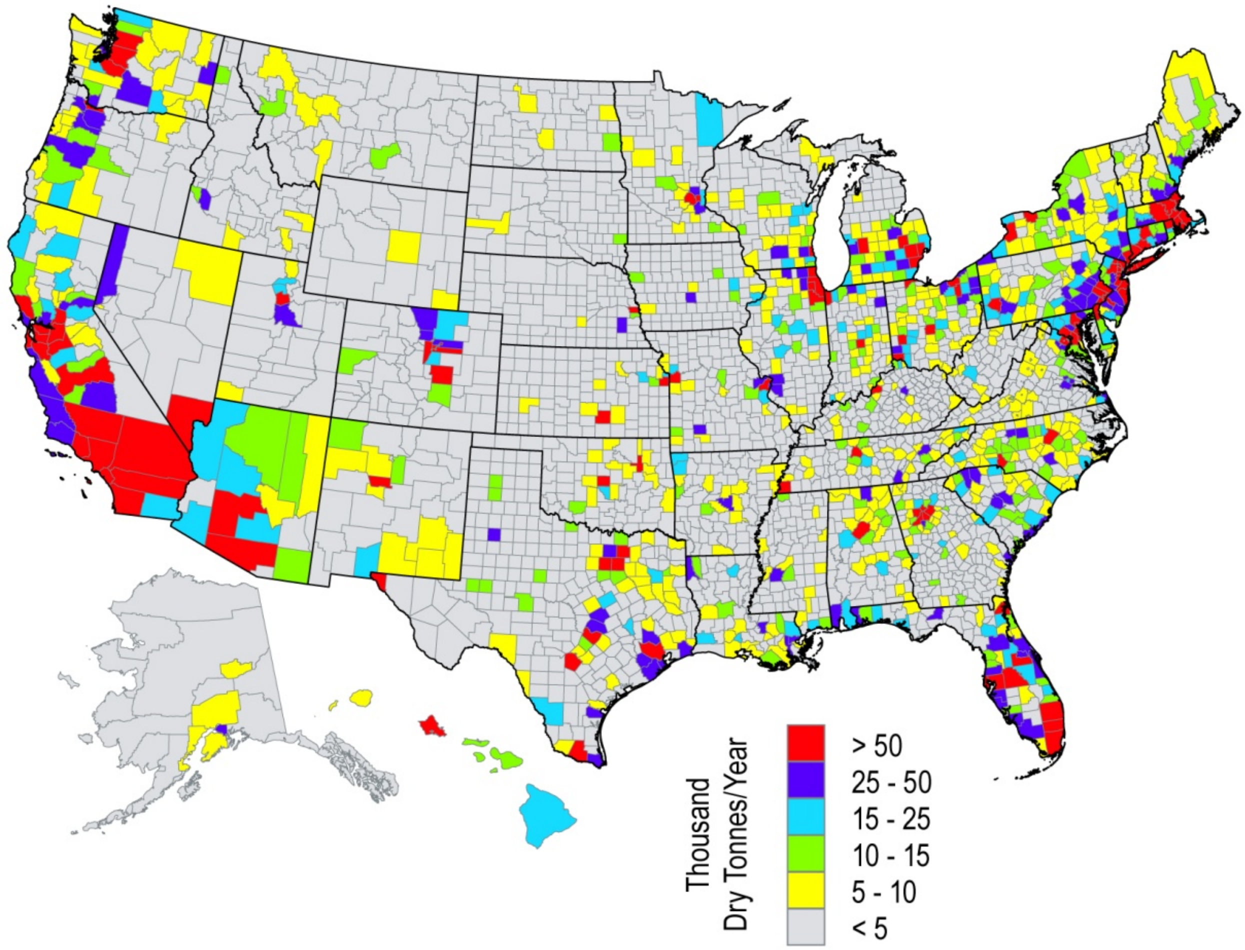


Figure 6-4. Distribution of urban wood residues in the United States

Urban wood waste includes wood residues from MSW (wood chips and pallets), utility tree trimming and private tree companies, and construction and demolition sites. Urban wood residue distribution is proportional to population. Data are from U.S. Census Bureau, 2000 population data; Kaufman et al. 2004; County Business Patterns 2002 (U.S. Census Bureau n.d.). For more information about the development of these data, see Milbrandt (2005).[10]

[10] See also and http://www.nrel.gov/gis/biomass.html.

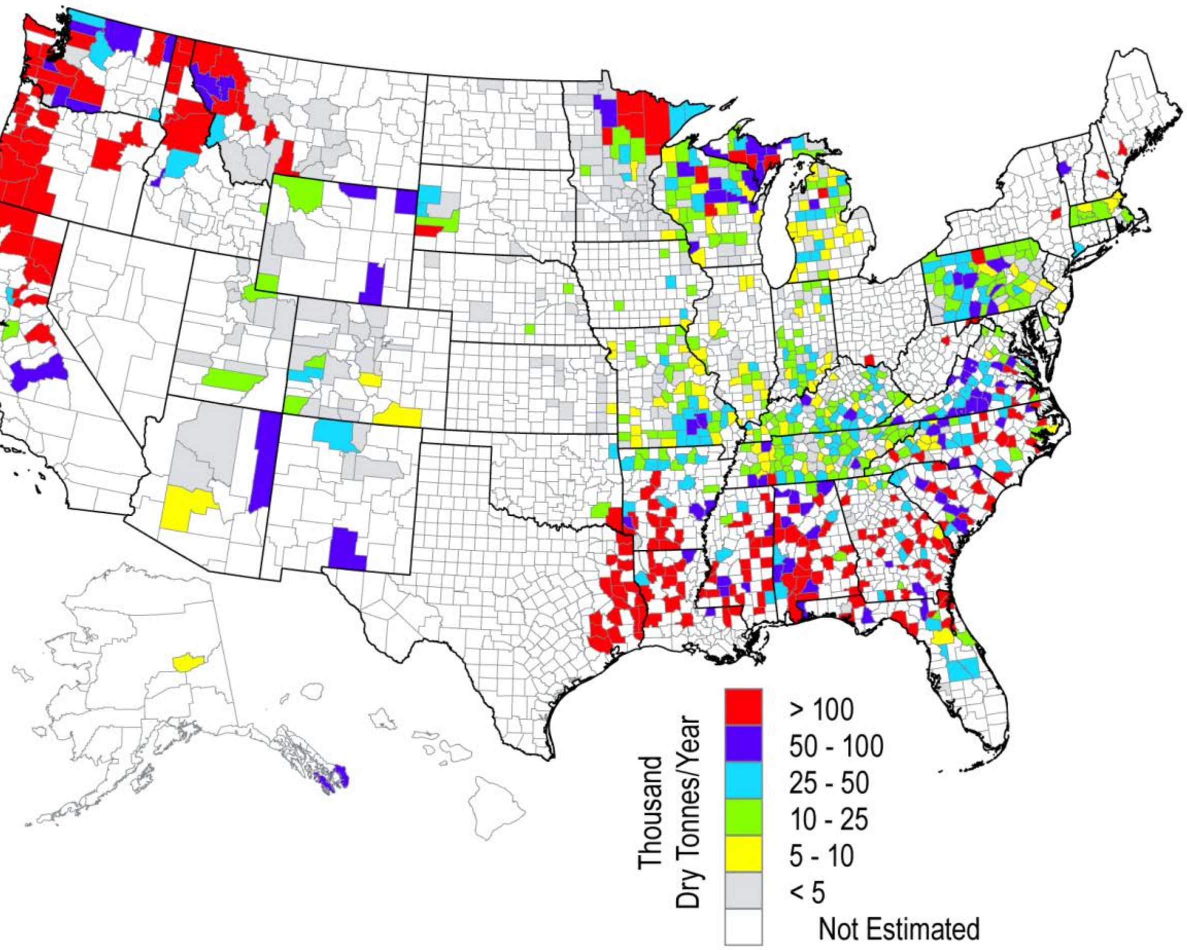


Figure 6-5. Distribution of primary wood mill residues in the United States

Primary mill residues include wood materials (coarse and fine) and bark generated at manufacturing plants (primary wood-using mills) when round wood products are processed into primary wood products like slabs, edgings, trimmings, sawdust, veneer clippings and cores, and pulp screenings. Primary mill residues are located in regions with existing commercial wood product industries. Data are from USDA (USDA n.d.). For more information about the development of these data, see Milbrandt (2005), which describes the methodology used to develop an older assessment. The information in Milbrandt (2005) applies to RE Futures; the only difference between the two analyses lies in the date ranges of the data.

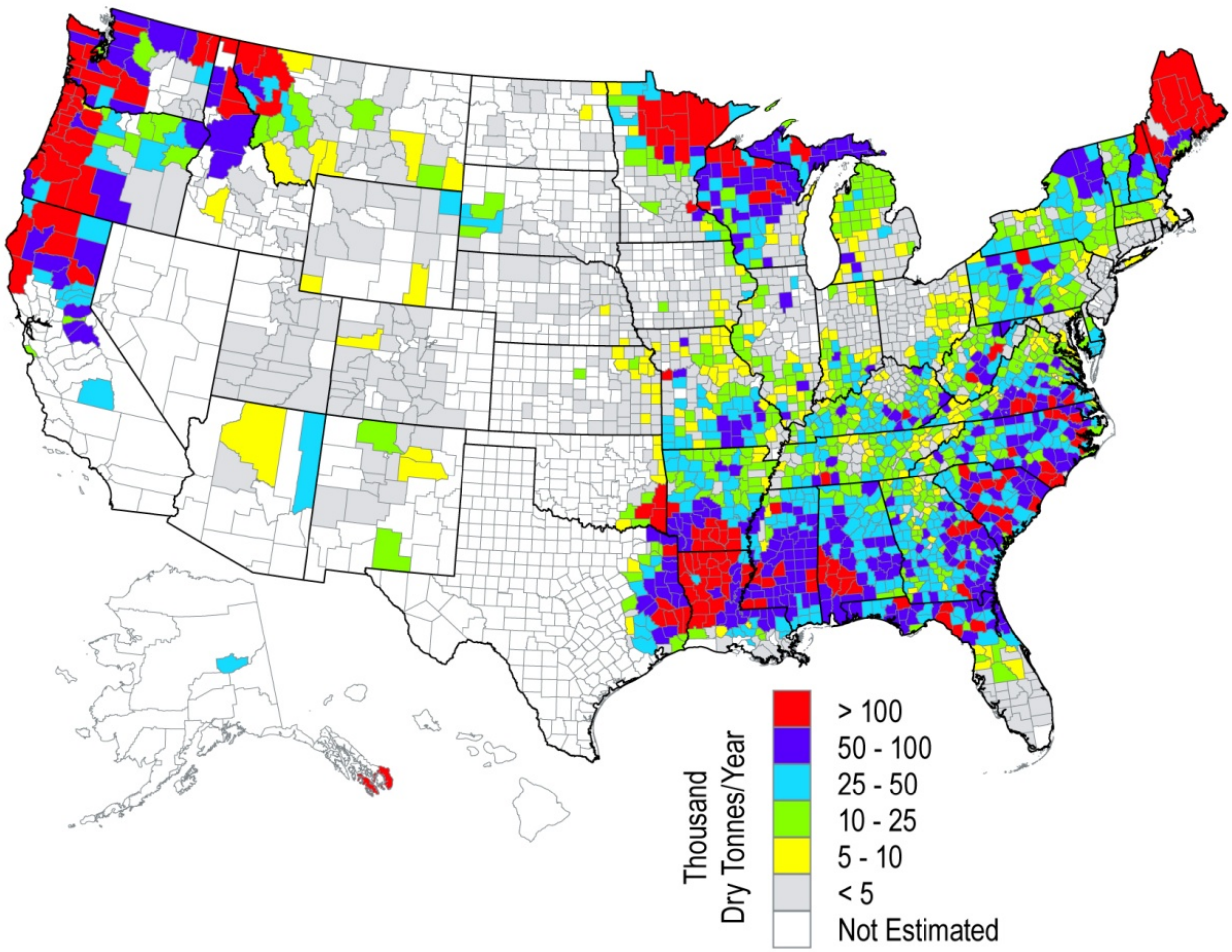


Figure 6-6. Distribution of forest residues in the United States

Forest residues include logging residues and other removable material left after carrying out silviculture operations and site conversions. Logging residue comprises unused portions of trees cut or killed by logging and left behind. Data are from USDA (USDA n.d.). Forest residues are located in regions with commercial forestry industries. For more information about the development of these data, see Milbrandt (2005), which describes the methodology used to develop an older assessment. The information in Milbrandt (2005) applies to RE Futures; the only difference between the two analyses lies in the date ranges of the data.

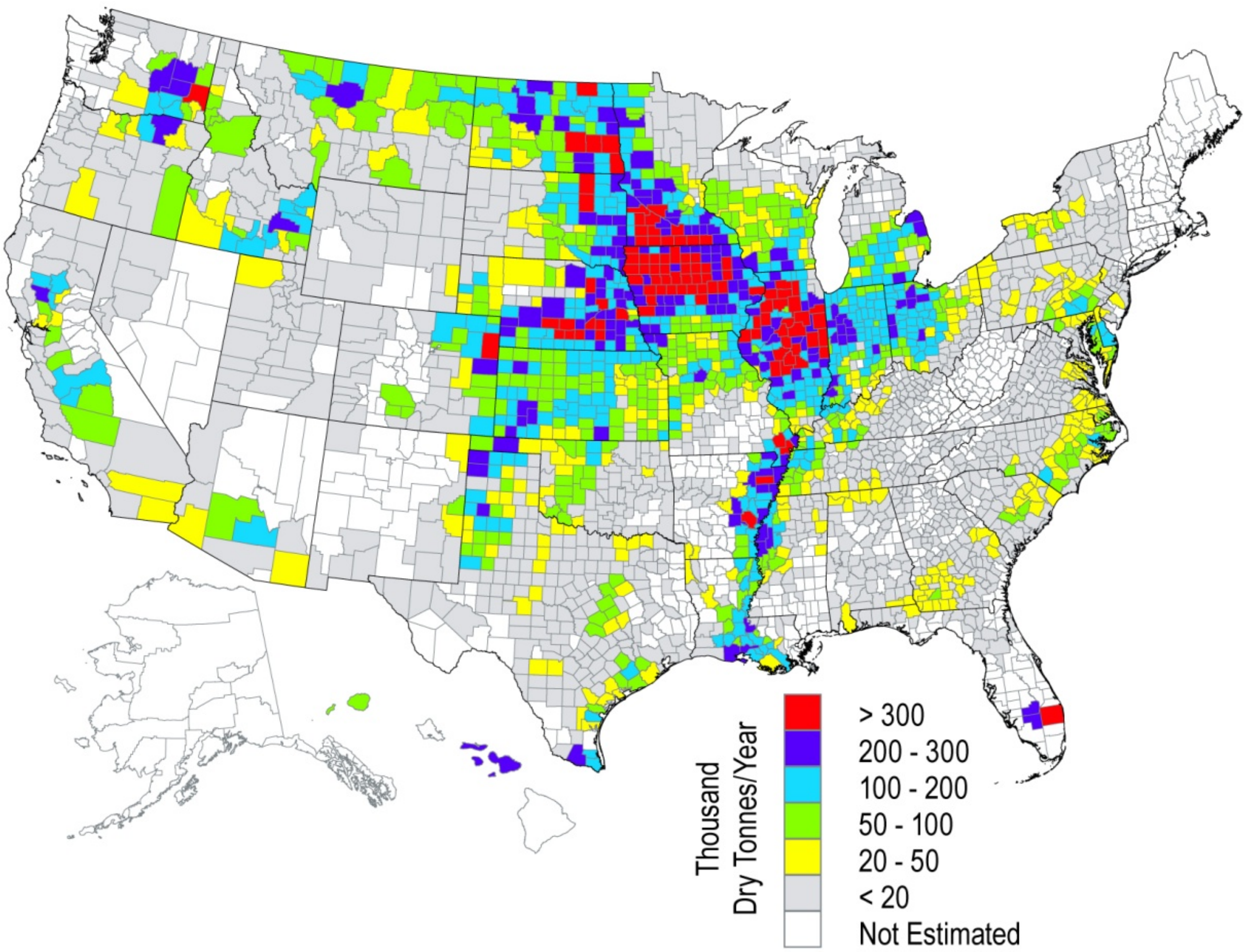


Figure 6-7. Distribution of crop residues in the United States

The following crops were included: corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, dry edible beans, dry edible peas, peanuts, potatoes, safflower, sunflower, sugarcane, and flaxseed. The quantities of crop residues that can be available in each county are estimated using total grain production, crop-to-residue ratio, and moisture content, and by considering the amount of residue left on the field for soil protection, grazing, and other agricultural activities. Data are from USDA NASS (n.d.). Crop residues are located in existing agricultural regions, with the primary concentration in the Midwest. For more information about the development of these data, see Milbrandt (2005), which describes the methodology used to develop an older assessment. The information in Milbrandt (2005) applies to RE Futures; the only difference between the two analyses lies in the date ranges of the data.

The biogenic fraction of MSW is another biomass resource that can be used for electric power production. There are approximately 3.7 GW (3.4 GW from the electric power sector and 0.3 GW from the end-use sector) of existing generating capacity using biogenic MSW (see Table 6-1) (EIA 2010a). Historical total (biogenic and non-biogenic) MSW tonnages are given in Figure 6-8 (EPA 2008). In 2007, approximately 230 million dry tonnes of MSW were generated in the United States. Of that, approximately 33.5% was recycled and composted; 12.5% was used for energy generation; and 54% went to landfills or other disposal. Per capita, MSW generation has remained constant since 1990 at approximately 0.76 tonnes/person/yr. Since 1990, the percentage of materials recovery has increased from 16.2% to 33.5%; generation use has decreased from 14.5% to 12.6%; and landfilling has decreased from 69.3% to 54.0%. Uncertainties about future MSW composition (biogenic versus non-biogenic) and disposition (e.g., recycling or combustion or landfilling) preclude detailed modeling of MSW and landfill gas. It is still useful to estimate the maximum potential generation from MSW. Based on disposition of MSW in 2007 (EPA 2008), DOE projected population growth rate (EIA 2010a), and assuming no change in disposition percentages, the maximum capacity of MSW generation from the unused biogenic portion of MSW is approximately 12 GW, as shown in Table 6-3. The actual capacity will probably be less due to further increases in recycle percentages.

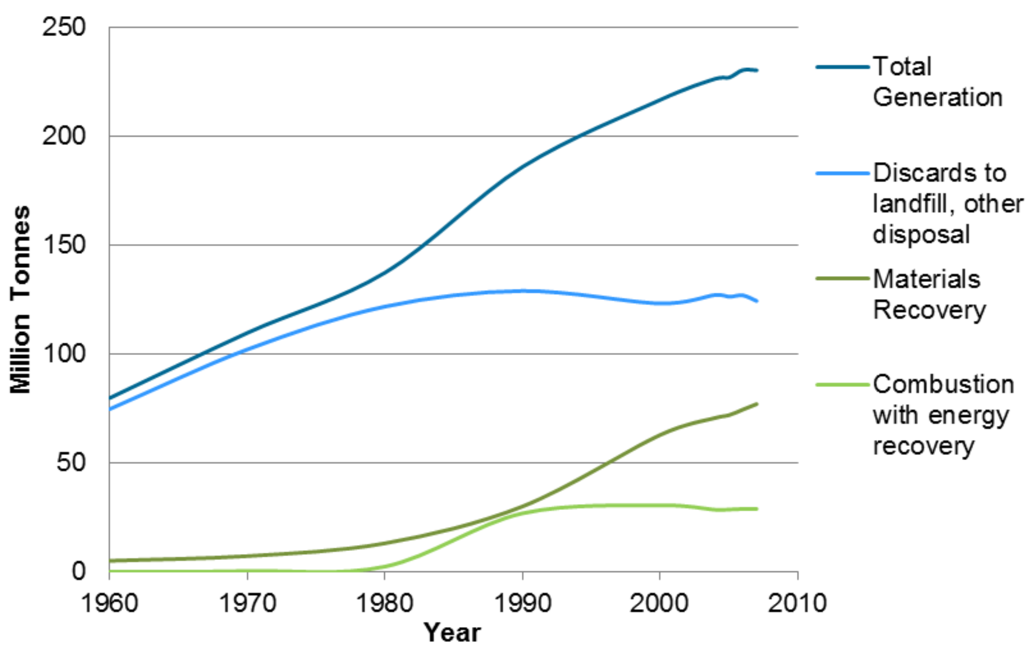


Figure 6-8. Municipal solid waste generation and use in the United States

Source: EPA 2008

Table 6-3. Potential Biogenic Municipal Solid Waste Generation Capacity through 2050[a]

Products	Million Tonnes Generated in 2007	Million Tonnes Recovered in 2007	Percent Recovery	Million Tonnes Available in 2007	Potential Generation in 2007 (TWh)[b]	Potential Capacity GW[c]		
						2007	2030[c]	2050[c]
Durable goods [d]								
Wood	5.11	0.00	0.00	5.11	3.08	0.44	0.54	0.65
Textiles	3.02	0.42	0.14	2.60	1.57	0.22	0.28	0.33
Nondurable goods [d]								
Paper and paperboard	39.10	18.42	0.47	20.68	12.47	1.78	2.19	2.61
Textiles	7.57	1.31	0.17	6.26	3.77	0.54	0.66	0.79
Containers and packaging								
Paper and paperboard	36.20	22.59	0.62	13.61	8.20	1.17	1.44	1.72
Wood	7.75	1.20	0.15	6.55	3.95	0.56	0.69	0.83
Other wastes								
Food, other	28.76	0.73	0.03	28.02	16.89	2.41	2.96	3.54
Yard trimmings	29.57	18.96	0.64	10.61	6.40	0.91	1.12	1.34
Total	157.07	63.62	0.41	93.45	56.32	8.04	9.88	11.81

[a] EPA 2008 (Table ES5).
[b] Assume: Population increase = 0.9% per year (EIA 2010a), constant per capita generation = 0.76 tonnes/person/yr, heating value = 9.92 million Btu/tonne, heat rate = 16,460 Btu/kWh
[c] Assume: 80% capacity factor
[d] Durable goods are goods that last longer than three years; nondurable goods are goods that last fewer than three years. Containers and packaging are assumed to be discarded in the same year as the products they contain are purchased.

To develop electricity supply curves (economic potential) for biopower ($/kWh versus kWh/yr), biomass supply curves are necessary. (Prices are plant gate prices and do not include any processing of wastes at conversion facilities.) Biomass supply curves have been estimated by Milbrandt (2005) for 2007; the Environmental Protection Agency (EPA) Integrated Planning Model (EPA 2006a) for 2010; Walsh (2008) through 2025; Khanna et al. (2011) for 2030; and DOE (2011) for 2030, as shown in Figure 6-9, and are presented in terms of primary energy content using 18.6 GJ/dry tonne for woody feeds and 18 GJ/dry tonne for agricultural residues and dedicated crops. The DOE 2011 supply curves give a range of quantities based on assumed annual increases in productivity of food crops (agricultural residues) and dedicated crops.

For RE Futures, biomass supply costs and annual amounts available are based on county-level distribution percentages estimated by Milbrandt (2005) and are used to provide the geographical detail for estimates at the regional level needed for ReEDS modeling (see Short et al. 2011). The use of this estimate imposes constraints on resource availability compared to supply curve projections in out-years that are not geographically detailed enough to use in ReEDS modeling. Because ReEDS is an electric sector model, the impact of biofuels on biomass resource availability was not estimated. Although the recent estimate by DOE (2011) includes estimates on a county-level basis, the database has not been converted to a geographic information systems model that can be used in ReEDS.

To better estimate both biopower and biofuels potential in future studies, spatially detailed biomass resource supply curves (costs versus potential tonnes) at a county level through 2050 and the use of a multi-sector (at least electricity, transportation, and agriculture) model are needed.

In general, the existing resource curves are based on data from EPA for urban woody wastes, the U.S. Forest Service for wood residues, and USDA for agricultural residues.

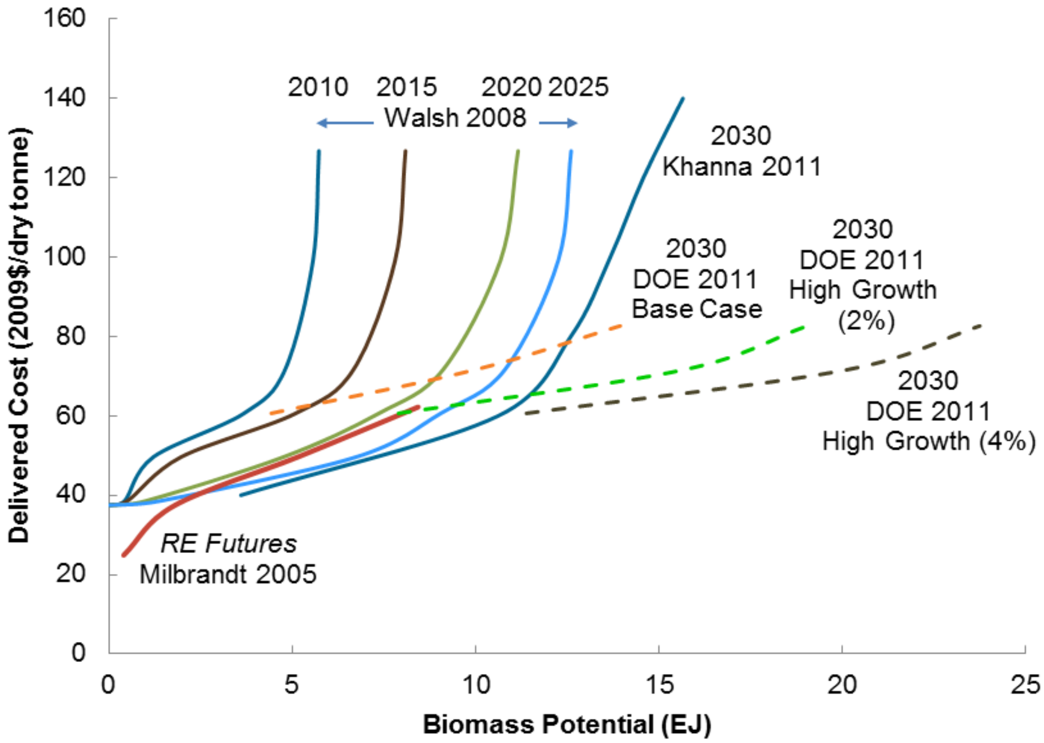


Figure 6-9. Cost curves for potential delivered biomass, 2005–2030

Based on: Walsh (2008), Milbrandt (2005), Khanna et al. (2011), DOE (2011)

6.3 Technology Characterization

Biopower technologies include those that directly combust biomass (direct-fired biomass and co-firing) in a furnace to produce steam that is used in a steam turbine generator (STG) and those that convert solid biomass to an intermediate gas or liquid that is then used in a prime mover to produce electricity. These conversion processes include thermal gasification (gaseous product), thermal pyrolysis (liquid product), and anaerobic digestion (dedicated system or landfill process to produce a methane-rich gas). Prime movers include STG (using an intermediate furnace/boiler), gas turbine generators (GTG), or internal combustion engines (ICE) generators. Generation using pyrolysis, landfill gas, and anaerobic digestion direct intermediates is not included in RE Futures. The number of facilities, based on feed type, prime mover and capacities are given in Table 6-4. For utility-scale power generation from biomass fuels, combustion (Section 6.3.1.2) has long been the technology used in the United States. Almost all biomass- and waste-fired power plants in the United States rely on direct combustion technology. Because biomass has lower sulfur content than coal, coal-fired power plants that co-fire biomass can significantly reduce sulfur dioxide emissions. Biomass gasification is a technology that can be used in advanced power cycles, such as integrated gasification combined cycle (IGCC). Although advanced biomass gasification technology has yet to be deployed in the United States, commercial scale biomass gasification facilities are operational in Europe.

Table 6-4. Biopower Generators and Capacity, 2008[a]

Biomass Category	Prime Mover	Number of Generating Units[b]	Summer Capacity (MW)
Biomass	STG	179	3,006
Landfill gas	ICE	1,157	1,362
Municipal solid waste	STG	94	2,213
Other biomass gas	ICE	77	155
Black liquor[c]	STG	145	3,663
Total		1,652	10,398
Fossil fuel co-firing (unit capacity)	STG	78	2,323
Biopower estimate @ 5% level			116

[a] Many biopower units can co-fire fossil fuel, not separated in this table.
[b] This column represents generators, not facilities.
[c] Black liquor is the spent cooking liquor from the kraft chemical pulping process used to produce paper pulp by removing lignin, hemicellulose, and extractives from cellulose fibers.
EIA (2010b)

6.3.1 Technology Overview

6.3.1.1 Co-Firing with Coal

Co-firing is the practice of introducing biomass as a supplementary energy source in coal boilers. Co-firing with coal in existing boilers is the lowest-cost biopower option because existing boilers and generating equipment are used, and the major investment is in feed systems. Investments are facility-specific and minor modifications of boilers may be required. The typical co-firing system represented in Figure 6-10 encompasses the feed handling and preparation necessary for separate injection of biomass into a coal boiler. The preparation system includes:

1. Truck unloading station (could also be a rail unloading system)
2. Conveyer for transfer to a stacker system
3. Stacker system to distribute biomass in the primary storage pile
4. Reclaim system to recover biomass from the primary storage pile
5. Weigh belt conveyor/metal recovery system to determine feed weights and remove tramp metals
6. Size-reduction system consisting of a primary "hogger" (typically a hammer mill), disc screening to remove oversize material ("overs"), and a secondary grinder for overs
7. Storage of comminuted material in a live bottom vessel (typically referred to as a day bin)
8. Metering system for transfer to a conveying system
9. Pneumatic conveying system to transport biomass to the boiler
10. Dedicated biomass boiler injectors.

Extensive demonstrations and commercial operations in the United States (EIA 2009b) and Europe (Cremers 2009) have shown that effective substitutions of biomass energy up to approximately 15% of the total energy input (approximately 5% for co-feed systems and 15% for separate injection systems) (McGowin 2007) can be made with primarily burner and feed system modifications to existing stations. The largest commercial co-firing plant is the Drax plant in Yorkshire, United Kingdom, which co-fires at 7% in a 4,000-MW, six-boiler facility (Drax 2011).[11] The impact of biomass co-firing on capacity and heat rate is facility-specific and a function of co-firing rate and boiler control characteristics. McGowin (2007) estimates an increase in heat rate of 1.5% at 10% power output from biomass. Because biomass generally has significantly less sulfur than coal does, there is a sulfur dioxide benefit, operations suggest there is a nitrogen oxide reduction potential of up to 20% with low-nitrogen woody biomass. Each feedstock/boiler combination needs to be evaluated to determine the actual impact on sulfur dioxide and nitrogen oxide. Investments are very site-specific and are affected by the available space for yarding and storing biomass, the installation of size reduction and drying facilities, and the nature of required boiler modifications.

A number of potential problems have been identified (van Loo and Koppejan 2002) that should be evaluated for each potential project:

- Increased ash deposition in the boiler furnace and convective tube banks,
- Increased rates of metal wastage of boiler components due to gas-side corrosion,
- Reduced collection efficiency of the particulate collection equipment and increased dust emissions,
- Interference with the operation of SO_x and NO_x emissions control equipment, and
- Impacts on the utilization/disposal of solids discards from the power plant.

Biomass co-firing can also include co-gasification in coal-based IGCC systems. Co-gasification is being practiced commercially at the NUON Buggenum, the Netherlands' 250-MW IGCC system where biomass is co-fired at 10% by heat, and has been experimentally tested at the Elcogas 335-MW IGCC in Puertollano, Spain (up to 10% by weight).

[11] Accessed December 20, 2010: http://en.wikipedia.org/wiki/Drax_power_station.

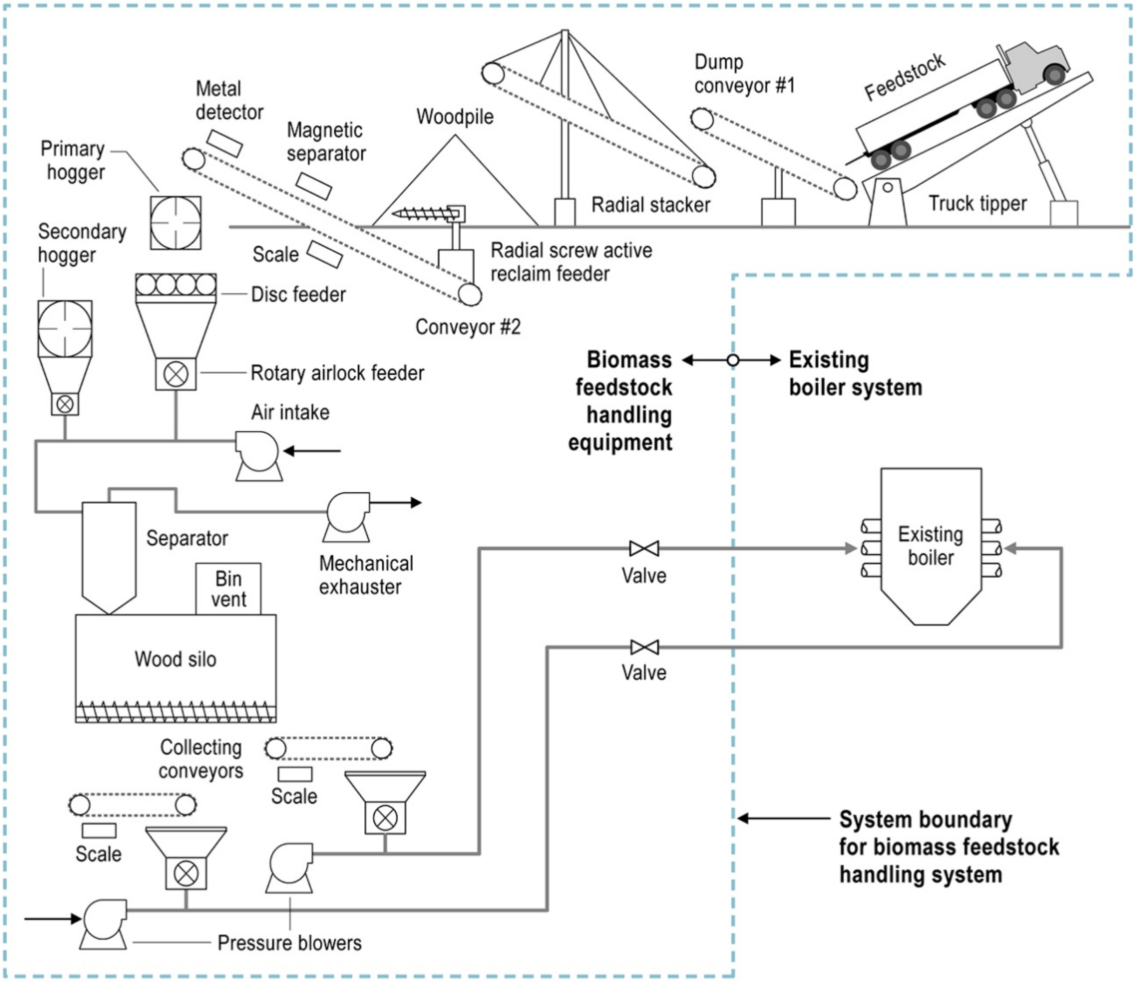


Figure 6-10. Schematic of a separate injection biomass co-firing system retrofit for a pulverized coal boiler

Reproduced from DeMeo and Galdo (1997)

6.3.2 Direct-Fired Combustion Technologies

6.3.2.1 Direct Combustion

Most biopower plants in the United States using solid biomass residues use direct-fired systems. Direct combustion (see Figure 6-11) involves the oxidation of biomass with excess air to give hot flue gas, which produces steam in the heat exchange sections of boilers. The steam is used to produce electricity in a Rankine cycle. In electricity-only processes, all of the steam is condensed in the turbine cycle, while in CHP operation, a portion of the steam is extracted to provide process heat.

The process shown in Figure 6-11represents a simplified generic direct combustion plant. The storage and feed preparation subsystems are similar to that described for stand-alone co-firing. The size reduction required is a function of the type of boiler employed. The majority of biopower boilers are stoker[12] grate furnaces or boilers of the moving grate or vibrating grate design. The volumetric heat released by direct combustion of biomass is typically 128.5–187.4 kW/m^3 (13,000–20,000 Btu/ft^3/hr) (McGowin 2007); this is lower than the volumetric heat released by coal combustion, 187.4–234.2 kW/m^3 (20,000–25,000 Btu/ft^3/hr), due to the lower heat content and higher moisture content in biomass. Steam conditions are a function of boiler capacity and range from 600 psig/750°F for lower capacity boilers (e.g., 250,000 lb steam/hr) to 1,250 psig/950°F for larger units. To a lesser extent, bubbling bed and circulating bed boilers are also employed for biopower. In the future, fluid bed systems may be the preferred design because of emissions performance characteristics. The steam turbine is typically designed as a condensing turbine for power-only applications. For CHP application, steam is typically extracted at 50 psig and 150 psig.

Biomass-fired steam cycle plants typically use single pass steam turbines. However, efficiency and design features previously found in only large-scale steam turbine generators have been transferred to smaller capacity units. These designs include multi-pressure, reheat, and regenerative steam turbine cycles as well as supercritical steam turbines.

The addition of dryers and the incorporation of more rigorous steam cycles raise the efficiency of direct combustion systems by approximately 5%–7% over today's industry average 22% efficiency (McGowin 2007; EPA 2006b).

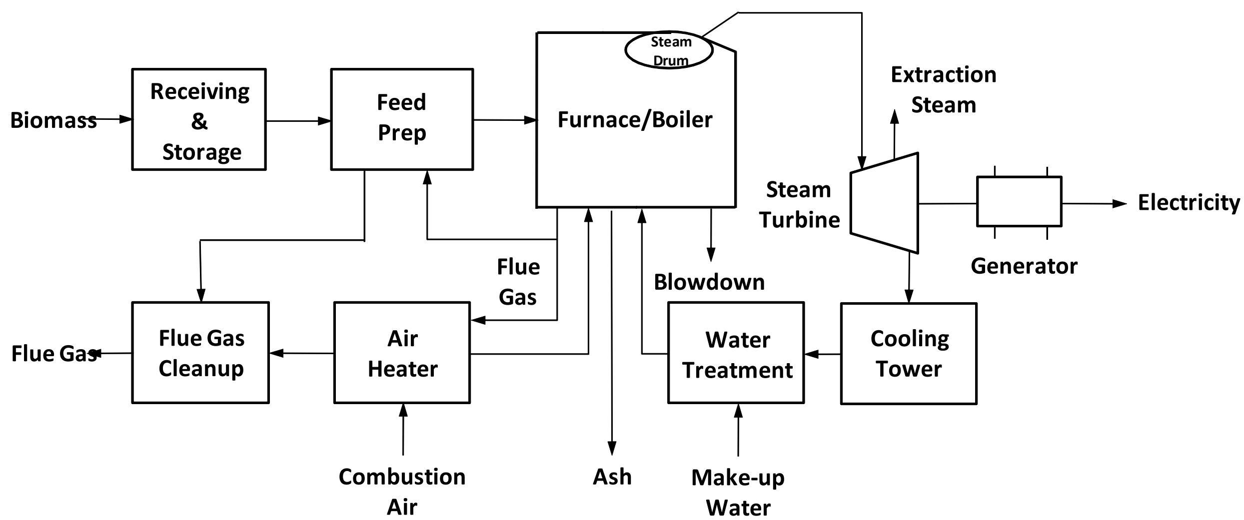


Figure 6-11. Schematic of a direct-fired biopower facility

[12] A stoker is a machine or device that feeds fuel to a boiler.

6.3.2.2 Gasification

Gasification involves the conversion of biomass in an atmosphere of steam or sub-stoichiometric air/oxygen[13] to a medium- or low-calorific gas to produce a gas rich in carbon monoxide and hydrogen plus other gases such as methane and carbon dioxide. A medium-calorific-value gas has a heating value of 10–20 MJ/m^3 (270–540 Btu/ft^3), and a low-calorific gas has a heating value of 3.5–10 MJ/m^3 (100–270 Btu/ft^3) (Rezaiyan and Cheremisinoff 2005). A biomass-based power plant that uses an IGCC system is shown in Figure 6-12. The system shown in Figure 6-12 consists of:

1. Feed handling and preparation system (comparable to the system in the co-firing discussion)
2. Biomass dryer (typically a rotary dryer)
3. Biomass gasifier (in this case a partial oxidation gasifier)
4. Gas cooler (to reduce gas temperature to the maximum allowable temperature of a hot gas filter and to preheat water for a heat recovery steam generator)
5. Hot gas filter (either a ceramic or sintered metal filter)
6. Gas cleanup for contaminants such as sulfur or chlorine
7. Brayton cycle combustion turbine (gas turbine) with air extraction for gasifier use (also called a topping cycle)
8. Heat recovery steam generator using turbine exhaust gas to produce steam
9. Rankine cycle extracting/condensing steam turbine (steam extracted for gasifier use), also called a bottoming cycle
10. Ancillary utilities.

Gasifiers are typically referred to as direct (pyrolysis, gasification, and partial combustion take place in one vessel) or indirect (pyrolysis and gasification occur in one vessel, combustion occurs in a separate vessel). For direct gasification, air and sometimes steam are directly introduced to the single gasifier vessel. For indirect gasification, an inert heat transfer medium, such as sand, carries heat generated in the combustor to the gasifier to drive the pyrolysis and char gasification reactions. Current indirect gasification systems operate near atmospheric pressure. Direct gasification systems have been demonstrated at both elevated and atmospheric pressures. Any of these gasifier systems can be used in the generic gasifier block represented in the main system, although some specific characteristics of the integrated system may vary. Biomass gasification combined cycle systems are at the demonstration stage, while smaller-scale gasification internal combustion systems are at the commercial stage.

[13] Partial oxidation that involves the use of less oxygen than that required for complete combustion to carbon dioxide and water

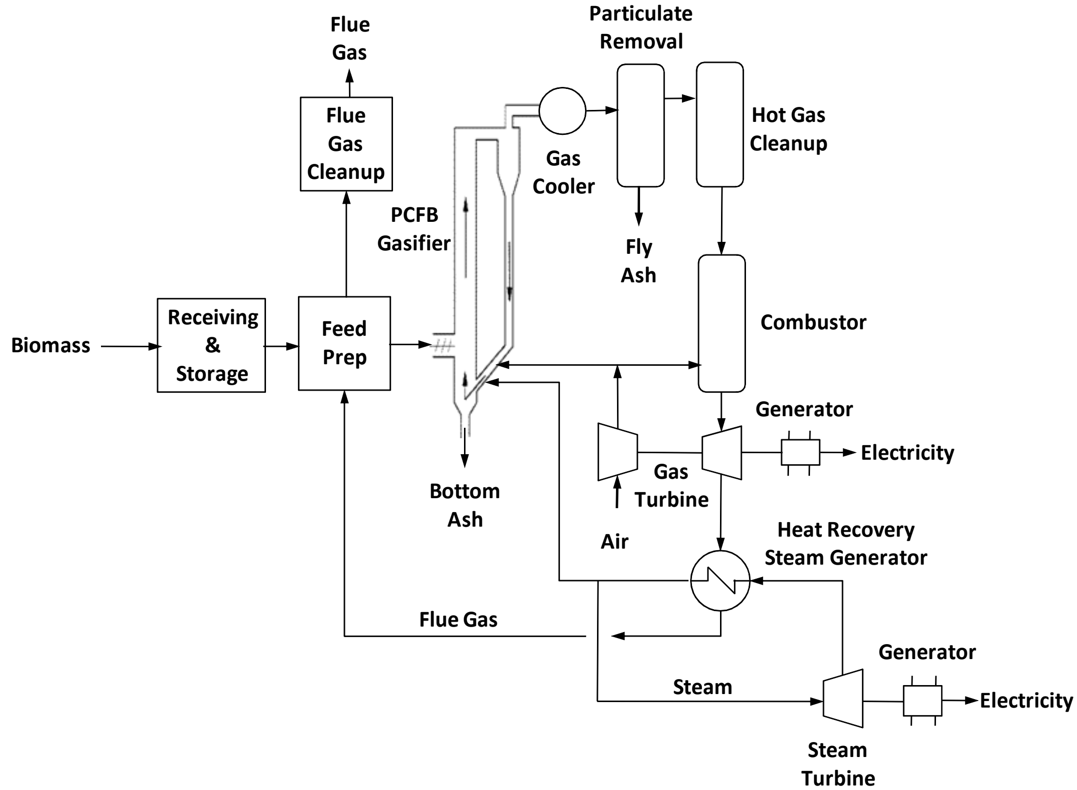


Figure 6-12. Schematic of a gasification combined cycle system

6.3.2.3 Advantages and Disadvantages

A short list of advantages and disadvantages of the three technologies is given in Table 6-5.

Table 6-5. Advantages and Disadvantages of Biopower Technologies

Technology	Advantages	Disadvantages
Co-firing	Commercial technology	Does not add to existing capacity when practiced in existing coal-fired power plants
	Lowest cost option Retains efficiency (-1.5% delta) of existing generator	Comingling of coal/biomass ash does not permit ash sales in cement market (ASTM 2008)
Direct combustion	Commercial technology	Lowest efficiency option due to small scale when compared to scale of coal systems
Gasification	Potential for carbon capture and storage	Biopower gasification systems are at an early commercial stage, primarily in Europe Large scale required to capture cost and efficiency benefits

6.3.3 Technologies Included in RE Futures Scenario Analysis

RE Futures included retrofit co-firing and stand-alone direct biopower systems. Biomass co-firing was limited to a maximum of 15% of total fuel, depending on the boiler type and the number of modifications made to the boiler. The co-firing methods evaluated were fuel blending, separate injection, and gasification. New stand-alone dedicated biopower systems are assumed to be direct combustion systems at the beginning of the study period (2010–2050) with a gradual introduction of gasification technologies over the study period.[14] Although biopower gasification technologies using advanced power cycles have yet to be deployed in the United States, commercial scale biopower gasification facilities are operational in Europe.

6.3.4 Technology Cost and Performance

Future capital cost, performance (generally represented as capacity factor or heat rate), and operating costs of electricity generating technologies are influenced by a number of uncertain and somewhat unpredictable factors. As such, to understand the impact of RE technology cost and performance improvements on the modeled scenarios, two main projections of future RE technology development were evaluated: (1) renewable electricity-evolutionary technology improvement (RE-ETI) and (2) renewable electricity-incremental technology improvement (RE-ITI). In general, RE-ITI estimates reflect only partial achievement of the future technical advancements and cost reductions that may be possible, while the RE-ETI estimates reflect a more complete achievement of that cost-reduction potential considering only evolutionary improvements of currently commercial technologies. The RE-ITI estimates were developed from the perspective of the full portfolio of generation technologies in the electric sector. Black & Veatch (2012) includes details on the RE-ITI estimates for all (renewable and conventional) generation technologies. RE-ETI estimates represent technical advances currently envisioned through evolutionary improvements associated with continued R&D from the perspective of each renewable electricity generation technology independently. The RE-ETI biopower technology improvements are described in this section. It is important to note that these two renewable energy cost projections were not intended to encompass the full range of possible future renewable technology costs; depending on external market conditions, policy incentives, or other factors, these anticipated technical advances could be accelerated or achieve greater magnitude than what is assumed here.[15] Cost and performance assumptions used in the modeling analysis for all technologies are tabulated in Appendix A (Volume 1) and Black & Veatch (2012).

Capital and operating costs for the RE-ETI estimates were developed using extant plant costs and engineering studies (Black & Veatch 2012; DeMeo and Galdo 1997; EPRI 1993; McGowin 2007). These costs are shown in Table 6-6, along with the RE-ITI estimates[16] and EIA estimates (EIA 2010d). Historical capital costs do not show the cost reductions of many of the alternative

[14] The gradual introduction of gasification technologies was represented in the ReEDS modeling through improvements in heat rate over time.

[15] In addition, the cost and performance assumptions used in RE Futures are *not* intended to directly represent DOE Office of Energy Efficiency and Renewable Energy technology program goals or targets.

[16] For standalone biopower during the study period, RE-ITI projections were based on a standard Rankine cycle. Base costs were assumed to be $3,872/kW (Black & Veatch 2012), -25%, and +50%. Gasification systems were assumed to displace the direct combustion systems gradually over the study period, resulting in an average system heat rate that improved by 14% over the 40 years.

renewable electricity technologies because direct combustion technology is a mature commercial technology and, as seen in Figure 6-1, the industry has been static for the past 15 years. As shown in Table 6-7, system component percentages of direct combustion capital costs (excluding general facilities) from McGowin (2007) are 6%–7% for feed handling and processing, 44%–47% for boiler and air quality assurance, 33%–35% for steam turbine and auxiliaries, and 13%–14% for balance of plant. Component details of processes shown in Table 6-7 but not in Table 6-6 are given in Appendix E.

Capital costs, shown in Figure 6-13, were compiled from various publications[17]; these costs represent published biopower cost information. Heat rates of potential dedicated biopower technologies are given in Figure 6-14. As shown in Figure 6-13 and Figure 6-14, the capital cost estimates from the two capital cost projections in RE Futures are almost identical; however, much greater heat rate improvements are estimated in RE-ETI than were estimated with RE-ITI. The capital costs and heat rates used by the EIA in the Annual Energy Outlook are based on the assumption of commercialization of gasification technologies. In RE Futures, advanced gasification was also considered a potential technology improvement, and commercial penetration was based primarily on commercial combustion and co-firing technologies, with a gradual introduction of gasification technologies over the study period. Capital costs for co-firing are given in Figure 6-15. The capital costs of co-firing systems where biomass is mixed with coal before coal grinding are less than they are for separate injection systems. Co-firing capital costs range from $350–550/kW for co-feed systems (coal-biomass co-feed) to $990/kW for systems based on separate biomass feeding. RE Futures used separate injection because of the ability to co-fire at higher levels (e.g., 15%). Heat rates of co-firing systems are assumed to be unchanged from that of the base coal plant heat rate. Retrofit co-firing costs are estimated to be the same under RE-ITI and RE-ETI.

[17] All RE Futures modeling inputs, assumptions, and results are presented in 2009 dollars unless otherwise noted.

Table 6-6. Capital and Operating Costs of Representative Biopower Systems

Technology (2010$)	Year	Plant Size (MW)	Capital Cost		Operating Costs				Heat Rate	Reference
			Overnight	w/AFUDC[a]	Fixed	Variable	Feed[b]			
			(1,000 $/MW)		($/kW-yr)	($/MWh)	($*/tonne)	($/MWh)	(MMBtu MWh)	
Combustion, stoker	2010	50	3,657	3,794	99	4	82.60	59	12.50	McGowin (2007)
Combustion, stoker	2010	50	3,742	4,092	99	5	82.60	68	14.48	DeMeo and Galdo (1997)
Combustion, circulating fluidized bed	2010	50	3,771	3,911	102	6	82.60	59	12.50	McGowin (2007)
Combustion, bubbling fluidized bed[c]	2010	50	3,638	–	94	5	82.60	63	13.50	EIA (2010d)
CHP	2010	50	3,859	4,002	101	4	82.60	67	14.25	McGowin (2007)
Gasification, base	2010	75	4,194	4,417	94	7	82.60	44	9.49	DeMeo and Galdo (1997)
Gasification, advanced	2010	75	3,607	3,795	60	7	82.60	38	8.00	DeMeo and Galdo (1997)
Gasification, IGCC[d]	2010	20	7,498	–	322	16	82.60	58	12.35	EIA (2010d)
Composite[d]	2010	50	3,872	–	95	15	82.60	68	14.50	RE-ITI, Black & Veatch (2012)
Composite[d]	2030	50	3,872	–	95	15	82.60	63	13.50	RE-ITI, Black & Veatch (2012)
Composite[d]	2050	50	3,872	–	95	15	82.60	59	12.50	RE-ITI, Black & Veatch (2012)
Composite[d]	2010	50	3,865	–	103	5	82.60	59	12.5	RE-ETI
Composite[d]	2020	50	3,864	–	102	5	82.60	59	12.4	RE-ETI
Composite[d]	2030	50	3,843	–	89	5	82.60	52	11.1	RE-ETI
Composite[d]	2040	50	3,822	–	76	6	82.60	46	9.7	RE-ETI
Composite[d]	2050	50	3,811	–	63	7	82.60	39	8.4	RE-ETI
Co-firing, pulverized coal, co-feed[e]	2010	20	559	555	13	2	82.60	47	Coal Heat Rate +1.5%	McGowin (2007)
Co-firing, Cyclone Co-feed[e]	2010	20	353	353	13	1	82.60	47	Coal Heat Rate	McGowin (2007)

Technology (2010$)	Year	Plant Size (MW)	Capital Cost Overnight	Capital Cost w/AFUDC[a]	Operating Costs Fixed	Operating Costs Variable	Feed[b]		Heat Rate	Reference
			(1,000 $/MW)		($/kW-yr)	($/MWh)	($*/tonne)	($/MWh)	(MMBtu MWh)	
									+1.5%	
Co-firing, separate feed[d]	2010	–	1,000		20	0	82.60	47	10.00	Black & Veatch 2012
Municipal solid waste	2010	–	7,251	7,601	265	29.1	–	–	16.46	EPRI (1993)

[a] Allowance for funds used during construction
[b] Using a representative biomass cost of $82.60/tonne ($75/ton). The ReEDS and GridView models used supply curves in actually calculating costs so that the feedstock cost reflected available supply in a particular region and was not simply set at $82.60/tonne throughout. This value is used here simply to be representative.
[c] Preliminary: Costs adjusted using Chemical Engineering Plant Cost Index value from August 2010
[d] Composite combustion and gasification mix, with gasification increasing over time
[e] Biomass cost based on heat rate of 10.00 MMBtu/MWh

Table 6-7. Direct Combustion Capital and Operating Costs for Biopower (2010$)

	Units	Stoker	CFB[a]	CHP[b]
Capacity	MW_e	50	50	50
Cogenerated steam output	1,000 lb/hr	–	–	100
Cogenerated steam conditions	psig, saturated	–	–	100
Physical plant unit life	years	30	30	30
Construction Schedule				
Preconstruction, license and design times	years	1.5	1.5	1.5
Idealized plant construction time	years	2	2	2
Capital Costs	$/kW			
Fuel handling, preparation		119	119	129
Boiler and air quality control		783	875	851
Steam turbine and auxiliaries		620	620	704
Balance of plant		246	246	246
General facilities and engineering fee		1,148	1,148	1,148
Project and process contingency		109	112	114
Total plant cost		3,025	3,120	3,192
AFUDC[c]		137	140	143
Escalation during construction total plant investment		3,161	3,260	3,335
Owner Costs	$/kW			
Due diligence, permitting, legal, development		632	651	667
Taxes and fees		0	0	0
Total Capital Requirements	$/kW	3,794	3,911	4,002
O&M Costs				
Fixed	$/kW-yr	98.9	101.8	100.7
Variable	$/MWh	4.0	4.6	4.1
Feed @ $82.60/tonne ($75/ton)	$/MWh	58.59	58.59	66.80
Performance/Unit Availability				
Net heat rate	Btu/kWh	12,500	12,500	14,250
	MMBtu/MWh	12.50	12.50	14.25
	%	27.31	27.31	23.96
Equivalent planned outage rate	%	4	4	4
Equivalent unplanned outage rate	%	6	6	6
Equivalent availability	%	90	90	90
Emission Rates				
Carbon dioxide (CO_2)	lb/MMBtu	220	220	220
Nitrogen oxide (NO_x)	lb/MMBtu	0.15	0.08	0.15
Sulfur oxide (So_x)	lb/MMBtu	0.10	0.04	0.10

Source: McGowin (2007)
[a] Circulating fluid bed boiler
[b] Combined heat and power
[c] Allowance for funds used during construction

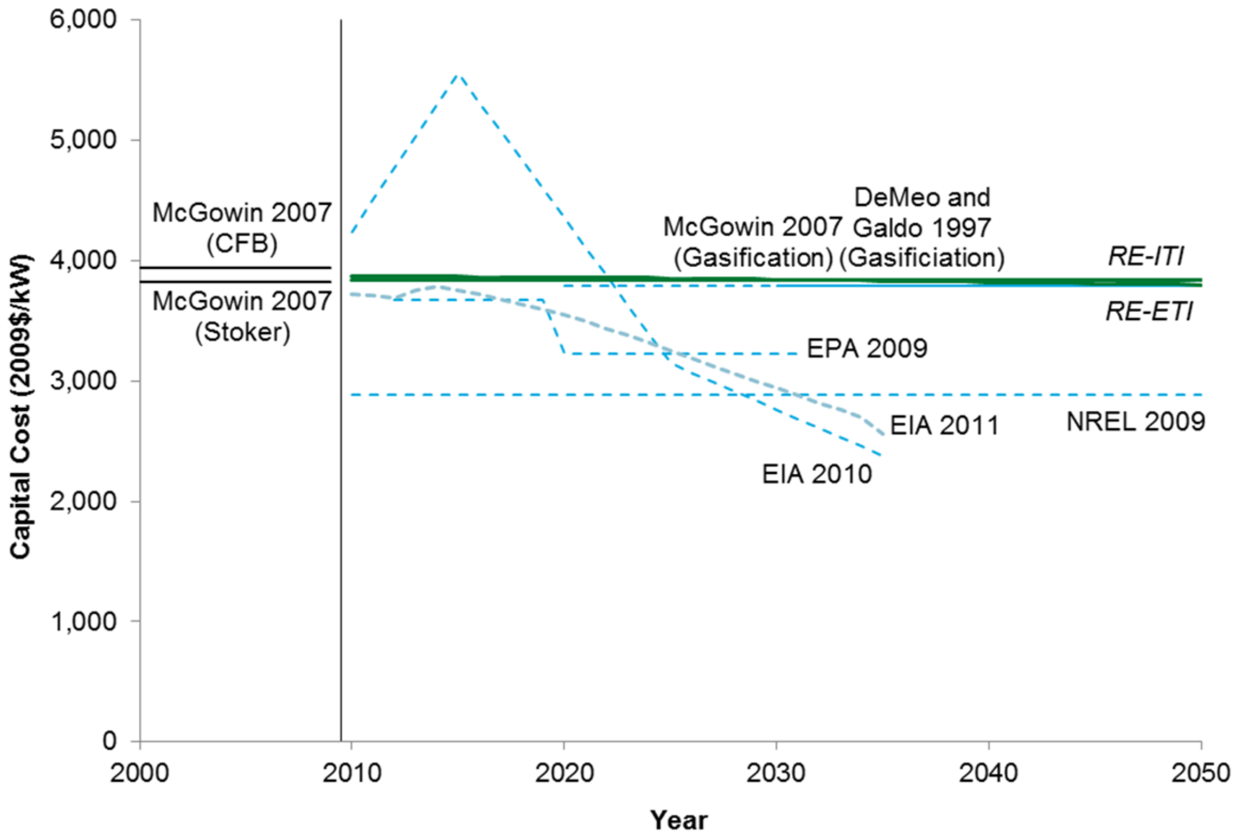


Figure 6-13. Capital costs for dedicated biopower ($/kW)

Historical data represent costs of stoker and circulating fluidized bed (CFB) technologies from McGowin (2007). These data and the data from DeMeo and Galdo (1997) and McGowin (2007) are for commercial combustion systems. For the projections, many data sets (RE-ITI, RE-ETI, EIA 2010, EPA 2009) combine direct combustion technologies with gasification technologies to produce a dynamic mixed fleet that gradually includes more gasification technologies. Other data sets include only direct combustion technologies (NREL 2009; EIA 2011) or only gasification technologies (McGowin 2007; DeMeo and Galdo 1997).

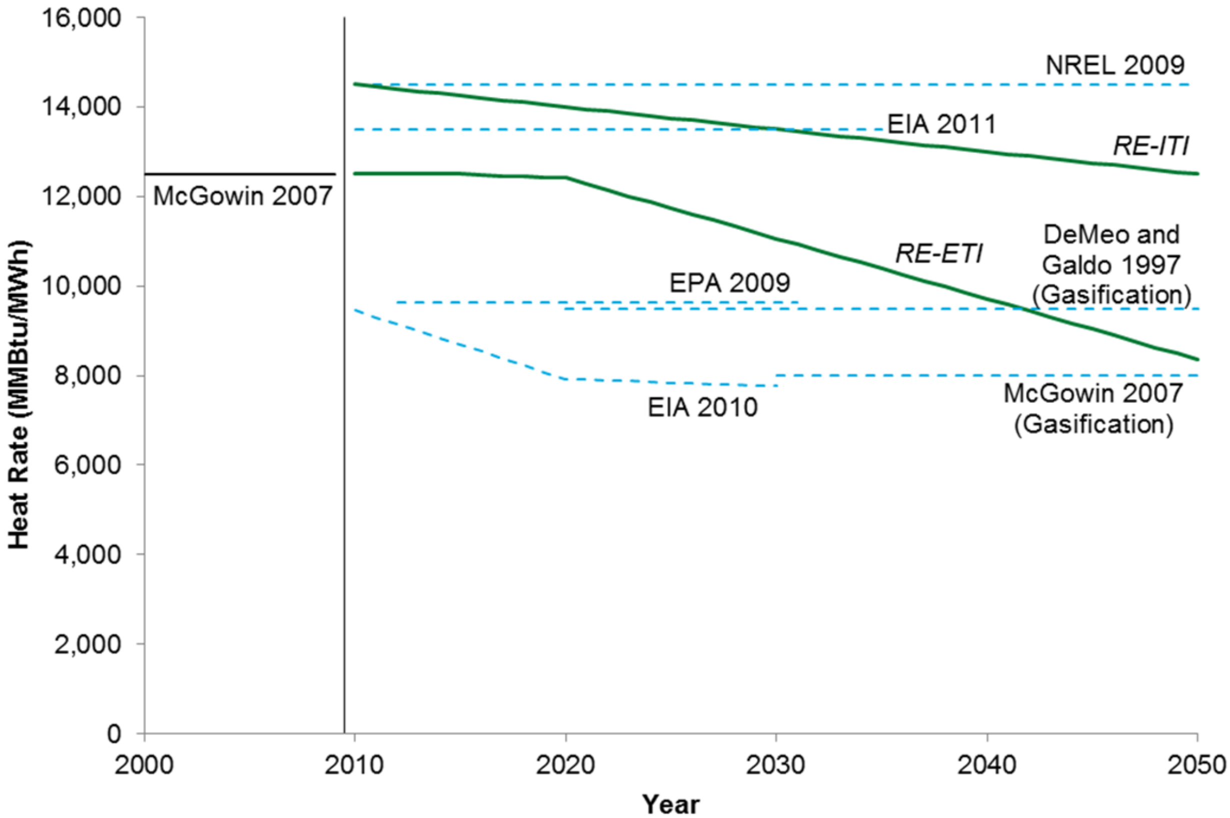


Figure 6-14. Heat rates for dedicated biopower (MMBtu/MWh)

Historical data are from McGowin (2007). For the projections, many data sets (RE-ITI, RE-ETI, EIA 2010, EPA 2009) combine direction combustion technologies with gasification technologies to produce a dynamic mixed fleet that gradually includes more gasification technologies. Other data sets include only direct combustion technologies (NREL 2009; EIA 2011) or only gasification technologies (McGowin 2007; DeMeo and Galdo 1997). Unless otherwise noted, all heat rates shown are based on higher heating value.

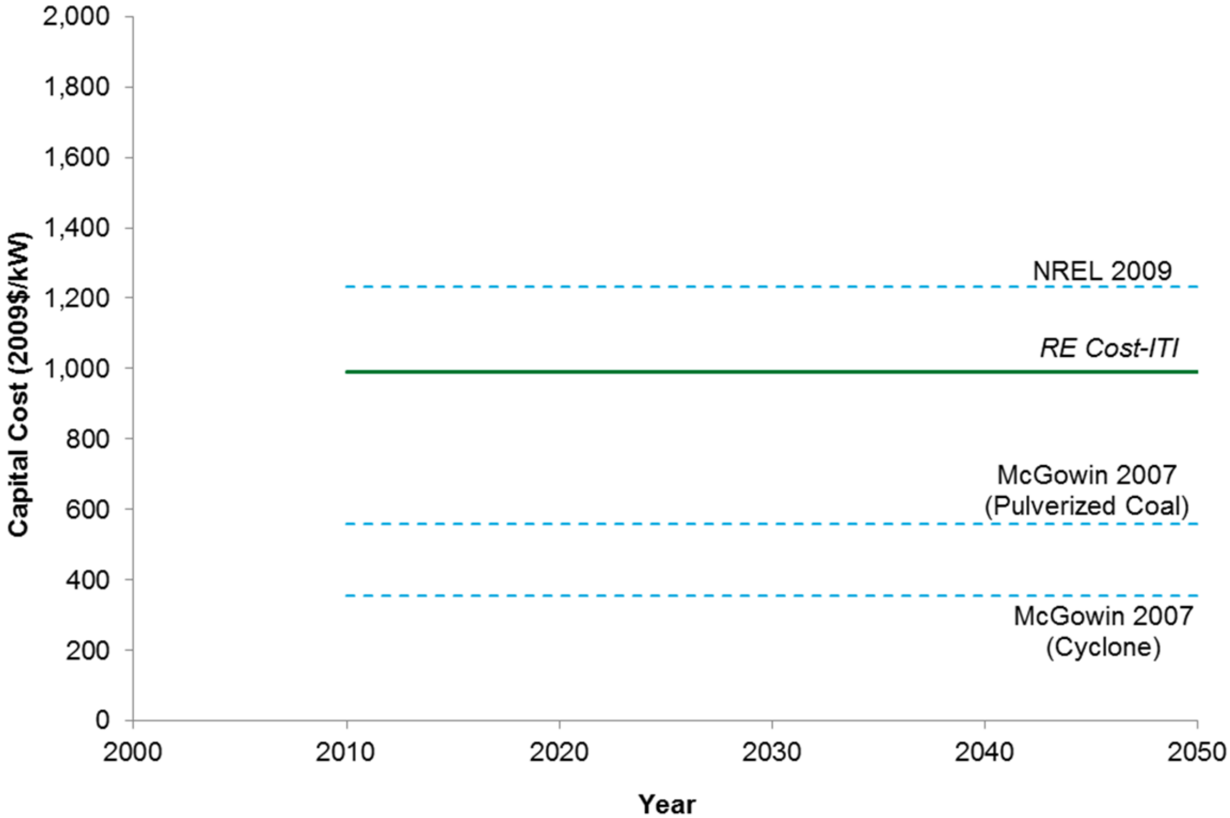


Figure 6-15. Capital costs for retrofitting existing coal plants to co-firing ($/kW)

Capital cost estimates represent cost of retrofits of existing coal facilities for biomass combustion component only. RE-ITI and RE-ETI estimates have identical capital costs associated with retrofits to co-fired facilities.

6.3.5 Technology Advancement Potential

6.3.5.1 Engineering Analysis of Advancement Potential

Direct combustion systems are commercial technologies. The addition of dryers and the incorporation of more rigorous steam cycles are expected to raise the efficiency of direct combustion systems by approximately five percentage points over today's 22% efficiency to roughly 27% efficiency (McGowin 2007; EPA 2006b).

6.3.5.2 Advancement Potential Relative to RE Futures Scenario Analysis

The major technology advancement relative to the RE Futures scenarios is the adoption of biomass gasification integrated combined cycle technology (BIGCC) that has the potential to reduce capital intensity (see Figure 6-13) and reduce heat rate (see Figure 6-14) leading to lower levelized costs. However, all estimates are for n^{th} plant costs. Advanced gasification-based Rankine and Otto power cycles are used commercially in Europe, but this technology has yet to be deployed widely in the United States. Without co-funding of demonstration and first generation commercial plants, the introduction of BGCC may not occur, because there is a lack of commercial combustion turbines (with standard guarantees and warranties) for low heat content gases in the size range needed for demonstration projects.

6.4 Output Characteristics and Grid Service Possibilities

6.4.1 Electricity Output Characteristics

Biopower systems, whether co-firing with fossil fuels or in dedicated plants, use large conventional AC generators that produce electricity in the same manner as conventional generators and feed into the transmission network at high voltages. Biopower provides dispatchable energy, but typically provides essentially base-load generation with a high capacity factor. Biopower can also provide load following and ancillary services (regulation, contingency, and other reserves) similar to other thermal plants, subject to cold-start or minimum-load requirements. Dispatch time will be in the hourly time frame, with typical ramp rates of 10% per hour (see technology characterization in Appendix E).

6.4.2 Technology Options for Power System Services

RE Futures evaluated only electric sector generation. In this context, the primary use of biomass will be for co-firing and dedicated biopower systems providing base-load and dispatchable power. Although outside the scope of RE Futures, end-use sector poly-generation processes that produce both biofuels and biopower may generate incremental amounts of electricity in the future. NREL's estimates of electricity generation from advanced ethanol processes range from 1.7 kWh/gallon of ethanol to 3.4 kWh/gallon of ethanol (Davis and Tan 2010). Using the ethanol yield information from Table 6-10 (2.3 bbl ethanol/tonne for biochemical ethanol) the byproduct electricity from advanced ethanol process is 0.16–0.32 MWh/tonne, compared to 1.1–1.6 MWh/tonne (Table 6-10) for biomass feedstock used only for electricity production.

According to the Energy Independence and Security Act of 2007, P.L. 110–140 (EISA 2007), the renewable fuel requirement in 2022 is 21 billion gallons of renewable biofuels other than corn ethanol. If this requirement is met, there is the potential for 36–71 TWh of associated end-use generation using the Davis and Tan estimates. The recent National Academy of Science report on liquid transportation fuels from coal and biomass (NAS 2009) estimates lignocellulosic biofuels potential at 30 billion gallons by 2035, which could result in 51–102 TWh of electricity, again based on the Davis and Tan (2010) estimates. The maximum electricity generation potential from these biofuels projections represents approximately twice the 55 TWh (Table 6-1) of electric sector and end-use biopower generation in 2009.

6.5 Deployment in RE Futures Scenarios

Biopower plays a significant role in all of the RE Futures scenarios described in Volume 1. Table 6-8 and Figure 6-17 show the variation in 2050-installed dedicated biopower[18] and co-fired capacity[19] between the six (low-demand) core 80% RE Futures scenarios and the high-demand 80% RE scenario. In addition, Table 6-8 shows the biopower contribution of the total 2050 generated electricity between these scenarios. Biopower capacity deployment is significant in all 80% RE scenarios modeled. In fact, excluding the constrained resources scenario, biopower capacity deployment and 2050 generation show little variation among the other six 80% RE scenarios; the 2050 installed capacity for biopower ranged from 93 GW to 100 GW, and the biopower contribution to the percent of total generated electricity ranged from 13.3% to 14.1% for the low-demand scenarios[20] for the 80% RE scenarios excluding the constrained resources scenario. The similar biopower capacity deployment and biopower generation levels found in many of the scenarios reflect the limiting role the feedstock supply played in deployment. In fact, for almost all of the 80% RE scenarios, greater than 90% of the assumed U.S. feedstock supply was used in 2050 for electricity generation,[21] with the supply exhausted in many regions in the Eastern Interconnection. This indicates that if a greater feedstock resource estimate were used in the ReEDS modeling, biopower technologies would likely see greater expansion beyond the levels shown in Figure 6-17. In fact, other feedstock resource estimates project a greater level of resource availability than that used in the ReEDS modeling (see Section 6.2). Additionally, the lack of variation of biopower penetration shows the robustness of biopower technology deployment compared with other renewable technologies. For example, the dispatchability of biopower plants enable it to realize high levels of deployment in a scenario where power system flexibility is assumed limited (constrained flexibility scenario). In addition, the existence of feedstock across most regions in the contiguous United States enables large-scale deployment in the constrained transmission scenario despite the strict constraints on new transmission growth in that scenario. However, the constrained resources scenario indicates that high renewable electricity futures can be achieved even if large amounts of biomass feedstock are instead used for transportation fuel or are otherwise not accessible for power generation.

[18] The dedicated biopower category includes the existing MSW and landfill gas plants.

[19] The estimated co-fired capacity presented in Figure 6-17 and Figure 6-18 represents 15% of the total capacity of coal plants that were retrofitted to co-fire biomass. For example, in the High-Demand 80% RE scenario, 104 GW of coal capacity retrofitted to co-fire biomass remained online in 2050, of which 16 GW can be used to generate electricity from biomass fuel.

[20] Although the percentage of total generated electricity from biomass was smaller under the High-Demand 80% RE scenario, the absolute amount of electricity was similar between this scenario and the low-demand 80% RE scenarios, excluding the Constrained Resources scenario.

[21] In terms of feedstock use, the 80% RE-ETI scenario used less than 70% of the national available feedstock for electricity generation in 2050 compared to greater than 90% of the available feedstock for the 80% RE-ITI scenario. The reason for the lower utilization of feedstock, yet comparable capacity and generation, is the lower dedicated biopower heat rate estimated in this scenario compared to the other 80% RE scenarios.

Table 6-8. Deployment of Biopower in 2050 under 80% RE Scenarios[a,b]

Scenario	Dedicated Biopower Capacity (GW)	Dedicated Biopower Generation (%)	Co-Fired Biopower Capacity (GW)	Co-Fired Biopower Generation (%)	Total Biopower Generation (%)
High-Demand 80% RE	84	10.6%	16	1.3%	11.9%
Constrained Transmission	84	13.6%	14	1.5%	15.1%
Constrained Flexibility	81	13.5%	14	1.5%	15.0%
80% RE-ITI	82	13.8%	13	1.4%	15.2%
80% RE-ETI	83	14.1%	11	1.1%	15.2%
80% RE-NTI	80	13.3%	13	1.3%	14.5%
Constrained Resources	40	6.7%	11	1.2%	7.9%

[a] See Volume 1 for a detailed description of each RE Futures scenario.
[b] The capacity totals represent the cumulative installed capacity for each scenario, including currently existing biopower, municipal solid waste, and landfill gas capacity

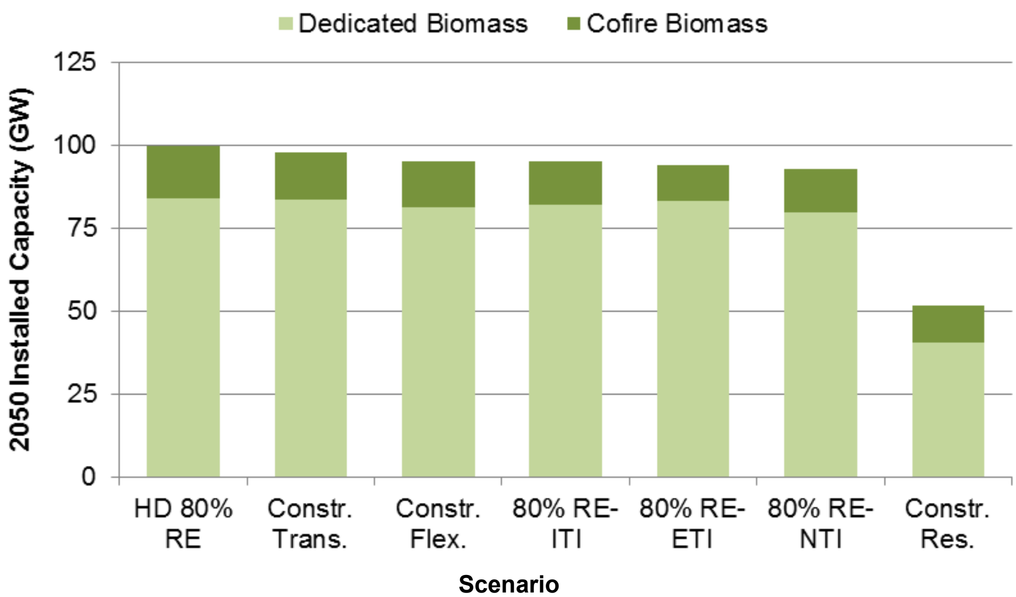


Figure 6-16. Deployment of biopower in 80% RE scenarios

The modeling analysis was restricted to the electric sector, and thus, did not directly examine biofuel production. In particular, the ReEDS model did not consider any impacts that biofuel use for the transportation sector might have on feedstock availability or cost for electricity production. As described previously, in many of the 80% RE scenarios, a large fraction of the U.S. feedstock supply was projected for use in electricity generation, which seemingly left little feedstock supply for biofuel production. However, as described in Section 6.2, the feedstock supply used in the ReEDS modeling was relatively conservative compared to other estimates, particularly for the years in the latter part of the study period; if other estimates of feedstock supply described in Section 6.2 are realized, there appears to be sufficient supply for electricity generation at the levels indicated here and for biofuel production. In addition, a constrained resources scenario was designed to generally evaluate how environmental and other concerns, which limit the developable potential for renewable technologies, might influence the achievability of 80% RE penetration. For the constrained resources scenario, the available feedstock supply for electricity generation was halved under the assumption that competition with other uses (e.g., biofuel) and land use concerns may limit supply. As described in Volume 1, even under this severe constraint, ReEDS found that 80% renewable electricity by 2050 was possible with additional small direct electric sector cost implications (see Volume 1, Appendix A). The role of biopower technologies in the electricity sector is found to be smaller in the constrained resources scenario compared to the other 80% RE scenarios; as shown in Figure 6-16, the total installed capacity from biopower technologies reached 52 GW, about half of the capacity levels realized in the other 80% RE scenarios. Even this lower level of deployment, however, is a significant increase from the approximately 5 GW in 2010. Similar to most of the other 80% RE scenarios, the constrained resources scenario used nearly all of the available feedstock supply in 2050, but because the feedstock availability for electricity generation was halved, by design, a significant amount for biofuels remains.

Among the 80% RE scenarios listed in Table 6-8, the high-demand 80% RE scenario realized the greatest deployment of biopower capacity. As described previously, deployment in the high-demand 80% RE scenario and most of the low-demand core 80% RE scenarios were similar; therefore, the results shown below are representative of the collection of 80% RE scenarios. Figure 6-17 shows the cumulative and annual installed capacity for biopower technologies for the high-demand 80% RE scenario. In this scenario, biopower contributed about 12% (685 TWh) to the total generation mix in 2050 (nearly all of which was produced from dedicated biopower plants). By 2050, the estimated coal capacity retrofitted to co-fire biomass grew to 104 GW (of which 15%, or 16 GW, could be used to generate electricity from biomass), as listed in Table 6-8[22] with most of this growth occurring prior to 2030. Dedicated biopower capacity grew to 84 GW in 2050. From 2030 to 2050 (the latter half of the study period), dedicated biopower installations dominated new biopower installations with new annual installments exceeding 5 GW/yr in some years. From 2040 to 2050, there is a decrease in co-fired capacity due to the retirement of coal plants.[23] Figure 6-17 also includes the decade-averaged annual capital investments for the corresponding capacity.

As shown in Figure 6-4 through Figure 6-7, biomass feedstock is available in nearly every U.S. state, with the midwestern states possessing the most abundant supply. Although the capacity expansion optimization routine of ReEDS considers many variables (e.g., cost of all technologies, fuel costs, transmission needs, demand profiles, and generator flexibility), as described earlier, feedstock availability and costs are the most significant drivers in regard to the deployment of biopower generation. Figure 6-18 shows distributions of dedicated biopower capacity and co-fired capacity, respectively, for the high-demand 80% RE scenario. Dedicated biopower installations were found to be located in the midwestern states where the feedstock is

[22] In the remainder of this section, the co-fire capacity represents the biomass portion of the retrofitted coal capacity.
[23] Description of plant retirement assumptions can be found in Appendix A (Volume 1).

abundant. Co-fired capacity was concentrated in regions with existing coal facilities and where feedstock is available, including the Ohio Valley, the southeastern states, and Texas.

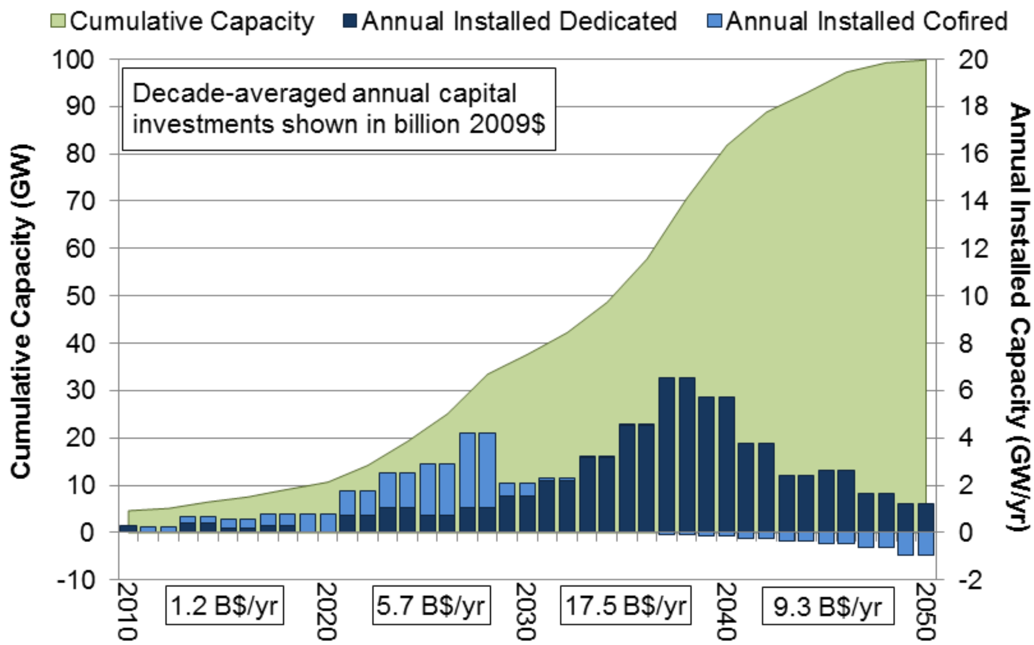
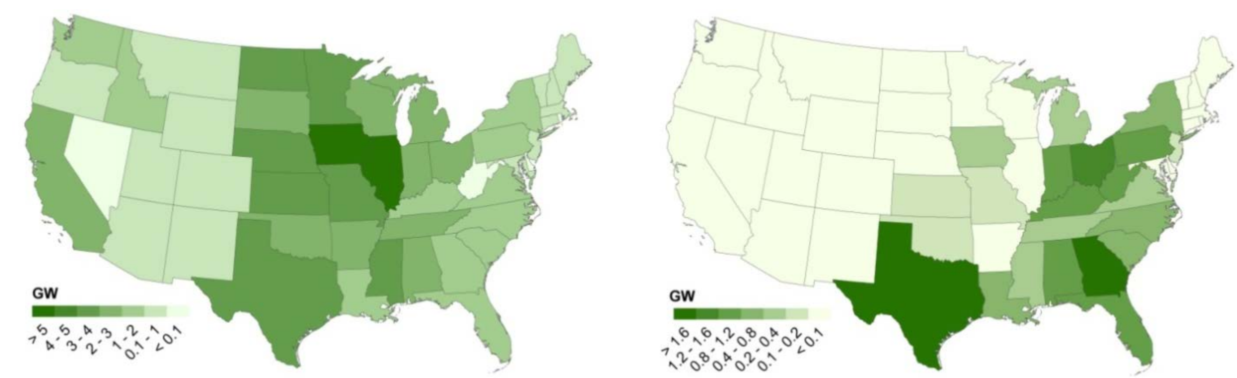


Figure 6-17. Deployment of biopower in high-demand 80% RE scenario



(a) Dedicated Biopower Capacity in 2050 (b) Co-Fired Biopower Capacity by 2050

Figure 6-18. Regional deployment of dedicated and co-fired biopower in the high-demand 80% RE scenario

Figures 6-18 and 6-19 shows deployment results for only one of many model scenarios, none of which was postulated to be more likely than any other. In addition, as a system-wide optimization model, ReEDS cannot capture all of the non-economic and, particularly, regional considerations for future technology deployment. Furthermore, the input data used in the modeling is also subject to large uncertainties. As such, care should be taken in interpreting model results, including the temporal deployment projections and regional distribution results; uncertainties certainly do exist in the modeling analysis.

6.6 Large-Scale Production and Deployment Issues

Issues considered for large-scale production include technical considerations, competition for feedstock, land use, water use, air emissions, and manufacturing and deployment challenges.

6.6.1 Technology Issues

No technology-related issues are associated with large-scale deployment of co-fired and dedicated biopower technologies because they are commercial technologies. Outstanding issues associated with co-firing are primarily related to the existing American Society for Testing and Materials standard ASTM C618 for fly ash (ASTM 2008), which limits the use of fly ash to coal, which is an issue for existing coal plants that sell fly ash into the Portland cement market.

As stated earlier, without co-funding of demonstration and first-generation commercial plants, the introduction of large-scale gasification systems will probably not occur. Demonstration plants are needed to identify technical issues specific to gasification associated with such scale-up. These issues will include feed systems and gas cleanup and conditioning. In addition, there is a lack of commercial combustion turbines for low heat content gases in the size range needed for demonstration projects.

6.6.2 Competition for Feedstock

The most important issue for large-scale deployment of biopower is feedstock competition with lignocellulosic biofuels and other uses for wood. Although biomass can serve a dual role in helping to meet both U.S. electricity generation needs and transportation energy needs, RE Futures resource estimates were not adjusted for potential use in biofuels production. Both biopower and biofuels will play important roles in the future. To the extent that electricity serves a transportation role through plug-in hybrids and battery electric vehicles, biopower will serve a transportation role. In many conceptual biofuels processes, electricity is produced as a byproduct, much like it is in the existing pulp and paper industry. The existing biopower industry uses primarily residues and waste materials with widely varying properties and with limited control of feed properties and therefore uses feeds that are unsuitable for those biofuels processes that currently require very uniform feedstocks. The issue of future feedstock competition between the power and fuel sectors is unresolved. Some studies (WGA 2008) argue that feedstock for biofuels projects may lead to greater economic benefit for feedstock producers. Unless future public policy drives resource use for one sector over the other, there will be increasing competition for biomass resources. Biomass is considered an allowable resource in most state renewable portfolio standard incentive programs (NCSU 2010), and EISA mandates biofuels production quantities (EISA 2007). To date, there is no comprehensive policy covering both options.

To fully evaluate alternative uses of biomass resources, a comprehensive deployment model that incorporates the utility electricity sector, the end-use electric sector, the transportation sector, the agriculture sector (food, fodder, and fuel), the forest products sector (saw wood, fiber, and fuel), and public policy (including sustainability) on both a domestic and international basis would be required. The RE Futures modeling effort addresses only the utility electric sector, and does not address multiple sectors of the economy. One alternative would be to modify the resource supply curves to let EISA govern primary use of the biomass resource (assuming a nominal yield of biofuel per tonne of biomass). This is reasonable but has two complications for RE Futures. First, EISA only covers the period through 2022, not through 2050. Second, actual renewable fuel standards required quantities are set by EPA each fiscal year, depending on actual cellulosic biofuels capacity, which to date has been much lower than anticipated by EISA. For example, the 2011 EPA renewable fuel standard (EPA 2010b) required amount of cellulosic biofuel has been reduced to 0.06 billion gallons from the original EISA 2011 volume of 0.25 billion gallons. Therefore, in RE Futures, biopower penetration is estimated independently, and a check on potential feedstock availability, based on required EISA volumes, has been made to point out potential feedstock availability limitations and reinforce the need for more comprehensive modeling.

Because biomass is a limited resource, the amount of electricity and biofuels that can be produced is limited. Up to 675 million dry tonnes of biomass will be available annually in 2025 at $100/dry tonne delivered (Walsh 2008). The recent DOE update (DOE 2011) of the billion-ton study (Perlack et al. 2005) gives a baseline estimate of 696 million dry tonnes in 2030 at approximately $83/dry tonne delivered. High growth cases for enhanced dedicated crop productivity rates show higher availability in 2030, with values ranging from 951 million dry tonnes to 1,184 million dry tonnes at about $83/dry tonne delivered, assuming 2% and 4% annual growth improvement, respectively. Independent estimates of total biomass needed (1) by RE Futures in 2022 and 2035 for electricity (ReEDS's estimates of co-firing and dedicated biopower); (2) for biofuels production (Recovery Act requirements); and (3) in 2035 for potential biofuels production (NAS 2009) are given in Table 6-9. Although the estimated biomass requirements are comparable to the estimated supply, this level of biomass use will have a large impact on feedstock costs for projects, as shown by the supply curves in Figure 6-9.

Table 6-9. Biomass Requirements Based on Projected Electricity and Biofuels Amounts

Year	Co-Firing[a]			Dedicated Biopower[a]			Biofuels[b]		Total Biomass
	GW	TWh	Million tonnes biomass	GW	TWh	Million tonnes biomass	Billion Gallons	Million tonnes biomass	Million tonnes
2022	6.2	43.8	27.4	5.2	36.4	28.3	21	210	265.7
2035	21.4	149.8	93.6	29.1	203.9	166.2	30	300	559.8

[a] ReEDS output (RE Futures)
[b] 2022 data (EISA 2007), 2035 data (NAS 2009)

Comparative yields of biopower and biofuels technologies, based on analysis of existing and developing technologies, are given in Table 6-10. On an equivalent energy content basis, the electricity yields from direct combustion and BIGCC—4.1 GJ/tonne and 6.6 GJ/tonne biomass, respectively—are substantially lower than the energy content yields of proposed biofuels technologies (e.g., 6.8 GJ/tonne for Fischer Tropsch liquids and 8.1 GJ/tonne for thermochemical cellulosic ethanol). Combined heat and power systems (considered part of the end-use sector and not modeled in RE Futures) have high efficiencies (80% or greater).

Bioproducts, biopower, and biofuels, however, are generally intended for different energy sectors. Comparisons have been made for common use in the transportation sector that compare the overall cycle efficiency of biomass for transportation use (e.g., biomass to electricity for battery electric vehicles and biomass to biofuels for internal combustion vehicles). Campbell (2009) indicates that bioelectricity has the potential to produce an average of 80% more transportation kilometers and 129% more emissions offsets per unit area of cropland than cellulosic ethanol does. The much higher efficiency of battery electric vehicles, 55% (estimate based on Samaras and Meisterling 2008) compared to a light-duty internal combustion vehicle efficiency of 13% (estimate based on Wang 2009), more than offsets the lower efficiency of electricity production.

Table 6-10. Comparative Yields of Biopower and Biofuels Technologies

Product	Feed	Unit	Yield (Unit/ dry tonne)	Yield (GJ/dry tonne feed)
Feed				
Wood			–	18.6
Corn stover			–	18.0
Electricity				
Direct combustion	Wood	MWh	1.1	4.1
Biomass IGCC	Wood	MWh	1.6	6.6
Direct combustion CHP	Wood	MWh_e/MWh_t	1.1/3.3	4.1/12.3
Biofuels				
Methanol	Wood	Barrels ethanol eq*	3.0	10.2
DME	Wood	Barrels ethanol eq	2.8	9.4
Fischer Tropsch liquids	Wood	Barrels ethanol eq	2.0	6.8
Thermochemical ethanol	Wood	Barrels ethanol	2.4	8.1
Biochemical ethanol	Corn stover	Barrels ethanol	2.3	7.9
Methanol-to-gasoline gasoline	Wood	Barrels ethanol eq	2.2	7.5
Pyrolytic fuel oil	Wood	Barrels ethanol eq	3.4	11.4

Sources: Bain 2007, Hamelinck et al. 2003, Phillips et al. 2011

* Equivalent

6.6.3 Environmental and Social Impacts

Biopower deployment has several potentially significant environmental and social impacts that should be addressed. Land use and land use change is an important consideration in large-scale deployment of biopower technologies. To the extent that biomass residues are used that are byproducts of other industries (e.g., pulp and paper), land use is not a consideration. The primary consideration involves land use for new dedicated crops. Water use is also a consideration. In general, water use is primarily for flue gas cooling. Air emissions are important, and biopower systems are designed to meet existing air permit regulations. The impacts of new and proposed air emission regulations need to be evaluated. These impacts, along with greenhouse gas impacts, are discussed below.

6.6.3.1 Land Use

Another potential issue for large-scale biopower deployment is the required land use. Table 6-11 gives ReEDS' biopower requirements in 2050 in energy units and in the associated land area for the 80% RE-ITI scenario. Land use requirements for residues are assumed to be zero because the land use is for the primary production (e.g., corn, lumber, or pulp wood). Therefore, the only land use estimate is for dedicated crops (switchgrass is the assumed default crop). Assuming switchgrass has an 18 GJ/dry tonne heating value and productivity of 9.9–18.8 dry tonne/ha/yr (Perlack et al. 2005), the dedicated cropland requirement is 65,000–122,000 km^2. The lower value is somewhat larger than the land area of West Virginia (63,000 km^2), and the upper value is somewhat less than the land area of Iowa (146,000 km^2). Over the entire range of (low-demand) core 80% RE and high-demand 80% RE scenarios, the land requirement ranges from 33,000 to 128,000 km^2. Although these land area requirements are large, the billion-ton study (Perlack et al. 2005) shows that this land requirement could be met through land use change, based on a combination of improved yields for traditional agricultural crops (smaller acreage required to meet projected food requirements) and conversion of existing pasture land, resulting in no new net land use required. Also possible is the development of new, dedicated crops (e.g., mixed prairie grasses) that might be amenable to marginal or degraded cropland.

Table 6-11. Feed Requirements in 2050 under the ReEDS 80% RE-ITI Scenario

Biomass Resource	Quads	EJ	%	Area 000 km^2
Urban Wastes	1.27	1.34	15.4	–
Mill Wastes	1.32	1.40	16.1	–
Forest Residues	0.77	0.81	9.4	–
Agricultural Residues	2.79	2.94	33.9	–
Switchgrass	2.07	2.19	25.2	65–122
Total	8.23	8.68	100	65–122 (85 using a midpoint estimate for crop yield)

Conversion factors: Low 9.9 dry tonnes/hectare; high 18.8 dry tonnes/hectare

Land use change is an important issue that affects sustainability and GHG emissions. Although a detailed examination is beyond the scope of this report, some discussion of the issues is relevant. The majority of studies are for biofuels, but the issues are the same for biopower based on dedicated feedstocks. Direct land use change issues (E4tech 2009) primarily concern impacts associated with the removal of existing carbon stocks (carbon inventory in existing biomass and associated soil carbon). Direct land use changes are a function of the type and quantity of existing biomass. Direct land use change impacts may be large if existing forests are used and will be smaller if existing grasslands, marginal grasslands, or degraded croplands are used.

The Congressional Budget Office (CBO 2010) summarized the reported times required to achieve break-even carbon emissions for biofuel use compared to petroleum use. A summary for U.S. cases is given in Table 6-12. The CBO notes that the estimates vary widely and that they are a function of the assumptions used in the analyses. The CBO notes that while some researchers conclude that decades to hundreds of years are needed to offset land use change, the EPA—although agreeing that emissions associated with land use change are important—is assessing the impact of biofuels on greenhouse gas emissions, concluded that less time might be necessary for biofuels to offset emissions from land use change. Table 6-12 includes both existing biofuels, such as corn ethanol and soy biodiesel. Future biofuels will primarily be based on cellulosic feedstocks, and Table 6-12 also provides comparative data for one cellulosic biofuel, switchgrass ethanol. Although individual sources give very different estimates, it can be seen that carbon payback times are lower for cellulosic ethanol than corn ethanol (due to lower fossil energy usage), and lower for grassland than forests (due to the larger carbon inventory of forests).

Table 6-12. Time to Achieve Breakeven Carbon Emissions for Biofuels versus Petroleum with Land Use Change

Land Converted	Product	Years Until Net Carbon Reduction	Study
Grassland	Corn ethanol	93	Fargione et al. (2008)
Abandoned cropland	Corn ethanol	48	Fargione et al. (2008)
Mix of forest and grassland	Corn ethanol	167	Searchinger et al. (2008)
Mix of forest and grassland	Corn ethanol	14	EPA (2010e)
Cropland	SWG[a] ethanol	52	Searchinger et al. (2008)
Mix of forest and grassland	SWG ethanol	1	EPA (2010e)
Forest	Soy biodiesel	179–481	RFA (2008)
Grassland	Soy biodiesel	14–96	RFA (2008)
Mix of forest and grassland	Soy biodiesel	9	EPA (2010e)

[a] SWG = switchgrass

Although ultimately a biopower project based on a dedicated feed or existing forests may become GHG-neutral, operational time is involved in doing so. The recent Manomet study by Walker et al. (MCCS 2010) has estimated times for biopower projects using existing forest biomass in Massachusetts to recover the initial carbon debt through forest regrowth and to have net negative GHG emissions relative to fossil energy alternatives. These times range from 5 years for a CHP project replacing fuel oil (CHP has a high overall efficiency compared to power only), to 21 years when replacing coal electric, to more than 90 years when replacing natural gas electric. The Manomet analysis assumes that the existing forest represents sequestered carbon that has to be replaced through regrowth to eventually replace carbon inventory. This can be contrasted with using grassland for a dedicated crop on a closed loop basis where the carbon debt may be as short as one year (EPA 2010b).

The other land use issue is indirect land use change involving existing commercial crops (e.g., corn). Displacing the production of a commercial crop, or using that crop for a different purpose (e.g., fuel versus food) may cause food supplies to decrease and prices to rise, which in turn may lead to increased production of that crop elsewhere to make up for the decreased supply of that crop. This may lead to an indirect carbon debt for the replacement production of the crop. Quantification of the impact is difficult (requiring a general equilibrium model or equivalent of the international agriculture and forestry markets and governmental policies), and results are subject to the base assumptions used in modeling.

The widely varying range of results for indirect land use change points out the complexity of the analyses involved in determining impact. A large number of factors, including carbon debt and carbon sequestration potential of the existing biomass, fertilization for improved use, conversion process efficiency and emissions, etc. These factors and many more need to be put into to detailed integrated assessment models that include uncertainty analysis (to account for different assumptions)to determine the potential range of such impacts. A recent report discussing the topic is given by Cruetzig et al. (2012).

6.6.3.2 Water Use

Biopower is a thermoelectric generating technology and has consumptive water use[24] requirements characteristic of coal power plants. Davis and Tan (2010) estimated average consumptive water use from NETL (2006) on a gallon per kilowatt-hour basis. This estimate is valid for co-firing using existing coal capacity and for dedicated biopower because the majority of consumptive water use in a steam plant is due to evaporative cooling tower water losses and is independent of feed. The average consumptive water use was estimated at 1.741 m^3/MWh (0.46 gal/kWh). For the 330 TWh of generation projected in 2035 (see Table 6-9), the estimated water use is 0.573 billion m^3 (150 billion gallons) in that year, the same as would be required by coal plants. Consumptive water use can be reduced through alternative cooling techniques, primarily by using air cooling. However, this increases capital and operating costs. The transition to combined cycle systems will reduce the cooling water requirement by about two-thirds. Estimating the magnitude of potential changes in capital and operating costs, water consumption, and other factors, across these technologies would clarify the trade-offs of the various options.

The majority of biopower feedstock will come from areas with sufficient rainfall to obviate the need for irrigation and the crops used will be those that generally do not require irrigation, are perennial and minimize soil loss, and require minimal additions of fertilizers. The National Research Council has examined the potential future use of water associated with dedicated crops in areas requiring irrigation (NRC 2008). Applied water can (1) be incorporated into the crops, (2) leave the field through transpiration from plants (evapotranspiration), (3) leave the field through run-off to streams and rivers, or (4) infiltrate to aquifers. Incorporated or evapotranspiration water is considered consumptive water use. Plant evapotranspiration is highly variable with climate and plant. For example, in North Texas (NRC 2008), annual evapotranspiration rates for different agricultural crops range from 580 mm for sorghum to 1,600 mm for alfalfa.

The primary water issues associated with biomass for energy will involve (1) regional changes in consumptive water use due to changes in plant type on existing agricultural land and on marginal lands resulting in changes in evapotranspiration and irrigation requirements (for example, conversion of Conservation Reserve Program lands to active agriculture) and (2) potential changes in water quality resulting from soil tillage and nutrient run-off (sediment, nitrogen, and phosphorus). To minimize impacts, agricultural practices can be optimized in a number of areas, such as irrigation practices, soil erosion prevention, nutrient pollution reduction, and precision agriculture. In addition, crops optimized for fuel versus food may allow the use of plants with improved nitrogen-use efficiency, increased drought/salt resistance, and improved root characteristics that may minimize water use and water quality impacts. Mixed prairie grasses (Tilman, Reich, and Knops 2006; Tilman, Hill, and Lehman 2006) may give improved water and other environmental benefits.

Although consumptive water use for plant growth is much larger than it is for energy production use, plant growth water impacts are regional in nature, while conversion facility water use is local in nature. The impact of both of these consumptive water uses is the subject of other ongoing studies.

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[24] Consumptive water use is the amount of water withdrawn from the source and not returned to the source.

6.6.3.3 Air Emissions

Major emissions of concern from traditional biomass power plants are particulate matter, carbon monoxide,[25] volatile organic compounds,[26] and nitrogen oxides.[27] Biopower releases very little sulfur dioxide or mercury because of the low amount of sulfur or mercury typically found in biomass. The actual type and amount of air emissions depends on several factors, including the type of biomass combusted, the furnace design, and the operating conditions of the plant. Average emissions data for existing wood combustion systems from EPA AP-42 Compilation of Air Pollution Emission Factors (EPA 2009) are given in Table 6-13. AP-42 data represent average emissions data for systems configured to meet allowable permit levels and do not represent best available control technology or maximum achievable control technology values.

Table 6-13. Average Existing Biopower Emissions[a]

Filterable Particulate Matter		PM[b]	PM-10	PM-2.5	PM	PM-10	PM-2.5
			lb/MMBtu			lb/MWh[c]	
Dry wood	No control	0.40	0.36	0.31	6.14	5.53	4.76
	Mechanical collector	0.30	0.27	0.16	4.61	4.14	2.46
Wet wood	No control	0.33	0.29	0.25	5.07	4.45	3.84
	Mechanical collector	0.22	0.20	0.12	3.38	3.07	1.84
All fuels	Electrolyzed gravel bed	0.10	0.074	0.065	1.54	1.14	1.00
Wet scrubber		0.066	0.065	0.065	1.01	1.00	1.00
Fabric filters		0.10	0.074	0.065	1.54	1.14	1.00
Electrostatic precipitator		0.054	0.04	0.035	0.83	0.61	0.54
NO_x[d], SO_2[e], CO[f]		**NO_x**	**SO_2**	**CO**	**NO_x**	**SO_2**	**CO**
Wet wood		0.22	0.025	0.60	3.38	0.38	9.21
Dry wood		0.49	0.025	0.60	7.52	0.38	9.21
TOC[g], VOC[h], CO_2[i]		**TOC**	**VOC**	**CO_2**	**TOC**	**VOC**	**CO_2**
All fuels		0.039	0.017	195	0.60	0.26	2,993

[a] EPA 2009
[b] PM = particulate matter
[c] Estimated using wood EPA National Electric Energy Data System (EPA 2006b) national average heat rate = 15,351 Btu/kWh
[d] NO_x = nitrogen oxides
[e] SO_2 = sulfur dioxide
[f] CO = carbon monoxide
[g] TOC = total organic carbon
[h] VOC = volatile organic compounds
[i] CO_2 = carbon dioxide

[25] Carbon monoxide is a colorless, odorless, and poisonous combustible gas that is produced during the incomplete combustion of carbon and carbon compounds (e.g., fossil fuels such as coal and petroleum); their products (e.g., liquefied petroleum gas, gasoline); and biomass.
[26] A volatile organic compound is any toxic carbon-based (organic) substance (e.g., solvents–paint thinners, lacquer thinner, degreasers, dry cleaning fluids) that easily becomes vapor or gas.
[27] Nitrogen oxides are the products of all combustion processes. They are formed by the combination of nitrogen and oxygen.

6.6.3.3.1 Environmental Regulations

Biopower impacts on air quality are governed under the Clean Air Act (EPA 2010a). The Clean Air Act, P.L. 91-604 (codified generally as 41 U.S.C. 7401-7671), has been in existence for 40 years and last underwent major amendments in 1990 (P.L. 101-549). McCarthy (2005) provides an extensive review of the Clean Air Act. The Clean Air Act sets national standards for air quality and assigns primary responsibility for compliance implementation through state implementation programs. The act establishes standards for hazardous air pollutants, for emissions causing acid rain, and for mobile emission sources, and it establishes specific standards for "non-compliance areas" not meeting national standards. Hazardous air pollutant emissions are governed by P.L. 101-549, Section 112, which set maximum achievable control technology standards for 188 pollutants. P.L. 101-549, Section 129, also set acid rain standards for electric generating facilities larger than 75 MW.

P.L. 101-549 established Title V, which requires states to administer permit programs for new or modified major stationary sources emitting air pollutants in excess of 100 tons/yr of any regulated pollutant (more stringent in non-attainments areas). Such sources are required to submit compliance plans as part of the permitting process. The Clean Air Act also limits permits to a maximum of five years.

6.6.3.3.2 New and Proposed Regulations

Two regulations—one new and one proposed—might have substantial impact on existing and future biopower facilities. The first is the "Tailoring Rule," enacted May 13, 2010, as an amendment to the Clean Air Act (EPA 2010c). This rule requires prevention of significant deterioration permitting for new facilities emitting more than 100,000 tonnes/yr of CO_2 equivalents and for new or modified facilities already subject to prevention of significant deterioration emitting 75,000 tonnes/yr. Initially, GHGs are to be measured and reported as part of the permitting and annual emissions reporting process. Best available control technology will be published later. The rule includes biopower facilities but also states that EPA is reviewing the potential inclusion of biopower as a best available control technology and is considering evaluating biopower differently under prevention of significant deterioration; guidance on this is still pending.

The second regulation is the proposed updated National Emissions Standards for Hazardous Air Pollutants maximum achievable control technology (EPA 2010d) that imposes new maximum achievable control technology permitting and continuous emissions monitoring and reporting requirements for industrial, commercial, and institutional boilers emitting greater than 10 tonnes/yr of any hazardous air pollutant and/or greater than 25 tonnes/yr of total hazardous air pollutants. The proposed rule will require permitting of existing and new facilities, along with compliance monitoring, and potential modification to attain compliance. Solid waste boilers are not covered. The hazardous air pollutants included and the proposed maximum achievable control technology limits are given in Table 6-14.

Table 6-14. Proposed Air Toxics Maximum Achievable Control Technology Standards for Biopower Facilities[a]

Pollutant	Stoker Boilers		Fluid Bed Boilers	
	Existing	New	Existing	New
Particulate matter (lb/MMBtu)	0.02	0.008	0.02	0.008
Hydrogen chloride (lb/MMBtu)	0.006	0.004	0.006	0.004
Mercury (lb/MMBtu)	0.0000009	0.0000002	0.0000009	0.0000002
Carbon monoxide[b] (ppm)	560	560	250	40
Dioxins (ng/dscm)[c]	0.004	0.00005	0.02	0.007

[a] Source: EPA 2010d
[b] at 3% oxygen
[c] ng/dscm = nanograms per dry standard cubic meter

6.6.3.4 Life Cycle Greenhouse Gas Emissions

Life cycle GHG emissions estimated for biopower generation are a result of the use of biomass production inputs (e.g., chemicals, irrigation), transportation, and facility construction and decommissioning. An important assumption of the ReEDS model is that carbon dioxide emissions from biopower generation equal the carbon dioxide absorption during biofeedstock growth, and thus "net" to zero.. Based on this approach, dedicated biopower life cycle GHG emissions per kilowatt-hour generated are estimated at 38.0 g CO_2e/kWh. GHG emissions from biomass/coal co-firing are estimated as a weighted average of dedicated biopower and coal based on the amount of input energy of biomass used (i.e., 15%). Volume 1, Appendix C, further describes the process by which these estimates were developed and how total GHG emissions for RE Futures scenarios were estimated. Life cycle GHG emissions for other technologies are summarized in Volume 1 and reported in detail in Appendix C.

6.6.4 Manufacturing and Deployment Challenges

No manufacturing challenges are associated with additional implementation of biopower combustion and co-firing technologies in the United States. The technologies are based on existing commercial technologies; they employ standard power plant processes; and they require no special or exotic materials of construction other than those required for existing commercial equipment (e.g., specialty materials for gas turbines). Advanced biomass gasification combined cycle technologies are not fully commercial, and they will require further commercial replication. A primary challenge in development of such systems is the lack of available demonstration gas turbines for low- and medium-Btu gases in the size range needed for first-generation biopower systems. Gas cleanup requires additional demonstration to maximize efficiency. There has only been one IGCC demonstration in Europe based on dedicated biomass gasification, and gas cleanup was shown to be sufficient. Coal/biomass IGCC at the NUON plant in Buggenum, the Netherlands, and the Elcogas IGGC in Puertollano, Spain, have demonstrated hot gas cleanup at commercial scale. Most biomass hot gas cleanup development is for fuels applications, which has a different set of issues relating to tars and light hydrocarbons removal. At small scale (i.e., less than 10 MW), hot gas cleanup has been commercially demonstrated for internal combustion engine power applications.

6.6.4.1 Manufacturing and Materials Requirements

No unique or special manufacturing requirements are associated with large-scale deployment of biopower technologies. The major system components—feed handling and preparation, boiler, pressure vessels, prime mover (e.g., steam turbine generator), emissions control, cooling tower, and balance of plant—are primarily made of metal, most of which are various types of steel. Cast irons and nickel base alloys are also used. Ceramics, refractories, coatings, and engineered combinations are used in certain applications.

6.6.4.2 Deployment and Investment Challenges

Combustion and co-firing technologies are commercial with low cost uncertainties. Deployment will be site-specific, with the largest uncertainty centered on feed availability and cost. Projects will require resource assessments and long-term feed contracts to satisfy financial requirements.

6.6.4.3 Human Resources Requirements

Biopower jobs include farming, other feedstock production, biorefinery processing, project development, manufacturing, operations, and other jobs similar to coal power plant work. Labor requirements are regional, type-specific, and site-specific. There is no standardized method of estimating current or future personnel requirements for renewable energy technologies. However, according to a 2007 study, the labor requirements for biomass power plants can range from 1 MW to 2 MW per worker (McGowin 2007). Co-firing plants may be on the upper end of this range, with most of the labor associated with feed handling operations. Potential investments and jobs impacts based on RE Futures' higher renewable electricity cost-estimated capacities are shown in Table 6-15.

Table 6-15. Potential Investments and Jobs for Dedicated Biopower and Co-Firing in the Electric Power Sector

	2009		2022		2035		2050	
	Co-firing	Dedicated	Co-firing	Dedicated	Co-firing	Dedicated	Co-firing	Dedicated
Total Capacity (GW)	0.5	0.2	15.3	15.3	28.2	28.2	18.4	69.4
Investment ($ billion)	0.5	0.8	15.3	57.4	28.2	105.8	18.4	260.3
Direct Jobs	250	200	7,650	15,300	14,100	28,200	9,200	69,400
Total Jobs	1,250	1,000	38,250	76,500	70,500	141,000	46,000	347,000

Co-firing capital expenditure = $1,000/kW, average dedicated capital expenditure = $3,750/kW
Co-firing direct jobs = 0.5/MW, Dedicated direct jobs = 1/MW
Total jobs multiplier = 5 (Perez-Verdin et al. 2008)

6.7 Barriers to High Penetration and Representative Responses

The DOE Biomass Program convened a stakeholder workshop in December 2009 (DOE/EERE 2010) to develop a strategy for future biopower development covering feed pretreatment and conversion technologies, large-scale systems, small-scale systems, feed supply, and market transformation. For each area, barriers and challenges were identified, and strategies to address them were proposed. The primary challenges for the biopower industry in each of these areas are summarized in the following sections.

6.7.1 Pretreatment and Conversion

There is a need for pilot projects of sufficient scale to provide confidence in commercial scale-up of developing pretreatment technologies. A lack of online sampling tools and analysis limits better understanding of technology performance. The removal of non-ferrous metals from fuel particles is also a barrier to improving the quality and consistency of the fuel. A better understanding of torrefaction is needed to determine technology status and commercial viability, particularly cost-effectiveness. Torrefaction is at the pioneer commercialization stage, and no large-scale commercial facilities exist. Torrefaction of biomass involves mild pyrolysis at temperatures below 300°C. Torrefaction is normally practiced as an energy densification process producing a material that has much of the free water removed and has a higher fixed carbon content. The product is hydrophobic, thus improving storage stability. Grinding tests of torrefied material have indicated much lower power requirements relative to untreated biomass. In general terms, torrefaction results in a product that contains 70% by mass of the original biomass and 90% of the original energy content (Bergman 2005), resulting in a material with approximately 1.3 times the energy density (MJ/kg) of the original biomass. The bulk energy density of torrefied pellets is approximately 1.75 times that of wood pellets (e.g.,18.4 GJ/m^3 for torrefied pellets and 10.5 GJ/m^3 for wood pellets). Torrefied material is also more friable than wood, and estimated reduction in its grinding power consumption varies from 70% to 90%.

The primary application of torrefaction as a biomass pretreatment step will be to produce a material that may allow combined feed co-firing at levels similar to the 15% separate feed level used in RE Futures but with capital costs associated with cofeed systems. Life cycle assessment is also needed to determine the value and future prospects of each pretreatment and conversion technology in relation to biopower applications.

6.7.2 Large-Scale Systems

Feedstock supply and sourcing, particularly the stability and maturity of fuel sourcing, present significant challenges. The lack of uniform, well-characterized feedstocks creates risk—how these fuels will perform and ultimately affect boiler and other system operations is not well understood. One key concern is the ability to convert biomass to a form that is most cost-effective and reliable for use in retrofit power plants with minimal impact on system integrity (e.g., corrosion). The ability to successfully scale technologies from pilot to large scale (e.g., achieving the same performance and reliability of equipment at larger scales) presents another challenge.

6.7.3 Smaller-Scale Systems

The most critical barrier to enabling high penetration of small-scale biopower CHP systems is the difficulty of finding users for cogenerated heat in close proximity to the source. Although gasification has significant potential, new scalable designs will be needed to integrate with the unique requirements of small-scale power. Another priority challenge is the need for cost-effective air emission controls, particularly for new systems (e.g., gasification). The high cost of pollution abatement and controls required to meet increasingly stringent (and potentially uncertain) standards makes it difficult to justify investment in small-scale power. The lack of continuously operating demonstration plants for new technologies in the United States, especially for smaller-scale systems, increases the technical risk of new systems.

6.7.4 Feedstocks for Biopower

Measuring the environmental and sustainable aspects of biopower both qualitatively and quantitatively is an important challenge for expansion of the biopower industry. A variety of studies to evaluate feedstocks, current land use, water requirements, soil types, growing regions, and other parameters would help clarify these potential environmental impacts. Feedstock movement, storage, and quality present other key challenges. Significant improvements in the way feedstock is grown, harvested, collected, and stored will be important for long-term sustainability.

6.7.5 Market and Regulatory Barriers

Widespread deployment of biopower faces market barriers at the local, state, and federal levels. Chief among these are high capital and operating costs for early-generation systems, uncertainty in feedstock cost and supply, varying policies and incentives, inconsistent or inadequate codes and standards, high investment risks, and lack of understanding of the performance and benefits of biopower and sustainable biomass feedstock supply in real-world operations.Table 6-16 describes some of the R&D that could help overcome these barriers and enable high penetration of biopower technologies.

Table 6-16. Barriers to High Penetration of Biopower Technologies and Representative Responses

R&D	Barrier	Representative Responses
Co-firing	Limitations in the percentage of biomass that can be use in fuel-blending co-firing	Demonstrate use of torrefied biomass to reduce pulverizer limitations related to increased power consumption and changes in coal particle size distribution in fuel blending co-firing
Gasification	Lack of commercial systems	Demonstrate biomass integrated gasification combined cycle systems at scale sufficient to develop commercial guarantees and warranties
Market and Regulatory	**Barrier**	**Representative Responses**
Resource potential	Lack of resource supply curves for “out” years	Develop and publish detailed (county-level) resource supply curves for the United States
Resource competition	Alternative uses for a limited resource	Develop integrated resource, electricity sector, and fuel sector models for evaluation of future market alternatives
Environmental and Siting	**Barrier**	**Representative Responses**
Water use	Water availability	Develop optimized systems minimizing water requirements for thermo-conversion processes
Sustainability and life cycle	Lack of consistent models	Develop integrated land use and conversion models with a standard protocol acceptable to regulatory agencies that is available for general stakeholder use

6.7.6 Siting and Environmental Barriers

Biopower faces the same challenges associated with building new power facilities as other systems. These challenges are normally addressed in the permitting process, which addresses the local impacts of construction and operations and infrastructure, such as transmission lines. As for other types of thermal power plants, biopower plants impact water supplies through the need for cooling, impacts on the local environment, and impacts to the natural landscape, and must also meet local residents’ concerns about siting. Biopower plants involve combustion and emissions, as shown previously, that impact siting, especially in non-attainment areas such as the Central Valley in California. Regulations apply to construction and address issues such as air quality, biota, cultural uses, land use, and special land and water designations (NAS 2010). In addition, one issue with co-firing is whether the coal facility must be re-permitted to allow biomass to be used in an existing plant.

Other than the known air and water quality environmental issues associated with permitting and operation of biopower plants, the primary environmental issues that must be addressed for biopower are overall sustainability and land use change impacts. These issues are the same as those associated with biofuels processes, and biopower will likely be subject to the same U.S. EPA reporting requirements (EPA 2010c).

6.8 Conclusions

Biopower, the third largest form of renewable electricity generation after hydropower and wind energy, is a mature source of renewable power, with costs on par with conventional fossil energy plants. Electricity produced from biomass is used as base-load or dispatchable power in the existing electric power sector and in industrial cogeneration. Potential biopower resources—wood wastes, mill residues, forest residues, agricultural residues, and dedicated herbaceous and woody energy crops—are widely distributed throughout much of the United States, with the midwestern states possessing the most abundant supply. These three factors resulted in biopower played a significant role in all of the RE Futures scenarios evaluated.

Biopower system technologies include direct firing fired combustion, co-firing, gasification, pyrolysis, landfill gas generators, and anaerobic digestion generators. RE Futures investigated opportunities for additional technology improvements that can lead to reduced cost, focusing on increasing system efficiencies by combining direct combustion technologies with gasification technologies to produce a dynamic mixed fleet that gradually includes more gasification technologies.

The most important issue for large-scale deployment of biopower is feedstock competition with lignocellulosic biofuels and other uses for wood. In addition to the known air and water quality environmental issues associated with permitting and operation of biopower plants, the primary environmental issues that must be addressed for biopower are overall sustainability and land use change impacts resulting from growing dedicated biomass feedstocks to support large-scale deployment of biopower technologies. Proactive strategies to reduce capital and operating costs for early-generation systems, reduce uncertainty in feedstock cost and supply, standardize policies and incentives, and improve and standardize codes and standards are needed to maximize biopower's contribution to a high-renewable electricity future.

6.9 References

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Chapter 7. Geothermal Energy Technologies

7.1 Introduction

The geothermal resource base is comprised of thermal energy stored in rock and fluids in the Earth's crust. The amount of electricity that can be generated from this thermal energy depends on its temperature, with higher temperature resources having a higher electricity-producing potential. The geothermal resource forms a continuum, with the best resources having high temperatures, large amounts of in situ fluids, and high reservoir permeability. The geothermal energy technology employed to recover the subsurface thermal energy varies depending on the nature of the resource. For RE Futures, geothermal resources were categorized based on the technology and methods used to develop the resource as described in Table 7-1.

Of the geothermal technologies listed in Table 7-1, hydrothermal is the only electricity producing technology broadly deployed on a commercial scale in the United States. Hydrothermal energy has provided renewable and reliable options for base-load electrical power for five decades. Historical growth of the hydrothermal industry is shown in Figure 7-1.

Table 7-1. Descriptions of Geothermal Resources, Technologies, and Methods Used

Resource	Description	Notes
Hydrothermal	Conventional, commercially available geothermal technology; hydrothermal reservoirs have sufficient naturally occurring thermal energy, in situ water, and permeability for development of geothermal electricity, typically at economically competitive costs	Hydrothermal resources are responsible for the majority of the geothermal electricity capacity in operation today. Hydrothermal resources are localized geologic anomalies that require site-specific characterization.
Enhanced Geothermal Systems	Resources with a large amount of thermal energy but lacking sufficient in situ water, permeability, or both, so that the reservoir must be engineered to extract the thermal energy	EGS resources are divided into (1) near-hydrothermal field EGS resources, located near conventional hydrothermal fields and (2) deep EGS resources, which in theory can be developed anywhere by drilling deep enough to access a high-temperature reservoir. Because EGS systems are still primarily in demonstration, they were not included in the RE Futures geothermal supply curve.
Co-Production from Oil and Gas Wells	Electricity generated from geothermal energy contained in fluids co-produced with oil and gas (or from abandoned oil and gas wells) using binary (organic Rankine cycle) power plants	Due to the geographically distributed nature of oil and gas wells, co-production systems are expected to consist of small (<1 MW_e), modular units. Because information for co-produced resource availability and cost information are limited, these resources were not included in the RE Futures geothermal supply curve.

Resource	Description	Notes
Geopressured	Highly pressurized shale and sandstone formations that contain high-temperature brine with dissolved methane; energy potential includes both thermal energy and methane stored in reservoirs	The best geopressured reservoirs are generally located along the Texas and Louisiana Gulf Coast. Because information for geopressured resource availability and cost information are limited, these resources were not included in the RE Futures geothermal supply curve.
Direct Use	Applications that use thermal energy from hydrothermal reservoirs directly rather than converting it to electrical energy; this includes space heating and cooling as well as other heating applications such as greenhouse operations, aquaculture, and recreation	Because direct-use applications do not produce electricity, they were not considered in the RE Futures geothermal supply curve. However, these applications may be useful for reducing thermal loads in buildings and other applications, as noted.
Geothermal/Ground Source Heat Pumps	Use the relatively constant temperature of the Earth near the surface as a heat source for heating and heat sink for cooling commercial and residential buildings; a widespread resource that can be used almost anywhere	Geothermal/ground source heat pumps do not produce electricity. Due to their high efficiency, they can significantly reduce energy requirements for heating and cooling. Because they do not produce electricity, they were not considered in RE Futures geothermal supply curve.

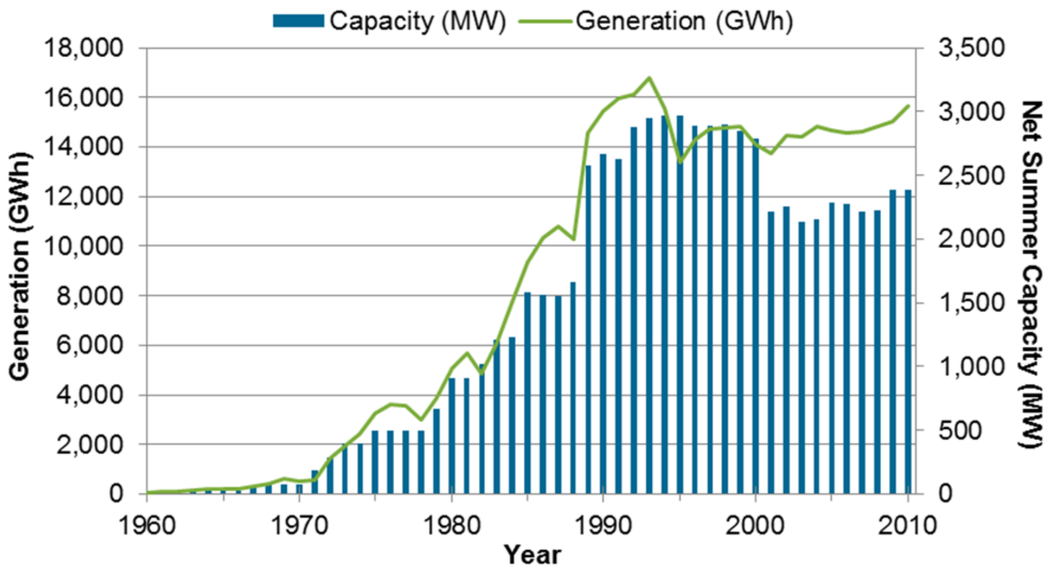

Figure 7-1. Electricity capacity and generation of geothermal energy technologies in the United States, 1960–2010

Source: EIA Annual Energy Review 2010

> The decrease in generation starting in the early 1990s was due to a rapid decline in production from the Geysers field in California. This decline actually began in 1987, but the impact was masked by the installation of additional capacity in other locations. Generation from the Geysers was stabilized by 1996 (Sanyal and Enedy 2011). The sudden decrease in capacity in 2001 was due to a revision of the definition of net summer capacity by EIA. Generation and capacity additions have leveled off in recent years.

Measures of current installed geothermal capacity differ depending on whether the nameplate or net power capacity of the power plant is reported. Nameplate capacity is based on the generating capacity stated on the turbines and generators in the power plant, while net power capacity accounts for parasitic losses to equipment required to run the plant, such as injection and production well pumps and seasonal variation in output. EIA adopted the net summer capacity in 2001 to measure installed plant capacity; the effect it had on the total installed geothermal capacity they report can be seen in Figure 7-1.

According to EIA (2011), the net summer electrical generation capacity of geothermal in the United States is 2.4 GW_e. The Geothermal Energy Association typically reports nameplate capacity, and reports installed capacity of 3.1 GW_e (Jennejohn 2011). Currently installed nameplate and planned capacity by state is shown in Figure 7-2.

Other than the U.S. DOE-funded oil and gas co-production demonstration site at the Rocky Mountain Oilfield Testing Center in Wyoming (0.25 MWe capacity), the entire installed capacity in the United States is comprised of conventional hydrothermal plants. Almost all planned capacity is also made up of hydrothermal projects. There are two co-production demonstration plants and two geopressured demonstration plants funded by the DOE Geothermal Technologies Program in the planning stages (GTP Projects n.d.). There are no commercial EGS sites currently operating in the United States, but DOE-sponsored EGS demonstration projects have been funded at seven locations and are in various stages of development (GTP Projects n.d.). While most of these demonstration projects are at or near existing commercial hydrothermal sites, two projects (in Newberry, Oregon, and Naknek, Alaska) are at locations that currently have no existing geothermal electricity generating capacity. Both direct-use systems and geothermal heat pumps are widely installed throughout the United States, but because the focus of RE Futures is on electricity, they are not discussed further but they were included in Table 7-1 for completeness.

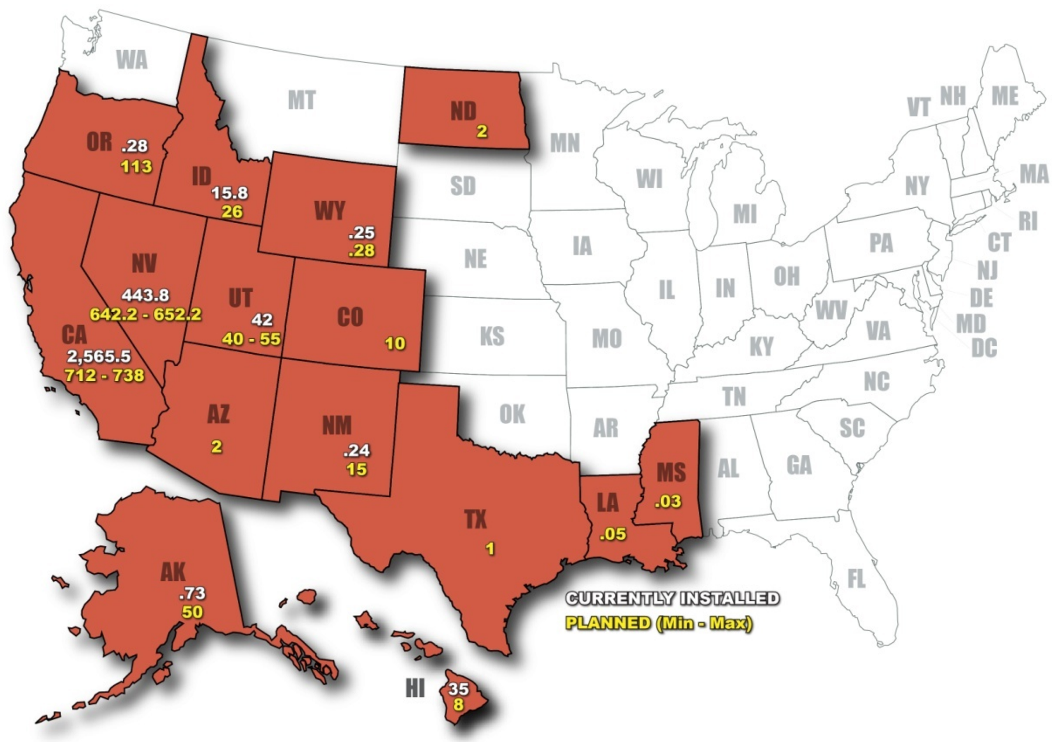

Figure 7-2. Map of current and planned nameplate geothermal capacity (in MW$_e$) in the United States

Data are from the Geothermal Energy Association (Jennejohn 2011) and descriptions of projects funded by the American Recovery and Reinvestment Act (GTP Projects n.d.). Planned capacity additions include projects in Phases 1–4 (as discussed in Jennejohn 2011) of development and unconfirmed projects. Total installed nameplate capacity is 3,104 MW$_e$, and total planned capacity addition range is 1,622–1,673 MW$_e$. Installed geothermal capacity is currently concentrated in California and Nevada. Planned capacity additions show that geothermal technologies are extending their reach to a larger number of states.

7.2 Resource Availability Estimates

Resource availability estimates based on available data were made for the electricity generating technologies listed in Table 7-1. The hydrothermal resource availability was adopted from the recent USGS geothermal resource assessment quantifying potential capacity for both identified and undiscovered hydrothermal resources (Williams et al. 2008). According to the assessment, the power generation potential from identified geothermal systems on private or accessible public lands (systems on closed public lands such as national parks were excluded) has a mean value of 9,057 MW_e. Removing the currently installed hydrothermal capacity in the United States from this data [assuming net summer capacity (GEA n.d.; EIA 2009)], and removing sites with reservoir temperatures less than 110°C, considered to be too low for cost-effective electricity production, leaves a remaining mean potential capacity for identified hydrothermal sites in the United States of 6,394 MW_e. This value was used in the RE Futures modeling analysis. USGS estimated the undiscovered resource using statistical methods based on geographic information systems to analyze the correlation between spatial data sets and existing geothermal resources to derive the probability of the existence of geothermal resources in unexplored regions. The undiscovered geothermal resource power generation potential from Williams et al. (2008) has a mean value of 30,033 MW_e, with a 95% probability of at least 7,917 MW_e, and a 5% probability of up to 73,286 MW_e. The mean value of 30,033 MW_e was used for RE Futures. The actual attributes of the undiscovered resources, such as reservoir depth and temperature, were estimated based on power capacity-weighted values of the identified resource in the region on a state-by-state basis as described in Augustine et al. (2010).

The EGS resource estimate was split into two categories: the near-hydrothermal field resource and the deep EGS resource. The near-hydrothermal field EGS resource consists of areas near hydrothermal fields that have sufficiently high temperatures to produce electricity but lack adequate permeability, in situ fluids, or both, and require the application of EGS reservoir engineering techniques to be developed for power production. Because they are hot and relatively shallow, they are likely to be the least expensive and first types of EGS resources commercially developed in the United States. A formal assessment of this resource has not yet been completed. However, a rough estimate of the near-hydrothermal field EGS resource has been derived for each *identified* hydrothermal site in the USGS geothermal assessment (Williams et al. 2008), and it resulted in 7,031 MW_e of available resource. This estimate was based on the difference between the 5% probability and the mean values of the power generation potential, and it assumed that the difference between the mean and high-end estimates of the electricity-generating potential capacity for each site could be bridged using EGS techniques. As with hydrothermal, identified sites with reservoir temperatures lower than 110°C were not considered due to expected prohibitively high development costs. The near-hydrothermal field EGS resource potential of the undiscovered hydrothermal resource was not considered.

The deep EGS resource estimate was also adopted from the USGS geothermal resource assessment by Williams et al. (2008). This assessment, which was limited to the western United States at depths of 3–6 km, estimated deep EGS resource potential with a mean value of 518 GW_e.

Because EGS systems are still primarily in demonstration and are not available commercially, neither the near-hydrothermal field EGS potential nor the deep EGS potential were included in any RE Futures scenarios.

USGS assessed the geopressured resource potential in USGS Circular 726 (Papadopulos et al. 1975) and updated it in USGS Circular 790 (Wallace et al. 1979). The assessments were limited to areas along the Gulf Coast of Texas and Louisiana, where the most promising geopressured resources are located. In Circular 726, recoverable energy estimates of the onshore resource were made for three resource development plans to provide a bounded, order-of-magnitude assessment of the resource. The basic plan, referred to as Plan 1 in the assessment, limited the wellhead pressure to a minimum of 2,000 lb/in^2 (14 MPa). In Plan 2, the reservoir pressure was completely depleted, while in Plan 3 reservoir pressure decline was limited to reduce the risk of subsidence. From the thermal energy recovery estimates alone, electrical power potential was 122 GW_e under Plan 1, and ranged from 191 GW_e under Plan 2 to as low as 28 GW_e under Plan 3. Circular 790 updated the Circular 726 resource assessment and extended it to include offshore areas in the Gulf Coast, but only considered Plans 2 and 3. The electricity producible from the recoverable thermal energy estimates ranged from 23 GW_e under Plan 3 to 240 GW_e under Plan 2. The assessments also quantified significant amounts of dissolved natural gas that would be produced along with the brine from the formation. Both assessments noted a lack of detailed data on the geopressured formations, and that additional, more reliable data are required to make a better approximation of the recoverable geopressured resource. Because of this, the geopressured potential was not included in RE Futures.

A thorough estimate of the geothermal electricity co-production from oil and gas resource has not been completed. The potential for the co-production resource is based on the 25 billion barrels of water produced during oil and gas extraction annually (Curtice and Dalrymple 2004). However, a detailed analysis of the temperature and thermal energy content of this co-produced water is required to assess its electricity production potential. In *The Future of Geothermal Energy,* MIT (2006) calculated the hypothetical power generation potential by assuming that the entire bulk of produced water was at a single temperature. The assumed temperature used in the calculations ranged from 100^{o}C to 180^{o}C, and the corresponding electricity generation potentials ranged from 4.5 GW_e to 22 GW, respectively. However, it must be noted that these assumptions are optimistic because it is unlikely that these temperatures would be found at all oil and gas wells, and the actual co-production resource potential is likely lower than even the lower part of this range. Without actual temperature data, a reliable estimate of the co-production potential cannot be made, and it therefore was not included in RE Futures. A summary of the geothermal resource availability estimates is given in Table 7-2.

Table 7-2. Summary of Geothermal Resource Availability Estimates

Resource		Remaining Resource Potential Capacity (GW_e)	Data Source	Included in RE Futures Scenarios?
Hydrothermal	Identified hydrothermal sites	6.4	USGS 2008 geothermal resource assessment (Williams et al. 2008)	Yes, all scenarios
	Undiscovered hydrothermal	30.0	USGS 2008 geothermal resource assessment (Williams et al. 2008)	Yes, all scenarios
EGS	Near-hydrothermal field EGS	7.0	Augustine et al. (2010), based on USGS data (Williams et al. 2008)	No
	Deep EGS	518[a]	USGS (Williams et al. 2008)	No
Geopressured		28–191[b] 23–240[b]	Papadopulos et al. (1975) Wallace et al. (1979)	No
Co-Production from Oil and Gas		N/A	Thorough resource availability estimate not available	No

[a] Limited to 11 western U.S. states (AZ, CA, CO, ID, MT, NM, NV, OR, UT, WA, WY) and depths of 3–6 km

[b] Electrical potential from thermal energy only; does not include natural gas potential

7.3 Technology Characterization

7.3.1 Technology Overview

Hydrothermal technologies are well developed. Commercial plants have been operating in the United States for 5 decades. To access the geothermal resource, wells are drilled into the geothermal reservoir. Most hydrothermal plants use geothermal fluids found at depths of less than 2 km. High-temperature steam or pressurized water is produced from the wells and used to operate a power plant typically 10–100 MW in size. The specific power plant technology used depends on the physical state (e.g., steam or liquid) of the produced fluid and on its temperature (GTP 2009). In a binary power plant, pressurized liquid geofluids are used to vaporize a working fluid, such as isobutane, in a closed-loop Rankine cycle (see Figure 7-3). Binary power plants are used for geothermal resources with temperatures of approximately 150–200°C (300–400°F) or less, and are the most commonly installed type of plant on a per-unit basis. Higher temperature resources use either (1) flash plants, in which pressurized liquid is quickly brought to a lower pressure to produce steam that is then used to drive a turbine or (2) dry steam plants, in which dry steam produced directly from the reservoir is used to drive a turbine. Some plants use a combination of flash and binary power plant technologies to maximize efficiency. Hydrothermal plants use either water-cooled or air-cooled condensers.

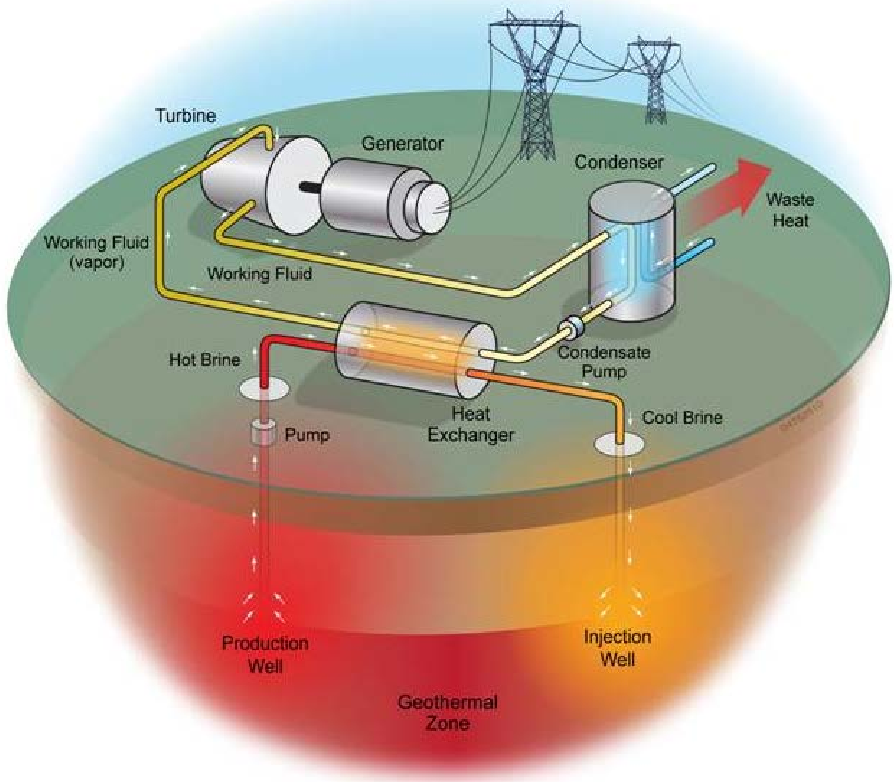

Figure 7-3. Schematic of a hydrothermal binary power plant

EGS technologies are used to develop geothermal resources that lack sufficient in situ fluids, permeability, or both, to be developed using conventional hydrothermal technologies. EGS (see Figure 7-4) are geothermal systems created by using technologies adapted from the oil and gas industry to drill into formations of hot rock, hydraulically stimulate the formation to open and extend fractures, intersect the fractures with one or more additional drilled holes, and then circulate fluid through the fractures. Injected fluid is heated by the hot rock as it circulates through the reservoir, is brought to the surface, and is then used to produce electricity using a power plant before being re-injected into the reservoir, forming a closed-loop system.

Many of the technologies required for EGS, such as drilling and power plant technologies, are commercially available and already used in the hydrothermal or oil and gas industry. The ability to create artificial geothermal reservoirs using hydraulic stimulation and manage these reservoirs over their lifetime remain the major technical hurdles. To hydraulically stimulate the reservoir, water is pumped into the reservoir at a sufficient pressure to induce shear fractures in the rock. These fractures are self-propping, so that the fractures remain open when hydraulic stimulation is completed. Unlike hydraulic fracturing operations in the oil and gas industry, special chemicals or proppants are not required. Technical feasibility of EGS concepts were first demonstrated at Fenton Hill in New Mexico in the late 1970s (MIT 2006, p. 4–5); however, the technology remains commercially immature. Key performance issues that must be addressed to enable commercialization of the technology include creating an artificial reservoir of adequate size that significant thermal drawdown does not occur over the lifetime of the reservoir, achieving adequate interwell connectivity to reduce pressure losses in the reservoir, and preventing or repairing fluid circulation short circuits in the reservoir (MIT 2006). Demonstration projects are currently under way in the United States, Europe, and Australia. Because EGS technology is not significantly commercial at this time, it was not included in the core RE Futures scenarios.

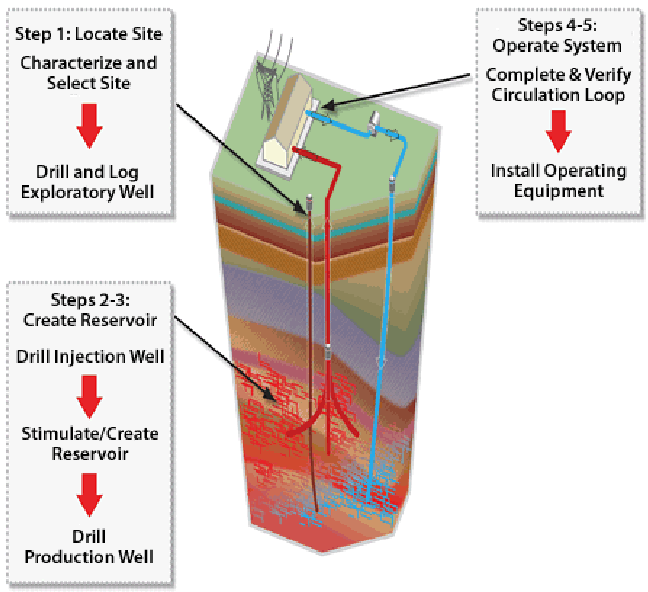

Figure 7-4. Schematic of an enhanced geothermal system

Source: DOE (http://www1.eere.energy.gov/geothermal/enhanced_systems.html)

Because of the nature of the geothermal resource continuum, distinguishing the boundaries between geothermal technologies is sometimes difficult. For example, re-injecting the geofluid into the field to maintain reservoir pressure is now common practice at hydrothermal power plants. At The Geysers complex of geothermal power plants in California, additional fluid from wastewater treatment plants is being successfully injected into the reservoir to sustain and potentially increase reservoir pressure and well productivity. Some in the geothermal industry consider these efforts EGS technologies. For the purposes of RE Futures, such practices currently employed at hydrothermal sites were considered hydrothermal technology.

Co-production systems are another emerging geothermal technology. Co-production systems use binary power plants to generate electricity from hot water that is "co-produced" during the extraction of oil and gas. Closely related are geopressured geothermal systems, which operate under the same principle but use wells drilled into naturally pressurized sedimentary reservoirs in which natural gas is dissolved in a high-temperature brine.[28] Although neither technology has

[28] Brine is a geothermal solution containing appreciable amounts of sodium chloride or other mineral salts. Not all geopressured reservoirs are necessarily at high temperatures. In RE Futures, geopressured geothermal brines were defined as hot (greater than 150ºC or 300ºF) pressurized waters that contain dissolved methane and lie at depths of 3 km to more than 6 km below the Earth's surface. The best-known geopressured reservoirs lie along the Gulf Coast in Texas and Louisiana.

been deployed on a commercial scale, both technologies have been successfully demonstrated by DOE-funded projects (Johnson and Walker 2010; Campbell and Hattar 1990) and there are no major technical barriers to either technology system. Because of the distributed nature of the resource, co-produced and geopressured power plants are expected to consist of small, modular units ranging in size from 0.25 MW to 10 MW. These were not included in the RE Futures grid modeling, but represent a significant opportunity.

7.3.2 Technologies Included in RE Futures Scenario Analysis

A broad array of future energy scenarios were considered for RE Futures. As the only geothermal technology already deployed on a large commercial scale, *conventional hydrothermal power was the only geothermal technology included in all RE Futures scenarios*. EGS technologies were considered not to be at a point of commercial maturity to be included in any scenarios. Co-production and geopressured geothermal technologies were not included in any of the RE Futures scenarios due to a lack of detailed resource and system cost estimates from peer-reviewed sources. As these EGS, geopressured, and other technologies advance, they have the potential to significantly increase the contribution of geothermal energy to U.S. and global electricity supplies. The remainder of the chapter, however, only considers hydrothermal technologies.

7.3.3 Technology Cost and Performance

Hydrothermal costs vary widely. In general, the LCOE for hydrothermal projects typically range from \$60/MWh to \$90/MWh but can range from \$40/MWh to \$150/MWh depending on the resource characteristics and project development finance structure (Taylor 2010a).[29] Because project costs for hydrothermal plants that have been developed depend heavily on the site-specific characteristics of the resource, broadly comparing geothermal cost trends over time is difficult. Historically, drilling and power plant development have been the largest cost contributors. Shallow, high-temperature resources tend to be the least expensive because drilling costs, which increase non-linearly with depth (see Figure 7-6), are low, and because a greater amount of electricity can be generated from each unit of geofluid.

The capital costs for geothermal power plant projects are normally broken down by project phase: resource identification (permitting, leasing, surface and non-drilling exploration); drilling (exploration, confirmation, and production well drilling); and power plant construction. The breakdown of overall development costs for a representative hydrothermal flash plant is shown in Table 7-3. Generally, 1%–3% of development costs are incurred during the resource identification phase, with the remaining project costs split between the drilling and plant construction phases. The costs for the drilling and plant construction phases are roughly equal in magnitude with the share of each depending on the resource being developed. The distribution of costs for the components of a geothermal power plant fluctuates depending on features such as the temperature and depth of the resource.

[29] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise.

Table 7-3. Estimated Development Costs for a Typical 50-MW Hydrothermal Flash Power Plant[a]

Developmental Stage	Cost ($/kW installed)	Cost as a Percentage of Total Cost
Exploration	14	0.4%
Permitting	50	1.4%
Exploratory Drilling	169	4.6%
Production Drilling	1,367	37%
Steam Gathering	250	6.9%
Plant and Construction	1,700	47%
Transmission	100	2.7%
Total	3,650	—

[a] Source: Cross and Freeman 2009

A bottom-up cost analysis for hydrothermal systems was performed to determine technology costs and performance characteristics. The analysis is nearly identical to that described in Augustine et al. (2010). Capital costs for the hydrothermal resources described in Section 7.3 were estimated using the Geothermal Electricity Technology Evaluation Model (GETEM) techno-economic model (GTP 2009) (see Text Box 7-1). The geothermal component cost data were based on input and results from the 2009 Geothermal Technologies Program technical risk assessment (Young et al. 2010). For the assessment, a group of industry experts was asked to submit values for an array of geothermal technology components based on their knowledge and expertise. Experts provided both present and future values based on predicted learning and assumed R&D advancements. Table 7-4 shows the component cost data used in the analysis.

Text Box 7-1. GETEM: Geothermal Electricity Technology Evaluation Model

GETEM is a deterministic Microsoft Excel-based, engineering-economic systems analysis tool for estimating the capital costs and LCOE of geothermal projects based on a set of user-specified variables. GETEM is a flexible tool with more than 180 user-defined inputs that can be used to tailor cost estimates to a specific site resource. The user defines the resource characteristics (e.g., hydrothermal or EGS, temperature, depth); project details (e.g., plant type and size, pump types, well productivity); and other required parameters. GETEM then calculates the individual component costs associated with each phase of the project, such as exploration, well field development, power plant construction, and O&M costs based on user-defined cost inputs, embedded cost and system performance correlations, and cost indices to account for the year the project is developed. GETEM provides the total capital costs and a breakdown of capital costs and LCOE contributions from the various project phases. GETEM was developed for the DOE Geothermal Technologies Program by Princeton Energy Resources International (Entigh 2006) in collaboration with researchers at DOE national laboratories and industry consultants to examine the impact of technology improvements and cost reductions on geothermal power costs.

Table 7-4. Cost Component Data for Geothermal Energy Technologies Used in Bottom-Up Cost Analysis[a]

Hydrothermal Technology Component	Units	Value 2008	2015	2025
Non-well exploration costs	$million	1.22	1.18	1.16
Exploration well success rate	%	34.8	37.6	39.8
Well drilling and completion cost[b]	$million	15.6	14.3	13.1
Production pump cost (per well)	$million	1.5	1.5	1.4
Binary system capital cost[c]	$/kW	2,500	2,400	2,271
Binary system O&M cost/year	¢/kWh	2.2	2.1	2.1
Brine effectiveness	W-h/lb_m[d]	9.50	9.63	9.74

[a] Based on expert data from Young et al. 2010

[b] Well drilling and completion costs were based on well depth of 6,000 m (19,685 ft). Drilling costs decreased by 30% from Young et al. 2010 values based on conversations with drilling contractors and changes in Bureau of Labor Statistics drilling cost indices to reflect recent large decreases in drilling costs.

[c] Binary system capital costs were based on costs for a 20-MW_e net output binary power plant designed for a 200°C resource using air-cooling.

[d] Watt-hours per pound (mass) of brine

The cost of a power plant depends mainly on the plant type and the quality (temperature) of the resource but also on the plant size, the type of cooling system used, and additional factors. Additionally, because construction materials (mainly steel and concrete) account for a significant portion of overall plant costs, the cost of a power plant tends to vary with the price of commodities. GETEM considers all these factors, including parasitic production and injection well pumping losses, when determining the cost of a power plant. As a consequence, there is not a simple correlation for GETEM power plant cost estimates. However, a strong correlation exists between resource temperature and plant capital costs. Figure 7-5 shows modeled power plant costs estimated by GETEM for the hydrothermal power plants in RE Futures. The power plant costs estimated by GETEM were adjusted to match expert input from Young et al. (2010).

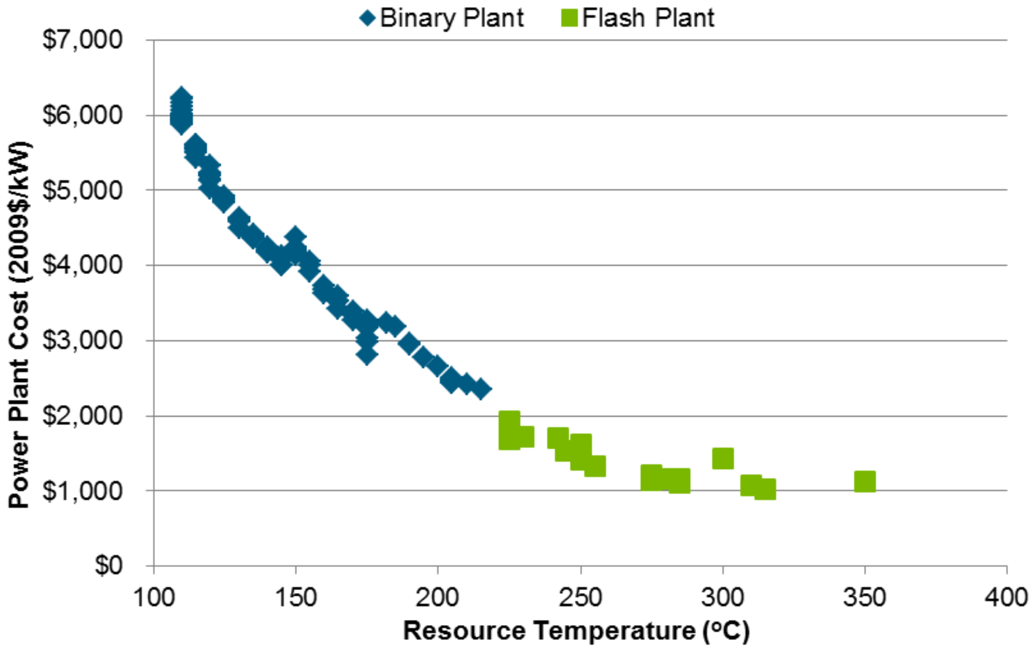

Figure 7-5. Power plant capital costs (2009$/kW) estimated by Geothermal Electricity Technology Evaluation Model and used in RE Futures for hydrothermal power plants

Drilling costs vary significantly with depth, rock type, current cost of rental equipment (rig rental rate), and knowledge of the area being drilled (Taylor 2010a). A single well can cost several million dollars to drill. Drilling costs are strongly affected by crude oil and natural gas prices; when oil prices are high and drilling rigs are in high demand, costs to rent rigs to drill for geothermal energy can increase sharply. Drilling costs are also affected by the cost of the steel and cement required to case and complete the wells, which can fluctuate based on commodity prices or their availability (Augustine et al. 2006). The cost of a single well is difficult to generalize and depends strongly on its design; however, when drilling cost data are viewed in aggregate, costs tend to increase exponentially with depth. GETEM includes three generalized cost curves (low, medium, and high) to estimate well drilling/completion costs as a function of depth. The costs used in RE Futures assumed the medium cost curve in GETEM for 2008 drilling costs, and they were adjusted to match expert input (Young et al. 2010). Figure 7-6 shows the resulting drilling costs as a function of depth used in RE Futures.

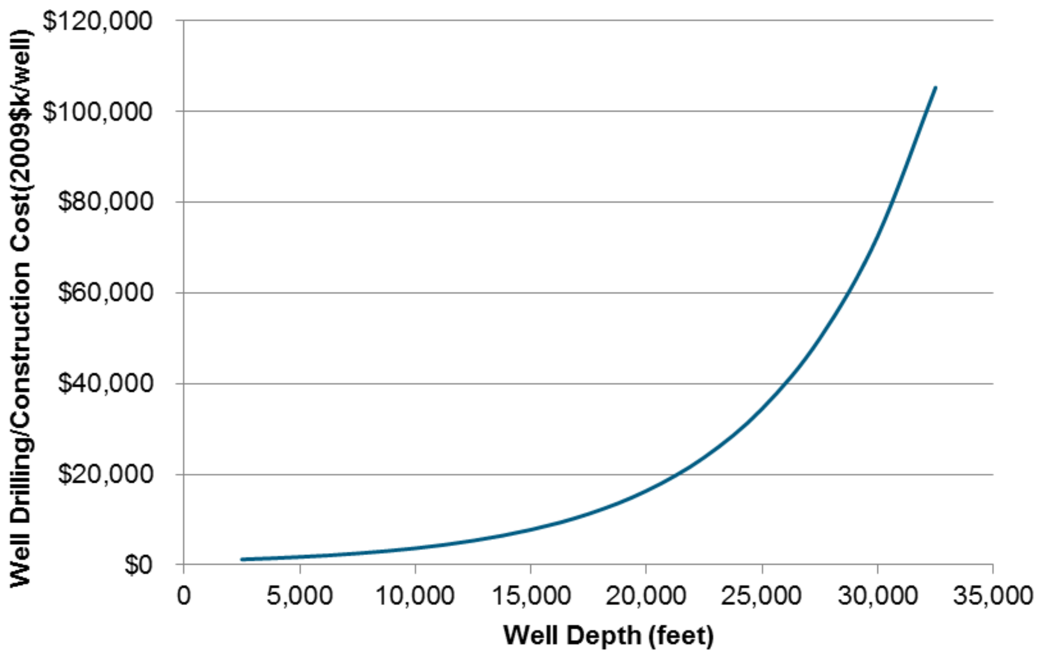

Figure 7-6. Well drilling and completion capital costs (2009$k/well) used in bottom-up cost analysis for geothermal energy projects in RE Futures

Adapted from Entigh 2006, Figure 5.2[30]

O&M costs of $30.69/MWh, which is in line with the sum of the O&M costs recommended by experts during the technical risk assessment for the power plant (Young et al. 2010) and estimated by GETEM for the well field, were adopted for all geothermal plants in RE Futures. For RE Futures modeling, these O&M values were converted to a per-kilowatt basis to represent fixed O&M costs by assuming an annual capacity factor of 85%. For example, $30.69/MWh corresponds to approximately $229/kW-yr.

Future capital cost, performance (generally represented as capacity factor), and operating costs of electricity generating technologies are influenced by a number of uncertain and somewhat unpredictable factors. For this reason, to understand the impact of RE technology cost and performance improvements on the modeled scenarios, two main projections of future RE technology development were evaluated: (1) renewable electricity-evolutionary technology improvement (RE-ETI) and (2) renewable electricity-incremental technology improvement (RE-ITI). In general, RE-ITI estimates reflect only partial achievement of the future technical advancements and cost reductions that may be possible, while the RE-ETI estimates reflect a more complete achievement of that cost-reduction potential considering only evolutionary improvements of commercial technologies. The RE-ITI estimates were developed from the

[30] Drilling costs were based on the medium cost curve in GETEM and updated to reflect 2008 drilling costs and expert input shown in Table 7-5. The medium cost curve for GETEM was developed from a best fit of post-1985 geothermal well cost data using an exponential function. Depth of wells in this data set range from approximately 1.8 km to 3.7 km. Well costs at depths outside this range were determined by extrapolation. For further discussion, see Entigh (July 2006, Section 5.5).

perspective of the full portfolio of generation technologies in the electric sector. Black & Veatch (2012) includes details on the RE-ITI estimates for all (renewable and conventional) generation technologies. RE-ETI estimates represent technical advances currently envisioned through evolutionary improvements associated with continued R&D from the perspective of each renewable electricity generation technology independently. Because the cost and performance of geothermal technologies depend strongly on site-specific conditions, the RE-ITI and RE-ETI estimates rely on the same resource supply curves described above and summarized in Figure 7-7. Differences between the two technology improvement projections are based solely on the degree of capital cost reduction over time as described below. These two renewable energy cost projections were not intended to encompass the full range of possible future renewable technology costs; depending on external market conditions or policy incentives, these anticipated technical advances could be accelerated or achieve greater magnitude than what is assumed here.[31] Cost and performance assumptions used in the modeling analysis for all technologies are tabulated in Appendix A (Volume 1) and Black & Veatch (2012).

Figure 7-7 shows various estimates of capital costs as a function of potential supply for hydrothermal technologies, including estimates from the bottom-up cost analysis presented above (RE-ITI). In general, the reason for the larger resource potential estimated in RE-ITI compared to the other estimates is the exclusion of undiscovered resource in the other estimates. Regional capital cost supply curves were represented in the ReEDS model (see Short et al. 2011). Augustine et al. (2010) include details on the supply curves used in the modeling analysis. Other geothermal technologies with potentially much greater potential supply (e.g., EGS) were not included in any scenarios modeled in RE Futures.

[31] In addition, the cost and performance assumptions used in RE Futures are *not* intended to directly represent U.S. DOE EERE technology program goals or targets.

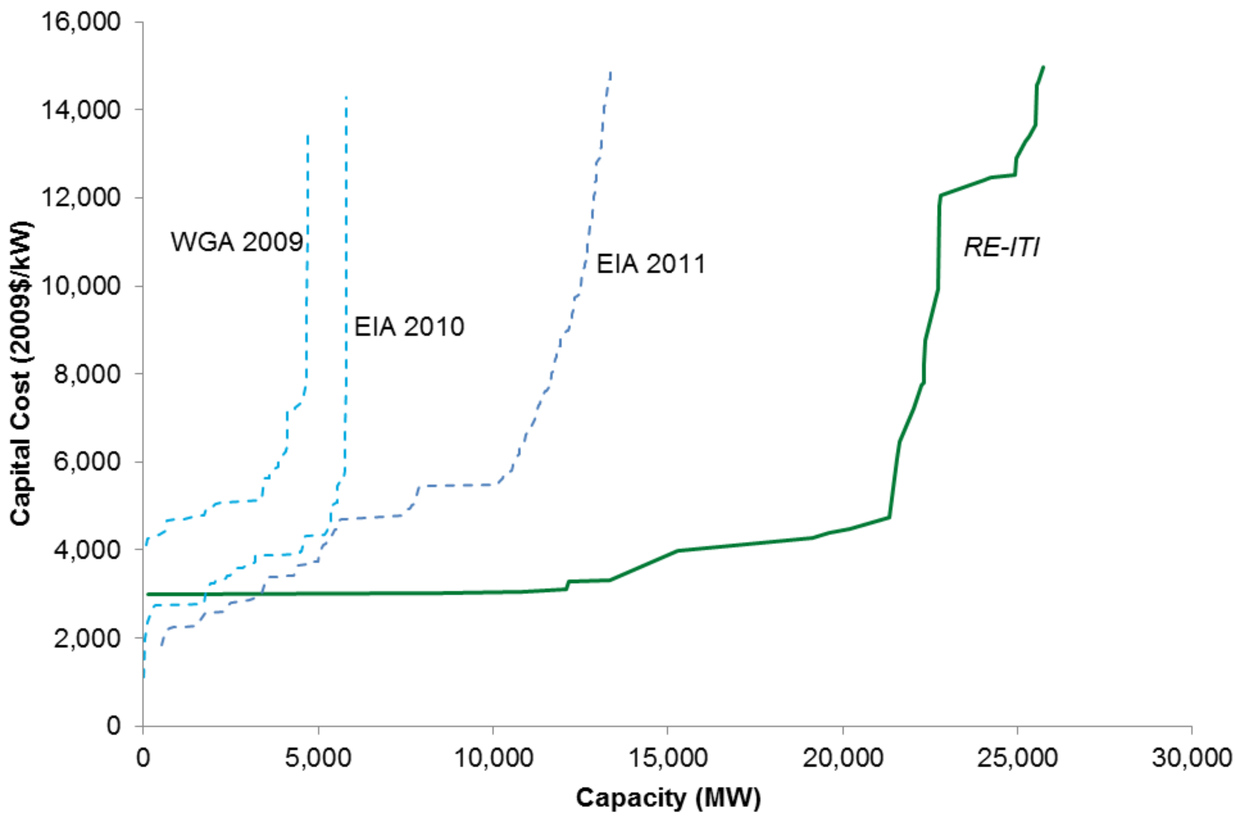

Figure 7-7. Supply curve for geothermal (hydrothermal) energy technologies

In general, the reason for the larger resource potential estimated in RE-ITI compared to the other estimates is the exclusion of undiscovered resource in the other estimates.

7.3.4 Technology Advancement Potential

Geothermal technology advances will support the continuing growth of the hydrothermal energy industry while reducing risks associated with project development. Areas for advancement include development of exploration and characterization tools, which reduce well-field costs through risk reduction by locating and characterizing low- and moderate-temperature hydrothermal systems prior to drilling. Geothermal subsurface operations can benefit from the development of high-temperature tools and electronics. Binary power plant designs using novel or mixed working fluids also show some promise of increasing plant efficiency. Incremental improvements in drilling technology can be expected. Additionally, DOE is funding several projects to develop advanced drilling systems that use flames or lasers to drill through rock, as well as work in areas of drilling steering technology, logging while drilling, and adaptation of other rock reduction technologies, in order to significantly reducing drilling costs.[32]

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[32] Beyond hydrothermal, the most important breakthrough technology requirements are those for creating enhanced geothermal reservoirs. For EGS, overall project well costs can be lowered by decreasing thermal drawdown rates and increasing flow rates, both of which decrease the number of wells that are needed (Young et al. 2010). Likewise,

7.3.5 Advancement Potential Relative to RE Futures Scenario Analysis

The only difference between the RE-ITI and RE-ETI projections is assumed improvement in capital costs over time under RE-ETI estimates compared with no improvements under RE-ITI. In the RE-ETI estimates, reductions in hydrothermal project costs were based on evolutionary improvements to component technologies predicted by experts in the Geothermal Technologies Program 2009 technical risk assessment (see Table 7-4). The future component costs were used to estimate capital costs of future projects in GETEM in the same manner as current year project costs were estimated. Due to improvements in technology, a 17% decrease in capital costs for hydrothermal projects by 2050 was assumed under the RE-ETI projections. Projected O&M costs were the same between the two projections, with both assuming no improvements over time for the modeling analysis.

7.4 Output Characteristics and Grid Service Possibilities

7.4.1 Electricity Output Characteristics

Geothermal plants typically use large conventional AC generators that are functionally equivalent to conventional fossil generators and feed into the transmission network at high voltages. The geothermal industry at present generally provides continuous (i.e., uninterrupted) base-load power. Geothermal resources have high availability, as measured by a utilization factor as high as 96% (Lund 2003).

While geothermal plants are not considered variable generators, their output is partially temperature dependent. Electric output from a geothermal power plant is controlled by the reservoir source temperature and sink temperature (i.e., the temperature at which heat is rejected from the power plant). Because heat sources for geothermal power plants are lower in temperature than those of conventional thermal power plants, geothermal power plant output is more sensitive to the type of cooling systems the plants use. Most geothermal power plants use water-cooled systems, typically in the form of cooling towers (Kagel 2008, p. 78). Because condensate from the geothermal fluid exiting the turbine and condenser is typically used for cooling in dry-steam and flash-hydrothermal power plants, an external water supply is not required. Although some binary power plants use water-cooled systems, most use air-cooled condensers (Kagel 2008, p. 78). The efficiency of power plants with air-cooled systems decreases as the ambient temperature increases, so that air-cooled systems exhibit higher diurnal and seasonal variability in outputs than water-cooled systems.

The output performance of a geothermal reservoir can decline with increasing time of production for two reasons. First, the geothermal fluid pressure in a hydrothermal reservoir can decline. This is often mitigated by the reinjection of cooled geothermal fluids, or by injection of supplemental fluids. Second, reservoir temperatures can decline if the heat is mined too quickly. This can be mitigated by reducing geothermal fluid pumping flow rates, increasing fracture surface area, or drilling additional wells. These features are important in designing sustainable geothermal reservoirs whose output performance does not decline at an unexpectedly rapid rate.

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decreasing the thermal drawdown rate reduces the need to periodically re-drill and re-stimulate an artificial reservoir, decreasing recurring costs over the lifetime of the power plant.

7.4.2 Technology Options for Power System Services

Geothermal plants have some ability to provide flexible output to the grid, although they currently have little economic incentive to do so. Operation scenarios and power plant design concepts for using geothermal energy in flexible load management have been analyzed (Armstead 1970). The motivation for load-following operations in some older hydrothermal fields is to mitigate reservoir performance decline. Steam fields experiencing pressure drawdowns due to long-term operation can limit the reservoir production to hours of the day when load requirements are greatest. The reservoir can then re-pressurize and re-heat during non-peak hours, thus extending the overall operating lifetime of the reservoir while providing electricity to the grid during hours of the day when demand is highest. Complete shutdown of geothermal circulation is not ideal because re-heating of well boreholes may take several hours.

7.5 Deployment in RE Futures Scenarios

Of the geothermal generation technologies described above, only hydrothermal technologies were included in RE Futures grid modeling scenarios. Hydrothermal technologies achieve relatively high levels of deployment compared to the size of the resource in all scenarios. Of the approximately 36 GW of remaining potential capacity considered in Section 7.3, approximately 11 GW are deployed by 2050 in the low-demand baseline scenario alone. Among the 80% RE scenarios shown in Table 7-5 and Figure 7-8, approximately 24–25 GW of total hydrothermal cumulative capacity were deployed by 2050 except for the constrained resources scenario. This deployment of approximately two-thirds of the estimated hydrothermal resource results in approximately 4% of total generated electricity among the low-demand scenarios and 3% in the high-demand 80% RE scenario.[33] The similar geothermal capacity deployment and generation levels found in many of the scenarios reflect the limiting role of resource supply. This indicates that if additional hydrothermal resources were available compared to what was used in the ReEDS modeling, or if other geothermal technologies (e.g., enhanced geothermal systems) achieve technology improvements approaching hydrothermal technologies, geothermal would likely see greater expansion beyond the levels shown in Table 7-5 and Figure 7-8. Additionally, the lack of variation of geothermal penetration shows the robustness of geothermal technologies compared with other renewable technologies. For example, the dispatchability of geothermal plants enable it to realize high levels of deployment despite limits to managing variability in the system (constrained flexibility scenario), and the current cost-competitiveness of geothermal technologies enable it to compete despite various renewable technology improvements scenarios (80% RE-NTI, 80% RE-ITI, and 80% RE-ETI). However, the constrained resources scenario indicates that high renewable electricity futures can be achieved even if half of the geothermal resources are assumed inaccessible. Under this scenario, the inability to access resources, due to siting, permitting, or other environmental concerns, resulted in only 12 GW of geothermal capacity being deployed by 2050. This deployment level was comparable to the deployment in the low-demand baseline scenario.

[33] Although the percentage of total generated electricity from geothermal was smaller under the High-Demand 80% RE Scenario, the absolute amount of electricity was similar between this scenario and the low-demand 80% RE scenarios, excluding the Constrained Resources scenario.

Table 7-5. Deployment of Geothermal Energy Technologies in 2050 under the 80% RE Scenarios[a,b]

Scenario	Hydrothermal	
	Capacity (GW)	Generation (%)
80% RE-NTI	25	4.2%
Constrained Flexibility	24	4.1%
80% RE-ITI	24	4.1%
Constrained Transmission	24	4.0%
High-Demand 80% RE	24	3.1%
80% RE-ETI	24	4.1%
Constrained Resources	12	2.1%

[a] See Volume 1 for a detailed description of each RE Futures scenario.
[b] Capacity totals represent the cumulative installed capacity for each scenario, including currently existing geothermal capacity.

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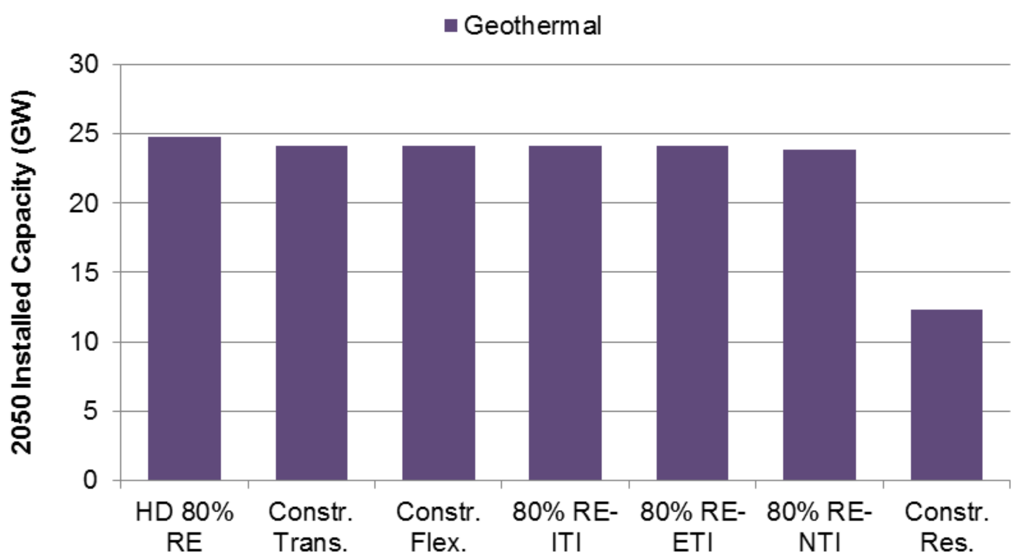

Figure 7-8. Deployment of geothermal in 80% RE scenarios

Among the 80% RE scenarios listed in Table 7-5, the 80% RE-NTI scenario realized the greatest deployment of geothermal capacity. As described previously, however, deployment in the 80% RE-NTI scenario and most of the other 80% RE scenarios were similar; therefore, the results shown in Table 7-5 are representative of the collection of 80% RE scenarios. In this scenario, geothermal contributed approximately 4.2% (185 TWh) to the total generation mix in 2050. Figure 7-9 shows the deployment of geothermal technologies over time and reveals some potential challenges: First, hydrothermal energy is deployed rapidly over the next decade, investing an average of $8.4 billion/yr between 2011 and 2020 to achieve annual installed capacity additions ranging from 0.5–2.5 GW/yr during this time. (The annual deployment between 2010 and 2020 is repeated between 2040 and 2050 because the technical lifetime of plants is assumed to be 30 years[34].) Second, a large portion of the hydrothermal capacity deployed by the ReEDS model in RE Futures is "undiscovered" hydrothermal resource. These are hydrothermal resources that are thought to exist but have not been discovered or proven as reserves. The size and probable location of the undiscovered resource was estimated using statistical methods based on geographic information systems (Williams et al. 2008). As with unproven oil and gas resources, evidence suggests the likely presence of the undiscovered hydrothermal resource, but exploration of these probable locations is still required. Figure 7-10 shows the hydrothermal capacity deployed in each state by 2050 in the 80% RE-NTI scenario. Hydrothermal technology is deployed in western states, with the majority of the installed capacity located in California.

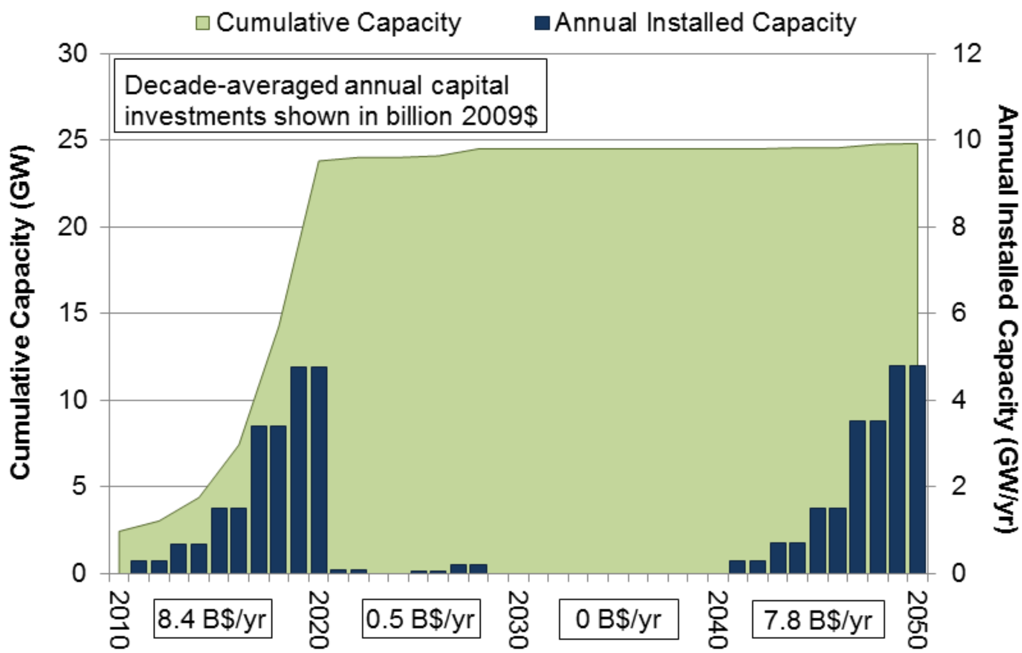

Figure 7-9. Annual and cumulative installed capacity levels for hydrothermal technology in the 80% RE-NTI scenario

[34] For renewable technologies, ReEDS assumes a retirement based on the technical lifetime of the plant (e.g., 30 years for geothermal), after which time the capacity is automatically "re-built" at the full plant cost, excluding interconnection costs. For geothermal technologies, the re-builds can be interpreted as plant replacements or upgrades, drilling additional injection and production wells, or other improvements to the resource. Description of plant retirement assumptions can be found in Appendix A (Volume 1).

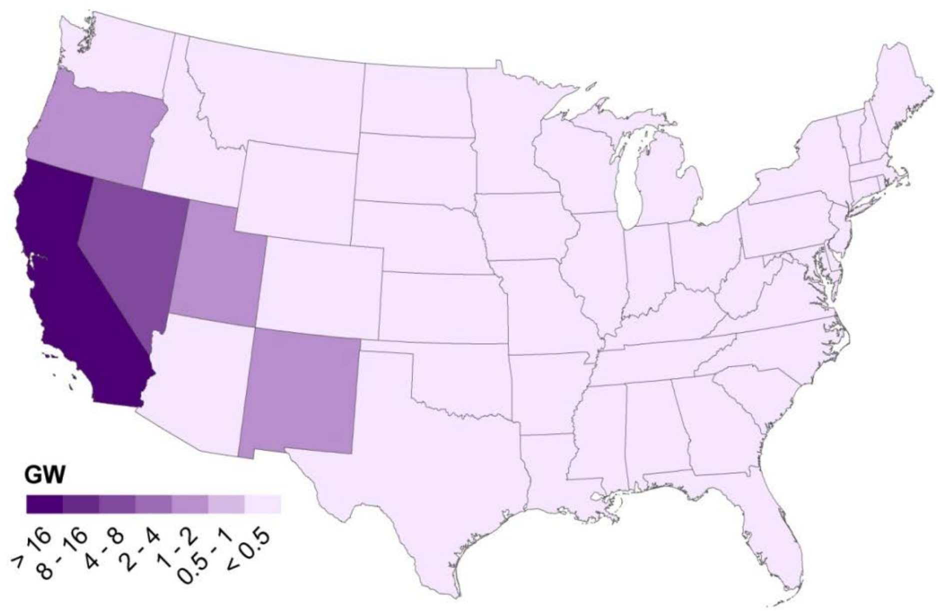

Figure 7-10. Map of capacity for geothermal energy technologies in the contiguous United States in 2050 in the 80% RE-NTI scenario

Figures 7-9 and 7-10 show deployment results for only one of many model scenarios, none of which was postulated to be more likely than any other. In addition, as a system-wide optimization model, ReEDS cannot capture all of the non-economic and, particularly, regional considerations for future technology deployment. Furthermore, the input data used in the modeling is also subject to large uncertainties. As such, care should be taken in interpreting model results, including the temporal deployment projections and regional distribution results; uncertainties certainly do exist in the modeling analysis.

7.6 Large-Scale Production and Deployment Issues

Large-scale deployment of geothermal technologies would require substantial growth of the relatively small existing geothermal industry and significant capital investment. Because the primary materials of construction for geothermal projects are steel and cement, geothermal is not likely to experience any bottlenecks from material constraints. While environmental impacts from geothermal installations, such as land use and air emissions, tend to be minimal, permitting difficulties tend to slow the development process and hamper the pace of deployment.

7.6.1 Environmental and Social Impacts

Relative to fossil energy, new geothermal plants have benign impacts in the areas of solid and gaseous emissions, water use, water pollution, and land use (DiPippo 2008); however, the development of geothermal reservoirs has its own distinct environmental challenges. Land subsidence and induced seismicity,[35] which depend on local geology, affect the areas around geothermal reservoirs to varying degrees, and they must be appropriately addressed to avoid serious consequences.

[35] *Seismicity* is the frequency or magnitude of earthquakes in an area.

7.6.1.1 Land Use

Geothermal energy has relatively low land use compared to many other renewable technologies. Land requirements for a geothermal power plant depend on the properties of the geothermal reservoir, power plant capacity, type of energy conversion system, type of cooling system, arrangement of wells and piping systems, and substation and auxiliary building needs. Hence, a representative value for geothermal land use is difficult to determine. Estimates for geothermal direct land use range from approximately 350 MW/km^2 (Kagel et al. 2007) to approximately 830 MW/km^2 (DiPippo 2008); the methods described in Volume 1 employ a mid-range estimate of 500 MW/km^2 (DOE and EPRI 1997).

7.6.1.2 Water Pollution and Use

Reinjection of geothermal fluid into the geothermal reservoir is the most commonly practiced method of managing geothermal waste fluid. Shallow potable aquifers are protected from contamination by geothermal brine using steel well casings cemented to the surrounding rock. Cement-bond logs are used to ensure casing integrity is maintained and to prevent water pollution. No record of water use problems in hydrothermal facilities exists in the United States (Kagel et al. 2007).

Geothermal development consumes water during drilling and well completion activities. Current geothermal (hydrothermal) facility operations, however, create minimal stress on fresh water sources. Water withdrawn from subsurface geothermal aquifers is hydrothermal brine, which lacks utility for freshwater uses, and is typically re-injected back into the geothermal aquifer.

Water consumption, therefore, is primarily a function of the cooling system used at the hydrothermal facility and the potential need for makeup water for the reservoir to replace brine lost to cooling systems. Many binary hydrothermal plants have air-cooled condensers and do not consume water during operations (Kagel 2008). More efficient, water-cooled plants, however, can consume approximately 5 gallons of freshwater/MWh (Kagel et al. 2007). However, at dry-steam and flash plants, this water requirement is often met using the geothermal fluid condensate from the turbine. Geothermal fluid that is lost to evaporation in the cooling system may have to be supplemented; makeup water is successfully furnished to The Geysers geothermal reservoir in California from non-potable, treated wastewater from several nearby communities, thus minimizing impacts on freshwater sources. Emerging technologies, such as advanced air-cooling and hybrid wet/dry cooling systems, seek to reduce water use by leveraging the inherent null water requirements of air-cooled systems with innovative cooling stages (mist evaporation) and cooling system arrangements (series and parallel) (Ashwood and Bharathan 2011).

7.6.1.3 Air Emissions

Emissions from geothermal power production are primarily a function of the physical characteristics of the geothermal resource being harnessed, but they are also a function of the number and type of generation units, the type of cooling system, the number of production and injection wells, and the arrangement of these wells within the geothermal field. This means generalized emissions impacts are difficult to identify and quantify; site-by-site assessments are most appropriate and required by law. Table 7-6 shows typical geothermal emissions for binary and flash power plants.

Table 7-6. Emissions for Binary and Flash Plants

Emissions	Binary	Flash
NO_x	0 kg/MWh	0 kg/MWh[a,b]
SO_x	0 kg/MWh	0.159 kg/MWh
PM10	0 kg/MWh	0 kg/MWh
H_2S	0 kg/MWh	0.5–6.4 kg/MWh[c]

[a] Barbier 2002
[b] Kagel et al. 2007
[c] Hunt 2001, p. 109

7.6.1.4 Life Cycle Greenhouse Gas Emissions

Estimates of life cycle GHG emissions for geothermal technologies consider all stages in the life of the electricity generation facility, including the extraction of raw materials, their transportation and manufacturing into plant components, plant construction, O&M, dismantling, and disposal. All geothermal electricity was assumed to be produced in flash steam hydrothermal plants, which was estimated to be 45 gCO_2e/kWh. Appendix C (Volume 1) further describes the process by which these estimates were developed and how total GHG emissions for RE Futures scenarios were estimated. Life cycle GHG emissions for other technologies are summarized in Volume 1 and reported in detail in Appendix C (Volume 1).

7.6.1.5 Other

7.6.1.5.1 Subsidence

Subsidence, which is a slow sinking of the land surface, can occur at geothermal developments. Reservoir fluids under hydrostatic pressure help support the overburden of the rock formation. Withdrawal of this fluid may leave some overburden unsupported and result in surface sinking (DiPippo 2008). Reservoir-temperature decline can also lead to contraction and subsidence. Subsidence, which is not a problem in most hydrothermal or EGS environments, can be managed by reinjection of produced fluids in the rare instances of fluid production from unconsolidated sedimentary formations.

7.6.1.5.2 Induced Seismicity

Most developed geothermal resources are located in tectonically active areas, making it difficult to separate naturally occurring tectonic activity from development-related events. Induced, low-magnitude, seismic events can result from production and injection operations. Development of EGS involves stimulating subsurface rock to open and extend existing fracture networks; induced seismicity is one result of this reservoir creation process. Although induced seismicity is a special concern for geothermal development in urban areas, its direct effect on the surrounding environment is normally negligible and can be successfully managed through proactive risk communication, proper siting, technology research and development, best practice methodology implementation, monitoring, and mitigation strategies. Such practices are outlined in Majer et al. (2008, Task D Annex I).

7.6.1.6 Mitigation and Minimization

Even with careful site selection, geothermal projects are likely to have some impact on the surrounding community. These impacts can be minimized by choosing plant designs tailored to the project area and resource, such as choosing power plant cooling technologies most appropriate for a site location and designing the plant to eliminate any non-condensable gases associated with a resource, and by engaging the community to educate and minimize and induced seismicity impacts.

7.6.2 Manufacturing and Deployment Challenges

As Figure 7-1 shows, the geothermal industry has seen only marginal growth in recent years. Increases in the rate of geothermal deployment would require expansion of the industry's manufacturing supply chain, investment community, and human resource pool. The ability of these groups to cope with increased deployment challenges is discussed in the section that follows.

7.6.2.1 Manufacturing and Material Requirements

Cement and steel, which are used for drilling and completing wells and for power plant construction, are the primary materials required for geothermal development. Drilling and completing wells requires steel for casing the well and cement to hold the casing in place. Given that more than 45,000 wells were drilled in the United States by the oil and gas industry in 2011—up from more than 38,000 wells the year before (EIA 2012)—the casing and cementing needs of the geothermal industry are not likely to affect the overall supply of these materials. Instead, geothermal drilling is vulnerable to price fluctuations caused by oil and gas drilling activity. The reliance of geothermal facilities on rare materials is minimal to non-existent; however, specific materials may be needed to prevent corrosion or failure of components exposed to the geothermal fluid. Hotter geothermal fluids are likely to contain dissolved minerals and gases that can damage carbon steels. Extremely high-salinity brines, such as those found at the Salton Sea, require titanium casing and the use of austenitic nickel-chromium-based alloys in surface equipment exposed to the geothermal fluid (van Wijngaarden and Chater 2006; Griffin 2009).

The ability of turbine manufacturers to keep up with the deployment projections in the RE Futures scenarios could be cause for concern. However, the geothermal turbine market is dominated by large and well-established companies, which have traditionally focused on turbines for flash and dry-steam plants (Taylor 2010b). In recent years, large and diverse companies have begun to manufacture binary turbines, which suggests the binary segment is primed for rapid growth (Taylor 2010b).[36]

[36] Given the current size of the geothermal market, the top suppliers of geothermal steam turbines do not maintain production facilities dedicated to geothermal turbine production. Rather, turbines for geothermal application are one-off versions of steam turbines produced for other technologies (e.g., coal) that are made on an as-needed basis. Any opportunity for domestic production of geothermal turbines would likely be the result of a domestic entrant into the steam turbines market for another technology.

7.6.2.2 Deployment and Investment Challenges

The 80% renewable electricity scenarios discussed above project annual installed capacity additions for hydrothermal ranging from 0.5 GW/yr to 2.5 GW/yr over the next decade. By comparison, the U.S. geothermal industry only added 176 MW of capacity in 2009 and 15 MW in 2010 (Jennejohn 2011). This indicates that there would be significant challenges for the industry to increase deployment to the levels projected under the renewable electricity scenarios. However, despite the minor amount of capacity additions in recent years, the geothermal industry appears to be positioned to deliver a significant amount of additional capacity to the grid in coming years. GEA reported 146 geothermal projects under way that are developing between 5,102 MW and 5,745 MW of geothermal resources. From these resources, developers have reported more than 1,600 MW of planned capacity additions, with 756–772 MW of new capacity in the drilling and construction phases (Jennejohn 2011). Based on these figures, the geothermal industry appears to have sufficient resources under way to rapidly increase deployment levels, given the proper conditions.

To close the gap between current hydrothermal deployment rates and the deployment rates required under the 80% renewable electricity scenarios, the geothermal industry will have to address the high up-front costs and uncertainty of resources during exploration coupled with long permitting and regulatory processes that result in a high project financing costs and a slow development processes:

- Permitting process can be slow, undefined, and duplicative; multiple agencies can require similar permits. Permitting varies from state to state and depends on land ownership. Some states do not have a defined permitting process for geothermal.
- High-risk well-field development comprises 32%–48% of capital cost (Hance 2005) (see Table 7-3).
- Greater than 50% of total power costs are associated with capital reimbursement and associated interest (Hance 2005)

7.6.2.3 Human Resource Requirements

There is no standardized method of estimating current or future personnel requirements for renewable energy technologies. However, it is certain that low availability of a qualified workforce will hinder efforts to ramp up geothermal development. Geothermal jobs include project development, systems engineering and design, manufacturing of equipment, resource extraction, drilling, equipment installation, and operations. Few institutions of higher education in the United States offer degree programs in geothermal energy or other geothermal technologies. Although similarities between geothermal and conventional power careers exist, workers will need training in specific geothermal fields, or retraining from more traditional energy fields, such as oil and natural gas production. Although geothermal drilling is similar to oil and gas drilling, it involves higher temperatures and poses unique challenges that drill rig crews must be specially trained to handle. Rapid growth in the number of simultaneously deployed drilling rigs with qualified crews in disparate locations could be challenging. Because the geothermal industry competes with the oil and gas industry for talent, recruiting a qualified workforce could also be made difficult by high fossil fuel prices that result in lucrative employment in the oil and gas industry.

7.7 Barriers to High Penetration and Representative Responses

High market penetration of geothermal power production faces a variety of market barriers that vary by geothermal technology. For hydrothermal technology, which is already commercially established, barriers include risk and long development timelines in early project stages of leasing, permitting and exploration. For emerging technologies, such as EGS and low-temperature geothermal technologies, barriers include an insufficient understanding of the resource, too few demonstration projects to confirm their technical feasibility, and incomplete basic R&D. These and other barriers and representative responses to help enable high market penetration of geothermal technologies are detailed in Table 7-7.

Table 7-7. Barriers to High Penetration of Geothermal Energy Technologies and Representative Responses

R&D	Barrier	Representative Responses
Data Collection and Management	Lack of data and difficulty in obtaining data on geothermal resources	Develop national geothermal database to track and publish geoscience and engineering data pertinent to geothermal resources.
Hydrothermal	Resource characterization of undiscovered resource	Develop innovative exploration techniques and regional resource exploration tools and approaches to identify undiscovered hydrothermal resources.
	Downhole equipment temperature limitations	Develop temperature-hardened flow meters, televiewers, and zonal isolation tools.
EGS	Technical feasibility challenges	Demonstrate EGS reservoir stimulation: low thermal drawdown, high flow rates.
		Enhance stimulation technology.
		Construct reservoir models capable of supporting reservoir stimulation planning and real-time management of stimulation operations.
		Develop the next generation of geophysical tools.
		Collect detailed borehole and surface petrologic, geohydrologic, and geomechanical data sufficient to build models in support of stimulation planning.
Low-temperature (e.g., co-produced, geopressured)	Lack of data on resource potential	Assess resource availability and cost to gain better understanding of available low-temperature resource
		Collect and manage data regarding current and decommissioned oil and gas wells with geothermal potential

Market and Regulatory	**Barrier**	**Representative Responses**
Permits and Leasing	Complicated permitting and leasing process	Summarize and clarify permitting and regulatory requirements on a state-by-state basis by land-ownership category.
Policy	Mismatched policy and geothermal development time frames	Establish clear and consistent long-term policies for geothermal development that address the long project time lines required for geothermal projects.
Financing	High risk in early stages of projects	Develop programs to address the risks and high project financing costs associated with the early stages of geothermal project development.
Environmental and Siting	**Barrier**	**Representative Responses**
Induced Seismicity	Public perception of seismic risks from geothermal (especially EGS) projects	Research the link between geothermal activities and seismic activity. Establish protocols for proceeding with projects that address best practices and safety measures (e.g., Majer et al., 2008). Educate the public on real versus perceived dangers of seismic events associated with geothermal projects.
Water	Access to water for cooling and for EGS projects	Continue research on advanced cooling technology (such as hybrid cooling). Determine the impact of water availability on high geothermal deployment scenarios.

7.8 Conclusions

Geothermal power using hydrothermal technology is broadly deployed on a commercial scale in the United States and has provided renewable and reliable options for base-load electrical power for five decades. Geothermal resources are primarily located in the western half of the United States. Hydrothermal technologies achieve relatively high levels of deployment compared to the size of the resource in all RE Futures scenarios evaluated.

The cost and performance of geothermal power plants depend strongly on site-specific conditions, including the quality (temperature and depth) of the resource, the specific plant type, plant size, and the type of cooling system used. Geothermal technology advances include development of exploration and characterization tools, high-temperature tools and electronics, binary power plant designs using novel or mixed working fluids and improvements in drilling technology can be expected. Large-scale deployment of geothermal technologies would require substantial growth of the relatively small existing geothermal industry and significant capital investment. While environmental impacts from geothermal installations, such as land use and air emissions, tend to be minimal, permitting difficulties and perceptions about induced seismicity from geothermal installations tend to slow the development process and hamper the pace of deployment.

In the near-term (through 2015), actions that address the potential of the resource and the ability to find it, such as a national geothermal database and advanced exploration techniques, are needed. In addition, market and regulatory barriers, such as leasing and permitting inefficiencies and ill-informed policy measures, must be addressed. In the mid-term (2015–2030), the discovery and development of hydrothermal resources must continue as basic R&D provides the tools to access higher-temperature resources and allows geothermal plants to operate in a water-constrained world. At the same time, EGS technologies must be proven and moved to the commercial sector. In the long-term (2030–2050), R&D must continue to expand the number and quality of EGS resources that can be developed economically so that the full scale of its resource potential can be realized.

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Chapter 8. Hydropower

8.1 Introduction

Hydropower has been a source of U.S. electricity since 1880. Although additions to hydropower capacity have been small since 1995 (see Figure 8-1), it is currently the largest source of renewable electricity generation in the United States, representing approximately 7% of total electricity generation. Historical growth in conventional hydropower capacity[37] is shown in Figure 8-1. The trend in hydropower development is reflected in the history of annual generation[38] shown in Figure 8-2. The variability in generation after 1975 reflects both variations in water availability and, especially, the implementation of environmental and fishery-related water management practices and constraints.

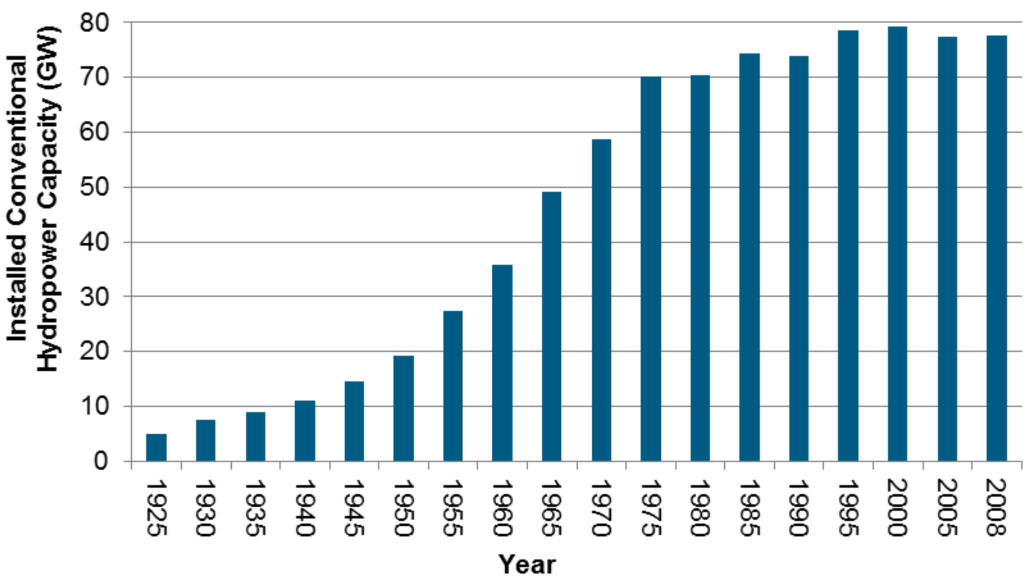

Figure 8-1. Capacity of conventional hydropower in the United States, 1925–2008

Source: Idaho National Laboratory

The current U.S. fleet of hydroelectric plants consists of slightly more than 2,200 conventional plants having a total installed capacity of approximately 78 GW and 39 pumped-storage plants with an installed capacity of slightly more than 20 GW (EIA 2008). Of the conventional plants, only approximately 15% are large plants with installed capacities greater than 30 MW, but they comprise 90% of the total installed capacity. The remaining conventional plants (more than 1,800 plants) are small plants with nameplate capacities of 30 MW or less. Approximately 70% of the conventional plants are privately owned, and 75% of total capacity is owned by federal and non-federal public owners, such as municipalities, public power districts, and irrigation

[37] This does not include pumped-storage capacity; existing and potential pumped-storage hydroelectric plants are discussed in Chapter 12.

[38] This includes pumped hydropower generation.

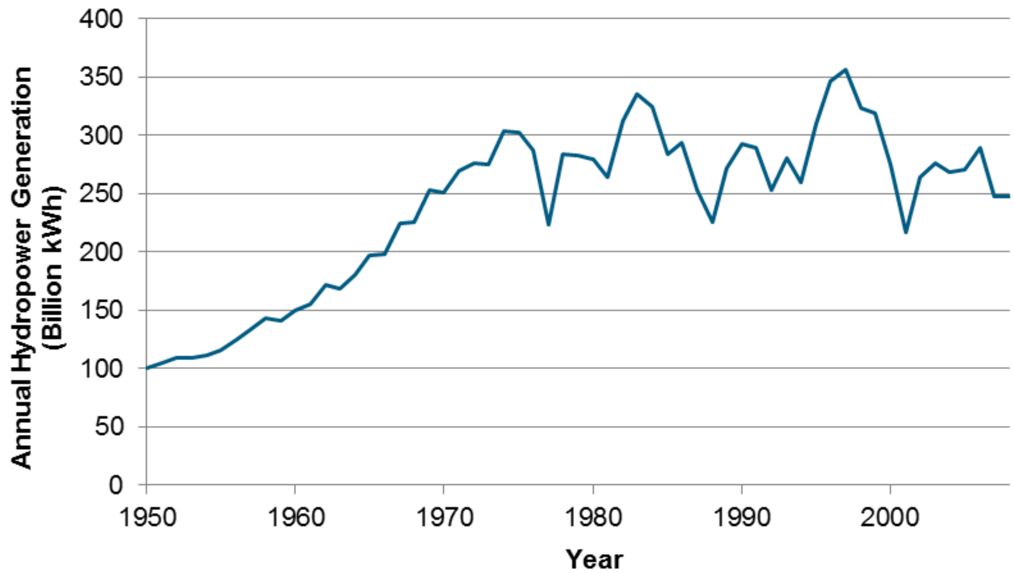

Figure 8-2. Annual hydropower generation, 1950–2008

Source: Idaho National Laboratory

districts. Hydroelectric plants are sited in all U.S. states except Mississippi (see Figure 8-2), with the greatest number being in California and New York. Washington and California have the greatest total installed capacities (Hall and Reeves 2006).

Hydropower potential used in RE Futures was limited to high-priced potential projects because the requisite data and information for lower price potential projects were unavailable. Lower-cost opportunities to increase hydropower capacity include: (1) retrofitting and upgrading equipment at existing hydroelectric plants, (2) the addition of power generation at existing non-powered dams, and (3) the use of constructed waterways (canals, water supply and treatment systems, and industrial effluent streams) as power resources. These resources are anticipated to be lower-price options because they have lower licensing and construction costs compared to "greenfield" sites. To include potential projects in RE Futures, three types of information are needed: location, capacity potential, and estimated project cost. A complete set of this information is not available for the lower-price potential projects. Studies funded by the DOE Water Power Program and the U.S. Bureau of Reclamation are currently being performed to obtain this information and will be available by 2013. This information will enable substantial updating of the hydropower supply curve (capacity versus unit development cost), and it is expected to make hydropower a more attractive option at a lower price point. This information will be of significant value for any future grid analyses, particularly given the ability of hydropower with reservoir storage to provide dispatchable power that can be used to provide ancillary services and enable greater penetration of variable renewable electricity sources.

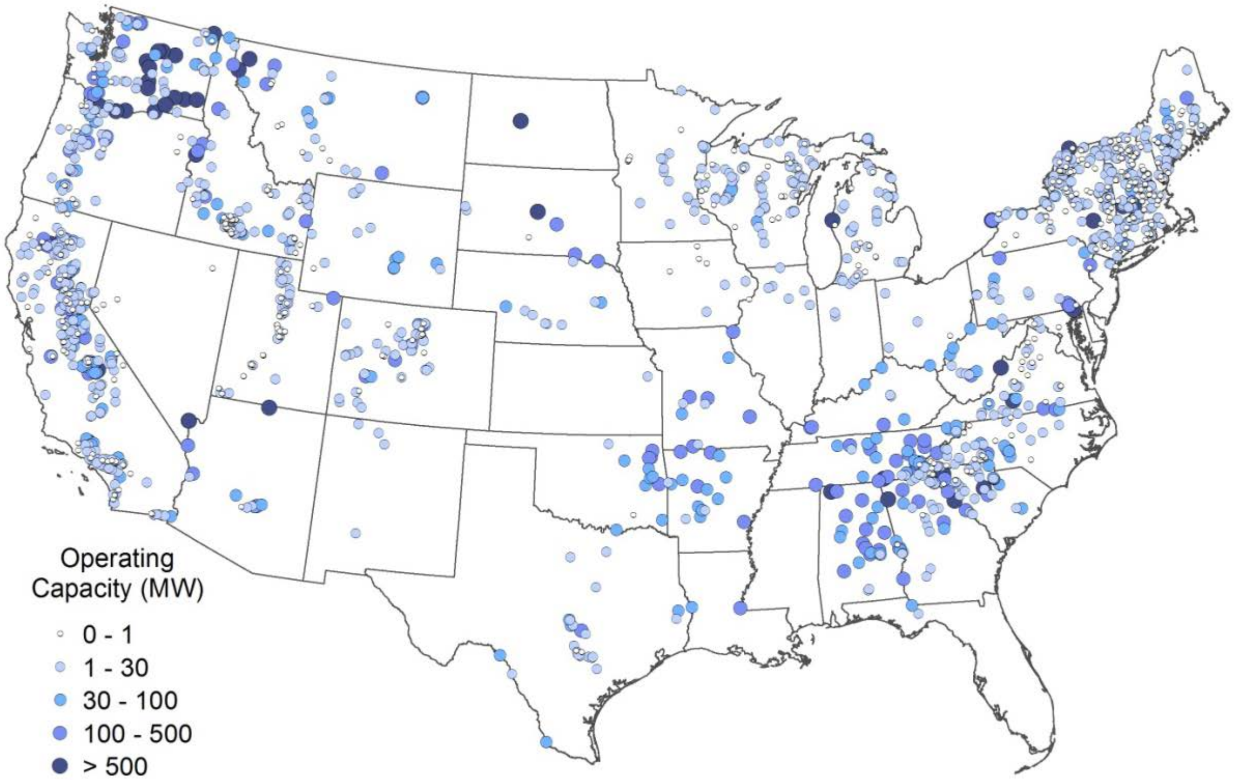

Figure 8-3. Map of hydroelectric plant locations in the United States

Data Source: Homeland Security Infrastructure Program 2010

8.2 Resource Availability Estimates

A conventional hydropower assessment of "natural streams" in the 50 U.S. states has recently been performed (Hall et al. 2004) and enhanced (Hall et al. 2006). An assessment of the power potential of explicitly adding generation at non-powered dams is under way; however, this power potential is implicitly included in the natural streams assessment for potential project sites corresponding to stream reaches[39] where a dam already exists. Additional assessments—planned and under way—address the potential for installing in-stream hydrokinetic turbines on natural streams, the potential for using constructed waterways, and the identification of sites for new pumped-storage plants.

The methodology used to perform the aforementioned conventional hydropower assessments couples the hydraulic head of a stream reach (elevation change from the upstream to the downstream ends of the reach) with an estimated reach flow rate to estimate the reach power potential. Power potential is reported as annual average power because the flow-rate estimates are derived from regression equations based on gauge-station flow rates over a 30-year period of record. Annual average power potential values are converted to potential installed capacity

[39] *Stream reaches* are stream segments between confluences. Some natural reaches were divided into smaller segments in the natural streams assessment.

values by assuming a capacity factor of 50% (0.5), which is the approximate national annual average capacity factor for hydroelectric plants (Hall et al. 2003). The use of "reach power potential" implies a development model using a stream-obstructing dam whether it is an existing or new structure.[40]

The geographic scope of RE Futures was limited to the 48 contiguous U.S. states. Therefore, the stream-reach database was screened to remove Alaskan and Hawaiian resources. Reaches having capacity potentials of less than 500 kW also were eliminated because they are unlikely to be economically feasible, and they contribute relatively little to the total gross power potential. The remaining potential project sites were further screened to remove sites in zones where development is unlikely to occur due to federal land use designations (e.g., national parks and monuments) or to being located in environmentally sensitive areas. Data from the Conservation Biology Institute (2003) were used to define the environmental exclusion zones. After removal of sites having capacity potentials less than 500 kW and those located in exclusion zones the total capacity potential of the remaining sites was 266 GW. This group of sites was further reduced by making subtractions to account for the number and total capacity of existing hydroelectric plants and questionable potential projects, as described in Section 8.3.3.2. After having made all of the described reductions, there were approximately 62,000 individual potential sites having an aggregate of 152 GW of capacity potential.

8.3 Technology Characterization

8.3.1 Technology Overview

Water behind a hydropower dam contains potential energy that can be converted to electricity in the hydropower plant. Potential energy is converted to kinetic energy as the water passes from its source through a penstock. The kinetic energy of the water is converted to mechanical energy as the water spins a turbine, which may be a simple waterwheel (e.g., Pelton and crossflow turbines), a reaction turbine (Francis turbine), a propeller-like device (e.g., simple Kaplan and bulb turbines), or a complex turbine with blades that can be adjusted during operation (articulated Kaplan turbine). The turbine is mechanically connected to a generator (see Figure 8-4), which converts the mechanical energy into electrical energy. Electricity produced in this way is commonly referred to as hydroelectricity. The capacity to produce hydroelectricity is dependent on both the flow through the turbine (typically measured in cubic feet per second or cubic meters per second) and the hydraulic "head." Head is the height measured in feet or meters; the headwater surface behind the dam is above the tailwater surface immediately downstream of the dam.

The articulated Kaplan turbine shown in Figure 8-5 illustrates the maturity of hydropower technology. This modern 100-MW unit is the product of a century of technology refinement. Figure 8-6 is a conceptual illustration of the cross section of a large hydroelectric plant that includes a dam that impounds water. This illustration represents one among the several plant configurations that are widely used for implementing hydropower, not all of which include a dam or a reservoir.

[40] Although site-specific assessments of the technical reasonableness are planned, they have not yet been performed.

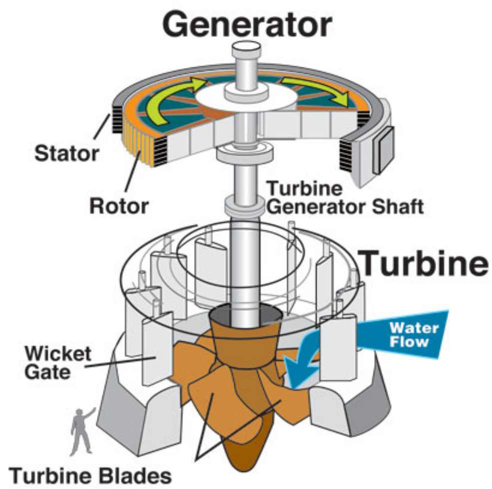

Figure 8-4. Typical hydropower turbine and generator

Courtesy of U.S. Army Corps of Engineers

Figure 8-5. An advanced modern hydropower turbine being lowered into position

Courtesy of Grant County Public Utility District

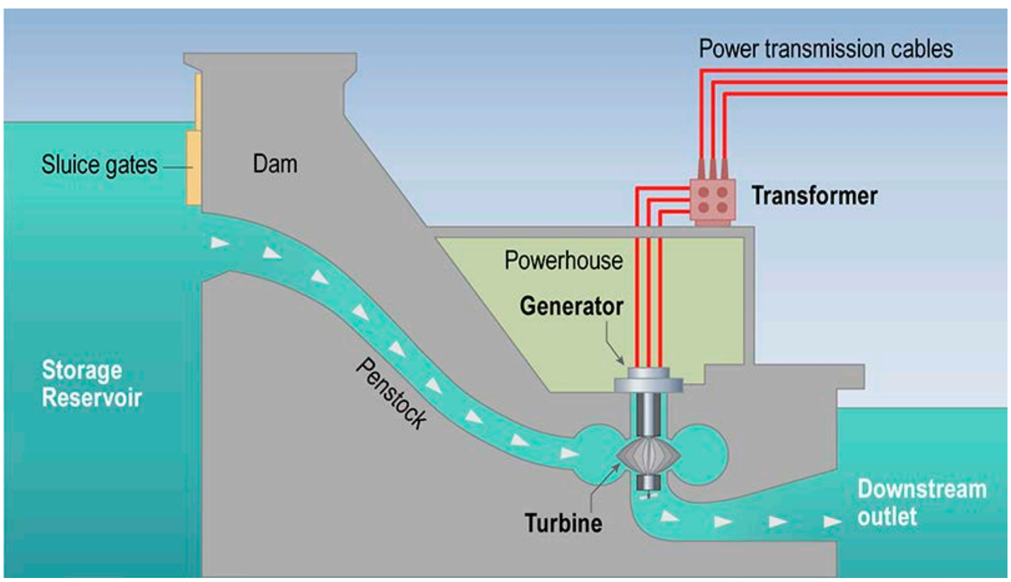

Figure 8-6. Cross section of a large hydroelectric plant

The two primary categories of conventional hydropower plants are "run-of-river"[41] and "storage" projects. A run-of-river project might or might not use a reservoir to create hydraulic head for generating power. For run-of-river projects, the flow rate of water through the turbines is very nearly the same as the rate at which water enters the reservoir from the river. A storage project uses a reservoir to increase the height of the water, but also stores water to shift the generation of power to the times or seasons having the greatest need for electricity. Water storage enables a project to vary generation and dispatch electricity to meet demand. In addition to electricity

[41] A run-of-river hydropower plant is a type of hydroelectric facility that uses the river flow with very little flow alteration and little or no storage of the water to generate electricity.

generation, storage projects commonly serve other functions such as flood protection, domestic and irrigation water supply, recreation, navigation, and environmental protection. These functions often dictate how the hydropower plant can be operated, resulting in less than optimal operation from an electricity generation perspective.

Hydroelectric plants vary in size and configuration. Plants in the U.S. fleet range from having installed capacities from 1 kW to more than 6,000 MW (FERC 2005). Large plants like that at Wanapum Dam shown in Figure 8-7 are typical of the public image of hydroelectric plants, but in reality they make up only about 15% of all hydropower plants in the U.S. fleet (Hall and Reeves 2006). At the other end of the size spectrum are small hydroelectric plants like the Fall River plant shown in Figure 8-8. These plants typically have very small footprints and often blend into the landscape. The Fall River plant is an example of one that does not incorporate a dam, has a very small footprint, and is not visible from the surrounding countryside. There is essentially no lower limit in plant size. Although small plants are useful for distributed generation, economic feasibility can be questionable with the cost of obtaining an operating license for non-federal projects.

Figure 8-7. Large hydroelectric plant

Courtesy of Grant County Public Utility District

Figure 8-8. Small hydroelectric plant

Courtesy of Idaho National Laboratory

8.3.2 Technologies Included in RE Futures Scenario Analysis

For the purposes of the RE Futures scenario analysis, conventional run-of-river hydroelectric plants were assumed to be installed to capture the available hydroelectric power potential (described in Section 8.2). A run-of-river plant typically incorporates a dam that creates a reservoir encompassing part of a stream or river channel. The dam creates an operating head; however, the entire water flow into the reservoir more or less simultaneously flows out of the plant.[42] In fact, for run-of-river plants, the balancing period over which inflow and outflow are equalized typically ranges from a few minutes to an hour or two. The capacity potential of sites

[42] Due to the coarse time resolution of the ReEDS model and the unpredictability of future dispatch schedules, dispatch of currently existing hydroelectric plants is constrained only by season in the ReEDS model, while new hydropower plants are considered run-of-river in ReEDS with constant output in each season. See Short et al. (2011) for details.

located in exclusion zones defined by federal land use or environmental sensitivities (as discussed in Section 8.2) were not included in the supply curves used in the ReEDS modeling.

Dams for run-of-river plants were assumed to be installed at the downstream end of each reach identified in the resource assessments. Therefore, the dam captures the hydraulic head of the reach and, consequently, its power potential as estimated in the assessments. No credit was taken for sites having an existing non-powered dam. In addition, no attempt was made to gang successive reaches on the same watercourse to define a single potential project. The conservative approach of assuming that each reach is a separate project tends to overestimate development cost because a series of small projects each having higher unit development costs will have a higher total cost than a single aggregated project representing the same total capacity potential. No assessments were made of the technical reasonableness or economic feasibility of particular potential projects (e.g., projects involving the unlikely damming of major rivers and projects that require unreasonably long dams because of relatively flat terrain). The highest-capacity potential projects that unrealistically assumed the damming of major rivers, however, were removed from the supply curves as described in Section 8.3.3.2.

8.3.3 Technology Cost and Performance

Future capital cost, performance (generally represented as capacity factor), and operating costs of electricity generating technologies are influenced by a number of uncertain and somewhat unpredictable factors. As such, to understand the impact of renewable electricity technology cost and performance improvements on the modeled scenarios, two projections of future renewable electricity technology development were evaluated: (1) renewable electricity –evolutionary technology improvement (RE-ETI) and (2) renewable electricity – incremental technology improvement (RE-ITI). In general, RE-ITI estimates reflect only partial achievement of the future technical advancements and cost reductions that may be possible, while the RE-ETI estimates reflect a more complete achievement of that cost-reduction potential. The RE-ITI estimates were developed from the perspective of the full portfolio of generation technologies in the electric sector. Black & Veatch (2012) includes details on the RE-ITI estimates for all (renewable and non-renewable) generation technologies. RE-ETI estimates represent technical advances currently envisioned through evolutionary improvements associated with continued R&D from the perspective of each renewable electricity generation technology independently. As a mature technology, hydropower was not projected to achieve cost or performance improvements in either RE-ITI or RE-ETI estimates. In fact, the only cost difference between the two cost projections for hydropower is a slight difference in variable O&M costs. It is important to note that these two renewable energy cost projections were not intended to encompass the full range of possible future renewable technology costs; depending on external market conditions or policy incentives, anticipated technical advances could be accelerated or could achieve greater magnitude than what is assumed here[43]. Cost and performance assumptions used in the modeling analysis for all technologies are tabulated in Appendix A (Volume 1) and Black & Veatch (2012).

[43] In addition, the cost and performance assumptions used in RE Futures are *not* intended to directly represent DOE EERE technology program goals or targets.

8.3.3.1 Cost of Electricity Production

The inherently long asset life of hydropower facilities represents an important economic attribute. Hydropower projects are able to recover costs before the end of their actual service life. These projects have no fuel cost, robust equipment, and extremely low operating costs after the debt service is paid. A privately developed hydropower project typically will have a debt payment structure for 10 to 17 years,[44] while a publicly funded project would have a slightly longer term. Upon retirement of the debt service, the only costs are O&M costs, and the cost of life extension of the equipment and structures. The cost of power is reduced significantly after the debt is repaid. For a micro or small hydropower project, the cost of power drops to less than $1/MWh, and for large-scale projects to less than $0.5/MWh.[45] Because of federal and private hydropower, states with significant older hydropower resources have been able to moderate their wholesale cost of power.

8.3.3.2 Development Costs

The resource supply curve provided for ReEDS modeling was based on the resource availability data described in Section 8.2. The cost of developing each of the potential project sites (stream reaches) was estimated using escalated versions of the cost curves from a study of hydropower economic parameters (Hall et al. 2003).[46] The cost curves are least squares curve fits of historical cost data. Because the cost of hydropower licensing is a significant component of the cost of developing a hydroelectric plant, the estimated cost of developing a site included both the cost of obtaining an operating license and the cost of constructing the plant. Figure 8-9 shows the original cost-estimating curve for licensing, and Figure 8-10 shows the original cost-estimating curve for construction; both are in 2002 U.S. dollars. The unit development cost of each site was obtained by dividing its estimated development cost by its potential installed capacity. Unit cost was found to have an inverse relationship to installed capacity (that is, higher-capacity plants have lower unit-development costs and vice versa). The unit costs of all sites before accounting for existing capacity and unrealistic projects on large rivers ranged from $2,000/kW to $5,600/kW. Hydroelectric plants are complex facilities composed of civil, mechanical, and electrical components. A bottom-up estimate of plant cost depends on the plant design, which relates to the topography, geology, and hydrology at the site. The cost of plants—even for plants of the same installed capacity—varies widely, as shown in Figure 8-10. Estimating the cost of constructing future plants must rely on the average cost of entire plants unless a specific plant design at a specific site is to be estimated considering all aspects of the plant design. Future reductions in development costs also are difficult to estimate because of the maturity of the technology. It is conceivable that less expensive construction techniques, the use of advanced materials, and reductions in the cost of electrical components will reduce future development

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[44] Figure based on actual experience of numerous load applications, 2009–2010.

[45] The costs of energy presented here differ from the costs of energy presented in Section 8.4 due to differences in financing assumptions and differences over the operating years considered. All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

[46] Escalated version of licensing cost from Hall et al. 2003 = 720,000∗capacity potential $(MW)^{0.7}$, and escalated version of construction cost from Hall et al. 2003 = 4,400,000∗capacity potential $(MW)^{0.9}$ for undeveloped sites in 2008 U.S. dollars.

costs. The cost of licensing some plants might be reduced in the future, but which plants will have reduced licensing costs and how much the cost will be reduced cannot be predicted.

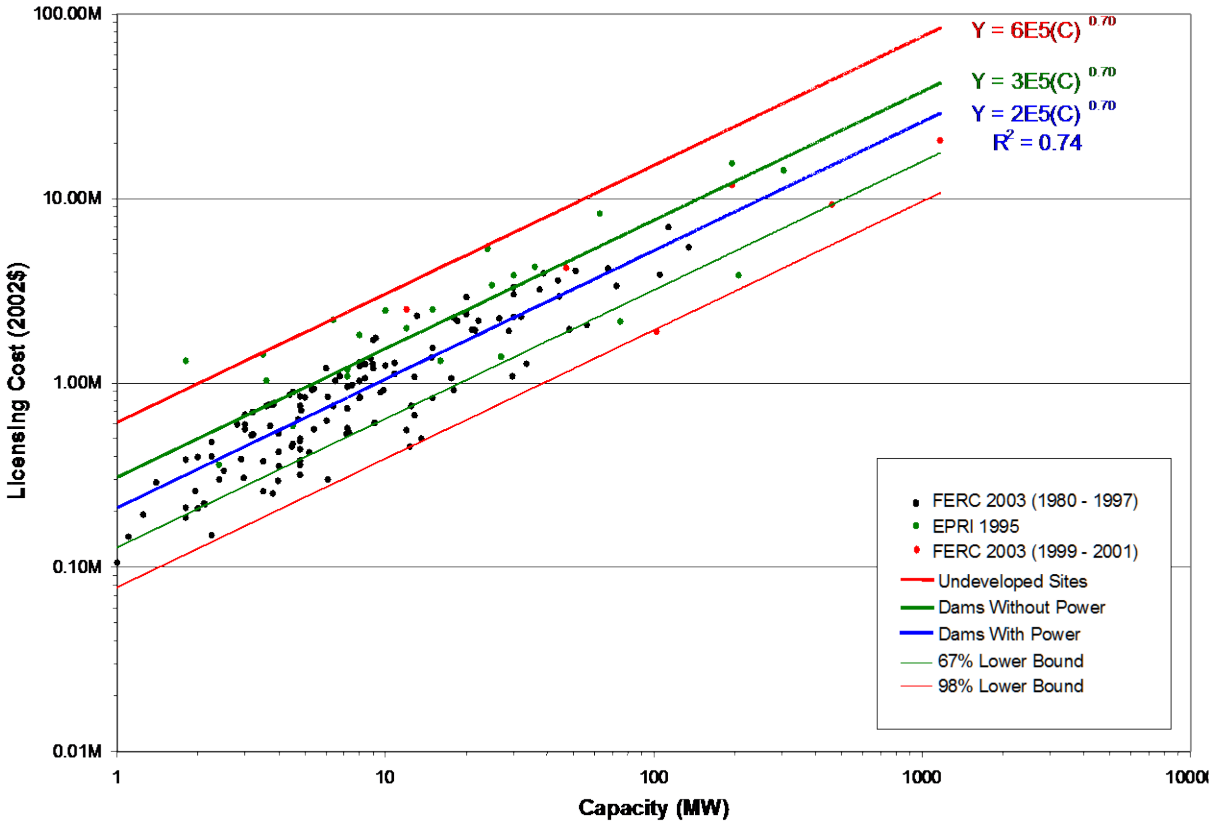

Figure 8-9. Original operating license cost-estimating curve (2002$)

Source: Idaho National Laboratory

The locations of potential projects were intersected with the boundaries of the 134 balancing areas (BAs) of the ReEDS model (see Volume 1 and Short et al. 2011) yielding the total potential capacity in each BA. Supply curves in the form of histograms provided the amount of potential capacity that could be developed in $1,000 increments of unit cost for each BA. A uniform unit cost in the middle of the increment was assigned to all of the capacities in the increment (e.g., $2,500/kW was assigned to all capacities having unit costs ranging from $2,000/kW to $3,000/kW).[47] The locations of all existing conventional hydroelectric capacity—based on the county in which the facility is located (not plant geographic coordinates) according to the EIA's 2008 listing of U.S. hydroelectric plants (EIA 2008)—were intersected with the BA boundaries. The currently existing total plant capacity was removed from the BA supply curve beginning with potential capacity at the lowest unit cost and advancing through the supply curve until an amount of potential capacity equal to the amount of currently installed capacity in the BA was removed. Sites with lesser unit costs corresponded to potential sites on larger rivers, which are likely not realistic dam sites. These potential sites effectively were removed from the

[47] All RE Futures modeling inputs, assumptions, and results are presented in 2009 dollars unless otherwise noted.

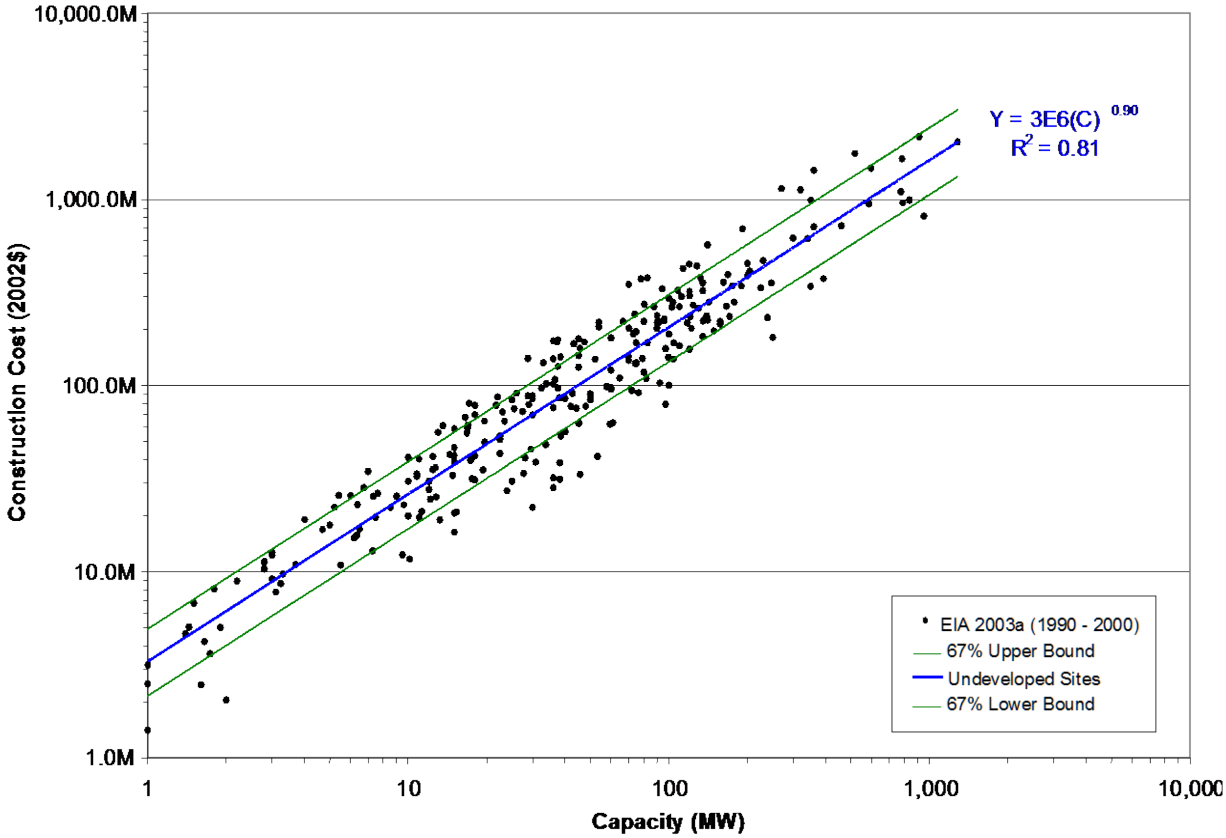

Figure 8-10. Original construction cost-estimating curve (2002$)

Source: Idaho National Laboratory

supply curves by removing all capacity having assigned unit costs of $2,500/kW. After this adjustment was made, the unit costs of potential capacity ranged from $3,500/kW to $5,500/kW.

Summary cost curves for the total population of potential sites before and after adjustment are shown in Figure 8-11. Prior to adjustment, the potential sites constituted 266 GW of potential capacity, with assigned unit costs ranging from $2,500/kW to $5,500/kW. After adjustment for existing capacity and removal of unrealistic projects, the potential capacity of the remaining sites was 152 GW with assigned unit costs of $3,500/kW to $5,500/kW. The potential was then further adjusted to account for the regional annual capacity factors used in ReEDS compared with the capacity factor of 50% assumed to convert potential annual average power values from the resource assessment to capacity potentials. This adjustment resulted in 228 GW of available new hydropower capacity considered in the modeled scenarios. While this adjustment modified the capacity potential, it preserved the generation estimate (in megawatt-hours) for each site from the resource assessment.[48]

[48] The assumption of a different capacity factor to convert potential annual average power (MWa) from the resource assessment to capacity potential (MW) at a site does not change the estimated annual generation since the new capacity factor was used to calculate annual generation (MWh) [generation (MWh) = annual average power (MWa)

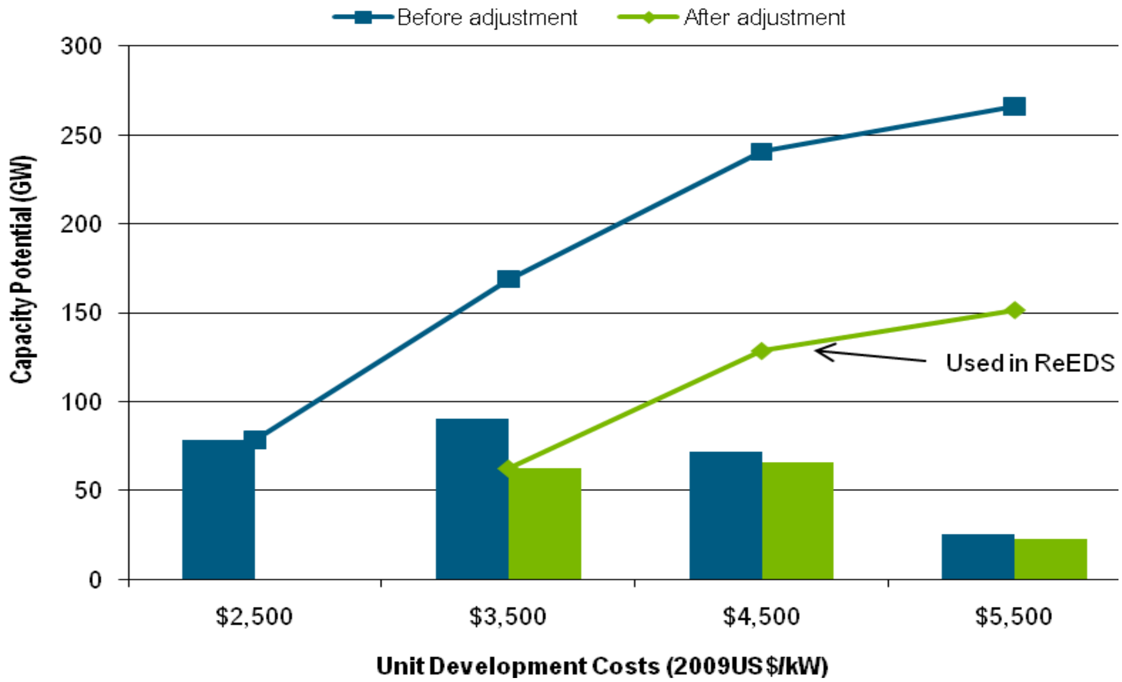

Figure 8-11. Cost supply curve for hydropower in the United States

Source: Idaho National Laboratory

The BA cost curves provided for ReEDS modeling contain notable conservative factors. The cost of developing all sites in the supply curves was based on the full construction costs of developing a "greenfield" site. No credit is taken for a site at which a non-powered dam might exist. Accounting for these sites would provide a significant amount of capacity at lower unit costs, both because of the savings in civil works construction and because of a (most likely) reduced cost of obtaining an operating license. Each of the potential sites corresponds to a single stream reach that is assumed to be developed as a separate project. There are cases in which multiple successive reaches have been identified as potential project sites. These reaches could be considered contributory to a single project having a unit cost less than the unit costs of the individual smaller projects. Due to the lack of resource availability data, potential projects on constructed waterways[49] have not been included. These projects also could offer lower unit costs because of reduced licensing costs and, quite likely, lower installation costs due to the relatively lesser complexity of the project. The inclusion of projects on constructed waterways also would increase overall capacity potential.

8.3.3.3 Operation and Maintenance

The basic technologies used for conventional hydroelectric and pumped-storage projects can be described as mature. Civil, mechanical, and electrical elements of well-built plants are robust;

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* 8,760 hours] is the same as [generation (MWh) = capacity factor*capacity (MW)*8,760 hours] where [capacity (MW) = annual average power (MWa)/capacity factor].

[49] Constructed waterways include irrigation canals, municipal water supply and water treatment systems, and industrial effluent streams.

some century-old hydroelectric plants continue in regular service—relying, for the most part, on the same structures and equipment that first were placed in service. By following generally accepted industry guidelines and good practices, long-term reliable operation with minimal forced outages routinely is achieved in hydroelectric plants of all ages and sizes.

Currently, most hydropower stations are unmanned and rely on remote monitoring and operation. Centrally dispatched crews often perform maintenance. Routine maintenance typically is conducted during regular working hours. Major overhauls—usually required after about 15–20 years of operation—are scheduled to minimize or eliminate plant unavailability (e.g., overhauls can be performed during a low-water-flow period). Moving parts exposed to water flow, such as turbine blade surfaces, could require frequent attention (e.g., annually) if the water carries heavy sediment burdens that cause surface erosion, or if operating conditions result in significant cavitation (a phenomenon that can damage surfaces).

It is common for various mechanical, electrical, and control equipment in a hydroelectric or pumped-storage plant to be upgraded or replaced during the plant's lifetime. Although it is rare to replace turbine casings (parts of which often are enclosed in concrete), turbine runners[50] often are replaced after 30–40 years of service. It is not unusual for an original runner to have been made from cast iron, and the replacement to be made of stainless steel. It also is common for the replacement to be more efficient and produce more power. Generators rarely are replaced; more often, they are rewound to provide greater power output using new, improved insulation because the old insulation degrades over time and due to electrical stress.

Control systems are now usually upgraded frequently, as compared to previous electro-mechanical plant equipment. In the mid-twentieth century, state-of-the-art electro-hydraulic controls could be expected to last essentially forever with proper maintenance. The newer controls have brought with them power imperatives in terms of plant operation (especially, for example, in connection with remote operation and monitoring), electrical grid operation, and direct labor savings in terms of plant O&M staffing. Moreover, it has become problematic for most plant owners to retain the expertise needed to keep older (often arcane) control systems adequately functional. This has led to a rapid transition to digital control technology, which was introduced and implemented over the past 20 years and is now at the heart of modern power-plant control systems.

Fixed O&M costs were assumed to be $14.90/kW/yr, and variable O&M costs were assumed to be $6/MWh under the RE-ITI projections used in the modeling analysis. RE-ETI technology cost projections were identical with the exception of lower ($3/MWh) variable O&M costs.[51]

8.3.4 Technology Advancement and Deployment Potential

Although hydropower turbine manufacturers incrementally have improved turbine technology to improve efficiencies, the basic design concepts have not changed for decades. This section discusses opportunities to advance the technology and deploy new facilities.

[50] The turbine runner is the shaft or hub with attached blades or buckets—the *turbine* in lay terms.
[51] Lower O&M estimate based on escalated value from Hall et al. 2003.

8.3.4.1 Technology Advancement Potential

Most U.S. hydroelectric and pumped-storage projects are several decades old. Although there are some newer plants, the average age of a project is 40–50 years.[52] Many plants have been upgraded and modernized. Nonetheless, much opportunity remains for improving older plants by replacing obsolete equipment and making other changes to improve operability, efficiency, and environmental performance. For projects subject to Federal Energy Regulatory Commission (FERC) licensing (which includes all investor-owned projects), relicensing after approximately 30–50 years often leads to thorough project modernization.

Rehabilitation and upgrading of existing facilities can prove to be extremely cost-effective, often ranging from approximately $200/kW to approximately $600/kW, which is a fraction of the cost of new facilities. Modernization often leads to a facility's increased power output and energy production. Increases of 3%–15% are not uncommon.[53]

Conventional hydroelectric and pumped-storage technologies generally are considered to be mature. Nonetheless, important advances have been made in recent years due to the application of newer materials and, especially, due to computer technology advances. Newer materials have contributed to longer component lifetimes. Computer technology has led to more efficient and more effective controls for plants. Use of computer-aided design tools, such as computational fluid dynamics software, has produced advanced designs, such as for hydraulic turbines. The Advanced Hydropower Turbine System program—undertaken through a partnership of industry and DOE—led to improved turbines that are both more "fish friendly" and more efficient. Several of these multimillion-dollar machines have been installed on the Columbia River in Washington. Research is continuing on fish-friendly turbine concepts that hold promise for broad application. Notwithstanding the many improvements made in the past, more opportunities remain for improving hydroelectric (including pumped-storage) technologies and their application.

8.3.4.2 Deployment Potential

Potential opportunities for improvement and additional deployment of hydroelectric projects include existing facilities and "greenfield" developments.

8.3.4.2.1 Existing Facilities

The installed capacity of conventional hydroelectric power plants (approximately 80 GW)[54] in the United States is greater than the total capacity of all other renewable technologies. Small improvements in efficiency and effectiveness to conventional hydropower facilities can lead to substantial benefits nationally. Moreover, good opportunities for making beneficial improvements occasionally arise during the lifetime of a facility.

One important opportunity within this category is project redevelopment. Essentially, an old project is replaced with a new and better project. A current example is that of the Holtwood

[52] Estimate based on FERC license and federal hydropower project lists.
[53] Estimates based on actual experience.
[54] Figure from National Hydropower Association. The term *conventional* is used to differentiate from pumped-storage hydropower, which is not included in the 80 GW total capacity figure.

Hydroelectric Plant, which has been in continuous operation with minimal upgrading for more than a century. An expansion project in 2010 increased the output from 108 MW to 233 MW. The expansion takes better advantage of the hydraulic potential at the site than did the original development. Funding made available through the American Recovery and Reinvestment Act of 2009 played a critical role in advancing the long-planned redevelopment.

Although few improvements are of the magnitude and scope of the Holtwood project, gains are being made at many hydropower and pumped-storage facilities. Numerous opportunities remain that—within a suitable policy framework—could bring sizable new power resources into the U.S. power supply.

8.3.4.2.2 Greenfield Developments

8.3.4.2.2.1 Large-Scale Conventional Hydropower Potential

In most areas of the United States, the best sites suitable for the development of large hydroelectric projects (more than 50 MW) either have already been developed or are considered preempted from development. The majority of large hydropower projects are publicly owned, most of which by the federal government. The U.S. Army Corps of Engineers has 75 hydropower projects with 20,474 MW of capacity; the Bureau of Reclamation has 58 projects with approximately 15,000 MW; and the Tennessee Valley Authority has 30 projects with 5,191 MW. Together, these projects provide approximately 40,000 MW of federally owned and operated capacity. Some large hydropower projects are owned by non-federal public entities. For example, Grant County Public Utility District in Washington owns two large hydropower plants—the 1,038-MW Wanapum project and the 855-MW Priest Rapids project.

Preemption of potential sites from hydropower development includes both actual and de facto preemption. Actual preemption is a result of laws that prevent development (e.g., the federal Wild and Scenic Rivers Act of 1968),[55] thus establishing a mechanism by which Congress can exclude certain river reaches from development. More than 11,000 river miles currently are protected under the Act. De facto preemption is a consequence of both practical and political factors. Practical factors include preemption due to preexisting development. Populated or otherwise developed areas often create difficulties with new hydroelectric development. Today, any attempt to develop a large hydropower project that inherently requires commitment of substantial land areas and river resources is a very controversial undertaking. Regardless of the support garnered for such a project, a project proposal usually draws significant opposition. The intensity of opposition—and its effects on broader public opinion—often poses a difficult obstacle.

8.3.4.2.2.2 Small-Scale Conventional Hydropower Potential

For RE Futures, a demarcation between large-scale and small-scale hydropower was established at 50 MW. As a practical matter, no such demarcation exists. Nonetheless, there is a qualitative difference between large, visible, high-consequence projects such as the 2,080-MW Hoover Dam on the Colorado River and the thousands of smaller projects that often are relatively inconspicuous.

[55] Wild and Scenic Rivers Act, Public Law 90-542, 90th Cong. (October 2, 1968).

Development of small-scale (less than 50 MW) projects is more likely to be undertaken by private developers. A project with costs on the order of $100 million and installed capacity of approximately 50 MW is a significant project for a private hydropower developer. This is in contrast to a utility power supplier, which might deem a project of 50 MW or less as too small and likely not worthy of pursuit. However, many thousands of potential opportunities for small-scale "greenfield" hydropower development exist in the United States.[56] Additionally, existing dams that currently do not have hydroelectric facilities might offer good opportunities for power development. Moreover, a great number of closed conduits and canals could have potential for the addition of hydropower facilities. Although these constructed waterways have not been assessed to determine their hydropower potential, a number of hydroelectric installations already are installed on them.

Additional assessment and verification to ascertain "ground truth" for potential sites in all categories is an important step if they are to be pursued. A single inventory of available small-scale hydropower facilities that lists potential sites on a state-by-state basis would assist such an effort. The Idaho National Laboratory developed the Virtual Hydropower Prospector, a Web-based tool that can provide a useful platform for collecting, displaying, and evaluating resource information.[57]

8.4 Output Characteristics and Grid Service Possibilities

The range of plant sizes is large, from approximately 1 kW to more than 6,000 MW (FERC 2005). The output from hydropower plants depends on the type of plant, water availability (seasonal variation and annual variability), and stream flow requirements for navigation, irrigation, and environmental protection. Run-of-river plants have little water storage capability and therefore operate principally as baseload plants. While the output of these plants may be subject to seasonal variability, their output varies over long enough timescales to make them predictable contributors to the electricity supply and thus easily integrated into the grid. Larger plants with water storage capability have both the capability to generate independent of seasonal water availability and provide load following and ancillary services. Pumped-storage hydropower plants, which are discussed in Chapter 12, are particularly suited to load following and providing firm capacity. A particularly important capability of hydropower is its ability to start with no available grid power and rapidly ramp to full continuous generation.

By considering future power system requirements, the benefits associated with changing the operating parameters, making specific upgrades, or adding new hydropower resources can be identified and valued. To identify these values, DOE funded (with industry cost-share) a team led by EPRI to quantify the full value of hydropower to the transmission grid.[58] This investigation is scheduled to be completed in 2012.

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[56] Estimate based on a resource assessment by the Idaho National Laboratory.
[57] For more information, see the Virtual Hydropower Prospector at http://hydropower.inl.gov/prospector/.
[58] Funding Opportunity Number DE-FOA-0000069, Topic Area 4.

8.5 Deployment in RE Futures Scenarios

As discussed in Section 8.1, hydropower is currently the largest of all contributors of renewable resources to the U.S. generation mix. In 2050, hydroelectric power continues to play a significant role in all of the RE Futures scenarios described in Volume 1. Table 8-1 and Figure 8-12 show the variation in 2050 installed hydropower capacity between the six (low-demand) core 80% RE scenarios and the high-demand 80% RE scenario. In addition, Table 8-1 shows the hydropower contribution of the total 2050 generated electricity for each of these scenarios. Cumulative installed capacity for hydropower, including the capacity that is currently operational (78 GW in 2010 not including pumped-storage capacity), ranged from 81–174 GW and the hydropower contribution to the percent of total generated electricity ranged from 8.3%–16%. Hydropower deployment showed modest sensitivity to many of the different system constraints modeled; however, it was most affected by the assumed cost and performance of renewable technologies. As hydropower is a relatively mature technology, it was estimated to have no cost or performance improvements over the 40-year study period. The scenario results indicate that the deployment of hydropower under an 80% RE-by-2050 scenario depended strongly on the relative cost of the other renewable technologies. For example, the 80% RE-ETI Scenario relied on technology cost projections where all renewable technologies experienced cost reductions or performance improvements over time except for hydropower. As such, hydropower deployment was very limited in this scenario, with only a few gigawatts of *new* capacity installed over the 40-year period. In contrast, hydropower deployment exceeded 170 GW (nearly 100 GW of new capacity) in the 80% RE-NTI Scenario, where no cost or performance improvements were assumed for any renewable technology. As shown in Figure 8-12, hydropower also realized significant deployment in the high-demand 80% RE scenario, where electricity demands were significantly higher than in the other low-demand scenarios.

Table 8-2. Deployment of Hydropower in 2050 under 80% RE Futures Scenarios[a,b]

Scenario	Capacity (GW)	Generation
80% RE-NTI	174	16.0%
High-Demand 80% RE	141	10.3%
Constrained Transmission	124	11.8%
Constrained Flexibility	124	12.2%
80% RE-ITI	114	11.4%
Constrained Resources	104	10.3%
80% RE-ETI	81	8.3%

[a] See Volume 1 for a detailed description of each RE Futures scenario.

[b] The capacity totals represent the cumulative installed capacity for each scenario, including currently existing hydropower capacity (approximately 78 GW in 2010).

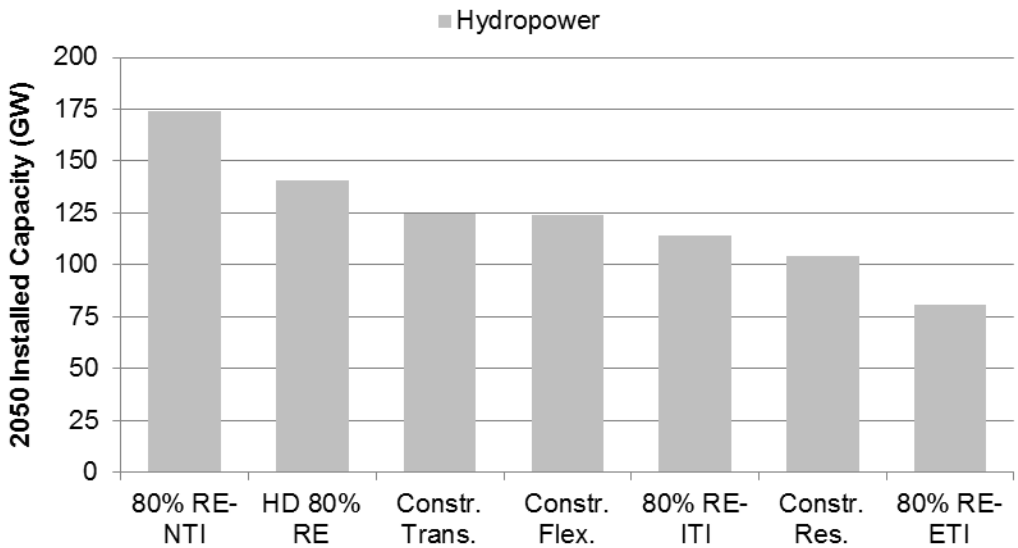

Figure 8-12. Deployment of hydropower technologies under 80% RE scenarios

As described previously, the greatest amounts of new hydroelectric capacity additions were required in the 80% RE-NTI scenario, in which the installed hydropower capacity in 2050 more than doubled the current existing capacity in the contiguous United States. Generation from hydropower increased to almost 16% of total generation in 2050, compared to approximately 7% in 2010.[59] Although growth in hydropower has been modest over the past few decades, the 80% RE-NTI scenario showed annual growth of almost 1 GW/yr (equivalent to one large coal-fired or nuclear power plant) from 2010 to 2020, with annual investments of approximately $1.7 billion/yr (see Figure 8-13). From 2020 to 2040, significant growth in hydropower capacity was indicated, with an average annual growth of approximately 2–4 GW/yr during that time and investments of approximately $9 billion–$10 billion/yr. In this scenario, growth in hydropower installations continued and even accelerated in the last decade of the study period. Annual installations peaked in 2050 with more than 7 GW/yr installed and a decade-averaged investment of nearly $19 billion/yr.

Hydropower resources are available in nearly every state; however, higher-quality resources are predominantly located in the Northwest, California, and the Northeast. Figure 8-14 shows the installed hydropower capacity (including the existing capacity today) in 2050 for the 80% RE-NTI scenario. The ReEDS-selected capacity was most prevalent in the Northwest, where water resources coupled with mountainous terrain are relatively abundant. Significant deployment of hydropower also occurred in New York, New England, and California.

[59] The hydropower generation or percent generation values quoted in this chapter include all electricity imported from Canada. In contrast, the quoted capacity figures only include existing and new plants that are located within the contiguous United States. Assumed electricity imports from Canada make up approximately 2% of U.S. electricity demand in 2050 under the low-demand assumption. See Short et al. (2011) for description of treatment of electricity imports in the models.

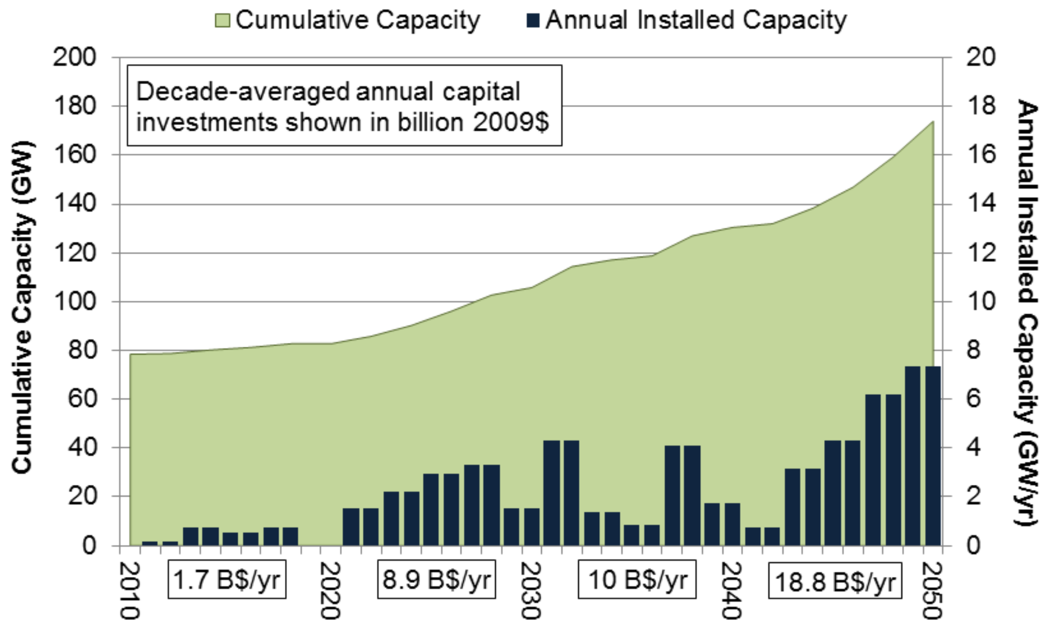

Figure 8-13. Deployment of hydropower in the 80% RE-NTI scenario

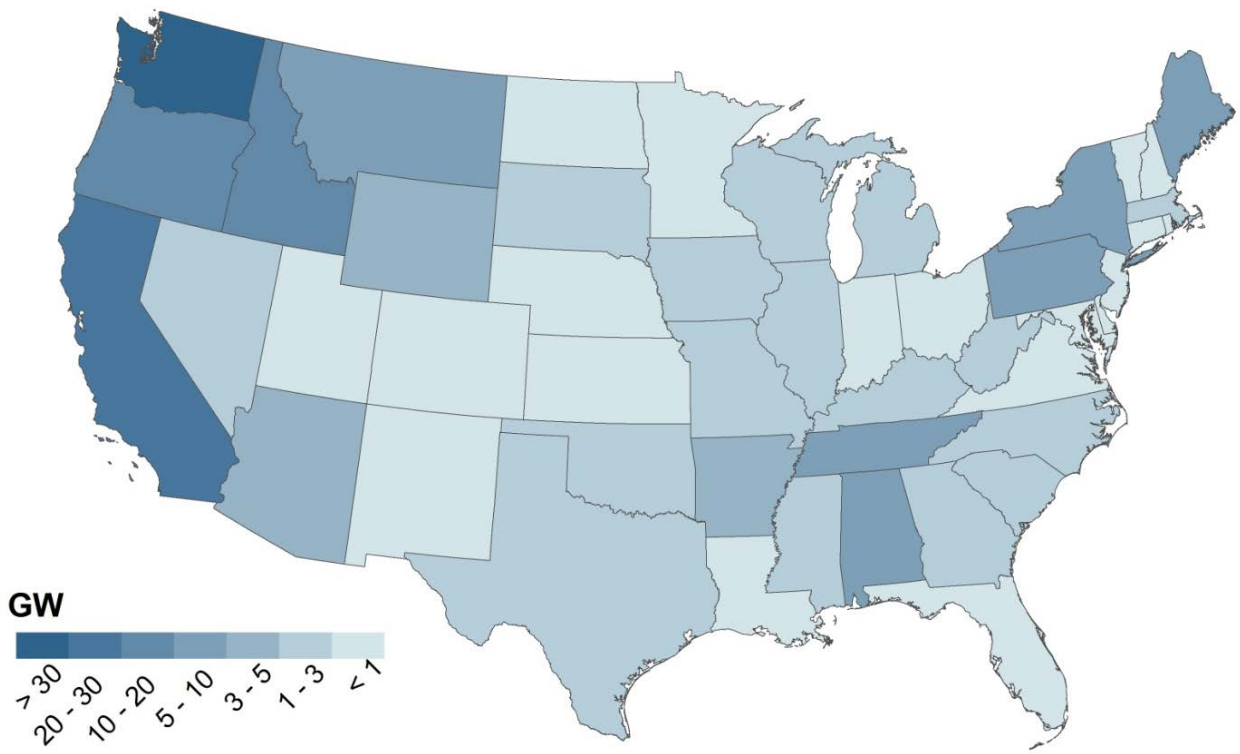

Figure 8-14. Map of hydropower capacity deployment in 2050 in the 80% RE-NTI scenario

Figures 8-13 and 8-14 show deployment results for only one of many model scenarios, none of which was postulated to be more likely than any other. In addition, as a system-wide optimization model, ReEDS cannot capture all of the non-economic and, particularly, regional considerations for future technology deployment. Furthermore, the input data used in the modeling is also subject to large uncertainties. As such, care should be taken in interpreting model results, including the temporal deployment projections and regional distribution results; uncertainties certainly do exist in the modeling analysis

8.6 Large-Scale Production and Deployment Issues

There are no technology-related issues associated with large-scale deployment of conventional hydropower technologies because they are mature technologies. Hydropower plants generate minimal emissions and few solid wastes; however, they can alter the aquatic environment in a number of ways. Additional deployment will require significant capital investment and long lead times. Because the primary materials of construction for hydropower projects are cement and steel, hydropower is not likely to experience bottlenecks from material constraints. However, siting and permitting are key challenges in deploying new hydropower plants.

8.6.1 Environmental and Social Impacts

Hydroelectric power production largely is free of several major classes of environmental effects associated with non-renewable energy sources. Hydroelectric projects can affect the environment by impounding water, flooding terrestrial habitats, and creating barriers to the movements of fish and aquatic organisms, sediments, and nutrients. Alteration of water flows also can affect aquatic and terrestrial habitats that are downstream of dams.

Table 8-3. Potential Environmental Benefits and Adverse Effects of Hydropower Production

Benefits	Adverse Effects
• No emission of sulfur and nitrogen oxides • Few solid wastes • Minimal effects from resource extraction, preparation, and transportation • Flood control • Water supply for drinking, irrigation, and industry • Reservoir-based recreation • Reservoir-based fisheries • Enhanced tailwater fisheries • Improved navigation on inland waterways below the dam	• Inundation of wetlands and terrestrial vegetation • Emissions of greenhouse gases (CH_4, CO_2) from flooded vegetation at some sites • Conversion of a free-flowing river to a reservoir • Replacement of riverine aquatic communities with reservoir communities • Displacement of people and terrestrial wildlife • Alteration of river flow patterns below dams • Loss of river-based recreation and fisheries • Desiccation of streamside vegetation below dams • Retention of sediments and nutrients in reservoirs • Development of aquatic weeds and eutrophication • Alteration of water quality and temperature • Interference with upstream and downstream passage of aquatic organisms

8.6.1.1 Land Use

The land use of a hydroelectric plant installation is highly variable based on the plant capacity, configuration, and installation site. For example, a run-of-river plant[60] where a dam is obstructing the river in a deep canyon can result in almost no inundation. It would only require land for equipment storage and for an electrical yard if the powerhouse were located in the dam. One estimate of the land requirements of this type of facility is about 1 hectare for a 10-MW facility. The Saskatchewan Energy Conservation and Development Authority listed the land use of a 10-MW hydroelectric plant as 1 hectare or approximately 2.5 acres in 1994.[61] Over the range of modeled 80% RE scenarios this corresponds to an additional land requirement of 80–175 km^2. Conversely, a run-of-river plant located on relatively flat terrain could require a long dam and create a sizeable reservoir even though its volume is not intended to vary. Research to estimate inundation associated with individual projects is needed.

8.6.1.2 Water Use

The creation of a reservoir floods terrestrial vegetation and displaces resident populations—both wildlife and human—within the flooded area. The significance of flooding depends on the size and location of the reservoir.

Most adverse environmental effects of dams are related to habitat alterations. Reservoirs associated with large dams can inundate large areas of terrestrial and streamside (riparian) habitat and can displace local residents. Diverting water from stream channels or curtailing reservoir releases to store water for future electrical generation can dry out riparian vegetation. Insufficient water releases degrade habitat for fish and other aquatic organisms in rivers below dams. Water in reservoirs is stagnant as compared to water in free-flowing rivers. Consequently, water-borne sediments and nutrients can be trapped, resulting in the undesirable proliferation of algae and aquatic weeds (eutrophication). In some cases, water spilled from high dams can become supersaturated with nitrogen gas, resulting in gas-bubble disease in aquatic organisms inhabiting the tailwaters.

Hydropower projects can have other direct effects on aquatic organisms. Dams can block upstream movements of fish, which can have severe consequences for migratory species.[62] Fish moving downstream might be drawn into the power-plant intake flow. Such entrained fish are exposed to physical stresses as they pass through turbines, which can cause disorientation, physiological stress, injury, and mortality. (Research and development on fish-friendly turbines has reduced rates of fish injury and mortality.)

Hydropower reservoirs also produce benefits. A primary benefit is the ability gained to produce—and often to store—energy. Reservoirs typically create water surface areas that are larger than the original river channels that they flood. Consequently, reservoirs can provide more

[60] A run-of-river hydroelectric plant is one for which the stream flow rate downstream of the dam is equal to the stream flow rate upstream of the dam at all times; hence, there is no dispatchable impoundment of water. The natural stream flow either passes through the turbines or passes the dam via the spillway.

[61] Saskatchewan Energy Conservation and Development Authority. This does not include any flooded area.

[62] Anadromous fish are born in fresh water and spend most of their lives in saltwater before returning to fresh water to spawn. Catadromous fish live in fresh water and enter saltwater to spawn.

habitat area for waterfowl and, in arid regions, can create permanent sources of drinking water for wildlife. Human populations often benefit from additional, non-power uses for hydropower reservoirs, such as reliable sources of water for drinking, industry, and agriculture; flood control; recreation; and fisheries. Very large reservoirs—whether used for hydropower or other purposes—are qualitatively different from smaller reservoirs in that they can affect the character of entire regions. Reservoir creation requires careful planning to minimize and mitigate effects on both naturally existing and human populations.

8.6.1.3 Emissions and Waste

Hydroelectric generation does not lead to the emission of toxic contaminants (e.g., mercury) or to the emission of sulfur and nitrogen oxides that can cause acidic precipitation. Although construction of hydropower projects could result in temporary emissions—including dust and emissions from equipment.

Hydroelectric power plants generate few solid wastes. Land might be required for the disposal of material dredged from reservoirs or for the disposal of waterborne debris. The amounts of land needed for such disposal, however, are small compared with conventional energy sources and such materials are generally not toxic. Many other environmental effects that are associated with the overall fuel cycles of non-renewable energy sources, including resource extraction, fuel preparation, and transportation, are minor or nonexistent for hydroelectric power.

8.6.1.4 Life Cycle Greenhouse Gas Emissions

Hydropower projects long have been assumed to emit fewer GHGs than fossil fuel-based energy plants. This assumption seems to be correct for the vast majority of U.S. reservoirs. It now is recognized, however, that the decomposition of inundated vegetation and other organic matter within a reservoir can result in GHG emissions that can continue for decades after initial flooding. In some tropical regions of the world, the GHG emissions from hydroelectric reservoirs appear to be significant. The amount of GHGs released from a hydropower reservoir vary greatly depending on geography, altitude, latitude, water temperature, reservoir size and depth, depth of turbine intakes, the specifics of hydropower operations, carbon input from the river basin, and reservoir construction (e.g., whether vegetation was cleared from the reservoir before inundation). GHGs also are emitted during the extraction, transportation, and manufacturing of raw materials used for hydropower components, as well as during construction and decommissioning of hydropower facilities.

In the estimation of life cycle GHG emissions of the 80% RE-ITI scenario presented in Appendix C (Volume 1), the GHG emissions from hydropower facilities were not considered. Although this assumption leads to an underestimation of the true GHG emissions from the RE Futures scenarios, the magnitude of underestimation is small (less than 5%) for three reasons:

- Little hydropower capacity was added or decommissioned under the 80% RE-ITI scenario evaluated (<3% of cumulative capacity additions to 2050).[63]

[63] A larger amount of new hydropower capacity was deployed in some of the other RE Futures scenarios (see Table 8-1), which would lead to greater life cycle GHG emissions. These life cycle GHG emissions for hydropower

- Most of the existing hydropower capacity in the United States has been in place for decades; therefore, GHG emissions associated with the existing plants have already occurred.
- Ongoing reservoir-related GHG emissions are likely zero or near zero as any inundated biological material has long-since decayed.

8.6.1.5 Mitigation and Minimization

Construction and operation of hydroelectric plants might require efforts to minimize and mitigate potentially deleterious effects by incorporating structural design features, prescribed operating practices, or both. Although effects requiring minimization or mitigation are site-specific, this section discusses some of the issues that often are addressed.

Water-quality effects that occur during construction of hydroelectric plants and reservoirs can be managed by well-known engineering practices, including soil stabilization techniques and storm-water retention dikes. In most cases, long-term effects that occur during operation of a hydropower project are of greater concern than short-term effects that occur during its construction.

Maintaining water temperatures within desirable ranges—especially for the tailwater discharged from a hydropower plant—is not technically difficult. However, it can require significant capital and operating expense. Devices such as propellers have been used to break up thermal stratification in small reservoirs. For large reservoirs, multi-level intakes allow water to be withdrawn and mixed from different depths so that water of the appropriate temperature can be discharged into the tailwater.

In a variety of instances, increasing dissolved oxygen concentrations in discharged waters is necessary to protect fish and other aquatic species. Structural alternatives for accomplishing this include the use of specially designed "aerating" turbines. Dissolved oxygen levels also can be increased through modifications in dam operations, including fluctuating flow releases, spilling surface water from the tops of dams, and mixing flow by using multi-level water intakes.

Nitrogen gas supersaturation downstream from hydropower projects can negatively affect fish and aquatic species. Conditions that contribute to nitrogen supersaturation include project designs in which high-velocity tailwaters from a high dam discharge into a deep plunge pool so that air bubbles dissolve in the water under elevated pressures. One proven method for preventing nitrogen gas supersaturation is to install "flip lips." Flip lips are structures installed at the base of the spillway that redirect the spilled water into a horizontal plane so that it does not descend deep into the plunge pool. Keeping spilled tailwater (with entrained air bubbles) near the surface reduces the opportunity for excess nitrogen gases to dissolve into the water.

Mitigating alterations in the nutrient balance of a river or reservoir is possible but often costly and complicated. Excess growth of large aquatic plants can be controlled by mechanically harvesting the plants or by introducing herbivorous fish, but microscopic planktonic algae are

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would, however, be offset by lower life cycle GHG emissions from other technologies that would be deployed to a lesser extent.

difficult to control. To limit algal production, it often is easier to take steps to reduce the input of nutrients from the watershed or to flush nutrients from the reservoir.

The simplest way to mitigate adverse sediment and nutrient trapping in a reservoir is to dredge as needed. Numerous mechanical and hydraulic dredging techniques can serve this purpose. Sediments located in some reservoirs can be flushed through pipes or notches in the dams. Large reservoirs impound enough water so that sediments can be flushed at any time, but in smaller reservoirs, sediments only can be flushed during floods and other high-streamflow events.

Releasing a predetermined amount of water down a river channel often is required to sustain the in-stream uses of water, including uses related to fish and wildlife communities, streamside vegetation, recreation, aesthetics, water quality, and navigation. Providing flows downstream from a storage reservoir or hydroelectric diversion is simple; water can be spilled from the dam instead of being diverted to a pipeline or stored in a reservoir. Releasing water to support in-stream uses below the dam usually makes that water unavailable for electricity generation; therefore, hydropower operators are interested in providing sufficient—yet not excessive—releases. Methods have been developed to ascertain the in-stream flow requirements for many in-stream water uses. Although a variety of in-stream flow assessment methods are available to help determine how much water needs to be released, the needs of biological resources often are difficult to assess with a desirable degree of accuracy.

Dams pose physical barriers to upstream-migrating fish. Many hydroelectric projects have implemented ways to assist upstream fish movement. Methods include the use of fish ladders, trap-and-haul operations, and fish elevators. All methods of facilitating upstream fish passage slow upstream movement to some extent.

Fish migrating downstream past a hydropower project have three primary routes available. Fish can be (1) drawn into the power-plant intake flow (entrainment) and passed through a turbine, (2) diverted via bypass screens into a gatewell and then moved to a collection facility or the tailrace, or (3) passed over the dam in spilled water. Recent modifications made to dams to decrease the number of turbine-passed fish include guiding migrating fish towards spillbays[64] and using surface bypass systems and behavioral guidance walls. Ice and trash sluiceways also have been modified to provide surface passage routes for migrating fish.

Turbine-passed fish are exposed to physical stresses from pressure changes, shear, turbulence, and blade strike that can cause injuries. In the best existing turbines, up to 5% of turbine-passed fish can be injured or killed, and mortalities in some turbines can be 30%. New design concepts under development show promise of reducing mortality of turbine-passed fish to 2% or less in circumstances that would permit installation of these advanced designs.

8.6.2 Manufacturing and Deployment Challenges

8.6.2.1 Manufacturing and Materials Requirements

Hydroelectric plant construction takes a variety of forms—from adding a relatively small powerhouse to an existing non-powered dam, to installing a large dam and powerhouse and

[64] A spillbay is a structure that delivers water over or around a dam or other obstruction.

creating a large reservoir. In the small hydropower case, many designers could undertake the planning, the civil construction likely would be similar to other industrial construction, and equipment probably could be supplied by any one of several dozen suppliers. The building of large hydropower projects—several hundred megawatts and larger—greatly reduces the number of sources for engineering, construction, and equipment supply. For example, it is unlikely that there are more than 10 manufacturers worldwide for large turbines or generators. Indeed, many of the resources for undertaking large projects tend to be supplied from international sources.

Key equipment needed for hydropower plants includes hydraulic turbines, generators, transformers, and monitoring and control equipment. Other equipment includes spillway gates, intake gates, hoisting equipment, trash racks, trash rakes, powerhouse cranes, and fish-protection systems. For new "greenfield" developments, the civil construction of the dam, powerhouse, and roads usually represents the dominant expense. The cost of equipment tends to represent a relatively small part of overall project cost. For larger plants, turbines invariably are specially designed for a specific project. When turbine runners are replaced (e.g., during upgrading), the replacement is also a customized design. Smaller hydropower plants tend to rely on standardized designs. In many instances, large castings needed for turbine runners and other turbine-generator components no longer can be manufactured in the United States and must be sourced offshore.

Manufacturing capabilities for hydropower plant equipment have expanded worldwide, especially in developing countries. China, India, and Brazil each have had notable expansion in their capabilities for supplying hydropower equipment. There is significant hydropower equipment manufacturing in the United States, and a small part of production (10% to 15%)[65] serves international markets. Most of the U.S. supply is focused on serving the existing base of installed plants—providing equipment for maintenance, repair, upgrading, modernization, and improving environmental performance.

8.6.2.2 Deployment and Investment Challenges

New hydropower and pumped-storage projects are capital intensive. Consequently, large projects are almost exclusively in the domain of public financing. This is a worldwide pattern; it does not occur exclusively in the United States. Private developers can undertake smaller hydropower projects, but commercial financing terms generally are not favorable for hydropower. Although projects can be expected to have very long lifetimes—30 years or more—without requiring significant reinvestment, securing hydropower project financing for even a 20-year term is difficult.

During the 1980s, tax incentives and rapid depreciation allowances were major factors leading to the development of approximately 800 hydropower projects in the United States. Incentives that motivate investment and subsidize power production during the early years of a hydroelectric plant continue to be effective mechanisms for stimulating hydropower development.

For comparable public investments in incentives and subsidies, hydropower is very economically competitive as a source of renewable electricity in terms of dollars per kilowatt or dollars per kilowatt-hour. This is true for new projects and especially for existing projects. Due to the large

[65] The figure represents National Hydropower Association information.

installed base of existing hydropower, there are many opportunities for relatively small investments in upgrades and modernization to yield significant results in terms of increased power- and energy-production capabilities.

Federally owned projects face unique barriers. Unlike privately owned projects—in which improved performance can increase revenues, which in turn, can be used to pay for performance enhancements—federal projects for the most part do not have a performance-revenue connection. Instead, the vast majority of power revenues from federal hydropower projects flow into the federal treasury. Most of the funding to pay for operation, maintenance, and repairs comes from congressional appropriations. This "business model" fails to provide incentives that lead to maximizing performance.

8.6.2.3 Human Resource Requirements

There is no standardized method of estimating current or future personnel requirements for renewable energy technologies, and no new large hydropower plants have been built in the United States in recent years. However, Navigant Consulting (2009) assessed employment in the hydropower industry for various types of hydropower projects, including modifications to existing plants, addition of power production at non-powered dams, and development of greenfield sites. The assessment estimated that 2.8–13.2 full-time-equivalent jobs are required per megawatt generated. It projected that the majority of future hydropower jobs—both direct and indirect—will be in the Western region, which has the largest hydropower potential, followed by the Northeast because of its manufacturing base.

8.7 Barriers to High Penetration and Representative Responses

Several barriers constrain high penetration of conventional hydroelectric generation, and various responses have been used or could be considered, as enumerated in Table 8-3. These issues are categorized in three major areas: R&D, market and regulatory, and environmental and siting. Barriers and their representative responses are listed for each of the sub-areas.

Table 8-4. Barriers to High Penetration of Hydropower Technologies and Representative Responses

R&D	Barrier	Representative Responses
Resource Assessment	None; currently funded by DOE Water Power Program	Identify potential development sites (natural streams, existing non-powered dams, constructed waterways) Estimate developable power potential and levelized cost of energy
Turbine Development	Cost of researching advanced materials for turbine runners Cost of retrofitting existing runners with those made of advanced materials	Assist advanced materials research for turbine runners and other components Incentives or other assistance for retrofits
System Components	Cost of advanced control system development Cost of retrofitting existing control systems with advanced systems	Support or other assistance for advanced control system development Provide incentives or other assistance for retrofitting control systems

Market and Regulatory	Barrier	Representative Responses
FERC Licensing	Project characteristics that will allow fast-track licensing or exemption, thus reducing the time and cost of obtaining an operating license have not been defined	Implement identification of fast-track project characteristics Determine and possibly expand FERC latitude under the Federal Power Act
	Benchmarking U.S. hydropower licensing against processes used in peer countries to identify ways to further reduce the time and cost of obtaining an operating license while ensuring appropriate safeguards	Benchmark licensing processes here and abroad If necessary, amend the Federal Power Act to implement changes in the licensing process or requirements
	Each developer must research or produce environmental data needed to obtain a FERC operating license which, in many cases, is so expensive that it renders the project economically unviable	Compile an environmental data library that can be used by all hydropower stakeholders
Market	Hydropower ancillary services[66] are not sufficiently compensated	Modify energy pricing to ensure proper compensation of all ancillary services, either through the action of public utility commissions or via state or federal legislation

Environmental and Siting	Barrier	Representative Responses
Dam and Reservoir	Inundation of wetlands and terrestrial vegetation	Reduce the size of the storage reservoir; create alternate wetlands
	Emissions of GHGs from flooded vegetation at some sites	Reduce the size of the storage reservoir; clear vegetation from flooded area
	Conversion of a free-flowing river to a reservoir	No mitigation available
	Replacement of riverine aquatic communities with reservoir communities	No mitigation available
	Displacement of people and terrestrial wildlife	Relocation
	Retention of sediments and nutrients in the reservoir	Periodically flush or dredge the reservoir
	Interference with upstream and downstream passage of aquatic organisms	Install fish ladders or elevators for upstream passage Improve downstream passage survival with screens, bypasses, or fish-friendly turbines

[66] Ancillary services include load following, frequency regulation and other operation reserves, and black-start capability.

River	Alteration of river flow patterns below the dam	Release environmental flows in a natural seasonal pattern, and avoid rapidly varying flow releases
	Loss of river-based recreation and fisheries in impounded area	No mitigation available; enhance reservoir fisheries and recreation
	Desiccation of streamside vegetation below the dam	Release environmental flows in a natural seasonal pattern
	Development of aquatic weeds and eutrophication	Employ herbivorous fish, herbicides, mechanical removal, light-blocking dyes, and other vegetation-control measures
		Reduce sediment and nutrient input to the reservoir
	Alteration of water quality and temperature	Reduce the size and depth of the storage reservoir
		Control the depth from which water is released by multiple outlets
		Employ aerating turbines

8.7.1 Market and Regulatory Barriers

Extensive requirements are in place for obtaining the licenses and approvals necessary for constructing or modifying a FERC-jurisdictional hydroelectric or pumped-storage project.[67] No other generation source, except nuclear power, bears a comparable regulatory burden. Gaining approvals and a FERC license typically takes five years or more. Renewal of a FERC license ("relicensing") typically involves a multi-year process that can approach the time required for the original license. Owners must also obtain multiple approvals from other federal, state, and local authorities.

Efforts to simplify and streamline the FERC licensing process have been made in recent years and resulted in improvements. However, the process has inherent complexities because of the multiple interests represented. Proposals for simplifying and streamlining selected categories of development currently are being put forth, including the addition of hydroelectric generation at existing private and federal dams within suitable parameters. Such projects would be considered for a FERC license exemption and permitting requirements and approvals would be streamlined. It is important for the industry to continue to pursue efforts aimed at facilitating beneficial hydropower and pumped-storage development.

8.8 Conclusions

Hydropower, the largest source of renewable electricity generation in the United States, is one of the most mature sources of renewable power, with costs that are competitive with conventional fossil energy plants. Conventional run-of-river plants have little water storage capability and therefore operate principally as base-load plants. Larger plants with water storage capability have both the capability to generate independent of seasonal water availability and provide load following and ancillary services, such as firming variable generation (e.g., wind and solar generators). Hydropower resources are available in nearly every state; however, higher-quality

[67] FERC jurisdiction does not apply to federally owned facilities.

resources are predominantly located in the Northwest, California, and the Northeast. Hydroelectric power played a significant role in all of the RE Futures scenarios evaluated.

As hydropower is a relatively mature technology, it was estimated to have no cost or performance improvements over the 40-year study period. However, because most U.S. hydroelectric and pumped-storage projects are several decades old, opportunities to improve older plants include replacing obsolete equipment and making other changes to improve operability, efficiency, and environmental performance. In addition, less expensive construction techniques, the use of advanced materials, and reductions in the cost of electrical components could reduce future development costs.

The most important issues for future large-scale deployment of new hydropower plants are the high capital cost of new hydropower projects and the lengthy licensing and approval process, which typically takes five years or more. The primary environmental impacts of hydroelectric projects include impounding water, flooding terrestrial habitats, and creating barriers to the movements of fish and aquatic organisms, sediments, and nutrients. Alteration of water flows also can affect aquatic and terrestrial habitats that are downstream of dams. Proactive mitigation strategies to streamline the licensing process and address environmental concerns are needed to ensure hydropower contributes to a high-renewable electricity future.

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Chapter 9. Ocean Energy Technologies

9.1 Introduction

Ocean energy, or marine hydrokinetic (MHK) energy, is often referred to as ocean power, marine renewable energy, and marine power. In this chapter, ocean renewable energy is categorized as energy generated by waves, tidal currents, open-ocean currents, river currents, ocean thermal gradients, and salinity gradients, as defined in the Ocean Energy Glossary of the International Energy Agency Ocean Energy Systems Agreement (IEA-OES 2007). In the United States, the generation technologies that use these renewable resources are often referred to collectively as MHK energy technologies. Hydrokinetic forms of energy broadly include any kinetic energy inherent to a moving fluid, such as a wave or flowing water. Ocean thermal gradients and salinity gradients are different forms of marine energy, and are included here to cover the forms of marine and hydrokinetic energy that are currently under the most active R&D. Due to the immature development status and lack of tested commercial systems, ocean energy technologies were not modeled in RE Futures deployment scenarios, but they may offer large resource potential, additional diversity and regional advantages if technological advancesment enable commercialization.

Marine hydrokinetic renewable energy is quite different from the most common form of waterpower—hydroelectric generating plants. Conventional hydroelectric plants use dams to impound water and convert the potential energy due to the elevation of the water into electricity. This chapter will not address conventional hydropower, which is covered in a separate chapter, nor does this chapter cover tidal barrage plants, which also employ dams using conventional hydroturbines to generate electricity from the elevation difference of tidal flows into and out of estuaries. Other forms of marine energy will not be discussed here, including hydrothermal vent energy on the ocean floor, various forms of oceanic biomass that can be used to produce energy, and biochemical energy generated by ocean organisms.

MHK technologies have been under development since the 1973 oil embargo, but their development has been sporadic and inconsistent. Only prototypes and early production models have been deployed in demonstration projects. The current state of the industry can be compared to the early stages of the wind energy industry, in that many concepts have been proposed with a wide variety of methods for energy capture and conversion but with little technology convergence. The most recent development cycle for MHK technologies was initiated in Europe over a decade ago, and it has been gaining momentum. Worldwide hundreds of companies are developing MHK technologies.

The capacity of MHK devices installed around the world is quite small, only tens of megawatts, excluding tidal barrage plants, and these installations are generally engineering prototype test devices or small several-unit demonstration wave and tidal projects. No open ocean thermal energy conversion (OTEC) electricity generating devices are currently being tested. The large European wholesale electricity dealer, Statkraft, is operating a small, several-kilowatt, prototype salinity gradient test plant near Oslo, Norway. The current development status of ocean thermal energy conversion devices and salinity gradient devices will be briefly discussed.

In Europe, the European Marine Energy Center (EMEC) on Orkney Island, U.K., provides commercial testing services for prototype wave and tidal devices. The European Marine Energy Center (EMEC n.d.) has four berths for wave devices and five berths for tidal devices that are grid-connected. The European Marine Energy Center facilities are fully booked with tests for the near future. Wave and tidal testing facilities have also been developed in Ireland, Portugal, Demark, France, and Spain, and numerous prototype devices are currently being tested. Many of these devices are full-scale prototype devices, but some are subscale engineering development prototypes.

In the United States, numerous companies are developing MHK technologies. Verdant Power began development testing of a prototype tidal turbine in 2002. Verdant tested a prototype 35-kW, 5-m, 3-bladed tidal turbine in New York City's East River in the 2002 to 2006 timeframe. From 2006 to 2008, Verdant installed and tested six turbines in a tidal array at the same site (Verdant Power 2009). Verdant is planning to install and commercially operate a megawatt-scale array for power production at this same site. Ocean Power Technology began testing a small prototype wave device in 1997, and later scaled the device to a 40-kW-rated prototype for further testing (OPT n.d.). In 2010, Ocean Power Technologies grid-connected the energy buoy for tests with the U.S. Navy in Hawaii. Ocean Power Technologies' newest product is a 150-kW buoy. This 150-kW design is to be tested at the European Marine Energy Center, and a second unit is slated to be installed and tested at Reedsport, Oregon. Following the single buoy test at Reedsport, an array of ten 150-kW buoys is planned.

Several other U.S. companies have MHK projects. Hydro Green Energy, LLC, is developing a ducted current turbine that generates electricity from flowing water, such as river currents, tidal currents, and ocean currents (Hydro Green Energy n.d.). In partnership with the City of Hasting, Minnesota, Hydro Green Energy installed two barge-mounted test turbines with a total power of 250 kW in the Mississippi River in the downstream flow of the existing dam and lock near the city. In 2010, Alaska Power and Telephone installed a 25-kW, in-stream river turbine near Eagle, Alaska (AP&T 2010). Alaska Power and Telephone tested its effectiveness as a power source for the village. The low-speed, vertical axis water turbine is mounted on a floating platform and was manufactured by New Energy Corporation. Beginning in early 2012, Ocean Renewable Power Company will install and test its new commercial TidGen™ Power System in Cobscook Bay near Eastport Maine, ORPC (n.d.). After running and monitoring the initial system for one year, Ocean Renewable Power Company will install additional units over three years to increase the capacity of the plant to 3 MW and supply electricity to the local utility.

The MHK development efforts briefly described here have been undergoing open-water prototype testing in the United States; however, many more technologies are undergoing testing in Europe and around the world. In addition, there are also numerous technologies at earlier stages of engineering development.

The DOE Wind and Water Power Program supports R&D on a wide range of advanced waterpower technologies, with the objective of better understanding their potential for energy generation, and identifying and addressing the technical and nontechnical barriers to their application and deployment. Congressional appropriations for fiscal year 2008 allowed the program to fund research in MHK technologies for the first time since the early 1990s. The DOE Water Power research is focused on technology development and market acceleration. The technology development research includes support for the development of marine and hydrokinetic devices. Market acceleration efforts include project siting activities as well as market assessment and development activities. To facilitate a better understanding of MHK technologies, the DOE Wind and Water Power Program has supported the development of an online marine and hydrokinetic technology database that describes each of the hundreds of technologies, companies, and projects under development around the world (DOE 2011a; DOE 2011b).

To support the development of these technologies, DOE has recently designated three National Marine Renewable Energy Centers to perform testing of MHK devices. These new centers are:

- **Northwest National Marine Renewable Energy Center:** Oregon State University in Corvallis, Oregon, and The University of Washington in Seattle are jointly running the Northwest National Marine Renewable Energy Center with wave testing to be done off the Oregon coast and tidal testing in Puget Sound. The Northwest Center provides a full range of capabilities to support wave and tidal energy development.
- **National Marine Renewable Energy Center of Hawaii:** The University of Hawaii in Honolulu established a center to facilitate the development and implementation of commercial wave energy systems and to assist the private sector in moving ocean thermal energy conversion systems beyond proof-of-concept into pre-commercialization and long-term testing.
- **Southeastern National Marine Renewable Energy Center:** Florida Atlantic University has established a center to facilitate the development and implementation of ocean current systems and to assist in moving ocean thermal energy conversion systems and ocean water-cooling systems research through testing and commercialization.

Additional information on the DOE MHK research program activities is provided on the program website (DOE 2011a).

9.2 Resource Availability Estimates

Assessing the available resource for MHK technologies is a difficult and complex task. Each technology involves a distinctly different technical discipline and requires estimating different physical variables in the natural environment. For devices that extract energy from tidal, ocean current, and river flows, the quantity of interest is the velocity field and its time history. For wave devices, the time history of the wave height is the quantity of primary interest. For ocean thermal energy converters, the temperature difference between the surface waters and waters at depth is used to run a heat engine to generate electricity. Salinity gradient energy devices make use of the energy released from the mixing of saltwater and freshwater, which depends on the concentration of salt and the availability of a freshwater source. Most of these quantities are not well documented historically. For example, tidal flows have always been of great interest to seafarers, but generally, the range of tidal heights was recorded and not the velocity field. This leaves little historical data on tidal velocities to support kinetic energy estimates.

Resource estimates are often separated into two distinct quantities. The first quantity of interest is the kinetic energy in the natural flow at a particular location, such as at a river cross section, a tidal estuary cross section, or the wave energy along a length of coastline at some distance from shore. The kinetic energy contained in the natural flow (kWh/yr) is the energy moving through a particular cross section of an estuary or channel over time. Alternatively, the kinetic power density (kW/m^2) of the flow at a location can be assessed. Integrating the kinetic power density over time at the cross-sectional area will then give the total energy at the cross section for the year. The kinetic energy and the kinetic power density are quantities that provide an estimate of the amount of energy that is present in the natural environment, and are sometimes referred to as theoretical potential, gross potential, or potential resource. This type of estimate for the kinetic energy in the natural resource gives insight into the locations of high potential MHK resources, and an estimate of the spatial extent and quality of those resources.

The second resource quantity of interest is the amount of the MHK potential resource that can be feasibly or practically extracted. Estimating the potential resource is difficult, but estimating the practicable extractable resource is even more difficult, and in most cases, the practicable extractable resource cannot be directly derived from an estimate of the potential resource alone. The difficulty occurs because the amount of extractable resource can be changed by the introduction of the energy extraction device into the flow. Generally, it is expected that the introduction of the device will reduce the amount of energy that can be extracted from the flow, but this is not always the case, as discussed below in Section 9.4. The interaction of a device with the natural physical flow at a site will change the physics of the flow. Depending on the flow constraints, this can either increase or decrease the extractable energy. In addition, environmental considerations that require no significant impacts and other usage restrictions, such as fishing and shipping lanes, almost always reduce the possible level of extraction at a particular site. The following sections provide the status of the assessment of MHK potential resources.

9.3 Energy Resource

9.3.1 Natural Wave Energy

Ocean waves can be considered as a form of solar energy because they are formed by the far-field interaction of ocean surfaces and wind currents, which in turn, are the result of differential heating of Earth's surface. Generally, wave energy increases at higher latitudes of 30–60 degrees from the equator. There is greater wave resource potential on the West Coast of the United States because global winds tend to flow from west to east across the Pacific Ocean toward the coast. On the East Coast, the flow is most often away from shore. The total energy contained in the waves depends on the linear length of the wave crest, the wave height, and the wave period. The wave power density is the generally accepted measure of the natural wave energy resource. The wave power density is defined as follows:

$$\text{Wave power density} = \frac{P}{L} = kH_s^2 T_z \text{ in kW/m}$$

Where P is the power in the wave of linear crest length L, H_s is the significant wave height in meters, T_z is the mean zero-crossing wave period in seconds, and k is a constant ranging from approximately 0.4 to 0.6, which depends on the relative amounts of energy in short-period, wind-driven waves and the longer period swells in a particular sea state (Bedard 2008). The power density for waves has the units of power per unit wave crest length, or kilowatts per meter. The energy content of the wave decreases rapidly with water depth, and the above equation accounts for the energy as a function of depth, so that the power density in this case is given per unit of wave crest length, rather than per unit area.

The Ocean Energy Systems IEA Technology Initiative has estimated the theoretical global natural wave energy resource, including both kinetic and potential (due to the elevation of the wave) energy, to be approximately 29,500 terawatt-hours (TWh/yr) (OES 2011). Bedard (2008) estimated the total natural U.S. wave energy resource potential to be approximately 2,100 TWh/yr, divided regionally as shown in Figure 9-1. A more recent study by EPRI using a different methodology than that used by Bedard estimates the U.S. wave energy resource potential as 2,640 TWh/yr (EPRI 2011). *The practically extractable energy will be significantly less than the theoretical potential due to various constraints*. These include device interactions with the wave field and machine inefficiencies; restrictions due to environmental impacts; other important ocean-use priorities like fishing, shipping lanes, recreational uses, visual aesthetics, marine sanctuaries, and other access-restricted areas. Additionally, much of the U.S. resource is located in Alaska far from the major load centers.

9.3.2 Natural Tidal Energy

The oscillatory gravitational force exerted on the ocean by the sun and moon, and the rotation of the Earth around the Earth-moon center, creates a natural tidal energy resource. As the moon circles the Earth, the ocean waters closest to the moon experience a larger gravitational force causing the tide to rise, while the waters on the far side, which are further away, feel a reduced gravitational attraction also causing a simultaneous high tide on the far side. This produces two tidal cycles per day at most locations on Earth. However, the Earth's landmasses are barriers to the free movement of tidal flows. In addition, the shape of coastlines can divert the natural flows, changing the timing of the tides and resulting in very different tidal patterns at different geographic locations. Because the tidal forces follow repeating cycles, the tides can be accurately predicted years into the future. Sites with high potential hydrokinetic tidal energy typically occur in narrow passageways between oceans and large estuaries or bays for a couple of reasons. First, as the flow enters a narrowing passageway, the tidal flow must accelerate to maintain conservation of mass along the passageway, and, consequently, the water velocity increases. Second, depending on the size and shape of the passageway and the estuary, a dynamic resonance can occur that results in high velocity flows in and out of the estuary, much like airflow in an organ pipe where the resonance creates the musical tone. Both of these situations can result in high kinetic energy flows that are ideal for tidal energy production.

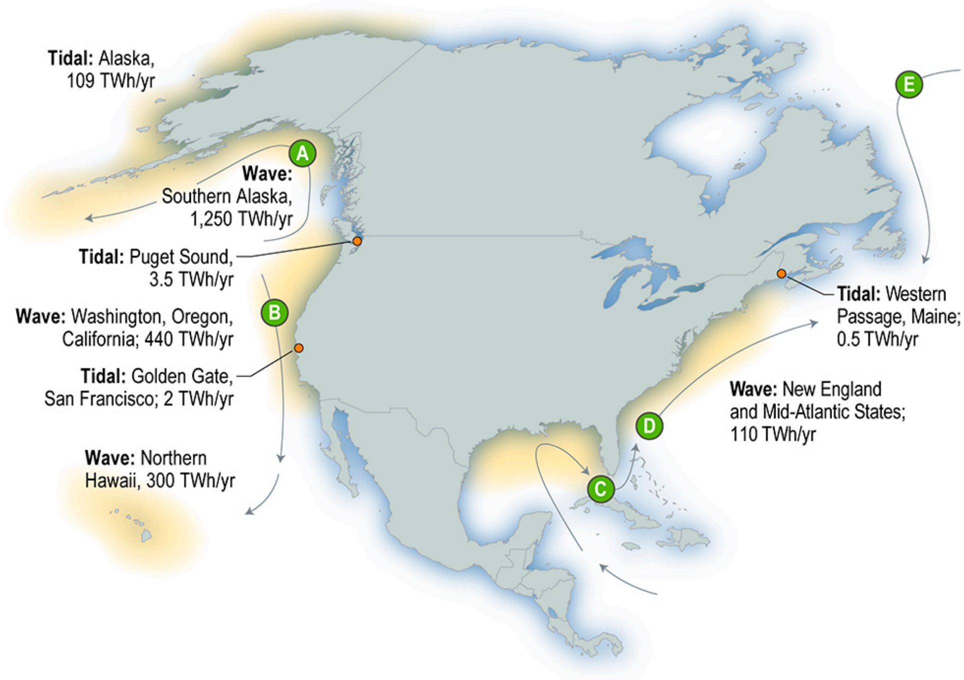
The current approach for computing the natural tidal energy resource at a site is to estimate the mean natural kinetic energy of the flow through the channel at the site of interest without considering the interaction of the flow and the device. The natural tidal energy is then taken as some fraction of this mean energy accounting for any known access restrictions.

This methodology is described by Hagerman et al. (2006) and was used for the Electric Power Research Institute's North American tidal energy feasibility study. To apply this methodology, the instantaneous power density is computed using the equation,

$$\text{Instantaneous power density for a tidal flow} = \left(\frac{P}{A}\right) = \frac{1}{2}\rho V^3$$

Where ρ is the density of the water in kg/m^3, A is the area of interest normal to the flow in m^2, and V is instantaneous flow velocity of the natural current at the area of interest in m/s. This equation gives the instantaneous power density at the area of interest in kW/m^2. Tidal velocities vary as a function of time, so the annual tidal velocity histogram for the location must be known from which the corresponding instantaneous power density histogram can be computed. The annual power density histogram for the site can be averaged to give the mean annual kinetic energy density for the channel, which is the natural kinetic energy resource in the flow. Multiplying the mean annual power density by the usable cross-sectional area of a tidal channel gives the mean annual natural energy resource.

Using the methodology described above, Bedard (2008) estimated the U.S. natural tidal resource at 115 TWh/yr for the few sites studied to date. Figure 9-1 illustrates the regional distribution of these tidal sites. Most of the U.S. tidal resource is in Alaska. As previously discussed, these numbers do not represent the extractable resource for any of these sites—they are simply an estimate of the kinetic energy in the natural flow. To address the need for improved resource assessment of U.S. tidal resources, the DOE Wind and Water Power Program funded Georgia Tech Research Corporation to conduct an assessment of the energy production potential from tidal streams. Georgia Tech used an advanced ocean circulation numerical model to predict tidal currents and to compute available tidal current power. This study, by Haas et al. (2011), estimated the U.S. natural tidal resource at approximately 50 GW of potential, with 47 GW of that in Alaska. An assumed average capacity factor for this resource of approximately 33% indicates approximately 111 TWh/yr of potential energy, which is in good agreement with the rough estimate of Bedard (2008). Both assessments indicate that the vast majority of the resource is in Alaska.



Adapted from Bedard 2008

Figure 9-1. Total natural tidal current energy and ocean wave energy resource in the United States

A – Alaska Ocean Current (low velocity not considered a viable energy source)

B – California Ocean Current (low velocity not considered a viable energy source)

C – Florida Ocean Current (resource estimate provided below in Figure 9-2)

D – Gulf Ocean Stream (low velocity not considered a viable energy source)

E – Labrador Ocean Current (low velocity not considered a viable energy source)

9.3.3 Natural Ocean Current Energy

An ocean current is a continuous, directed movement of ocean water generated by the forces acting upon the mean flow, such as breaking waves, wind, Coriolis force, temperature and salinity differences, and tidal forces. In the United States, high kinetic energy potential ocean current resources are found primarily in the Florida Current. The Florida Current and several other much lower velocity currents around North America are shown in Figure 9-1.

The ocean current near the United States with potential as an energy resource is the Florida Current because of its high core velocity of about 2 m/s. The other ocean currents have much lower flow rates and are not considered viable for energy generation. The relatively constant energy density near the surface of the Florida Current is about 1 kW/m^2 of flow area (MMS 2006). In addition, Hanson et al. (2010) estimated the power available in the Florida Current at one cross section as a function of the flow speed, which is shown by the curve in Figure 9-2. This curve estimates the power in the flow area where the current speed is greater than the flow speed designated "rotor minimum operating speed" in Figure 2. The curve does not account for conversion limitations or seasonal variations in flow, so this is simply the power of the current resource at the measurement cross section.

Figure 9-2 indicates that the total power in the Florida Current at latitude 27 degrees north is approximately 20 GW. The current varies seasonally and meanders laterally, which means that the current speed at a fixed location could vary significantly. The energy in a flow is power times time, so assuming that the average power in the current is 20 GW, then the yearly energy content of the Florida Current would be approximately 175 TWh/yr for comparison with U.S. wave and tidal resources. As is the case for wave and tidal energy, the extractable resource is significantly less for essentially the same reasons of conversion limits, inefficiencies, environmental constraints, and access restrictions associated with these ocean current energy resources.

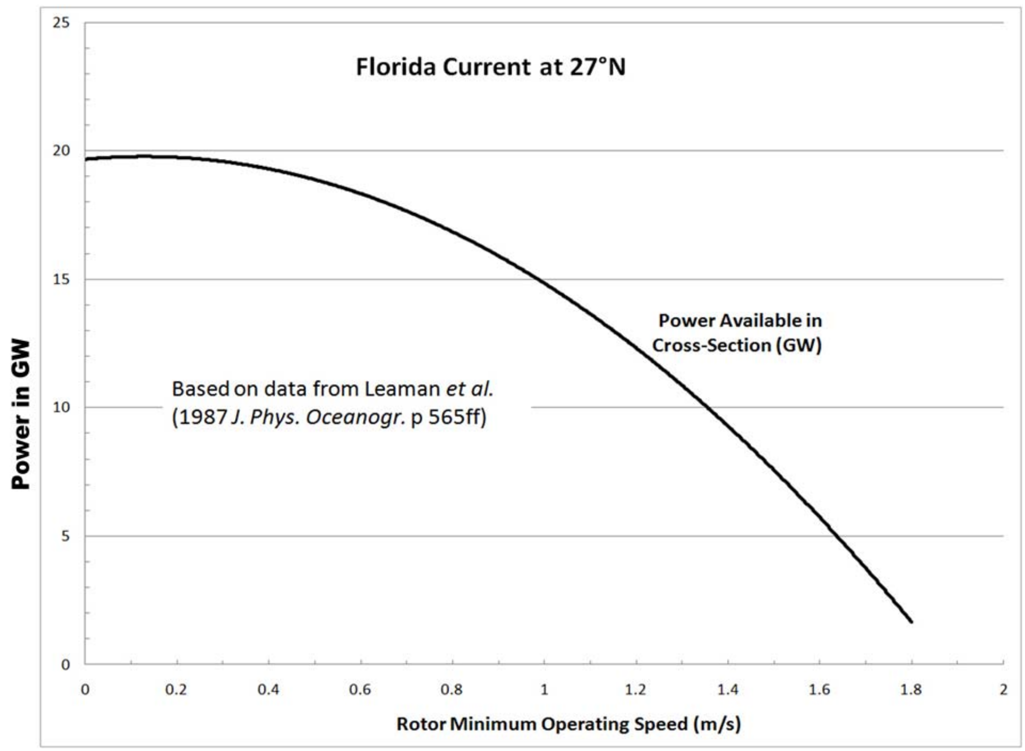


Figure 9-2. Power available in the Florida Current as a function of current speed

Source: Hanson et al. 2010 with data from Leaman et al. 1987

9.3.4 Ocean Thermal Energy Natural Resource

Ocean thermal gradient energy is created by a temperature difference between surface water and deep water in the ocean. OTEC requires a temperature difference of approximately 20°C for practicable generation. In tropical and subtropical latitudes between 24° north and 24° south of the equator, ocean water temperatures vary by 20°C from 20 m to 1,000 m in depth as illustrated by Figure 9-3 (HINMREC n.d.). The upper panel in Figure 9-3 illustrates the global OTEC resource (indicated by the green through orange and red color bands) for August 2005. The lower panel shows how the region of feasibility for OTEC was reduced in February 2005 when the sea surface temperature in the northern hemisphere was reduced.

Nihous (2007) used a one-dimensional theoretical analysis to show that steady state operation of OTEC plants could extract an estimated 40,000 TWh/yr, or approximately 5 TW, of steady continuous power from thermal gradient energy resources worldwide. In addition, little of this energy resource is located close to shore, making practical extraction and use more difficult and costly, except near Florida, Hawaii, and other Pacific islands. The Hawaii National Marine Renewable Energy Center and the Southeast National Marine Renewable Energy Center have active research projects to develop this resource. More information on thermal energy conversion resources is available from the Hawaii National Marine Renewable Energy Center (HINMREC n.d).

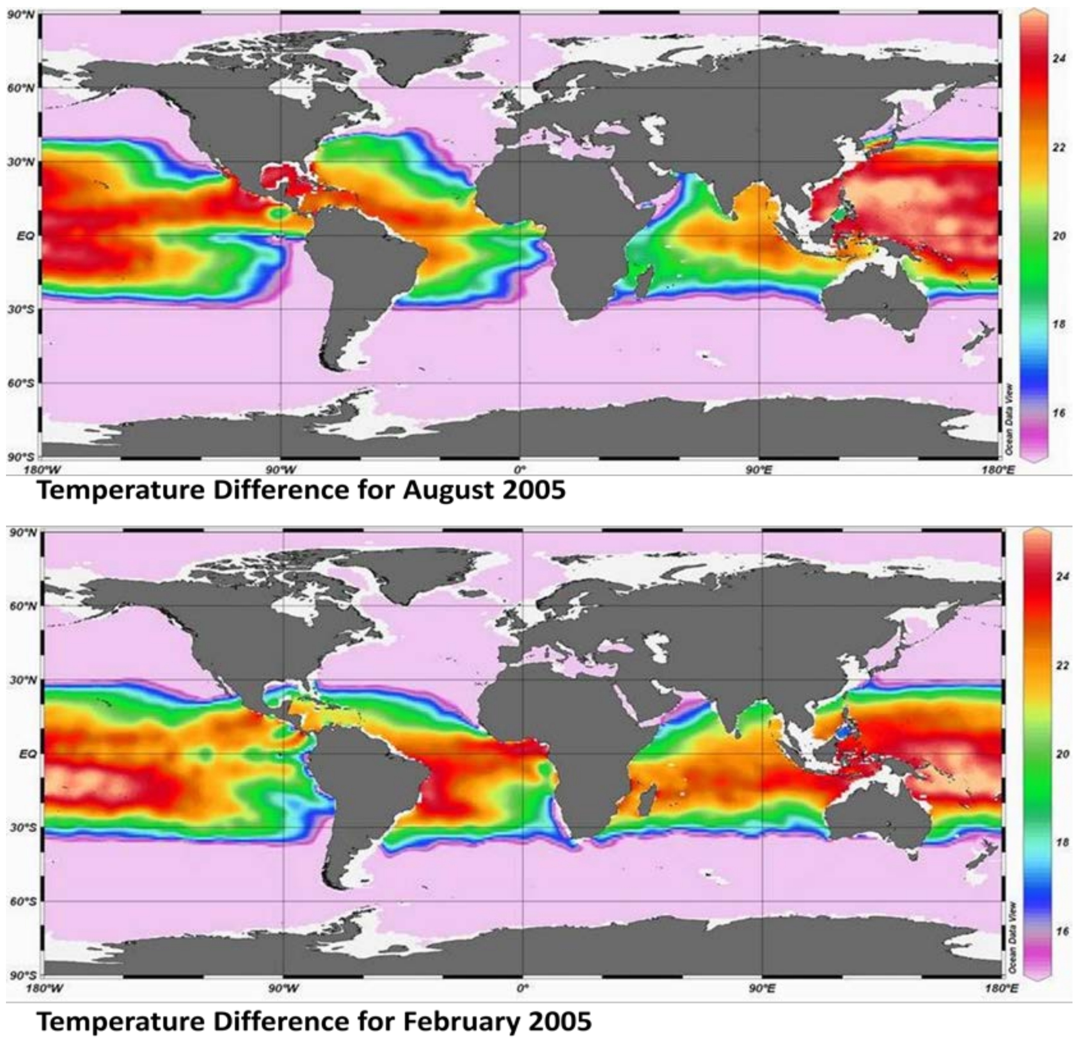


Figure 9-3. Ocean temperatures at 20-m and 1,000-m depths

Source: HINMREC (n.d.)

The natural OTEC energy resource estimate presented above is different from those for wave, tidal, and ocean current resources in that the thermal interaction of the device with the resource is taken into account. However, other restrictions such as environmental and other use limitations are not accounted for, so this estimate should be considered an upper bound on the practicable extractable resource.

9.3.5 Salinity Gradient Energy

At the mouth of rivers where freshwater mixes with saltwater in the ocean, energy is released from the mixing, resulting in a very small increase in the local temperature of the water. Two concepts are undergoing research for converting this mixing energy into electricity: reverse electrodialysis and pressure-retarded osmosis, which are explained in more detail by Jones (2003). Both of these electricity generation technologies are at the laboratory development stage and were not considered for modeling in RE Futures, but the salinity gradient conversion is discussed here for complete coverage of MHK technologies. The OES (2011) estimated worldwide theoretical salinity gradient energy natural resources to be approximately 1,650 TWh/yr. The U.S. natural resource has not been estimated.

9.4 Practicable Extraction Potential

9.4.1 Wave Energy—Practicable Extractable Potential

Bedard et al. (2007) made some engineering assumptions for extraction limits and wave device performance to estimate the extractable wave energy resource. Bedard et al. assumed a conversion of 15% wave energy to mechanical energy, which is limited by device spacing, device energy capture, and sea space constraints; a power train efficiency of 90%; and a plant availability of 90%. Under these assumptions, the electrical energy produced is approximately 260 TWh/yr giving an average power output of approximately 30,000 MW for all of the United States, including Hawaii and Alaska. Further assuming that the plant had a capacity factor of 33%, the installed capacity would be approximately 90,000 MW. The wave-generated electrical energy from this would be approximately 6.5% of the U.S. yearly electrical energy generation in 2010. If only the natural resources within the contiguous 48 states are considered, the practical extraction potential would be approximately 67 TWh/yr of electrical energy. Although these are experience- and judgment-based assumptions, they are not unreasonable and thought to be conservative. Thus, the U.S. wave energy resource has the potential to make a reasonable contribution to the United States's renewable energy portfolio close to west coast load centers and in Alaska and Hawaii. The wave energy in Alaska and Hawaii is of great value locally given their high electricity costs, but it is unlikely to contribute to the electricity needs in the contiguous 48 states within the timeframe of RE Futures, which is why a separate estimate is made excluding those resources.

To address the need for better estimates of wave energy resource than those of Bedard et al. (2007), the DOE Wind and Water Power Program funded EPRI to determine estimates for the maximum amount of practicable extractable offshore wave energy along U.S. coastlines. The study (EPRI 2011) used advanced wave modeling techniques and buoy-based wave measurements to estimate the total available and extractable wave energy resources on a state-by-state basis, as well as regional and national totals. Using a completely different approach than Bedard (2008) for calculating extractable energy, the EPRI study estimates the total extractable U.S. wave energy resource as 1,170 TWh/yr, which broken out by region is: 250 TWh/yr for the West Coast, 160 TWh/yr for the East Coast, 60 TWh/yr for the Gulf, 620 TWh/yr for Alaska, 80 TWh/yr for Hawaii, and 20 TWh/yr for Puerto Rico. For the contiguous United States, the extractable potential is approximately 470 TWh/yr, which is 7 times more than the estimate by Bedard et al. (2007). As has already been discussed, it is quite difficult to estimate the practicable extractable energy for technologies that exist only in prototype versions, where their limitations and environmental impacts are not yet quantified. So, it is not really a surprise that the different assumptions yield very different results for conversion potential. Undoubtedly, these differing extraction estimates will be reviewed and refined over time.

9.4.2 Tidal Energy—Practicable Extractable Potential

Bedard et al. (2007) and the EPRI team also made engineering assumptions in order to develop an estimate of the extractable tidal energy resource for a few selected sites in the United States. The study assumed a conversion of 15% tidal kinetic energy to mechanical energy, typical power train efficiencies of 90%, and a plant availability of 90%. The natural tidal energy resource in the contiguous 48 states for the three sites assessed—Puget Sound, Golden Gate, and the Western Passage in Maine—under these assumptions totals up to 6 TWh/yr. Under these energy conversion assumptions, the practicable extractable electricity produced at the three U.S. sites would be approximately 0.73 TWh/yr. This is equivalent to an average power of approximately 83 MW, and an installed capacity of approximately 220 MW, assuming a capacity factor of 38%, as in the EPRI study. It should be emphasized that this estimate is only for the three sites that EPRI studied and therefore is, at best, a lower bound. As was the case for wave energy, tidal energy in Alaska is of great value locally, but it is unlikely to contribute to the electricity needs in the contiguous 48 states within the time frame of RE Futures, which is why a separate estimate of extraction potential was made for the contiguous United States.

The tidal resource assessments for sites in the United States characterize the resource in terms of the natural kinetic power at a selected cross section of the flow and have assumed that the extractable resource is some fraction of this kinetic power. Although this is a simple and straightforward approach, it is fundamentally flawed. Karsten et al. (2008), Polagye et al. (2008), Garrett and Cummins (2007), and Bryden et al. (2004) have all shown that the problem is much more complex, and that there is no simple relationship between average natural kinetic power at a site and the amount that is practicable to extract for large-scale power production. Karsten et al. (2008) made the point that extracting power actually increases the tidal forcing that drives the flow, which in turn increases the energy that can be practicably extracted. Polagye et al. (2008) concluded that the effects of extraction could be relatively moderate, but that tidal flow response to extraction cannot be generalized. Therefore, extraction limits may need to be determined by modeling the tidal system's response to extraction on a case-by-case basis. However, there is general agreement that for small levels of power extraction, as has been assumed here, the resulting flow impacts should be small. Because only three sites have been assessed and because assessing the extraction limits is a complex task, practicable tidal power extraction limits for the contiguous 48 states are still unknown.

9.4.3 Ocean Current Energy—Practicable Extractable Potential

There is no established practicable extraction limit for ocean current energy. As previously discussed in Section 9.3, the Florida Current velocity field has been characterized at one cross section and the natural energy of the resource estimated to be approximately 175 TWh/yr. If the same engineering estimates used by Bedard et al. (2007) are used to estimate tidal power extraction potential (Section 9.4.2), the Florida Current extractable energy potential would be approximately 21 TWh/yr, or about 2.4 GW, of average power.

Ocean current turbines are similar to tidal turbines but sometimes mounted on a hydrofoil or floating platform and are anchored in relatively deep waters like the Florida Current, rather than on bottom fixed towers in shallower estuaries. Ocean current turbines are expected to be even closer in concept to wind turbines due to the unconstrained rotor size, although the hydrofoil and mooring clearly will be a significant variation. The added benefit of the steadiness of the Florida Current could potentially give high capacity factors and near base-load power production, if high reliability can be achieved and appropriate power control schemes can be developed. Flow velocity measurements and related statistics for the Florida Current reported by Raye (2002) verify the achievability of high capacity factors. Two turbine-control strategies could potentially allow controllable power output. To achieve controlled power output, the turbine designer would need to over-size the rotor for the mean flow velocity, and then use either rotor pitch control or depth control of the hydrofoil to control power. Just as in the atmospheric boundary layer, the flow velocity slows with depth due to proximity to the sea floor, which exerts a viscous drag on the flow. Raye (2002) also provided typical velocity-shear profiles of the Florida Current. Ocean currents do vary seasonally and they can meander, so there would be limits in the ability to regulate power production.

The Southeastern National Marine Renewable Energy Center located in Florida at Atlantic University will be performing further research to assess the energy extraction potential of ocean currents. The recent workshop sponsored by Florida at Atlantic University on renewable ocean energy in the marine environment provides the status of ongoing research on this topic. The workshop presentations are available online at the workshop website (FAU 2010).

9.4.4 Ocean Thermal Energy Practical Extractable Potential

Nihous (2007) developed a one-dimensional theoretical analysis that shows a steady state operation of OTEC plants that could extract an estimated 40,000 TWh/yr, or approximately 5 TW of steady continuous power from thermal gradient energy resources worldwide. Although the resource is vast, the potential is limited due to its geographical placement. The only regions in the United States that can conveniently generate electricity from this resource are Florida, Hawaii, and other Pacific Islands, making the direct electrical use of this resource fairly limited. Hawaii and Florida combined use approximately 236 TWh/yr, which represents a crude first estimate for the electricity that could be generated by ocean thermal generators, assuming that all of these states' electricity came from OTEC plants.

The Lockheed Martin Company is working under a DOE grant to develop a geographical information system-based tool to assess the practicable extractable energy from global and domestic OTEC resources to identify regions of high resource potential. Southeast National Marine Renewable Energy Center at Florida Atlantic University and the Hawaii National Marine Renewable Energy Center at the University of Hawaii are teaming with Lockheed Martin to build this GIS database, while the National Renewable Energy Laboratory is validating the assessment methodology. This project will improve understanding of the geographic distribution of the resource and the extraction potential.

9.4.5 Salinity Gradient Energy—Practical Extractable Potential

Salinity gradient generation technologies are at the laboratory development stage, as has previously been discussed. No estimates are available for the U.S. natural resource, so the practicable extractible potential cannot be estimated.

9.4.6 Summary of Marine Hydrokinetic Energy Resource

Table 9-1 summarizes the potential extractable U.S. marine hydrokinetic renewable resources that have been discussed in Section 9.2. As is noted in Table 9-1, there is considerable uncertainty in these estimates, and the extractable limits are based on rough engineering assumptions that have not been verified with real-world test data. In fact, the methodology for estimating the tidal resources is complex and may need to be done by modeling each particular situation. For this reason, the estimates in Table 9-1 probably represent a lower bound for the actual tidal resources. They are reported here simply to provide an understanding of the status of MHK resource assessment and provide a guide to the relative abundance of the resource categories.

Table 9-1. Summary of Currently Available Estimates for Marine Hydrokinetic Energy Resources

Energy Source	Natural Resource	Extractable Resource (Current Estimates)	Comments and Notes
Wave Energy	**Total U.S.** 2,100 TWh/yr (Bedard 2008) 2,600 TWh/yr (EPRI 2011)	**Contiguous U.S.** 67 TWh/yr (Bedard et al. 2007) 470 TWh/yr (EPRI 2011)	Bedard and EPRI used very different extraction assumptions
Tidal Current	**Total U.S.** 115 TWh/yr (Bedard 2008) 111 TWh/yr (Haas et al. 2011)	**Contiguous U.S.** Unknown (complex analysis) 6 TWh/yr (Bedard estimate for 3 U.S. sites)	Agreement that the U.S. tidal resource is relatively small compared to wave
Ocean Current	**Florida Current Only** 175 TWh/yr (Florida resource assessment is in progress and no other U.S. currents are viable)	**Florida Current Only** 21 TWh/yr (Florida resource assessment is in progress and no other U.S. currents are viable)	Based on Hanson et al. (2010) and tidal extraction assumptions by Bedard et al. (2007)
OTEC	**Worldwide** 40,000 TWh/yr (U.S. resource not estimated)	**Contiguous U.S.** Not estimated (U.S. assessment in progress)	Large worldwide resource based on Nihous (2007) analysis
Salinity Gradient	**Worldwide** 1,650 TWh/yr (OES 2011;U.S. resource not assessed)	**Contiguous U.S.** Not estimated (Not currently being assessed)	Worldwide resource based on OES (2011) estimate

9.5 Technology Characterization

Many MHK concepts have been proposed with a variety of methods for energy capture and conversion. More than 100 different concepts are in various stages of development in 24 countries (Khan and Bhuyan 2009). In the United States alone, at least 40 MHK concepts are in development; however, there is little convergence of the technology toward a particular configuration or energy resource, indicating that no particular technology or configuration has yet been shown to be superior. Figure 9-4 shows the technologies under development worldwide.

Figure 9-4 includes the tidal barrage concept, which has not been discussed up to this point. Tidal barrages are dam structures built across the mouth of an estuary with a high tidal range. The barrage is conceptually identical to a conventional hydroelectric dam on a river, except that the barrage, or dam, can generate power during incoming and outgoing tides. The chapter on hydropower provides more information on barrage systems and will not be considered further in this chapter. Figure 9-4 includes tidal current devices and ocean current devices in one category. Many tidal devices are also being proposed for ocean current applications with a modified supporting structure, foundation, or mooring arrangement. From Figure 9-4, it is clear that most of the development is in the area of wave and tidal/ocean current technologies, which is why this chapter primarily focuses on these technologies. However, there is growing interest in OTEC, which is briefly reviewed here.

The following sections describe typical configurations for the major device types for each ocean energy resource. A comprehensive list of marine and hydrokinetic device configurations, current projects, and development companies is provided in the Marine and Hydrokinetic Technology Database on the DOE website (DOE 2011).

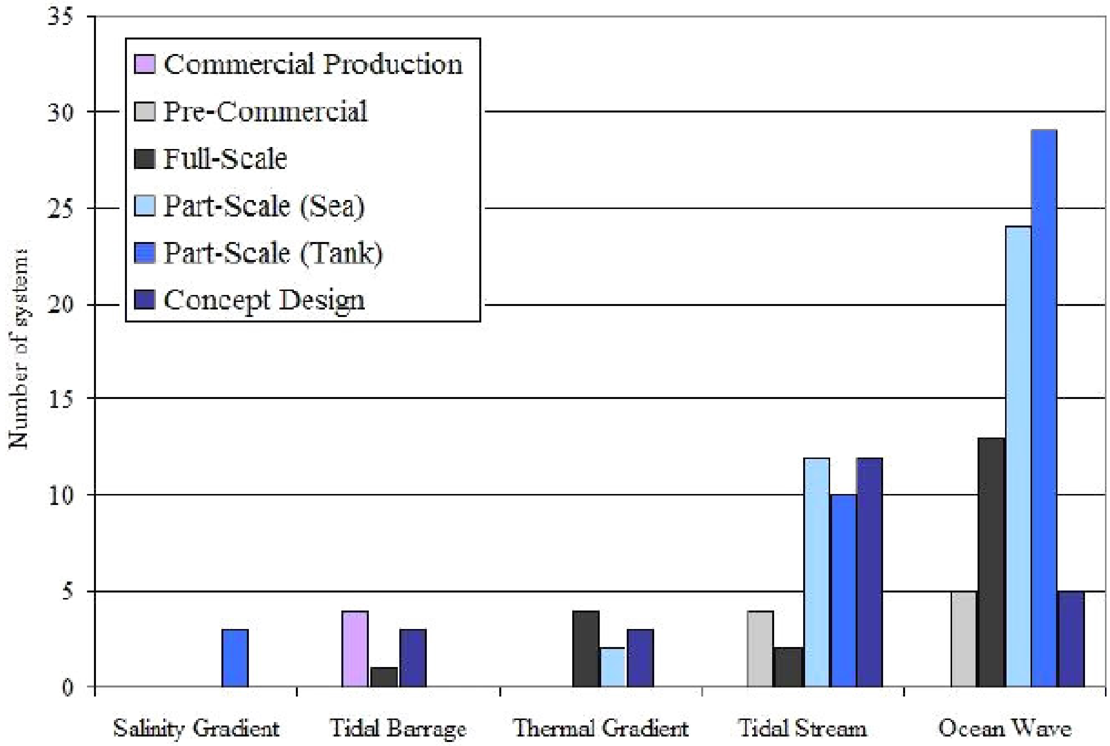


Figure 9-4. Marine hydrokinetic technologies in development worldwide

Source: Khan and Bhuyan 2009

9.5.1 Status of Wave Energy Technologies

The several types of wave energy technologies illustrated in Figure 9-5 that are deployed or under development can be classified into the following general categories:

- *Point absorbers* extract energy from the movement of a buoy relative to the ocean floor with the rise and fall of waves. This movement is converted to electrical energy either through a linear or rotary generator.
- *Overtopping devices* allow waves to lift water over a barrier, which fills a reservoir that is drained through a hydro-turbine. They are often described as low-head hydropower facilities because they convert the potential energy of the elevated water in the upper reservoir to generate power much like a conventional hydropower dam.
- *Oscillating water columns* are partially submerged enclosed structures. Air fills the upper part of the structure above the water level. Incoming waves are funneled into the structure from below the waterline, causing the water column within the structure to rise and fall with the wave motion. This alternately pressurizes and depressurizes the air column,

pushing and pulling it through an air turbine mounted in a portal in the top of the column structure.

- *Attenuators* capture wave-energy with a principal axis oriented parallel to the direction of the incoming wave. They convert the energy created by the relative motion of the articulated bodies of the device as the wave passes along it.
- *Inverted pendulum devices* use the surge motion of waves to rotate a large, hinged paddle back and forth. The flapping motion drives hydraulic pumps that in turn drive electrical generators. Alternatively, linear generators are used to directly convert the wave energy into electrical energy.

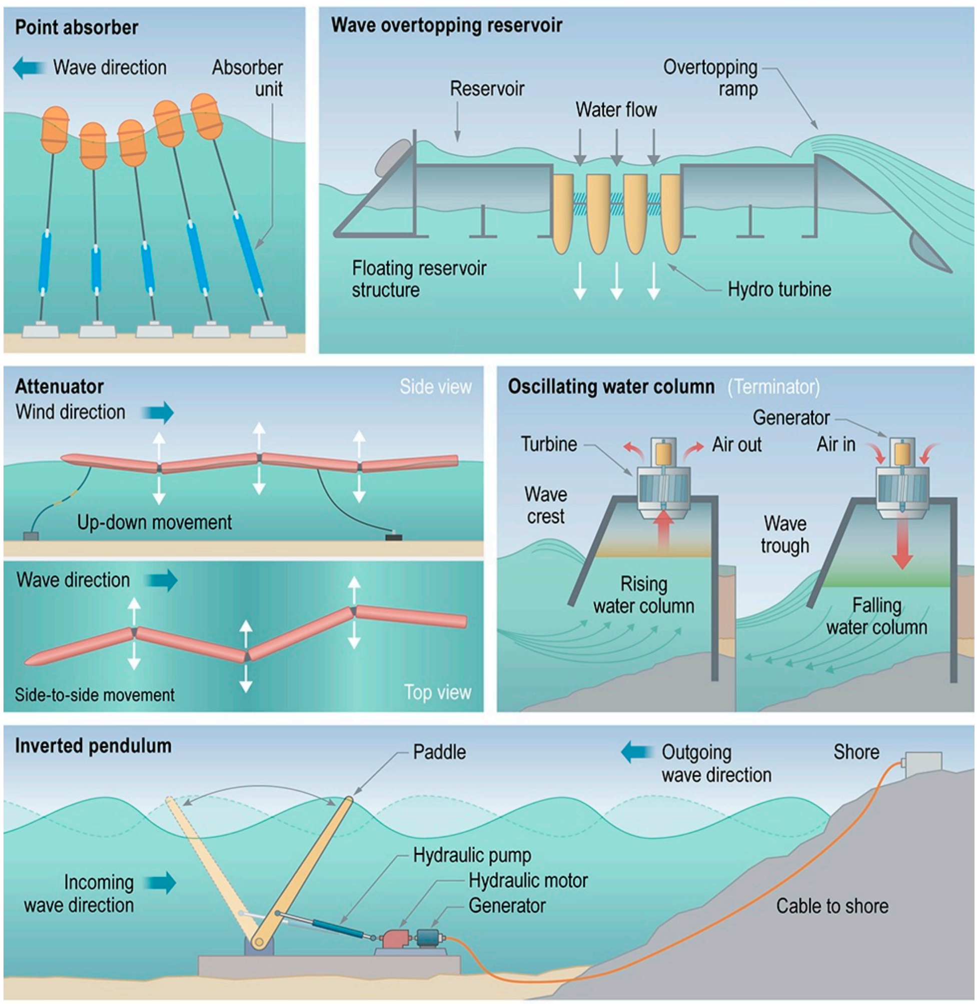


Figure 9-5. Primary types of wave energy devices

Adapted from: Bedard 2006 (illustrations not to scale)

9.5.2 Status of Tidal, Open Ocean, and River Current Hydrokinetic Turbine Technologies

Tidal, ocean, and river current turbines convert the kinetic energy of flowing water into electricity in exactly the same manner that a wind turbine converts the kinetic energy of wind into electricity. Figure 9-6 illustrates four typical tidal energy devices: an axial-flow horizontal-axis turbine, a vertical-axis cross-flow turbine, a shrouded (venturi-augmented) axial-flow horizontal-axis turbine, and an articulated arm oscillating hydrofoil generator. Although the illustration pictures a vertical-axis cross-flow turbine, cross-flow turbines can have the rotor spin axis oriented either horizontally or vertically. There are many different configurations for turbine shrouds. They can have a large inlet area, with a large area change between the entrance and the throat, as shown in the illustration. Alternatively, they can be relatively short with a smaller area ratio. In some designs, the primary purpose is to capture and accelerate more of the flow to improve energy capture. In other cases, the primary purpose is service as structural housing for a large ring generator enclosed in the shroud. In still other situations, it is to increase energy capture while minimizing the shroud-related cost and weight. Tidal barrages, as already mentioned, are dam structures built across the mouth of an estuary with a high tidal range. Chapter 8 provides more information on impoundment systems.

Tidal and ocean current turbines can look quite similar and have the same operating principles. However, several key differences can significantly alter the size, operational control, and mooring of the devices. Ocean current turbines operate in relatively steady, lower velocity flows that are unidirectional, fluctuate seasonally, and can be far from shore in deeper water, as has already been discussed.

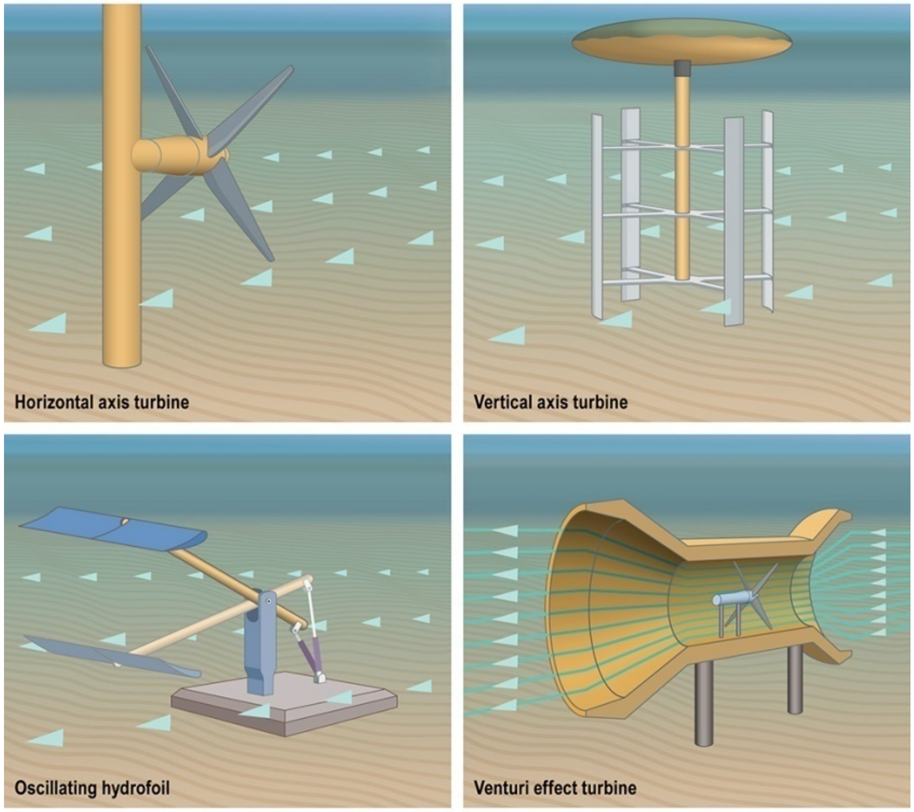


Figure 9-6. Primary types of tidal flow energy conversion devices

Adapted from Bedard 2006 (illustrations not to scale)

9.5.3 Status of Ocean Thermal Energy Conversion

Ocean thermal energy is generated when warm surface water is used to boil a working fluid, such as ammonia, which is run through a turbine before being condensed by cold water that is pumped from the ocean depths. With a large enough gradient, the amount of power produced by the turbine exceeds the power required to pump the cold water to the surface. There are two basic OTEC configurations: open-cycle and closed-cycle. Vega (2002) described all competing technologies and their relative strengths and weaknesses in a primer on OTEC. In addition, Vega (2010) developed an engineering capital cost estimate of $7,900/kW[68] for a 100-MW scale OTEC plant.

OTEC has some desirable operating characteristics due to relatively steady energy production, unlike some other renewable sources. It has a relatively high capacity factor providing close to base load operating characteristic, even though the output might vary annually due to the seasonal changes in the water temperature differential between the surface and 1,000 m in depth. An abundant resource exists along the Florida coast and around Hawaii, as shown in Figure 9-1, and it could contribute to the U.S. electricity supply.

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[68] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

9.5.3.1 Open-Cycle Ocean Thermal Energy Conversion

Open-cycle technologies use the warm surface ocean water as the working fluid, which is drawn into a vacuum vessel causing the working fluid to vaporize. The expanding vapor from the boiling seawater drives a turbine that is connected to a generator. The steam, almost salt-free vapor, is then condensed with the cold ocean water as shown in Figure 9-7. The main advantage of this cycle is that it produces both electricity and desalinated water for fresh drinking water.

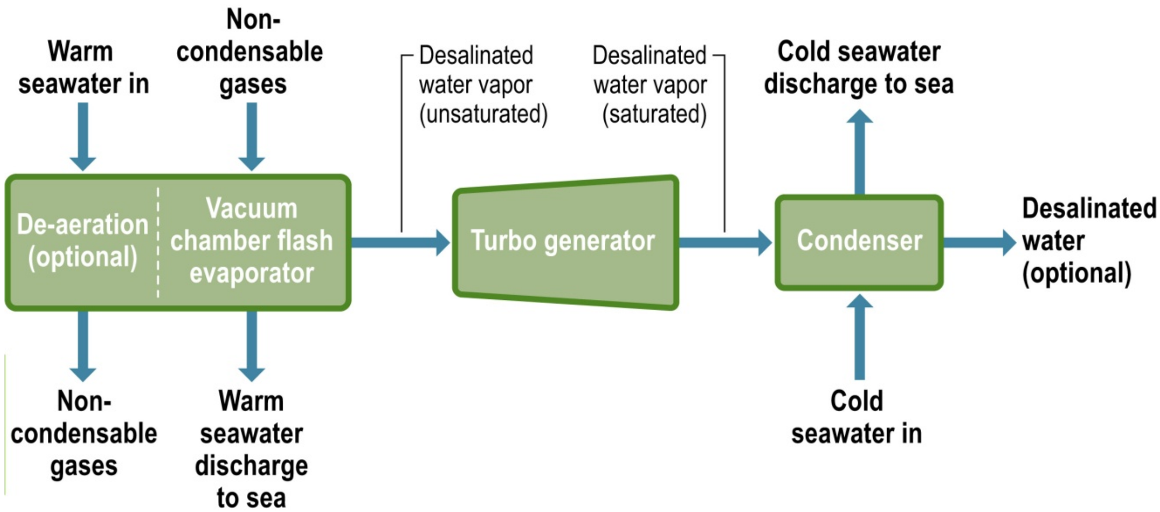

Figure 9-7. Open-cycle ocean thermal energy conversion system

Source: DOE 2009

9.5.3.2 Closed-Cycle Ocean Thermal Energy Conversion

Closed-cycle OTEC is similar to open-cycle OTEC but uses a working fluid, such as ammonia, that boils at a lower temperature than water. The ammonia is vaporized by the warm surface water, which drives a turbo generator, as shown in Figure 9-8. The steam is condensed with cold water from lower depths, and the ammonia is condensed back into the working fluid.

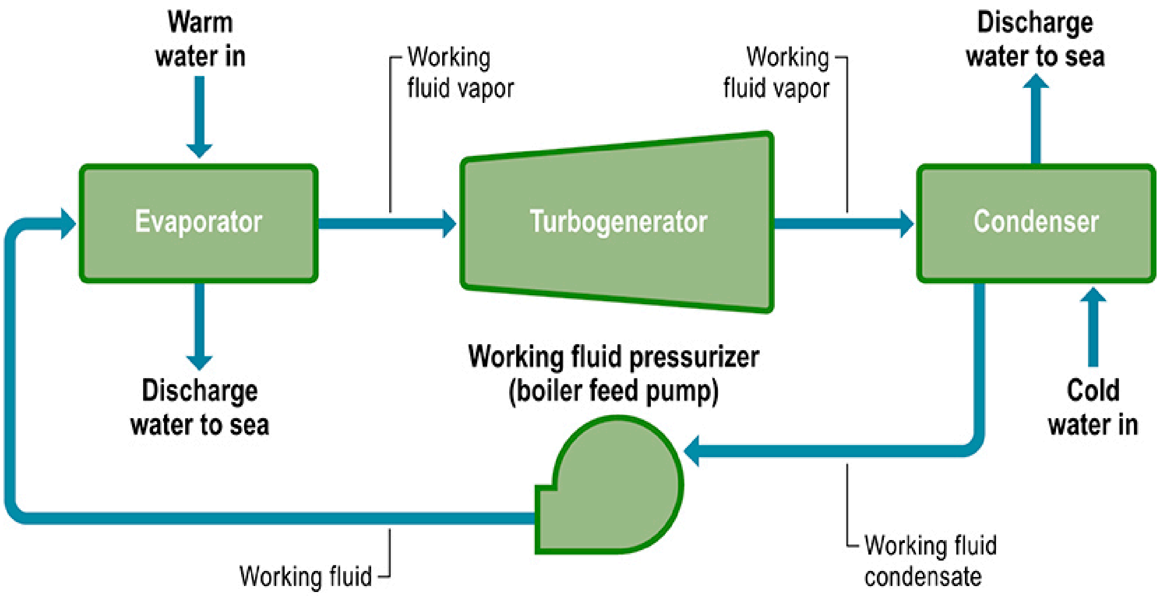

Figure 9-8. Closed-cycle ocean thermal energy conversion system

Source: DOE 2009

9.5.4 Status of Salinity Gradient

Salinity gradient power generation uses the potential energy available when freshwater and seawater mix. Figure 9-9 shows how a pressure retarded osmosis power generator would work. In the diagram, freshwater and saltwater both flow through a reaction module separated by an artificial semi-permeable membrane. Osmotic pressure drives the freshwater through the membrane to the saltwater side, increasing the pressure and the flow in the saltwater channel of the module. The high pressure, higher flow rate channel is then passed through a turbine to produce electricity. Statkraft (n.d.) has built a 2–4-kW pilot plan to perform research on the feasibility of salinity gradient power.

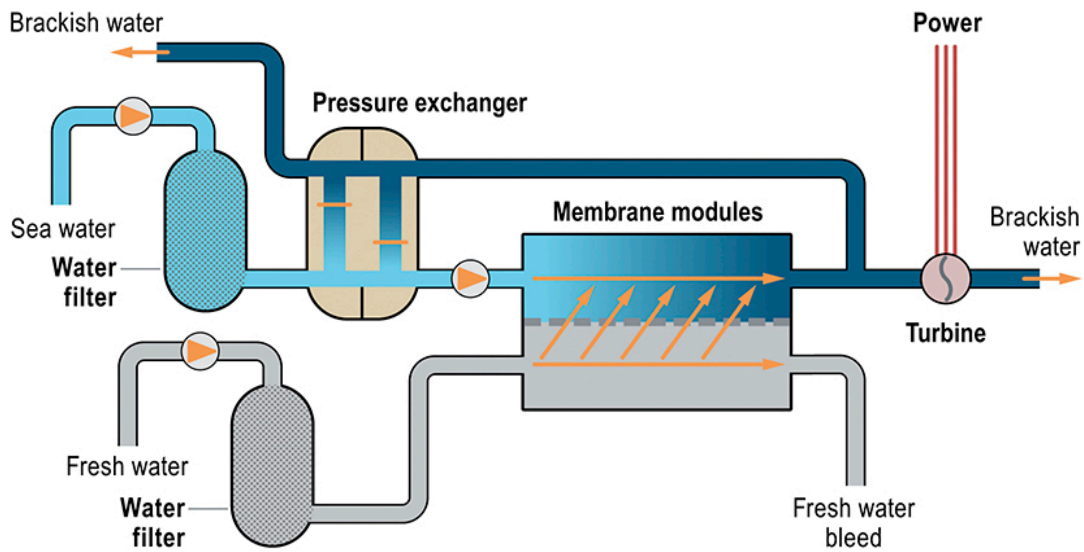

Figure 9-9. Pressure-retarded osmosis energy conversion system

Source: Khan and Bhuyan 2009

9.6 Ocean Technologies RE Futures Scenario Analysis and Cost and Performance Estimates

Neither wave nor tidal energy technologies were represented in the RE Futures modeling because of their early immature stage of development and they are not yet commercially available. The modeled scenarios in RE Futures included currently commercially available technologies only. Cost and performance estimates were, however, provided by Black & Veatch (2012) for development of renewable and conventional technology projections used in the modeling analysis. Although wave and tidal technologies are at the most advanced stage of development compared to the other MHK technologies, only a few prototype devices have been tested in North America.

At this time, the United Kingdom has the most experience in designing and testing wave and tidal generators. The United Kingdom also has the most real-world performance and cost information and has made the most recent wave and tidal cost of energy estimates. These estimates were based on first-of-a-kind devices and small arrays of about the 10-MW scale. The Carbon Trust report titled *Accelerating Marine Energy* provides these cost-of-energy estimates based on this experience (Carbon Trust 2011). To develop these cost-of-energy estimates, the Carbon Trust worked with leading industry developers to perform a bottom-up analysis on the technologies. The estimates include all capital and operating costs associated with the array of devices, including the cost of the electrical interconnection to the grid, but does not account for any potential grid upgrades. The levelized cost-of-energy is calculated by summing all of the discounted lifetime costs and then dividing by the lifetime energy generated. A discount rate of 15% and lifetime of 20 years was assumed for this analysis. The relatively high discount rate accounts for the risk involved in these new types of marine energy projects. Lower discount rates would be expected as the technology matures and experience grows. This analysis puts the baseline cost of energy for tidal devices at 29–33 British Pence/kWh for a tidal farm 10 MW in size. This translates to approximately 47–54 U.S. cents/kWh, at the exchange rate of 1.63 U.S. dollars per British Pound. These figures are based on the most recent U.K. knowledge of real, full-scale project costs and operating experience. For wave energy projects, this analysis estimates the cost of wave energy at 38–48 British Pence/kWh. This converts to approximately 62–78 U.S. cents/kWh. The report also accounts for uncertainties in the costs and performance estimates, which puts large uncertainty bands around these estimates.

These costs are quite high in comparison with conventional, fossil-based generation and are even high when compared with other renewable technologies. However, *MHK technologies are immature, and all of the competing renewable energy technology costs started out as high, or higher, when research was first initiated in the 1970s and 1980s*. For example, land-based capital costs for wind plants in the early 1980s were approximately $4,500/kW, and this cost was reduced to approximately $2,100/kW in 2011 (Wiser and Bolinger 2011). This represents a cost reduction factor of approximately 2.1, and if wave and tidal cost were reduced by a similar factor, they would be approaching the range of costs for offshore wind energy.

Furthermore, at the current prototype stage of MHK technology development, innovation of the engineering designs to reduce cost and improve performance prior to large-scale deployment represents the most promising opportunity for advancement in MHK technologies. This is consistent with early wind turbine development experience during the initial deployments in California in the 1980s, and themes presented in the Carbon Trust report by Callaghan and Boud (2006). Conceptually, the cost of energy can be reduced in four main ways:

- **Develop breakthrough innovations** that in one step dramatically reduce weight and cost, or allows simplified assembly and installation, and greatly reduced maintenance, or provides greatly increased performance
- **Detail design refinements** that incrementally over time reduce weight and cost, simplify assembly and installation, reduce maintenance, or increase performance
- **Develop design advancements** that improve economies of scale, such as improvements that increase the unit size of the machine as has been done for wind turbines over the past three decades
- **Continue learning** in production, construction, installation, and O&M as has been done by wind turbine manufacturers.

Innovative concepts, although important at any stage of development, tend to be most successful during the early stages of development for new technologies when the preferred configuration for devices is still in question, as is the case for all MHK technologies. In the early stages of development, the cost of innovation is minimal and change involves little additional risk. In the later stages of development, the market selects a particular configuration (optimal or not) and the perception of risk (and financing costs) due to major innovations increases significantly. For this reason, major configuration changes to these machines are expected to occur early in the development cycle, prior to large-scale deployment and probably during early prototype and demonstration cycles. Although innovations continue even during large-scale commercial deployment, the pace is slower because of the increased financial risk of incorporating a design flaw into a model undergoing a large production run. The latter three ways of improving the technology tend to be more important in later development stages when the devices are in mass production and deployment.

Device energy-capture represents another area where improvement is possible. In wave tank tests with regular sinusoidal waves, the device capture width of wave devices can be larger than the device under certain operating conditions; thus, high wave device capture efficiencies are possible as illustrated in Cruz (2008). The theoretical conditions to maximize power extraction from wave devices are understood, and various control strategies to maximize power are being implemented (Falcão 2010). Tidal devices also have the potential to increase energy capture, although some water turbines have energy captures that achieve the capture efficiency (power coefficient) of modern wind turbines.

9.7 Output Characteristics and Grid Services Possibilities

9.7.1 Electricity Output Characteristics

MHK and ocean energy generators use a variety of generator types. However, most employ rotating generators that produce direct, utility-grade AC or DC that is then converted into AC via an inverter. The output characteristics of MHK devices vary considerably given the wide range of resource characteristics and device configurations.

- Ocean current generators, OTEC, and possibly salinity gradient power plants are expected to have a relatively steady output on a daily and weekly timescale and therefore could be characterized as a base load resource. However, output will vary seasonally with annual resource cycles. For example, the Florida Current meanders and varies seasonally, so the output of a current generator will probably vary slowly.
- Wave devices under development consist of those that have direct generation and others that feature buffering of output through hydraulic power take-off systems with accumulators or short-term electrical storage. The latter would have a beneficial impact on high-frequency fluctuations. Most wave energy devices will be deployed as modular units in an array, similar to wind farms. Such wave farms will have a collector system that provides the benefit of smoothing the power output from the entire array and provides redundancy. Such a configuration would benefit from an averaging effect, and with strategic device placement, could achieve a steadier output. Integration of offshore wind and wave systems might provide further opportunity to reduce this output variability. In general, it is expected that wave energy farms will show less variability than wind energy. The wave energy resource varies seasonally and is produced by far-field, weather-driven wind and water interactions, and the mean sea state can be forecast with high accuracy up to three days in advance.
- Tidal current variability consists predominantly of half-day and 14-day cycles. Tidal energy is highly predictable well into the future because the tidal cycle is driven by well-understood phenomenon.

There are very limited data on the actual measured time history output from MHK devices or arrays, so firm conclusions on the electrical system integration requirements remain uncertain.

9.8 Deployment of Marine Hydrokinetic Energy Technologies in 80% Renewable Electricity Scenarios

Wave, tidal, and ocean current technologies were not modeled in ReEDS due to the immature status of MHK technologies and the lack of commercially availability devices at this time. The high capital costs of MHK technologies indicate their early stage of development. MHK technologies will need additional research, development, and demonstration prior to becoming competitive with other renewable technologies and conventional generators. Modern wind, solar, and biomass technologies have been in development more than three decades, yet they are still not fully cost competitive with conventional electricity generation technologies, some of which began development more than a century ago.

Fixed-bottom offshore wind achieved significant deployment in the 80% RE scenarios. This provides a benchmark to gain some insight into the cost and performance targets that MHK technologies need to achieve to be competitive with land-based renewable generators. A comparison of the technology cost projections for fixed-bottom offshore wind with those for ocean technologies, as developed by Black & Veatch (2012), for the RE-ITI data used in some of the modeled scenarios[69] reveals the improvements needed by MHK. In particular, in 2030, wave technology capital costs are roughly 60% higher, and the O&M is more than twice as high per kilowatt-hour. From this, it is clear that for MHK technologies to be on a par with fixed-bottom offshore wind power, they need to significantly reduce capital and O&M costs, and improve performance. The fixed-bottom offshore wind capital cost of approximately $2,000/kW and performance resulting in a capacity factor of approximately 35%–40% can thus serve as rough metrics for the competitiveness of MHK technologies. Deep-water floating wind systems were similarly treated as non-commercial, and like MHK technologies were not included in the 80% RE scenarios. Other attributes, such as visual acceptance and environmental impacts, might also influence which technologies are ultimately deployed.

At the current prototype stage of development, innovation of engineering design to reduce cost and improve performance prior to large-scale deployment represents the most promising opportunity for advancement in MHK technologies. This is consistent with early wind turbine development experience prior to the initial deployments in California in the 1980s, and themes presented in the Carbon Trust report by Callaghan and Boud (2006). Conceptually, the cost of energy can be reduced in four main ways, as noted above: conceive breakthrough innovations; detail design refinements; develop advancements that improve economies of scale; and continue learning.

Breakthrough innovations can occur at any stage of development, but tend to be most successful during the early stages of development for new technologies when the preferred configuration for devices is still in question, which is clearly the case for all MHK technologies. In the early stages of development, the cost of innovation is minimal and change involves very little risk. In the later stages of development, the market selects a particular configuration (optimal or not) and the cost and risk of major innovations increases significantly. For this reason, major improvements to these machines are expected to occur early in the development cycle, prior to large-scale deployment and probably during early prototype and demonstration cycles. Although

[69] All RE Futures scenarios modeled are described in Volume 1.

innovations continue even during large-scale commercial deployment, the pace is slower because of the increased financial risk of incorporating a design flaw into a model undergoing a large production run. Several wind companies have filed bankruptcy after manufacturing and deploying a great number of units built using a design with undiscovered minor problems that had to be fixed in the field at high cost. The other three ways of improving the technology tend to be more important in later development stages when the devices are in mass production and deployment.

Device energy-capture represents another area where improvement is possible. In wave tank tests with regular sinusoidal waves, the device capture width can be larger than the device under certain operating conditions; thus, high device capture efficiencies are possible as illustrated in Cruz (2008). The theoretical conditions to maximize power extraction from wave devices are understood, and various control strategies to maximize power are being implemented (Falcão 2010). Tidal devices also have the potential to increase energy capture, although some water turbines have energy captures that are approaching the efficiency of modern wind turbines. Finally, modeling improvements for MHK devices can also reduce risk and improve the cost effectiveness of these machines. For example, energy capture for large device arrays is an area of uncertainty that can be addressed using computational fluid dynamics (CFD) in a high-performance-computing environment. CFD can be used to predict the very complex hydrodynamic array interactions, as well as the environmental fluid mechanical impacts of the energy extraction process.

9.9 Large-Scale Production and Deployment Issues

Moving ocean technologies from their current level of maturity to commercially viable systems will require significant investment in research, development, and deployment (RD&D) followed by significant capital investment and the development of large ocean industries. The possible environmental impacts, particularly with respect to water and marine habitat impacts, of new and emerging ocean energy systems are not well understood. Although ocean energy technologies do not appear to have manufacturing, transportation, facilities or basic materials barriers to continued development or deployment, concerns about potential environmental impacts will make it difficult to site and permit projects.

9.9.1 Environmental and Social Impacts

Ocean energy could provide a viable electrical energy source, displacing fossil fuel-based energy resources and providing benefits to the environment by reducing the production of carbon dioxide, which leads to climate change and ocean acidification. However, there is an environmental risk due to introducing these unique new devices into the marine environment. There are concerns about their physical presence and the introduction of moving devices, the artificial reef effect cause by adding hard barrier structures, and the alternation of the natural flow through energy conversion. In order to appropriately site and operate these devices, a better understand of their environmental effects is needed. Despite the strong global interest in MHK development, the environmental unknowns associated with siting and permitting of MHK projects have been a significant barrier to their deployment and operation. While there has been much interest and discussion concerning the potential environmental effects of MHK devices, the actual effects have not been directly measured in the open water environment. The following sections briefly summarize the concerns expressed about potential environmental impacts.

9.9.1.1 Land Use, Water, Air, and Ecological Impacts

The possible environmental effects associated with new and emerging MHK technologies is not well understood. Boehlert et al. (2008) reviewed the possible environmental effects of wave development, and Grecian et al. (2010) independently reviewed the specific potential effect of wave development on marine birds. Polagye et al. (2010) reviewed the potential environmental effects of tidal development, and Gill (2005) and Inger et al. (2009) called for multi-disciplinary scientific research to develop a better understanding of the environmental implications of MHK technologies before they are widely deployed.

At this time, there is a fairly comprehensive understanding of the range of possible environmental effects and interactions that could take place as MHK technologies are deployed. In addition, there seems to be a reasonable understanding of which of these effects could potentially be of high ecological significance, but there is little or no understanding of the actual impacts. This is because there are no devices in the water to observe and measure the real impacts, which many agree is a logical next step. It is generally agreed that the potential for significant impacts is almost negligible, provided early deployments are small and that the installations are appropriately monitored.

There are additional concerns that measuring the actual impacts of single prototype and small installations might be difficult due to the highly variable environment in the ocean. In addition, there are no generally accepted monitoring protocols for MHK projects in the United States. However, in Europe, a project called EquiMar (n.d.) has been established to develop harmonized monitoring protocols for MHK prototype deployments. These European protocols for the assessment of marine energy converters are summarized in Ingram et al. (2011) and could serve as a starting point for study and field data collection efforts in the United States, as well as the development of U.S. specific protocols. Finally, the OES (2011) recently established a new task to share environmental information among the member counties in an effort to accelerate the development of a thorough and universal understanding of any potential environmental impacts due to MHK technologies.

Studies to better understand and estimate the significance of any impacts on marine life, marine geography, recreation, cultural resources, and public safety will be needed before MHK technologies can be widely deployed. The following list of environmental stressors and potential impacts is summarized from the workshops and papers noted above:

- Ocean wave, current and river stressors, and potential impacts:
    - Effects of energy-removing structures on wave height, tidal current flow patterns, and the resulting sediment transport
    - Effects of electromagnetic fields on fish and marine mammals
    - Interactions of MHK devices with fish and marine mammals
    - Impacts of chemical emissions into the ocean
    - Effects of introduced hard structures, including artificial reefs or other devices that have the effect of aggregating fish
    - Acoustic effects of many devices on fish and marine mammals
    - Visual impacts
    - Conflicts with other uses of sea space (e.g., fishing, boating, shipping, clamming, crabbing)
    - Effects of installation and decommissioning
    - Cumulative impacts of all the environmental effects over many sites and time
- Land-based potential impacts:
    - Visual impacts
    - Social impacts on coastal communities
- Atmospheric potential impacts:
    - Impacts of chemical emissions into the atmosphere
    - Acoustic effects of marine operations
    - Impacts on aquatic birds and migrating bats flying far offshore.

9.9.1.2 Life Cycle Greenhouse Gas Emissions

MHK technologies do not burn fuel to generate electricity, so there are no GHG emissions associated with generation of electricity from MHK like there are with conventional fuel-burning technologies. However, MHK technologies contribute to GHG emissions during their life cycle stages, including the extraction of raw materials, transportation, and manufacturing into mechanical components, plant construction, O&M, dismantling, and disposal. However, because MHK technologies are not deployed in RE Futures scenarios, their GHG emissions are not considered in this study.

9.9.2 Manufacturing and Deployment Challenges

Today and for the foreseeable future, the MHK industry does not appear to have manufacturing, transportation, facilities, or basic materials barriers to continued development or deployment. The current size, complexity, and materials for fabricated of MHK devices do not represent a manufacturing or deployment challenge. Even over the longer term, the manufacturing challenges are comparable in many ways to the wind turbine and the oil and gas industry and are felt to be manageable with the continued growth of the industry. The major challenges for the MHK industry are a consequence of its newness, and lack of a proven record of accomplishment, as a renewable energy generator. The more mature renewable technologies, such as solar and wind, have 30 or more years of experience and much more is understood about their performance, cost, and environmental benefits and impacts. In contrast, MHK technologies remain immature and unproven, and they have not been deployed in significant numbers, resulting in costs that are estimated to be too high to be competitive. There also remain many concerns about potential environmental impacts, which makes it difficult to site and permit projects. Finally, the financial investors are unwilling to take on the amount of risk that MHK projects would require with the current level of uncertainty.

9.9.2.1 Manufacturing and Materials Requirements

MHK technologies already benefit from the experience of renewable energy technologies now in mass production. Various institutions involved in ship-building, offshore oil and gas development, wind energy, aerospace, insurance, and finance are becoming actively involved in ocean energy projects. This activity is being driven by several factors, including the need to diversify operations; the existence of trained workforces; the availability of equipment that can be applied to MHK manufacturing; and the availability of coastal locations with adequate real estate for manufacturing and fabrication of devices.

Manufacturing, fabrication, and assembly will require dock space, adequate land, and anticipated onshore O&M facilities. The major materials needed to manufacture MHK technologies include: steel, composites, concrete, electronics, and many plastic materials that are in abundant supply. Component and subsystem suppliers purchase electronic parts, connectors, and other specialties from manufacturers in the United States and, in some cases, from throughout the world for project developers. Therefore, at this time, facilities, components, and materials do not have limited short-term or long-term supply constraints.

It is probable that over a period of time, the power output, physical size, and weight of MHK devices will increase, as has been the case for wind turbines. As has been the case for wind turbines, the physical size of machines has grown and the weight per unit of energy has decreased, resulting in a lower cost of energy while the overall weight and size have dramatically increased, making transportation an issue. For this reason, it can be expected that most large-scale final assembly of MHK technologies will need to be located near deployment sites for ocean transport and installation. However, manufacturing of components will likely take place at existing facilities around the United States and globally. The use of rail, truck, and barge services is also anticipated as manufacturing centers begin to mature and serve regional needs. In this case, transportation of assembled devices might—to some extent—involve specialized deployment vessels. However, to avoid the time and costs associated with specialty deployment and retrieval vessels, some companies are currently designing their technology so that it can be deployed using existing smaller boats. Still other companies have modified existing tugboats and other seagoing vessels for deployment of MHK technologies. The National Oceanic and Atmospheric Administration and the U.S. Coast Guard can assist the industry by defining appropriate salvage, safety, and emergency services requirements.

9.9.3 Deployment and Investment Challenges

Device developers need to get projects "into the water" so that they can refine and prove their designs under real-world conditions. This will demonstrate the viability of the technologies and attract investment capital. However, the real-world environmental impacts of MHK technologies have not been measured at this time. In this situation, permitting agencies may request more extensive baseline studies, which can slow the demonstration of MHK technologies. Technical specifications, standards, and certification methods are only recently being developed to provide the necessary confidence to insurers and financial institutions that the existing MHK devices have been rigorously designed to the best state-of-the-art practices and will survive and perform as expected. The United States is involved in the development of international standards through the American National Standards Institute and the International Electrotechnical Committee (IEC 2010). However, the committee (TC 114) is only developing technical specifications because ocean energy technologies are not mature enough for the development of full standards yet. A complete standard and certification process will need to follow as soon as possible for the MHK industry to develop and fully mature.

9.9.4 Human Resource Requirements

Jobs in MHK technologies include: design, development, manufacturing, project development, deployment, shoreline development, port logistics, O&M, and recovery. Many of these jobs are engineering jobs for the design and project development stages, while the manufacturing, O&M, and recovery stages of projects are primarily technicians and skilled labor jobs. EPRI (Bedard 2006) estimated that a 100-MW wave power plant provides approximately 24 permanent local jobs during the operational phase of the power plant.[70] In this industry, deployment and recovery will require experienced personnel with offshore construction expertise. Currently, educational institutions with curricula relevant to MHK technologies are limited. As the technology begins to mature, national and local workforce development and training programs would improve the supply and skill of U.S. workers for the domestic ocean energy industry. More than likely, a successful MHK industry will be international in nature with a global workforce much like the oil and gas industry today. There is no standardized method for estimating current or future personnel requirements. Because the U.S. MHK industry is just beginning, the employment requirements are particularly difficult to estimate. Therefore, no estimate is provided.

9.10 Barriers to High Penetration and Representative Responses

Given the current cost of MHK technologies, a significant investment in R&D to reduce cost and improve performance will be required to make them commercially viable in electricity markets. In addition, MHK technologies will probably need an appropriate form of market support to initiate early deployments and reduce risk for early adopters, similar to the support provided for wind and solar technologies. The level of support needs to be sufficient to make the use of these new technologies profitable and allow a relatively low-risk development of the manufacturing and user experience base. This, in turn, will allow learning and manufacturing cost reduction that with aggressive R&D can make MHK technologies competitive in future electricity markets. As described in Section 9.9.1, the environmental effects of MHK technologies are not well understood and have not been measured for actual projects. In addition, there is very little public

[70] Jobs per megawatt reported in particular studies should not be considered a standard linear metric.

understanding or knowledge of ocean energy, the benefits that might be provided to coastal communities, or the potential of ocean energy to mitigate climate change and increase energy security. Table 9-2 summarizes the barriers and representative responses to accelerate the widespread acceptance of MHK technologies.

Table 9-2. Barriers to High Penetration of Marine Hydrokinetic Technologies and Potential Responses

Response Type	Barriers	Representative Responses
R&D	• High capital cost; unproven technologies that are not cost-competitive with conventional energy-generation technologies • Unproven functionality, performance, and reliability “in the water” at full scale • Resource quantity and variability are not well quantified • Undefined utility requirements	• Conduct device-specific research to improve cost, performance, and reliability • Conduct R&D on enabling technologies, such as moorings, foundations, materials, installation and transportation, O&M, and manufacturing • Develop facilities and centers for open-water tests, laboratory-tank tests, test protocols, instrumentation, and sensors • Characterize the resource, including resource assessments, forecasting tools, mean environment and variability characterizations, turbulence levels, and extreme-event definition • Develop standards and test procedures for performance, reliability, survivability, and other characterization measures • Conduct grid-integration studies, including assessments of variability impacts on grid, capacity value, and interconnection and transmission requirements
Market and Regulatory	• New and unfamiliar technologies • Technologies that are not cost-competitive • Lack of infrastructure, specialized equipment, and trained labor pool for installation and O&M	• Develop policy options to support a stable market price for MHK technologies • Perform economic analyses of alternative support mechanisms • Educate policymakers and the public on the benefits and impacts of MHK technologies • Develop a market-expansion-needs-assessment that includes jobs, ports, ships, materials, training, and education • Develop international standards for technology design, testing, and installation • Assess electrical transmission needs
Environmental and Siting	• Uncertain environmental impacts • Extensive permitting studies and lead times	• Perform environmental research and develop study protocols, instrumentation, and lab and field studies of impacts before and after installation • Develop siting and permitting guidelines, regulations, best practices, and adaptive management practices

Table 9-2 summarizes material gathered from workshops and other publications, including Bedard 2008, Thresher 2010, Boehlert et al. 2008, Polagye et al. 2010, Gill 2005, Grecian et al. 2010, Inger et al. 2009, EquiMar n.d., and FAU 2010.

9.10.1 Research and Development Representative Responses

Recent reports on MHK energy technologies have identified specific R&D advances required for achieving high MHK energy penetration rates in the energy market. These requirements are summarized in Table 9-2. These requirements parallel those identified in a workshop held to prioritize the research, development, deployment, and demonstration needs of the MHK energy industry (Bedard 2008), as well as by the IEA-OES (2007). They also reflect those identified in an effort to develop a technology roadmap for the ocean energy options that includes the policy, market, economic, and institutional needs that are essential to the commercialization of these technologies (Thresher 2010).

9.10.2 Market and Regulatory Barriers

The Energy Policy Act of 2005 authorized R&D on marine and hydrokinetic technologies, and in 2008, Congress funded research on these technologies for the first time since 1992. As the ocean energy technology sector has grown, federal agencies are beginning to support it. Overall, representative market and regulatory actions to address market and regulatory barriers include:

- A stable, supporting policy that encourages the development of this technology
- The appropriate regulatory support to facilitate deployment and monitoring of MHK technology operation and performance during early stages of development
- A review of policies affecting renewable energy development in the United States to minimize conflict and to align the benefits and priorities represented in environmental policy, tax policy, energy-supply policy, and energy security
- Alignment of the regulatory process to minimize environmental impacts while facilitating responsible deployment of MHK technologies
- Development of appropriate safety requirements and emergency procedures.

9.10.3 Environmental and Siting

At this early stage of development for MHK technologies, permitting agencies sometimes request extensive baseline studies prior to permitting a project. These studies can be time consuming and costly. In addition, lack of a well-coordinated process among multiple federal and state agencies, together with stakeholder opposition, can sometimes cause delays. Issues like this can slow down deployment, but should subside with increasing experience when the environmental effects are better understood and quantified. Uniform policies would help developers comply with environmental requirements and allow them to develop standard streamlined less costly baseline studies, as well as needed mitigation methods and possible adaptive management approaches.[71] Adaptive management provides a useful tool to minimize impacts to the environment after a project has been constructed and measures to reduce them might need to be taken.

[71] Adaptive management is a structured, iterative process of optimal decision making in the face of uncertainty, which aims to reduce uncertainty over time via system monitoring. In this way, decision making simultaneously maximizes one or more resource objectives and, either passively or actively, accrues information needed to improve future management. Adaptive management is often characterized as "learning by doing."

Ocean energy generation projects must be sited where adequate energy resources exist (as identified in Section 9.2) and in places where there will be the least conflict with other users (e.g., fishing, navigation). Other relevant siting considerations that will be needed in the future include the availability of coastal transmission and distribution, as well as the sufficient transmission to move power to load centers.

9.11 Conclusions

MHK technologies are not currently commercially available and therefore were not included in the modeling analysis. However, these technologies offer greater diversity of renewable resource supply if they can achieve maturity levels similar to other renewable technologies. For MHK technologies to move towards effective deployment, representative responses to barriers, such as those described in Table 9-2, would be completed in the time frame between 2015 and 2020, including demonstrating the performance and reliability of the devices and assessing the significance of environmental effects, which requires that devices be tested in their anticipated operating environment. Following such demonstrations and evaluations, other representative responses, as indicated in Table 9-2, would assist MHK technologies to become commercially available and widely deployed.

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Chapter 10. Solar Energy Technologies

10.1 Introduction

The U.S. population uses about 4,000 TWh of electrical energy each year, which is approximately the same amount of energy that the U.S. land surface receives from the sun in a few hours of daylight.[72] Solar energy technologies have access to a larger energy resource than any other renewable energy technology, and the solar resource is more evenly spread over the U.S. land surface than other renewable energy sources.

The fraction of U.S. electricity generated by solar technologies currently is small, but it is growing rapidly. In 2011, the United States added just under 1,500 MW of grid-tied AC-equivalent PV capacity,[73] bringing the cumulative total to more than 3,400 MW (SEIA/GTM 2012). Concentrating solar power (CSP) capacity grew by about 100 MW from 2009–2011, bringing the cumulative total to approximately 520 MW (NREL 2012; SEIA/GTM 2012). This corresponds to approximately 0.2% of U.S. electricity demand being met by PV and 0.015% by CSP (EIA 2012). The U.S. PV market is responsible for a small fraction of the total global PV market, which reached approximately 48 GW of grid-connected AC-equivalent capacity by the end of 2011 (Photon 2012). The U.S. CSP market made up approximately one third of the cumulative installed global CSP capacity by 2011, with the majority of remaining CSP capacity located in Spain (NREL 2012). While the science behind both PV and CSP technologies builds on discoveries ranging back several centuries, active development of bulk electricity generating technologies began in the 1970s and 1980s. The operating mechanism that enables PV cells to generate electricity—the PV effect—was first discovered in the mid-1800s. However, the first silicon-based PV cell using this mechanism was not developed until the mid-1900s, and manufacturing techniques for bulk electricity generating PV modules were not developed until the late 1970s and 1980s. Thin-film PV technologies, many of which are non-silicon based, were first demonstrated in the 1970s, and commercial-scale production of bulk electricity generating modules began over the last two decades. Concentrating solar power technology was demonstrated in the late 1800s for agricultural applications, but was not developed for bulk electricity generation until the 1980s.

Figure 10-1 shows the historical growth of U.S. PV and CSP capacity, beginning in 1980. Solar deployment was initially dominated by strong CSP growth in the 1980s and 1990s. However, CSP experienced no growth from the early 1990s until the mid-2000s. PV has experienced exponential market growth, although starting from a small initial base. Both PV and CSP markets are expected to grow significantly over the next decade. At the end of 2011, more than 1,000 MW of CSP capacity was under construction in the United States (SEIA/GTM 2012), and more than 5,000 MW of additional CSP capacity was under various stages of development

[72] Total electricity demand in the United States was approximately 3,900 TWh/yr in 2011 (EIA 2012), which is roughly equivalent to 0.5 kWh of solar energy reaching each of the 7.7 trillion m^2 of land in the contiguous United States. The mean U.S. solar resource (see Figure 10-2) shows that this amount of energy would conservatively reach the U.S. land surface over the course of a few daylight hours.

[73] Photovoltaic capacity is expressed here in terms of equivalent AC capacity. The AC PV capacity is calculated from DC capacity using an 80% derate factor, which corresponds to a 20% loss in power from the rated DC module capacity to the AC system output (Marion et al. 2005).

(NREL 2012). A similar amount of U.S. PV projects were under development at the end of 2011 (SEIA/GTM 2012), and even if only a small fraction of these projects are built, the U.S. solar industry will experience significant growth in the near future.

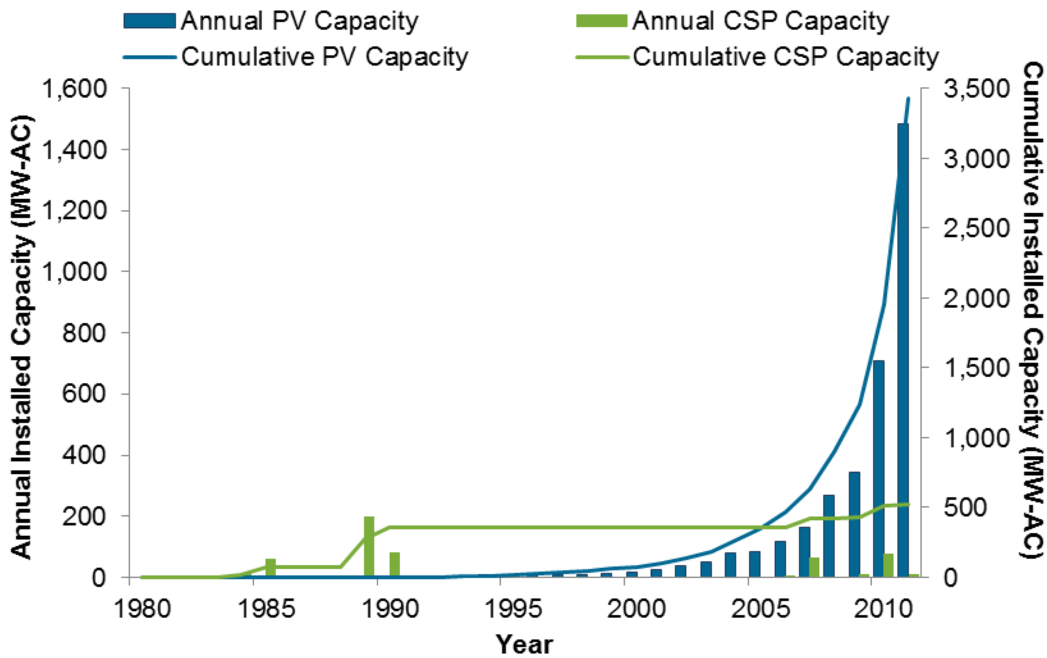

Figure 10-1. Growth of U.S. solar PV and CSP markets, given in units of AC-equivalent generation capacity

Solar technologies capable of supplying a large fraction of U.S. electricity demand have already been developed and demonstrated at scale. Key issues for developing robust U.S. solar markets will be to continue improving the price and performance of solar technologies and to integrate solar electricity into the electricity grid as solar markets grow. Grid integration of very high levels of solar deployment could require additional transmission capacity, enabling technologies (e.g., demand response), storage capacity, and policy-based support (e.g., interconnection standards, net metering, and transmission expansion) as discussed in Volume 1 and in DOE (2012).

10.2 Resource Availability Estimates

Solar energy contains a direct component (sunlight that has not been scattered by the atmosphere) and a diffuse component (sunlight that has been scattered by the atmosphere). This distinction is important because only the direct solar component can be focused effectively by mirrors or lenses. The direct component typically accounts for 60%–80% of surface solar insolation[74] in clear-sky conditions and decreases with increasing relative humidity, cloud cover, and atmospheric aerosols (e.g., dust, urban pollution). Technologies that concentrate solar intensity—such as CSP and concentrating PV—perform best in arid regions with high direct-

[74] *Insolation* is a measure of radiant solar energy received on a given surface area over a period of time.

normal irradiance.[75] Solar technologies that do not concentrate sunlight, such as most PV and passive solar heating applications, can use both the direct and diffuse components of solar radiation and thus are suitable for use in a wider range of locations and conditions than concentrating technologies.

Figure 10-2 shows the mean U.S. solar resource available to a standard fixed-tilt PV system that is facing south and tilted at an angle equal to each location's latitude. The PV solar resource includes both direct and diffuse solar radiation. Figure 10-3 shows a similar resource map for a 1-axis tracking parabolic trough CSP system, which orients the system's mirrors to track the sun from east to west throughout the day. Both maps illustrate the solar resource in units of the mean radiant energy reaching one square meter of land during one day (e.g., $kWh/m^2/day$), and are calculated using hourly solar insolation data and models (NREL 2007). Hourly electricity generation profiles are simulated for both PV and CSP based on the combination of solar resource, local temperature and wind speed using models like the System Advisor Model (Gilman et al. 2008).

The solar resource available to PV is greatest in the southwestern United States, but the solar resource is generally high—at or above 4 $kWh/m^2/day$—in all U.S. states except for Alaska and coastal regions in the Pacific Northwest. The annual output of a PV system[76] in Boston, Massachusetts, for example, is only 17% less than the annual output of a similar system in Los Angeles, California. For reference, the annual output of a PV system in Munich, Germany, is 40% less than that from an identical PV system in Los Angeles and 9% less than a system in Seattle, Washington, yet Germany is currently the world leader in PV installations[77] (Kann 2010).

The solar resource available to CSP is highest in the southwestern United States and falls off in eastern and northern states. This is because CSP technologies can only effectively concentrate the direct component of solar radiation, which is highest in arid regions. Concentrating PV technologies have access to a similar solar resource as CSP. Non-concentrating, tracking PV systems can access a higher solar resource than that shown in Figure 10-2, because the modules are oriented to maximize their utilization of direct solar radiation, but they can still effectively convert diffuse solar radiation to electricity.

[75] Direct normal insolation (DNI) is solar radiation that is parallel to a line extending from the sun to the solar receiver, and is typically measured as the amount of radiation received, per unit area, by a surface that is perpendicular (or normal) to this sun-receiver line.
[76] Annual PV generation was calculated using the System Advisor Model (www.nrel.gov/analysis/sam/; accessed 12/2010), for 1-axis tracking systems with an 80% derate factor, which corresponds to a 20% loss in power from the rated DC module capacity to AC system output.
[77] Cumulative installed global PV capacity reached approximately 40 GW by the end of 2010. Germany accounted for approximately 44% of the global market, Spain accounted for 10%, Japan 9%, Italy 9%, the United States 6%, and the rest of the world 22% (REN21 2011).

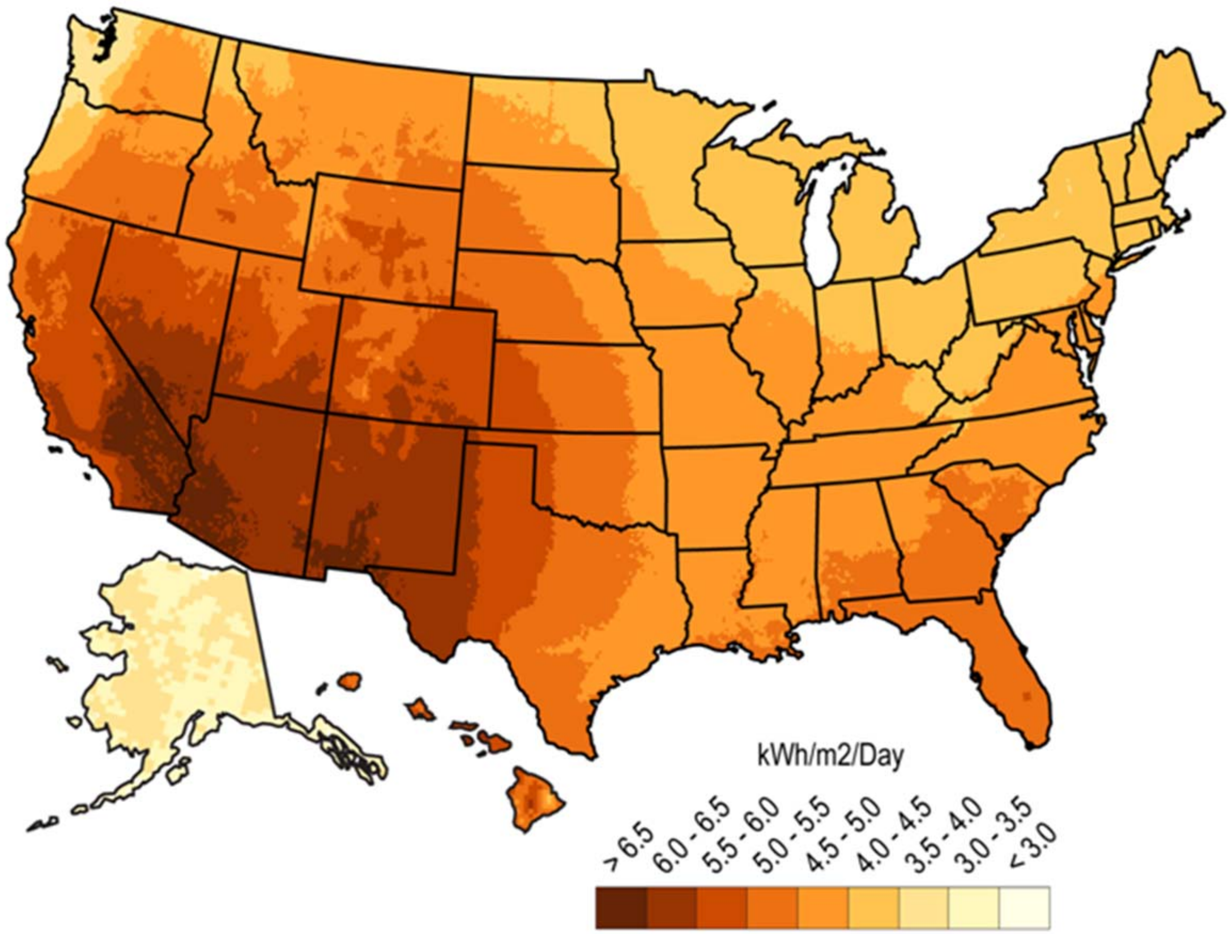

Figure 10-2. Map of the mean solar resource available to a PV system that is facing south and is tilted at an angle equal to the latitude of the system

Annual average solar resource data are shown for a PV module that is facing south, tilted at an angle equal to its latitude, and fixed in place. The data for Hawaii and the 48 contiguous states are modeled at 10 x 10 km^2 using satellite data from 1998–2005 (NREL 2007). Data for Alaska are generated at 40 x 40 km^2 using the Climatological Solar Radiation Model (Maxwell et al. 1998).

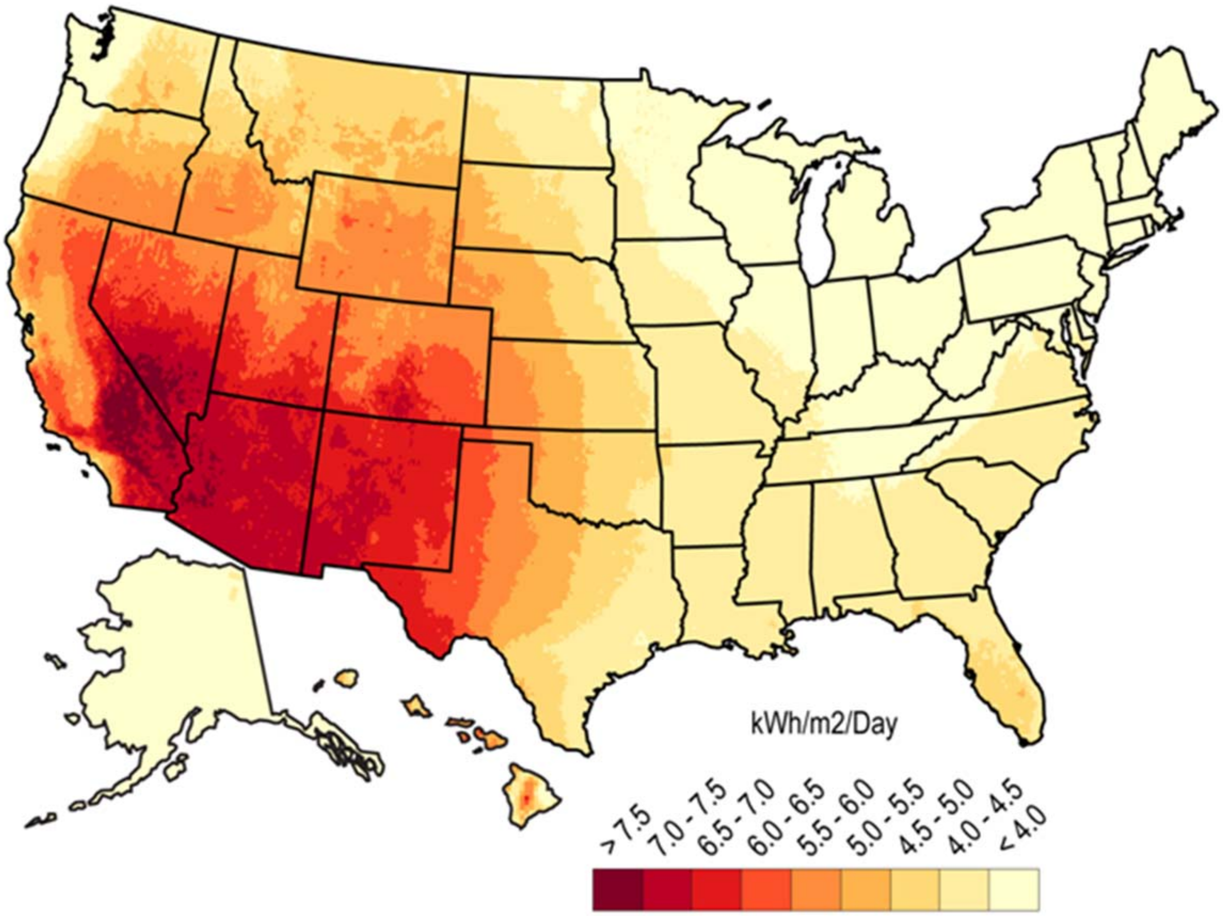

Figure 10-3. Map of mean U.S. solar resource available to concentrating solar power systems with 1-axis tracking that follows the daily trajectory of the sun from east to west

Annual average direct normal solar resource data are shown. The data for Hawaii and the 48 contiguous states are modeled at 10 x 10 km^2 using satellite data from 1998 – 2005 (NREL 2007). Data for Alaska are generated at 40 x 40 km^2 using the Climatological Solar Radiation Model (Maxwell et al. 1998).

10.3 Technology Characterization

10.3.1 Technology Overview

10.3.1.1 Solar Photovoltaics

Photovoltaic technologies convert sunlight directly into electricity by enabling solar photons to "excite" electrons from their ground state, producing a freed (photo-excited) electron and a "hole" pair. The electron and hole are then separated by an electric field that is formed by the design of the PV cell and pulled toward positive and negative electrodes, generating DC electricity.

Several PV technologies have been commercially deployed at the gigawatt (10^9 watt) scale, including those based on crystalline silicon cells (the most widely deployed PV technology to date), and thin-film cells, including amorphous silicon (a-Si) and cadmium telluride (CdTe). A number of emerging PV technologies have been commercially demonstrated, including copper indium gallium diselenide (CIGS) thin-films, concentrating PV (using a range of PV cell technologies), and organic PV cells. Several promising next-generation PV device concepts are being developed, but they have not yet reached sufficient maturity to be introduced to the market. Examples include dye-sensitized PV cells and several PV nanostructures like quantum dots. These, and other, next-generation PV technologies have the potential to lower module costs by using less expensive materials and simpler manufacturing processes, but there have been challenges in reaching high-efficiency and long-term durability for the materials explored to date.

Figure 10-4 illustrates the basic components of a typical crystalline silicon PV cell. Several PV cells are wired together and encapsulated to form PV modules. PV projects typically include tens to thousands of PV modules connected electrically into an array. Photovoltaic arrays generate DC electricity, which can be converted to AC electricity using an inverter. PV project costs are frequently categorized into module costs and balance of systems (BOS) costs which typically include inverters, mounting or tracking structures, wiring, site-specific installation, and indirect costs (e.g., engineering, procurement and construction costs, land costs, and project management costs).

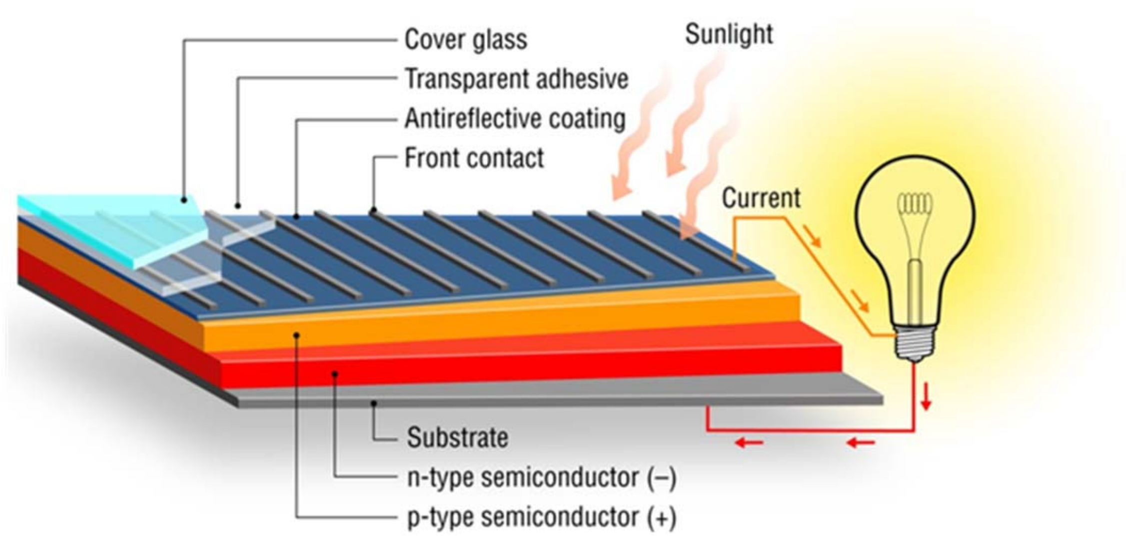

Figure 10-4. Components of a silicon PV cell

10.3.1.2 Concentrating Solar Power

CSP technologies use mirrors or lenses to focus sunlight onto a receiver. The receiver contains a working fluid,[78] which transfers the thermal energy to a heat engine that drives an electrical generator. Figure 10-5 illustrates the basic solar-field components for the main CSP technologies. Parabolic trough concentrators use a 1-axis tracking linear receiver to collect concentrated sunlight. Solar power towers use an array of 2-axis tracking flat mirrors (heliostats) to focus sunlight onto a fixed central receiver. Linear Fresnel systems use a fixed linear receiver and an array of 1-axis tracking heliostats. Dish concentrators use a 2-axis tracking dish to focus solar energy onto a receiver, which is typically a Stirling engine (a closed-cycle heat engine).

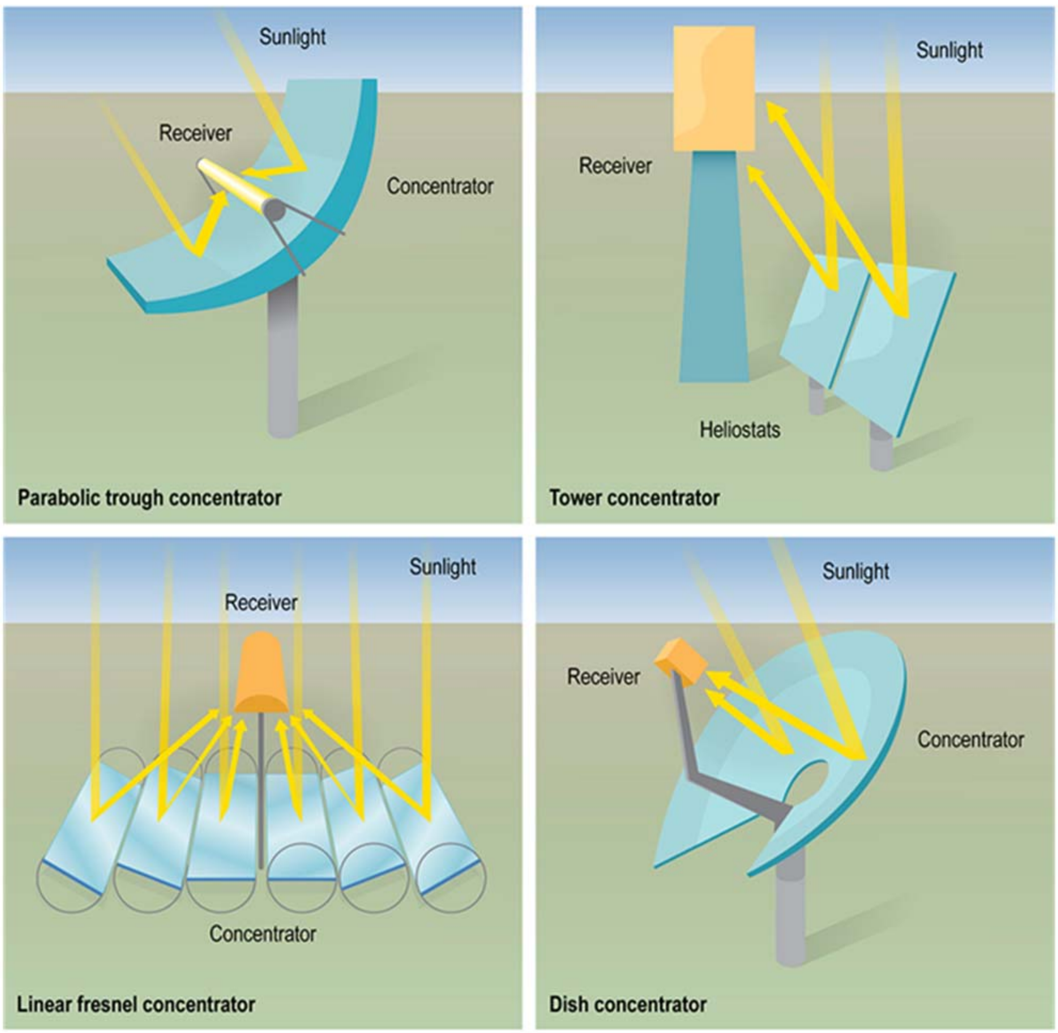

Figure 10-5. Solar-field components of a CSP system

[78] Several working fluids are used. Parabolic trough and linear Fresnel systems currently use an oil-based heat transfer fluid. Power towers frequently use a molten salt or direct steam heat transfer fluid. Dish concentrators typically use air inside a closed-cycle heat engine.

Figure 10-6 shows the solar-field and power-block components of a parabolic trough CSP plant, as well as optional components including thermal energy storage and a natural gas backup boiler. The solar-field components can be oversized relative to the power block[79] so that energy captured during the day can run the power block and provide additional heat energy to the thermal storage medium. This stored energy then can be used to run the power block during cloudy periods and at night, significantly increasing the capacity factor of the CSP power block. Currently, CSP systems with more than 7 hours of thermal storage are operating in Spain (Andasol 1 and 2), and trough and tower systems with storage are under development in the United States (NREL 2012).

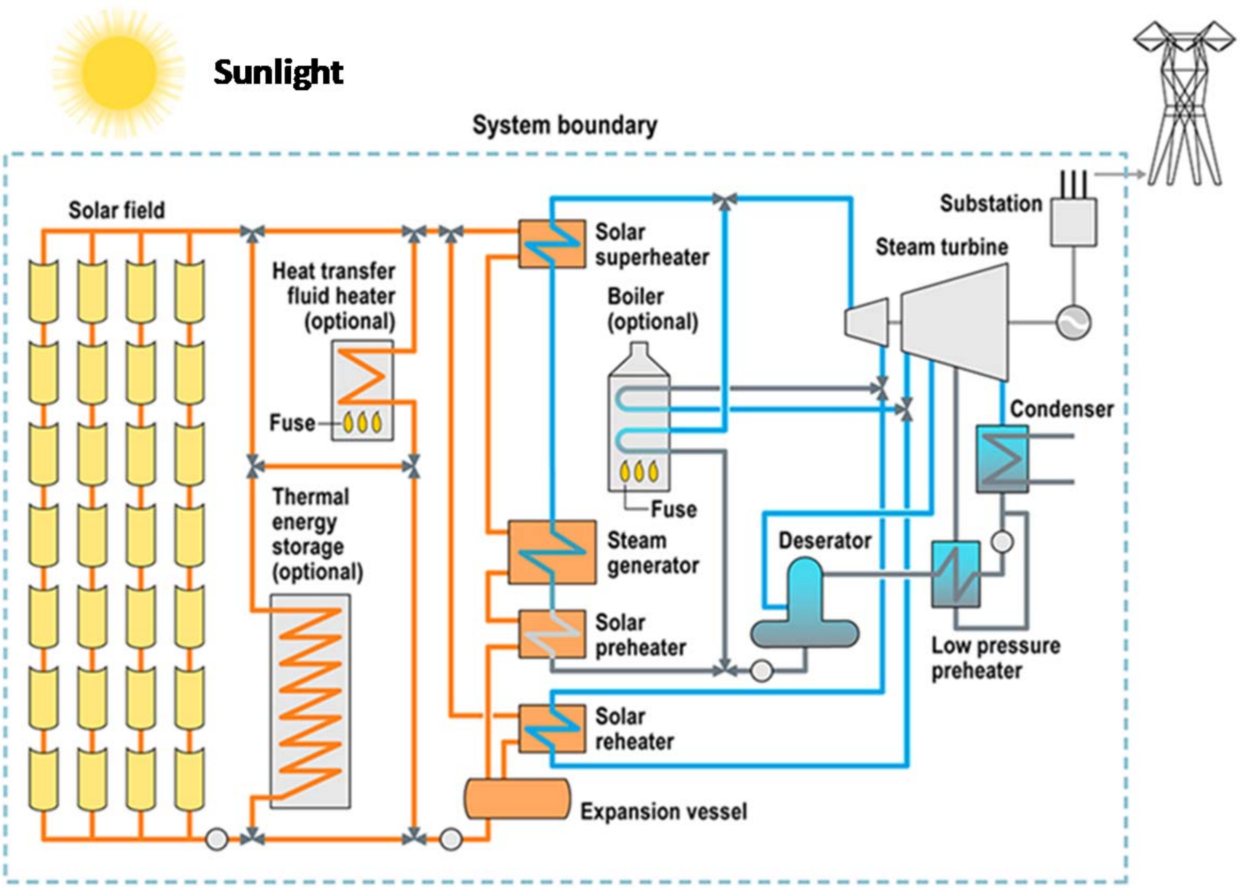

Figure 10-6. Solar-field, storage, and power-block components within a parabolic trough CSP plant

[79] The power block includes the steam turbine, electrical generator, and power electronics

Parabolic trough systems were first commercialized in 1984 and account for 96% of global CSP deployment (NREL 2012). Power tower systems have a shorter operational history. Solar Two, a 10-MW power tower with 3 hours of molten salt thermal storage, demonstrated the technology in California in the mid-to-late 1990s, and there are two commercial solar power towers operating in Spain. Dish Stirling concentrators and linear Fresnel systems have been demonstrated at the pilot scale (NREL 2012). Several integrated solar thermal systems have been developed, in which solar thermal energy is used to heat steam for CSP-natural gas projects, CSP-coal projects,[80] and as process heat for a variety of industrial applications. Several demonstrated CSP systems use natural gas for backup energy—like the solar energy generating systems (SEGS) plants built in the 1980s (NREL 2012)—but these are fundamentally different from new CSP designs where solar thermal energy is directly used to augment combined cycle natural gas generators or a coal generators (NREL 2012).

Next-generation CSP thermal collectors are not likely to be fundamentally different from today's technologies, but likely R&D trends include developing more advanced solar collector coatings, reduced cost support structures, increased use of molten salt heat transfer fluids, and the increased use of thermal storage (NREL 2012). Another trend is a renewed interest in power towers to achieve higher operating temperatures, particularly for systems using thermal storage. Next-generation CSP configurations may be fundamentally different, including several types of integrated solar thermal-conventional fuel generators.[81] Also, solar-only combined-cycle CSP systems[82] are in the early stages of development, and could lead to significant efficiency improvements.

10.3.1.3 Other Solar Technologies

Several additional solar technologies—including water heating, space heating, cooling, and lighting—do not generate electricity but do displace end-use electricity and fossil fuel consumption. Although these technologies are not explicitly modeled in RE Futures, they are likely to be an important complement to energy-efficiency investments for stabilizing or reducing end-use electricity demand as envisioned in several RE Futures modeling scenarios (see Volumes 1 and 3).

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[80] In 2010, a 75-MW integrated solar thermal-natural gas combined cycle system was installed in Florida, and a 2-MW integrated solar thermal-coal demonstration project was completed in Colorado (NREL 2012). In both designs, thermal energy from the solar field is used in conjunction with energy from fossil fuels to generate steam and increase plant capacity.

[81] Integrated solar thermal plants (NREL 2012) use energy from the solar field to augment conventional fuel use and increase plant capacity. These systems are fundamentally different from older solar thermal plants that used natural gas backup to augmented energy from solar field.

[82] Solar-only combined cycle plants have been envisioned for power tower systems with an advanced receiver capable of heating air to temperatures in excess of 1,400°C. However, these design concepts are in the early stages of research.

10.3.2 Technologies Included in RE Futures Scenario Analysis

Four PV markets were modeled in RE Futures: grid-connected residential rooftop PV, grid-connected commercial rooftop PV, distributed utility-scale PV, and central utility-scale PV. Rooftop PV systems generate electricity on site and displace retail electricity. Utility-scale systems typically displace wholesale electricity either on the transmission network (centrally located systems) or on the distribution network (distributed systems). Rooftop PV markets are modeled using the Solar Deployment System (SolarDS) model and utility-scale PV markets are modeled using the ReEDS model (see Volume 1).

Three CSP technologies were modeled in RE Futures: trough systems with no storage, trough systems with thermal energy storage, and tower systems with thermal energy storage. For CSP systems with storage, the ReEDS model optimally sizes thermal energy storage components subject to a minimum constraint of 5 hours of storage capacity.[83] Integrated CSP-natural gas and CSP-coal systems were not modeled in the RE Futures scenarios, and modeled CSP systems did not include fossil fuel backup.

10.3.3 Technology Cost and Performance

Solar technologies have experienced a steady trend of cost and performance improvements, and these trends are likely to continue into the future. This section describes historical solar trends and highlights potential pathways for future improvement. While solar technologies may achieve revolutionary improvements over time, the RE Futures scenarios are based on incremental or evolutionary improvements to demonstrated technologies only.

Future cost and performance improvements for electricity generating technologies are influenced by several uncertain and inherently unpredictable factors. To understand the impact of RE technology cost and performance improvements on modeled deployment, two projections of future RE technology costs were evaluated: (1) renewable electricity-evolutionary technology improvement (RE-ETI) and (2) renewable electricity-incremental technology improvement (RE-ITI). Both cost projections consider evolutionary improvements to demonstrated commercial technologies. The RE-ITI projections represent only a partial achievement of the potential cost and performance improvements, while the RE-ETI projections represent a more complete achievement of the potential cost and performance improvements. RE-ITI estimates were developed for the full portfolio of electric-sector generation technologies by Black & Veatch (2012). RE-ETI estimates were developed for this study, representing evolutionary advances from continued R&D and learning-based improvements to manufacturing processes. RE-ETI estimates were developed for each renewable electricity generation technology independently, and the solar RE-ETI projections are described in this section. It is important to note that these two cost projections are not intended to characterize the full range of possible future renewable technology costs. Several factors could increase or decrease the potential improvement of system cost and performance parameters, both the rate of improvement and the total amount of improvement, relative to the two scenarios assumed in this study[84] (e.g., DOE 2012). Cost and

[83] Five hours of thermal storage was determined to be the minimum amount of storage for a CSP resource to provide firm capacity to the system.

[84] In addition, the cost and performance assumptions used in RE Futures are *not* intended to directly represent DOE EERE technology program goals or targets. See Section 10.3.3.3 for a discussion of the DOE SunShot Initiative.

performance assumptions used in the modeling analysis for all technologies are tabulated in Appendix A (Volume 1) and Black & Veatch (2012).

In this chapter, we frequently refer to both solar costs and solar prices. *Solar costs* typically refer to bottom-up estimates of the cost of materials, manufacturing, and installation with margins added to characterize a sustainable business model (Goodrich et al. 2012). *Solar prices* typically refer to market prices, including the range of historical PV system prices (Barbose et al. 2011), and module prices in global markets (Mints 2011b). Solar prices are typically higher than costs because they include additional margins at several steps in the supply chain, from manufacturer to distributer to installer. One exception to this distinction between solar costs and prices is the treatment of overnight capital cost projections (Figures 10-11 through 10-13 for PV and Figures 10-15 through 10-16 for CSP). These projections represent future market prices that were estimated using bottom-up cost analysis with sustainable margins, and we assume that market prices will roughly converge to these bottom-up costs as solar markets mature. We refer to these as cost projections to be consistent with the terminology used in other chapters of the report. Also, we generally refer to system costs for current and future CSP systems, because there aren't established wholesale or retail markets for large, unique CSP projects like there are for PV modules.

10.3.3.1 Solar Photovoltaics Cost and Performance

10.3.3.1.1 Historical Photovoltaics Price and Performance Improvements

PV price and performance have improved consistently over the past several decades through R&D-driven technology innovation, improved manufacturing techniques, and learning-based improvements as global PV markets have grown and matured. Figure 10-7 illustrates the improvement in laboratory-cell conversion efficiency for several PV technologies over the past four decades. Although there are a number of challenges in adapting laboratory techniques to commercial-scale manufacturing processes, commercial module efficiencies typically track laboratory improvements with a time lag.

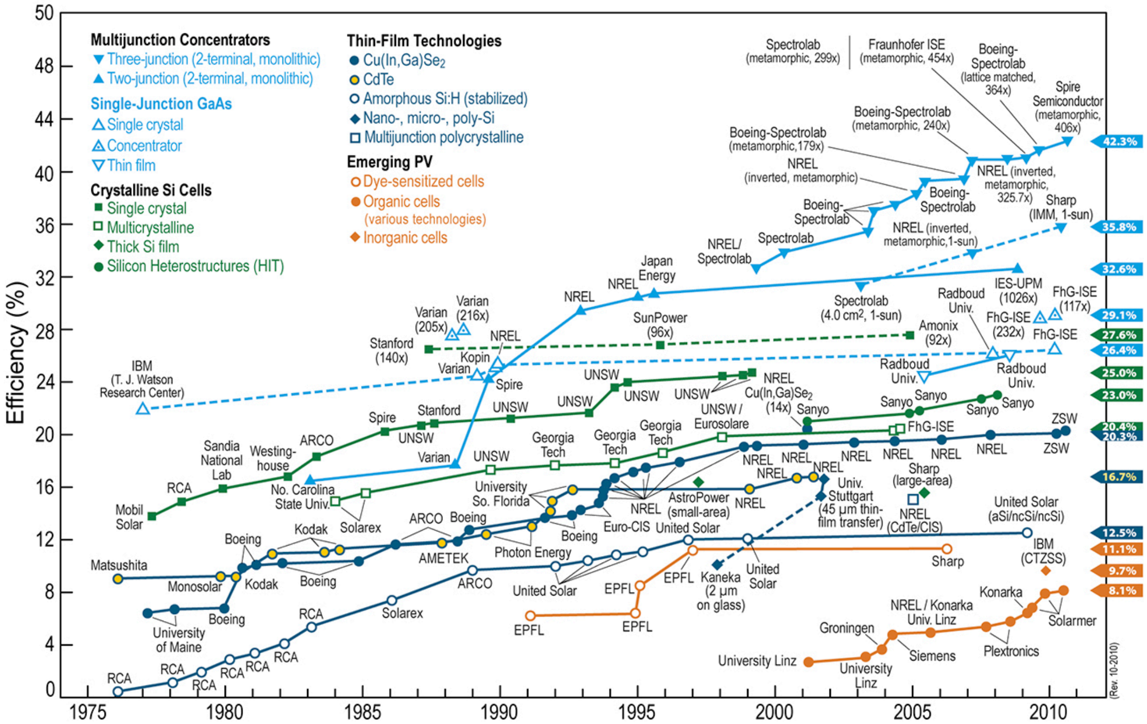

Figure 10-7. Laboratory best cell-conversion efficiencies for various PV technologies

The National Center for Photovoltaics compiled these data. For the most current efficiencies and additional information, see http://www.nrel.gov/ncpv/.

Since the early 1980s, factory-gate PV module prices have decreased by more than 90%, reaching approximately \$2/W by 2010 (see Figure 10-8), and about \$1.25/W by the end of 2011 (Mints 2011b; SEIA/GTM 2012). The average selling price of modules has declined by approximately 20% for every doubling of cumulative installed capacity (Mints 2011a). PV prices deviated from this historical trend from 2004–2008, based on a temporary imbalance between global supply and demand (DOE 2010; Barbose et al. 2011). As global supply caught up with demand, PV prices nearly converged with the historical trend in 2010, and exceeded the historical trend by the end of 2011 (Mints 2011b; SEIA/GTM 2012).

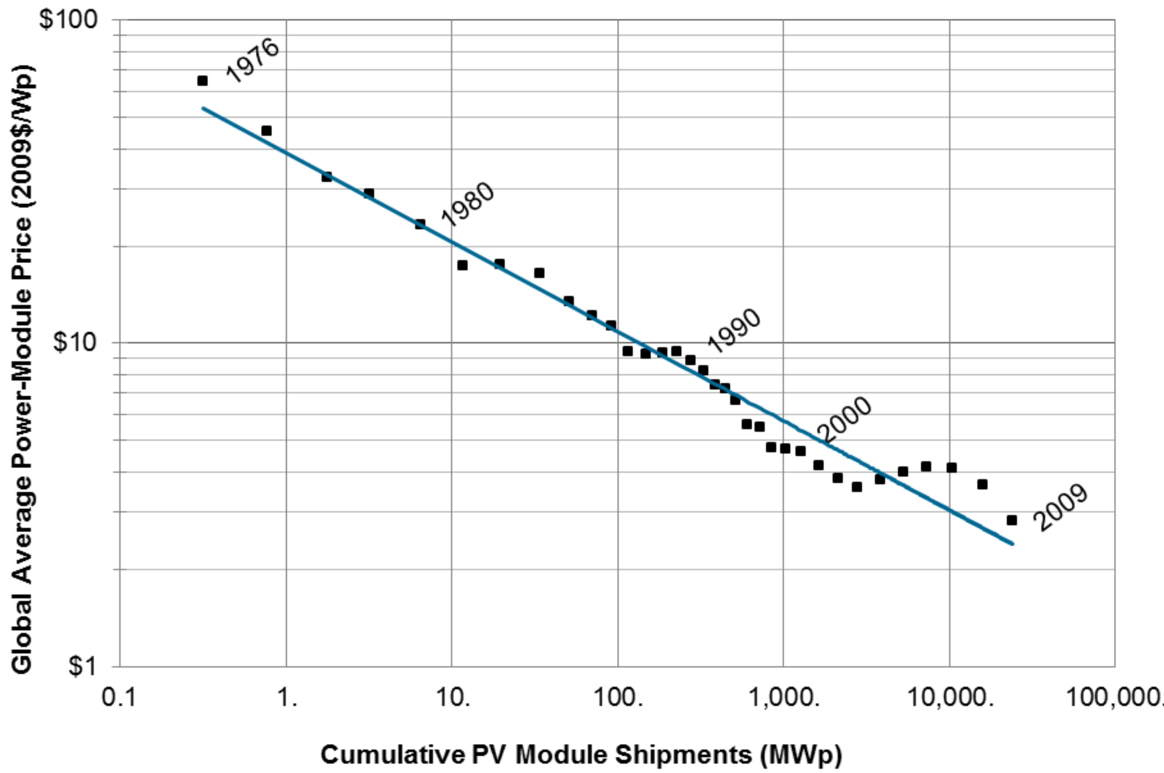

Figure 10-8. Decreasing PV module prices with cumulative sales

Based on Mints 2011a, Mints 2006, and SU 2003;
PV module prices are given in dollars per watt of DC capacity. Note the logarithmic scales.

10.3.3.1.2 Engineering Analysis of Advancement Potential for Solar Photovoltaics

PV prices will likely continue to decrease by achieving incremental improvements to existing technologies and by developing new technologies with a potential for significant price breakthroughs. Improvements to PV modules will likely come from a combination of increasing module efficiencies, increasing manufacturing throughput, reducing wafer thickness (crystalline silicon) or the thickness thin-film semiconductor layers, and developing new semiconductor materials (DOE 2012; Goodrich et al. 2012). Non-module price improvements will likely come from a combination of improving power electronics, reducing supply chain complexity and cost, and decreasing installation costs and margins as markets mature.

While the RE Futures scenarios represent only evolutionary improvements to commercially demonstrated technologies, the modular nature of PV could allow new technologies to rapidly gain market share, and significantly impact future solar deployment. Table 10-1

Table 10-1 shows the rapid growth in manufacturing capacity for five high-growth PV companies. Each company has demonstrated that it could expand from initial commercial manufacturing to become a major global player within five years.

Table 10-1. Manufacturing Capacity[a] for Several Solar PV Companies

Year	FirstSolar[b] (MW)	Suntech[c] (MW)	Yingli Green Energy Holding Company[d] (MW)	Trina Solar[e] (MW)	LDK Solar[f] (MW)
2005	25	150	50	—	—
2006	100	300	100	28	215
2007	308	540	200	150	420
2008	716	1,000	400	350	1,460
2009	1,228	1,100	600	600	1,800
2010	1,502	1,800	1,000	1,200	3,000
2011e[g]	2,308	2,400	1,700	1,900	4,000

[a] Manufacturing capacity represents the amount of PV capacity that could be manufactured in one year, and is generally higher than historical production.
[b] (FirstSolar 2011b)
[c] (Suntech Power 2011)
[d] (Yingli Green Energy Holding Company 2011)
[e] (Trina Solar 2011)
[f] (LDK Solar 2011); manufacturing capacity refers to poly-silicon wafers, not cells or modules.
[g] Expected

10.3.3.1.2.1 Module Prices for Solar Photovoltaics

The PV market is dominated by multicrystalline and monocrystalline silicon PV modules, which represent approximately 85% of the global market. However, thin-film PV technologies, including cadmium telluride (CdTe) and amorphous silicon (a-Si), represent a significant market fraction. Current PV prices and price reduction potentials are unique for each technology, but there are clear trends across technologies.

Figure 10-9 illustrates evolutionary price and performance improvements for monocrystalline silicon PV modules (multicrystalline silicon modules show similar trends). Component costs were calculated using a detailed PV manufacturing-cost model (Goodrich et al. 2012). Cost reductions result primarily from efficiency gains, thinner wafers, and reduced materials loss. Efficiency gains were assumed to be driven by a transition from front contact cells to all back contact cells, along with other incremental improvements. The manufacturing roadmaps estimate that median crystalline silicon module efficiencies could reach 21.5%, corresponding to an approximate cell efficiency of 24%. This evolutionary pathway suggests that monocrystalline PV modules could reach a direct manufacturing cost of $0.58/W and an average selling price of $0.68/W (Goodrich et al. 2012).

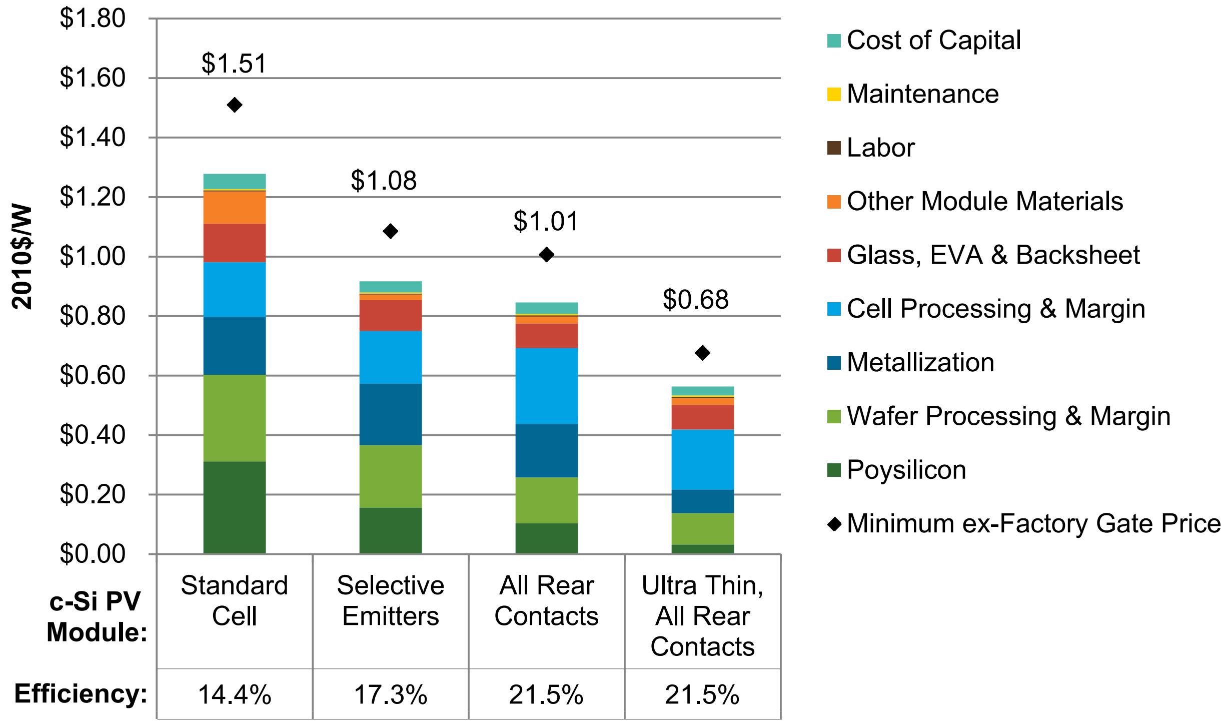

Figure 10-9. Module price projections, by component, for monocrystalline silicon PV (2010$/Watt of DC Capacity)

Source: Goodrich et al. 2012

Thin-film PV technologies have similar cost-reduction potentials. Figure 10-10 shows a FirstSolar road map for reducing CdTe module costs from $0.93/W in the first quarter of 2009 to between $0.52/W and $0.63/W by 2014. These cost targets represent the cost of goods sold, which includes the cost of raw materials, and manufacturing. FirstSolar targets assume increased module efficiencies, increased production-line throughput, decreased spending (overhead costs on a per-kilowatt basis if efficiency and throughput improvements are realized), and developing larger manufacturing facilities in low-cost regions (e.g., Malaysia and China). Between the first quarter of 2009 and the first quarter of 2011, module costs were reduced to $0.75/W (FirstSolar 2011b). Module prices are higher than costs, based on additional manufacturing margins and supply chain costs and margins.[85] Thin-film copper indium gallium diselenide (CIGS) technology is less mature but has a similar cost-reduction potential to CdTe, and manufacturing cost reductions will likely target similar improvements.

[85] The final module price paid by a PV consumer includes additional margins charged by the manufacturer, wholesaler, distributor, and retailer. The thin-film cost roadmap in Figure 10-10 does not include retail margins, module margins, or shipping costs, which must be added to represent the price of modules selling into the market.

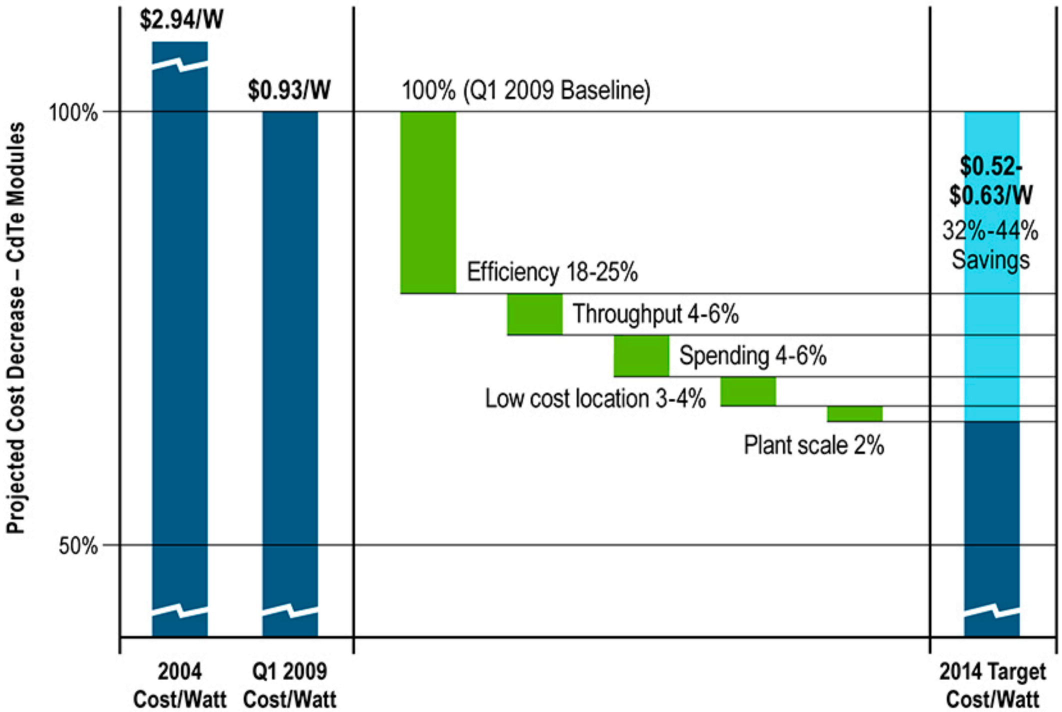

Figure 10-10. Module cost projections for cadmium telluride PV from FirstSolar—module prices would be higher based on additional manufacturing margins and supply chain costs and margins (2010$/Watt of DC Capacity)

Source: FirstSolar 2010

The global module-selling price for all PV technologies is strongly influenced by the price of crystalline silicon PV modules, which represent approximately 85% of the global PV market. Thin-film PV technologies, such as CdTe, typically sell at prices that are slightly less than crystalline silicon PV modules to compensate for lower module efficiencies, which can translate to higher balance-of-systems costs for a project.

10.3.3.1.2.2 Balance-of-Systems Costs for Solar Photovoltaics

Balance-of-systems (BOS) costs include the cost of inverters, transformers, support structures (including trackers), mounting hardware, electrical protection devices, wiring, monitoring equipment, shipping, land, installation labor, permitting, and fees. BOS costs are frequently higher than module costs, adding approximately $1/W to $4/W depending on system size, location, and project margins.

BOS cost reductions will come from reducing both "hard costs" (inverters, support structures, trackers, mounting hardware, wiring, monitoring equipment, and land) and "soft costs" (system design, engineering, permitting, interconnection, inspection, financing, installation, and operation and maintenance). BOS costs reduction efforts should target both types of costs:

- Hard BOS
  - Increase module efficiency, reducing the size of the installation
  - Develop racking systems that enhance energy production or require less robust engineering (e.g., Bony et al. 2010)
  - Integrate racking or mounting components in modules (e.g., SunPower 2011)
  - Create standard packaged system designs
  - Improve supply chains for BOS components
  - Improve inverter price and performance, possibly by integrating micro-inverters into modules
- Soft BOS
  - Reduce supply chain margins (e.g., profit and overhead charged by suppliers, manufacturers, distributors, and retailers); this will likely occur naturally as the U.S. PV industry grows and matures
  - Streamline installation practices through improved workforce development and training, and developing standardized PV hardware
  - Expand access to a range of innovative financing approaches and business models
  - Develop best practices for permitting, interconnection, and PV installations such as subdivision regulations, new construction guidelines, and design requirements

BOS costs are proportionally higher for smaller PV systems, such as residential rooftop projects, than for large systems, such as utility-scale PV projects. This is because small rooftop PV systems frequently require more time, per unit of PV capacity, to design, permit, and install than larger systems. In addition, large system installers frequently negotiate module prices directly with manufacturers, which reduces or eliminates the costs added by distributors and/or retailers. The combination of higher installation and hardware costs can make residential rooftop projects twice as expensive as utility-scale projects, per unit of installed capacity. However, increased competition as PV markets grow and mature will likely decrease the relative difference between large and small system costs.

10.3.3.1.3 Photovoltaic Cost Projections

Two main cost[86] projections were developed to simulate a range of PV deployment for each of the RE Futures scenarios. These cost scenarios are used to explore the relative impact of PV cost on their potential PV deployment in the different high renewable electricity scenarios. The RE-ITI price projections are based on the bottom-up engineering analyses described in Black & Veatch (2012), and the RE-ETI price projections are based on the bottom-up engineering analysis described in this chapter. The DOE SunShot Vision Study (DOE 2012) explored the

[86] Solar cost projections represent market prices (cost for materials, manufacturing, distribution and installation plus margins for each step in the solar supply chain) that are seen as potential capital cost investments to electricity providers.

impact of achieving additional solar price and performance improvements, and the increased levels of solar deployment found in that study are briefly summarized in Section 10.6.2.

Crystalline silicon module prices reached about $1.25/W by the fourth quarter of 2011 and thin-film modules sold for below $1.00/W in 2011 (Mints 2011b; SEIA/GTM 2012). The bottom-up engineering analysis described in this chapter illustrates clear pathways for reducing module costs further from a range of evolutionary improvements (Figures 10-9 and 10-10). If BOS costs are similarly reduced to about $1/W for utility-scale systems, the cost of an installed PV project could reach approximately $2–$3/W, using today's demonstrated technologies. Exceeding these price reductions will likely require continued R&D efforts to develop cost effective manufacturing techniques to mass produce today's laboratory technologies, and healthy competition within the domestic PV supply chain to eliminate excess costs and reduce margins.

Figure 10-11shows both historical PV price trends and several PV cost[87] projections for utility-scale PV systems. Historical PV prices are based on a range of PV market prices compiled in Barbose et al. (2011). Future PV cost projections include the RE-ITI prices (described in Black & Veatch 2012), the RE-ETI (based on the bottom-up engineering analysis included in this chapter), along with cost projections from several recent studies.[88] All PV cost projections represent only incremental or evolutionary improvements to commercially demonstrated technologies.

[87] Solar cost projections represent market prices (cost for materials, manufacturing, distribution and installation plus margins for each step in the solar supply chain) that are estimated through bottom-up costs analysis that includes sustainable margins.
[88] All RE Futures modeling inputs, assumptions, and results are presented in 2009 dollars unless otherwise noted.

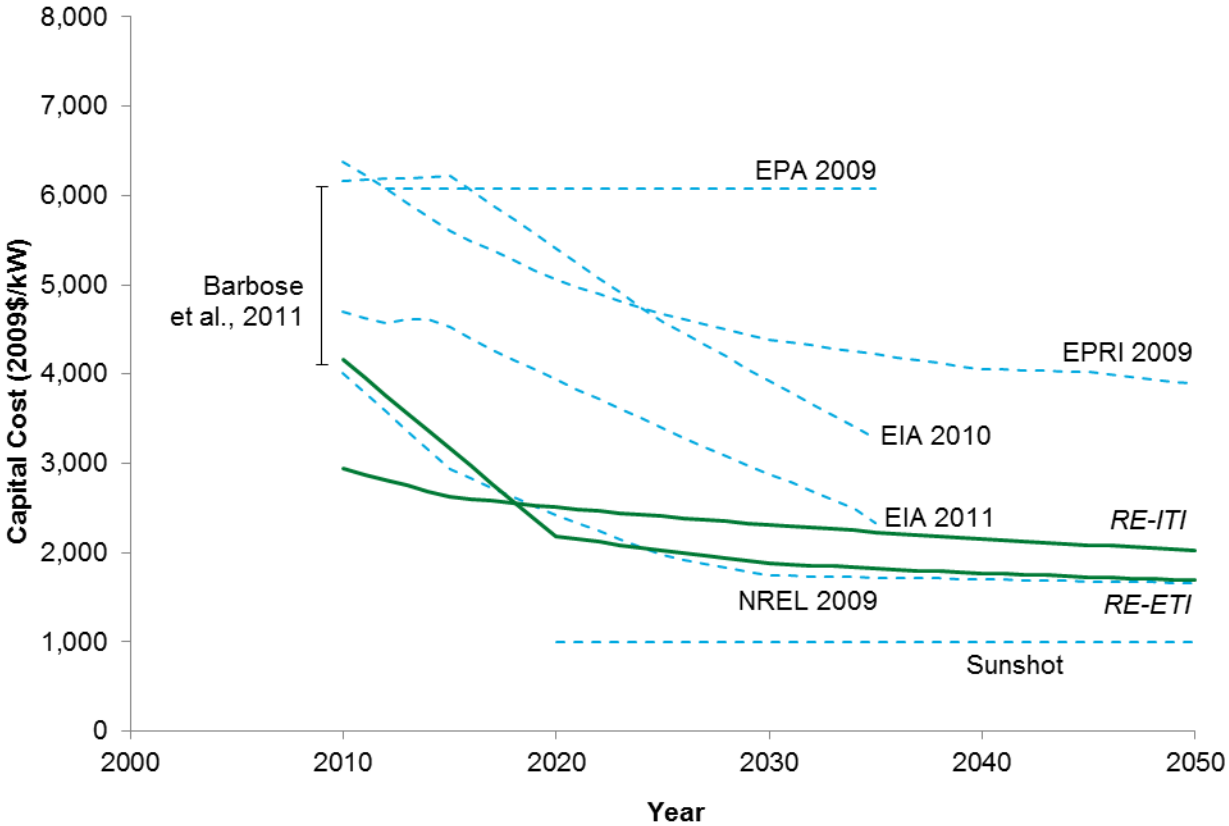

Figure 10-11. Capital cost projections for 1-axis tracking utility-scale PV systems, 2000–2050 ($/kW of DC capacity)

Historical data and projections have been adjusted to exclude construction financing costs (approximately 5% of total capital cost). Capital cost projections represent market prices.

The PV cost projections from the Annual Energy Outlook 2010 (EIA 2010), Electric Power Research Institute (EPRI 2009), and EPA (EPA 2009) are at or above current market prices through 2030. The 2010 PV prices for the RE-ETI scenario represent the mean market price from utility-scale projects (greater than 10 MW) installed in the United States from 2009-2011, and the 2010 PV price for the RE-ITI[89] scenario represents 2010 price bids for PV plants installed in 2011 or after (Black & Veatch 2012).

Figure 10-12 and Figure 10-13 similarly show historical PV price trends and cost projections for residential and commercial PV systems. Historical PV prices are also based on the range of residential and commercial market prices compiled in Barbose et al. (2011), and represent the minimum, maximum, and capacity-weighted average from several sources. Future PV cost

[89] The RE-ITI utility-scale PV prices represent nth plant 100-MW PV systems, where an nth plant is typically defined as five systems demonstrated commercially for five years. Since the U.S. market did not meet this criteria for a 100-MW nth plant in 2010, historical PV market price were used for utility-scale PV systems in 2010 and prices were assumed to transition to the nth plant projection by 2015.

projections include the RE-ITI and RE-ETI scenarios and additional projections from several recent studies.

Figure 10-11through Figure 10-13 show that there has been a large range in historical PV market prices, driven by several factors, including site-specific differences in distribution and installation costs, PV incentives, and the relative immaturity of the U.S. PV market (Barbose et al. 2011). However, the spread in PV market prices is likely to narrow as PV markets mature, particularly because PV is a modular technology is essentially sold as a commodity in global markets.

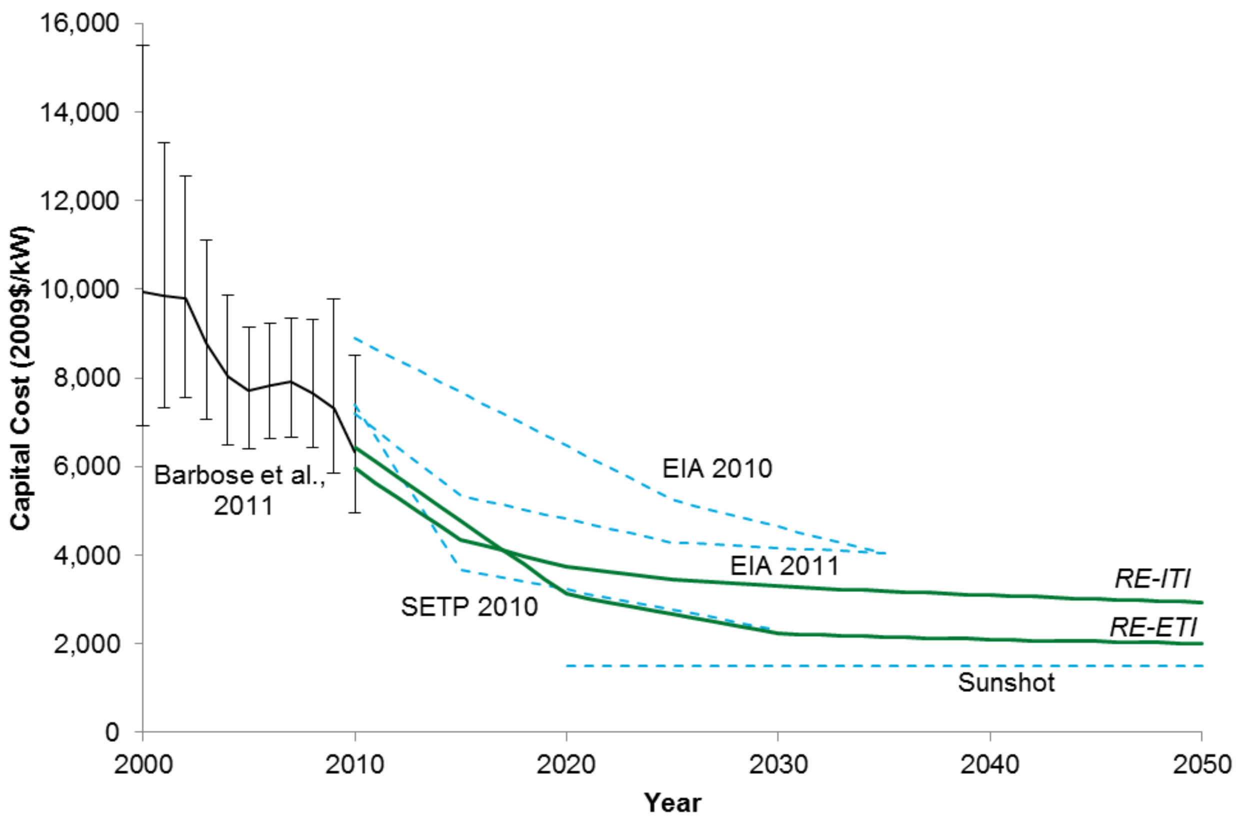

Figure 10-12. Capital cost projections for residential rooftop PV systems, 2000–2050 ($/kW of DC capacity)

Ranges in the historical data represent the 10th and 90th percentiles of reported data. Historical data and projections have been adjusted to exclude construction financing costs (approximately 5% of total capital cost). Capital cost projections represent market prices.

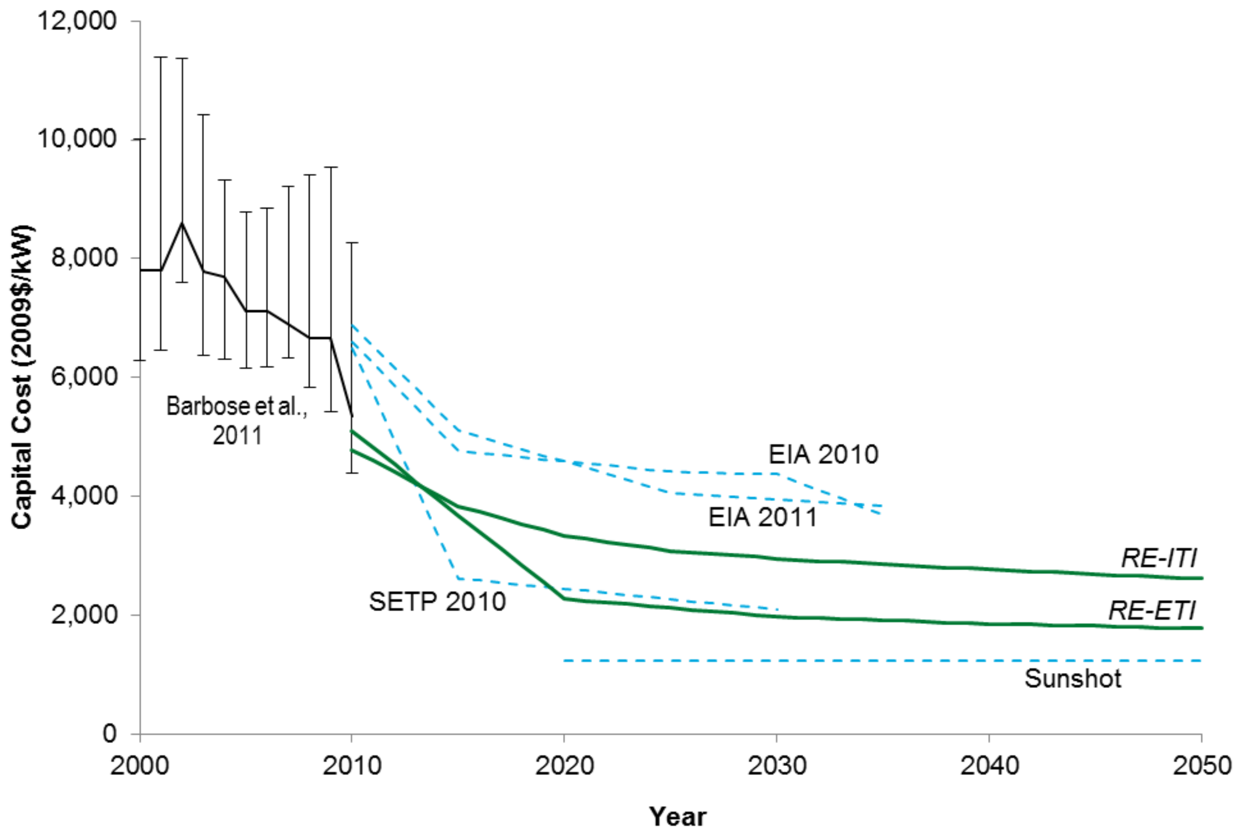

Figure 10-13. Capital cost projections for commercial rooftop PV systems, 2000–2050 ($/kW of DC capacity)

Ranges in the historical data represent the 10th and 90th percentiles of reported data. Historical data and projections have been adjusted to exclude construction financing costs (approximately 5% of total capital cost). Capital cost projections represent market prices.

Table 10-2Table 10-2 through 10-5 summarize component-level costs for the RE-ITI and RE-ETI projections. The BOS/other category represents BOS hardware costs, labor, shipping, owners' costs, and additional margins. Both the RE-ITI and RE-ETI projections show similar BOS/other reductions for utility-scale PV (see Table 10-2Table 10-2). The main difference between projections is the lower module price projections in RE-ETI that closely track the improvements shown in Figure 10-9Figure 10-9. Global PV module prices reached about $1.25/W by the end of 2011 (Mints 2011b; SEIA/GTM 2012) and are continuing to trend down in 2012, beating the module cost projections by several years for the RE-ETI scenario and by several decades for the RE-ITI scenario. The BOS/other cost are reduced to approximately $1/W by 2030, and are projected to achieve marginal improvements from 2030 through 2050.

Table 10-2. Cost Projections for Utility-Scale 1-Axis Tracking PV (2009$/Watt of DC capacity)

		Incremental Technology Improvement Scenario[a] (RE-ITI)			Evolutionary Technology Improvement Scenario[b] (RE-ETI)			
Price	**2010[c]**	**2020**	**2030**	**2050**	**2010[c]**	**2020**	**2030**	**2050**
Total PV Cost	4.02	2.53	2.33	2.04	4.02	2.20	1.90	1.70
Module	1.80	1.42	1.27	1.05	1.80	1.05	0.85	–
BOS/Other	2.22	1.11	1.06	0.99	2.22	1.15	1.05	–

[a] Based on a bottom-up engineering analysis by Black & Veatch (2012)
[b] Based on a bottom-up engineering analysis as part of RE Futures
[c] Represents mean 2010 market prices.
[d] Represents n^{th} plant costs for a 100-MW PV system; see Black & Veatch (2012) for details

Table 10-3 and 10-4 summarize commercial and residential rooftop PV costs. Rooftop PV cost projections are higher than utility-scale costs because rooftop PV systems are typically much smaller and have higher relative installation and supply chain costs, per unit of installed capacity. Both module and BOS/other cost projections are lower in the RE-ETI projections than they are in the RE-ITI projections, reflecting a more complete realization of potential cost and performance improvements. Global PV module prices (Mints 2011b; SEIA/GTM 2012) are similarly beating the residential and commercial module cost projections by several years for the RE-ETI scenario and by several decades for the RE-ITI scenario.

Table 10-3. Cost Projections for Commercial-Scale Fixed-Tilt PV (2009$/Watt of DC capacity)

		Incremental Technology Improvement Scenario[a] (RE-ITI)			Evolutionary Technology Improvement Scenario[b] (RE-ETI)			
Year	**2010**	**2020**	**2030**	**2050**	**2010**	**2020**	**2030**	**2050**
Total PV Cost	4.82	3.36	2.98	2.64	5.15	2.40	2.00	1.80
Module	2.33	1.65	1.42	1.17	2.00	1.10	0.90	–
BOS / Other	2.49	1.71	1.56	1.47	3.15	1.30	1.10	–

[a] Based on a bottom-up engineering analysis by Black & Veatch (2012)
[b] Based on a bottom-up engineering analysis as part of RE Futures

Table 10-4. Cost Projections for Residential-Scale Fixed-Tilt PV (2009$/Watt of DC capacity)

	High RE Cost Scenario[a] (RE-ITI)				Mid Cost Scenario[b] (RE-ETI)			
Year	**2010**	**2020**	**2030**	**2050**	**2010**	**2020**	**2030**	**2050**
Total PV Cost	6.01	3.78	3.33	2.96	6.50	3.15	2.25	2.00
Module	3.00	1.76	1.53	1.26	2.25	1.20	1.00	–
BOS / Other	3.01	2.02	1.80	1.70	4.25	1.95	1.25	–

[a] Based on a bottom-up engineering analysis by Black & Veatch (2012)
[b] Based on a bottom-up engineering analysis as part of RE Futures

10.3.3.2 Cost and Performance for Concentrating Solar Power

10.3.3.2.1 Historical Cost and Performance Improvements for Concentrating Solar Power

Utility-scale CSP plants have operated successfully since the mid-1980s. After 15 years of relative inactivity in new construction, several new CSP plants were built in the United States and Spain beginning in the mid-2000s, and more than a dozen new plants are currently under development (NREL 2012).

Recent trends include a renewed interest in power towers that are capable of attaining higher operating temperatures than trough systems,[90] and incorporating thermal storage to enable dispatchable generation and higher capacity factors (NREL 2012). There is also a trend toward larger plant sizes to achieve economies of scale, which is not likely to be a technical challenge (trough system sizes can be increased modularly, and multiple tower systems could be sited in one location), but could represent a new challenge for securing project financing and accessing transmission. Another trend is the planned use of dry cooling, which can reduce water consumption by more than 90% (WorleyParsons 2009; Turchi et al. 2010). The cost and performance impacts of designing CSP plants with dry cooling depend on the system design and location. For example, dry-cooled CSP systems can be developed at similar costs to wet-cooled systems, but annual electricity generation is reduced by approximately 3%–6%; alternately, dry-cooled systems can be designed to generate the same annual electricity output as wet-cooled systems at a cost that is about 3%–6% higher than the wet-cooled systems (Turchi et al. 2010). Hybrid wet-dry systems are also being developed that combine the increased performance of wet-cooled systems on hot dry days, and the reduced water consumption of dry-cooled systems on cooler days.[91] The amount of water saved with hybrid wet-dry systems depends on the project location and operating strategy. Hybrid cooling can reduce water consumption by 40%–90% while maintaining 97%–99% of the performance efficiency (DOE 2009). However, hybrid systems currently have higher life-cycle costs than wet-cooled systems (Turchi et al. 2010).

[90] Trough operating temperatures are currently limited by their oil-based heat transfer fluids. Considerable R&D efforts are focused on developing higher temperature heat transfer fluids, like the molten salt or steam currently used in tower systems.
[91] On hot, dry days, wet-cooled systems are able to condense steam exhaust at significantly lower temperatures than dry-cooled systems can. The performance difference between wet- and dry-cooled systems, however, decreases with decreasing temperature.

Drawing a clear price trend from installed systems is difficult because only a limited number of CSP plants have been built, capital costs are site-dependent and sensitive to global commodity markets, and plant costs are frequently proprietary because of the highly competitive nature of the CSP industry. However, the experience gained from three decades of real-world plant operation has significantly reduced O&M issues, particularly those related to trough receiver tubes, and associated O&M costs.

10.3.3.2.2 Engineering Analysis of Advancement Potential for Concentrating Solar Power

Renewed interest in CSP has led to increased private-sector investment and deployments that will drive near- and mid-term cost reductions. CSP technologies have significant cost-reduction potential from technical advances, economies-of-scale benefits, and experience-based learning as more CSP plants are developed.

Building CSP systems with several hours of thermal energy storage represents one likely future trend. Systems with storage are more expensive, per unit of installed capacity, than systems without storage because of the additional cost of building more solar collectors per unit of power-block capacity[92] and adding thermal storage resources. However, CSP with storage has the potential to generate less-expensive electricity because storage can be used to significantly increase the amount of electricity generated by a CSP plant (i.e., increasing plant capacity factors) and increase the value of CSP electricity by making it a dispatchable generation resource.

Figure 10-14 shows current and projected CSP costs and potential capacity factors, which could increase if CSP projects are developed with several hours of thermal energy storage (DOE 2012). Current CSP trough costs are based on systems without thermal storage and are benchmarked to Nevada Solar One (NREL 2012). Near-term trough and tower costs represent systems with 6 hours of thermal storage. Near-term tower costs are lower than trough costs based on reduced solar-field costs and higher operating temperatures from the use of a molten salt heat transfer fluid (HTF) rather than an oil-based HTF. Higher operating temperatures increase power-block efficiencies and decrease storage costs (less storage medium required per unit of stored thermal energy). Later-term trough costs represent systems with 12 hours of thermal storage, increased operating temperatures from the use of a molten salt HTF, and reduced solar-field costs through technology improvements and learning-based cost reductions. Later-term tower costs represent systems with 14 hours of thermal storage, increased power-block efficiency by transitioning to a supercritical steam power cycle, and decreased solar-field costs based on improved heliostat design and learning-based cost reductions. The CSP cost and performance improvements shown in Figure 10-14 were developed for RE Futures, and they differ slightly from the reference assumptions used in the *SunShot Vision Study* (DOE 2012).

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[92] For CSP systems with several hours of thermal storage, the energy output from solar collectors during the day must be sufficient to run the thermal generator and store energy for later use. This is accomplished by significantly oversizing the solar field (collectors) relative to the thermal generator. The convention in the CSP industry is to characterize plant capacity by the thermal generator capacity, not solar field output, so these plants cost more on a capacity basis.

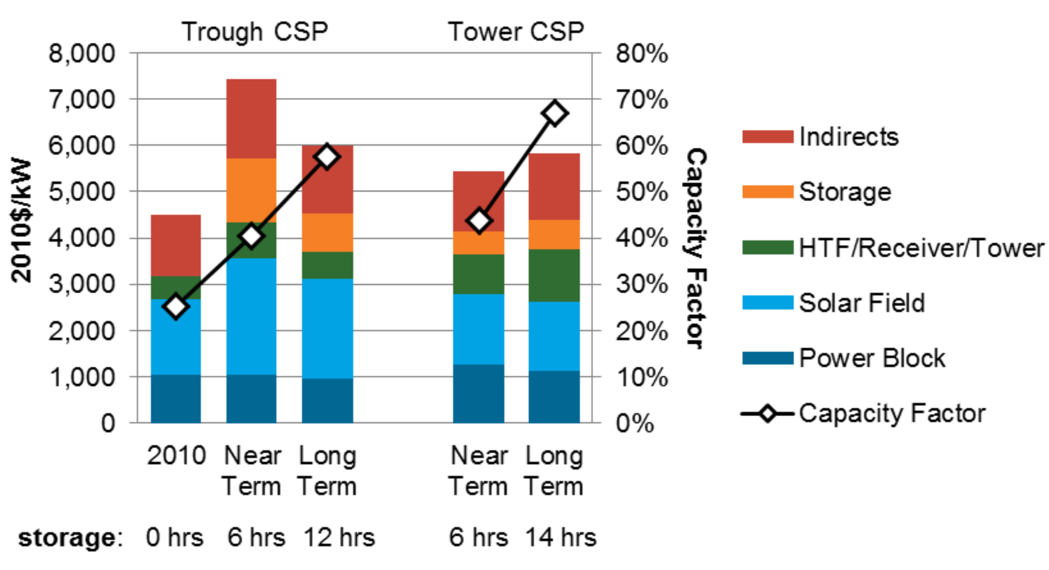

Figure 10-14. Current and projected CSP trough and tower costs (2010$/kW of AC capacity) and capacity factors

CSP capacity factors are projected to increase with the inclusion of more thermal storage capacity.

The CSP costs shown in Figure 10-14 are projected to increase, on a dollars-per-kilowatt basis, during some periods to support additional thermal storage capacity. However, the corresponding increase in CSP capacity factors from adding storage more than offsets the additional system costs, and the resulting cost of CSP generated electricity could decrease from 5%–30% in the near term to 45%–55% in the long term.

10.3.3.2.3 Cost Projections for Concentrating Solar Power

Figure 10-15 and Figure 10-16 show several CSP cost[93] projections for systems without thermal storage and systems with 6 hours of thermal storage. The CSP cost projections include RE-ITI (described by Black & Veatch [2012]), RE-ETI (based on the bottom-up engineering analysis in this chapter), and projections from recent studies. All CSP cost projections represent incremental or evolutionary cost and performance improvements and do not consider the impact of greater technological advances, such as high-temperature hybrid CSP and combined-cycle configurations (SolarPACES 2008). CSP systems without storage (see Figure 10-15) are less expensive on a capacity basis than CSP systems with storage[94] (see Figure 10-16); however, systems with storage frequently generate lower-cost electricity because they have higher capacity factors.

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[93] Solar cost projections represent market prices (cost for materials, manufacturing, distribution and installation plus margins for each step in the solar supply chain) that are seen as potential capital cost investments to electricity providers.

[94] CSP systems with thermal storage cost more per unit capacity because they include an oversized solar field (to enable additional solar energy to be collected and stored during the day) and thermal storage facilities. However, since CSP systems with storage can generate electricity for more hours per day, they have higher capacity factors, and can produce lower-cost electrical energy.

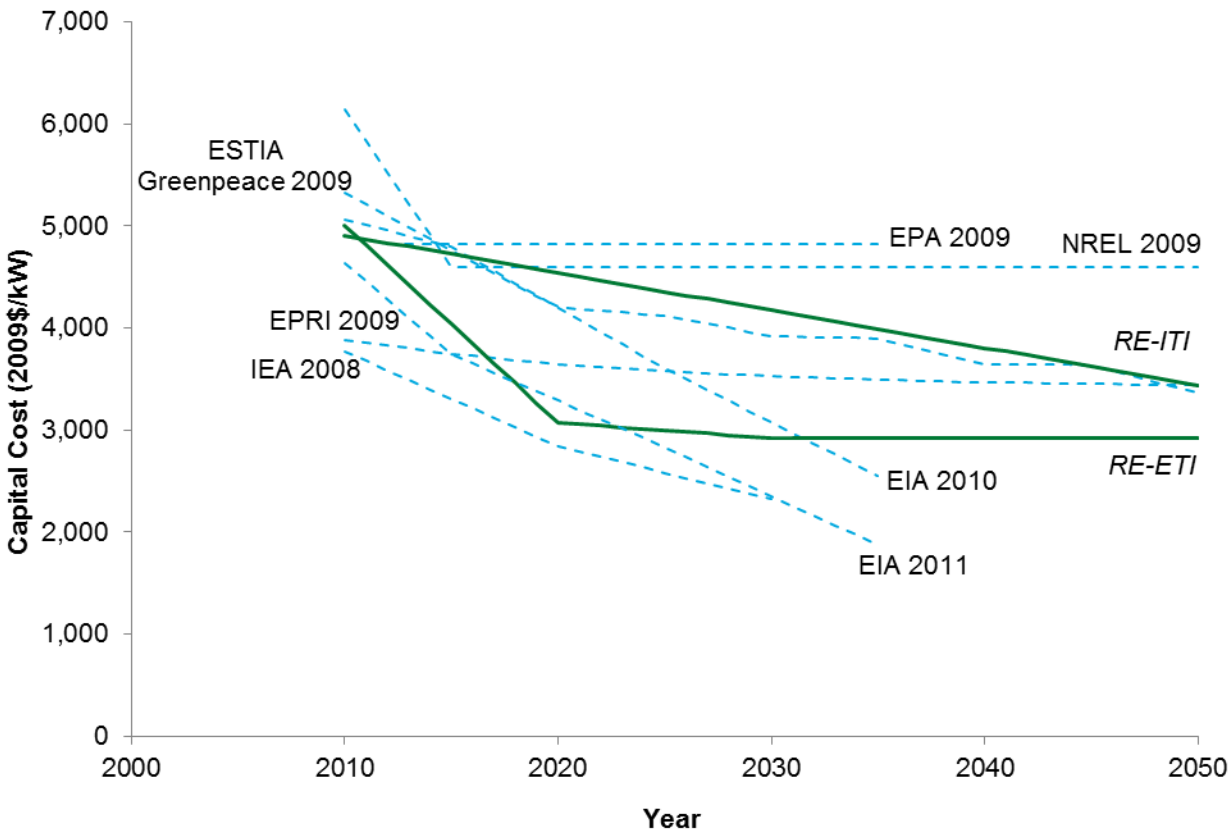


Figure 10-15. CSP capital cost projections for systems without storage, 2010–2050 ($/kW of AC capacity)

The RE-ITI cost projections represent parabolic trough systems through 2025, and tower systems from 2025–2050. The RE-ETI cost projections represent trough systems through 2015, and tower systems for the remainder of the study period. Future CSP cost projections show a significant range. There are several reasons for this, including: site-specific and technology-specific system costs, different plant designs that are optimized to meet different generation profiles, and a wide range in commodity price assumptions.

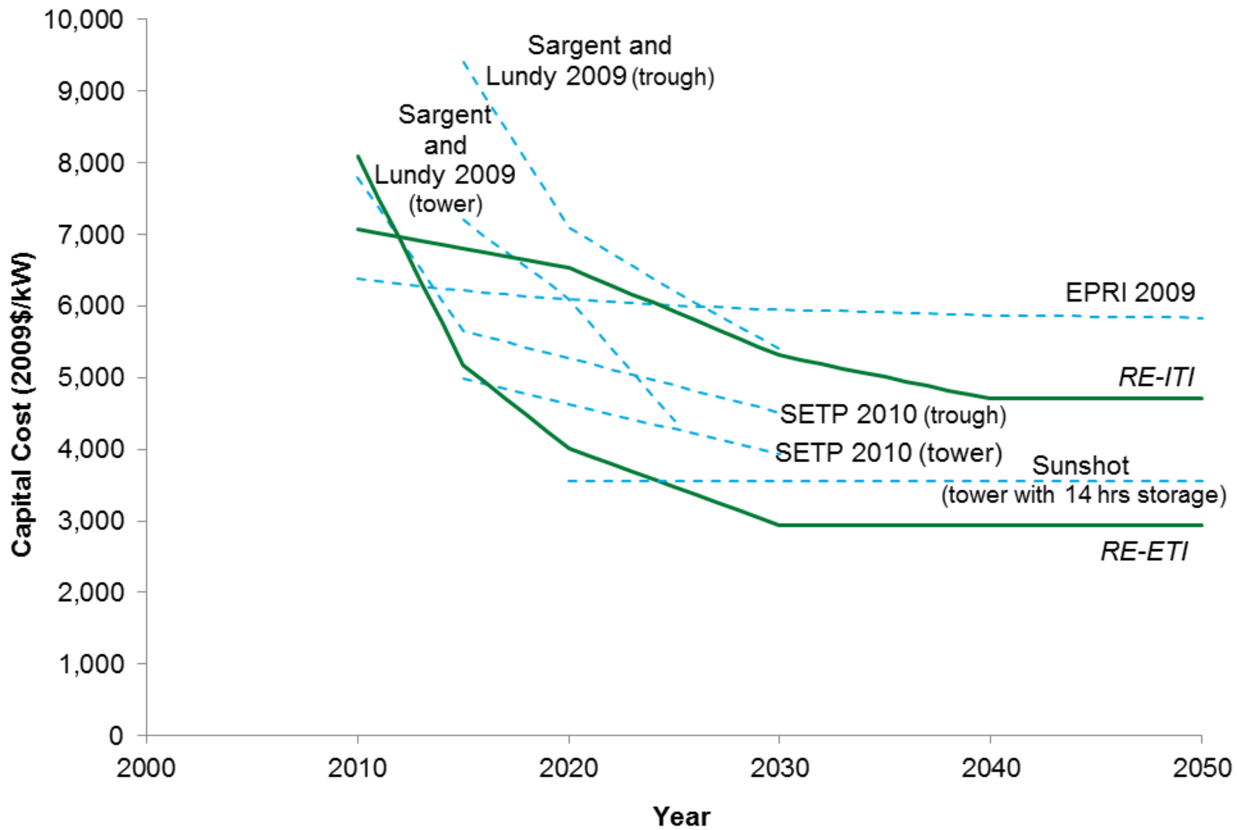


Figure 10-16. CSP cost projections for systems with 6 hours of energy storage, 2010–2050 ($/kW of AC capacity)

All projections are based on systems with 6 hours of energy storage except for the Sunshot projections, where 14 hours of energy storage are assumed. RE-ITI projections represent parabolic trough systems through 2025, and tower systems from 2025-2050. The RE-ETI projections represent trough systems through 2015, and tower systems after 2015.

Table 10-5 summarizes the cost projections for trough systems without storage, trough systems with 6 hours of thermal storage,[95] and tower systems with 6 hours of storage. The main difference between the RE-ITI and RE-ETI projections for trough systems is the speed at which performance improvements are developed and demonstrated. The RE-ETI CSP projections for 2020 are about 10% less expensive than the 2050 RE-ITI projection, where the main cost difference lies in assumed indirect costs (18.5% for RE-ETI and 30% for RE-ITI). However, the 2020 RE-ETI and 2050 RE-ITI projections represent similar systems. The differences in the tower CSP cost projections represent both a difference in when performance improvements will be developed, and a difference in the final system characteristics. The 2030 RE-ETI system is approximately 40% less expensive than the 2050 RE-ITI system, primarily reflecting lower solar field and indirect costs as well as lower tower, receiver, and power-block costs. The two CSP cost projections represent different timelines for achieving cost and performance improvements for troughs and towers, and the additional potential for tower performance improvements.

[95] For comparison with previous cost projections, total costs are given for systems with 6 hours of thermal storage. In the model analysis, component-level costs were used to optimally size thermal storage components, and systems frequently were built with 10–12 hours of storage.

Table 10-5. Component Costs for CSP Trough Systems[a,b,c]

Component	200-MW Trough System with No Storage				200-MW Trough System with 6 Hours Storage				200-MW Tower System with 6 Hours Storage				
	RE-ETI		RE-ITI		RE-ETI		RE-ITI		RE-ETI			RE-ITI	
	2010	2020	2010	2050	2015	2020	2010	2050	2015	2020	2030	2020	2050
Site and Solar Field ($/m^2)	350	210	300	195	350	210	300	195	230	163	121	235	155
Solar Field Size (m^2/kW)	6.6	6.3	6.6	6.1	8.9	8.4	9.5	8.9	8.9	8.8	8.2	11.5	10.8
High-Temperature Thermal Fluid (HTF) ($/kW)	500	255	500	375	665	465	500	375	–	–	–	–	–
Tower and Receiver ($/kW)	–	–	–	–	–	–	–	–	522	494	396	852	512
Power Block ($/kW)	1,010	775	975	900	1,010	775	975	900	920	775	775	950	875
Storage ($/kWh-t)[d]	0	0	0	0	80	25	80	40	30	20	20	30	20
Contingency (%)	10	10	10	10	10	10	10	10	10	10	10	10	10
Indirect Costs (%)	18.5	18.5	30	30	18.5	18.5	30	30	18.5	18.5	18.5	30	30
Total Installed Cost ($/kW)	5,000	3,070	4,960	3,530	8,110	4,460	7,135	4,995	5,170	4,015	2,940	7,040	4,750

[a] Watts are given in AC capacity.

[b] All costs are presented in 2009 dollars.

[c]The ETI and ITI cost projections were developed from bottom-up engineering analysis based on several cost and performance assumptions. ETI costs are frequently, but now always, lower than ITI cost estimates for any given year.

[d]Storage costs ($/kWh-thermal) are higher for trough systems than tower systems primarily because troughs have lower operating temperatures and require more storage medium per unit of stored energy than higher temperature tower systems.

10.3.3.3 Solar Cost Projections in the SunShot Vision Study

DOE launched the SunShot Initiative in 2011, a strong, coordinated effort to push solar energy to become cost competitive with conventional technologies in wholesale and retail energy markets (DOE 2012). The SunShot Initiative targets a combination of technology improvements that could enable the price of solar generated electricity to decrease by approximately 75% from 2010 to 2020. Achieving these targets would make the cost of solar electricity competitive with the cost of other energy sources, paving the way for rapid, large-scale adoption of solar electricity in the United States.

The primary SunShot assumptions include:

- PV costs are targeted to reach \$1.00/W (2010 U.S. \$/W) for utility-scale systems, \$1.25/W for commercial rooftop systems, and \$1.50/W for residential rooftop PV systems by 2020. Achieving these cost reductions would enable the levelized cost of energy (LCOE) from utility-scale PV to reach 5–7 cents/kWh, and PV could become broadly competitive in wholesale and retail electricity markets without incentives.

- CSP costs are targeted to reach \$3.60/W for systems with 14 hours of thermal storage capacity by 2020. This corresponds to CSP LCOE of approximately 6 cents/kWh, enabling CSP to become broadly competitive in wholesale electricity markets without incentives. Additionally, CSP systems with thermal storage are dispatchable, and could provide several grid services in addition to energy generation.

The RE Futures modeling scenarios (see Volume 1) are based on incremental or evolutionary improvements to solar technologies, as outlined in this section, and do not reach the SunShot price and performance targets. The *SunShot Vision Study* (DOE 2012) explores the possible deployment of solar technologies if the SunShot price targets are reached and the study results are compared to solar deployment in several of the RE Futures scenarios in Section 10.6.2.

10.4 Resource Cost Curves

Regional resource cost curves were developed for four solar markets—rooftop PV, distributed utility PV, central utility PV, and CSP—and were used to optimally deploy PV and CSP in the ReEDS and SolarDS models. The resource cost curves were derived using solar resource characteristics from the National Solar Radiation Database (NREL 2007) and from land characteristics from the National Land Cover Data (Homer et al. 2004). Hourly surface solar radiation (direct and diffuse) from the National Solar Radiation Database was inferred from geostationary satellite imagery (Perez et al. 2002). Hourly PV and CSP performance were simulated using the solar-radiation data with meteorological data from more than 1,000 U.S. field stations.[96] The resulting high-resolution PV and CSP performance data set was associated with land-cover characteristics from the National Land Cover Data and was filtered to generate resource supply curves. General land filters were applied to all solar technologies to remove land area with terrain slopes greater than 3%, and to remove land that was identified as developed, water-covered, wetland, or protected (including wilderness areas, state parks, and national

[96] These data consist of archived meteorological data from the National Oceanic and Atmospheric Administration's National Climatic Data Center database (http://www.ncdc.noaa.gov/).

parks). For CSP, additional filters required that the mean direct-normal irradiance resource was at least 5 kWh/m^2/day and that the contiguous land area was at least 1 km^2. For distributed utility PV, the land was filtered to include locations with at least 20 contiguous National Land Cover Data grid cells—each 30 m by 30 m—equivalent to the amount of land required to site approximately 2 MW of tracking PV capacity (Denholm and Margolis 2008b). For central utility PV, the land area filter included sites with at least 36 contiguous cells, equivalent to the amount of land required to site approximately 3.5 MW of tracking PV capacity (Denholm and Margolis 2008b).

Figure 10-17 shows aggregate national PV and CSP resource cost curves. The cost metric is given in terms of relative LCOE.[97] The rooftop PV supply curve represents solar resource variability, roof characteristics, and roof-orientation statistics based on *Denholm and Margolis* (2008a). The non-rooftop supply curves represent solar resource variability and the various land filters applied to characterize each market. These cost curves do not include transmission or interconnection costs, which depend on how and when each resource is developed.

The PV and CSP solar resource is several orders of magnitude greater than the levels of deployment explored in the RE Futures scenarios. Resource availability will not limit solar deployment. Figure 10-17 also shows that the solar resource is relatively similar across different U.S. regions, and the difference between an average U.S. solar resource and the best and worst locations is approximately ±20%.

[97] Relative LCOE is used here as a cost multiplier that characterizes the range of PV and CSP generation over the entire United States and a distribution of panel orientations for rooftop PV. A relative LCOE of 1 represents a PV or CSP system in the best U.S. resource region, with an optimal orientation. The increase in relative LCOE with additional capacity shows the additional cost associated with developing PV and CSP resources in lower quality solar resource locations or orientations. Although LCOEs for systems depend on capital costs and financing assumptions, the relative LCOE cost multiplier is independent of these assumptions.

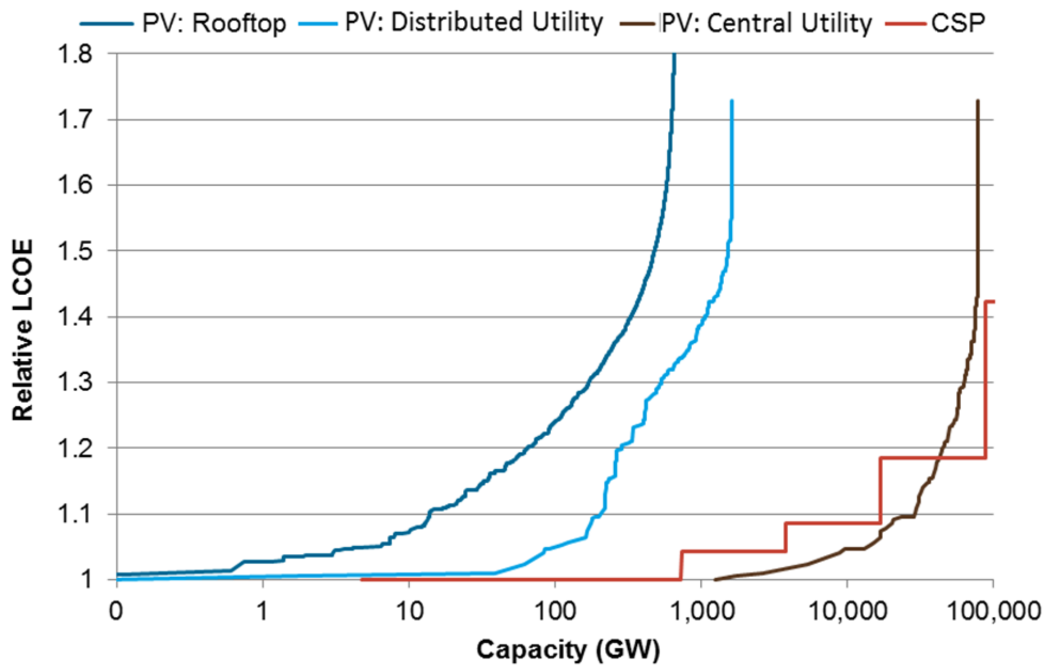


Figure 10-17. Supply curves for solar PV (DC capacity) and CSP (AC capacity)

Rooftop PV has a technical potential of nearly 700 GW in the United States, as shown in Figure 10-17. Distributed utility PV has a technical potential of approximately 2,000 GW, which could be sited in urban and suburban regions near load centers. The technical potential of central utility PV was calculated using only marginal land—including shrubland, bare rock, sand, and clay land types—and is approximately 80,000 GW. Including additional land types would increase the technical potential significantly. The marginal land resource, however, is hundreds of times greater than the levels of deployment explored in RE Futures, and land availability is not likely to limit PV deployment. The CSP land resource is similarly large, with a technical potential of approximately 37,000 GW for systems with 6 hours of energy storage and a solar multiple[98] of 2. Although land availability is not likely to constrain CSP deployment, access to a high direct-normal irradiance will lead to increased levels of deployment in the southwestern United States. Although land is prevalent in the Southwest, developers of utility-scale CSP and PV systems must complete environmental review procedures to assess and minimize their impact on the desert habitat.

[98] The solar multiple of a CSP plant represents the ratio of maximum thermal power generated by the solar collector field to the thermal power required to operate the power block at full capacity. CSP plants without storage are typically designed with a solar multiple greater than 1 so the energy gathered by the solar field is sufficient to operate the power block at full capacity for several hours during the day. CSP systems with storage can have solar multiples much greater than 1, enabling thermal energy to be collected and stored during the day and used to operate the power block in the evening and at night.

10.5 Output Characteristics and Grid Service Possibilities

10.5.1 Electricity Output Characteristics

Solar electricity consists of two distinct technologies with different generation characteristics. PV produces DC electricity from individual modules that are typically 100–200 W. These modules are combined to form systems that range in size from a few kilowatts to hundreds of megawatts. The DC generation is converted into utility-grade power at 60 Hz AC. Depending on the location, this electricity is fed into the local grid in either the distribution network or the transmission network. CSP plants use conventional AC generators that are functionally equivalent to conventional fossil generators and feed into the transmission network at high voltages.

As with wind, there are a number of differences between solar and traditional energy sources. Three of the more important factors are variability, uncertainty, and capacity value. Variability reflects the fact that solar generation is weather-dependent. The power delivery characteristics of an individual solar generator are dependent on time of day and weather conditions including cloud cover. One key difference between wind and PV is that a single small PV system frequently exhibits greater variability than wind in short-term power output (seconds to minutes) due to passing clouds (Curtright and Apt 2008). However, the aggregate output from a large PV plant (several MWs), or several small PV systems distributed over a wide geographical area, has far less variability and significantly reduced short-term ramp rates than a single small PV system (see Figure 10-18). Even the combined output of a few PV systems has been shown to significantly reduce the magnitude of peak fluctuations in power output. This suggests that the distributed nature of PV installations can mitigate the short-term variability of the system as a whole.

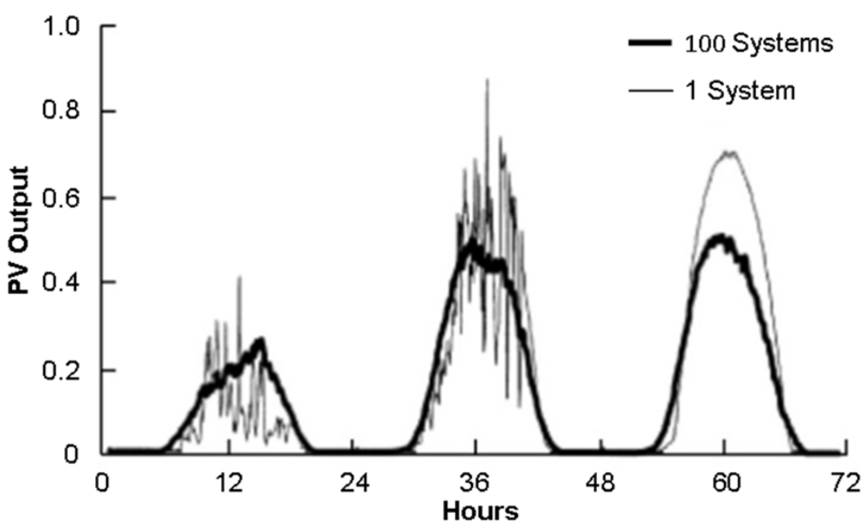


Figure 10-18. Normalized power output from 100 small PV systems across Germany, June 1995

Source: Wiemken et al. 2001

The "y" axis represents normalized PV output.

The variability of aggregate solar output depends on the correlation of cloud-induced variability between solar plants. The correlation of solar output between plants generally decreases with distance, and the variability over shorter time periods (minutes) is less correlated than variability over longer time periods (multiple hours) (Murata et al. 2009). CSP systems exhibit less short-term variability than PV systems because of the thermal inertia within the system (Mehos et al. 2009). A parabolic trough plant using an oil-based HTF and employing a modern steam turbine can typically operate with no solar input for about half an hour (Steinmann and Eck 2006). CSP systems with thermal storage can be operated as a dispatchable resource, significantly reducing most variability and predictability concerns. In addition, CSP with storage can be dispatched to improve power quality, voltage, and frequency stability.

Figure 10-19 illustrates the magnitude of PV forecasting errors for forecast horizons of up to three days made using different methods. The simplest forecasting method—called a persistence forecast—assumes that future conditions will be the same as current conditions. This is reasonably accurate for shorter timescales (one minute to one hour) but is inappropriate for longer timescales. Solar forecasts based on numerical weather simulations[99] are much more accurate for longer timescales (multiple hours or days). Figure 10-19 shows that near-term PV forecast errors are slightly reduced (5%–10%) by using complex forecast methods and are reduced significantly (20%–30%) by forecasting aggregate solar output rather than the output of a single small system.

[99] Numerical weather simulations are developed using mathematical models of atmospheric dynamics and are used to predict the weather hours to days in advance (GE Energy 2010).

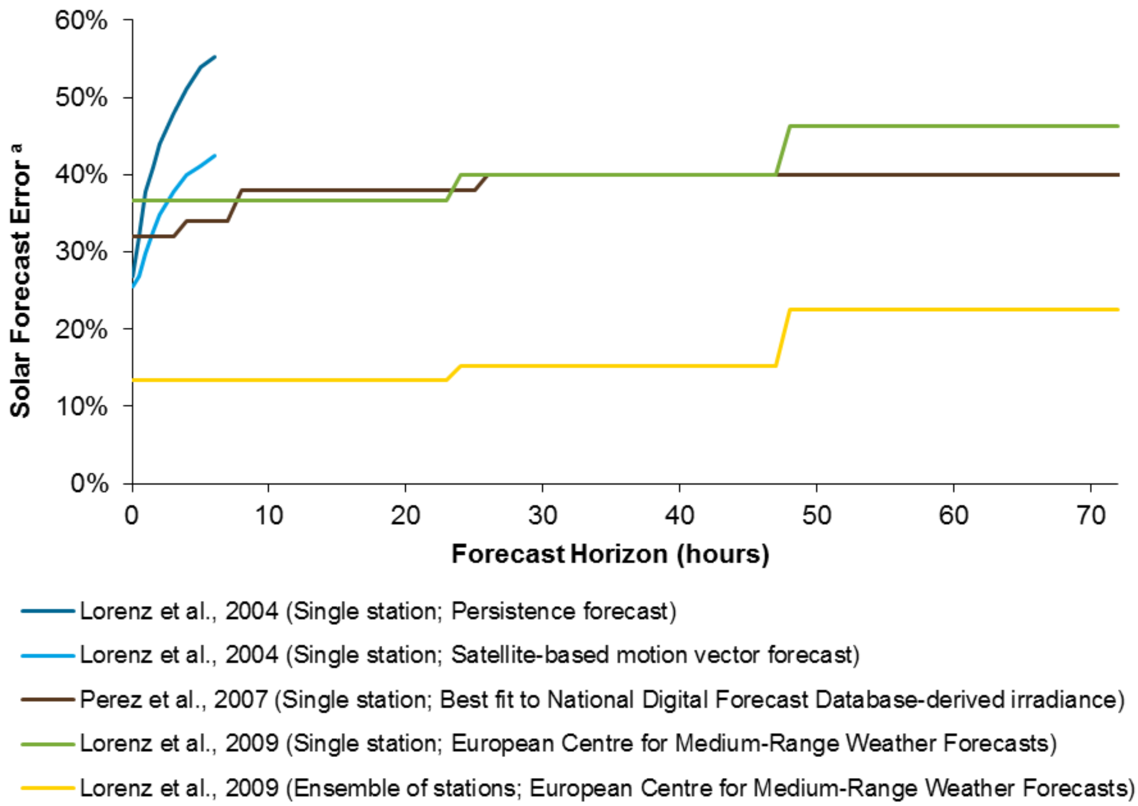


Figure 10-19. PV forecast error (root mean square error) for different forecast horizons and different prediction methods (data provided by Mills 2011)[100]

[a] Relative root mean square error of global solar insolation forecast

The capacity value of solar refers to the contribution of a power plant to reliably meet demand. Peak solar output occurs during early summer afternoons and strongly correlates to peak afternoon air-conditioning loads. For resource planning, this correlation can lead to a greater capacity credit being assigned to solar generation than is assigned to wind, which is weakly correlated to peak demand (Xcel Energy 2009; Hoff et al. 2008; Perez et al. 2006). The capacity credit for PV systems—and for CSP systems without thermal storage or backup fossil energy generation—will decrease, however, with increasing deployment on a utility system.[101] Concentrating solar power systems with thermal storage or fossil energy backup can have a very high capacity credit because of their inherent dispatchability (Madaeni et al. 2012).

A unique element of PV is its opportunity to be distributed within load centers. An advantage of distributed PV is that electricity is generated at the distribution level, which can reduce utility

[100] Personal communication A. Mills, Lawrence Berkeley National Laboratory, April 29, 2011.
[101] PV capacity values increase with initial deployment because the aggregate PV generation from several small systems, or from multi-megawatt systems, is much smoother than the generation from one small PV system (see Figure 10-18). However, as more PV is added to the system, the peak in net load (load minus PV generation) shifts from afternoon to evening where PV output is less (Denholm and Margolis 2007), and capacity values can decrease significantly. CSP without storage will experience the same capacity factor decrease with deployment.

line losses and electric system congestion due to the proximity of PV source to loads. Distributed electricity generation also introduces integration concerns that include flicker, voltage sags and swells, operational deterioration on transformer tap changers and voltage regulators, and increased levels of harmonics. A number of standards are in place to ensure safe, reliable operation of distributed energy resources. For example, the industry standard IEEE 1547, which applies to any distributed energy resource up to 10 MW, includes requirements for connecting PV systems deployed on the distribution system. Most PV inverters are designed and tested to this standard, which requires them to drop offline in the event of significant voltage and frequency disturbances, and are required to have anti-islanding provisions to prevent power flow during grid outages.

The lessons learned from wind and solar grid-integration studies (Enernex 2010; GE Energy 2010) provide valuable insight for integrating solar resources. These studies demonstrate the importance of using increased operating reserves, increasing access to flexibility in conventional generation plants, increasing access to other sources of flexibility in power systems including demand response, and incorporating wind and solar forecasting into systems operations.

10.5.2 Technology Options for Power System Services

There are several options for improving the grid flexibility of solar generation. For PV, an important option is better utilizing the capabilities of the inverter's power electronics. This includes provision of reactive power, voltage control, and low-voltage ride through. This capability supports system voltage and minimizes short-duration voltage variations that might otherwise be experienced by loads and customers. New standards and codes will be required to fully implement these capabilities. Communication capability could be added to the PV inverter to allow the distribution system to signal the inverter to dispatch power and loads to optimize power flow to the utility. As with wind, PV could also vary output below the maximum available output. This allows PV to provide a variety of reserves services including up and down regulation and contingency reserves. Provision of these services would require the economic penalty of reduced energy output, but could be increasingly valuable at high penetration.

For concentrating solar power systems, a significant source of grid flexibility is the use of thermal energy storage. Storage turns a variable and uncertain resource into one with a high degree of dispatchability. It can be used to shift generation from times of peak solar output to times of peak demand, resulting in a capacity credit nearly equivalent to a conventional generator (Madaeni et al. 2012). Storage also increases the ability of CSP to ramp in response to the increasing variability of net load resulting from wind and solar (Denholm and Mehos 2011). CSP can also provide the same array of ancillary services as a conventional generator including regulation and contingency reserves. Many CSP plant designs can also be readily augmented with fossil-fueled generation, providing either short- or long-term dispatchable output in the absence of solar input. As a source of dispatchable energy, CSP can increase the flexibility of the electric power system, improve power quality, and increase the level of variable renewable resources that can be incorporated into the grid (Denholm and Mehos 2011).

10.6 Deployment in RE Futures Scenarios

Solar technologies play significant roles in almost all of the RE Futures scenarios described in Volume 1. Table 10-6Table 10-6 and Figure 10-20 show the variation in 2050 installed (utility and rooftop) PV and CSP capacity between the six (low-demand) core 80% RE scenarios and the high-demand 80% RE scenario. In addition, Table 10-6 shows the contribution of solar technologies to the total 2050 generated electricity across the 80% RE scenarios. Excluding the 80% RE-NTI scenario, solar technologies contributed a large fraction to the 2050 total generated electricity, with the percent of generation from solar ranging from 13% to 22%. The ranges in PV and CSP capacity deployed in 2050 were 149–294 GW and 33–126 GW, respectively, among these scenarios. Note that the greater capacity factor of CSP systems leads to greater annual energy production for a given gigawatt of installed capacity as compared to PV systems.[102] Solar deployment was much more limited in the 80% RE-NTI scenario, which assumed no price or performance improvements for renewable technologies. As solar technologies are at a relatively early stage of commercial maturity compared with other renewable technologies considered in the modeling analysis, this assumption depressed solar deployment to a greater degree than it does other renewable resources.

Table 10-6. Deployment of Solar Energy in 2050 under 80% RE Scenarios[a,b]

Scenario	PV			CSP		Total Solar	
	Utility PV Capacity (GW)	Rooftop PV Capacity (GW)[c]	Generation (%)	Capacity (GW)	Generation (%)	Capacity (GW)	Generation (%)
High-Demand 80% RE	293	128	12.7%	79	6.4%	493	19.1%
Constrained Transmission	124	170	10.4%	33	3.4%	327	13.9%
Constrained Resources	118	85	7.9%	120	13.9%	324	21.9%
80% RE-ETI	86	85	6.6%	126	14.1%	297	20.6%
Constrained Flexibility	64	85	5.6%	89	10.4%	238	16.0%
80% RE-ITI	83	85	6.4%	56	6.6%	225	13.0%
80% RE-NTI	5	85	2.9%	1	0.1%	91	2.9%

[a] See Volume 1 for a detailed description of each RE Futures scenario.
[b] The capacity totals represent the cumulative installed capacity for each scenario, including currently existing solar capacity.
[c]Rooftop PV markets were simulated using the SolarDS model (Denholm et al. 2009) as described in Volume 1. These projections were based on RE-ITI rooftop PV cost projections and resulted in 85 GW of rooftop PV capacity by 2050. This projection was used in all but two of the 80%-by-2050 RE scenarios. The constrained transmission scenario explored twice the level of rooftop PV capacity (170 GW), and the high-demand scenario explored about 50% more rooftop PV electricity, reflecting the increase in end-use electricity demand.

[102] Concentrating solar power resources with approximately 8–12 hours of storage are preferentially deployed in the ReEDS model. These CSP systems represent dispatchable resources with capacity factors ranging from 55% to 75%.

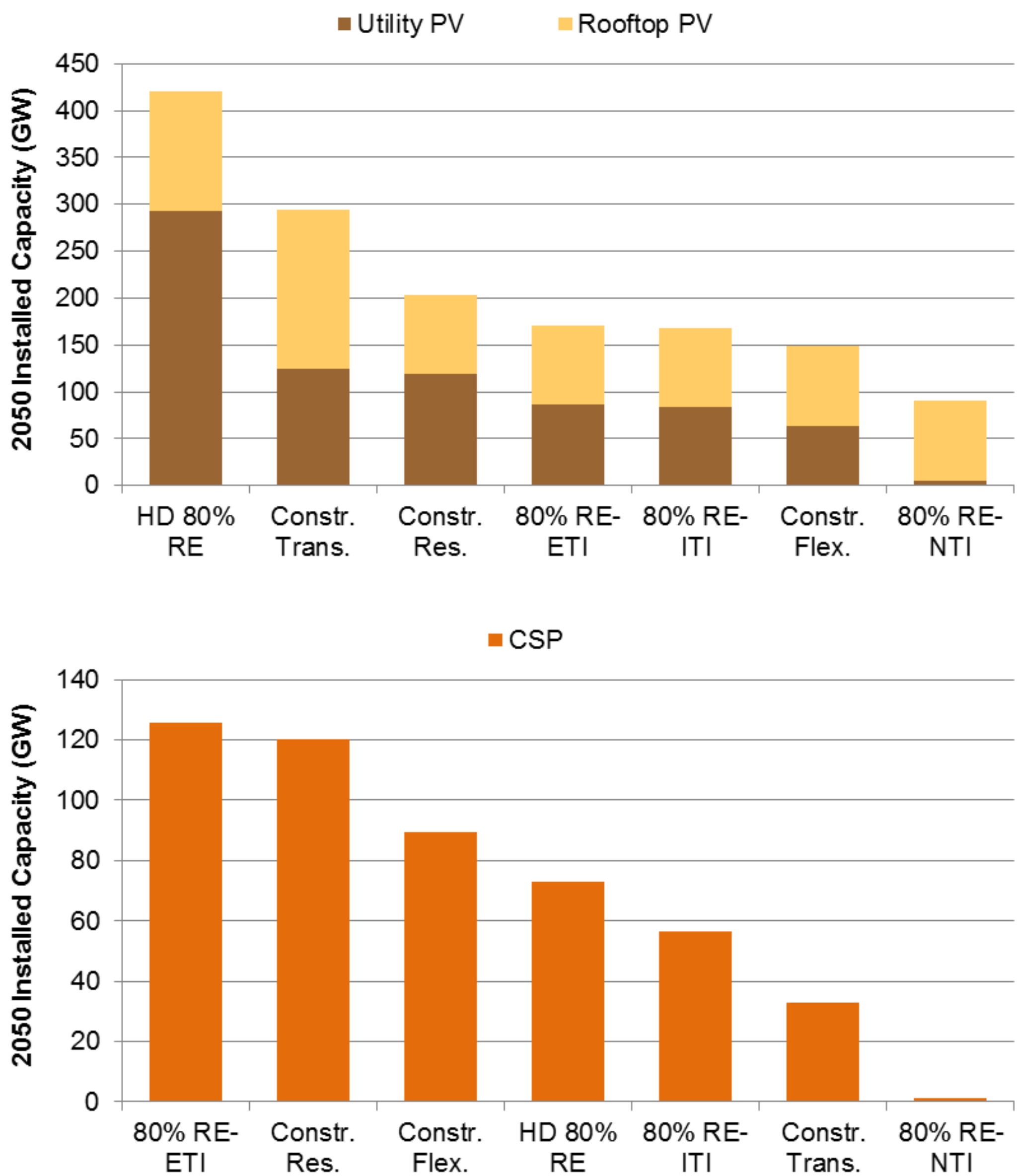


Figure 10-20. Deployment of solar PV technologies (top) and CSP (bottom) in 80% RE scenarios

The large range in solar deployment among the modeled scenarios demonstrates the strong influences future decisions will have on solar penetration levels. Solar resources are developed more aggressively if it is assumed that renewable energy technologies achieve significant cost and performance improvements (80% RE-ETI scenario); electricity demand increases over time (high-demand 80% RE scenario); and the technical potential of all renewable resources is limited (constrained resources scenario).[103] As described previously, solar resources are developed to a lesser extent if renewable technologies were to achieve little future cost reduction. In addition,

[103] U.S. solar resources are several orders of magnitude greater than the levels of deployment explored in the RE Futures scenarios. This is generally not the case for many of the other renewable electricity technologies.

PV and CSP technologies have different characteristics that affect their deployment. For example, PV deployment increases and CSP decreases if transmission expansion is limited due to the greater location-dependence of CSP resources. Concentrating solar power deployment increases and PV decreases if institutional flexibility is limited due to the variability and uncertainty inherent in PV systems without storage.[104] These trends are described in detail in Volume 1.

Among the 80% RE scenarios listed in Table 10-6Table 10-6, the high-demand 80% RE scenario realized the greatest deployment of PV capacity with more than 420 GW (293 GW utility-scale and 128 GW rooftop) installed by 2050. Figure 10-21shows annual and cumulative PV deployment, along with the annual cost of developing PV resources, averaged by decade, for the high-demand 80% RE scenario.[105] The early growth was partly driven by renewable portfolio standards requirements and the solar investment tax credit.[106] Rooftop PV markets show relatively consistent growth over time; however, utility PV markets fluctuated in the first half of the study period, primarily based on changes in the solar investment tax credit. Annual installations ranged from 2 GW/yr to 15-GW/yr from 2010 to 2030, resulting in nearly 140 GW of installed PV capacity by 2030. Although PV growth slowed immediately after 2030, PV deployment was found to be very significant in the last decade of the study period, with a peak annual installation rate of nearly 25 GW/yr at an average investment cost of approximately $50 billion/yr.

The high-demand 80% RE scenario realized widespread deployment of PV technologies across the contiguous United States. Rooftop PV was deployed in all 48 states, with the highest deployment occurring in California, Texas, Florida, and New York (see Figure 10-22[a]). A number of factors contribute to economic deployment of rooftop PV, including solar resource, retail electricity rates, and population. Utility PV was primarily deployed in the southern states, driven by solar resource and the coincidence of PV-generation profiles with summer air-conditioning demand (see Figure 10-22[b]). The southeastern states developed a strong utility PV market due, in part, to the relatively good solar resource, the presence of large load centers, and the relatively low availability of many other renewable resources in that region.

[104] Although CSP systems without thermal storage are included in ReEDS, these technologies do not show significant levels of deployment based on the cost and performance assumptions used.
[105] The annual installed capacity and decade-averaged annual costs include end-of-life replacements that are calculated using a 30-year operational lifetime.
[106] Current statute for commercial customers (e.g. applicable to utility-scale solar and commercial rooftop PV investments) specifies that the solar investment tax credit drops from 30% to 10% at the end of 2016 with no legislatively established expiration. For residential customers, current statute specifies that the investment tax credit of 30% expires at the end of 2016. To avoid modeling outcomes that are impacted by such preferential long-term policy decisions, the ReEDS analysis assumed the expiration of the 10% investment tax credit in 2030. The SolarDS rooftop PV modeling assumed the same investment tax credit decrease and expiration for commercial rooftop PV. However, for residential rooftop PV, the investment tax credit in SolarDS was assumed to follow current statute and simply expire in 2016. This modeling choice was not intended to represent any policy recommendation or to discount the potential role of such mechanisms to impact market development for new technologies.

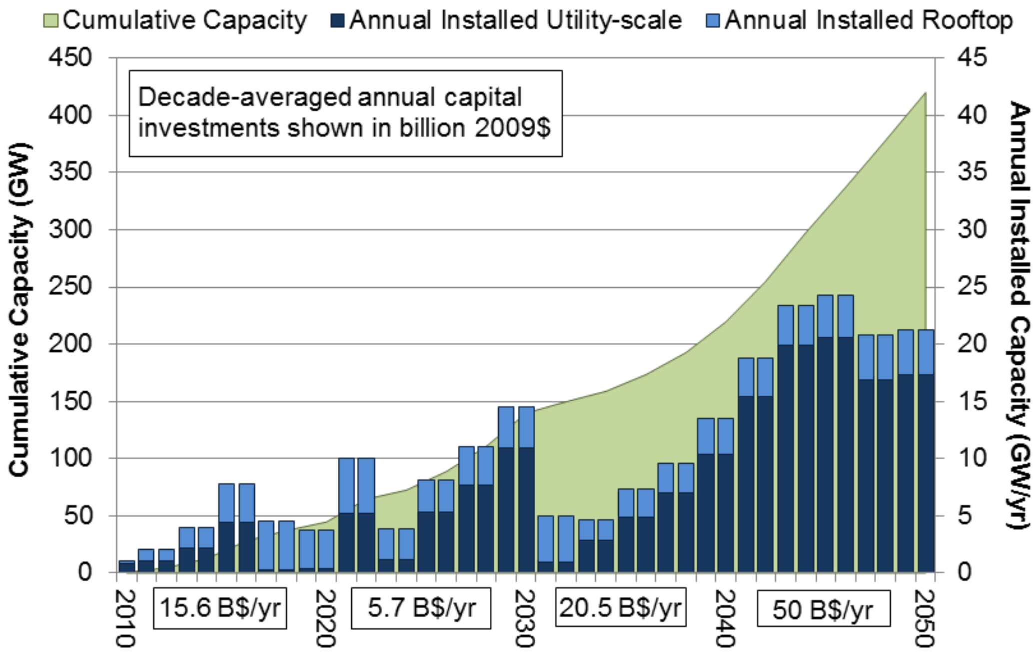
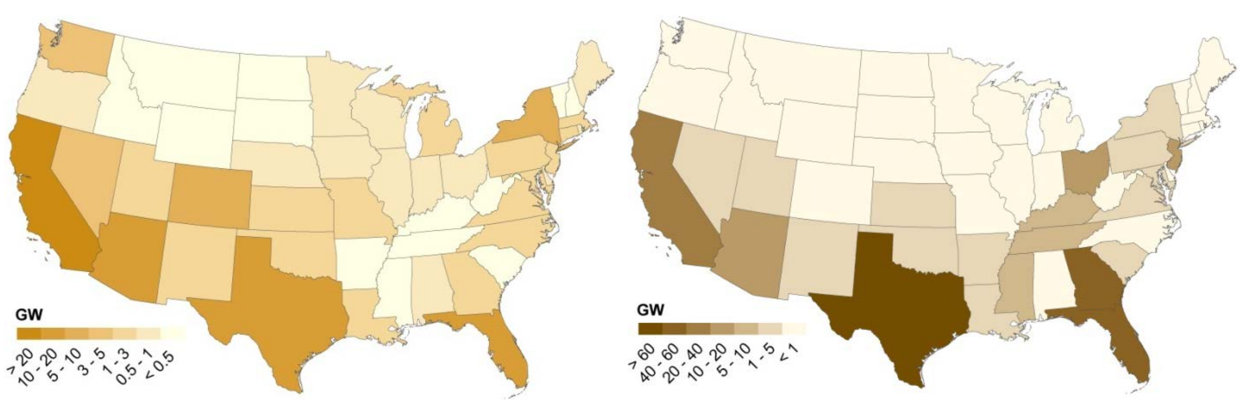


Figure 10-21. Deployment of solar PV in the high-demand 80% RE scenario



(a) Rooftop PV capacity by state, 2050

(b) Utility PV capacity by state, 2050

Figure 10-22. Regional deployment of rooftop and utility-scale PV in the high-demand 80% RE scenario

The 80% RE-ETI scenario demonstrated the highest level of CSP capacity deployment with 126 GW of CSP capacity installed by 2050. For this scenario, ReEDS simulations suggest that CSP resources were primarily developed in the latter half of the study period (see Figure 10-23). Although there are currently a large number of CSP projects in various stages of development (NREL 2012), the ReEDS model did not consider these planned projects because there is considerable uncertainty regarding which plants will actually be developed.[107] In addition, as a system-wide economic optimization model, ReEDS cannot capture all of the non-economic, and particularly regional, considerations for future technology deployment. As such, ReEDS likely underestimates near-term CSP growth. In the second half of the study period, however, the installation rate for CSP technologies was substantial, ranging from approximately 5 GW/yr to 7 GW/yr at a cost of greater than $20 billion/yr. The ReEDS model primarily developed CSP resources with approximately 10–12 hours of storage, and stored CSP was used to augment PV and wind generation in the evening and at night as described in Volume 1 (see also Denholm and Mehos 2011).

The reliance of CSP technologies on direct-normal insolation largely restricts CSP deployment to the Southwest.[108] Figure 10-23 highlights the states for which CSP capacity was installed in the 80% RE-ETI scenario. Almost all of the concentrating solar power installations were located in Texas, New Mexico, Arizona, and California. Other western states also realized some CSP deployment, and, to a much more limited extent, CSP installations were present in Florida.

Figure 10-21 and Figure 10-22 show PV deployment results for only one of many model scenarios, none of which was postulated to be more likely than any other. Similarly, Figure 10-23 and Figure 10-24 show CSP deployment results for only one of the model scenarios. Care should be taken in interpreting model results from any one scenario because the input data and model assumptions are subject to significant uncertainty, and because ReEDS is a system-wide optimization model that was not designed to capture all of the non-economic, and particularly regional, considerations for future technology deployment.

[107] The ReEDS model did not consider planned projects for any (renewable, conventional, or storage) technologies because there is significant uncertainty regarding whether projects will be completed.

[108] The lowest resources considered in ReEDS had an annual average direct-normal incident radiation of 5 kWh/m^2/day.

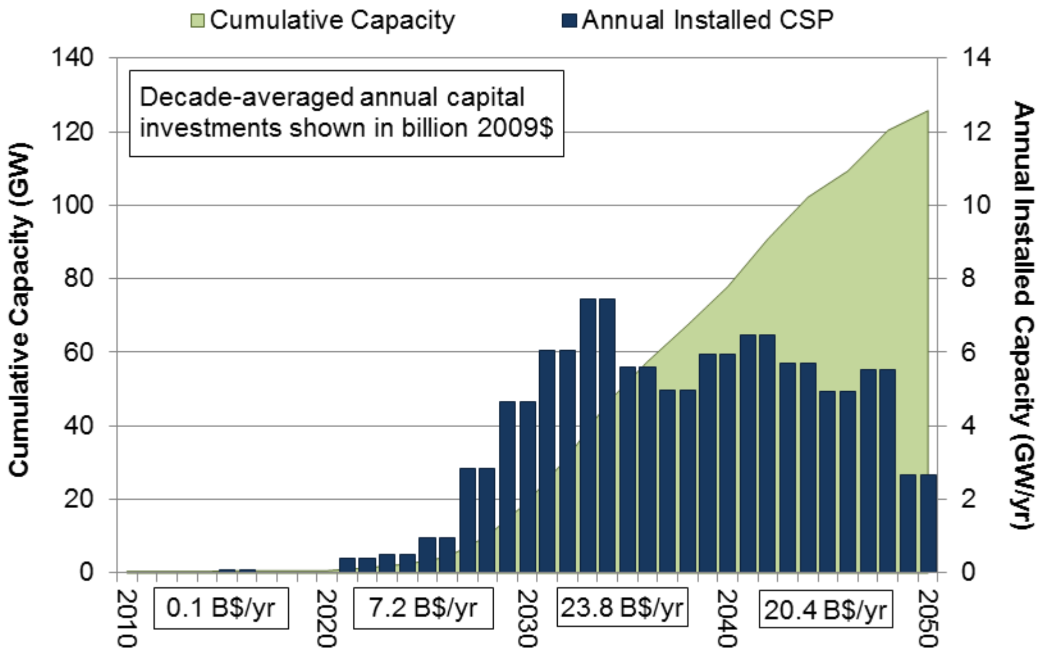


Figure 10-23. Deployment of CSP in the 80% RE-ETI scenario

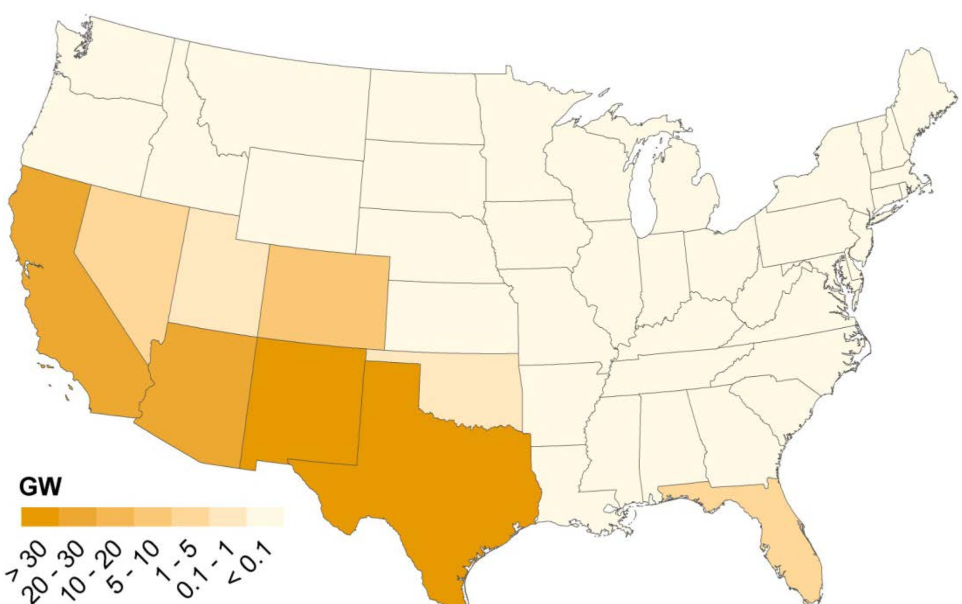


Figure 10-24. Map of deployment of CSP in the 80% RE-ETI scenario

10.6.1 Comparison of Solar Deployment in RE Futures and the SunShot Vision Study

The *SunShot Vision Study* (DOE 2012) complements the RE Futures Study by exploring solar deployment in a scenario with very low solar costs, high electricity demand, and no fixed renewable energy target. In the *SunShot Vision Study* scenarios, solar markets evolve to supply 14% of U.S. electricity demand by 2030 and 27% by 2050, which is higher than the solar contribution in any of the RE Futures scenarios.

Figure 10-25 compares the amount of PV and CSP capacity deployed by 2050 in the *SunShot Vision Study* to solar deployment in several RE Futures scenarios. This figure also shows the fraction of electricity generated by solar technologies in the SunShot and RE Futures scenarios. In the *SunShot Vision Study*, 632 GW of PV capacity and 83 GW of CSP capacity were developed by 2050. This most closely matches the levels of solar deployment in the RE Futures high-demand scenario, where 421 GW of PV and 79 GW of CSP capacity were developed by 2050. The solar generation fraction reached about 27% by 2050 in the SunShot scenario and 19% in the RE Futures high-demand 80% RE scenario. Solar generation fractions are highest in the RE Futures constrained resources (22%) and 80% RE-ETI (21%) scenarios, both of which also showed a significant increase in the amount of CSP developed. This suggests two main points: (1) the size of solar markets (capacity) is largest in scenarios with high electricity demand because there is increased need for total electricity generation, and (2) the fraction of electricity generated by solar technologies is highest when the economic competitiveness of solar improves with additional cost reductions (80% RE-ETI scenario), or decreased resource potential for all renewable technologies, which can constrain access to resources for other renewable energy technologies (constrained resources scenario).

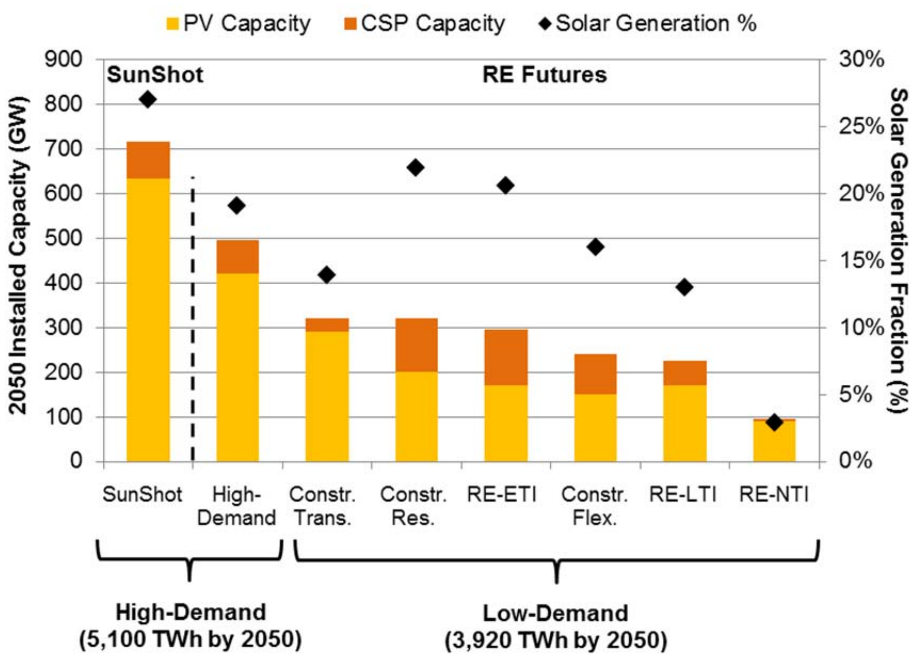


Figure 10-25. Solar deployment by 2050 for the *SunShot Vision Study* scenario and several RE Futures deployment scenarios

Figure 10-26 explores the link between decreasing solar costs and increasing market potential in the *SunShot Vision Study*. Solar deployment increases non-linearly with decreasing solar costs, and solar markets begin to achieve robust growth when assumed solar costs decline by more than 50%. This represents utility-scale PV costs below $2/W and similar levels of cost reductions for residential and commercial rooftop PV, and CSP (see Table 10-7). Solar technology costs were similar to (PV) or higher than (CSP) this 50% cost reduction threshold, and additional solar cost reductions beyond the levels explored in the RE Futures scenarios would likely have resulted in significantly higher solar penetration. However, characterizing how much higher is challenging because the increase in solar deployment with decreasing cost is highly dependent on several additional market and model assumptions, including the cost of other renewable and conventional technologies, and potential solar integration costs and challenges.

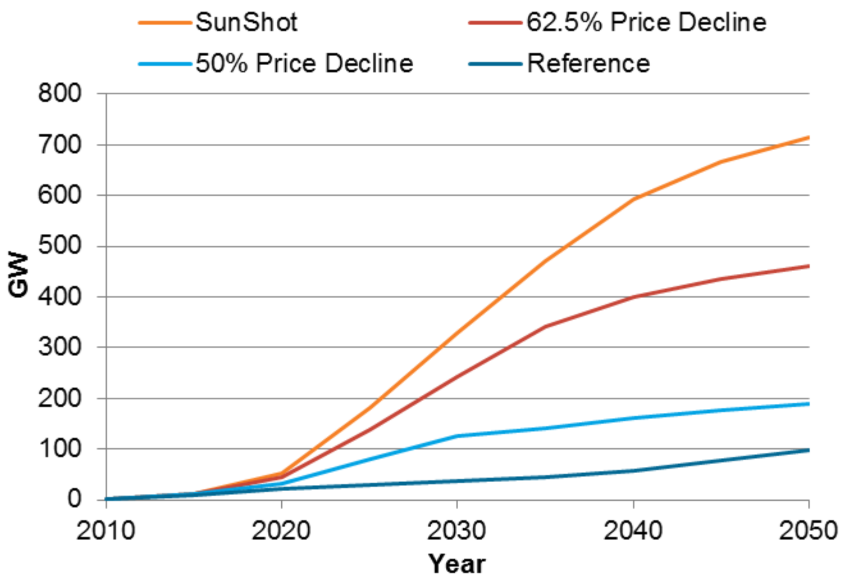


Figure 10-26. Solar deployment for a range of solar cost-reduction scenarios

Source: DOE 2012, p. 265

Table 10-7. Solar Technology Prices in the SunShot Price Sensitivity Analysis[c]

Column Name	Utility-Scale PV ($/W)	Commercial Rooftop PV ($/W)	Residential Rooftop PV ($/W)	CSP ($/W)
SunShot (2020–2050)	1.0	1.25	1.5	3.6[a]
62.5% (2020–2050)	1.5	1.9	2.25	5.4[a]
50% (2020–2050)	2.0	2.5	3.0	7.2[a]
Reference (2020)	2.5	3.4	3.8	6.6[b]
Reference (2050)	2.0	2.6	3.0	4.8[b]

[a] 14 hrs thermal storage
[b] 6 hrs thermal storage
[c] 2010 dollars

10.7 Large-Scale Production and Deployment Issues

Moving solar technologies from their current small base to large-scale deployment will require significant capital investment and the development of large solar industries. Additionally, it will require significant use of materials (e.g., rare minerals, land, and water); it will require energy use in manufacturing; and it will change the physical landscape as more solar radiation is harnessed to generate electricity.

10.7.1 Environmental and Social Impacts

All electricity generating technologies, including solar technologies, affect the environment in several ways. However, renewable technologies have the potential to significantly mitigate electric sector environmental impacts by reducing GHG and criteria pollutant emissions, as well as reducing electric-sector water use.

10.7.1.1 Land Use

The total land area suitable for PV and CSP in the United States is several orders of magnitude greater than the levels of deployment explored in the RE Futures scenarios (see Figure 10-17). However, a significant amount of land will be required to meet the RE Futures deployment targets. Land requirements for utility PV are estimated to range from approximately 25 MW/km^2 to 70 MW/km^2 (DOE 2012), based on site design and whether or not tracking systems are used. CSP land requirements vary based on the amount of thermal energy storage included for different plants. CSP densities range from approximately 15 MW/km^2 to 60 MW/km^2 based on plant design and the number of hours of thermal storage capacity[109] (DOE 2012). The density of CSP capacity (MW/km^2) decreases with increasing thermal storage; however, the density of CSP energy generation (MWh/km^2) does not scale with the amount of thermal energy storage because CSP capacity factors increase approximately in proportion to the increase in solar-field area.

The U.S. land resource for solar energy technologies is huge (see Figure 10-17), development could focus on previously disturbed areas (i.e., brownfields and former mining land) and avoid more ecologically sensitive areas. PV is modular in nature, and can be sited virtually anywhere. There are several opportunities for siting PV in multi-use land applications, like adding PV to existing transmission or transportation corridors. CSP is likely to be preferentially deployed in remote regions in the Southwest adjacent to transmission corridors where there are vast tracks of undeveloped land and limited competition for land resources.

10.7.1.2 Water Use

Table 10-8 summarizes water consumption for CSP plants (both wet- and dry-cooled) and PV systems. The water consumed for a wet-cooled CSP system ranges from about 800 gal/MWh to 1,000 gal/MWh, a rate of consumption that is similar to that of coal and nuclear power plants (DOE 2006; NETL 2009). The use of dry-cooling or hybrid wet-dry cooling, however, can reduce water use by up to 97%, based on system design and location. Because of water constraints in arid regions, all CSP systems are assumed to use dry cooling in RE Futures, and the CSP cost and performance projections are based on dry-cooled systems. Some PV systems

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[109] CSP systems with storage have an oversized solar field, represented by a solar multiple greater than one, so they can run the power block and store thermal energy during the day. Trough CSP systems with 6 hours of thermal storage typically have a solar multiple of approximately 2.

are washed occasionally which does require minimal amounts of water, and this water is frequently trucked in from nearby regions.

Table 10-8. Water Consumption of CSP and PV Systems

Technology	Water Consumed for Cooling (gal/MWh)	Other Water Consumed in Generation[a] (gal/MWh)
CSP trough or tower (wet cooled)[b, c,]	710–960	40–60
CSP trough or tower (dry cooled)[b,d]	0	30–80
PV[b,e]	0	0–5

[a] Other water consumption primarily represents water used for washing mirrors and steam cycle blow-down and make-up for CSP systems. Mirror and module soiling and washing rates are site- and developer-specific factors.
[b] From DOE (2012) and Turchi et al. (2010)
[c] Towers will be at the lower end of the cooling-water range and troughs at the higher end due to thermal-efficiency differences.
[d] There is more uncertainty in other water consumed for dry-cooled trough/tower technologies than for wet-cooled technologies because fewer dry-cooled plants have been built.
[e] Utility-scale PV washing rates and other water use are not well documented and vary by site/developer. The estimate of 0–5 gal/MWh is based on Aspen Environmental Group (AEG 2011a; AEG 2011b) as well as industry knowledge.

Manufacturing PV involves water-intensive processes that are not included in the water-use estimates in Table 10-8. For example, the water used in manufacturing crystalline silicon modules could reach 6 gal/W.[110] Most of this water, however, can be processed and returned locally. Manufacturing capacity can be sited in regions with good water resources because module-shipping costs are typically less than 5% of the total installed cost (Goodrich et al. 2012).

10.7.1.3 Life Cycle Greenhouse Gas Emissions

Estimates of life cycle GHG emissions for solar technologies consider those associated with all stages in the life of the electricity generation facility, including the extraction of raw materials and their transportation and manufacturing into plant components, plant construction, O&M, dismantling, and disposal. The lifetime carbon reductions from PV and CSP far outweigh the upfront manufacturing emissions (Drury et al. 2009). It was assumed that life cycle GHG emissions are not sensitive to whether they are deployed at utility or distributed scale. Life cycle GHG emissions for CSP frequently are calculated based on parabolic trough systems in the literature. Because of this, embodied CSP emissions were calculated assuming life cycle GHG intensities from trough systems with storage. This simplifying assumption, however, is not likely to have significant impact because the life cycle GHG emissions for trough and tower systems with thermal storage are likely to be similar. Per kilowatt-hour of electricity generated, life cycle GHG emission estimates used in RE Futures are as follows:

[110] NREL internal analysis, fall 2009; does not include upstream water use for generating electricity or processing fuels

PV: 45.5 g CO_2e/kWh

CSP: 19.0 g CO_2e/kWh

Appendix C (Volume 1) further describes the process by which these estimates were developed and how total GHG emissions for RE Futures scenarios were estimated. Life cycle GHG emissions for other technologies are summarized in Volume 1 and reported in detail in Appendix C.

10.7.1.4 Other Impacts

CSP systems frequently use an oil or molten salt heat transfer fluid, similar to those used in several industries. Although the use of these materials is not risk-free, following established operating procedures can mitigate risk. Another concern is the glint or glare from PV panels or CSP reflectors, primarily from stray reflections when tracking systems are in a standby position or moving to or from stow positions. Sandia National Laboratories is working to quantify glint and glare risks (Ho et al. 2010), and develop operating procedures to minimize these impacts. Additional impacts include the use of desert land, plant noise, tower and structure height, and visibility. These impacts will need to be managed by deploying CSP in regions that mitigate environmental impact.

Deploying solar technologies that increase the absorption of solar radiation has raised concern about the climate impact of reducing Earth's albedo.[111] Recent analysis, however, suggests that the reduction in carbon emissions from displacing fossil fuel use with low-carbon PV electricity far outweighs (up to 30 times) the impact of decreasing surface albedo (Nemet 2009).[112] Reduced surface albedo does not seem to be a significant concern for PV and CSP deployment at the scale examined in RE Futures.

10.7.1.5 Mitigation and Minimization

Even with the most careful land selection and water use, projected utility-scale PV and CSP will have ecological impacts, especially on portions of southern U.S. states where PV and CSP are preferentially deployed. These potential impacts—and ways to mitigate them—are being studied by various stakeholders, including the BLM and DOE (DOE and DOI 2010), the Wilderness Society, Natural Resources Defense Council, and others (ANL 2009).

10.7.2 Manufacturing and Deployment Challenges

10.7.2.1 Manufacturing and Materials Requirements

At the levels of PV and CSP deployment evaluated in RE Futures, the required scale-up in global solar manufacturing capacity is not likely to limit deployment. Global PV manufacturing capacity grew from approximately 1.4 GW/yr in 2004 to 22.5 GW/yr by the end of 2010 (Mints 2011a). The capital required to build a 1-GW/yr PV manufacturing facility ranges from

[111] *Albedo* is the fraction of incident light that is reflected by a surface.

[112] The study assumed that PV had a 5% albedo, and that 20% of PV was installed on rooftops with 10% albedo; 40% of PV was installed over desert-like land surfaces with 33% albedo; and 40% of PV was installed over grassland-like land surfaces with 20% albedo. Deploying 20 TW of PV capacity resulted in a mean positive forcing of 0.003 W/m^2 (compared to the 2.6 W/m^2 forcing from anthropogenic GHG emissions), and resulted in a -0.1-W/m^2 forcing from reduced carbon emissions by 2100.

approximately \$1 billion to \$2 billion per plant (FirstSolar 2011a). As global PV markets grow and mature, PV modules have increasingly become a global commodity, supported by multi-national investments to develop manufacturing resources and supply chains. Neither the cost of building new PV manufacturing capacity nor the rate of manufacturing scale-up required to meet the PV deployment levels explored in RE Futures are out of line with current and projected trends. Similarly, the projected scale-up of CSP manufacturing capacity could be met if robust domestic markets evolve.

The availability of raw materials is not likely to limit solar deployment in the RE Futures scenarios. However, the availability of some rare elements may limit the growth of some PV technologies. Of particular concern is tellurium used for cadmium telluride (CdTe), and indium used for copper indium gallium diselenide (CIGS).

Tellurium is primarily extracted as a byproduct of electrolytic copper refining, and global supply is estimated at approximately 630 MT/yr (DOE 2011). Tellurium supply is expected to increase over time based on increasing global copper demand (ICSG 2006; DOE 2011), using extraction methods with higher efficiencies (Green 2006; Ojebouboh 2008), and direct mining from known ores (Green 2009) or from existing copper mine tailings.

Indium is primarily extracted as a byproduct of zinc refining, and global supply is estimated at about 1,300 MT/yr (DOE 2011). Nearly all of the indium supply is used to make transparent conductive oxide coatings, such as those used for flat-panel liquid crystal displays. Global indium supply is projected to increase to meet demand for non-PV applications, and potentially for PV applications as well (DOE 2011).

Currently, it takes approximately 60–90 MT of tellurium to make 1 GW of cadmium telluride (Zweibel 2010; DOE 2012; Woodhouse et al. 2012), and approximately 25–50 MT of indium to make 1 GW of copper indium gallium diselenide (DOE 2012). Resource constraints can be mitigated by reducing material requirements (i.e., reducing the thickness of semiconductor layers, increasing PV efficiency), and increasing material supply (i.e., increasing annual ore extraction and refining, improving process utilization and in-process recycling). For example, recent studies have suggested that CdTe supply could increase by a factor of 8 by reducing semiconductor thickness, increasing module efficiency, and improving resource extraction efficiencies (Fthenakis and Kim 2009; Zweibel 2010; Woodhouse et al. 2012). There are similar pathways for decreasing indium intensities and improving extraction efficiencies. These factors could combine to increase the thin-film materials availability from a few gigawatts per year at present to hundreds of gigawatts per year over the next few decades (Fthenakis and Kim 2009; Zweibel 2010; Woodhouse et al. 2012; DOE 2012). However, competition with non-PV applications for rare materials could significantly restrict supply, particularly for indium (DOE 2011), and could increase both material prices and price volatilities.

Material feedstocks for crystalline silicon PV are virtually unlimited, and supply constraints are not likely to limit growth. However, crystalline silicon cells typically use silver for electrical contacts, which could be subject to price spikes if there are supply shortages (Feltrin and Freundlich 2008). The use of different contact materials is an area of active research, and could reduce supply price risk. The glass, steel, and aluminum used as encapsulation and support structures are not subject to rigid supply constraints, but their costs are tied to changing commodity prices.

Concentrating solar power facilities primarily are constructed from glass, steel, aluminum, and concrete. These materials are not subject to rigid supply constraints, but the cost of CSP facilities will be affected by changing commodity prices. Steel, aluminum, and glass are highly recyclable, and it is anticipated that these materials will be recycled at the end of a plant's life.

10.7.2.2 Deployment and Investment Challenges

Solar facilities have high up-front costs and low operating costs, and are long-lived assets. Access to low-cost, long-term financing arrangements is critical to enabling investment recovery to be spread over an extended period, resulting in lower per-unit production costs over the life of each facility. Along with financing capacity additions, the solar supply-chain infrastructure from manufacturing through distribution also must have access to capital. Attracting adequate investment for expanding the solar supply chain is not likely to be a problem if robust markets evolve, because the relevant mechanisms are well developed and readily available. Historically, the solar supply chain in the United States has been financed with a mix of venture capital, private equity, public equity, and corporate debt. Although there has been a dramatic increase in investment in the U.S. and global solar supply chains, continued access to capital is required to develop robust markets able to meet or exceed the deployment targets of RE Futures.

10.7.2.3 Human Resource Requirements

Additional skilled workers will be needed to design, manufacture, install, and maintain solar energy systems. Recent studies have estimated PV job intensities at 30–60 jobs/MW of annual installed PV for the production and installation of systems, and 0.5–0.6 jobs/MW of cumulative installed capacity for PV O&M[113] (McCrone et al. 2009; TSF 2010). CSP job intensities have been estimated at approximately 40 jobs/MW of annual installed capacity for the production and installation of projects, and about 1 job/MW of cumulative installed capacity for O&M (DOE 2012). As solar costs decline, labor intensities for PV and CSP systems are also expected to decrease based on improved efficiencies in solar manufacturing, supply chain, installation, and maintenance requirements (DOE 2012).

10.8 Barriers to High Penetration and Representative Responses

Stable, long-term government policies can play an important role for the large-scale deployment of all emerging energy technologies, including solar energy. For solar energy technologies, government policies are particularly important for resource siting, transmission maintenance and upgrades, and tax and finance issues. For both PV and CSP, market and policy conditions are important for continued market growth and increasing private investment.

10.8.1 Research, Development, and Deployment

Continued cost reductions and performance improvements for PV and CSP technologies will enable these technologies to contribute significantly to a low-carbon electric sector in a cost-effective manner. PV and CSP costs will continue to decline through incremental improvements,

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[113] The estimates discussed here include full-time equivalent direct jobs and some indirect jobs in the solar supply chain. These estimates do not include induced jobs (i.e., jobs due to indirect purchase of goods and services).

and possibly through technical breakthroughs that significantly reduce PV module, power electronics, and BOS costs as well as CSP solar collector, HTF, storage medium, and power-block costs. Continued R&D serves a critical role in conjunction with market and manufacturing scale-up, which can drive learning-based improvements. Some of the key R&D needs for PV and CSP are summarized in Table 10-9 and additional R&D opportunities are discussed in DOE (2012).

Table 10-9. Research, Development, and Deployment Opportunities to Enable High Penetration of Solar Energy Technologies

R&D Area	Barrier	Representative Responses
Photovoltaics (PV)	Improve market competitiveness	Increase module efficiency by improving interface characteristics, including junction dynamics, back- and front-contact solar cells, and layer characteristics.
		Reduce module costs through several processes including, but not limited to: reducing wafer thickness (crystalline silicon) or active semi-conductor layer thickness (thin films), increasing manufacturing throughput, and improving material utilization.
		Develop and demonstrate next-generation PV technologies in a laboratory setting, and develop the manufacturing techniques to bring these products to market.
		Reduce non-module costs (e.g., reduce the cost and complexity of mounting systems, integrate mounting structures in modules, standardize module connectors, reduce permitting and installation costs)
Concentrating Solar Power (CSP)	Improve market competitiveness	Reduce solar-field costs, including costs for solar collectors, receivers, and heat transfer fluids
		Reduce storage component costs (e.g., operate at higher temperature, transition from a two-tank molten-salt storage system to an advanced single-tank system, develop improved thermal storage media)
		Move toward higher-temperature heat transfer fluids and storage materials

Market and Regulatory	Barrier	Representative Responses
Market design and structure	Small operational areas increase the cost of integrating solar energy into the grid. Curtailment of low marginal cost solar energy. Transporting solar energy from remote generation regions to population centers over long distances.	Develop policy and market designs that consolidate smaller operating areas to cooperatively balance generation and demand, and curtail less low marginal cost energy. Resolve limits on long-distance power transfers, including developing new methods for allocating transmission costs.
Operational value	Solar energy may be penalized for the variable and uncertain nature of solar generation. The value of grid services provided by solar energy may not be monetized.	Improve methods and tools for valuing solar energy and grid services, and design market products to monetize the value added to the system.
Workforce development	Skilled labor is required to support a rapidly expanding solar industry.	Develop standardized training programs and establish strong university R&D resources.
Environmental and Siting	**Barrier**	**Representative Responses**
Wildlife impacts	Impacts on protected or endangered species can inhibit deployment of solar energy. Extensive permitting requirements increase deployment costs.	Develop strategies that minimize the impact of solar deployment on wildlife habitats, and standardize permitting requirements to facilitate low-impact development.
Siting policy	Inadequate or unclear zoning or land use policy increases developer risk. Lack of local water resources in arid regions.	Assist policymakers in developing policies that protect local interests while facilitating deployment and local economic development. Manage solar deployment to minimize water use impacts.

10.8.2 Market and Regulatory Barriers

The rooftop PV market is particularly sensitive to local regulatory structure and policies. For example, net metering regulations—which determine how excess generation from a customer sited PV system is valued—is one of the key economic drivers for rooftop PV systems.[114] Net metering policy is typically determined by local regulatory bodies like public utility commissions. Standardizing net metering policy to appropriately represent the value of PV generation on the distribution grid would help create consistent market signals for distributed PV markets. Permitting costs have been estimated to add up to $0.40/W to a rooftop PV system (SunRun 2011), a large fraction of which is based on completing the permit application and city and county fees. Simplifying and standardizing the permitting process could reduce permitting costs, installation times, and associated adoption barriers considerably. Another policy-based market driver is allowing third-party ownership of rooftop PV systems, which are leased by the building occupant. Third-party ownership can reduce or remove the upfront cost of installing a rooftop system, repackage the value of a PV system as a monthly bill savings to the building occupant. Allowing third-party businesses into all states could dramatically increase rooftop PV market growth (Drury et al. 2012; SEIA/GTM 2012). However, only approximately half of all U.S. states currently allow third-party ownership models (DSIRE 2011).

10.8.3 Siting and Environmental Barriers

Although land availability will not limit the deployment of solar-energy technologies, companies developing solar resources will face challenges due to environmental and other concerns when acquiring and developing the land to deploy solar technologies. Engaging public, private, non-profit, and other groups early in such a process can assist in developing a responsive process to resolve concerns and responsibly deploy new generation resources at an appropriate scale and within an appropriate timeframe.[115]

10.9 Conclusions

The fraction of U.S. electricity generated by solar technologies currently is small, but it is growing rapidly. Both PV and CSP technologies have been demonstrated at scale, and current technologies are capable of supplying a large fraction of U.S. electricity demand. CSP systems with thermal storage can be operated as dispatchable resources, which can be used to improve power quality and frequency stability, and augment variable wind and PV generation. Solar technologies played significant roles in most of the RE Futures scenarios investigated.

Key issues for developing robust U.S. solar markets are improving the cost and performance of solar technologies and integrating solar energy into the electricity grid as solar markets grow. Large-scale deployment will require significant capital investment, and the development of large solar industries and a specialized labor force. Additionally, large-scale deployment will require significant use of material resources (e.g., rare minerals, water), and will change the physical

[114]Net metering is a market mechanism that determines the value of PV generation that exceeds electricity use. In areas with full net metering, excess PV electricity is purchased by the local utility at full retail electricity rates. Other areas have partial net metering policies, where excess PV generation is valued similar to wholesale electricity rates and roughly capture the value of offsetting fossil-fuel use. Other areas have no net metering policy, and excess PV generation is provided to the utility at no cost.

[115] DOE and the U.S. Bureau of Land Management are assessing the impact to public lands under the Solar Energy Programmatic Environmental Impact Statement. For more information, see http://solareis.anl.gov/.

landscape as more solar radiation is harnessed to generate electricity. Even with the most careful land selection and water use, projected utility-scale PV and CSP will have ecological impacts, especially on portions of southern U.S. states where solar technologies are preferentially deployed. These impacts can be managed through sensible deployment of solar resources. For example, engaging public, private, and non-profit groups to collectively develop a responsible and responsive deployment strategy can enable solar technologies to significantly contribute to a high renewable electricity future.

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Chapter 11. Wind Energy Technologies

11.1 Introduction

Large-scale electricity production using wind generators began attracting attention in the United States in the 1970s due to the energy crises initiated by oil embargoes. The first wind plants began to be installed in 1980, stimulated by aggressive policy provisions. Although some of these first installations were under-designed and did not survive the early years of operations, some of the best technology continues to operate, some 30 years later, producing electricity as part of profitable commercial businesses. After gaining a foothold during the early- to mid-1980s, however, the U.S. wind industry slipped as favorable policy and tax provisions dried up, and throughout the late 1980s and most of the 1990s, there was little to no U.S. growth (see Figure 11-1). However, with the return of a more favorable policy regime at both the state and federal levels and continued reductions in the cost of energy from wind, the U.S. industry regained traction in the late 1990s. There has been particularly strong growth in U.S. wind energy deployments since 2005 (see Figure 11-1), and wind energy constituted 35% or more of annual electric power capacity installations in 2007, 2008, and 2009 (Wiser and Bolinger 2011). Drivers of recent growth include an abundant resource,[116] relatively low cost,[117] and state and federal policy.

Through 2010, the total installed wind capacity in the United States exceeded 40,000 MW (AWEA 2011), and in 2010, wind power systems generated nearly 2.4% of the U.S. electricity production (EIA 2011).[118] U.S. deployment of wind power in 2010 was approximately 5,100 MW (AWEA 2011). Worldwide, the capacity added during 2010 was more than 38,000 MW, representing an estimated $71.8 billion[119] in asset investments (GWEC 2011).

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[116] Strictly from a resource perspective (i.e., without considering technical, cost, or siting limitations), wind energy could supply several times the United States' electricity needs (see also Section 11.2).

[117] Depending on specific market and policy conditions, when the wind resource is very good or the power generation costs from other sources are relatively high, wind can be cost competitive with conventional power generation. In addition, policy may be used to increase the economic attractiveness of wind energy. Under recent market and policy conditions in the United States, wind power prices have been competitive with the prices of wholesale power generation in the United States (Wiser and Bolinger 2010).

[118] See Volume 1 for a more complete description of methods and data used to calculate wind energy's contribution to the country's electricity supply.

[119] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

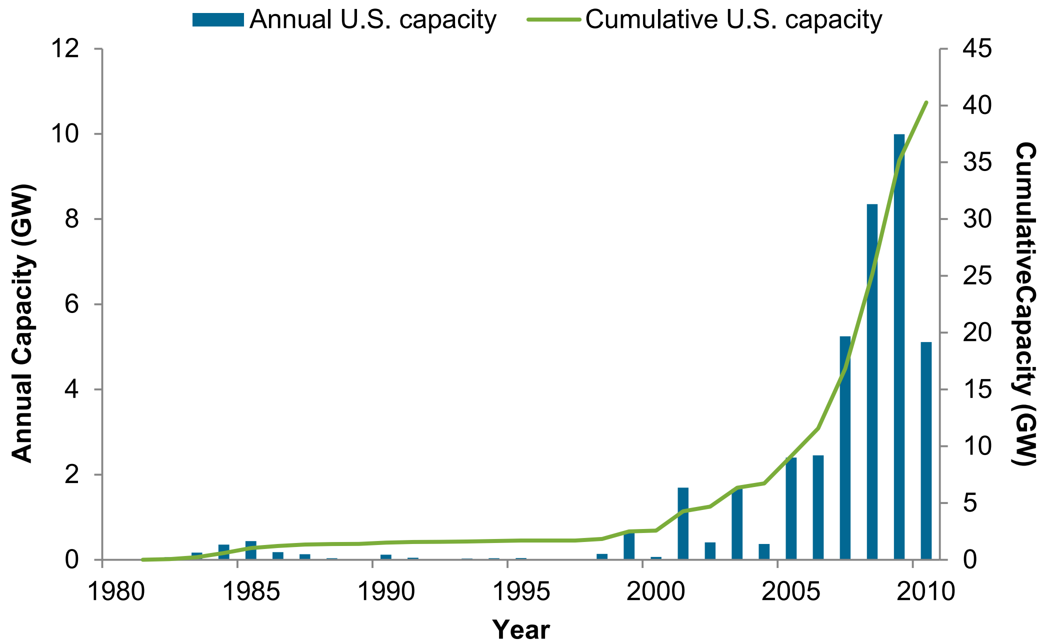

Figure 11-1. Installed wind power capacity in the United States, 1981–2010

Source: Wiser and Bolinger 2011

To date, there are no offshore wind projects in the United States; however, a number are planned along the East Coast. Europe installed 883 MW in 2010, bringing the total operational European offshore fleet to 2,946 MW at year-end 2010 (EWEA 2011). Worldwide, floating offshore wind generation systems have been deployed only in the pilot stage (e.g., Statoil 2011) and are not yet a commercially viable technology.

This chapter details the resource, technology, cost, and performance characteristics of wind-driven energy generation systems as well as the role that wind energy plays in the modeling scenarios for RE Futures. It also discusses possible future wind energy technology innovations and their potential impact on the cost of wind-generated electricity, power output and grid service capabilities, and the social and environmental factors that impact the deployment of wind energy. The RD&D discussion emphasizes land-based and fixed-bottom offshore technologies because these are the only technologies considered in the RE Futures scenarios. However, floating offshore RD&D considerations are discussed as successful commercialization of floating offshore technology would open additional high-value wind resource areas to development, potentially within the time frame considered by RE Futures.

11.2 Resource Availability Estimates

The land-based wind resource is widely distributed across the United States. Figure 11-2 depicts the U.S. wind resource for the contiguous 48 states at an 80-m hub height and with a 2.5-km spatial resolution (Elliot et al. 2010). The 80-m height approximates the hub height of many currently installed utility-scale turbines and approaches the hub height (90–100 m) of turbines now beginning to be used in onshore wind installations. Wind resource estimates are derived from AWS Truepower MesoMap® modeling and are validated with empirically collected data from 304 sites in 19 states (Elliot et al. 2010).[120]

After applying standard exclusions (e.g., urban areas, environmentally sensitive or protected areas, reservoirs, and lakes)[121] and assuming a land-use power density (i.e., the amount of land required for a given amount of wind power) of 5 MW/km^2,[122] Elliot et al. (2010) estimated that the 80-m wind resource of the contiguous 48 states could support more than 10,000 GW of wind capacity with a capacity factor of 30% or greater.[123] Although this amount of wind capacity is not expected to be built, theoretically, this capacity estimate translates to approximately 37 million GWh of potential annual energy generation (Elliot et al. 2010). This can be compared with the existing nationwide electricity generation of approximately 4 million GWh annually (EIA 2010).

[120] Empirical data were collected from six western states, six Midwestern states, and seven eastern states. All towers referenced for empirical data were 45 m or greater.
[121] Exclusions eliminate approximately 19% of potentially developable land from consideration in the capacity and resource estimates detailed here.
[122] Standard industry approximation as well as site- and project-specific conditions may result in variability in actual wind power capacity density (Denholm et al. 2009). For details, see Section 11.5.1.3.
[123] The maximum estimated capacity factor exceeds 50%.

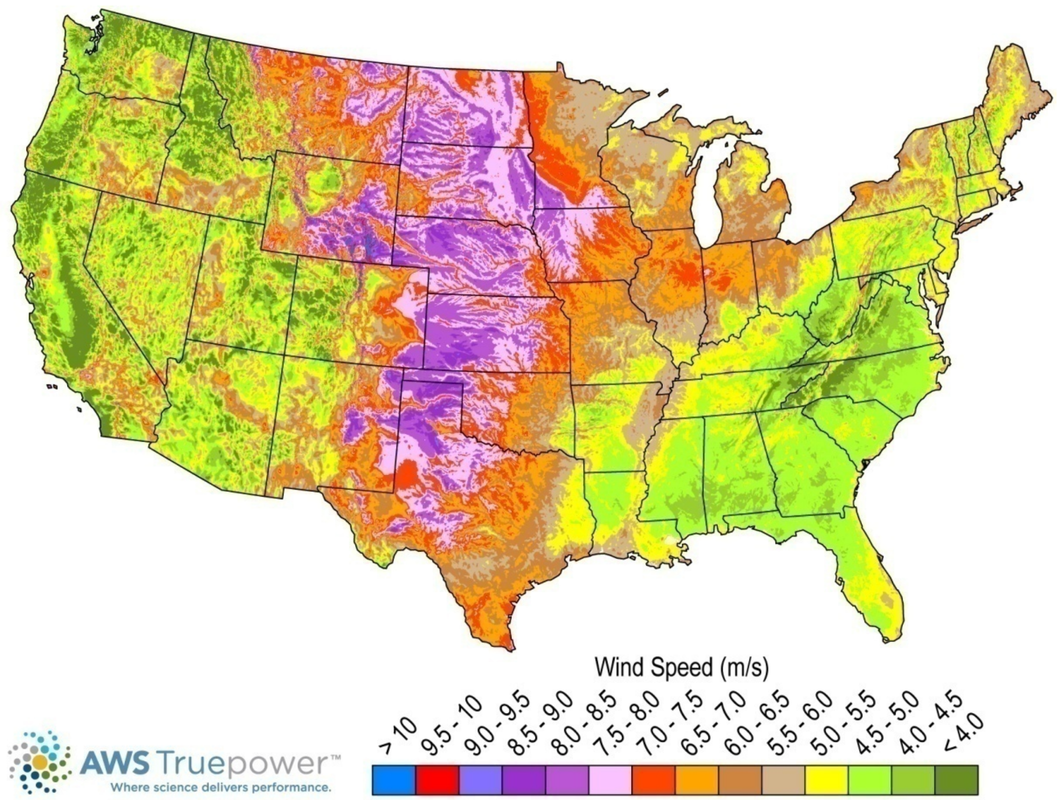

Figure 11-2. Onshore wind resource (annual average wind speeds) at 80-m hub height in the contiguous United States

Source of wind data: AWS Truepower, LLC
Spatial resolution of wind data: 2.5 km

For more information, see
http://www1.eere.energy.gov/wind/.

The wind resource data shown here are not the resource data used in modeling the RE Futures scenarios. These data were not used because higher-resolution resource data are required for ReEDs modeling. The ReEDS modeling relies on 50-m data, adjusted, assuming constant wind shear, to be in accordance with the 80-m hub heights of modern wind turbines (see Appendix F for additional information on the wind resource used in the in this analysis). Although better-validated data at higher hub heights became available at the end of 2010, the data used in the RE Futures modeling represents the best available at the time the analysis was being conducted.

The offshore wind resource has not been characterized as well as the onshore resource. Wind resource models can be used to estimate offshore resource potential; however, the validation of model results is more difficult because of fewer offshore wind measurement stations.

Preliminary work indicates strong offshore wind resource availability along the coastlines of the United States, including the Great Lakes (Kempton et al. 2007; Dhanju et al. 2008; Schwartz et al. 2010) (see Figure 11-3). Schwartz et al. (2010) estimate the offshore wind resource greater than 7.0 m/s, at a height of 90 m above the surface of the water, and extending 50 nautical miles from the shore of the contiguous United States to be greater than 4,000 GW.

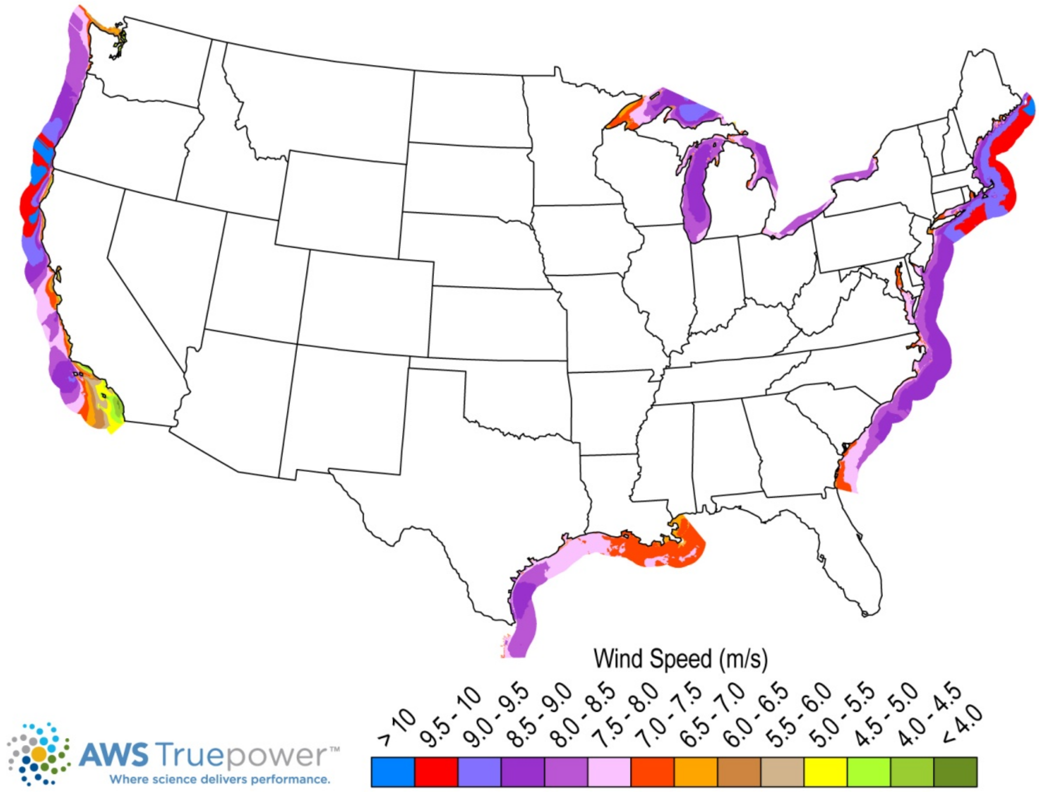

Figure 11-3. Offshore wind resource at 90-m hub height in the contiguous United States

Source of wind data: AWS Truepower, LLC
For more information, see http://www1.eere.energy.gov/wind/

The map omits the offshore resource for Mississippi, Alabama, and Florida because mapping efforts for those states have not been completed.

Ultimately, even when accounting for the land area exclusions mentioned above—and excluding other areas for such factors as habitat disturbance, flyways used by migrating birds, areas where interference with military and civilian radar occurs, and others—the remaining wind resource is many times larger than total electricity consumption by the United States. Wind resource availability is not expected to limit the growth of wind energy in the United States.

Current wind resource research seeks to better understand the average wind resource at high-geographic resolution. However, the importance of better understanding, representing, and predicting the temporal and spatial variability of the wind resource has also increased. Such work, which includes the ability to forecast the wind resource in real time via daily, hourly, and even 10-minute increments, is expected to allow for better integration of wind-generated electricity with conventional power generation sources.

11.3 Technology Characterization

Wind turbines are capable of providing utility-scale power generation in commercial markets around the world. More than 30 years of technology development and operational experience have reduced land-based wind energy costs by a factor of five and resulted in land-based plant availabilities of 97% to 98% (EWEA 2009; IEA 2009). Continued R&D is expected to further reduce the cost of land-based wind energy (Cohen et al. 2008; Bywaters et al. 2005; Junginger et al. 2005; Malcolm and Hansen 2006).

With only a decade of operational experience (limited primarily to northern Europe) and a different set of design challenges, offshore wind technology is less mature. Consequently, offshore wind technology currently represents increased technical risks and higher cost uncertainty but generally is perceived to have greater opportunities for technology improvement and cost reductions relative to land-based installations (Junginger et al. 2004).

11.3.1 Technology Overview

Wind turbines operate by converting the kinetic energy of wind into mechanical and, subsequently, electrical energy. The available power in the wind increases by the cube of the wind speed. However, with current technology, the ability of a wind turbine to capture and convert the power carried by the wind is defined by the Lanchester-Betz limit. This upper bound, based on a simple theoretical model of energy extraction from an unconstrained flow, defines the maximum percentage of available wind power that can be captured as 59%.[124]

The electric power output of a wind turbine as a function of wind speed is described by the power curve. As depicted in Figure 11-4, the power curve has four wind-speed regions. In Regions I and IV, the turbine does not operate due either to insufficient wind (Region I) or wind speeds that exceed the turbine design ratings (Region IV). Power generation occurs in Regions II and III. Region II commences at the 3–5 m/s cut-in wind speed, the speed at which the turbine starts to produce power. In Region II, the turbine power output increases with wind speed up to the rated wind speed, the speed at which the turbine is capable of producing its designed, rated power, typically between 12 m/s and 15 m/s.[125] In Region III, the power output is held relatively constant at the rated power. This is accomplished either by passive stall control or, more typically, by active blade pitch angle adjustments. Such controls prevent machine and generator overloading by allowing excess power to pass through the rotor of the turbine, uncaptured. To limit machine loads and prevent damage to a wind turbine's structural components, wind turbines are designed to shut down at cut-out wind speeds between 25 m/s and 30 m/s.

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[124] Advanced technology concepts (i.e., shrouded turbines) may appear to exceed the Lanchester-Betz limit, but actually do not when flow area is calculated based on the exit area of the shroud. In addition, they have not yet proven to be economically viable.

[125] Wind turbines operate with variable speed capabilities. Over Region II of the power curve for a wind turbine, the rotational speed of the rotor and drivetrain are proportional to the wind speed. This allows the machines to spend more hours per year at the rotor's most efficient operating point, resulting in increased energy production in Region II.

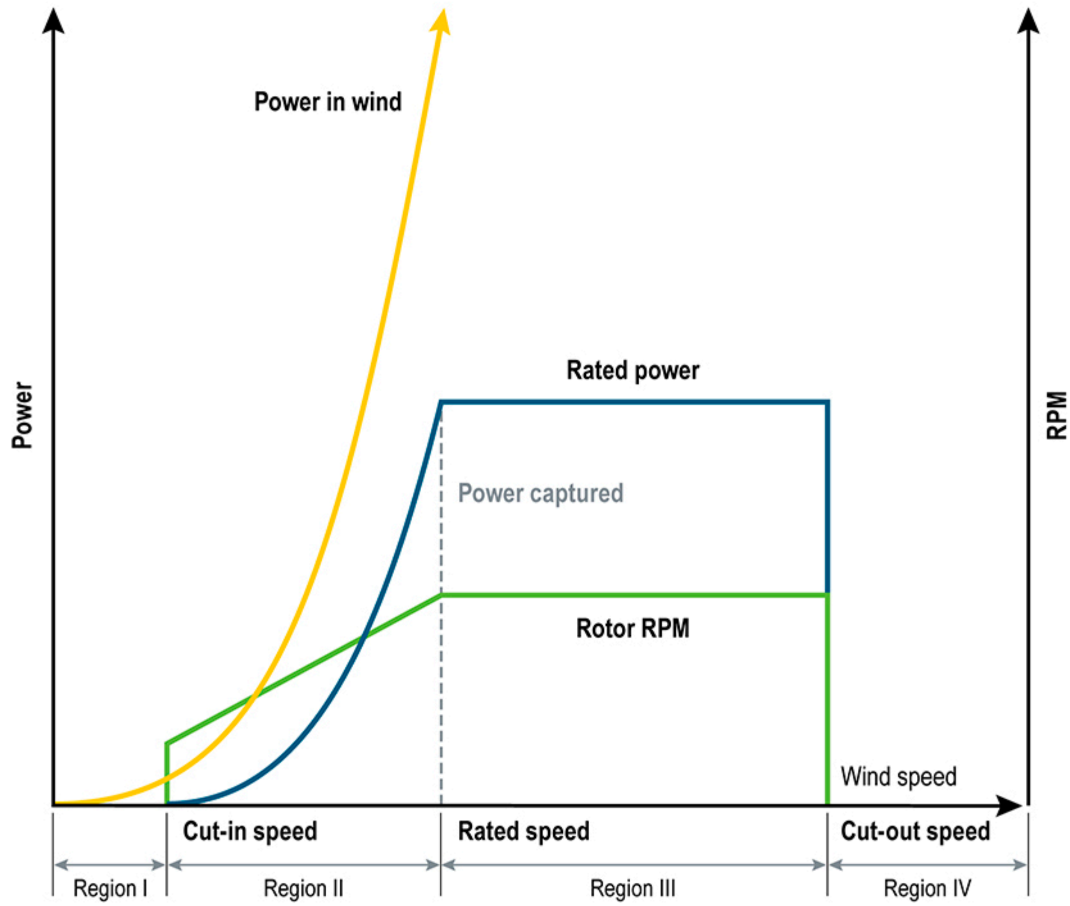

Figure 11-4. Conceptual power curve for a modern variable-speed wind turbine

Source: DOE 2008

Utility-scale wind turbines are dominated by horizontally configured, three-bladed, pitch-controlled, upstream rotor machines. Figure 11-5 illustrates such a machine. Current power ratings extend above 3 MW with models under development having power ratings between two and three times this value. Rotor diameters typically range from 80–100 m with their supporting towers having a comparable height. The largest machines under design (typically 5–10 MW) are primarily intended for offshore installations. Widespread growth of land-based turbines greater than 3–4 MW is expected to be constrained by the logistics challenges associated with overland transport. However, new technologies such as Gamesa's segmented InnoBlade concept (Gamesa 2011), Enercon's segmented blade concept (De Vries 2009), and the increasing use of concrete towers (Acciona 2011) continue to reduce logistics challenges, potentially allowing for continued growth of land-based wind turbines.

The three-bladed rotor of a wind turbine transfers power and torque to the balance of the turbine drivetrain. The drivetrain, including the gearbox and electric generator among other components, is enclosed within the nacelle, a fiberglass enclosure situated atop the supporting tower. An upstream wind turbine rotor is oriented into the prevailing wind flow by an active yaw system, consisting of a set of motors that rotate the nacelle and rotor around the vertical axis of the machine. Typically, the generator power is conveyed by cables to power electronic conversion equipment situated at ground level within the tower. The power electronic equipment converts the non-standard, variable-voltage, variable-frequency electricity delivered by the generator into utility-standard electric power (e.g., 575 V, 60 Hz). While enabling variable-speed operation, the power electronics also provide an important control function in smoothing the output power and limiting drivetrain torque transients through rapid control of the generator torque. In addition, the power electronics enable a number of grid support functions, such as frequency stability and reactive power delivery (discussed in detail in Section 11.4).

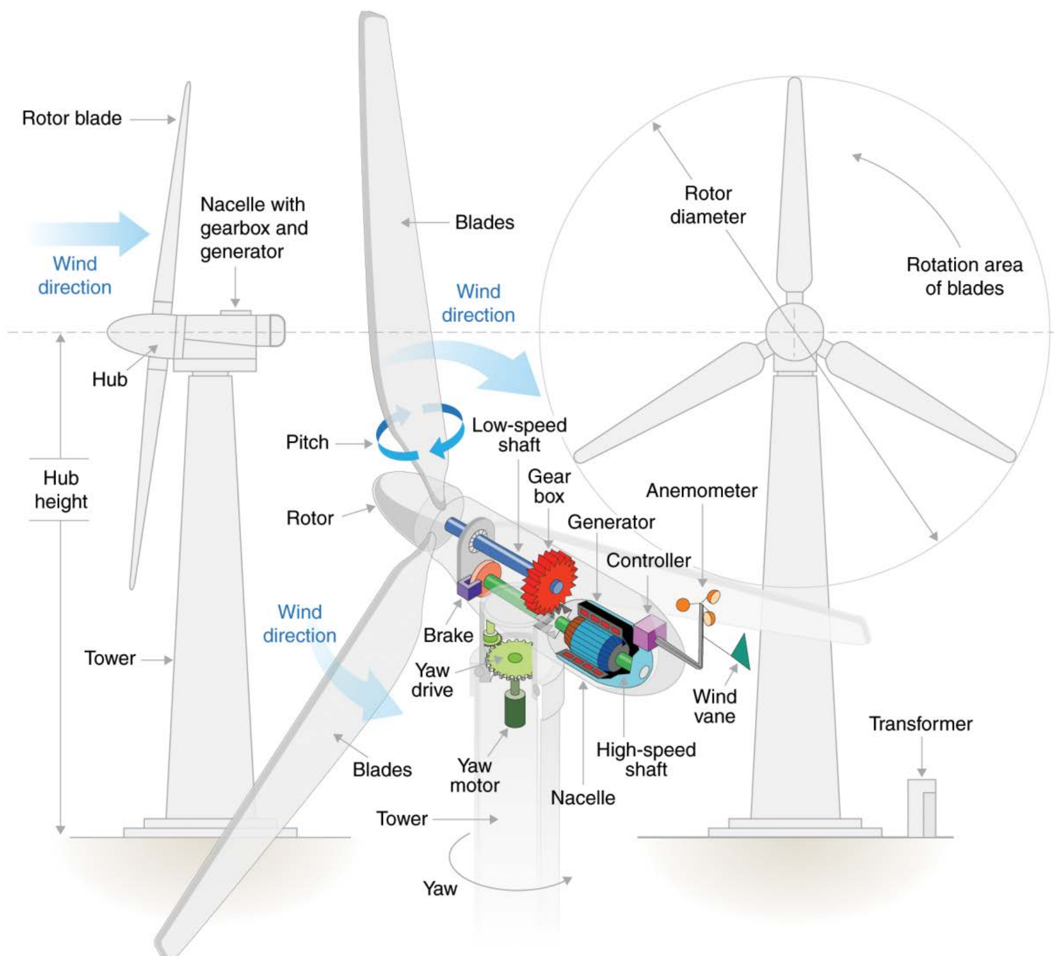

Figure 11-5. Components of a modern horizontal-axis wind turbine with gearbox

Two principal drivetrain configurations are employed in commercial wind turbines; the emergence of two distinct designs is the result of differing optimizations of system variables including performance, weight, cost, and reliability. The drivetrains of most operating turbines (see Figure 11-5) consist of the aerodynamic rotor, a two- or three-stage gearbox, and the electric generator. The speed-increasing gearbox matches the rotational speed of the aerodynamic rotor, in the range of 8–15 rpm, with the most-efficient rpm of the electric generator, ranging from 1,200 rpm to 1,800 rpm. The primary alternative to the geared drivetrain is the direct-drive generator, which matches the speed of the generator to the speed of the rotor. An estimated 14% of global turbine supply is constituted by direct-drive drivetrains (BTM 2010).The direct-drive generator arguably offers superior reliability by using fewer moving parts. Historically, however, for the direct-drive generator to operate efficiently at typical rotor speeds, the generator diameter and weight have often increased significantly among other changes. Nevertheless, there is much interest in and activity around direct-drive systems with higher energy density using rare-earth permanent magnet solutions to compensate and reduce the size and weight of the generator. Such technologies are already making their way into commercial technology today (see Section 11.4.2.1.4). Details on these two drivetrain configurations as well as other variants can be found in DOE (2008).

Recent offshore wind plants employ what is essentially a standard onshore turbine adapted to the marine environment and installed on a fixed-bottom foundation; installations to date primarily include a mono-pile, effectively an extension of a land-based tower driven into the ocean floor, or a gravity-base, which is a heavy weight placed on the ocean floor. Floating offshore turbines, tethered to fixed spots on the ocean floor rather than mounted directly to the seabed, exist only in prototype and concept stages of development. In addition to withstanding the greater corrosive properties of the marine environment, offshore turbines must be capable of withstanding a more complex structural vibration environment. Fleet availability has generally been lower and O&M costs higher for offshore installations (Carbon Trust 2008; Morgan 2008). Further complicating offshore operations is the fact that maintenance access is more difficult and costly. In addition, balance-of-station (BOS) costs in the form of complex foundations and underwater power collection and transmission systems are much greater for offshore wind energy projects (Junginger et al. 2004; Blanco 2009). Future offshore turbines are expected to be increasingly designed—from concept to commercial product—for the unique attributes of the marine environment and to better account for the more challenging access conditions associated with infrastructure sited in the water. They are expected to continue to grow in size, substantially exceeding the size of the largest onshore turbines. This trend is driven by the belief that the O&M and BOS costs per kilowatt-hour will decrease with increasing turbine size. Moreover, the move to larger turbines is facilitated by the expectation that offshore wind turbines will require less overland transportation, therefore reducing many of the transportation and logistics constraints specific to land-based wind turbine installations.

11.3.2 Technologies Included in RE Futures Scenario Analysis

Onshore and fixed-bottom offshore turbine installations are included in all RE Futures scenarios. Because floating-platform offshore turbines are not yet commercially available, this technology is not included in any of the modeled scenarios. The available fixed-bottom offshore resource is conservatively restricted to marine areas where the water depth is less than 30 m, although this does not represent the technical depth limit on fixed-bottom structures.[126] Energy contributions

[126] Germany's Alpha Ventus wind project consists of twelve 5-MW turbines on tripod and jacket foundations in approximately 30-m water depths (http://www.alpha-ventus.de/). Talisman Energy's Beatrice project consists of two 5-MW turbines on jacket foundations in approximately 45-m water depths (see http://www.beatricewind.co.uk/). In

are not tied directly to a particular configuration or unit size, but instead, are based on measures of the wind resource strength and expected capacity factors.[127]

11.4 Technology Cost and Performance

The cost of wind-generated electricity is driven by the capital cost (i.e., the installed cost) and the performance (i.e., energy production, O&M costs, and plant lifetime) of the technology over the course of its operating life. In this section, cost and performance characteristics for onshore and offshore wind energy installations, as well as the factors that influence these variables, are discussed.[128]

11.4.1.1 Installed Costs

For onshore wind projects, installed costs can constitute as much as 75%–80% of the lifetime project investment (Blanco 2009; EWEA 2009). The principal installed-cost components of a wind plant include (1) pre-development and project management; (2) turbine and equipment purchases, including transportation; and (3) BOP costs (e.g., turbine foundations, turbine erection and installation, roads and other civil works, power collection networks and substations, operation and maintenance facilities, tooling, spare parts, data communication and control subsystems, financing costs). Individual installed-cost components vary with the size of the facility, the power rating of the component turbines, the location, and current market conditions.

The average installed cost of an onshore wind project built in the United States in 2010 was $2,155/kW (Wiser and Bolinger 2011). Of this average installed cost, turbine costs are estimated to be approximately 75% (Wiser and Bolinger 2011). The past three decades have brought about large reductions in the installed costs for onshore wind technology. Figure 11-6 illustrates this trend with data ($/kW) from the past 25 years. These data show that two decades of declining costs were followed by rising costs over much of the last decade. More recently, however, steep reductions in turbine prices (Bolinger and Wiser 2011) are expected to once again move wind power capital costs downward.

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addition, there are more than 10 approved and 40 planned projects around the world at water depths ranging from 31-m to 57-m water depth, according to internal data compiled from an variety of publicly available and private data sources by the National Renewable Energy Laboratory.

[127] Although capacity factor assumptions are based on improvements in technology—which include continued scaling trends toward machines with larger rotors, taller towers, and improved control systems—they are not connected explicitly to a specific machine size or configuration.

[128] Cost and performance estimates are based on industry data circa 2010.

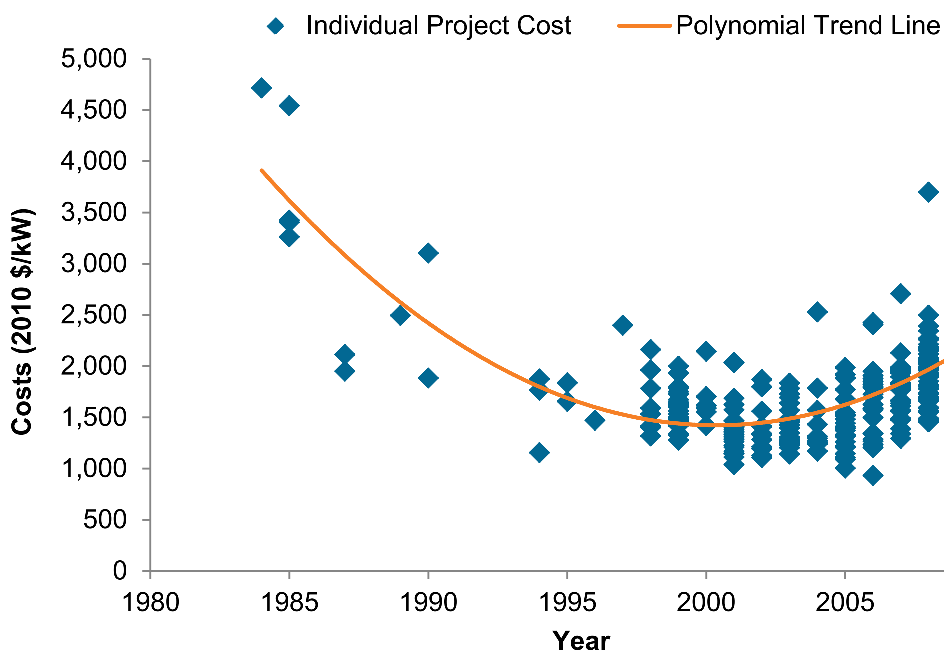

Figure 11-6. Installed capital cost for onshore wind energy

Source: Wiser and Bolinger 2011

The declining costs observed from the early 1980s through the early 2000s resulted from a variety of technical innovations and increased industry volume (EWEA 2009), as well as from economies of scale. Technical innovations have allowed the industry to scale machines to be larger in rated capacity, rotor diameter, and tower height. While individual technical innovations have direct impacts on technology costs, the shift to larger machines can also reduce BOP costs. Primary drivers of the proportional reduction in BOP costs ($/MW) for larger machines are the reductions in supporting infrastructure (i.e., fewer roads and less underground cabling) and reductions in time spent moving heavy equipment, like cranes, between turbine sites. Figure 11-7 illustrates the project level cost breakdown for recent installations using 1.5-MW and 2.5-MW turbines.[129]

[129] The cost distribution assumes flat terrain using current technology turbines. Percentages are derived from project costs for a 100-MW project.

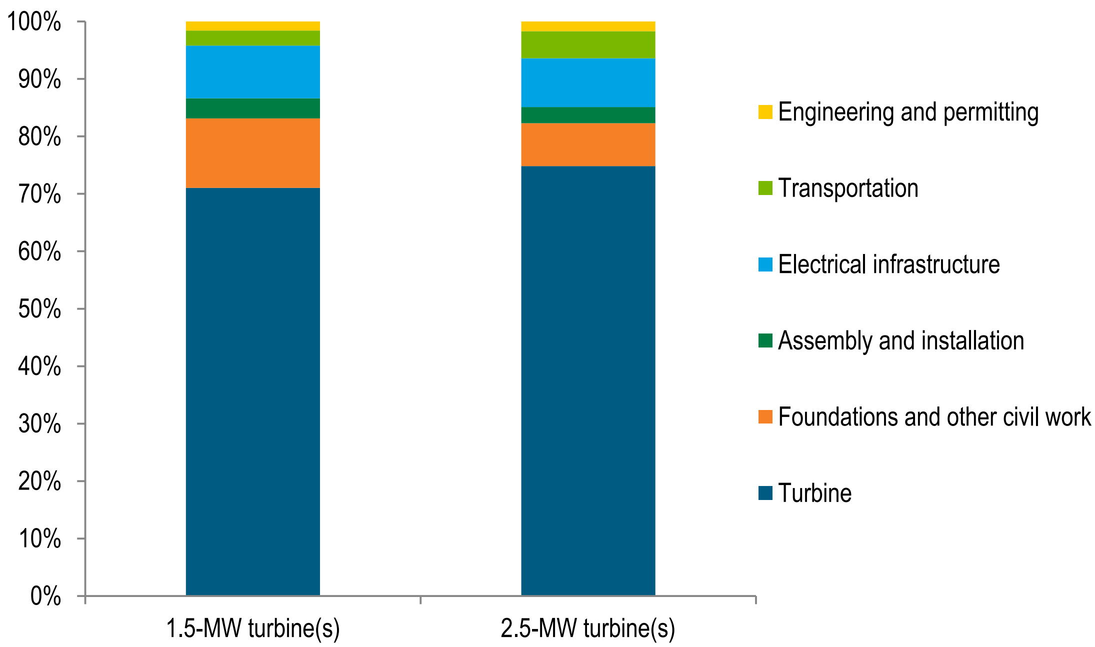

Figure 11-7. Relative costs for an onshore wind power plant with 1.5-MW and 2.5-MW turbines (% of total cost)

Larger projects and economies of scale have also reduced installed costs by:

- Spreading development costs (i.e., permitting, component procurement, financing, and legal costs), which increase only nominally for larger projects over a greater number of units
- Spreading the costs of the specific supporting infrastructure (i.e., the electrical substation, interconnection, and O&M facilities), which also increase nominally with larger project sizes
- Allowing for large purchases of the principal components (i.e., turbines and BOP components) to create an opportunity for reduced cost through volume.

Ease of siting for offshore wind (due to the potential for reduced visual and nuisance impacts at a distance offshore) could allow for larger installations and greater economies of scale than for typical land-based installations.

The more recent trend of installed cost increases (see Figure 11-6) stems primarily from increases in turbine prices; it is discussed in detail by Bolinger and Wiser (2011), who note that the sources of turbine price increases include:

- Increased costs of raw materials (e.g., steel, copper, cement, and composite materials)
- Increased costs associated with scaling larger turbines on taller towers (although generally energy productivity also increases with scaling, potentially offsetting increases in the overall cost of energy)
- Increased labor costs
- Variable foreign exchange rates (at least for markets outside of the Eurozone)[130]
- Increases in OEM profitability and warranty provisions

In part, factors such as increased OEM profitability and perhaps increased labor costs have been driven by significant global demand growth over the latter half of the past decade. However, Bolinger and Wiser (2011) observed that the single largest factor pushing turbine prices upward were the scaling trends toward larger machines placed on taller towers. Of course, such improvements also result in energy production gains that were actually sufficient to offset the additional cost that can be attributed to turbine scaling (Bolinger and Wiser 2011). Notably, the increase in costs for commodity or input materials has also greatly impacted the installed cost of conventional power generation technologies (Chupka and Basheda 2007; Winters 2008; Black & Veatch 2012). At present, however, reduced demand in many markets coupled with new, well-financed market entrants, and the global recession that has reduced commodity prices, have resulted in significant turbine price declines that translate (or are anticipated to translate) into capital cost reductions in markets around the world. In the future, wind power capital costs are expected to resume their historical declines, with reductions in the cost of energy anticipated by an array of independent estimates to be on the order of 20%–30% (Lantz et al. 2012).

Initially, installed costs for fixed-bottom offshore wind plants were roughly 50%–100% higher than installed costs for onshore wind facilities. Data through 2010 for proposed U.S. and European projects suggest that offshore costs are in excess of $4,000/kW (see Figure 11-8) (Musial and Ram 2010). The capital cost data show a significant rise in offshore costs from less than $3,000/kW in 2007 to in many cases more than $5,000/kW for projects currently under development. A number of factors have contributed to this increase. As was the case for onshore wind industry costs, offshore cost increases have also been affected by commodity price increases, scaling to larger turbines, and upward trends in OEM labor costs and profitability. Offshore project costs have also grown due to increased siting complexity and the need for increased contingency reserves (i.e., greater risk premiums), which reflect limited operational experience and significant uncertainties associated with the difficult offshore installation, logistics, and O&M environment.

[130] Especially pertinent for the wind industry during the past decade is the changing value of the euro (€) relative to the U.S. dollar ($) due to heavy reliance on European manufacturing for much of the past decade.

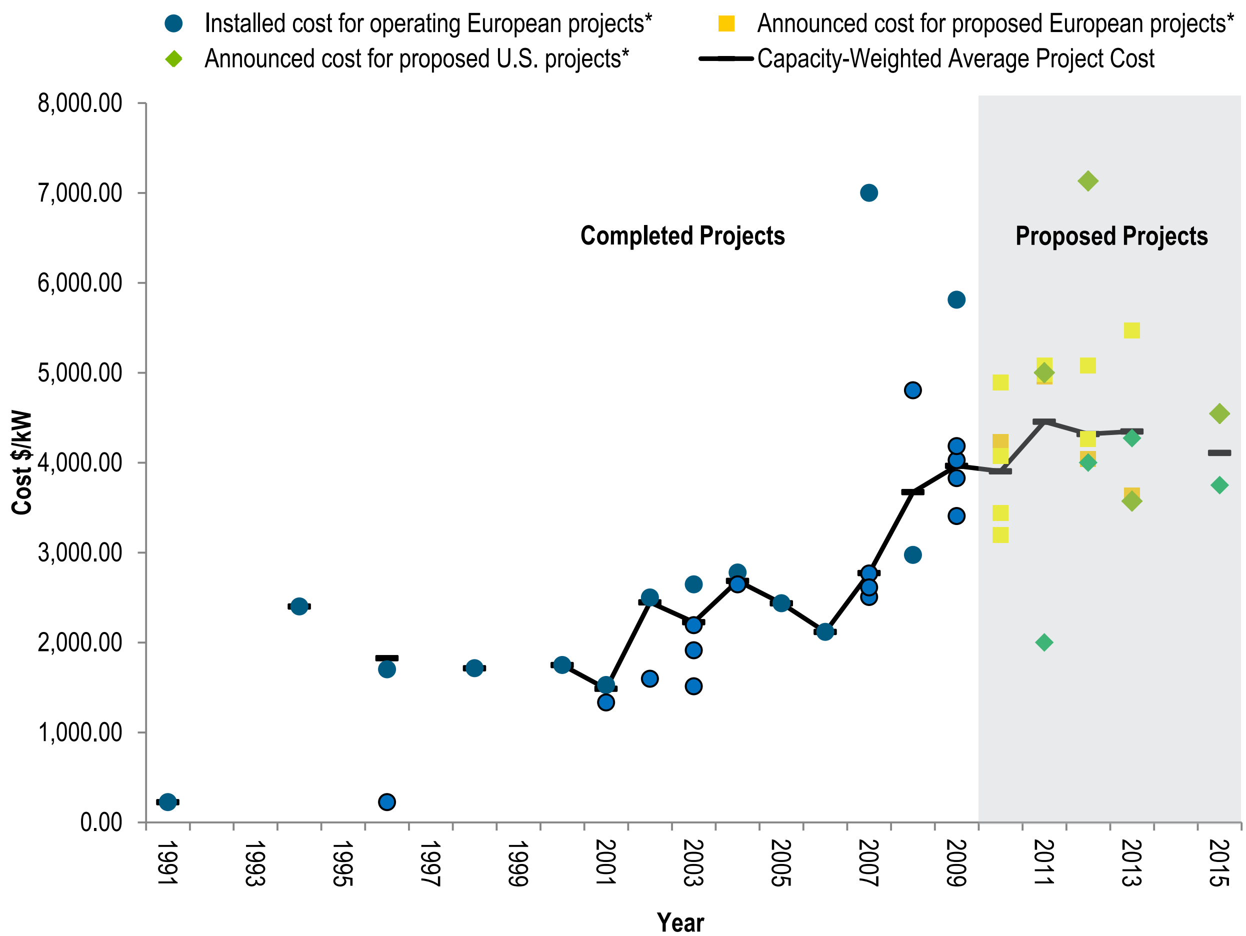

Figure 11-8. Global capital costs for offshore wind energy (2010 dollars)

Source: Musial and Ram 2010

Historical costs are on the left. Projected costs, on the right in the shaded area, represent projections for announced projects.

Compared with onshore installations, the distribution of costs between elements of an offshore project can vary greatly. Offshore, the turbine cost typically represents 30%–50% of the total installed cost of the wind project; this is compared with land-based projects where the turbine cost represents 70%–75% of total installed cost (Junginger et al. 2004; Blanco 2009). BOP costs are much higher for offshore projects due to more sophisticated foundation designs, the challenge of at-sea construction, and the cost of underwater cabling (see Table 11-1) (Junginger et al. 2004; Blanco 2009). Water depth and distance to shore also have a significant influence on offshore wind BOP costs. Assuming approximate installed costs of $5,000/kW, Table 11-1 indicates that the turbines represent approximately $1,700/kW, associated infrastructure (e.g., foundations and electrical collector system) costs are on the order of $1,650/kW, and installation costs are approximately $760/kW.

Table 11-1. Distribution of Offshore Wind Installation Costs[a]

Cost Category	Percentage
Turbine	34%
Foundation	19%
Installation	19%
Electrical infrastructure	14%
Project management and consenting	12%
Other	2%

[a] Source: Blanco 2009

11.4.1.2 Operation and Maintenance Costs

O&M costs make up the balance of total lifetime project cost, approximately 20%–25% (Blanco 2009; EWEA 2009). Approximately 10% of total project investment can be considered "pure" O&M, specifically repair and replacement costs (Blanco 2009). Additional sources of operations costs include routine monitoring and management, insurance, land rent, property taxes, and other day-to-day expenses. Increased reliability gained through operating experience and R&D (sponsored by both the U.S. government and private companies) has also been an important contributor to the overall reduction in wind energy costs over the past 30 years.

Limited data make precise estimates of current O&M costs difficult. However, Wiser and Bolinger (2011) report U.S. O&M costs from a limited data set to average $33/MWh for projects completed in the 1980s, $22/MWh for projects completed in the 1990s, and $10/MWh for projects completed in the 2000s. These findings are generally consistent, in terms of scale and range, with similarly limited data for O&M costs from Europe (Lemming et al. 2009). Nevertheless, it remains unclear precisely how O&M costs will change over time because recently completed projects have yet to accumulate years of operating wear and tear. Asmus and Seitzler (2010) report that initial O&M cost estimates from the early 2000s may have severely underestimated long-term O&M costs and suggest a median lifetime estimate for turbines installed in the early 2000s of approximately $30/MWh with a range of $10/MWh to as high as $80/MWh, in exceptional cases. Underestimates of lifetime O&M costs are believed to potentially be the result of premature component failures, primarily in gearboxes and blades, and variable maintenance practices (Asmus and Seitzler 2010).

11.4.1.3 Performance

Wind plant energy generation performance has improved significantly over the past 20 years.[131] Fleet-averaged capacity factors increased from about 25% for wind plants installed in 1999 to nearly 35% for wind plants installed in 2008 (Wiser and Bolinger 2011). Despite some inter-annual variability resulting from an array of factors—including annual wind resource variability, transmission congestion (particularly in 2009), and variability in the quality of the wind resource at sites where new projects are located—Figure 11-9 illustrates that the past decade has observed

[131] This discussion measures plant performance in terms of capacity factor. This should not be confused with capacity value or capacity benefit, a measure of available capacity during utility peak demand periods.

relatively continual incremental improvements in fleet-wide capacity factor.[132] Average capacity factors for projects built since 2004 have been above 30% (Wiser and Bolinger 2010).[133] Capacity factor increases are generally attributed to increases in turbine hub heights that allow access to better wind resources, and larger rotor diameters relative to generator capacity.

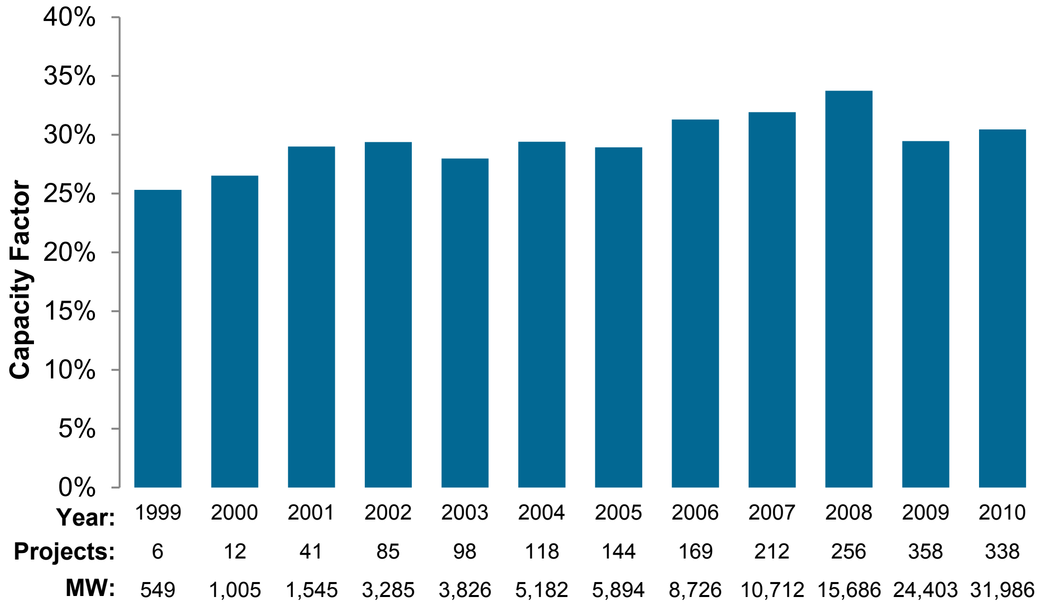

Figure 11-9. Cumulative average sample-wide capacity factor by calendar year

Source: Wiser and Bolinger 2011

Inter-annual variability in the data shown here result from an array of factors (see text above); however, by focusing on the broad trends in the data, it is clear that there has been a gradual increase in fleet-wide performance over time. For additional detail on wind power capacity factors in the United States, see Wiser and Bolinger (2011) and Wiser et al. (2012)

Fleet-wide capacity factor improvements have occurred in spite of wind projects being increasingly sited in less-desirable wind regimes. For example, wind plants installed in 2008 were, on average, installed in high Class 3 wind resource regimes, whereas wind plants built from 1998 to 2001 were, on average, installed in Class 5 wind resource regimes (Wiser 2010). This trend is likely a function of limited transmission access, rather than an absence of Class 5 wind resource areas.[134] By combining continued turbine technology improvements—which are expected to improve performance within a given resource class (Cohen et al. 2008)—with new

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132 The year 2009 was a particularly poor year for wind resources. It was also impacted more by curtailment (as a result of transmission congestion, primarily in ERCOT but also in other markets) than years prior. Curtailment in 2009 was estimated at more than 17% in ERCOT (Wiser and Bolinger 2011).

133 The values noted here are fleet averages; however, the full range of capacity factors includes projects with capacity factors below 20% and greater than 45% (see Wiser and Bolinger 2010).

134 There is no conclusive data to verify this; however, it is generally accepted that transmission access and other siting challenges are the primary drivers of the trend toward lower quality wind resource sites.

transmission, which will presumably open up new high-quality wind resource areas for development, continued improvements in fleet-wide capacity factors are expected.

Offshore wind resources tend to have higher power densities than onshore resources and should yield higher capacity factors. Offshore resources also tend to have lower shear and turbulence as a result of more limited surface interference (EWEA 2009).[135] European projects report offshore capacity factors ranging from 29% to 48% (Lemming et al. 2009).

11.4.2 Technology Advancement Potential

In the past, engineers were able to reduce costs or increase energy production by designing turbines with larger rotors, larger capacity ratings, and taller towers while applying new materials and design techniques to reduce weight and increase efficiency. Continued technology improvements in each of these areas are expected to impact the future cost of wind-generated electricity.

Generally, two methods are used to quantify the potential for technology advancements. Learning curves (Junginger et al. 2005; Nemet 2009; Wiser and Bolinger 2009), which rely on aggregated historical data and project past trends into the future, assume that technology improvement is a function of cumulative installations and that the rate of technology improvements observed in the past will extend into the future.[136] In contrast, engineering-based analysis involves the evaluation of specific proposed and anticipated technology advancements. By evaluating the potential for individual and tangible innovation opportunities, an engineering analysis can be used to substantiate or qualify learning curve projections. Here, an engineering-based analysis of future turbine costs and technology advancement is discussed.

11.4.2.1 Engineering Analysis of Wind Turbine Advancement Potential

A number of studies have sought to evaluate the impact of specific technology advancements on the cost of wind energy. Often, these studies consider the impacts that continued scaling of wind turbines (i.e., scaling as has been observed in the past) would have on energy production and capital cost. Categories of technology improvement opportunities frequently highlighted include more effective turbine controls, reduced drivetrain losses, increased reliability, and increased efficiency in the power conversion and collection system. Much of this work was captured by DOE in a series of studies constituting the Wind Partnership for Advanced Component Technologies (WindPACT) project (GEC 2001; Griffin 2001; Shafer et al. 2001; Smith 2001; Malcolm and Hansen 2006). One comprehensive evaluation of the work that emerged from the WindPACT studies was completed by Cohen et al. (2008); their results are summarized in Table 11-2.

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[135] Shear refers to the change in wind speed with height above ground. Turbulence refers to unsmooth or chaotic airflow resulting from mixing of air of different velocity and direction. Surface interference in the form of trees, hills, buildings, and other landscape features can increase wind shear and introduce turbulent airflow. Because such landscape features do not exist at sea, turbulence and shear are typically lower in offshore wind regimes.

[136] How far into the future a specific learning rate will extend remains an open question. Authors of learning curve analyses frequently acknowledge that some degree of diminishing returns is foreseeable; however, little is known about the rate of learning decay.

Table 11-2. Areas of Potential Technology Improvement[a]

Technical Area	Potential Advances	Increments from Baseline (Best/Expected/Least Percent): Annual Energy Production (%)	Increments from Baseline (Best/Expected/Least Percent): Turbine Capital Cost (%)
Advanced tower concepts	• Taller towers in difficult locations • New materials and processes • Advanced structures and foundations • Self-erecting	+11/+11/+11	+8/+12/+20
Advanced (enlarged) rotors	• Advanced materials • Improved structural-aero design • Active controls • Passive controls • Higher tip speed and lower acoustics	+35/+25/+10	-6/-3/+3
Reduced energy losses and improved availability	• Reduced blade soiling losses • Damage-tolerant sensors • Robust control systems • Prognostic maintenance	+7/+5/0	0/0/0
Advanced drivetrains (gearboxes, generators, and power electronics)	• Fewer gear stages or direct drive • Medium- and low-speed generators • Distributed gearbox topologies • Permanent-magnet generators • Medium-voltage equipment • Advanced gear tooth profiles • New circuit topologies • New semiconductor devices • New materials (GaAs,[b] SiC[c])	+8/+4/0	-11/-6/+1
Manufacturing learning	• Sustained, incremental design and process improvements • Large-scale manufacturing • Reduced design loads	0/0/0	-27/-13/-3
Totals[d]		+61/+45/+21	-36/-10/+21

[a] Source: Cohen et al. (2008). The baseline for these estimates was a turbine system installed in the United States in 2002. Capacity factor increases observed since 2002 suggest that the overall impact to capacity factor, from current technology, will be somewhat less than reported in Table 11-2. However, turbine capital cost increases observed since 2002 suggest that the proposed cost reductions highlighted in Table 11-2 remain achievable. Cohen et al. (2008) did not consider any changes in the overall wind turbine design concept (i.e., two-bladed turbines).
[b] Gallium arsenide
[c] Silicon carbide
[d] Technology improvement opportunities have been analyzed for their independent impact and, as a result, the opportunities suggested here are in fact generally additive.

Table 11-2 presents the percent impact on turbine capital cost and annual energy production expected from technology improvement opportunities identified in the WindPACT project. Because there is uncertainty in the actual magnitude of impact, a range was provided that captures the best case or maximum beneficial impact, the expected or most likely impact, and the worst or least beneficial impact that could result from the specific categories of technology improvements. Recognizing that improvements are unlikely to be entirely additive and that improvements in one area might limit improvements in another, the expected or most likely impact is that the annual energy production would increase by 45% while capital cost would decrease by 10%.

Since the 2002 baseline used by Cohen et al. (2008), there have already been some sizeable improvements in onshore U.S. capacity factors. Over the past decade, capacity factors have risen to almost 35% (Wiser and Bolinger 2008). At the same time, capital costs have increased. Working from a 2008 baseline, one might expect a more modest increase in annual energy production, but given recent cost increases, it seems reasonable to assume that the 10% capital cost reduction identified by Cohen et al. (2008) remains to be captured.

Within the impacts summarized in Table 11-2 is an array of component-level innovation opportunities. The following sections discuss some of the primary elements that make up the categories of innovations highlighted in Table 11-2. Because these innovations are focused exclusively on turbine technology, their successful deployment is expected to be applied in both onshore and offshore equipment. However, due to the additional technical requirements for offshore turbines, a supplementary discussion of offshore-specific opportunities is also included.

11.4.2.1.1 Advanced Tower Concepts

Tower technology represents one of the most significant opportunities for reductions in the cost of wind energy. By providing access to improved wind resources, taller towers increase energy capture, thus putting downward pressure on cost of energy. For example, a simplified energy production calculation (using a Weibull distribution of average wind speed) reveals that for a 2.5-MW, 100-m rotor machine situated in a Class 4 wind regime, increasing the tower height from 80 m to 100 m increases annual energy production by 5%. However, larger towers require more materials, taller cranes, and they could trigger specific logistics challenges; any one of these factors could result in higher installed costs. To help provide transportation alternatives and shift to lower-cost materials, some turbine suppliers have begun offering concrete or hybrid concrete and steel towers with the option to pour the concrete portion of the tower onsite.

11.4.2.1.2 Advanced (Enlarged) Rotors

Increasing the rotor diameter of wind turbines is perhaps the most intuitive pathway for increasing energy capture. However, doing so requires that engineers find ways to eliminate blade weight while maintaining the structural integrity and aerodynamic conversion efficiencies of current technology (Griffin 2001). In some cases, weight reductions might be achieved simply by eliminating reinforcement where it is not needed and by adding critical reinforcement in regions with the greatest loads and stresses (Fingersh et al. 2006). Implementing this level of technological advancement could result in a 3% reduction in installed cost for the 2.5-MW, 100-m rotor turbine noted above.

Additional technological advancements might allow a reduction in loads borne by rotor blades without reducing power generation, and a subsequent reduction in design requirements resulting in additional weight and cost reductions. Possibilities include:

- Use of high-tech composite materials or curved blades to allow passive shedding of loads achieved through engineered blade deformation and twisting (Ashwill 2009)
- Development of partial blade span actuation and sensing strategies to adapt to localized variability in wind speed and turbulence across the rotor disk (Buhl et al. 2005; Lackner and van Kuik 2009)
- Incorporation of trailing edge flaps or micro tabs coupled with sensors that can "see" the wind and preemptively react to changes in wind speed and turbulence (Andersen et al. 2006; Berg et al. 2009).

11.4.2.1.3 Reduced Energy Losses and Improved Availability

Underperformance can result from array effects, blade soiling, damaged sensors, or control errors. Using the same simplified energy production calculation noted above, but for a Class 4 wind regime, reducing these types of losses from 15% to 12% for the 2.5-MW turbine can increase annual energy production by approximately 4%. A large number of R&D initiatives specifically target the development of advanced controls designed to monitor and adapt to wind conditions and blade soiling in order to increase energy capture (Johnson et al. 2004; Johnson and Fingersh 2008; Frost et al. 2009).

Unscheduled turbine downtime might also result in lost energy production. Premature equipment failure is a primary source of unplanned turbine downtime. Assuming no change in wind resource and again using the 2.5-MW machine described above, increasing availability from 95% to 98% could result in a 3% increase in annual energy output.[137] Condition-monitoring technology is under development to allow real-time observation and evaluation of critical turbine components. Such data would allow for appropriate replacement and repair to be scheduled at opportune times, during low-wind speed periods and before catastrophic failure (Hameed et al. 2010).

11.4.2.1.4 Advanced Drivetrains, Generators, and Power Electronics

Drivetrain reliability and weight factor heavily into long-term O&M costs and turbine installation costs. Efforts are under way to analyze gearbox dynamics in order to contribute to designs that are more reliable (Peeters et al. 2006; Heege et al. 2007). However, manufacturers and researchers also continue to experiment with a handful of drivetrain designs. One potentially significant evolution already being applied in an increasing number of commercially available wind turbines is the use of rare-earth permanent magnets, which, by reducing generator size and weight, provide an opportunity to resolve some of the longstanding trade-offs of direct-drive wind turbines (i.e., traditional direct-drive generators are heavier and larger in diameter than

[137] Increased wind turbine availability may not translate directly into increased energy output if the turbine downtime (i.e., when it is not available) is already planned to coincide with a low-wind period in which the turbine would not normally operate. However, eliminating unplanned downtime that occurs during high-wind periods, of course, would increase energy output.

designs incorporating permanent magnets; these characteristics significantly increase transportation and logistics challenges and require significant added reinforcement, and therefore cost in other critical components like the tower and foundation). In addition to the conventional three-stage gearbox and the direct-drive machines, other drivetrain designs employed in the industry include the single-stage, medium-speed gearbox and generator, and the multi-generator drivetrain. The former is designed to capture the benefits of both the three-stage gearbox high-speed generator machines and the direct-drive machines while the latter reduces the torque applied to each individual drive path (Cohen et al. 2008).

Increased turbine-generating capacity continues to apply pressure to develop higher capacity, higher voltage power electronics. Advanced power electronics further enable wind turbines to provide grid services (see Section 11.5) and modest but non-trivial performance increases while reducing costs (Cohen et al. 2008). Some machines use doubly fed induction generators that require only a portion of the power to be processed through the power electronics, thus providing some of the benefits of variable-speed operation and grid services, but without the electrical losses caused by full conversion. Full conversion, however, allows the use of synchronous generators that provide greater flexibility and enhanced turbine control.

11.4.2.1.5 Manufacturing Learning

Manufacturing learning encompasses a mix of manufacturing optimization and development of new manufacturing techniques. Increased automation could reduce costs and provide for more consistent component production, allowing reduced design margins. Re-evaluating manufacturing requirements and techniques could eliminate or greatly reduce traditional logistics challenges. For example, the continued development of segmented blades would facilitate their transport overland (but at the risk of introducing additional failure modes that will need to be carefully addressed). On-site fabrication techniques minimize the need for long-haul transport even though they might require novel manufacturing methods. Higher volume allows for greater distribution of the fixed costs associated with manufacturing infrastructure and might allow manufacturers to operate with reduced profit margins. Simply reducing manufacturing mark-ups from 20% to 15% (Cohen et al. 2008) could provide measurable cost of energy savings.

11.4.2.2 Offshore-Specific Innovation Opportunities

Offshore turbine concepts are often focused on larger (5–10 MW and perhaps greater), lighter, and more flexible machines. As a result, offshore technology is expected to benefit from each of the innovation opportunities highlighted in Table 11-2, and may, in fact, drive their implementation. Overall cost of energy reduction is the primary driver of such innovations; however, limited access makes reliability paramount in the offshore environment. Tower-top weight becomes increasingly important because the tower spans both above and below the waterline to a total height that makes supporting the mass on the top especially expensive. Offshore wind technology R&D must also consider offshore-specific servicing and access needs, installation and assembly techniques, foundation and support structure design, and application-specific turbine design criteria. Floating and other turbine concepts provide additional innovation opportunities.

Limited, difficult access coupled with the harsh marine environment requires continued evaluation of O&M strategies. Development of new access and maintenance techniques might provide access over a wider range of conditions (van Bussel and Bierbooms 2003). More sophisticated use of advanced O&M strategies, including telemetered performance and real-time condition monitoring results, are expected to provide increasingly detailed levels of turbine performance and manipulation from an onshore control room. Although such concepts have been evolving for many years, their importance, widespread application, and continued development are critical to driving down offshore wind operations expenditures. Increased knowledge of turbine function, coupled with greater knowledge of failure indicators, can help provide appropriate preventive maintenance and identify impending failures, in turn maximizing the efficacy of access opportunities (Wiggelinkhuizen et al. 2008).

Offshore wind turbines are currently installed as individual components in much the same way as land-based machines are installed. However, with manufacturing located at or near ports, offshore equipment might be able to eliminate many of the logistics challenges faced by land-based turbines. Concepts exist where fully assembled turbines are stockpiled at port and then transported on special-purpose vessels to the project site where they can be directly mounted on previously installed support structures, rather than assembled piece by piece. A primary innovation challenge is developing and designing purpose-built installation and servicing vessels that can perform such tasks with near- and long-term turbine and foundation designs in mind.

Of primary concern to researchers is the development and advancement of offshore wind turbine foundation and support structures. Such structures must be capable of responding to specific wind and wave loads. Integrated analyses of turbines and their foundations, coupled with better knowledge of soil and seabed conditions, are critical to the continued development of offshore foundations (Nielsen et al. 2009, pp. 201–257). New technology concepts might offer access to greater water depths. Such concepts include suction caissons, a large-diameter foundation that is mounted to the seabed by creating negative pressure inside of the foundation rather than driving it deep into the seafloor (see Figure 11-10); space-frame or jacket structures consisting of framed support structures attached to piles in the seafloor (see Figure 11-10); and tension-leg moorings, a buoyant structure fixed to the seafloor with a series of tubular steel moorings or tension legs (see Figure 11-11).

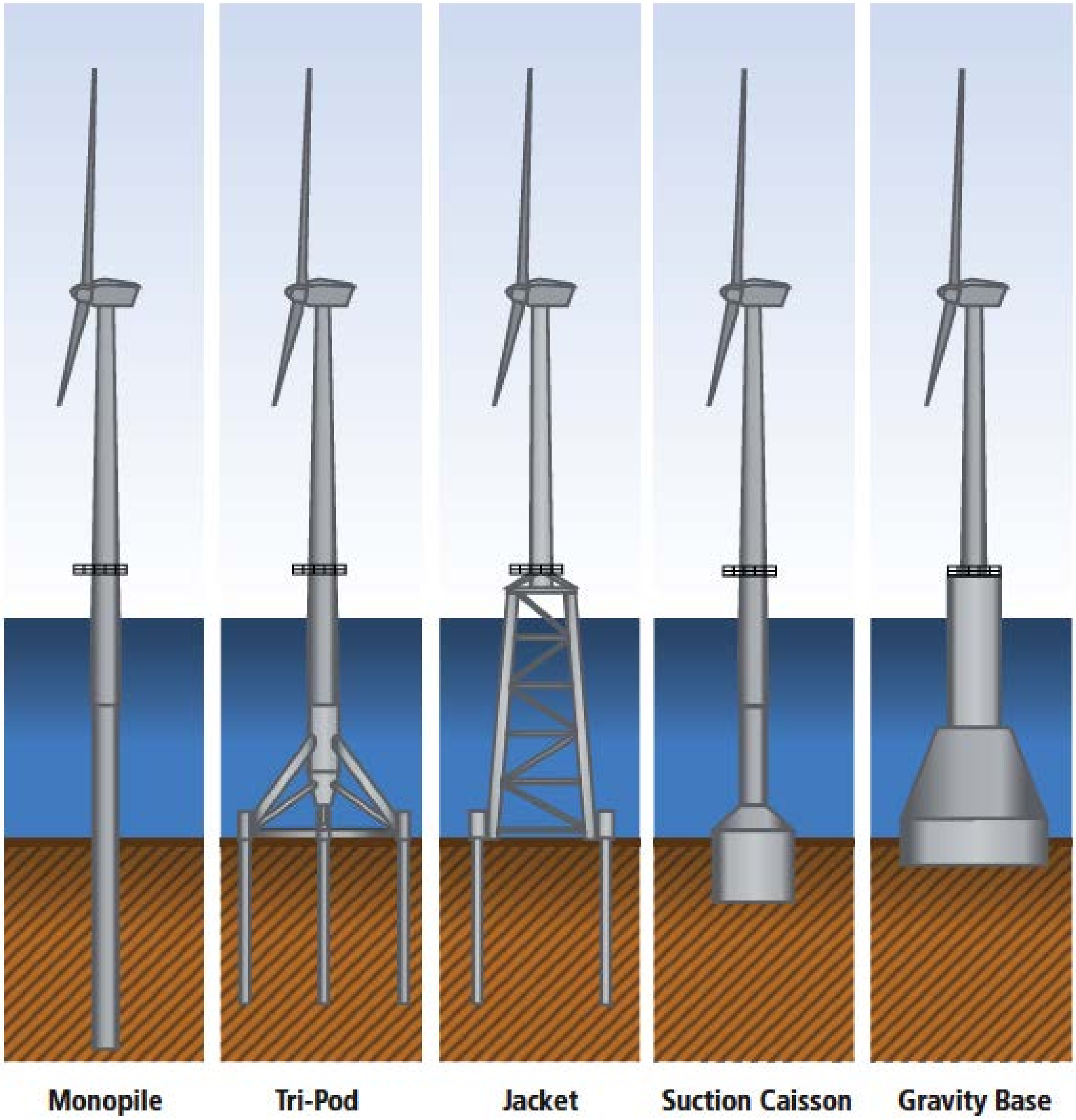

Figure 11-10. Near-term offshore foundation concepts

Source: IPCC 2012, Figure 7.19

The vast majority of offshore wind turbines in operation today are placed on monopiles, which are essentially extended turbine towers driven into the seabed. Tripods and jackets have emerged as greater water depths have been pursued; they consist of framed structures fixed to the seabed with smaller pilings. Jacket structures designed for wind turbines are a derivative of the common fixed platforms used in offshore oil drilling. Suction caissons entail large diameter foundations fixed to the seabed with negative pressure or vacuum, rather than pilings. Gravity-based foundations are fixed to the seabed by their sizable submerged mass.

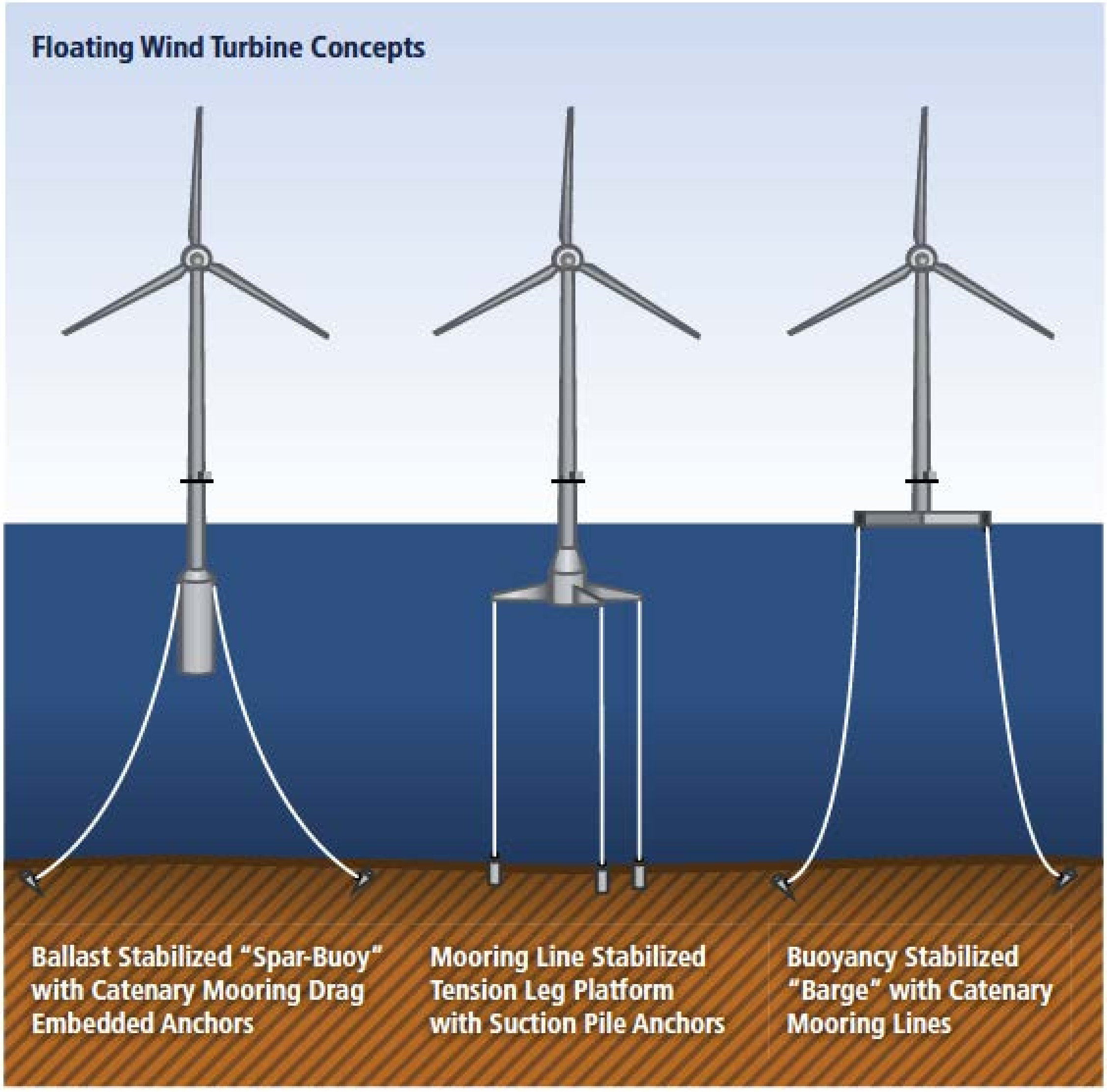

Figure 11-11. Floating-offshore wind turbine concepts

Source: IPCC 2012, Figure 7.19

The ballast stabilized spar-buoy employs a buoyant structure that is stabilized by a large ballast placed on the lower portion of the structure; the floating structure is fixed to the seabed with mooring lines but relies on the ballast to remain upright and withstand wave and wind loading. In contrast, tension leg platforms consist of a buoyant structure located below the surface of the water that is fixed to the seabed and stabilized by taut or "tensioned" mooring lines. The buoyancy stabilized "barge" uses a large buoyant structure for both stability and floatation; the size of the buoyant structure is expected to provide the required stability.

In contrast to current fixed-bottom technology, floating wind turbines could provide access to a significantly greater resource area and offer the opportunity to develop more uniform offshore installation techniques because they would minimize variable seabed and water-depth considerations. Increased technology standardization would facilitate the development of purpose-built vessels, in turn enabling more efficient installation, servicing, and decommissioning. However, floating turbines also open an array of additional design considerations. Namely, floating turbines must be capable of withstanding heaving and pitching moments from wave action. In 2009, the first full-scale (2.3-MW) floating wind turbine pilot project was deployed off the coast of Norway at a 220-m depth (Statoil 2011).

Finally, distant offshore sites, where sound and visual impacts are less critical, are expected to allow for the relaxation of certain design criteria. Specifically, reduced concern about sound allows for increasing tip speeds, reducing rotor torque loads, and potentially for developing two-bladed, downwind turbine concepts. Downwind turbines offer notable advantages in the form of greater inherent yaw stability and blade deflections away from the tower, providing the opportunity to use softer, more flexible blades. However, because of the resulting orientation of the rotor downwind from the tower, these turbines have much greater low-frequency noise characteristics and, as a result, they are not used on land or in close proximity to residences or occupied buildings (Breton and Moe 2009).

11.4.2.3 Advancement Potential Relative to RE Futures Scenario Analysis

Future capital cost, energy production (generally represented as capacity factor), and operating costs of electricity generating technologies are influenced by a number of uncertain and somewhat unpredictable factors. As such, to understand the impact of renewable electricity technology cost and performance improvements on the modeled scenarios, two projections of future renewable electricity technology development were evaluated: (1) renewable electricity-evolutionary technology improvement (RE-ETI) and (2) renewable electricity-incremental technology improvement (RE-ITI). In general, RE-ITI estimates reflect only partial achievement of the future technical advancements and cost reductions that may be possible, while the RE-ETI estimates reflect a more complete achievement of that cost-reduction potential considering only evolutionary improvements of commercial technologies. Black & Veatch (2012) includes details on the RE-ITI estimates for all (renewable and conventional) generation technologies. RE-ETI estimates represent technical advances currently envisioned through evolutionary improvements associated with continued R&D from the perspective of each renewable electricity generation technology independently. The RE-ETI wind technology improvements are described in this section. It is important to note that these two renewable energy cost projections were not intended to encompass the full range of possible future renewable technology costs; depending on external market conditions or policy incentives, these anticipated technical advances could be accelerated or achieve greater magnitude than what is assumed here.[138] Cost and performance assumptions used in the modeling analysis for all technologies are tabulated in Appendix A (Volume 1) and Black & Veatch (2012).

[138] In addition, the cost and performance assumptions used in RE Futures are *not* intended to directly represent DOE EERE technology program goals or targets.

The RE Futures scenarios rely on wind capital cost and capacity factor inputs to determine optimum deployment levels. Innovation opportunities impacting either capital cost or capacity factor will impact the contribution of wind energy in the RE Futures scenarios. In the RE-ITI technology cost estimates, the overnight capital cost[139] was assumed to be $1,980/kW in 2010 and was projected to remain at that level through 2050, as shown in Figure 11-12.[140] This value was consistent with average installed capital costs in the years leading up to 2010 and assumes that the macro-economic influences as well as recent supply and demand pressures that placed upward pressure on capital costs in the recent past are moderated. It also assumes that technology scaling, which increases energy capture but also has placed upward pressure on recent costs, continues to prevent significant installed cost reductions.

Figure 11-12 places the RE-ITI projection in context with recent capital cost trends since the year 2000, as well as with other projections for future onshore wind capital costs. Comparing the RE-ITI projections with the full set of projections shown in Figure 11-12 and the engineering analysis by Cohen et al. (2008) described above, suggests that a constant overnight capital cost of $1,980/kW was a relatively conservative assumption. Rooted in the work of Cohen et al. (2008), the RE-ETI projections assumed a capital cost reduction of approximately 10% between 2010 and 2035 and a flat cost thereafter. Considering that recent learning curve estimates assume an 11% capital cost reduction for every doubling of global installed capacity (Nemet 2009; Wiser and Bolinger 2009) and that Cohen et al. (2008) envision the majority of the innovation opportunities highlighted above to be near-term tangible opportunities, RE-ETI technology cost estimates were also conservative.

The conservative nature of the installed costs for both the RE-ITI and RE-ETI estimates is justified by two primary considerations. First, installed costs have escalated dramatically over the past decade due to an array of upward price pressures, including commodity prices, efforts by OEMs to maintain profitability and meet labor cost increases, and exchange rate variability. Although many of these price pressures have moderated in the recent past, such pressures could continue to limit future reductions in the installed cost of wind energy.[141] Secondly, and perhaps more important, is the industry trend towards larger machines on taller towers and with larger rotors. Continued scaling of turbines typically puts upward pressure on installed costs but also contributes to increases in energy capture. As a result, scaling turbines can reduce cost of energy even without a decrease in installed cost per kilowatt. Given an assumed positive influence of upward scaling on the balance of plant and O&M cost reductions, as well as improved capacity factors from taller towers and larger rotors, it is generally assumed that technology R&D will continue to push the envelope on turbine size and hub height. The RE Futures installed cost estimates for wind energy have been predicated on the assumption that continued technology advancement will seek to maximize energy capture (as opposed to minimizing installed cost) to

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[139] The overnight capital cost excludes the costs of financing during construction as well as the costs associated with transmission interconnection. For onshore wind projects, this amounts to approximately 5% of the total installed cost. Although historical cost data presented here have been adjusted, historical data are often reported as all-in capital costs and are likely to include construction financing costs.
[140] All RE Futures modeling inputs, assumptions, and results are presented in 2009 dollars unless otherwise noted.
[141] Of course, to the extent that commodity cost price pressures and related factors affect wind power installed costs, they are also likely to impact conventional power plants, as discussed in Black & Veatch (2012).

drive down cost of energy. This is evidenced by up to an approximate 8% increase in capacity factor projected in the RE –ITI and RE-ETI estimates.[142] Technological innovation and advancement are presumed to allow performance improvements to occur in the RE-ITI estimates without increases in installed costs per kilowatt and in the RE-ETI estimates with a modest decrease in installed cost per kilowatt.

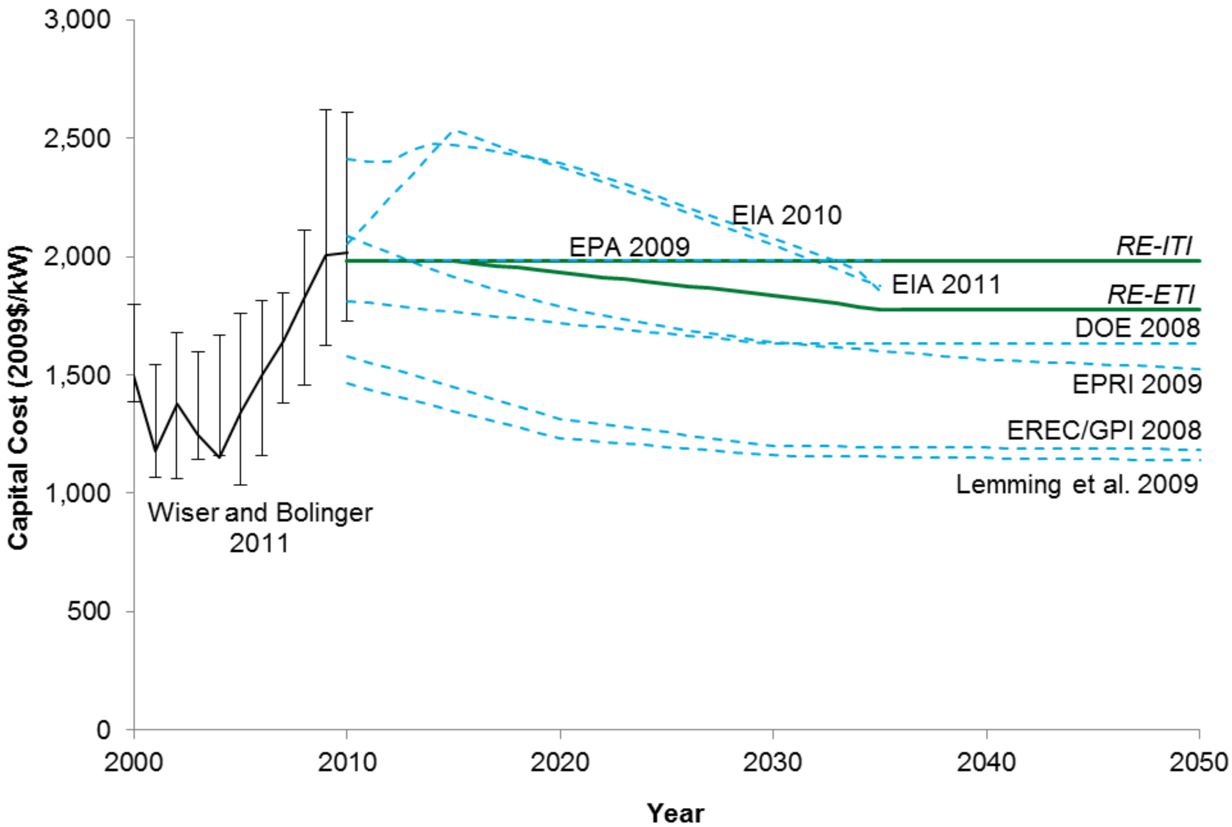

Figure 11-12. Historical and future capital cost for onshore wind energy, 2000–2050

Historical data represent capacity-weighted averages (Wiser and Bolinger 2011). Ranges in the historical data represent the 10th and 90th percentiles of reported data. Historical data and projections have been adjusted to exclude construction financing costs (approximately 5% of total capital cost).

142 The RE-ITI projection assumes an approximate 8% increase in capacity factor for lower wind resource classes and no change in capacity factor for high resource class areas; the RE-ETI projection assumes an 8.5% and a 5% increase in capacity factors, respectively.

Wind project capacity factors differ based on the particular turbine in use and the wind resource at a given location. Figure 11-13 shows the 10^{th} to 90^{th} percentile of historical capacity factors for a large sample of wind projects operating in the United States as well as the projected capacity factor estimates used in the RE Futures study by wind resource class. The historical data shown in the left part of Figure 11-13 illustrate year 2010 weighted average capacity factors for projects installed between 2000 and 2009 (i.e., year 2000 data in the figure reflect the 2010 performance for projects installed in year 2000). Projected capacity factors are indicative of expected performance within a given resource regime and are independent of actual installations within a specific resource area as well as future fleet-wide average capacity factors.[143] The full range of capacity factors for wind projects operating in the United States in 2010 is from 20% to 46% (Wiser and Bolinger 2011). The apparent discrepancy between the historical and projected data is the result of data limitations surrounding the historical dataset as well as the presentation of 10^{th} to 90^{th} percentile data. Including only those projects for which a full year of data were available means that the most recent projects captured in these data were installed in 2009. As a result, the dataset does not capture the sizable performance improvements that are associated with currently available state of the art technology going in the ground today. Moreover, the vast majority of projects installed in the latter part of the 2000 to 2009 time period captured here were in class 3 to class 5 wind regimes, with fewer installations going into classes 6–7 due to a limited availability of such sites to new wind development.

The historical data in Figure 11-13 illustrate how to some extent newer vintage projects have observed increases in capacity factor relative to older vintage projects. Notwithstanding the limitations of the historical data set noted above Figure 11-13 also allows comparisons among the capacity factors applied in the RE-ITI and RE-ETI projections and the industry's recent past. When considering the historical data and the performance at newer projects not captured in the data set below the RE-ITI capacity factors can generally be achieved with little or no improvement in wind energy capacity factors within specific resource class areas. The RE-ETI projections will require continued incremental improvements in capacity factor not unlike those observed for 2006 projects relative to projects installed in the early 2000s.

Future technology advancements are expected to increase capacity factors for all wind classes. However, greater capacity factor increases are expected for lower wind resource classes as innovations like larger rotors and taller towers are more suited to Class 3 and Class 4 wind resource areas. Similar to the capital cost projections, other model projections and engineering analyses (Cohen et al. 2008) suggest that improvements to the onshore wind capacity factor greater than those modeled in RE Futures are technically possible.

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[143] It is possible that siting, transmission, or other constraints will prevent otherwise viable project installations. Such trends could place downward pressure on future fleet-wide average capacity factors regardless of expected performance in any given resource class.

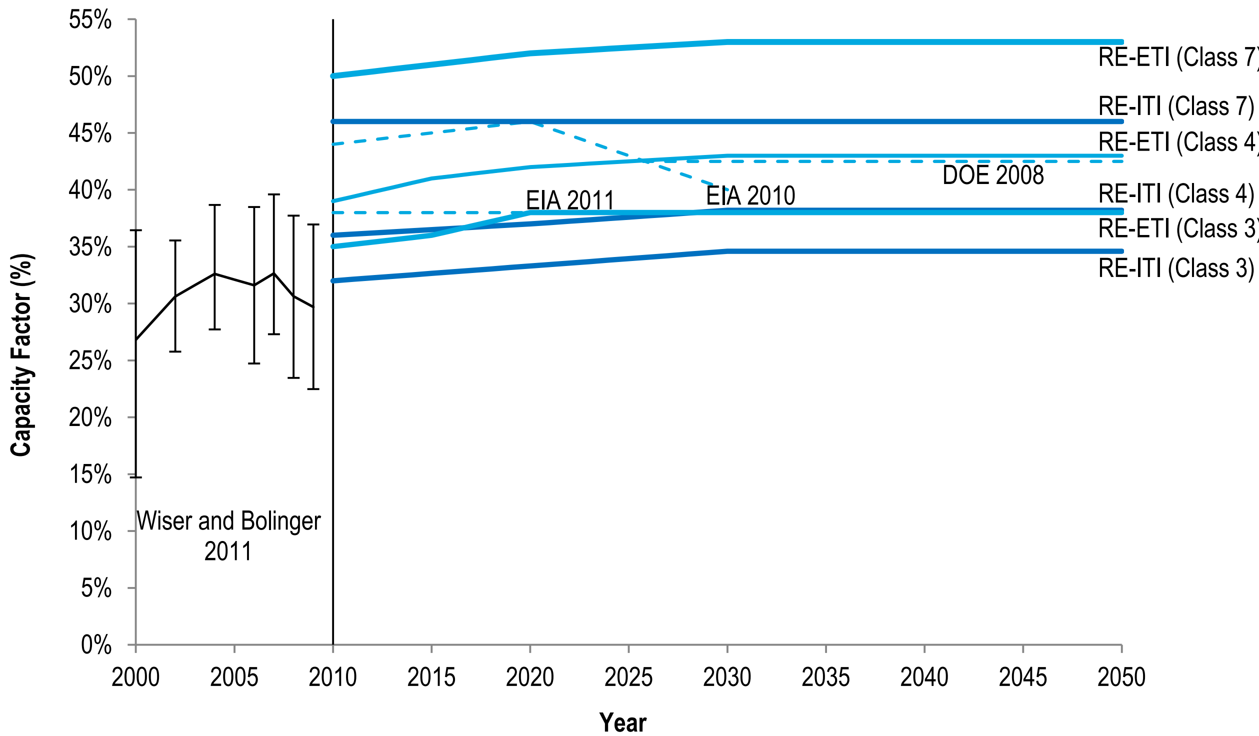

Figure 11-13. Historical and future capacity factors for onshore wind energy, 2000–2050

Historical data represent the weighted average capacity factor data for operating plants installed through 2009 in the year 2010. Data are sorted by project vintage such that year 2000 data in the figure represent the 2010 performance for plants installed in the year 2000. The range shown here reflects the 10th to 90th percentile of empirical capacity factors for wind classes 3–7; the full range of individual project capacity factors extends from 20% to 46%. The data presented likely do not fully reflect the performance of current state of the art technology in class 6 and class 7 wind regimes due to limitations of the data. The vast majority of the historical data shown here reflect installations in class 3 and 4 wind regimes. Newer 2010 and 2011 installations that utilize state of the art technology have offered performance in class 6 and class 7 wind regimes on par with that shown in the projections. Historical data are derived from Lawrence Berkeley National Laboratory (LBNL) analysis of data presented in Wiser and Bolinger (2011). EIA (2010), EIA (2011), and DOE (2008) data represent a Class 4 wind resource. RE-ETI onshore wind capacity factors are equivalent to DOE (2008) capacity factors.

A comparison of installed costs for recently completed European offshore wind projects and the projections used in the RE-ITI and RE-ETI estimates is shown in Figure 11-14. Projections for offshore wind capacity factors are included in Figure 11-15. Because no offshore wind projects have been installed in the United States, there is significant uncertainty about the cost of the initial offshore projects. RE-ITI estimated capital costs start at $3,640/kW and decline about 18% to $2,990/kW in 2030. This capital cost starting point is generally in line with offshore wind project costs completed in 2008 and 2009.[144]

[144] Capital costs reported here are based on industry data reported by Musial and Ram (2010), but are adjusted for interest accrued during construction and transmission interconnection costs. The additional costs associated with

RE-ITI and RE-ETI projected costs in 2030 and 2050 are approximately 50% higher than land-based wind energy costs. This long-term estimate is based on the observed cost difference when offshore projects were initially installed in Europe (DOE 2008). RE-ETI estimated an overall capital cost decline of roughly 26% between 2010 and 2035. Other projections estimated overall cost reductions on the order of 10% to 45% (see Figure 11-14) and indicated reductions in capital cost for fixed-bottom offshore wind projects that occur sooner than what is assumed in the RE Futures scenarios. This reflects the greater potential, due to significantly less experience and learning, for capital cost reductions in offshore wind technology relative to onshore technology.

Beginning in 2010, capacity factors for offshore wind projects range from 36% to 50% for the RE-ITI projection (see Figure 11-15) and are modestly higher in the RE-ETI projection (see Figure 11-15). This range roughly corresponds with the range observed for existing European projects (Lemming et al. 2009).[145] Offshore capacity factors could increase over time based on improvements in technology as discussed above.

Similar to the onshore wind capital cost projections, the RE Futures offshore wind capital cost projections are relatively conservative compared with other literature. The conservative nature of these projections also reflects the expected onshore industry trend of minimizing cost of energy through increased performance rather than decreased capital costs. Nevertheless, the offshore installed cost assumptions were somewhat more aggressive than the RE Futures onshore cost projections. The more aggressive cost trajectory for offshore wind was justified by the relative immaturity of the offshore wind industry. As noted in Section 11.3.3.2, turbines designed exclusively for offshore application and installation—as well as development of an installation infrastructure and equipment, foundation technology, and a complete offshore supply chain—are believed to offer greater relative cost savings than is expected for onshore wind energy. Nevertheless, there is a large degree of uncertainty regarding the timing in which these offshore innovation opportunities will be realized. If innovations are slow to come to market, the near-term estimates for offshore wind capital cost and capacity factor might be optimistic. Explicit RE-ETI capital cost, O&M cost, and capacity factor estimates used in the modeling analysis for onshore and offshore wind technologies can be found in Appendix F.

interest during construction and interconnection are captured by the modeling tools applied in this analysis, but not as part of the model inputs.

[145] Again, these data reflect the overall range of capacity factors by resource class, not necessarily fleet-wide or average capacity factors.

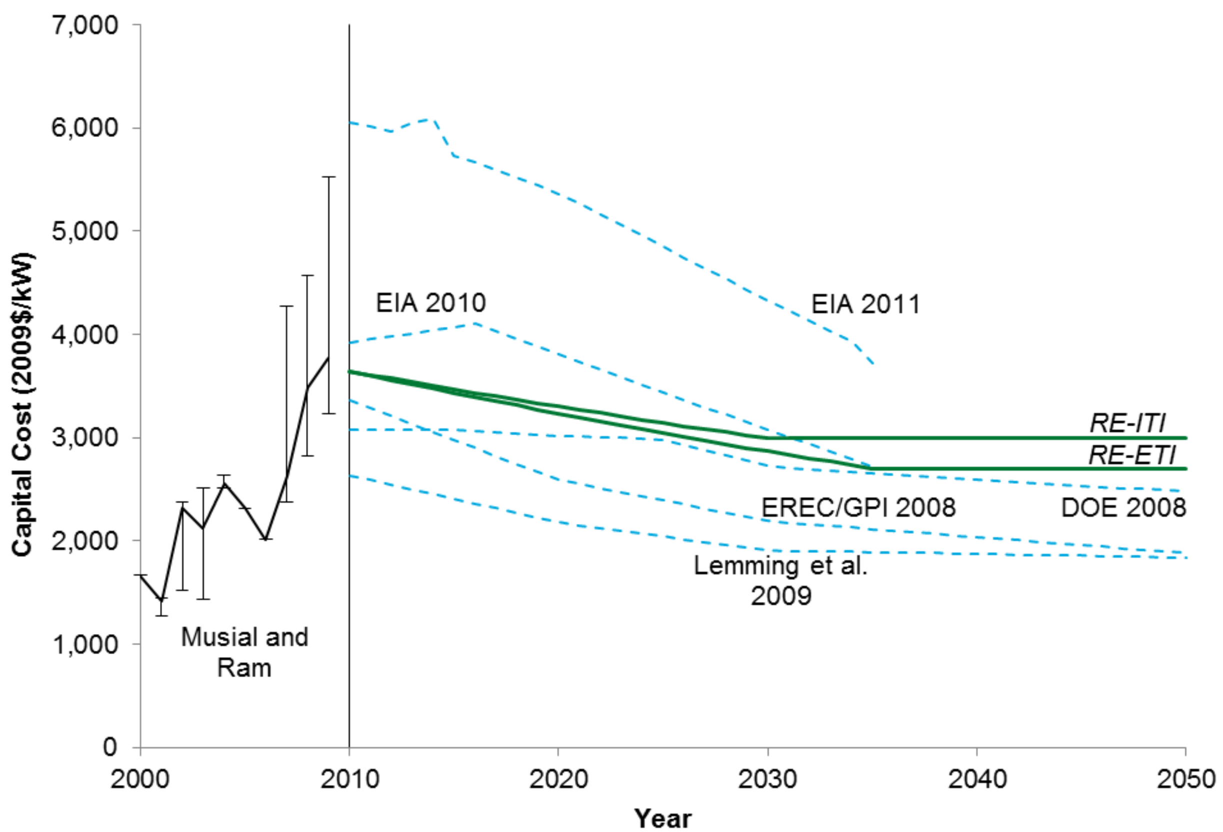

Figure 11-14. Historical and future capital costs for offshore wind energy, 2000–2050

Historical data represent capacity-weighted averages from Musial and Ram (2010). Historical data and projections have been adjusted to exclude construction-financing costs (approximately 5% of total capital cost).

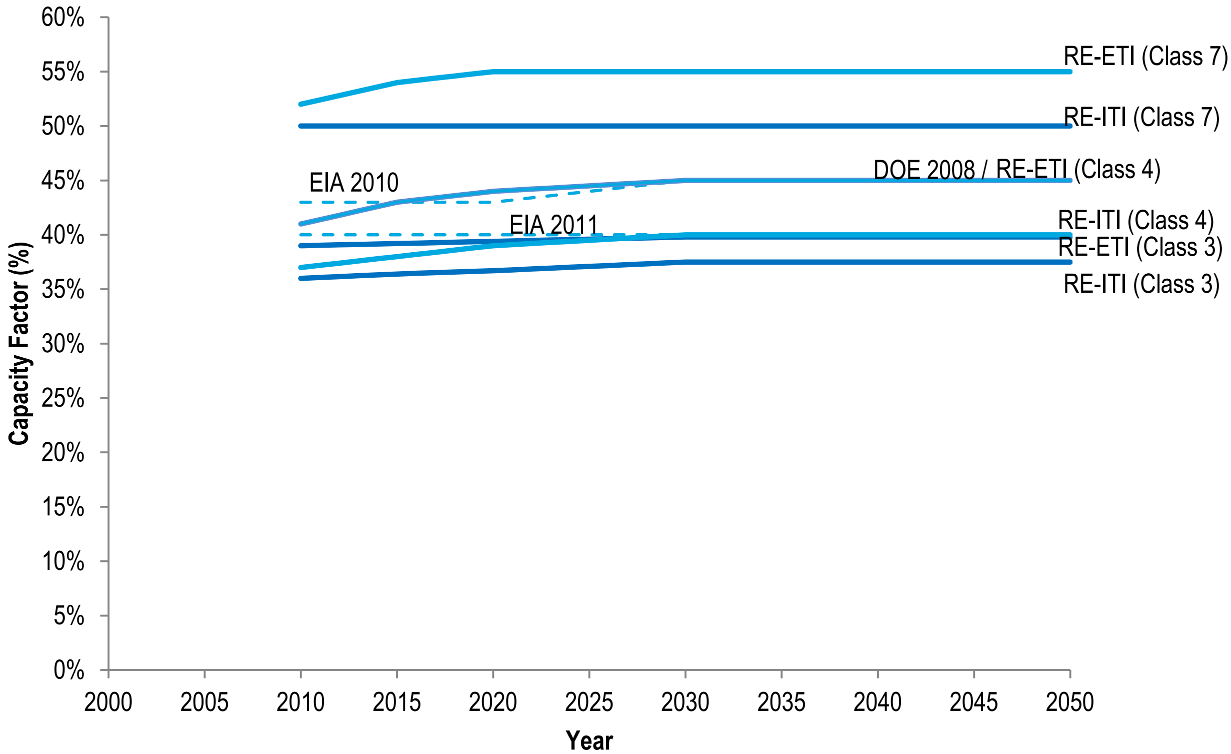

Figure 11-15. Future capacity factors for offshore wind energy, 2010–2050

Because there are no historical capacity factor data for U.S. installations, only projections are shown here. EIA (2010), EIA (2011), and DOE (2008) data represent Class 4 wind resource. RE-ETI offshore wind capacity factors are equivalent to DOE (2008) capacity factors.

11.5 Output Characteristics and Grid Service Possibilities

11.5.1 Electricity Output Characteristics

Large-scale, utility-connected wind plants consist of arrays of wind turbines that feed energy to a point-of-common connection on the grid, typically a substation dedicated to the wind plant. Individual utility-connected wind turbines generally have power ratings ranging from 1 MW to 5 MW but may exceed this range in the future.[146] A typical, single wind plant, consisting of hundreds of individual wind turbines, can have a power rating in the hundreds of megawatts. Individual wind turbines typically generate at 690 V, which is stepped up at a transformer at the base of the turbine to 34.5 kV. Underground cables then run from each individual turbine to a substation transformer that increases the voltage to levels required for grid transmission, often in the range of 115 kV to 345 kV. Modern communications and control systems enable direct monitoring and control of the power delivery status of wind plants and their individual turbines, within the independent system operator and utility service territories.

[146] Offshore turbines, in particular, are expected to grow well beyond this range that captures current typical machine sizes.

As a variable resource, there are a number of differences between wind and traditional energy sources. Three of the more important factors are variability, uncertainty, and capacity value.

Variability reflects the fact that wind generation is weather dependent, and the power delivery characteristics of an individual turbine vary depending on the magnitude of the wind speed. For lower operating wind speeds, the power delivered increases with the wind speed. At higher wind speeds, the power output is relatively constant (see Section Figure 11-4).

The variability of power generation from wind is averaged (i.e., smoothed) when it is collected over larger areas. This begins within an individual wind plant composed of tens to hundreds of wind turbines. The smoothing effect strengthens as the area grows for wind plants across a region, across a balancing area, or even across an entire interconnection (Grubb 1991; McNerney and Richardson 1992; Ernst et al. 1999; Wan et al. 2003; Holttinen 2005; Wan 2005; Sorensen et al. 2007). Smoothing is the result of temporal and spatial variability of the wind resource within and among wind power plants so that the sum over a given geographical area is statistically more constant than at any single location.

Associated with variability is the uncertainty of the wind resource, or the ability to predict wind output over various timescales. As wind penetration has increased, utilities are increasingly using wind forecasts to better integrate wind and ensure system reliability. Current day-ahead wind forecasts typically have errors in the range of 10%–20% mean absolute error (Grant et al. 2009; Monteiro et al. 2009; Porter and Rogers 2010; Lew et al. 2011). Improving wind forecasts is a major focus of research and is expected to result in reduced costs to integrate variable output wind power.

Capacity value refers to the contribution of a power plant to reliably meet demand. As a result of variability and uncertainty of the wind resource, the capacity value (or capacity credit) of a wind power plant is substantially less than that of a conventional fossil or nuclear generator, making the primary value of wind more of an energy resource than a source of firm capacity. A number of assessments of the capacity value of wind have been performed, including effective load carrying capability methods, and time-based approximation methods done in current systems. In general, results of the contribution of a wind generator to meeting demand are typically between 10% and 30% of nameplate capacity. This body of literature has been summarized at various points by Keane et al. (2011), Milligan and Porter (2008), and Milligan and Porter (2005).

Integration studies to date have evaluated the ability of grids to reliably accommodate up to 30% of their energy from wind (GE Energy 2005; GE Energy 2006; Smith et al. 2007; Ela et al. 2009; Schuerger and Zavadil 2010; CRA 2010; GE Energy 2010). These studies have shown systems to be capable of reliably and economically incorporating wind energy, but often with changes to some current operating strategies. Changes in operations include balancing area cooperation, sub-hourly scheduling (Milligan et al. 2009; Milligan and Kirby 2008; Kirby et al. 2010); intelligent integration of wind forecasting (Grant et al. 2009; Monteiro et al. 2009; Porter and Rogers 2010; Lew et al. 2011); and increases in operating reserves (Doherty and O'Malley 2005; Ela et al. 2010; Ela et al. 2011; Matos and Bessa 2011). Additional information and discussion of operational issues can be found in Volume 4.

11.5.2 Technology Options for Power System Services

Modern wind turbines and wind power plants are capable of providing a wide range of active[147] and reactive[148] power control functions. These capabilities are important for maintaining power system reliability in an economic fashion at high levels of wind penetration, especially when conventional generation has been taken off line due to high wind plant output.[149]

Grid services provided by modern wind turbines include:

- *Low-voltage ride-through:* Low-voltage ride-through is the ability of the wind plant to stay online and deliver power through brief grid disturbances. This capability supports system voltage and minimizes short-duration voltage variations that might otherwise be experienced by loads and customers (FERC 2005; Vittal et al. 2009).[150]

- *Reactive power:* The power electronics subsystem of contemporary wind turbines are capable of providing reactive power at the individual turbine level to compensate for the inductive characteristics of most utility loads. This component of power can be dynamically adjusted on a fractional-second timescale to meet the changing needs of grid loads. This turbine-level control is widely available in modern turbines. Reactive power compensation can also be provided at the substation with existing well-known Flexible Alternating Current Transmission System (i.e., FACTS) technology.

- *Operating reserves:* Wind turbines have the ability to vary output below the maximum available output. This allows turbines to provide a variety of reserves services including inertial control, primary frequency response (Keung et al. 2009; Miller et al. 2010; Erlich and Wilch 2010), up and down regulation (Rodriguez-Amenedo et al. 2002), and contingency reserves. Some of these services can only be provided if the wind plant operates below the maximum available output, which carries an economic penalty with it; however, this is an economic decision to be made on a case-by-case basis (Kirby et al. 2010; Liang et al. 2011).[151]

The full range of capability available from current technology enables a wind plant to be a strong contributor to maintaining grid voltage and frequency, with the purpose of supporting system reliability. Studies have shown that the fast control available from a wind plant can even improve system behavior beyond that available from a traditional fossil energy plant with conventional

[147] The range of real power output control includes the ability to accept an operating set point, up-ramp rate control, and the ability to operate at a fixed level below the available output (delta power control).
[148] The range of reactive power control includes fixed or variable power factor control, and static or dynamic voltage control, even at zero real power output.
[149] Supporting analysis from ReEDS and GridView assumed that operations and planning occur at the level of the regional transmission organization or independent system operator, allowing geographic diversity of wind plants to facilitate integration of wind energy into the grid.
[150] Ancillary services such as reactive power, low-voltage ride-through, and deployment of sub-hourly ancillary services were not modeled in the supporting ReEDS or GridView analyses.
[151] Of course, there is an economic penalty for conventional power plants to provide grid services as well. Most power systems will co-optimize energy and ancillary services to use all available resources in the most efficient manner.

synchronous generators (Miller, Clark, and Shao 2011; Miller, Shao, and Venkataraman 2011). In the future, the ability of a wind plant to provide real-time information on plant status, output, and meteorological conditions will allow updated wind plant output forecasts to be made, and system simulations to be performed. In turn, this will enable wind plants to become a completely integrated part of utility system operations.

As wind plants are increasingly integrated into regional and national power generation and delivery systems, there is also expected to be an enhanced ability to monitor, coordinate, and control their online-offline and power delivery status. In many cases, these capabilities will be within the control of the independent system operator or a regional utility system. These capabilities become increasingly important and useful on a routine operational basis as wind penetration levels approach the high levels considered in this study over large regions.

11.6 Deployment in RE Futures Scenarios

Wind energy technologies play a significant role in all RE Futures scenarios described in Volume 1. Table 11-3 and Figure 11-16 show the variation in 2050 installed onshore and offshore wind capacity between the six (low-demand) core 80% RE scenarios and the high-demand 80% RE scenario. In addition, Table 11-3 shows the wind contribution to the total 2050 generated electricity between these scenarios. Wind technologies are deployed to significant levels for all 80% RE scenarios presented, with the 2050 installed wind capacity ranging from 386 GW to 603 GW, compared with the nearly 47 GW installed in the United States by the end of 2011. The wind contribution to total generated electricity in 2050 ranged from approximately 32% to 43%, of which offshore wind contributed 5.6% to 16.1%. Among the low-demand 80% renewable electricity scenarios, wind deployment was greatest when no cost or performance improvements were assumed (80% RE-NTI scenario) for any renewable technology. This is a consequence of wind being a relatively mature renewable energy technology. Wind deployment was also high in the constrained resources scenario, which demonstrates the large available wind resource described in Section 11.2 compared with other, more resource-constrained renewable technologies (e.g., biomass, geothermal). Wind deployment was lowest in the 80% RE-ETI scenario, where assumed advances in cost, technology, or increased efficiency enable other renewable energy technologies (particularly solar energy) to obtain greater proportional cost-of-energy improvements. In the constrained flexibility scenario, wind witnessed somewhat modest deployment levels as a direct result of the more limited ability of the system to manage wind (and PV) variability and uncertainty by design in that scenario.

Offshore wind realized the greatest installed capacity in the constrained transmission scenario, where 185 GW of offshore wind was deployed by 2050. Offshore wind resources were strongly used in this scenario, primarily due to their proximity to load centers on the East Coast, thereby mitigating new transmission requirements. In contrast, land-based wind capacity is lower in this scenario compared to all other 80% renewable electricity scenarios present in Table 11-3, as many high-quality, land-based resources are located remotely from load centers.

Table 11-3. Deployment of Wind Energy in 2050 Under 80% RE Futures Scenarios[a,b]

	Onshore		Offshore		
Scenario	**Capacity (GW)**	**Generation (%)**	**Capacity (GW)**	**Generation (%)**	**Total Wind Generation (%)**
High-Demand 80% RE	463	26.6%	141	9.9%	36.6%
Current RE Costs	441	32.8%	115	10.6%	43.4%
Constrained Resources	395	29.4%	103	9.3%	38.7%
Constrained Transmission	280	20.2%	185	16.1%	36.2%
80% RE-ITI	349	26.5%	112	10.5%	37.0%
Constrained Flexibility	322	24.2%	100	9.3%	33.5%
80% RE-ETI	330	26.7%	56	5.6%	32.3%

[a] See Chapter 1 (Volume 1) for a detailed description of each RE Futures scenario.
[b] The capacity totals represent the cumulative installed capacity for each scenario, including currently existing wind capacity.

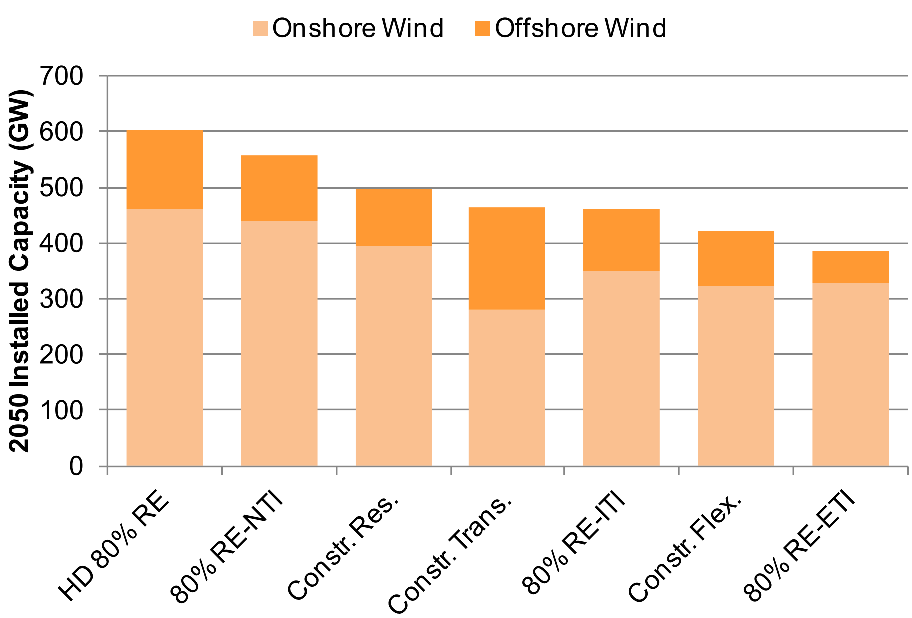

Figure 11-16. Deployment of wind technologies in 80% RE scenarios

Among the 80% RE scenarios, the high-demand 80% RE scenario realized the highest level of total (onshore and offshore) wind capacity deployment. For the high-demand 80% RE scenario, wind contributed roughly 37% to the total generation mix in 2050 (with nearly 10% originating from offshore resources). This scenario included more than 600 GW of wind capacity, approximately 140 GW of which came from fixed-bottom offshore wind. Figure 11-17 shows the cumulative installed wind capacity and a combination of the annual "greenfield" capacity additions with the replacement of older vintage capacity over time for the high-demand 80% RE scenario.[152] In the first half of the study period, annual onshore wind capacity installations ranged from approximately 10 GW to 20 GW with average annual investments of approximately $33 billion/yr–$48 billion/yr. During this period, annual installments of offshore wind capacity grew, increasingly displacing onshore capacity. Wind capacity growth continued through the latter half of the study period, peaking at approximately 35 GW/yr, and with average annual installations exceeding 30 GW during the last decade. Growth in cumulative installed capacity was generally consistent throughout the study period (2010–2050), reaching slightly more than 300 GW by 2030, and exceeding 600 GW by 2050.

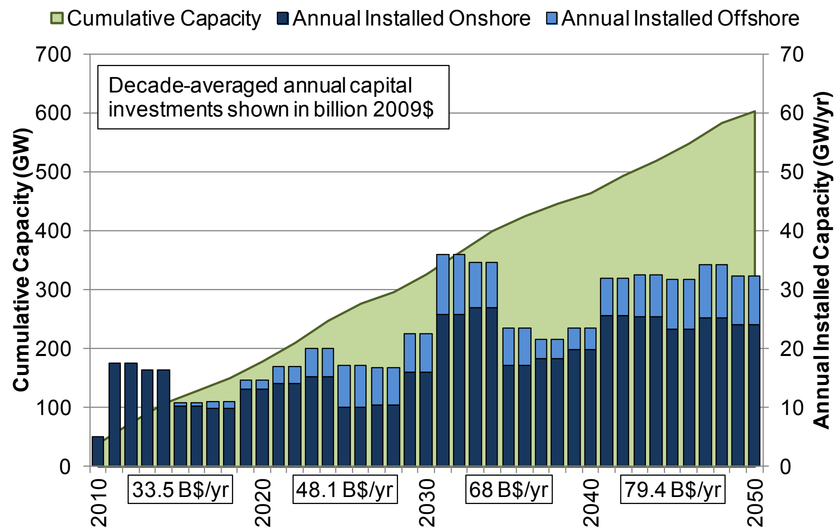

Figure 11-17. Deployment of wind energy in high-demand 80% RE scenario

Annual installations include new "greenfield" additions and replacement of existing equipment.

Substantial wind resources exist in nearly every U.S. state. In all RE Futures scenarios, large markets were assumed that were characterized by the easy transfer of electricity (i.e., no wheeling charges) and reserve-sharing over large areas (see Volume 4 for additional discussion of grid operations and integration related issues). Wind capacity installations were selected by ReEDS based on a number of criteria, including the estimated energy production from a given site, the time profile of the energy production, the cost of the technology, the proximity of a site to existing transmission lines and population centers, the correlation of variable wind output at a given site with other sites selected in previous simulation years, and the planning and operating reserve requirements in each reserve-sharing group (Short et al. 2011). The result of this complicated combination of criteria was that ReEDS selected a cost-optimized geographic distribution of wind resources. Figure 11-18 shows the onshore and offshore wind capacity installed for the high-demand 80% RE scenario. Onshore wind capacity installations occurred in nearly every state, although the installations were concentrated in the middle part of the country,

[152] Wind power plants have an assumed physical lifetime of 20 years in the ReEDS model; they are re-installed automatically with the capital cost and performance characteristics of the re-installation year. Grid interconnection equipment is assumed to remain operating; therefore, costs associated with grid interconnection are excluded for the re-installation.

while offshore wind capacity installations were primarily concentrated in the Mid-Atlantic with additional capacity in the Great Lakes, North Atlantic, California, Texas, and Florida.

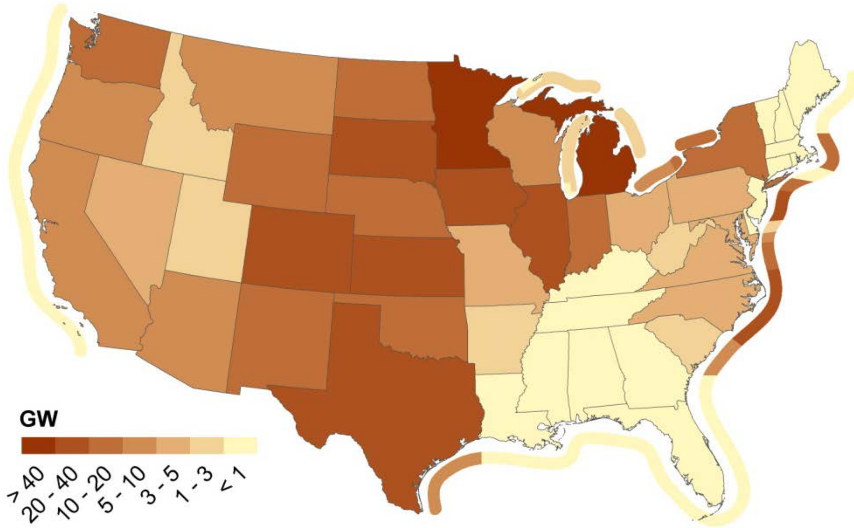

Figure 11-18. Regional deployment of onshore and offshore wind in the high-demand 80% RE scenario

Figures 11-17 and 11-18 show deployment results for one of many model scenarios, none of which was postulated to be more likely than any other. In addition, as a system-wide economic optimization model, ReEDS cannot capture all of the non-economic and, particularly, regional considerations for future technology deployment. Furthermore, the input data used in the modeling were also subject to large uncertainties. As such, care should be taken in interpreting model results, including the temporal deployment projections and regional distribution results; there are uncertainties in the modeling analysis.

11.7 Large-Scale Production and Deployment Issues

While wind power emits no air pollutants and requires no water, deployment of wind energy is expected to result in a number of environmental and social impacts—particularly with respect to land use including ecological and landscape impacts. From a manufacturing perspective, raw materials are not expected to become a limiting factor with continued wind energy deployment, although a rapidly growing global wind industry could result in various short-term supply chain bottlenecks.

11.7.1 Environmental and Social Impacts of Large-Scale Deployment

Deployment of wind energy, averaging roughly 10 GW/yr[153] to 30 GW/yr (depending on the scenario) over the next four decades (see Figure 11-17), is expected to result in a number of notable environmental and social impacts. For example, wind energy emits no GHG emissions or other air pollutants during power production. In addition, wind energy produces only small amounts of waste (e.g., consumed lubricants), requires very small amounts of water for periodic

[153] Approximately 10 GW was installed in 2009.

blade cleaning, and requires no mining for fuel. However, the manufacture and production of wind turbine equipment requires mining and does result in GHG and other emissions; the integration of wind into the grid can also modestly increase emissions from conventional equipment. Together, these partially offset the benefit of wind power generation having no emissions.

This level of deployment would also impact large land areas, with associated ecological and social impacts, including impacts on habitats. As public awareness of wind energy development has increased, more local, state, and federal agencies have begun developing siting regulations and guidelines to address some of the perceived negative impacts of wind energy.[154] In some areas, this has increased efficiency, but in others, it has added additional steps and time requirements to the development process. Wildlife permitting, for example, may take two years and can require extensive coordination with the U.S. Fish and Wildlife Service. Developers face a growing range of issues that must be addressed in the environmental analysis as well as increased political and public pressures during the permit-approval process. In addition, developers must address a range of potential social impacts, including possible sound and visual impacts on households and communities, as well as safety concerns. It is essential that such environmental and social issues be addressed up front to the greatest extent possible.

Discussed here are some of the environmental and social issues relevant to widespread deployment of wind energy technologies as envisioned in the RE Futures scenarios, current experience in addressing them, and approaches for mitigating and minimizing these impacts if large-scale deployment occurs.

11.7.1.1 Life Cycle Greenhouse Gas Emissions

Estimates of life cycle GHG emissions for wind energy consider all stages in the life of the electricity generation facility, including the extraction of raw materials, transportation and manufacturing of raw materials into plant components, plant construction, O&M, dismantling, and disposal. The estimates do not include potential emissions impacts resulting from changes in grid systems operations or changes in the overall mix of system-wide generation. For the analysis of life cycle GHG emissions, it was assumed that all wind energy would be generated by utility-scale turbines. Consistent with the technology assumptions in RE Futures modeling, GHG emissions for all offshore wind installations were based on shallow offshore wind. Given these assumptions, the estimates used in RE Futures are:

- Onshore wind: 12.0 g CO_2e/kWh
- Offshore wind: 12.2 g CO_2e/kWh

Appendix C (Volume 1) further describes the process by which these estimates were developed and how total GHG emissions for RE Futures scenarios were estimated. Life-cycle GHG emissions for other technologies are summarized in Volume 1 and reported in detail in Appendix C.

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[154] Examples of wildlife regulations pertaining to wind plants at the federal level include the Endangered Species Act, Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act.

11.7.1.2 Air Emissions—Power System Emissions Impacts

Assessing the full emissions impact of wind energy requires consideration of how wind energy affects and interacts with the broader power production system. In the short-term, it is generally held that wind energy offsets non-baseload generators or generators operating at the margin. Often it has been assumed that the emissions savings are equivalent to the emissions profile of the system's non-baseload generators. However, this simplified approach does not take into account the impacts to system operations associated with variable output wind energy, including an increase in balancing reserves or reduced loading on conventional generators. An increase in balancing reserves coupled with partial loading of conventional generators has been argued to reduce overall system efficiency resulting in an emissions (GHG and otherwise) penalty to the system when wind is introduced.[155] After conducting an in-depth literature review, Gross et al. (2006) conclude that the impacts on system efficiency, and therefore emissions, are limited to only a few percentage points. In fact, Gross et al. (2006) determined that for wind energy penetrations up to 20%, the effective system-wide emissions reduction is 93% to 100% of that predicted by assuming simple direct displacement of fossil generation. As such, at moderate penetration levels, efficiency losses throughout the power system have only a marginal impact on broader emissions savings from wind energy (Gross et al. 2006). Since this work, a number of authors have found similar results including Pehnt et al. (2008), Gross and Heptonstall (2008), Fripp (2011) and, in a somewhat narrower analysis, Göransson and Johnsson (2009). Further discussion on the impacts of variable generation on electric system operations is provided in Volume 4.

11.7.1.3 Land Use

Total land use for wind plants is extensive due to turbine spacing requirements. The spacing can be described in terms of the rotor diameter D. Array configurations depend on the site terrain and wind directional characteristics. When the winds are predominantly out of a single direction, turbines are laid out along rows with turbines typically spaced 3–5 rotor diameters apart. Between rows, there are typically 10–12 rotor diameters. Terrain with ridgelines favors rows of turbines placed along the ridgelines. In flat terrain where there is no predominant wind direction, turbine spacing is often more uniform. Multiple landowners and varied usage (e.g., fields, roads) can also play a major role in determining the layout, sometimes resulting in an irregular pattern. For turbines rated at 2–3 MW (80-m to 95-m rotor diameter), a single turbine can require 70–130 acres.[156] However, only approximately 3%–5% of the total land area occupied by a wind plant is uniquely dedicated to the wind turbines and their supporting infrastructure (e.g., access roads, O&M buildings). Typically, the balance of acreage can be used for multiple purposes, such as livestock and agriculture. At a wind plant with a land-use power density of 5 MW/km^2, the land-based portion of the RE Futures scenarios would be 48,000 km^2 to 85,000 km^2. [157] Land

[155] Because emissions are a function of fuel consumption and changes in efficiency directly drive fuel consumption, a modest reduction in system efficiency is equivalent to a modest increase in system wide emissions.

[156] The ultimate layout of a wind project is highly dependent on a variety of site-specific characteristics such as terrain, property lines and lease agreements with landowners, setback requirements, and other landscape features including roads. Local siting constraints—rather than spacing requirements necessary to minimize power loss among rows of wind turbines—often determine the site-specific minimum land area requirements.

[157] An approximate industry rule of thumb is 5 MW/km^2. Analysis by Denholm et al. (2009) found actual project densities ranging from 1.0 MW/km^2 to 11.2 MW/km^2 with an overall average of 3.0 ± 1.7 MW/km^2.

displaced from traditional uses would range from 2,400 km^2 to 4,200 km^2. In comparison, the total U.S. land area identified as agricultural land is 4.8 million km^2 (Lubowski et al. 2006); the overall footprint of wind plants would then be 1.0%–1.8% of U.S. agricultural land, and the area within that actually dedicated to the turbines and infrastructure would be 0.05%–0.09% of U.S. agricultural land.

11.7.1.4 Water Use and Impacts

Wind turbines require no cooling water, in contrast to conventional thermal power plants, and only use water for periodic blade cleaning. Thus, their direct water requirement is effectively zero. This is a significant advantage over thermal power plants, which account for about 3% of U.S. water consumption.

11.7.1.5 Ecological Impacts

Ecological concerns associated with wind development remain focused on impacts to avian and bat populations. Of primary concern is direct mortality of avian and bat species from collisions. However, indirect impacts, such as avoidance of the wind plant area due to habitat fragmentation and degradation, are also of concern. Additional ecological considerations include offshore impacts on marine life and fisheries, impacts to the local climate and weather patterns, and impacts from associated infrastructure (e.g., roads, transmission lines, substations).

Several studies evaluating wildlife impacts from wind plants have been initiated in the United States over the past several years.[158] Agencies and organizations involved in collaborative work have included the U.S. Fish and Wildlife Service Wind Turbine Advisory Committee, the Bats and Wind Energy Cooperative, and the American Wind Wildlife Institute. Participating Federal laboratories and industry have included NREL, the American Wind Energy Association (AWEA), and the National Wind Coordinating Collaborative.[159] Past research has greatly informed knowledge of impacts to avian and other wildlife populations and has resulted in changes to tower designs and the associated electrical infrastructure as well as siting practices and criteria.

A literature survey conducted by the U.S. National Research Council (NRC 2007) estimated bird fatalities to range from 0.95 fatalities/MW/yr to 11.67 fatalities/MW/yr. If data collected more recently from more than 40 site studies compiled by Western EcoSystems Technology, Inc. are included, avian fatalities range from less than 1 fatality/MW/yr to 14 fatalities/MW/yr (NWCC 2010).

With respect to raptors, a review of more than 25 site studies indicated that raptor fatalities range from nearly 0 to 0.9 fatalities/MW/yr (NWCC 2010). For bats, a review of more than 40 studies indicated bat fatalities ranging from approximately 0 to 40 fatalities/MW/yr (NWCC 2010).

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[158] NREL's Wind Wildlife Impacts Literature Database contains a large collection of studies evaluating the interactions and impacts of wind energy on wildlife. This database of studies is available at http://www.nrel.gov/wind/wild.html.

[159] The National Wind Coordinating Collaborative is a consensus-based collaborative of stakeholders that includes representatives from industry, utilities, government, consumer, and regulatory bodies.

Impacts to avian populations have received the greatest level of attention from researchers over the past two decades. More recently, research on impacts to bat populations has been spurred by large fatality events at wind facilities in the eastern United States (Arnett et al. 2009). To date, bat fatalities are most prominent among migratory species and peak during midsummer through fall, when bats are expected to be undertaking southward migrations (Arnett et al. 2008). However, certain states such as Texas and California lack data, and continued monitoring of bat fatalities is needed to better understand fatality patterns (Arnett et al. 2008). Preliminary studies of operations-based mitigation strategies indicate potential opportunities to reduce bat fatalities, but require continued research (Arnett et al. 2009).

Avian habitat displacement and fragmentation are more recent ecological concerns. Specifically, the potential for avoidance by prairie chicken and sage grouse populations has the potential to be particularly problematic (Shaffer and Johnson 2008). Such issues are notable because these types of grassland and shrub-steppe grouse often range over large portions of open grassland and may avoid brooding or nesting in areas adjacent to wind energy infrastructure (NWCC 2010).

Less is known about the impacts of offshore wind energy on marine life and fisheries. As with onshore wind energy, impacts appear to be highly variable and site-specific (Michel et al. 2007). Current knowledge indicates that continued research is merited, but it is not expected that wildlife impacts from offshore wind energy will preclude the development of a robust offshore wind industry.

Concerns have also been raised regarding potential effects on local climate due to the removal of energy from the wind and the increased vertical mixing that occurs in the wake of a wind turbine. However, evidence is mixed on the extent of impacts to local climate (Christiansen and Hasager 2005, 2006; Frandsen et al. 2007; Keith et al. 2004; Kirk-Davidoff and Keith 2008; Wang and Prinn 2010).

11.7.1.6 Impacts to Human Activities and Well-Being

Siting turbines at the scale suggested by the RE Futures scenarios requires sensitivity to landscape and human dwellings (e.g., residences, workplaces) as well as careful consideration of aviation and military use, shipping and transportation corridors, and communications and radar systems.

The visual impacts of wind turbines have been a public concern since the 1980s (Pasqualetti and Butler 1987) and are often among the top concerns of residents whose communities are considering wind projects (Wolsink 2007; Wüstenhagen et al. 2007; Firestone and Kempton 2007). Visual impacts are expected to become more challenging as projects grow in size and are sited closer to populated areas. In some instances, the regulatory framework clearly identifies the process for determining potential visual impacts (e.g., the National Environmental Policy Act process for projects on land managed by a federal agency). However, local or state regulations addressing visual assessments often vary. In the future, coordinated, multi-stakeholder, and regional planning might reduce project opposition based on visual impacts. Nevertheless, this opposition has the potential to extend the approval time and cost associated with acquiring land use permits.

A variety of nuisance and safety concerns have also been raised. Shadow flicker, a phenomenon resulting from the motion of shadows cast by rotating wind turbines, is typically resolved through careful siting of wind turbines, curtailment under specific lighting conditions, or both. Safety concerns—including ice throws, fires, or turbine collapse—are addressed through a combination of stringent design standards, which ensure that these events are extremely rare, as well as siting strategies, which minimize the risk to individuals and property should such events occur.

Particularly challenging for the industry, however, are noise complaints from individuals living in the immediate vicinity of wind turbines. Generally, environmental noise guidelines protect the public from direct and immediate health impacts (e.g., hearing loss) (McCunney and Meyer 2007, pp. 1295–1138). However, individuals begin to be annoyed by wind turbine noise even at relatively low levels of 38 A-weighted decibels [dB(A)] to 45 dB(A) (Pedersen et al. 2009; Pedersen and Persson Waye 2007). Moreover, initial evidence suggests that noise from wind turbines is more annoying than noise from traditional environmental noise sources including railways, traffic, and aircraft.[160] Pedersen et al. (2009) found that even at relatively modest noise levels of 40 dB(A) to 50 dB(A), approximately 10% to 20% of their sample(s) were annoyed and 5% to 15% were highly annoyed.

A potential consequence of the perceived visual and nuisance impacts of wind turbines is a reduction in property values for homes and residences sited near wind turbines. It is widely understood that conventional power plants and transmission lines can result in a reduction in residential property values (Simons 2006); however, published research has generally found little or no evidence to substantiate widespread concerns of property value reductions due to wind turbine installations (Sims and Dent 2007; Sims et al. 2008; Hoen et al. 2009). The lack of evidence supporting these claims suggests that current siting and setback practices might be conservative enough to mitigate many of the most significant concerns of potential homebuyers.[161] Alternatively, property value losses might well occur, but not with enough frequency or magnitude to be identified using traditional statistical analysis tools. Continued research is expected to focus on property value impacts for homes located within 1 km of wind turbines and to focus on changes in property values over time.[162]

[160] Of course, there are many possible explanations for such a trend. In fact, the visibility of the turbine as well as perceptions of wind energy are correlated with annoyance. Moreover, as a new element in the landscape, wind energy has the potential to be the subject of greater attention and scrutiny initially, with the possibility for more broad-based acceptance and attenuation of annoyance, over time.

[161] This line of thought is consistent with the property value impacts associated with transmission lines, which are found to exist within a short distance of transmission lines, but also to fade at distances on the order of 100 m (Des Rosiers 2002).

[162] Wolsink (2007) found that perceptions of wind turbines changed notably over time for those living in communities where wind projects were built. Initial widespread support of wind energy dropped to its lowest level after a project had been announced and was in planning. Support for wind energy often returns after the plant becomes operational. This suggests that if property value impacts do exist, they are likely to be most dramatic during the planning, development, and construction stage of the project, and they may fade over time as perceived risks become more closely aligned with actual risks.

Local communities are also frequently concerned about impacts from associated infrastructure, including roads and transmission infrastructure. However, impacts from wind energy infrastructure are generally in line with the impacts of other forms of commercial construction or industrial development.

Wind turbines can also be sources of electromagnetic interference (Krug and Lewke 2009). This is of particular concern with respect to civilian and military radar and other communications technology. Wind turbines can interfere with signal reception and detection as a result of blockage or reflection of electromagnetic signals (Krug and Lewke 2009). Various Federal agencies including the Federal Aviation Administration, the U.S. Department of Defense, and the U.S. Department of Homeland Security sometimes have radar-related interests that conflict with new wind turbine projects (AWEA 2008). Failure to obtain the appropriate radar-related approvals is estimated to have delayed or halted multiple gigawatts of wind power development (Brenner et al. 2008).

11.7.1.7 Mitigation and Minimization

Addressing and mitigating environmental and social concerns in regard to wind energy projects is fundamental to the successful deployment of wind energy. With respect to both ecological and social concerns, the industry has developed an array of mitigation techniques. The first line of mitigation often emphasizes responsible development. Responsible development entails setting aside specific areas or exclusions that are off limits to wind energy development, among other factors. The RE Futures analysis establishes an array of exclusion areas around environmentally sensitive or otherwise designated protected areas. However, beyond widespread exclusion areas, technological solutions, coupled with responsible siting practices, are expected to assist in minimizing negative environmental impacts.

Mitigation of avian, bat, and other wildlife impacts has been primarily focused on identification and reduction of risk before beginning construction of a wind energy project. Current industry practice is to conduct one year of pre-construction monitoring. Typically, an area is mapped at an early stage of wind plant development to assess the types of species present and the range of potential impacts to habitat that could result from project development. Researchers also continue to seek to better understand wildlife impact mitigation strategies for operating wind plants. Recent research suggests that curtailing wind plant operations during periods of low wind speed could be a cost-effective means of reducing bat fatalities. Initial testing indicates bat fatalities can be reduced by 53%–80% (Arnett et al. 2009, Baerwald et al. 2009) with alternative low wind speed operational practices. Continued research is expected to provide new insights into animal-turbine awareness and behavior, potentially allowing for greater pre-construction risk reduction as well as the development of effective deterrents. As insights become available, other mitigation techniques and practices are expected to be implemented. Compensatory mitigation for impacts to habitat might become more common as wind energy development expands. However, increased site monitoring and implementation of mitigation strategies have the potential to extend development timelines and increase operating costs.

Mitigating the impacts of wind turbine sound on project neighbors is also a priority for technology researchers. Through technology advancements, the sound levels of wind turbines have been reduced. Blade surface imperfections have been minimized through improved handling and manufacturing, while mechanical noise from the gearbox, generator, cooling fans, or pumps has been addressed by installing sound-absorbent materials within the nacelle or designing nacelles to better isolate noise (Bastasch et al. 2006). However, aerodynamic sound produced by airflow over wind turbine blades persists as a source of annoyance among project neighbors. In this regard, researchers continue to search for a solution (Lutz et al. 2007). Future innovations might lead to continued incremental reductions in noise emissions, but because there are design tradeoffs associated with sound reduction strategies, policy and regulatory solutions might also assist in mitigating noise and related nuisance concerns.

Careful siting of wind turbines can generally reduce the impacts of electromagnetic interference (Hohmeyer et al. 2005). Radar, on the other hand, continues to present challenges. Dated radar infrastructure can have difficulty distinguishing wind turbines from aircraft or weather, therefore presenting significant security and safety concerns with respect to air navigation. Upgrading to state-of-the-art equipment as well as the application of software solutions offers substantial mitigation opportunities (Brenner et al. 2008). The development and deployment of “stealth” blades (i.e., blades that are not detected by radar) has also been proposed as a potential technological solution (Matthews et al. 2007). In addition, Brenner et al. (2008) suggest a handful of regulatory solutions, such as requiring all aircraft operating in airspace around wind farms to use transponders. Overall, a variety of existing solutions can help mitigate radar interference; however, coordinating an effective set of solutions amongst an array of federal agencies and stakeholders is likely to require some time.

Offshore wind installations offer one solution to constrained land availability. For the United States, offshore wind also offers closer proximity to East Coast load centers, thus reducing the need for new high-voltage transmission from the Midwest and Great Plains to serve coastal lands as well as reducing land use demands. However, as with sound-related complaints, policies governing land use are critical to responsible deployment of wind energy. Excluding environmentally sensitive areas or areas with strong cultural value is likely to aid in mitigating siting challenges and maintaining public support for wind energy.

11.7.2 Manufacturing and Deployment Challenges

The RE Futures scenarios result in wind power deployments on the order of hundreds of gigawatts through 2050. On average, depending on the period and specific scenario considered, deployments of approximately 7–12 GW/yr are anticipated. This can be compared to the 10 GW of wind installed in the United States in 2009. A rapidly growing global industry can result in various short-term supply chain bottlenecks. In recent years, supply chain bottlenecks occurred in the manufacture of specific wind turbine components, including large-diameter bearings, large castings, and large gears (Blanco 2009). The industry responded rapidly by developing significant new manufacturing facilities and suppliers for these and other components (Wiser and Bolinger 2011). New production investment has largely reduced, or in some cases eliminated, the supply chain constraints. However, with inconsistent growth in many markets around the world, such short-term supply shortages, could arise again as demand often changes more quickly than new production facilities are brought online.

There will also be a continuing, critical need for trained engineering, maintenance, and management professionals to manage and maintain a rapidly growing fleet of new power generation assets. Challenges include attracting new industry entrants, finding new manufacturing sources of major subsystems, and expanding workforce training programs.

The offshore deployment defined by the RE Futures scenarios will require a significant investment in ports and purpose-built offshore wind installation-servicing vessels. In addition, the extremely large offshore turbines and foundation structures are highly likely to be manufactured in dockside factories because the completed systems are likely to grow too large to transport over road or rail. This necessitates the development or redevelopment of major manufacturing facilities in port areas. See Musial and Ram (2010) for a complete description of the required infrastructure for large-scale offshore wind deployment.

11.7.2.1 Manufacturing Materials Requirements

The principal materials used for the manufacture of wind turbines include steel, copper, glass and carbon fibers, and polymer resins. With the possible exception of glass and carbon fibers, which have been identified as potential materials impediments, raw materials are not expected to become a limiting factor with continued wind energy deployment.

Although not a principal material, an increasing number of modern wind turbines are now using permanent magnet materials to create the magnetic field of the generator. The magnet material most often used is the rare-earth compound neodymium-iron-boron, commonly sourced from China. It is also frequently used in many other industrial applications. Significant new demand from an array of industries, coupled with heavy dependence on China as the primary global supplier of rare earth materials (DOE 2010), has given rise to concerns about the potential quantity and availability of the rare-earth compounds used in permanent magnets (Laxson et al. 2006; DOE 2010). Long-term uncertainty regarding availability of rare-earth compounds has spurred research to develop permanent magnet materials that require reduced amounts of rare-earth compounds, to develop domestic sources of the permanent magnet materials, and to explore other approaches such as the use of high-temperature superconductor systems for generators.[163]

As turbine rotors continue to grow in size, the weight of the blades becomes the most important factor determining the required structural strength. This is particularly important for the larger offshore turbines being designed or considered. Lighter materials, such as carbon fiber (instead of glass fiber), become essential enablers for continued growth in turbine rotor size. However, carbon fiber remains significantly more expensive than glass fiber. Although continued growth in the volume of carbon fiber manufacturing worldwide has led to some cost reductions, the need remains to further lower those costs by developing innovative manufacturing processes.

[163] Concern over global availability of rare-earth materials is not limited to the wind industry, and this topic has received increasing attention from the news media and other sources (see, for example Bradsher 2011 and Hsu 2011). An array of strategies are being pursued by governments and businesses around the world to address potential rare-earth material supply constraints.

11.7.2.2 Deployment and Investment Challenges

As turbines increase in rated power, the physical size of the blades, nacelle, and other components creates difficulties when transporting components from manufacturing plants to installation sites. For onshore installations, this might lead to changed approaches to construction, such as on-site fabrication of blades and towers along with on-site final assembly of the nacelle and its internal drivetrain components. Logistical challenges such as this have contributed to the attractiveness of offshore installations, where the assembly can take place at coastal facilities with subsequent barge transport to the offshore installation site.

Attracting the required investment capital hinges on a favorable balance of installed capital cost, reliability, energy prices, and return on investment. Over the past five or more years, the rapid growth of wind energy installations worldwide has demonstrated that private sector investment capital is available for the financing of wind installations under the requisite policy frameworks and market conditions.

11.7.2.3 Human Resource Requirements

There is no standardized method of estimating current or future personnel requirements for renewable energy technologies; however, wind energy jobs include project development, manufacturing, installation, maintenance, and offshore-related work, such as port and vessel operations for offshore wind energy. The rapid growth exhibited by the wind industry worldwide has revealed the critical need for personnel at all levels, ranging from maintenance technicians to designers of next-generation turbines. Because of the capital-intensive nature of the wind industry, a significant portion of the job creation potential lies in the manufacturing sector (Lantz and Tegen 2008). Long-term market demand, similar to that shown in the RE Futures scenarios, coupled with relatively high transportation costs and increasing logistics challenges as the equipment grows in size, is expected to continue to incentivize domestic production of wind turbine equipment. Creating a vibrant wind industry manufacturing sector not only has the potential to generate manufacturing jobs, it could also provide some degree of insulation from price fluctuations that result from changes in currency valuation, as has occurred in the recent past.

To date, workforce needs across the industry are increasingly addressed through educational programs offered at two-year technical colleges, vocational training programs, and universities. However, compared to the significant academic wind research investment being demonstrated in Europe, low national investment has contributed to a continuing shortage of graduate-level opportunities to train researchers at U.S. universities. Although international turbine suppliers are opening R&D offices in the United States, their role will be minor compared with European contributions if highly trained researchers are not developed at U.S. universities. Workforce development remains important if the industry is to reach the wind power penetration levels suggested in the RE Futures scenarios.

11.8 Barriers to High Penetration and Representative Responses

This section highlights many of the more significant market and technology challenges to high penetration of wind energy technologies. A comprehensive assessment of the challenges of generating 20% of U.S. electricity from wind energy by 2030 was developed in *20% Wind Energy by 2030* (DOE 2008). Table 11-4 summarizes the barriers and identifies opportunities for potential improvements in wind energy technologies that would facilitate high penetration deployment of wind energy systems. This section also discusses how resolving these barriers could affect future wind energy penetration levels.

From a technology perspective, high penetration of wind energy is in many respects already feasible. However, a great deal of current R&D effort is focused on the long-term incremental objectives of increased energy capture and reduced technology costs in order to increase the competitive position of wind power in electricity markets around the world. Additionally, increased efficiency with respect to grid operations and long-distance power transfers—along with the ability to appropriately value wind energy integration costs and ancillary services benefits—could provide immediate opportunities for wind development. A more sophisticated understanding of wind turbine and project impacts on wildlife and humans would also help define clear permitting processes and expectations, including timelines for regulatory responses. Over the mid-term (i.e., 2016–2030), better concurrence of component requirements with actual site demands, improved quality control, enhanced O&M practices, and the increasing use of advanced power electronic control and direct-drive generators might further increase technological reliability. Innovative rotor and tall-tower technologies may allow for development of lower wind resource class sites. Offshore equipment (turbines and installation vessels) will likely become increasingly specialized, potentially resulting in more robust projects and greater offshore efficiencies both during installation and operations. Coupling these technology advancements with an improved interstate transmission system that is more capable of moving wind energy to load centers would also greatly facilitate high penetrations of wind energy. Mid-term evaluation of siting policy could help determine whether existing policies are effectively preserving local interests without placing undue burdens on wind projects; such evaluations could also assist in identifying appropriate mitigation strategies where necessary. Over the long term, standardization of development and siting requirements for responsible wind development would help facilitate robust high-penetration deployment. The development of floating platform technology could open large resource areas to development.

Table 11-4. Research, Development, and Deployment Opportunities to Enable High Penetration of Wind Energy Technologies

R&D Area	Barrier	Representative Responses
Onshore turbines	Marginal competitiveness exists with conventional generation resources.	Develop and apply advanced technology solutions to increase reliability; reduce technology, logistics, and installation costs; and maximize energy capture
Offshore turbines	Offshore-specific design needs and challenges	Develop dedicated offshore equipment to minimize work at sea; increase ease of maintenance and accessibility from offshore vessels; maximize the value of large turbines and simplified at-sea transport
Offshore foundations and support structures	Current foundation structures add to costs and limit the depth of water for offshore installations.	Minimize foundation costs through standardization and design refinement. Commercializing floating platform technology opens up new regions for development
Wind resource assessment	A sophisticated understanding of both onshore and offshore wind resources and flow through plants is lacking. Limited wind forecasting capabilities inhibit grid operations and dispatch planning.	Develop a network of resource assessment facilities to better characterize the wind resource. Continue to develop and implement improved wind plant modeling and forecasting capabilities
Market and Regulatory	**Barrier**	**Representative Responses**
Market design and structure	Small operations areas increase the cost of integrating wind energy into the grid. Transporting wind energy to population centers requires simple transfers of power over long distances. Curtailment with low marginal costs could become a problem with high renewable electricity penetration.	Develop policy and market designs that allow smaller operating areas to function in a consolidated manner. Resolve limits on long-distance power transfers, including cost allocation for new transmission projects. Ensure grid market access to plants with operational characteristics of renewable electricity
Operational value	Wind energy may be penalized for its variable output nature and not recognized for its grid service capabilities; wind ancillary services are not monetized.	Methods for accurately valuing the additional cost as well as the value of grid services can resolve issues of wind energy valuation

Workforce development	Skilled labor is required to support a rapidly expanding industry.	Facilitate the development of worker training programs and encourage committed interest in the industry, including the establishment of a strong university R&D effort.
Environmental and Siting	**Barrier**	**Representative Responses**
Wildlife impacts	Impacts on protected or endangered species can inhibit deployment of wind energy. Extensive permitting requirements increase deployment costs.	Continued monitoring of wildlife impacts, development of impact mitigation strategies, and standardized permitting requirements can facilitate low-impact development. Increased study of impacts to habitat and resulting wildlife displacement can inform policy solutions to persistent industry challenges.
Siting policy	Host communities might resist new development. Inadequate or unclear zoning or land use policy increases developer risk.	Enhanced comprehension of local wind energy impacts can assist policymakers in weighing the tradeoffs of wind energy and in developing policy that protects local interests while facilitating deployment and local economic development.
Radar and communications	Wind turbine impacts on aviation, military radar systems, and communications infrastructure eliminate otherwise viable windy areas from potential development.	Development of technological solutions can mitigate radar challenges. Software solutions and system upgrades can mitigate some radar and communications interference.

Over the past three decades, the policy measures implemented by state and federal government agencies have successfully brought wind and other renewable energy sources into the mainstream as contributors to the current energy mix. The financial incentives associated with these policy measures had the desired effect of attracting the private sector capital needed for the significant investments required. Going forward, periodic reviews of these policy measures and incentives could evaluate their effectiveness in fostering RD&D and indicate when it might be appropriate to phase them out or to identify alternative, more effective approaches to serve these purposes.

In the near-term, market and regulatory barriers are generally based on market operations and the ability to appropriately value wind energy costs and benefits. Utilities often impose requirements for reactive power characteristics at the interconnection point. Many wind turbines now on the market have the ability to deliver reactive power correction at the turbine level, with or without the wind blowing. However, the economic value of this capability has not been determined, nor has the value of the independent system operator's direct control at the turbine level been assessed. As the wind power industry moves forward, the capabilities for load-following, delivery of reactive power, and other contributions of wind energy to the independent system operators, utility systems, and ratepayers should be identified, acknowledged, and quantified. Whether this might require rethinking power purchase agreements has not been explored. Alternatively, this could become a moot point in light of the current evolution of grid codes under way around the world, which might simply require the provision of these services as the price of admission onto the grid for all generators.

Additional near-term market challenges include the ability of utility control areas to function in a consolidated fashion, sharing reserves and wheeling power between or through balancing authority areas with limited or no barriers. Permitting and building out high-value transmission lines is also critical in the near-term. Over the long-term, price signals that take into account curtailment and the low marginal cost of producing wind energy could play an important role in attracting continued investment under high-penetration renewables scenarios.

11.9 Conclusions

Wind energy is one of the most mature sources of renewable power, with costs that can be competitive with conventional fossil energy plants. The United States has an abundant wind resource with broad geographic diversity. These factors, coupled with state and federal policy, have led to significant growth in the installed wind capacity in the United States since 2005. The diverse resource and relatively low cost of wind were key factors that resulted in wind playing a large role in all of the scenarios that were considered for RE Futures. Continuing global growth and the resulting technology advancements suggest that for a wide range of economic and policy environments, wind will continue to play a leading role in the supply of renewable power for many decades.

Although wind energy technology is sufficiently mature for commercial success over a range of conditions, opportunities exist for additional technology improvements that can lead to reduced costs. This is particularly true for offshore wind technology, where increased capital costs and an uncertain policy environment have so far prevented offshore development in the United States. For the large-scale installations of wind considered in RE Futures to continue along the 80% RE-ITI scenario, very little technological advancement is required. Many opportunities exist to drive the costs to the 80% RE-ETI scenario. However, large-scale deployment will be challenging in the areas of high-penetration grid operations and in maintaining environmental compatibility. Proactive solutions and robust mitigation strategies would assist in getting ahead of these issues to keep them from blocking wind and its potential for a high renewable electricity future.

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Chapter 12. Energy Storage Technologies

12.1 Introduction

Energy storage is one of several potentially important enabling technologies supporting large-scale deployment of renewable energy, particularly variable renewables such as solar photovoltaics (PV) and wind. Although energy storage does not produce energy—in fact, it is a net consumer due to efficiency losses—it does potentially allow greater use of variable renewables by shifting energy from periods of low demand to periods of high demand, which reduces curtailment and eases integration challenges. Energy storage can also provide a variety of high value services such as firm capacity and multiple ancillary services.

Energy storage is used in electric grids in the United States and worldwide. It is dominated by pumped-storage hydropower (PSH), with about 20 GW[164] deployed in the United States and more than 127 GW deployed worldwide (EIA 2008; Ingram 2010). In the United States, PSH was built largely in response to market conditions in the 1970s, including high oil and natural gas prices, regulatory restrictions on plants burning oil and gas, dependence on low-efficiency steam plants for peaking power, and anticipated "build-out" of a largely inflexible nuclear fleet (Denholm et al. 2010). In addition to PSH, a single, 110-MW compressed air energy storage (CAES) facility has been constructed in the United States (EPRI/DOE 2003). CAES is described in Section 12.3.2.3.

Deployment of storage in the United States over the past two decades has been limited by low natural gas prices, availability of high-efficiency and flexible gas turbines, and limited cost reductions in storage technologies. In addition, the regulatory treatment of storage, costly licensing and permitting, challenges with storage valuation, as well as utility risk aversion (including market uncertainty) have also limited storage development (EAC 2008). Figure 12-1 shows the installations of bulk energy storage in the United States.

Interest in energy storage technologies, which has reemerged over the past decade, has been motivated by at least five factors:

- Advances in storage technologies
- Volatility of fossil fuel prices
- The development of deregulated energy markets, including markets for high-value ancillary services[165]
- Challenges to siting new transmission and distribution facilities
- The perceived need and opportunities for storage with variable renewable generators and their role to reduce carbon dioxide emissions.

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[164] Estimates for the total installed capacity for PSH in the United States range from 20 GW to 22 GW. This range is partially due to the use of different plant ratings. For example, the EIA lists the total nameplate capacity of PSH as of 2008 at 20.4 GW, while the summer capacity is listed at 21.9 GW.

[165] Areas in the United States with wholesale energy markets typically also include markets for both spinning contingency reserves and regulation reserves.

Along with this interest, there have been a number of new proposals and demonstration projects. Table 12-1 lists several proposed or installed projects (since 2000). Although there is significant interest in batteries and CAES, PSH continues to be the dominant proposed storage technology.

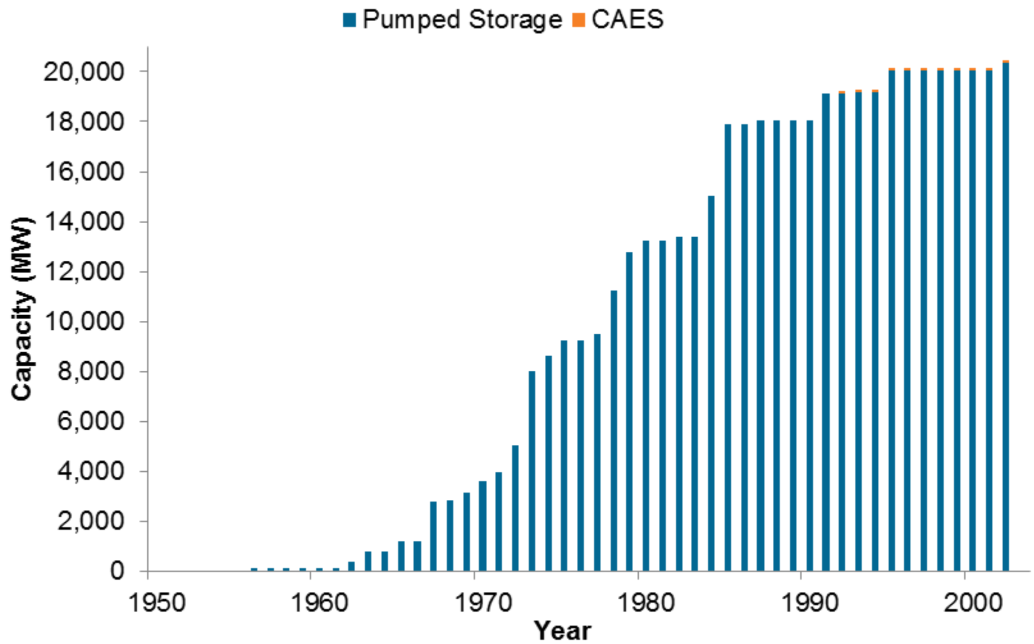

Figure 12-1. Capacity of bulk energy storage systems in United States, 1956–2003

Source: EIA 2008

Table 12-1. U.S. Electricity Storage Facilities Installed or Proposed Since 2000

Technology	Primary Application	Size (MW)	Owner/Developer	Location(s)	Status
PSH	Load leveling/firm capacity/ancillary services	>40,000	Various	Various (see Figure 12-9)	Proposed[a]
CAES	Load leveling/firm capacity/ancillary services				
		300	PG&E[c]	Kern County, California	Proposed
		150	NYSEG[d]	Reading, New York	Proposed
		2,700	FirstEnergy[e]	Norton, Ohio	Proposed
Sodium-sulfur (NaS) battery	T&D deferral/congestion relief	1	AEP[f]	North Charleston, West Virginia	Installed (2006)
		2	AEP	Bluffton, Ohio Balls Gap, West Virginia East Busco, Indiana	Installed (2008)
		4	AEP	Presidio, Texas	Installed (2009)
		1	Xcel Energy[g]	Luverne, Minnesota	Installed (2009)
Vanadium redox battery	T&D deferral/congestion relief	0.25	Pacificorp	Moab, Utah	Installed (2004)
Lithium-ion battery	Frequency regulation	1	AES/PJM Interconnection	Valley Forge, Pennsylvania	Installed (2008)
Flywheel	Frequency regulation	20	Beacon[h]	Stephentown, New York	Installed (2011)
		1	Beacon	Groveport, Ohio	Installed (2008)
		1	Beacon	Tyngsboro, Massachusetts	Installed (2009)

[a] As of December 2011, FERC had issued preliminary permits for 4d plants, representing approximately 35 GW of capacity. The capacity of proposed plants (including those with issued and pending preliminary permits exceeds 40 GW) (FERC n.d.). A map of proposed locations is provided in Figure 12-9.

[c] H. LaFlash "Compressed Air Energy Storage" slide presentation, Pacific Gas and Electric Company, November 3, 2010, http://www.sandia.gov/ess/docs/pr_conferences/2010/laflash_pge.pdf

[d] J. Rettberg, "Seneca Advanced Compressed Air Energy Storage (CAES) 150MW Plant Using an Existing Salt Cavern," slide presentation, November 3, 2010, http://www.sandia.gov/ess/docs/pr_conferences/2010/rettberg_nyseg.pdf NYSEG.

[e] Norton Energy Storage (2000)

[f] Parfomak (2012)

[g] Xcel Energy, http://www.gridpoint.com/Libraries/Featured_Media_Coverage_PDFs/wind-to-battery_-_Xcel_Energy_Brochure.sflb.ashx

[h] Beacon Power Corporation, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDY1Mjd8Q2hpbGRJRD0tMXxUeXBlPTM=&t=1, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MjAxNTh8Q2hpbGRJRD0tMXxUeXBlPTM=&t=1, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9ODI0OXxDaGlsZElEPS0xfFR5cGU9Mw==&t=1, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MzczNDQxfENoaWxkSUQ9MzcxMjE1fFR5cGU9MQ==&t=1, http://www.beaconpower.com/company/news.asp

12.2 Resource Availability Estimates

The ability to site certain storage technologies (conventional PSH and CAES) is based on specific geologic characteristics. These issues are discussed in the technology-specific sections (Section 12.3 and 12.4).

12.3 Technology Characterization

12.3.1 Technology Overview and Applications

Energy storage technologies are typically characterized by their applications, often in terms of discharge time. Three common categories are provided in Table12-2.

Table 12-2. Three Classes of Energy Storage

Common Name	Example Applications	Discharge Time Required
Power quality and regulation	Transient stability, reactive power, frequency regulation	Seconds to minutes
Bridging power	Contingency reserves, ramping	Minutes to ~1 hour
Energy management	Load leveling, firm capacity, T&D deferral	Hours

The first two categories of energy storage applications in Table 12-2 correspond to a range of ramping and ancillary services but do not typically require continuous discharge for extended periods. Storage technologies can provide local power quality benefits, such as voltage stability and provision of reactive power, and can increase the stability of the system as a whole by providing real or virtual inertia. As discussed in Chapter 4 (Volume 1), a high variable-generation grid will require increased operating reserves for frequency regulation due to short-term variability of the wind and solar resources; it will also require reserves covering forecast errors. Forecasting errors, especially over-prediction of wind or solar, requires time to allow fast-start thermal generators to come online. Hydropower and thermal units operating at part load typically provide operating reserves, but operating reserves can also be provided by energy storage technologies, often more efficiently or at a lower cost. Frequency regulation, for example, requires rapid response, and storage devices may provide faster response than traditional generators (Makarov et al. 2008). Storage technologies also have the unique ability to potentially provide reserves greater than their rated output while charging. A device charging at 1 MW can actually provide 2 MW of reserve capacity by stopping charging and rapidly switching to discharging; however, this ability is potentially limited by the technology-dependent switchover time. Previous analysis has demonstrated the potential benefits of providing fast ramping with energy storage to address the increase in sub-hourly variations resulting from large-scale deployment of variable generation (KEMA 2010).

The third category of services in Table 12-2 (energy management) corresponds to energy flexibility—the ability to shift bulk energy over several hours or more—which is the focus of storage deployment in the RE Futures scenarios.[166] An energy management device stores energy during periods of low demand (and correspondingly low energy prices) and discharges energy

[166] However, in the ReEDS and GridView modeling, storage devices also contribute to ancillary services (e.g., forecast error, contingency, and frequency regulation reserves).

during periods of high demand and prices. In a high renewables scenario, this operation would be the same, and the charging and discharging periods would be driven by the combination of normal demand patterns and the supply of available variable generation. This includes storing energy when it might otherwise need to be curtailed due to low demand or constrained transmission. Storage devices sized for energy management can provide an alternative (or supplement) to developing new transmission capacity. Use of dedicated long-distance transmission for wind or solar power will be limited by the relatively low capacity factor of the resource. Storage could help reduce curtailment due to transmission constraints by co-locating storage with variable-generation sources and allowing them to increase use of transmission lines (Desai et al. 2003). This could also decrease the amount of new transmission needed, but represents a trade-off between the most cost-effective use of storage, and the cost of new transmission (Denholm and Sioshansi 2009). Figure 12-2 provides one example of the range of technologies available for these three classes of services and shows that many technologies can provide services across the timescales shown. Many energy management storage devices can provide fast response and provide power quality and bridging power services (the discharge times shown represent the continuous discharge capability as opposed to the response time).

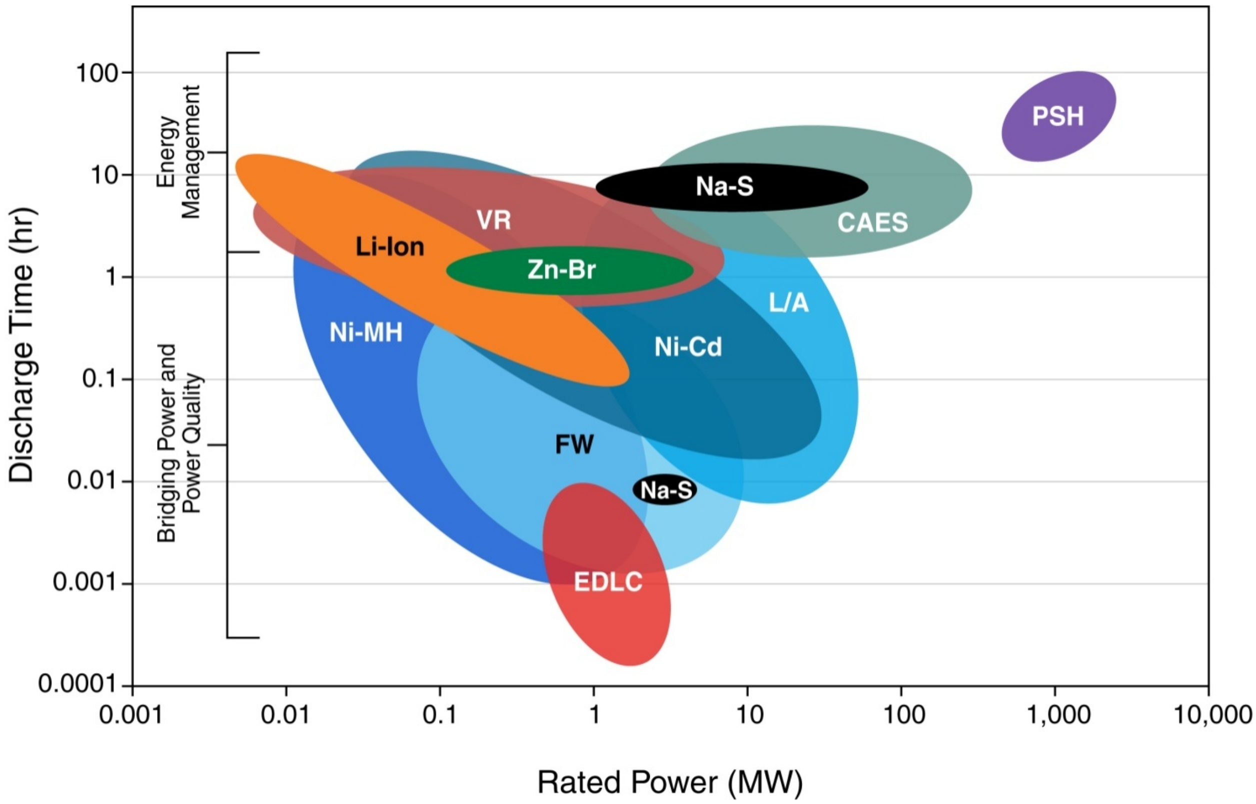

Figure 12-2. Energy storage applications and technologies

Source: Electricity Storage Association (ESA 2011)

System Ratings: Installed or proposed systems as of November 2008. This chart is meant to represent a general range of storage technologies and is not inclusive of all technologies, applications, and possible sizes.

CAES	Compressed air	Ni-Cd	Nickel-cadmium
EDLC	Dbl-layer capacitors	Ni-MH	Nickel-metal hydride
FW	Flywheels	PSH	Pumped-storage hydropower
L/A	Lead-acid	VR	Vanadium redox
Li-Ion	Lithium-ion	Zn-Br	Zinc-bromine
Na-S	Sodium-sulfur		

Figure 12-2 does not include thermal energy storage, which would cover a power range of a few kilowatts for thermal energy storage (TES) in buildings to more than 100 MW in concentrating solar power (CSP) plants, with a discharge time of minutes to several hours.

12.3.2 Technologies Included in RE Futures Scenario Analysis

Utility-scale electricity storage is modeled in the Regional Energy Deployment System (ReEDS) model to provide three services: firm capacity, energy supply shifting, and operating reserves. However, the primary grid integration challenge in a high renewable penetration scenario is the limited coincidence of renewables supply with normal electricity demand. Consequently, storage modeling for RE Futures focused on energy storage technologies that can provide energy management services or can store and discharge continuously for several hours (defined here as

8–15 hours, depending on the technology). This allows energy storage to u se otherwise potentially curtailed energy from variable-generation sources during periods of high generation and low load. As discussed later in this section, the modeling assumptions inherently undervalue shorter term and distributed storage devices, and they restrict their adoption; therefore, RE Futures cannot be used as an indicator of the opportunities for energy storage of all types.

Three technology groups meeting the criteria of being able to provide energy management services were included in the ReEDS modeling: high-energy batteries, pumped-storage hydropower, and compressed air energy storage. These technologies and their implementation in ReEDS are described in the following sections.

Notably absent from the modeling effort were short discharge and power quality applications such as flywheels and high power batteries. The most economic application for these devices appears to be fast-responding frequency regulation markets (Walawalkar et al. 2007). The ReEDS model combines frequency regulation and other reserves (for forecast error and contingency reserves), for example, into a single operating reserve constraint that can be provided by multiple technologies. Although RE Futures captures the increased need for operating reserves as greater levels of variable generation are deployed, it does not explicitly treat sub-hourly or sub-minute events (e.g., frequency regulation), and therefore cannot capture the high value of a regulation reserve device in isolation. As a result, although RE Futures can identify the overall need for reserves and the corresponding possible increase in the role of storage for operating reserves, it does not currently disaggregate the market and identify opportunities for individual reserve technologies. Recognizing this limitation, no attempt was made to estimate deployment of any individual reserve supplying storage technology.

In addition, because ReEDS is essentially a “bulk planning” model, it does not identify the potential value and opportunities of storage sited in the distribution system. In particular, it cannot evaluate opportunities to relieve local transmission or distribution congestion, or the value of T&D deferral. These applications are a primary application for current high-energy batteries such as flow batteries or NaS (Nourai 2007). This is also a primary application for end-use TES (ADM 2006). As a result, ReEDS will undervalue these and restrict their adoption into the marketplace.

Furthermore, the role of V2G was not explicitly evaluated in RE Futures. The RE Futures study included the value of controlled charging; however, uncertainty in the ultimate acceptance among original equipment manufacturers (OEMs), utilities, and consumers of V2G led to the conservative assumption to not include the potentially very large role of V2G.

Finally, limited deployment of hydrogen as a storage medium, and large uncertainty of cost-reduction and performance improvements of hydrogen storage, led to its exclusion as a core energy storage technology evaluated in RE Futures.

For these reasons, the ReEDS storage results are aggregated to show the total amount of storage deployed, as opposed to the deployment of individual storage technologies. RE Futures was used more to indicate the amount of bulk storage that may be beneficial to the grid (within the cost ranges and availability modeled) as opposed to evaluating particular storage technology types.

The particular energy storage technology deployed by ReEDS could actually be any of a number of storage technologies or an emerging technology not evaluated.

12.3.2.1 High-Energy Batteries

For many batteries, there is considerable overlap between energy management and shorter-term applications. Furthermore, batteries can generally provide rapid response, which means that batteries "designed" for energy management can potentially provide services over all applications and timescales discussed.

Several battery technologies have been demonstrated or deployed for energy management applications. The commercially available batteries targeted to energy management include two general types: high-temperature batteries and liquid electrolyte flow-batteries. Other commercially available battery types are generally targeted towards high-power applications and discussed in Section 12.3.4.

High-temperature batteries operate above 250ºC and use molten materials to serve as the positive and negative elements of the battery. The most mature high-temperature battery as of 2011 is the sodium-sulfur battery (NaS), which has worldwide installations that exceed 270 MW (Rastler 2008). Several utilities have deployed the NaS battery in the United States.

Alternative high-temperature chemistries have been proposed and are in various stages of development and commercialization. One example is the sodium-nickel chloride battery (Baker 2008). The second class of high-energy batteries is the liquid electrolyte "flow" battery. This battery uses a liquid electrolyte separated by a membrane (EPRI/DOE 2003). The advantage of this technology is that the power component and the energy component can be sized independently, with the electrolyte held in large storage tanks. As of 2011, there has been limited deployment of two types of flow batteries—vanadium redox and zinc-bromine. Other combinations such as polysulfide-bromine have been pursed, and new chemistries are under development (Yang et al. 2011).

In the United States, a primary focus of energy management batteries has been T&D deferral; however, demonstration projects have been deployed for multiple applications (Nourai 2007; EPRI/DOE 2003).

For RE Futures, batteries were combined into a single technology type, with performance based on a NaS battery; however, given the multiple battery types, and with uncertain cost reductions and technology improvements, the RE Futures battery technology should be considered a generic "high-energy" battery with 8 hours of discharge time. This could include technologies currently under various stages of development and deployment such as advanced lithium-based batteries. As with certain supply technologies, such as solar PV with multiple technology options, the goal was not to "pick winners" because the market will ultimately determine technology pathways based on cost and performance.

12.3.2.2 Pumped-Storage Hydropower

PSH is the only energy storage technology deployed on a gigawatt scale in the United States and worldwide. In the United States, about 20 GW is deployed at 39 sites, and installations range in capacity from less than 50 MW to 2,800 MW (EIA 2008). This capacity was largely built during the 1960s, 1970s, and 1980s (ASCE 1993). While there are a number of proposed plants, there has been no large-scale PSH development in the United States since 1995; however, development has continued in Europe and Asia (Deane et al. 2010). Lack of construction of new U.S. facilities has been largely been due to cost, market issues, and regulatory issues discussed in Section 12.1.

Pumped-storage hydropower stores energy by pumping water from a lower-level reservoir (e.g., a lake) to a higher-elevation reservoir using lower-cost, off-peak electric power. During periods of high electricity demand, the water is released to the lower reservoir to turn turbines to generate electricity, similar to the way in which conventional hydropower plants generate electricity.

Many existing PSH plants store 8 hours or more of energy, making them useful for load leveling, and providing firm capacity. PSH can also ramp rapidly while generating, making it useful for load following and providing ancillary services including contingency spinning reserves and frequency regulation (Phillips 2000).

Figure 12-3 shows a representative conceptual configuration of a PSH plant.

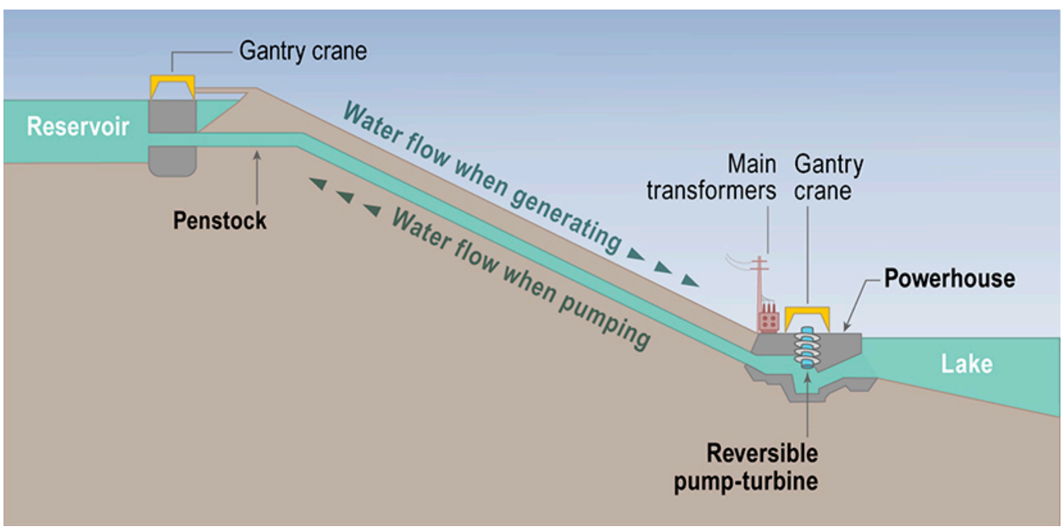

Figure 12-3. Simplified pumped-storage hydropower plant configuration

Pumped-storage hydropower plants often make use of an existing river or lake, avoiding the need for—and cost of—construction of a separate (usually the lower) reservoir. This is called an *open-cycle* PSH plant. In an instance in which a suitable natural water body is not available for use as one of the reservoirs, both the upper reservoir and the lower reservoir must be constructed. This type of construction is known as a *closed-cycle* plant, inasmuch as it has minimal interaction with natural water bodies. A water source is needed for a closed-cycle plant to provide water to initially fill the reservoir and compensate for losses during operation due to leakage and evaporation. Nearby rivers or streams are typical sources; treated municipal grey water or groundwater (wells) can also be used (Yang and Jackson 2011). Of the 45 PSH plants with preliminary permits from FERC, which include a total or more than 35 GW of capacity, at least nine have proposed closed-cycle PSH plants, and these exceed 9 GW of capacity (FERC n.d.).

12.3.2.3 Compressed Air Energy Storage

CAES stores energy by compressing air in an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage cavern, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, and the exhaust is expanded through a low-pressure gas turbine. The turbines are connected to an electrical generator (Succar and Williams 2008).

CAES is based on conventional gas turbine technology and is considered a hybrid generation and storage system because it requires combustion in the gas turbine.[167] Instead of a round-trip efficiency number, the performance of a conventional CAES plant is based on its energy ratio (energy in/energy out) and its fuel use (typically expressed as heat rate in Btu/kWh). (Succar and Williams 2008).

The first CAES plant was completed in 1978 in Huntorf, Germany. It was designed primarily to provide “black start” (provide a source of power to start conventional generators after a system-wide failure), and it was rated at 290 MW with 2 hours of capacity (Crotogino et al. 2001). A second plant was built in 1991 in McIntosh, Alabama (Schalge and Mehta 1993). It has a rating of 110 MW for 26 hours, providing firm capacity and load-leveling services. Both plants inject air into underground caverns solution mined from salt formations (Succar and Williams 2008). This plant has a single turbo-machinery drive train using a common motor-generator set connected to the compressor and expander via clutches. This results in turnaround times from compression to expansion of approximately 30 minutes, limiting its use in providing operating reserves and other services requiring fast response.

Proposed CAES plants include a dedicated motor drive compressor and expander-generator that would eliminate the single turbo-machinery train (Norton Energy Storage 2000). This would allow for faster switchover from compression to generation, thus increasing its usefulness for providing ancillary services and responding to increased variability of net load. Once operating, CAES plants can provide rapid ramp rates; the McIntosh plant is capable of ramping at approximately 18 MW (16% of full output) per minute, or rates that are more than 50% greater than a typical gas turbine (Succar and Williams 2008).

[167] The compressed air can be considered a method to assist conventional natural gas turbines by providing the compressed air that typically requires about two thirds of the energy generated by a gas turbine. This reduces the natural gas fuel used by a gas turbine by more than 50%, reducing the heat rate from approximately 10,000 Btu/kWh to approximately 4,000 Btu/kWh (Succar and Williams 2008).

Figure 12-4 shows a representative conceptual configuration of a CAES plant.

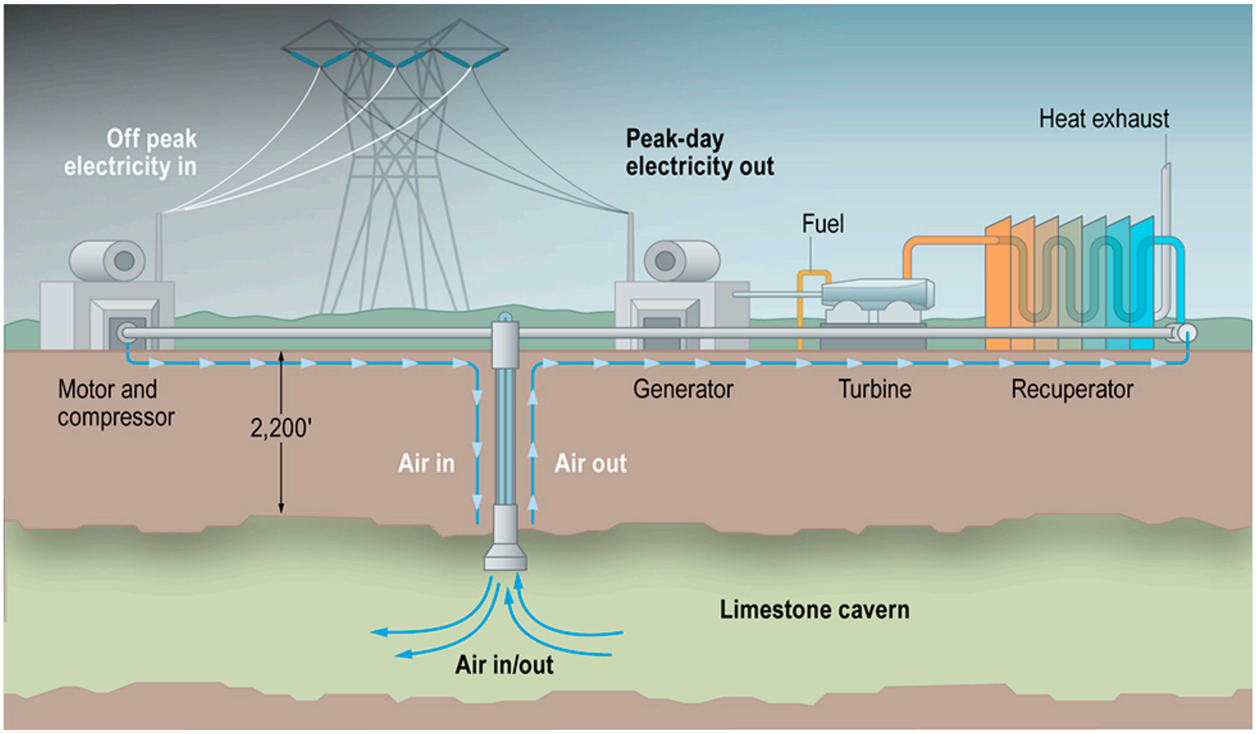

Figure 12-4. Configuration of a compressed air energy storage plant

The large volume of air storage required for CAES is most economically provided by geological structures (Allen 1985; Korinek et al. 1991). The two existing CAES facilities use salt domes, where the cavity is formed by solution mining: fresh water is pumped into the formation to dissolve the salt, and brine is pumped to the surface for disposal or other use (Thoms and Gehle 2000). Domal salt formations are self-healing, meaning pores on the cavity walls seal themselves with available air moisture, virtually eliminating the possibility of air leakage.

Other proposed formations for CAES include bedded salt, which features thinner "layers" of salt. CAES can also potentially be deployed using aquifers, depleted natural gas formations, and hard-rock caverns. A variety of alternative and advanced CAES cycles have been proposed, and these are discussed in Section 12.1.4.3.

12.3.3 Technologies Not Included in RE Futures Scenario Analysis

The following technologies offer substantial potential benefits in many applications, but were not included in the Renewable Electricity Futures modeling as they either provide services not explicitly evaluated in the analysis or have not yet been significantly commercialized in grid storage applications.

12.3.3.1 Flywheels

Flywheels store energy in a rotating mass. Flywheels feature rapid response and high efficiency, making them well suited for frequency regulation. Several flywheel installations have been planned or deployed in locations where frequency regulation markets exist in the United States (Parfomak 2012).

12.3.3.2 Capacitors

Capacitors (including supercapacitors and ultracapacitors) are devices that store energy in an electric field between two electrodes (EPRI/DOE 2003). Capacitors have among the fastest response time of any energy storage device, and they are typically used in power quality applications such as providing transient voltage stability. However, their low energy capacity has restricted their use to short time-duration applications. A major research goal is to increase their energy density and increase their usefulness in the grid (and potentially in vehicle applications) (Hadjipaschalis et al. 2009).

12.3.3.3 Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) stores energy in a magnetic field in a coil of superconducting material. SMES is similar to capacitors in its ability to respond extremely fast, but it is limited by the total energy capacity. This has restricted SMES to “power” applications with extremely short discharge times (Luongo 1996; Feak 1997). Several demonstration projects have been deployed (Ali et al. 2010), and reducing costs by using high-temperature superconductors is a major research goal (Fagnard et al. 2006).

12.3.3.4 High-Power Batteries

High-power batteries are associated with the provision of contingency reserves, load following, and additional reserves for issues such as forecast uncertainty and unit commitment errors. This set of applications generally requires rapid response (in seconds to minutes) and discharge times in the range of up to approximately 1 hour.

These applications are generally associated with several battery technologies, which include lead-acid, nickel-cadmium, nickel-metal hydride, and (more recently) lithium-ion. With their rapid response, batteries can provide power quality services such as frequency regulation, but the continuous cycling requirement can limit life of current technologies (Peterson, Apt, and Whitacre 2010). Lithium-ion batteries are currently the primary candidate for large-scale deployment in battery electric vehicles (EVs) and *plug-in hybrid electric vehicles* (PHEVs), and improvements in batteries designed for vehicles could be applied to stationary applications (Wadia et al. 2011). Several demonstration projects have been built using these technologies to provide operating reserves. Details of cost and performance are provided in EPRI/DOE (2003) and EPRI (2010).

12.3.3.5 Electric Vehicles and the Role of Vehicle-to-Grid

EVs (used here to represent both “pure” electric vehicles and plug-in hybrid electric vehicles) are a potential source of flexibility for variable-generation applications. Charging of EVs can potentially be controlled and can provide a source of dispatchable demand and demand response. Controlled charging can be timed to periods of greatest variable-generation output, while charging rates can be controlled to provide contingency reserves or frequency regulation reserves. Vehicle-to-grid (V2G) (where EVs can partially discharge stored energy to the grid) may provide additional value by acting as a distributed source of storage. EVs could potentially provide all three grid services discussed previously. Most proposals for both controlled charging and V2G focus on short-term response services such as frequency regulation and contingency. Their ability to provide energy services is more limited by both the storage capacity of the battery and the high cost of battery cycling. This could restrict their ability to provide time shifting (energy arbitrage) beyond their ability to perform controlled charging.[168] The role of V2G is an active area of research, and because EVs in any form have yet to achieve significant market penetration, assessing their potential as a source of grid flexibility is difficult. However, analysis has demonstrated potential system benefits of both controlled charging and V2G (Denholm and Short 2006). The role of EVs as an enabling technology requires additional analysis of their unique temporal characteristics of availability, unknown battery costs and lifetimes, and the availability of smart charging stations to maximize their usefulness while parked.

12.3.3.6 Hydrogen Energy Storage and Fuel Production

A hydrogen energy storage system consists of an electrolyzer, storage tanks or underground cavern storage, and either a fuel cell[169] or combustion technology to produce electricity from hydrogen. Hydrogen has been produced industrially via electrolysis since the 1920s. There are currently no utility-scale installations using hydrogen as an energy storage medium; however, electrolyzers and fuel cells are commercially available, and electrolysis is used in a variety of industrial processes (Suresh et al. 2010).

Megawatt-scale hydrogen energy storage systems—using both above-ground storage (in tanks) and below-ground storage in formations similar to CAES—have been proposed (Kroposki et al. 2006). Because compressed hydrogen has a higher energy density than air, a storage cavern could store more energy in the form of hydrogen than could compressed air.

The primary disadvantages of hydrogen energy storage are the relatively low round-trip efficiency (between 28% and 40% depending on electrolyzer and fuel cell efficiencies) and the high cost of fuel cells and electrolyzers (Steward et al. 2009). Recent research has focused on cost reduction and efficiency improvements for fuel cells and electrolyzers, as well as on combining the electrolysis and fuel cell functions in a single "reversible" fuel cell device (Hauch et al. 2006; Milliken and Ruhl 2003; TMI 2001). This could increase efficiency and lower costs for hydrogen storage system (TIAX 2002).

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[168] This conclusion depends on the anticipated cycle life and cost of EV batteries. See Sioshansi and Denholm (2010) and Peterson, Whitacre, and Apt (2010) for a discussion of the impact of battery life and cycling on the value of V2G. However, controlled charging (without V2G) is still a potentially significant source of flexibility, with the ability to raise the minimum load and avoid curtailment.

[169] A full cell is a device capable of generating an electrical current by converting the chemical energy of a fuel (e.g., hydrogen) directly into electrical energy. Fuel cells differ from conventional electrical (e.g., battery) cells in that the active materials such as fuel and oxygen are not contained within the cell but are supplied from outside. It does not contain an intermediate heat cycle, as do most other electrical generation techniques (http://www.eia.doe.gov/glossary/).

A hydrogen energy storage facility could provide increased flexibility and unique revenue opportunities to utilities, which could sell or use the hydrogen for other applications. Hydrogen could be mixed with natural gas for additional flexibility in power generation from the storage system, but this has yet to be demonstrated on a commercial scale. The use of hydrogen as a transportation fuel represents a potentially large market (Greene et al. 2008). In addition to hydrogen, there are pathways to use electricity to produce liquid or gaseous fuels for vehicles or energy storage (Sterner 2009).

12.3.4 Technology Cost and Performance

Limited deployment of many emerging energy storage technologies makes the estimation of costs challenging when deployed at scale. Even more mature technologies, such as PSH and CAES, have not been built in the United States in some time,[170] so the cost of the next plant is somewhat uncertain. Furthermore, PSH and CAES depend on site-specific geologic conditions, which make costs difficult to generalize. When considering costs of all storage technologies, the different applications must be considered. Storage technology costs include both an energy component and a power component, and the total cost of a storage device includes both components, within the limits of the target application. (This is discussed in more detail in Text Box 12-1.) Because the RE Futures modeling considered only bulk applications, only devices with multiple hours of discharge were evaluated. For uniform comparison, total costs were reported on a cost-per-kilowatt basis, where this cost includes both the power component and the energy component.

Text Box 12-1. Defining the Cost of Electricity Storage

A critical issue when discussing the costs of storage technologies is that storage devices in electric applications have both a power component (kW of discharge capacity) and an energy component (kWh of discharge capacity, which may also be expressed as hours of discharge at rated output). The total cost of a storage application must account for the ratings of both components, and it may be expressed differently depending on the application or audience. For example, because utilities universally define the cost of power plants only in terms of rated power ($/kW), they would expect to see costs in these terms, with the hours of storage (kWh capacity) expressed separately. A grid storage plant therefore might be expressed as costing $2,000/kW for a device with eight hours of discharge capacity. On the other hand, the battery community typically expresses costs in terms of rated energy ($/kWh), and it may or may not include the power component in the cost. So the cost of a battery might be stated as $500/kWh with the power capacity of the battery established separately. When evaluating the economics of storage technologies, care must, therefore, be taken to ensure that the costs for meeting both kW and kWh specifications are included and that both components are "sized" properly for any specific application.

12.3.4.1 High-Energy Batteries

Present and future costs for many battery types are uncertain, particularly for flow batteries, due to the relative immaturity of the technology. Table 12-3 provides several estimates for the cost of several battery technologies providing energy services (with an energy capacity of at least 4 hours of continuous discharge).

[170] There is one small PSH facility under construction as of November 2011 (the 40-MW Olivenhain-Hodges project) with completion expected in 2012 (SDCWA 2011).

Table 12-3. Battery Cost Estimates for Grid Storage Applications

Type	BOP[a] ($/kW)	Battery ($/kWh[b])	Storage Hours	Total/$/kW	Source
Vanadium	606	155–251	10	2,600–3,110	EPRI/DOE (2004)
Flow Battery (Several Technologies)	423–1,300	280–450	4	1,545–3,100	Rastler (2009)
NaS	450–550	350–400	4	1,850–2,150	Rastler (2009)
NaS	–	–	7.2	2,590	Nourai (2007)
Li-Ion	350–500	400–600	4	1,950–2,900	Rastler (2009)

[a] Balance-of-plant including power conversion system
[b] Although this column implies only the energy component, these estimates include the power component of the battery. As a result, the values in this table cannot be adjusted for more or less energy (hours of storage). Each cost assessment must be examined individually to determine the component costs.

Cost breakdowns for battery systems, including the balance of systems, installation, and other components, are provided by EPRI/DOE (2004) and Nourai (2007). The assumed cost for high-energy batteries (8–10 hours of discharge capacity) was $3,990/kW in 2010,[171] decreasing roughly linearly to $3,200/kW by 2050. Details about battery cost assumptions are provided in Black & Veatch (2012).

With battery efficiency, it is important to consider the alternating current (AC)-to-AC round-trip efficiency—battery efficiencies are often reported on a direct current (DC) basis without power conversion efficiencies—and to include the effect of "parasitic" loads, such as heating and cooling of batteries and power-conditioning equipment. Typical total AC-to-AC round-trip efficiencies for flow batteries and NaS are in the range of 65%–75%, including parasitic loads (Rastler 2008; Nourai 2007). Higher round-trip efficiencies for lithium-ion batteries have been reported in the range of 90% (KEMA 2008); however, this value does not include certain parasitic loads that can be considerable. A net roundtrip efficiency of 75% was assumed in this report.

12.3.4.2 Pumped-Storage Hydropower

Figure 12-5 provides historical cost data for U.S. PSH plants, inflated to 2009 dollars. There is a general trend toward increasing costs, with the last three plants constructed costing more than $1,000/kW.

[171] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

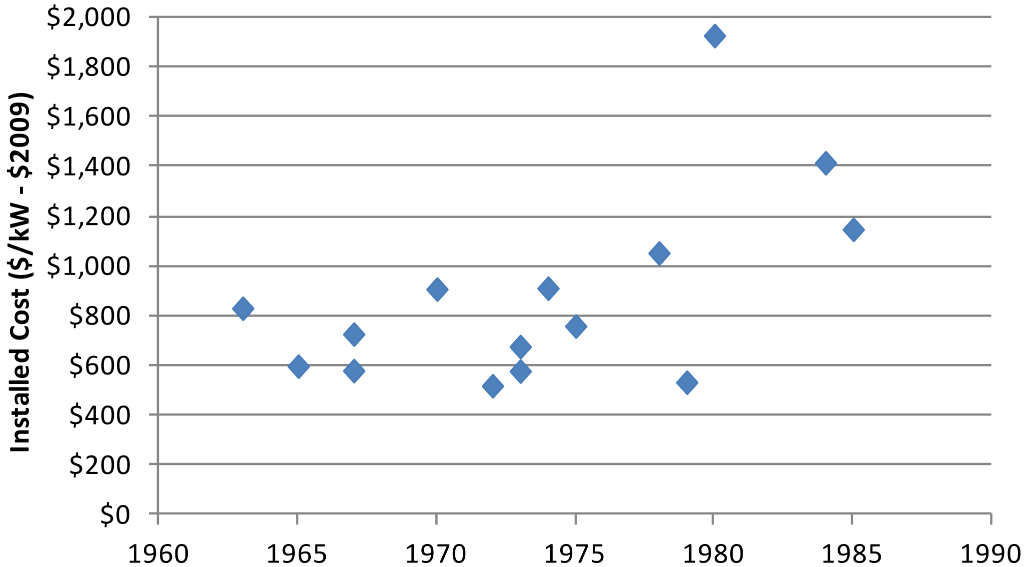

Figure 12-5. Installed cost of pumped-storage hydropower plants in United States

The cost of new PSH plants will vary. The geotechnical and geological characteristics and complexity of site are major factors in PSH development costs. Typically, the largest costs are for development of a project's upper and lower reservoirs and for underground components. One example is the Helms pumped hydropower plant, which was completed in 1984 at a cost of $1,411/kW (2009 dollars), with approximately 50% of the cost being the reservoir, and 28% being the powerhouse (ASCE 1993). No large projects have recently been built in the United States; however, a number of projects have been completed worldwide in the last decade, and there are a significant number of proposed plants both in the United States and internationally.

Table 12-4 lists several recently completed plants in Europe (Deane et al. 2010), along with proposed plants in the United States; capital costs (in dollars-per-kilowatt) are adjusted to 2009 dollars (NWPCC 2008). There are also a large number of proposed plants in Europe, with costs estimated in the range of $700/kW to more than $3,000/kW.

Table 12-4. Recently Completed or Proposed Pumped-Storage Hydropower Plants[a]

Location	Plant Name	Capacity (MW)	$/kW	Date of Completion
United States				
California	Eagle Mountain	1,300	1,019	Proposed
California	Iowa Hills PS	400	1,344	Proposed
California	Lake Elsinore	500	1,500	Proposed
California	Red Mountain	900	1,900–2,100	Proposed
Utah	North Eden PS	700	1,011	Proposed
Utah	Parker Knoll PS	800	1,215	Proposed
Austria	Feldsee	140	750	2009
Austria	Reisseck_II	430	1,091	2008
Germany	Goldisthal	1,060	1,321	2003
Slovenia	Avce	180	711	2009

[a] This represents a small subset of the proposed plants in the United States

Deane et al. (2010) provides a more comprehensive discussion of recent and projected future costs. Recent engineering estimates of new PSH construction costs per kilowatt in the United States include $2,100–$4,000 (Rastler 2009), $2,000–$4,000 (Black & Veatch 2012), and $5,595 (EIA 2010). A large component of this very large range is due to the variation in local conditions—low-price estimates may assume the availability of existing reservoirs (including abandoned mines or other formations), while the high estimates may assume “green field” development or modification of both reservoirs. Generating a supply curve would require evaluation of each individual potential site. Efforts have been initiated to characterize potential new PSH development at scale, but additional data were unavailable at the time of this analysis.

As a result, cost estimates were based on a combination of proposed plant costs described above and engineering estimates, focusing on lower-cost PSH opportunities. Two cost points were identified, at $1,500/kW and $2,000/kW.

One of the primary challenges associated with PSH development is the long construction time, as well as associated risks and uncertainty. State and local application and permitting (including obtaining water rights), FERC permitting, and construction require 10–12 years based on current schedules. Closed-cycle plants could reduce licensing and construction times to 6–8 years. These times (and resulting costs) can be increased due to siting opposition and environmental regulations (Strauss 1991).

Existing PSH facilities in the United States—most of which were constructed during the 1960s, 1970s, and 1980s—have high availability and few forced outages. The great majority of U.S. plants have multiple reversible pump-turbine motor-generator units. Reversible units operate as a motor and pump in the “pumping” mode, and as a turbine and generator in the “generating” mode. Having multiple units per plant allows for scheduling maintenance on one unit while keeping the other units available, typically minimizing effects on overall plant availability.

Figure 12-6 provides the round-trip efficiencies for existing U.S. PSH plants. There has been a trend toward increased efficiencies, and proposed plants have efficiencies that exceed 80% on an AC-to-AC basis (ASCE 1993). Assumed efficiency for new PSH for this study was 80%. There is little loss of performance due to age or throughput. Plants are upgraded through efficiency improvements and life extension on a project-by-project basis, and most U.S. projects have been modernized through runner (turbine) replacements, generator rewinds, control system upgrades, and other incremental improvements. Lifetimes of PSH plants can exceed 60 years (ASCE 1993).

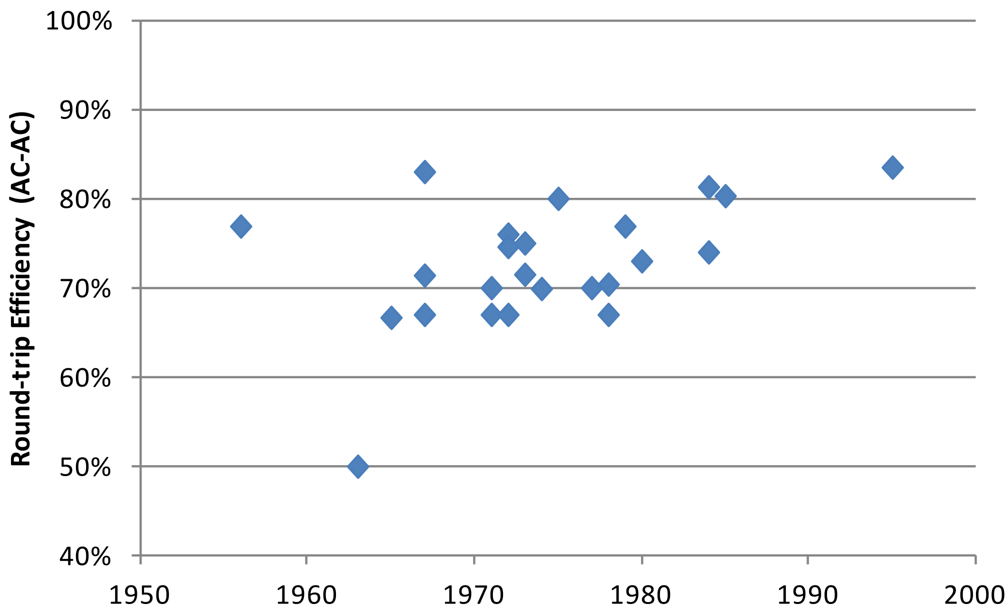

Figure 12-6. Historical efficiencies for pumped-storage hydropower plants in United States

Source: Performak 2012

Older PSH plants can require up to 30 minutes to switch between pumping and generation. However, modern PSH plants enable fast ramping rates in both pumping and generation modes and can begin pumping or generating within seconds.

RE Futures assumed that new PSH deployments would include variable speed (also referred to as "adjustable speed") operation. This technology has not yet been applied in a major U.S. installation, but has been used in several international plants (Yasuda 2000). Among the benefits of variable speed operation are faster response to grid requirements, higher efficiencies, ability to accommodate greater ranges of "head," and wider unit and plant operating ranges (i.e., an ability to operate with a lower minimum load in megawatts).

12.3.4.3 Compressed Air Energy Storage

The cost of CAES plants is driven by aboveground components, including compressors and the expander/generator equipment, as well as by belowground components. Aboveground equipment components are based largely on standard components, with the uncertainty in cost based largely on large swings in commodity prices and the general cost of capital-intensive projects. The largest uncertainty associated with CAES is related to underground cavern development and is especially associated with unproven approaches such as development in bedded salt and aquifers.

Salt caverns are generally the most economical excavated formations for siting CAES plants. Excavation costs for salt caverns, which are constructed by solution mining, can be kept extremely low compared to the costs for bedded salt formations, aquifers, and hard rock mining. Based on current experience with the construction of natural gas storage reservoirs and the Big Hill strategic petroleum reserves in Texas, costs can be maintained at approximately $2/m^3 of excavated cavern for solution mining compared to $20/m^3 in aquifers, and $300/m^3 in hard rock granite.

Table 12-5 provides several cost and performance estimates for proposed CAES plants. Table 12-6 breaks down costs for a conventional CAES system deployed with a salt cavern.

Table 12-5. Cost and Performance Estimates for Four Proposed Compressed Air Energy Storage Plants[a]

Name	Location	Cavern Type	Capacity (MW)	Cost ($/kW)	Heat Rate (Btu/kWh)	Energy Ratio[b]
Iowa Stored Energy Park	Dallas Center, Iowa	Aquifer	–	933–1,014	4,420	0.77–0.89
Norton Energy Storage	Norton, Ohio	Depleted hard-rock mine	2,700	–	3,860–4,300	0.7
PG&E	Kern County, California	Porous rock	300	1,187	–	–
Seneca (NYSEG/Iberdrola)	Schuyler County, NY	Bedded salt	150	833	–	–

[a] Performak 2012

[b] The energy ratio is defined as the amount of electrical energy in per unit of generation. Note that this number is less than 1 because CAES is a hybrid system that uses natural gas. The efficiency of a conventional CAES plant cannot be easily defined as a single number because it uses two different energy sources.

Table 12-6. Cost Breakdown for a Conventional Compressed Air Energy Storage System Deployed in a Salt Cavern

Component	Cost ($/kW)	Fraction of Total
Compressor	87	11%
Heat exchanger	34	4%
High pressure expander	62	8%
Low pressure expander	144	19%
Electrical	45	6%
Construction, labor, indirect costs	324	42%
Cavern development	77	10%
Total	774	100%

Source: CEC 2008

For RE Futures, the aboveground costs were based on a “reference plant” with a capacity of 220 MW. This reference plant assumes a multi-stage compressor, with the first stage using an axial flow compressor with a discharge pressure of 160 pounds-force per square inch gauge (psig) and requiring a power input of 90 MW. The discharge air is passed through an intercooler, which reduces the air’s specific volume and temperature in preparation for the second stage of the compression process in which the air is compressed to its final storage pressure of 1,250 psig.

Three installed costs were assumed for new CAES development for RE Futures: $900/kW for deployment with salt domes, $1,050/kW in bedded salt, and $1,200/kW in aquifers. These values are based on engineering estimates, discussed in detail in Black & Veatch (2012), and are within the range cost estimates in Table 12-5 of $730/kW to $1,200/kW for deployment in salt and aquifers. Hard rock caverns that must be excavated were not included in RE Futures, although opportunities for CAES deployments exist in depleted mines.

RE Futures assumed a CAES energy ratio of 0.8 kWh_{in}/kWh_{out} and a heat rate of 4,910 Btu/kWh. These estimates were based on expected performance of the proposed (and subsequently cancelled) Iowa Stored Energy Park (Black & Veatch 2005; Schulte et al. 2012). The reference plant for RE Futures assumed dedicated motor and generators to allow fast switchover times and provision of operating reserves. RE Futures assumed a very high availability, based on both the similarity of CAES to natural gas turbines and the historical performance of the McIntosh Power Plant in Alabama. Plant lifetimes are expected to be similar to conventional gas turbine plants, typically exceeding 20 years with normal maintenance (Crotogino et al. 2001). Additional discussion of CAES cost and performance assumptions is provided in Black & Veatch (2012).

12.3.5 Technology Advancement Potential

12.3.5.1 Batteries

There is considerable opportunity for cost reduction and improvements in many battery technologies. EPRI/DOE (2003 and 2004) describe several cost reductions that could result from engineering and manufacturing scale-up of flow batteries and NaS batteries. Historical “learning curves” show continued progress of both “mature” battery technologies and newer technologies such as lithium-ion. Figure 12-7 and Figure 12-8 illustrate the historical increases in energy density as well as cost for a variety of energy storage devices.

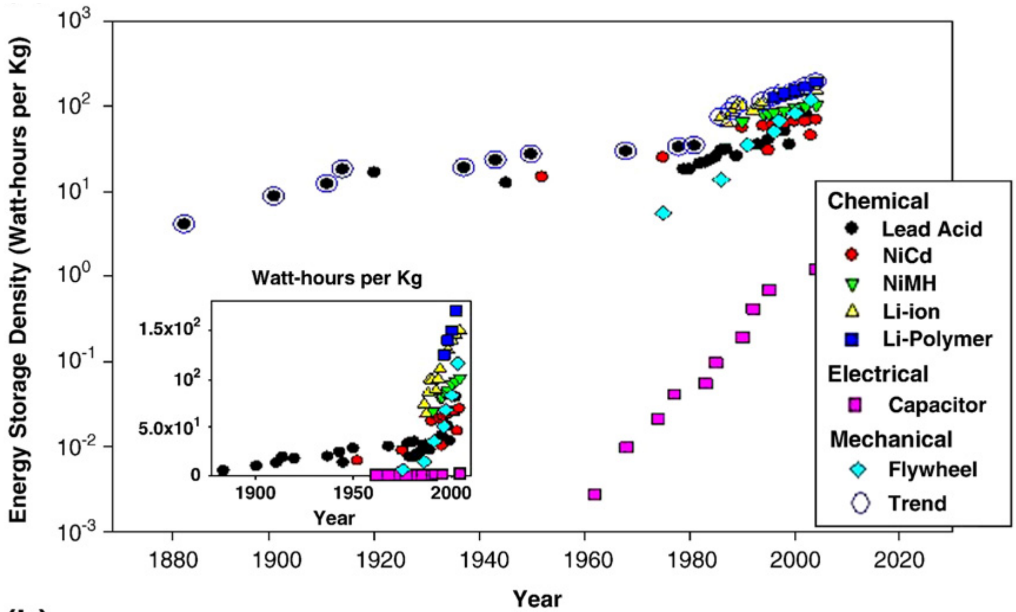

Figure 12-7. Historical improvements in storage energy density

Source: Koh and Magee 2008

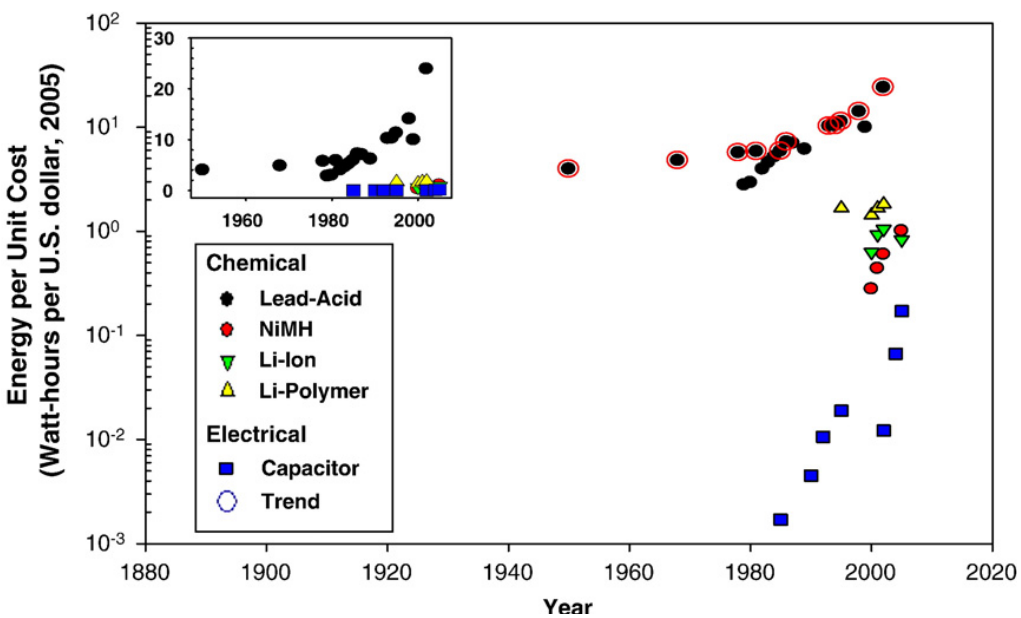

Figure 12-8. Historical improvements in energy storage cost

Source: Koh and Magee 2008

The emergence of nano-scale science provides opportunities for entirely new battery structures that could dramatically improve the power and energy density of several types of batteries. DOE

(2007) provided a detailed discussion of the potential opportunities for batteries. The target for the Advanced Research Projects Agency-Energy (ARPA-E) stationary storage program is $100/kWh.[172] In addition to research on stationary batteries, efforts to reduce the cost of transportation batteries could have significant impact on their application for grid services. RE Futures did not consider the impact of fundamental breakthroughs in battery science on reduced costs and subsequent deployment, nor did it evaluate the distribution level benefits of battery deployment.

12.3.5.2 Pumped-Storage Hydropower

Pumped-storage hydropower is considered a mature technology. However, incremental improvements in efficiency are possible, and the flexibility of existing and future plants may be improved using variable speed drive technologies. Other possible developments include use of saltwater PSH facilities in coastal regions and underground PSH (Tanaka 2000). Resource availability or detailed cost estimates of these alternative configurations were not available, so they were not considered for RE Futures.

12.3.5.3 Compressed Air Energy Storage

Although CAES is based on mature technologies, there are several possible advancements in conventional CAES. Previous CAES plants used components that were not optimized for the unique characteristics of the CAES expansion cycle. This is partially due to the small market for which developing dedicated equipment would not be worthwhile. A large CAES market could drive development of custom turbo-machinery, improving the efficiency of CAES components. Alternatively, several proposed CAES configurations use standard combustion turbines, potentially lowering cost significantly (Nakhamkin 2008). At least one proposed plant has considered an advanced CAES cycle (NYSEG 2009; Rettberg 2010).

Several other advanced CAES concepts were not included in RE Futures. These include aboveground CAES using pipes or other containers (which would have only a few hours of storage) or alternative fuels (such as liquid or gas biofuels). Other configurations not included in RE Futures include several proposed concepts that do not require natural gas. These include adiabatic CAES, which stores the heat of compression and uses this stored energy during expansion. This type of configuration has yet to be constructed, with cost and performance estimates based only on engineering studies (Grazzini and Milazzo 2008). However, at least one demonstration plant has been proposed in Europe (RWE 2010). Another approach being explored is isothermal CAES, which maintains constant temperature (Kepshire 2010).

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[172] The ARPA-E goal of $100/kWh includes both the power and energy component, including power conditioning equipment, installation, and other balance of system components. This corresponds to $800/kW for a device with 8 hours of storage capacity. This would require battery costs of well below $100/kWh, considering balance of system is currently a considerable fraction of $800/kW (U.S. DOE 2010b).

12.4 Resource Cost Curves

12.4.1 Batteries

Batteries do not have the geologic constraints of CAES or PSH. They also do not have fuel or water requirements, so they were assumed to be deployable at scale within each region.

12.4.2 Pumped-Storage Hydropower

New PSH development requires sufficient land for construction of the two requisite reservoirs, with a sufficient elevation difference between the reservoirs to enable economical generation.

Many areas of the United States offer suitable topography, and the technical potential of PSH is extremely large. Although there is no recent comprehensive estimate of PSH potential, older studies indicate the availability of hundreds of conventional PSH sites, more than 1000 GW of potential capacity in just six western states (Allen 1977), and more than 100 GW of potential in the Eastern Interconnection (Dames and Moore 1981). This capacity is roughly equivalent to the installed generation capacity for all of the United States (EIA n.d.). These older assessments include some areas that would be very difficult (or impossible) to develop based on current environmental restrictions. However, the capacity of recently proposed plants (exceeding 40 GW) is greater than the existing installed U.S. storage capacity and suggests there are considerable opportunities for new PSH capacity. RE Futures used an estimate for PSH availability based solely on the location and sizes of proposed plants for which data could be obtained (FERC n.d.). As a result, the developable potential of new PSH was fixed at 35 GW. Although this is much smaller than the technical potential of more than 1,000 GW, there are no data to estimate current development costs of this potential beyond engineering estimates that are as high as $5,595/kW. (Cost estimates are actually provided for much of this potential in the original assessment documents from the 1970s, but these costs are unlikely to reflect current market conditions.) The 35 GW of proposed capacity likely represents lower-cost opportunities as reflected in proposed costs, and reviews of these proposals were used to generate the two price points of $1,500/kW and $2,000/kW discussed in Section 12.1.3.2. Based on the reviews of proposed plants, the lower-cost value ($1,500/kW) was assigned to 10 GW of potential, while the higher cost ($2,000/kW) was assigned to 25 GW of potential. Figure 12-9 provides a map of the existing and proposed plants in the United States. The proposed plants were used to create a supply curve for new development (Figure 12-10), with the two cost points spread uniformly across the resource. Overall, the fact that costs could only be assigned to less than 4% of the technical potential indicates a fundamental need for understanding the potential of new PSH development.

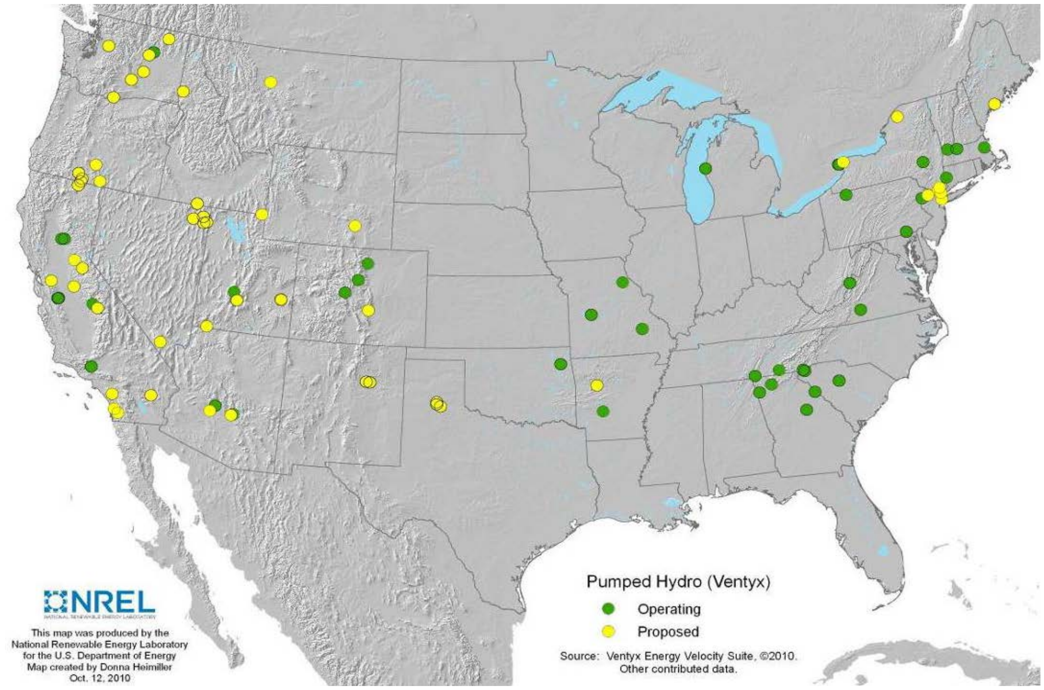

Figure 12-9. Location of existing and proposed (with Federal Energy Regulatory Commission preliminary permits) pumped-storage hydropower installations in the contiguous United States

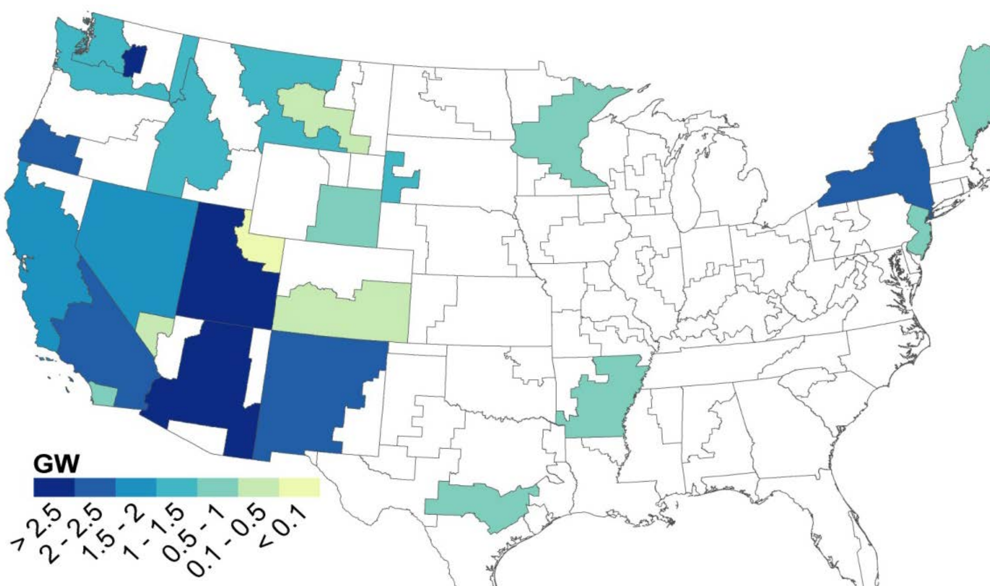

Figure 12-10. Pumped-storage hydropower resource potential used in the ReEDS modeling

12.4.3 Compressed Air Energy Storage

Estimating the amount of underground formations available for CAES is very difficult. Some estimates indicate that more than 75% of the land area of the United States could provide suitable geology for CAES projects (Allen 1985; Mehta 1992). However, each potential site must be individually screened, and this has proved challenging. For RE Futures, CAES deployment was limited to three options: domal salt, bedded salt, and porous rock (primarily aquifers).

Aquifer storage caverns are composed of permeable or fractured rock, and these formations are currently used to store natural gas. The identification of the necessary rock types and formations requires extensive geological testing to ensure the appropriate conditions exist for storage of compressed air. The major criteria for successful aquifer storage caverns are:

1. The existence of a structure shaped like an inverted saucer with the capability of sufficient air storage volume, which is determined from the porosity of the porous media comprising the aquifer
2. A continuous impermeable overlying caprock with a low permeability that inhibits the stored pressurized air from displacing water contained within the caprock pores
3. Sufficient structure depth (at least 600–800 feet or 183–244 m) having the full hydraulic pressure to assure adequate capacity of the aquifer pore volume along with the required characteristics to ensure adequate airflow from the formation
4. Permeability of the storage zone, not only in the air reservoir but also in the aquifer surrounding the structure.

The air under pressure will displace the water in the structure to form the storage reservoir. High permeability is needed to give a reasonable time to develop the reservoir and maintain proper airflow during injection and withdrawal.

CAES was excluded in certain porous rock formations such as depleted gas wells, except in California, where this application has been examined in some detail, and there is at least one proposed plant (Hobson et al. 1977; CEC 2008). Use of CAES in hard rock was also excluded due to lack of data. Although the cost of excavating hard rock solely for use in CAES is typically considered cost prohibitive, CAES could be used in existing depleted hard rock mines, and at least one large (2,700-MW) CAES plant has been proposed used an existing hard rock mine (Bauer and Webb 2000).

Figure 12-11 provides the estimates of CAES availability (in gigawatts) for the locations (by ReEDS balancing area), the availability (in gigawatts), and assumed cost (in dollars per kilowatt) for each of the three CAES deployment options (with the cost including both the power components and cavern development, assuming about 15 hours of storage capacity). For the contiguous United States, the potential CAES resource was estimated to exceed 120 GW, with about 23 GW in domal salt, 37 GW in bedded salt, and 62 GW in porous rock. No technology-driven cost improvements for CAES are assumed in the model scenarios.

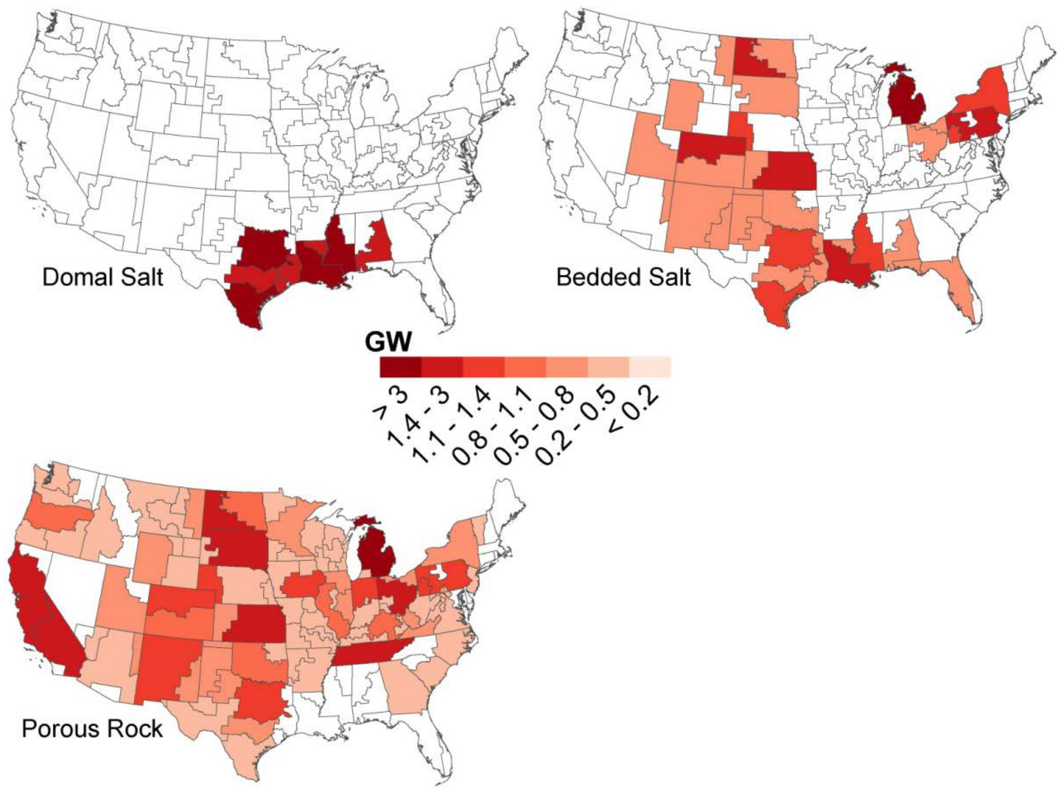

Figure 12-11. Assumed availability of compressed air energy storage in domal salt ($900/kW), bedded salt ($1,050/kW), and porous rock ($1,200/kW)

12.5 Output Characteristics and Grid Service Possibilities

Output characteristics and grid service possibilities are discussed in Section 12.3.

12.6 Deployment in RE Futures Scenarios

Deployment of new storage capacity is observed in all model scenarios described in Volume 1, and greater storage deployment is realized in scenarios with greater levels of renewables, and particularly variable renewable, penetration. For the (low-demand) core 80% RE scenarios described in Volume 1, 80–131 GW of new storage capacity was installed by 2050 in addition to the 20 GW of existing (PSH) storage capacity. Of the six core 80% RE scenarios, the constrained flexibility scenario projected the greatest level of storage deployment (152 GW of installed storage capacity by 2050). The constrained flexibility scenario was designed to capture greater institutional and technical barriers to managing variable generation, compared to the other 80% RE scenarios modeled. These barriers were implemented in ReEDS by halving the statistically calculated capacity values for wind and PV, increasing the reserve requirements for wind and PV forecast errors, reducing the flexibility of coal and biomass plants, and limiting the availability of demand response.[173] In the constrained flexibility scenario, new storage additions occur predominantly in the first two decades (2010–2030) of the study period, with an average annual installation rate of approximately 5 GW/yr and decade-averaged annual capital investments

[173] See Volume 1 for details on the design of the scenarios.

ranging from $4 billion/yr to $11 billion/yr between 2010 and 2030.[174] Figure 12-12 summarizes storage deployment in the constrained flexibility scenario, and Figure 12-13 shows the locations of storage deployment in the same scenario.

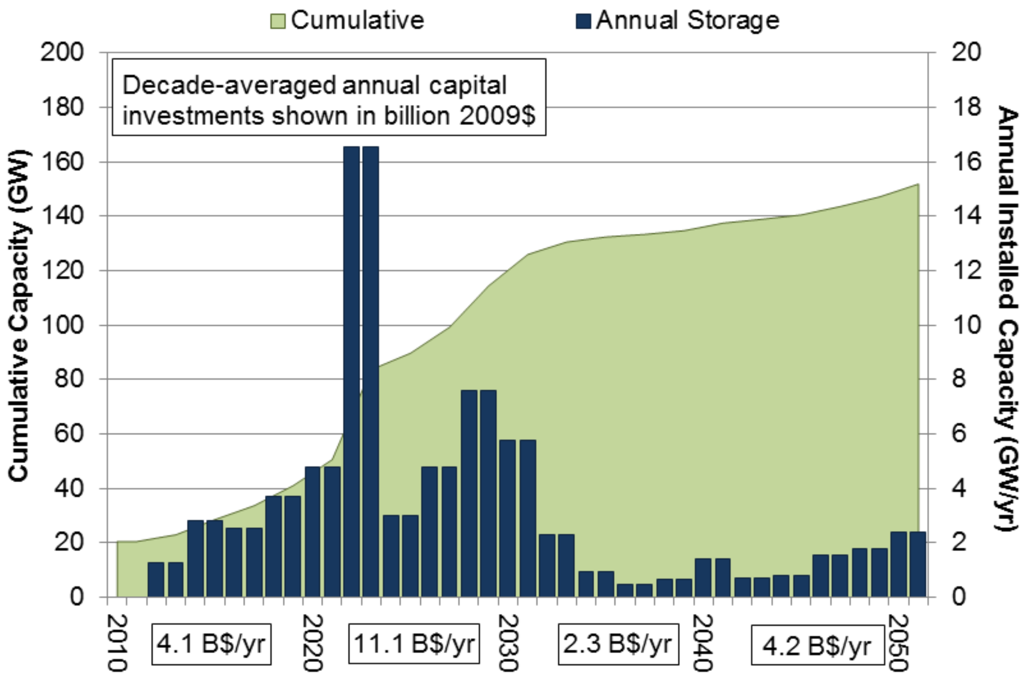

Figure 12-12. Deployment of energy storage technologies in the constrained flexibility scenario

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[174] As a cost optimization model, ReEDS produces deployment results that can fluctuate greatly from year to year, whereas the actual deployment of technologies tends to vary more smoothly over time.

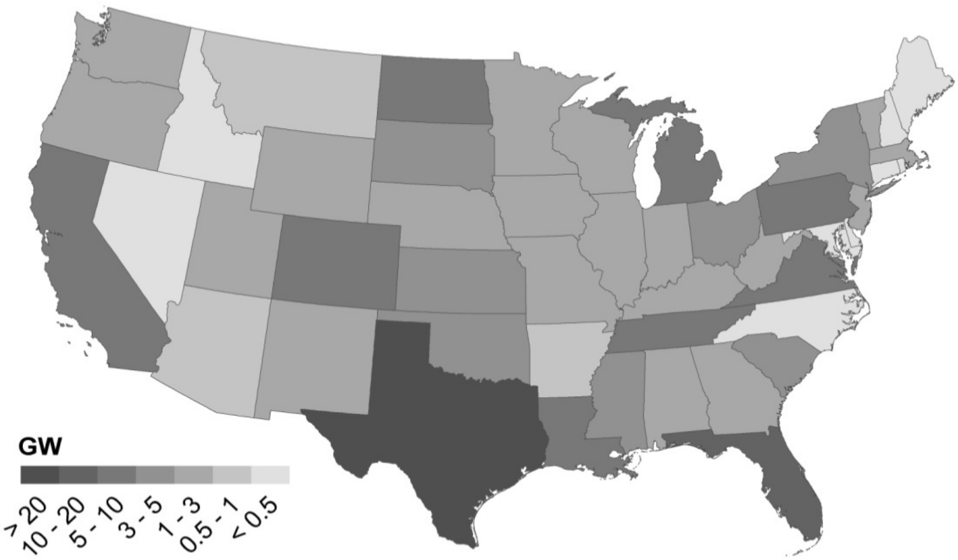

Figure 12-13. Regional deployment of storage in the contiguous United States in the constrained flexibility scenario

As discussed earlier, the modeled deployment indicates the general amount of storage that might be used to enable a high renewables scenario rather than to indicate a prescribed amount of each technology type. As a result of the modeling assumptions, most of the new storage is CAES; however, the tradeoff between CAES and PSH is largely due to the modeling and data limitations associated with the vast majority of potential PSH in much of the United States. In addition, the relative risk associated with CAES versus PSH was not considered. PSH is a proven technology, while CAES has yet to be deployed in either bedded salt or in porous rock formations, which represents a large fraction of assumed deployments. The limited deployment of batteries is due to their high cost and assumed minimal cost reduction but also to a lack of valuation of their benefits to the distribution system. This demonstrates an obvious discrepancy with relative historical and proposed deployment of these technologies, where PSH dominates. *The analysis of energy storage technologies for RE Futures demonstrates the need for more comprehensive estimates of the cost and resource availability for both CAES and PSH*.

Table 12-7 and Figure 12-14 show the variation in storage deployment between the low-demand core 80% RE scenarios and the high-demand 80% RE scenario. Between these scenarios, the 2050 installed storage capacity ranged from about 100 GW to 152 GW. A lower level of storage deployment is found under the 80% RE-ETI scenario, which included high levels of deployment of CSP with thermal storage and a corresponding lower deployment of variable generation technologies, thereby mitigating some of the need for the non-thermal storage technologies. Conversely, greater wind deployment in the 80% RE-NTI scenario and greater wind and PV deployment in the high-demand 80% RE scenario motivated high levels of storage deployment, although these two scenarios still realized slightly lower levels of deployment than the constrained flexibility scenario detailed above. Descriptions and results of the model scenarios are detailed in Volume 1.

Table 12-7. Deployment of Energy Storage Technologies in 2050 under 80% RE Scenarios[a,b]

Scenario	Capacity (GW)
Constrained Flexibility	152
80% RE-NTI	142
High-Demand 80% RE	136
Constrained Resources	131
Constrained Transmission	129
80% RE-ITI	122
80% RE-ETI	100

[a] See Volume 1 for a detailed description of each RE Futures scenario.
[b] Capacity totals represent the cumulative installed capacity for each scenario.

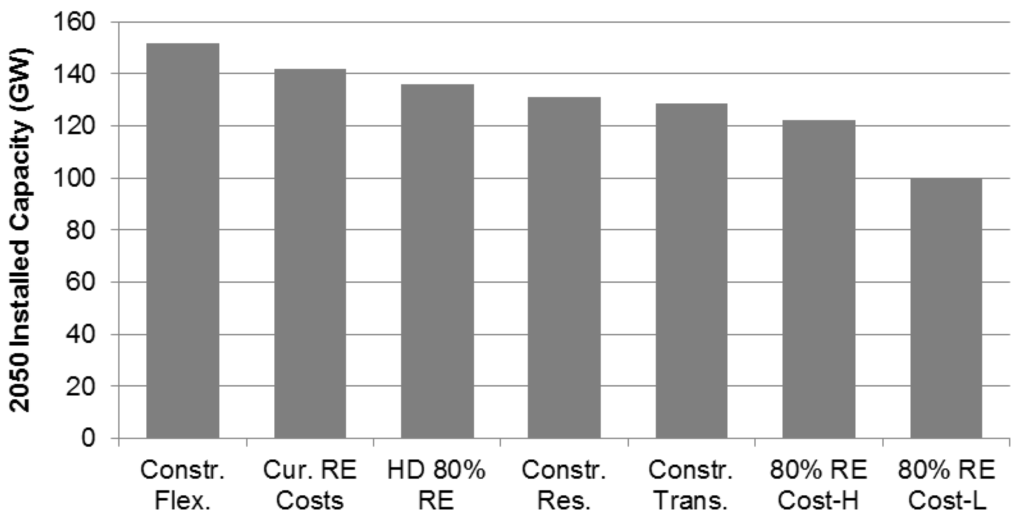

Figure 12-14. Deployment of energy storage technologies in 80% RE scenarios

12.7 Large-Scale Production and Deployment Issues

12.7.1 Environmental and Social Impacts

The impacts of energy storage are a function of two components. First is the localized impact due to development and direct use of the individual energy storage technologies. These vary significantly given the large differences in technology types. The second is associated with the upstream source of electricity, and the increased generation typically required due to inefficiencies in the storage process.

12.7.1.1 Land Use

Land use estimates for batteries are limited due to the lack of deployment at scale. For NaS, one estimate is approximately 211 m^2/MW with a 7.2-hour storage capacity (NGK n.d.), or approximately 300–350 m^2/MW for a 10- to 12-hour device more comparable to CAES or PSH. An estimate for a proposed (and subsequently cancelled) large (12 MW, 100–120 MWh) flow battery was approximately 850 m^2/MW (EPRI/DOE 2003) with additional land surrounding the facility (TVA 2001).

Land use impacts of CAES deployment are minimal because most of the plant is effectively underground. The land area estimates for one proposed CAES facility is approximately 140 m^2/MW (Norton Energy Storage 2000).

Pumped-storage hydropower can require a significant amount of land area for the upper and lower reservoir, depending on configuration. The total flooded area of three of the more recently constructed large PSH plants in the United States (the Bad Creek Hydroelectric Station in South Carolina, the Balsam Meadow Pumped Storage Project in California, and the Bath County Pumped Storage Station in Virginia) is in the range of 1,200 m^2/MW to 1,500 m^2/MW (ASCE 1993). Older PSH facilities with constructed upper and lower reservoirs have flooded areas that exceed 4,000 m^2/MW. New plants are more likely to have land use requirements towards the lower range, such as the proposed Eagle Mountain and Iowa Hill plants with flooded area requirements of approximately 1,100 m^2/MW (Tam 2008; Parfomak 2012). Additional discussion of land use associated with hydropower in general is provided in Chapter 8.

12.7.1.2 Water Use

For CAES, the dominant use of water is for formation of underground caverns in domal or bedded salt. Water use for solution mining is likely to be about 8 m^3 of water for each cubic meter excavated (Smith 2008) or about 4.8 million m^3 of fresh water withdrawals and brine management per 220-MW plant. Disposal of brine has been raised as a concern for some locations (Smith 2008). Additional cooling water is required during operation of the compressors, with one estimate of 2.5–3.0 million gallons per day for a 2700-MW facility (Ohio Power Siting Board 2001). Assuming a capacity factor of 25%, this corresponds to approximately 0.2 gallons/kWh.

Analysis and discussion of water impacts of PSH include Clugston (1980) and U.S. Bureau of Reclamation et al. (1993). Impacts on water quality and aquatic life have greatly delayed and even prevented operation of completed PSH facilities (Southeastern Power Administration 2009; U.S. GAO 1996). The actual water use and impacts of PSH depend partially on the source for the lower reservoir. Most existing U.S. PSH plants are “open-cycle” plants; that is, they use an existing water body, usually the lower reservoir, for one of their reservoirs. However “closed-cycle” plants—plants where both lower and upper reservoirs are constructed—will likely become more prevalent in the future because they minimize environmental effects as they do not interact with natural water bodies and they have little or no impact on aquatic life. Water sources for closed-cycle plants vary. Some proposed plants will use groundwater for the initial fill and make-up water required to replace seepage and evaporation. One estimate for make-up water for a 1,300-MW facility is 782 million gallons/yr (Tam 2008). Assuming a capacity factor of 25% (2,847 GWh/yr), this corresponds to a water consumption rate of approximately 0.3 gallons/kWh. At least one facility has proposed to use recycled wastewater, and it has been suggested that this could be a significant opportunity for other new PSH facilities (Yang and Jackson 2011).

12.7.1.3 Life Cycle Greenhouse Gas Emissions

Energy storage can add to net greenhouse gas (GHG) emissions in three ways. First, the losses associated with storage efficiencies increase the electricity needed to produce a unit of delivered energy via storage (energy storage losses can be partially offset by increased efficiency of thermal generators that is due to either operation that is closer to the "design point" or a reduced need for ancillary services [Denholm and Holloway 2005]). Second, energy storage technologies produce life cycle emissions that are due to construction and operations. These life cycle values for PSH, several battery types, and CAES (excluding natural gas use) are in the range of 5–40 grams equivalent carbon dioxide per kilowatt-hour (gCO_2e/kw) depending on operation, lifetime, and other factors (Denholm and Kulcinski 2004). This includes the methane emissions from vegetation decomposition by land flooded by new PSH reservoirs, which are relatively small, especially for sites in the United States (Gagnon and van de Vate 1997; Rosa and dos Santos 2000). Finally, CAES burns natural gas, emitting GHG emissions at a rate of about 215–240 gCO_2e/kWh of delivered energy, assuming a heat rate range of 4,000–4,400 Btu/kWh (plus GHG emissions associated with production and transport of natural gas.)

Given the uncertainty in storage technology mixes, and given limited data, the life cycle GHG emissions impacts due to energy storage manufacturing were not evaluated, resulting in a small underestimation of system-wide GHG emissions for the non-fuel storage component. However, the CAES fuel combustion emissions were counted. Thus, the degree of underestimation is likely very small because of both the limited deployment of storage and their relatively small emissions.

12.7.1.4 Other Waste and Emissions

In general, with the exception of CAES, energy storage does not require direct fuel or combustion processes, so it produces no direct air emissions. The use of natural gas in CAES produces the various impacts associated with gas exploration, production, transmission, and combustion. This produces emissions such as nitrogen oxides in a manner similar to conventional gas turbines, but at a correspondingly lower rate given the much lower heat rate. Nitrogen oxide emissions can be controlled using conventional emissions controls such as selective catalytic reduction, which has been proposed for use in the CAES plants under consideration (Norton Energy Storage 2000; CEC 2008.)

Batteries use a variety of materials, some of which are toxic. Lead and cadmium are examples, and collection and recycling programs are generally in place to avoid improper disposal (EPRI/DOE 2003). Additional programs would be required for new battery chemistries, depending on their level of deployment and materials used.

12.7.2 Manufacturing and Deployment Challenges

Both CAES and PSH are based on mature technologies that have been previously deployed in the United States at scale. For example, the equipment required for CAES is very similar to conventional gas turbines, and the historical installation of gas turbines has exceeded 10 GW/yr in some years (EIA n.d.). An additional discussion of issues related to PSH manufacturing is provided in Chapter 8. For batteries, the primary issues for large-scale deployment may be related to a combination of materials requirements and competition with automotive applications. Wadia et al. (2011) discusses this issue at length and finds essentially no material challenges for some technologies such as NaS, but potential constraints on others, such as Vanadium Redox or certain lithium-ion batteries using cobalt.

12.8 Barriers to High Penetration and Representative Responses

Although capital cost is a primary barrier to deployment of energy storage, many regulatory and market barriers prevent energy storage from competing equally with more conventional technologies that provide energy and capacity services.

Table 12-8 summarizes actions that could enable greater use of energy storage. Table 12-8 includes only a small subset of energy storage technologies. Other existing and emerging storage technologies could be deployed in substantial numbers given appropriate decreases in costs.

Table 12-8. Barriers to High Penetration of Electricity Storage Technologies and Representative Responses

R&D	**Barrier**	**Representative Responses**
Batteries	High capital cost, limited cycle life	Conduct fundamental science and engineering to improve power and energy density; research new electrolyte materials; standardize and integrate power conversion systems
CAES	Cost, efficiency, unproven availability of sites	Research and development into advanced CAES cycles, including cycles that reduce or eliminate use of natural gas; demonstrate CAES in aquifers, bedded salt, and depleted gas wells; conduct detailed national screening of suitable geologic formations
PSH	Availability of sites	Conduct detailed national screening of suitable formations
Market and Regulatory	**Barrier**	**Representative Responses**
All	Limited value proposition for energy storage	Provide comprehensive analysis of the system benefits of storage, including utility operations models that accurately represent the complete set of benefits of energy storage over multiple timescales
All	Unclear treatment of energy storage in regulatory framework	Establish a regulatory framework that provides fair and equitable cost-recovery mechanisms for new storage development congruent with its system benefits
Environmental and Siting	**Barrier**	**Representative Responses**
PSH	Land and water use	Conduct detailed screening of opportunities for closed-cycle plants, and siting on brown fields and other disturbed land

12.8.1 Research, Development, and Deployment

For batteries (and other electro-chemical storage technologies), most RD&D efforts are focused on reducing capital cost, increasing power and energy density, and increasing lifetimes. Several recent reports identify fundamental research and engineering needs for improving basic technologies, as well as developing manufacturing techniques to bring laboratory technologies to commercial products and to bring next-generation technologies to market (Hall and Bain 2008; APS 2007; DOE 2007).

The primary RD&D issues associated with both PSH and CAES are related to resource assessment. There is no known comprehensive assessment of the total availability of PSH or CAES geology to assess the resource potential, although efforts are underway by DOE and others to perform additional resource assessment for both technologies (Rogers et al. 2010). Additional near-term RD&D activities can aid in developing dedicated turbo-machinery equipment for CAES, providing incremental improvements in both cost and performance if deployed at large scale. Similarly, RD&D can provide incremental improvements to PSH pump-turbine equipment, and could examine opportunities to convert existing single speed units to variable speed operation (ORNL et al. 2010).

12.8.2 Market and Regulatory

The primary market and regulatory barrier to storage deployment in general is lack of appropriate valuation of storage benefits. Until recently, the value of ancillary services was largely unquantified. The creation of wholesale markets has placed value on those services and has increased participation of energy storage devices, but the level of participation varies by market.[175] In 2007, FERC issued Order 890 requiring wholesale markets to consider non-generation resources for grid services (Kaplan 2009). Since then, independent system operators and regional transmission operators have increased market access, including creating new tariffs for energy storage, and several storage projects have been proposed or built to take advantage of high-value ancillary service markets. However, market rules are still evolving in some locations (and of course, much of the United States has no access to restructured energy markets). A main benefit of energy storage is also its ability to provide multiple services, including load leveling (and associated benefits such as a reduction in cycling-induced maintenance) (Troy et al. 2010; Grimsrud et al. 2003) along with regulation and contingency reserves and firm capacity (Eyer and Corey 2010). However, quantifying these various value streams is difficult without sophisticated modeling and simulation methods. Because the economic analysis is difficult and benefits of storage are often uncertain, utilities tend to rely on more traditional generation assets, especially in regulated utilities where risk is minimized and new technologies are adopted relatively slowly. Changing and uncertain regulations and market structures also deter projects with long development times such as PSH, or uncertain technology challenges, such as CAES with site-specific geological screening requirements.

There are additional barriers to individual technologies. For PSH, the challenge of long permitting times could be reduced by applying an alternative licensing process to closed-cycle

[175] While ancillary services markets have been created in locations with restructured markets, large areas of the United States, including the entire West (excluding California) and most of the Southeast.

plants. These plants could be candidates for a streamlined FERC permitting process given their lack of interaction with any active stream, lake, or estuary.

12.8.3 Siting and Environmental Barriers

The primary siting challenge for new PSH and CAES is finding suitable geologic formations, discussed previously. PSH also faces potential opposition due to environmental impacts, which can be partially mitigated using closed-cycle plants. Both PSH and CAES plants are typically large, requiring new high-voltage transmission, which adds additional challenges, especially considering potentially remote locations. For batteries, the primary concern is the potential release of materials from liquid electrolyte flow-batteries. Proper containment and mitigation is required to minimize possible impacts (TVA 2001).

12.9 Conclusions

Energy storage is one of several potentially important enabling technologies supporting large-scale deployment of renewable energy, particularly variable renewables such as solar PV and wind. Energy storage is used in electric grids in the United States and worldwide. It is dominated by PSH. In addition to PSH, high-energy batteries and CAES can provide energy management services—shifting energy from periods of low demand to periods of high demand, which reduces curtailment and eases integration challenges associated with high levels of variable renewable generation—and were included in the RE Futures analysis. New storage capacity was deployed in all of the modeled scenarios and greater storage deployment is realized in scenarios with greater levels of renewables, and particularly variable renewable, penetration.

Capital cost is a primary barrier to deployment of energy storage. In addition, many regulatory and market barriers prevent energy storage from competing equally with more conventional technologies that provide energy and capacity services. A key issue for large-scale deployment of new storage capacity is finding suitable geologic formations for conventional PSH and CAES. PSH also faces potential opposition due to environmental impacts, which can be partially mitigated using closed-cycle plants. Both PSH and CAES plants are typically large, requiring new high-voltage transmission, which adds additional challenges, especially considering potentially remote locations. Batteries do not have the geologic constraints of CAES or PSH but large-scale deployment may face challenges related to a combination of materials requirements and competition with automotive applications.

More comprehensive estimates of the cost and resource availability for both CAES and PSH, advances in batteries to reduce capital cost, increase power and energy density, and increase lifetimes, and changes in market and regulations to quantify and value the ancillary services provided by energy storage are needed to support large-scale deployment of energy storage technologies in a high renewable electricity future.

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Appendix E. Supplemental Information for Biopower Technologies

This appendix presents additional information on biopower capacities and capital costs. Tables E-1 and E-3 are also given in the biopower chapter and are repeated here for comparison to the detailed tables in the Appendix. All acronyms and abbreviations that are used in this appendix but are not defined where they are used are listed in Table E-16.

Table E-1. Capacity and Generation, 2006–2010[a]

Net Summer Capacity, GW	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Electric Power Sector [b]								
Municipal Waste	3.19	3.19	3.21	3.39	3.42	3.43	3.20	3.30
Wood and Other Biomass	2.00	2.04	1.96	2.01	2.09	2.17	2.43	2.45
Total	**5.19**	**5.23**	**5.17**	**5.40**	**5.51**	**5.60**	**5.63**	**5.75**
End-Use Generators [c]								
Municipal Waste	0.27	0.33	0.34	0.33	0.33	0.33	0.36	0.35
Biomass	4.32	4.66	4.72	4.64	4.88	4.86	4.56	4.56
Total	**4.59**	**4.99**	**5.06**	**4.97**	**5.21**	**5.19**	**4.92**	**4.91**
Total, All Sectors								
Municipal Wastes	3.46	3.52	3.55	3.72	3.75	3.76	3.56	3.65
Biomass	6.32	6.70	6.68	6.65	6.97	7.03	6.99	7.01
Total	**9.78**	**10.22**	**10.23**	**10.37**	**10.72**	**10.79**	**10.55**	**10.66**
Generation, TWh								
Electric Power Sector								
Biogenic Municipal Wastes	20.84	19.86	12.70	13.71	13.88	14.49	16.10	16.56
Wood and Other Biomass								
Dedicated Plants	9.53	8.54	8.60	8.42	8.65	9.00	9.68	10.15
Co-Firing	0.00	1.19	1.97	1.91	1.94	1.90	1.06	1.36
Total	**30.37**	**29.59**	**23.27**	**24.04**	**24.47**	**25.39**	**26.84**	**28.07**
End-Use Generators								
Municipal Wastes	2.22	2.64	1.95	1.98	2.01	2.02	2.07	2.02
Biomass	28.00	28.90	28.33	28.32	28.43	27.89	25.31	26.10
Total	**30.22**	**31.54**	**30.28**	**30.30**	**30.44**	**29.91**	**27.38**	**28.12**
Total, All Sectors								
Municipal Wastes	23.06	22.50	14.65	15.69	15.89	16.51	18.17	18.58
Biomass	37.53	38.63	38.90	38.65	39.02	38.79	36.05	37.61
Total	**60.59**	**61.13**	**53.55**	**54.34**	**54.91**	**55.30**	**54.22**	**56.19**
EIA Form 923 Actual Generation					**55.40**	**55.06**	**54.34**	

[a] In 2003, co-firing plants classified as coal, 2003 data (EIA 2006), 2004 data (EIA 2007), 2005 data (EIA 2008b), 2006 data (EIA 2009), 2007–2009 data (EIA 2010b), 2010 data (EIA 2012)
[b] Include electricity-only and combined heat and power plants whose primary business is no to sell electricity, or electricity and heat, to the public
[c] Includes combined heat and power plant and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

Table E-2. Capacity, 2008 (December 31)[a]

Biomass Category	Number of Generating Units[b]	Summer Capacity (MW)
Biomass (AB, OBS, OBL, SLW, WDL, WDS)	179	3,006
Landfill Gas	1,157	1,362
Municipal Solid Waste	94	2,213
Other Biomass Gas	77	155
Black Liquor	145	3,663
Total	1,652	10,398
Fossil Fuel Co-Firing (Unit Capacity)	78	2,323

[a] Note: Many biomass units can co-fire fossil fuel, not separated in this table
http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html (March 31, 2010)
[b] This columns shows the number of generators, not facilities.

Table E-3. Generation, 2007 (EIA 2008a)

Fuel Code	Fuel Code Description	AER Code	AER Description	Reporting Units	Physical Unit Label	Total Fuel Consumption Quantity	Total Fuel Consumption (MMBtu)	Electric Fuel Consumption (MMBtu)	Net Generation (TWh)
AB	Agricultural Crop Byproducts/Straw/ Energy Crops	ORW	Other Renewables and Waste	15	short tons	3.510E+06	3.175E+07	6.809E+06	0.75
BLQ	Black Liquor	WWW	Wood and Wood Waste	94	short tons	6.772E+07	7.833E+08	1.177E+08	18.68
LFG	Landfill Gas	MLG	MSW & Landfill Gas	245	Mcf	1.688E+08	8.070E+07	7.971E+07	6.16
MSB	MSW - Biogenic Component	MLG	MSW & Landfill Gas	83	short tons	2.180E+07	1.625E+08	1.463E+08	8.30
OBG	Other Biomass Gas	ORW	Other Renewables and Waste	40	Mcf	1.593E+07	1.025E+07	6.762E+06	0.68
OBL	Other Biomass Liquids	ORW	Other Renewables and Waste	9	barrels	4.421E+04	1.753E+05	1.414E+05	0.01
OBS	Other Biomass Solids	ORW	Other Renewables and Waste	17	short tons	1.201E+06	1.203E+07	4.300E+06	0.42
SLW	Sludge Waste	ORW	Other Renewables and Waste	32	short tons	1.333E+06	2.800E+06	3.477E+05	0.07
WDL	Wood Waste Liquids	WWW	Wood and Wood Waste	3	barrels	1.333E+06	2.800E+06	3.477E+05	0.07
WDS	Wood/Wood Waste Solids	WWW	Wood and Wood Waste	224	short tons	5.291E+07	5.494E+08	2.350E+08	20.27
	Totals					3.345E+08	1.636E+09	5.974E+08	55.40

Table E-4. Generation, 2008 (EIA 2008a)

Fuel Code	Fuel Code Description	AER Code	AER Description	Reporting Units	Physical Unit Label	Total Fuel Consumption Quantity	Total Fuel Consumption (MMBtu)	Electric Fuel Consumption (MMBtu)	NET Generation (TWh)
AB	Agricultural Crop Byproducts/Straw/ Energy Crops	ORW	Other Renewables and Waste	18	short tons	4.234E+06	3.228E+07	7.741E+06	0.78
BLQ	Black Liquor	WWW	Wood and Wood Waste	89	short tons	6.537E+07	7.435E+08	1.133E+08	17.33
LFG	Landfill Gas	MLG	MSW & Landfill Gas	283	Mcf	1.968E+08	9.477E+07	9.422E+07	7.16
MSB	MSW - Biogenic Component	MLG	MSW & Landfill Gas	78	short tons	2.213E+07	1.667E+08	1.485E+08	8.10
OBG	Other Biomass Gas	ORW	Other Renewables and Waste	38	Mcf	1.301E+07	8.584E+06	6.329E+06	0.63
OBL	Other Biomass Liquids	ORW	Other Renewables and Waste	14	barrels	8.592E+04	2.853E+05	1.226E+05	0.01
OBS	Other Biomass Solids	ORW	Other Renewables and Waste	19	short tons	2.076E+06	2.071E+07	9.261E+06	0.90
SLW	Sludge Waste	ORW	Other Renewables and Waste	29	short tons	8.567E+05	4.858E+06	1.081E+06	0.18
WDL	Wood Waste Liquids	WWW	Wood and Wood Waste	1	barrels	1.195E+06	2.510E+06	3.832E+05	0.07
WDS	Wood/Wood Waste Solids	WWW	Wood and Wood Waste	223	short tons	5.103E+07	5.167E+08	2.251E+08	19.90
	Totals					3.568E+08	1.591E+09	6.060E+08	55.06

Table E-5. Generation, 2009 (EIA 2008a)

Fuel Code	Fuel Code Description	AER Code	AER Description	Reporting Units	Physical Unit Label	Total Fuel Consumption Quantity	Total Fuel Consumption (MMBtu)	Electric Fuel Consumption (MMBtu)	Net Generation (TWh)
AB	Ag Crop Byproducts/Straw/ Energy Crops	ORW	Other Renewables and Waste	18	short tons	2.835E+06	3.371E+07	7.374E+06	0.76
BLQ	Black Liquor	WWW	Wood and Wood Waste	67	short tons	5.995E+07	6.870E+08	1.046E+08	16.55
LFG	Landfill Gas	MLG	MSW & Landfill Gas	96	Mcf	2.250E+08	9.160E+07	9.011E+07	7.35
MSB	MSW - Biogenic Component	MLG	MSW & Landfill Gas	55	short tons	2.013E+07	1.630E+08	1.454E+08	8.34
OBG	Other Biomass Gas	ORW	Other Renewables and Waste	26	Mcf	1.429E+07	8.857E+06	6.031E+06	0.61
OBL	Other Biomass Liquids	ORW	Other Renewables and Waste	14	barrels	2.893E+07	3.108E+05	1.577E+05	0.02
OBS	Other Biomass Solids	ORW	Other Renewables and Waste	16	short tons	1.621E+06	1.818E+07	8.332E+06	0.83
SLW	Sludge Waste	ORW	Other Renewables and Waste	26	short tons	4.126E+06	5.134E+06	1.161E+06	0.18
WDL	Wood Waste Liquids	WWW	Wood and Wood Waste	1	barrels	1.239E+06	2.601E+06	3.868E+05	0.07
WDS	Wood/Wood Waste Solids	WWW	Wood and Wood Waste	151	short tons	4.970E+07	4.977E+08	2.125E+08	19.62
	Totals			470			1.508E+09	5.761E+08	54.34

Table E-6. Summary of Capital and Operating Costs

Technology (2010$)	Year	Plant Size (MW)	Capital Cost Overnight	Capital Cost w/ AFUDC	Operating Costs Fixed	Operating Costs Variable	Operating Costs Feed[a]		Heat Rate	Reference
			(1,000 $/MW)		($/kW-yr)	($/MWh)	($*/tonne)	($/MWh)	(MMBtu MWh)	
Combustion, stoker	2010	50	3,657	3,794	99	4	82.60	59	12.50	McGowin (2007)
Combustion, stoker	2010	50	3,742	4,092	99	5	82.60	68	14.48	DeMeo and Galdo (1997)
Combustion, CFB	2010	50	3,771	3,911	102	6	82.60	59	12.50	McGowin (2007)
Combustion, BFB[b]	2010	50	3,638	–	94	5	82.60	63	13.50	EIA (2010a)
CHP	2010	50	3,859	4,002	101	4	82.60	67	14.25	McGowin (2007)
Gasification, base	2010	75	4,194	4,417	94	7	82.60	44	9.49	DeMeo and Galdo (1997)
Gasification, advanced	2010	75	3,607	3,795	60	7	82.60	38	8.00	DeMeo and Galdo (1997)
Gasification, IGCC[b]	2010	20	7,498	–	322	16	82.60	58	12.35	EIA (2010a)
Composite[c]	2010	50	3,872	–	95	15	82.60	68	14.50	RE Futures (Appendix A, Volume 1)
Composite[c]	2030	50	3,872	–	95	15	82.60	63	13.50	RE Futures (Appendix A, Volume 1)
Composite[c]	2050	50	3,872	–	95	15	82.60	59	12.50	RE Futures (Appendix A, Volume 1)
Co-Firing, PC Co-feed[d]	2010	20	559	555	13	2	82.60	47	Coal Heat Rate +1.5%	McGowin (2007)
Co-Firing, Cyclone Co-feed[d]	2010	20	353	353	13	1	82.60	47	Coal Heat Rate +1.5%	McGowin (2007)
Co-Firing, separate feed[d]	2010	—	1,000		20	0	82.60	47	10.00	RE Futures (Appendix A, Volume 1)
Municipal solid waste	2009	—	7,251	7,601	265	29.1	--	--	16.46	EPRI (1993)

[a] Using a typical biomass cost of $82.60/tonne ($75/ton)
[b] Preliminary: Costs adjusted using CEPCI August 2010 value
[c] B&V used a composite combustion and gasification mix, with gasification increasing over time
[d] Biomass cost based on heat rate of 10.00 MMBtu/MWh

Table E-7. Base Rankine Cycles (2010$) (McGowin 2007)

		Stoker	CFB[a]	CHP[b]
Capacity	MWe	50	50	50
Cogen Steam Output	1000lb/hr			100
Cogen Steam Conditions	psig, sat			100
Year $		2010	2010	2010
Physical Plant				
Unit Life	years	30	30	30
Construction Schedule				
Preconstion, License, and Design Times	years	1.5	1.5	1.5
Idealized Plant Construction Time	years	2	2	2
Capital Costs	$/kW			
Fuel Handling, Prep		119	119	129
Boiler and Air Quality Control		783	875	851
Steam Turbine and Auxiliaries		620	620	704
Balance of Plant		246	246	246
General Facilities and Engineering Fee		1148	1148	1148
Project and Process Contingency		109	112	114
Total Plant Cost (TPC)		3025	3120	3192
AFUDC[c]		137	140	143
Escalation During Construction				
Total Plant Investment (TPI)		3161	3260	3335
Owner Costs	$/kW			
Due Diligence, Permitting, Legal, Development		632	651	667
Taxes and Fees		0	0	0
Total Capital Requirements (TCR)	**$/kW**	**3794**	**3911**	**4002**
O&M Costs				
Fixed	$/kW-yr	98.9	101.8	100.7
Variable	$/MWh	4.0	4.6	4.1
Feed @ $75/ton	$/MWh	58.59	58.59	66.80
Performance/Unit Availability				
Net Heat Rate	Btu/kWh	12500	12500	14250
	MMBtu/MWh	12.50	12.50	14.25
	%	27.31	27.31	23.96
Equivalent Planned Outage Rate	%	4	4	4
Equivalent Unplanned Outage Rate	%	6	6	6
Equivalent Availability	%	90	90	90
Emission Rates				
CO_2	lb/MMBtu	220	220	220
NO_x	lb/MMBtu	0.15	0.08	0.15
SO_x	lb/MMBtu	0.10	0.04	0.10

[a] Circulating fluid bed boiler
[b] Combined heat and power
[c] Allowance for funds utilized during construction

Table E-8. Costs for Direct Combustion (DeMeo and Galdo 1997)

Cost component	Units	Cost Factor	Scale Factor	RETC97	Updated to 2010$	Adjusted Heat Rate
Year $	$			1997	2010	2010
Cost Index (2 = M&S, 3 = CE)			2	97.04	133.83	133.83
Plant Size	MWe			50	50	50
Heat Rate	Btu/kWh			14483	14483	12500
	MMBtu/MWh			14.48	14.48	12.50
	Eff, %			23.56	23.56	27.30
Biomass Heating Value	MJ/kg			20.00	20.00	20.00
	MMBtu/ton			17.23	17.23	17.23
Biomass Feed Rate	dry short ton/day			1,009	1,009	870
	dry tonne/day			915	915	790
Stream Factor	%			80%	80%	80%
	MWh/yr			350,400	350,400	350,400
Feed	Dry short ton/yr			2.945E+05	2.945E+05	2.542E+05
Feed Price	$/short ton			4.760E+01	7.500E+01	7.500E+01
Capital Cost	$/kW					
Fuel Preparation				181	250	215
Dryer				—		—
Boiler				444	612	528
Baghouse & Cooling Tower				29	40	35
Boiler Feedwater/deaerator				56	77	67
Steam turbine/generator				148	204	176
Cooling Water System				66	91	79
Balance of Plant				273	376	325
General Plant Facilities				310	428	369
Direct Fixed Capital (DFC), also called TIC				1507	2078	1794
Engineering	DFC x MF	0.12		181	249	215
Construction	DFC x MF	0.13		196	270	233
Contractor & Legal	DFC x MF	0.08		121	166	143
Total Plant Cost (TPC)				2004	2764	2386
AFUDC	DFC x MF	0.1		151	208	179
Total Plant Investment (TPI)				2155	2972	2565
Prepaid Royalties				0	—	—
Initial Cat. and Chem. Inventory				2	3	3
Inventory Capital				11	15	13
Land				14	20	17
Startup				53	73	63
Total Capital Cost (TCC)				2236	3084	2661
Contingency/TPI	TCC*MF	0.3		671	925	798
Working Capital	DFC x MF	0.05		100	138	119
Total Capital Requirement	$/kW			3,007	4,147	3,579

Table E-9. Costs for Co-Firing (McGowin 2007)

	Units	Cyclone	Pulverized Coal	Cyclone	Pulverized Coal
Year $		2006	2006	2010	2010
Coal Plant Size	MWe	200	200	200	200
Biomass Feed System		Blended	Separate	Blended	Separate
Biomass Output Fraction	%	10	10	10	10
Biomass Equivalent Power	MWe	20	20	20	20
Physical Plant					
Life	years	10 to 20	10 to 20	10 to 20	10 to 20
Landing Area Required	acres	1	5	1	5
Scheduling					
Preconst., License & Design Time	years	1	1	1	1
Construction Time	years	0.5	1	0.5	1
Capital Costs	$/kW				
Fuel Handling/Prep		192	310	215	347
Boiler Modification		3	38	3	43
Balance of Plant		55	55	62	62
General Facilities and Engineering		15	20	17	22
Project & Process Contingency		40	63	45	71
Total Plant Cost (TPC)		305	486	341	544
AFUDC		0	0	0	0
Total Plant Investment (TPI)		305	486	341	544
Owner's Costs	$/kW				
Due Diligence, Permitting, Legal, Development		10	10	11	11
Taxes and Fees		0	0	0	0
Total Capital Requirements	$/kW	315	496	353	555
O&M Costs (based on biomass)					
Fixed	$/kW-yr	11.6	11.6	13.0	13.0
Variable	$/MWh	1.2	1.6	1.3	1.8
Feed	$/MWh				
Performance/Unit Availability					
Change in Net Heat Rate	%	1.5	1.5	1.5	1.5
Emissions Offsets vs 100% Coal					
CO2 (derived from coal)	%	-8	-8	-8	-8
NOx	%	-0 to -20	-0 to -20	-0 to -20	-0 to -20
SOx	%	-8	-8	-8	-8

Table E-10. Costs for Municipal Solid Waste (DeMeo and Galdo 1997)

	Units	Stoker 1992$	Stoker 2010$
Capacity	MWe	40	40
Year $		1,992	2,010
M&S		86.60	133.83
Physical Plant			
Unit Life	years	20	20
Construction Schedule			
Preconstruction, License, and Design Times	years	2.0	2.0
Idealized Plant Construction Time	years	2	2
Capital Costs	$/kW		
Fuel Handling, Prep		1,479	2,286
Boiler, BFW/Deaerator Systems		960	1,484
Steam Turbine and Auxiliaries		154	238
Cooling Water System		74	114
Balance of Plant		274	423
Environmental Capital		345	533
General Facilities and Engineering Fee		714	1,103
Project and Process Contingency		545	842
Total Plant Cost (TPC)		4,545	7,024
AFUDC		236	365
Escalation During Construction			
Total Plant Investment (TPI)		4,781	7,388
Total Cash Expended		4,692	7,251
Owner Costs	$/kW		
Due Diligence, Permitting, Legal, Development		227	351
Taxes and Fees		—	
Total Capital Requirements (TCR)	**$/kW**	**4,919**	**7,601**
O&M Costs			
Fixed	$/kW-yr	171.4	264.9
Variable	$/MWh	18.7	28.9
Feed	$/MWh		
Performance/Unit Availability			
Net Heat Rate	Btu/kWh	16,464	16,464
	MMBtu/MWh	16.46	16
	%	20.7	21
Equivalent Planned Outage Rate	%	6	6
Equivalent Unplanned Outage Rate	%	10	10
Equivalent Availability	%	85	85
Emission Rates			
CO2	lb/MMBtu		
NOx	lb/MMBtu		
SOx	lb/MMBtu		

Table E-11. Capital and Operating Costs for Gasification (DeMeo and Galdo 1997)

Cost component	Units	Cost Factor	Scale Factor	RETC97	Updated to 2010$	Updated High Efficiency
Year $	$			1997	2010	2010
Cost Index (2 = M&S, 3 = CE)			2	97.04	133.09	133.09
Plant Size	MWe			75	75	75
Heat Rate	Btu/kWh			9,488	9,488	8,000
	MMBtu/MWh			9.488	9.488	8.000
	Eff, %			35.96	35.96	42.65
Biomass Heating Value	MJ/kg			20.00	20.00	20.00
	MMBtu/ton			17.23	17.23	17.23
Biomass Feed Rate	dry short ton/day			991	991	836
	dry tonne/day			899	899	758
Stream Factor	%			80%	80%	80%
Annual Production	MWe			525,600	525,600	525,600
Feed	Dry short ton/yr			2.894E+05	2.894E+05	2.440E+05
Feed Price	$/short ton			47.60	75.00	75.00
Capital Cost	$/kW					
Fuel Preparation				113	155	131
Gasifier				519	712	600
Gas Turbine				216	296	250
Steam Turbine				48	66	56
Control system				9	12	10
Hot Gas Cleanup				43	59	50
Installation				208	285	241
Turbine Building				6	8	7
Waste Pond, etc.				2	3	2
Balance of Plant				311	427	360
General Plant Facilities				147	202	170
Direct Fixed Capital (DFC), also called TIC				1622	2224	1876
Engineering	DFC x MF	0.12		195	267	225
Construction	DFC x MF	0.13		211	289	244
Contractor and Legal	DFC x MF	0.08		130	178	150
Total Plant Cost (TPC)				2157	2958	2494
AFUDC	DFC x MF	0.1		162	222	188
Total Plant Investment (TPI)				2319	3181	2682
Prepaid Royalties				0	—	—
Initial Cat. and Chem. Inventory					—	—
Inventory Capital				10	14	19
Land				9	12	17
Startup				56	77	105
Total Capital Cost (TCC)				2394	3284	2823
Contingency/TPI	TCC*MF	0.3		718	985	847
Working Capital	DFC x MF	0.05		108	148	125
Total Capital Requirement	$/kW			3221	4417	3795

Table E-12. Costs for Landfill Gas (McGowin 2007)

Year $		2006	2010
Plant Size	MW	5	5
Unit Life	yr	20	20
Schedule			
Preconstruction, License, and Design	yr	1	1
Construction	yr	1	1
Capital Costs	$/kW		
Gas Conditioning and Compressor		189	211.5
Power Conversion		900	1007.2
General Facilities and Engineering		151	169.0
Project and Process Contingency		186	208.2
Total Plant Cost		1,426	1,595.8
AFUDC		—	
Total Plant Investment		1,426	1,595.8
Owners Costs	$/kW		
Due Diligence, Permitting, Legal, Development		285	318.9
Taxes and Fees		—	
Total Capital Requirements (TCR)		1,711	1,915
O&M Costs			
Fixed	$/kW-yr	52	58.2
Variable	$/MWh	13	14.5
Performance, Availability			
Net Heat Rate	Btu/kWh	13,500	13,500
Equivalent Planned Outage	%	4	4
Equivalent Unplanned Outage	%	11	11
Equivalent Availability		85	85

Table E-13. Modeling Costs for Co-Firing, Separate Injection under RE-ITI and RE-ETI Projections

Year	Maximum Injection	Overnight Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2010	15%	1,000	0	20	10,000	12
2015	15%	1,000	0	20	10,000	12
2020	15%	1,000	0	20	10,000	12
2025	15%	1,000	0	20	10,000	12
2030	15%	1,000	0	20	10,000	12
2035	15%	1,000	0	20	10,000	12
2040	15%	1,000	0	20	10,000	12
2045	15%	1,000	0	20	10,000	12
2050	15%	1,000	0	20	10,000	12

Table E-14. Modeling Costs for Stand-Alone Biopower (50 MW) under RE-ITI Projections (Black & Veatch 2012)

Year	Overnight Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	Minimum Load (%)	Quick Start Ramp Rate (%)
2010	3,872	—	—	—	—	—	—
2015	3,872	15	95	14,250	36	40	0.10
2020	3,872	15	95	14,000	36	40	0.10
2025	3,872	15	95	13,750	36	40	0.10
2030	3,872	15	95	13,500	36	40	0.10
2035	3,872	15	95	13,250	36	40	0.10
2040	3,872	15	95	13,000	36	40	0.10
2045	3,872	15	95	12,750	36	40	0.10
2050	3,872	15	95	12,500	36	40	0.10

Table E-15. Modeling Costs for Stand-Alone Biopower (50 MW) under RE-ETI Projections

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
2010	3,865	**5**	**103**	12.50
2015	3,865	5	103	12.50
2020	3,864	5	102	12.41
2025	3,853	5	95	11.74
2030	3,843	5	89	11.06
2035	3,832	6	82	10.39
2040	3,822	6	76	9.71
2045	3,811	7	69	9.04
2050	3,801	7	63	8.36

Table E-16 lists acronyms and abbreviations used in the appendix but not defined where used.

Table E-16. Acronyms used in Appendix E

AFUDC	allowance for funds used during construction
BFW	boiler feed water
CE	Chemical Engineering Plant Cost Index
CFB	circulating fluidized bed
CHP	combined heat and power
EIA	(U.S.) Energy Information Administration
GW	gigawatt
lb	pounds
M&S	Marshall & Swift Equipment Cost Index
Mcf	million cubic feet
MF	moisture free
MJ/kg	megajoules per kilogram
MMBtu	million BTU
MW_e	megawatts electric
MWh	megawatt-hour
NOx	nitrogen oxide
O&M	operation and maintenance
Psig	pounds per square inch
SOx	sulfur oxide
TAG-RE	Renewable Energy Technical Assessment Guide (EPRI)
TWh	terawatt-hour

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Appendix F. Supplemental Information for Wind Energy Technologies

Wind Resource Data and Exclusions Applied in all RE Futures Scenarios

The ReEDS model[176] takes as input the wind power class distribution (see Table F-1) in square kilometers for each ReEDS region. Wind resource estimates were derived from NREL's validated wind resource maps at 50-m height, where available; the estimates were supplemented with other state high-resolution wind maps or with low-resolution data from the Wind Energy Resource Atlas of the United States (Elliott et al. 1986).

Table F-9. Wind Power Class (50-m Height)[a]

Wind Power Class	Wind Power Density (W/m^2)	Speed (m/s)
3	300–400	6.4–7.0
4	400–500	7.0–7.5
5	500–600	7.5–8.0
6	600–800	8.0–8.8
7	>800	>8.8

[a] Wind speed measured at 50 m above ground level

Because the hub heights of modern wind turbines are typically 80 m, and because hub heights of future turbines could be higher, the 50-m wind resource data used in this study were generally adjusted to an equivalent 80-m wind resource, assuming a constant rate of wind shear (see Section 1.1.1 for details on this adjustment). To the extent that this conversion does not represent the actual 80-m wind resource, uncertainty is introduced into the ReEDS optimization. In addition, to the extent that the temporal nature of the wind resource at 80 m differs from that at 50 m, uncertainty is again introduced into the ReEDS optimization.[177]

Onshore Data

The onshore data represent a composite of high-spatial resolution (200-m to 1-km) data sets produced from 1997 to 2008 (see Table F-2). These data were sometimes produced with different modeling assumptions, leading to discontinuities at model borders, usually state borders.

[176] Appendix B (Volume 1) describes the models used in RE Futures, including ReEDS.
[177] NREL's wind data set was updated and re-released in February 2010; however, these data were not available for use at the time of the modeling for RE Futures. Some differences between NREL's updated data set and the data set used in the RE Futures include somewhat higher wind resource estimates for many Midwestern and Great Lake states and generally lower estimates in most western states and eastern states. These estimates are in part a function of the assumed constant shear exponent applied to the onshore RE Futures data set. NREL's latest data set suggests higher shear exponents in many Midwestern and Great Lakes states with somewhat lower shear exponents in the West. In addition, for most Appalachian states, NREL's new estimates are lower than the estimates used in the RE Futures data set; however, the reasons for these differences are not well understood at this time.

Most data sets were in the form of state maps and were completed with direct support from the Wind Powering America (WPA) initiative[178] and with cost sharing from individual states and regional partners. Under the WPA initiative, state wind resource maps were produced as described here: A preliminary state resource map was produced by AWS TruePower (AWST). NREL validated this map in cooperation with private consultants who had access to proprietary data, supplemental data, and knowledge of wind resources in each state. The validation results were used to modify the preliminary map and to create a final wind map. NREL mapped three states—Illinois, North Dakota, and South Dakota—before AWST became involved.

An important difference between the NREL and AWST maps is that the NREL mapping technique assumed low surface roughness (equivalent to short grasslands) while AWST used digital land cover data sets for surface roughness values. Increases in surface roughness generally decrease the estimated 50-m wind resource, so the initial NREL maps may overestimate the wind resource in areas that do not have low surface roughness. For Illinois, the discontinuity that this assumption causes is particularly noticeable when compared to adjacent states that show lower resource values when modeled with the explicit inclusion of surface roughness. In the composite data set used for RE Futures, the 50-m data for Illinois were adjusted downward to account for this difference in modeling assumptions. The 50-m wind power classes for individual grid cells on the WPA maps were used to determine available windy land for the ReEDS model.

Where power density data were available at 50 m, the onshore data were adjusted upward by one half power class to represent wind resource at 80-m height for use within ReEDS. Only resource data at or below Class 5 received this adjustment. The states where this adjustment could not be made are Alabama, Florida, Louisiana, Mississippi, and Texas.

[178] Wind Powering America provides high-resolution state wind maps and estimates of the wind resource potential that would be possible from development of the available windy land areas after excluding areas unlikely to be developed. For more information about WPA, see http://www.windpoweringamerica.gov/.

Table F-10. Resource Data (50-m Height)

State	Data Year[a]	Source[b]
Arizona	2003	N/AWST
Alabama	1987	PNNL
Arkansas	2006	N/AWST
California	2003	N/AWST
Colorado	2003	N/AWST
Connecticut	2002	N/AWST
Delaware	2003	N/AWST
Florida	1987	PNNL
Georgia	2006	AWST
Idaho	2002	N/AWST
Illinois	2001	NREL
Indiana	2004	N/AWST
Iowa	1997	Other
Kansas	2008	N/AWST
Kentucky	2008	N/AWST
Louisiana	1987	PNNL
Maine	2002	N/AWST
Maryland	2003	N/AWST
Massachusetts	2002	N/AWST
Michigan	2005	N/AWST
Minnesota	2006	Other
Mississippi	1987	PNNL
Missouri	2004	N/AWST
Montana	2002	N/AWST
Nebraska	2005	N/AWST
Nevada	2003	N/AWST
New Hampshire	2002	N/AWST
New Jersey	2003	N/AWST
New Mexico	2003	N/AWST
New York	2004	AWST
North Carolina	2003	N/AWST
North Dakota	2000	NREL
Ohio	2004	N/AWST
Oklahoma	2008	N/AWST
Oregon	2002	N/AWST
Pennsylvania	2003	N/AWST

	Data	
State	**Year[a]**	**Source[b]**
Rhode Island	2002	N/AWST
South Carolina	2005	AWST
South Dakota	2000	NREL
Tennessee	2008	N/AWST
Texas	2004, 2000	Other, NREL
Utah	2003	N/AWST
Vermont	2002	N/AWST
Virginia	2003	N/AWST
Washington	2002	N/AWST
West Virginia	2003	N/AWST
Wisconsin	2007	AWST
Wyoming	2002	N/AWST

[a] Year produced (1987 to present)
[b] N/AWST (NREL with AWS TruePower), PNNL (Pacific Northwest National Laboratory), NREL (not validated by NREL)

The composited and adjusted wind resource data were filtered to eliminate areas that were considered unsuitable or unlikely for development for environmental or land use reasons. These criteria, which are listed in Table F-3, were developed in consultation with industry and the WPA.

Table F-11. Wind Resource Exclusion Criteria[a]

Environmental Criteria	**Data Sources**
100% exclusion of lands managed by U.S. National Park Service and U.S. Fish and Wildlife Service	U.S. Geological Survey federal lands "shapefile" (December 2005)
100% exclusion of federal lands designated as park, wilderness, wilderness study area, national monument, national battlefield, recreation area, national conservation area, wildlife refuge, wildlife area, wild and scenic river, or inventoried "roadless" area	U.S. Geological Survey federal lands shapefile (December 2005); Inventoried Roadless Areas (2004); U.S. *Bureau of Land Management* Areas of Critical Environmental Concern (2008)
100% exclusion of state and private lands equivalent to the first two criteria , where geographic system data were available	State/GAP[b] Land Stewardship Data Management Status 1, from Conservation Biology Institute Protected Areas Database (2004)
50% exclusion of remaining U.S. Forest Service lands (including national grasslands) except ridge crests	U.S. Geological Survey federal lands shapefile, (December 2005)
50% exclusion of remaining U.S. Department of Defense lands except ridge crests	Military lands boundary files, Homeland Security Infrastructure Program (HSIP) (2007)
50% exclusion of state forest land, where GIS data were available	State/GAP land stewardship data management status 2, from Conservation Biology Institute Protected Areas Database (2004)
Land Use Criteria	**Data Sources**
100% exclusion of airfields, urban, wetland, and water areas	U.S. Geological Survey North America Land Use Land Cover (LULC), version 2.0 (1993); Esri airports and airfields (2006); U.S. Census Urbanized Areas (2000; 2003)
50% exclusion of non-ridge crest forest	Ridge-crest areas defined using a terrain-definition script, overlaid with U.S. Geological Survey LULC data screened for the forest categories
Other Criteria	Data Sources
Exclude areas of slope > 20%	Derived from 90-m national elevation data set
100% exclusion of 3-km surrounding area for all areas identified for 100% exclusions (except water)	Merged data sets and buffer 3 km

[a] 50% exclusions are not cumulative. If an area is non-ridge crest forest on U.S. Forest Service land, it is excluded at the 50% level only one time.
[b] U.S. Forest Service Gap Analysis Program (http://gapanalysis.usgs.gov/)

Offshore Data

The offshore data represent a composite of high-spatial resolution (200-m) data sets specifically produced to represent offshore wind resource, extrapolations of near shore wind resources modeled as part of onshore wind resource assessments, and an empirical evaluation using available meteorological data by NREL (see Table F-4). The data were further categorized by water depth to represent shallow (<30 m depth) and deep (>= 30 m depth) offshore installation technologies.

Table F-12. Resource Data (50-m Height)

State	Date	Source Type
Alabama	2006	empirical
California	2003	onshore
Connecticut	2002	onshore
Delaware	2003	onshore
Florida	2006	empirical
Georgia	2007	offshore
Illinois	2008	offshore
Indiana	2008	offshore
Louisiana	2007	offshore
Maine	2008	offshore
Maryland	2003	onshore
Massachusetts	2008	offshore
Michigan	2008	offshore
Minnesota	2008	offshore
Mississippi	2006	empirical
New Hampshire	2008	offshore
New Jersey	2003	onshore
New York (lake)	2008	offshore
New York (ocean)	2003	onshore
North Carolina	2003	onshore
Ohio	2008	offshore
Oregon	2002	onshore
Pennsylvania	2008	offshore
Rhode Island	2002	onshore
South Carolina	2006	empirical
Texas	2007	offshore
Virginia	2003	onshore
Washington	2002	onshore
Wisconsin	2008	offshore

Black & Veatch (2010) undertook identification of potential federal and state offshore wind resource exclusions in 2009. Areas were identified for exclusion, including national marine sanctuaries, wildlife refuges, nature preserves, shipping and ferry lanes, drilling platforms, pipelines, fairways, tow lanes, dredging sites, security areas, and other areas identified as protected in the federal Marine Protected Areas Inventory.

Conversion of Windy Land to Power Generation Capacity

The potential wind generation capacity was based on an assumed wind farm land-use power density of 5 MW/km^2, a standard industry rule of thumb (Denholm et al. 2009).[179] For each region, the generation capacity was used with an associated capacity factor value (a function of wind technology and the wind resource data) to arrive at an estimate of the energy production for each wind resource class. To generate the supply curve shown in Chapter 11, the energy values were coupled with the cost assumptions described in Volume 1 and Appendix A to calculate the levelized cost of energy.

Supplementary Input Data Tables

A complete summary of the 80% RE-ETI scenario wind performance and cost inputs used in ReEDS modeling is presented in Table F-5 and Table F-6. Appendix A (Volume1) contains the costs and performance data inputs used in the 80% RE-ITI scenario.[180]

Table F-13. Cost and Performance Projections for Onshore Wind Energy by Wind Resource Class, Applied in the 80% RE-ETI Scenario

Wind Resource Class	Year	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor
3	2010	1,980	12	6	35%
3	2015	1,932	12	5	36%
3	2020	1,884	12	5	38%
3	2025	1,836	12	5	38%
3	2030	1,776	12	5	38%
3	2035	1,776	12	5	38%
3	2040	1,776	12	5	38%
3	2045	1,776	12	5	38%
3	2050	1,776	12	5	38%
4	2010	1,980	12	6	39%
4	2015	1,932	12	5	41%
4	2020	1,884	12	5	42%
4	2025	1,836	12	5	43%
4	2030	1,776	12	5	43%
4	2035	1,776	12	5	43%
4	2040	1,776	12	5	43%

[179] Actual land-use power densities vary based on site-specific considerations (Denholm et al. 2009).
[180] See Volume 1 for a detailed description of each RE Futures scenario.

Wind Resource Class	Year	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor
4	2045	1,776	12	5	43%
4	2050	1,776	12	5	43%
5	2010	1,980	12	6	43%
5	2015	1,932	12	5	44%
5	2020	1,884	12	5	45%
5	2025	1,836	12	5	46%
5	2030	1,776	12	5	46%
5	2035	1,776	12	5	46%
5	2040	1,776	12	5	46%
5	2045	1,776	12	5	46%
5	2050	1,776	12	5	46%
6	2010	1,980	12	6	46%
6	2015	1,932	12	5	47%
6	2020	1,884	12	5	48%
6	2025	1,836	12	5	49%
6	2030	1,776	12	5	49%
6	2035	1,776	12	5	49%
6	2040	1,776	12	5	49%
6	2045	1,776	12	5	49%
6	2050	1,776	12	5	49%
7	2010	1,980	12	6	50%
7	2015	1,932	12	5	51%
7	2020	1,884	12	5	52%
7	2025	1,836	12	5	53%
7	2030	1,776	12	5	53%
7	2035	1,776	12	5	53%
7	2040	1,776	12	5	53%
7	2045	1,776	12	5	53%
7	2050	1,776	12	5	53%

Table F-14. Cost and Performance Projections for Fixed-Bottom Offshore Wind Energy by Wind Resource Class, Applied in 80% RE-ETI Scenario

Wind Resource Class	Year	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor (%)
3	2010	3,643	16	22	37%
3	2015	3,431	16	19	38%
3	2020	3,231	16	17	39%
3	2025	3,043	16	15	40%
3	2030	2,866	16	14	40%
3	2035	2,700	16	12	40%
3	2040	2,700	16	12	40%
3	2045	2,700	16	12	40%
3	2050	2,700	16	12	40%
4	2010	3,643	16	22	41%
4	2015	3,431	16	19	43%
4	2020	3,231	16	17	44%
4	2025	3,043	16	15	45%
4	2030	2,866	16	14	45%
4	2035	2,700	16	12	45%
4	2040	2,700	16	12	45%
4	2045	2,700	16	12	45%
4	2050	2,700	16	12	45%
5	2010	3,643	16	22	45%
5	2015	3,431	16	19	46%
5	2020	3,231	16	17	47%
5	2025	3,043	16	15	48%
5	2030	2,866	16	14	48%
5	2035	2,700	16	12	48%
5	2040	2,700	16	12	48%
5	2045	2,700	16	12	48%
5	2050	2,700	16	12	48%
6	2010	3,643	16	22	48%
6	2015	3,431	16	19	50%
6	2020	3,231	16	17	51%
6	2025	3,043	16	15	51%
6	2030	2,866	16	14	51%
6	2035	2,700	16	12	51%
6	2040	2,700	16	12	51%
6	2045	2,700	16	12	51%
6	2050	2,700	16	12	51%

Wind Resource Class	Year	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor (%)
7	2010	3,643	16	22	52%
7	2015	3,431	16	19	54%
7	2020	3,231	16	17	55%
7	2025	3,043	16	15	55%
7	2030	2,866	16	14	55%
7	2035	2,700	16	12	55%
7	2040	2,700	16	12	55%
7	2045	2,700	16	12	55%
7	2050	2,700	16	12	55%

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