Effective December 6, 2006, this report has been made publicly available in accordance with Section 734.3(b)(3) and published in accordance with Section 734.7 of the U.S. Export Administration Regulations. As a result of this publication, this report is subject to only copyright protection and does not require any license agreement from EPRI. This notice supersedes the export control restrictions and any proprietary licensed material notices embedded in the document prior to publication.

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Renewable Energy Technical Assessment Guide—TAG-RE: 2006



Renewable Energy Technical Assessment Guide—TAG-RE: 2006

1012722

Final Report, March 2007

EPRI Project Manager
C. McGowin

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Electric Power Research Institute (EPRI)

Energy Insights

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute, EPRI, and TOGETHER SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2007 Electric Power Research Institute, Inc. All rights reserved.

CITATIONS

This report was prepared by

Electric Power Research Institute (EPRI)
3420 Hillview Avenue
Palo Alto, CA 94304

Principal Investigators
C. McGowin
R. Bedard
S. Cardoso
D. O'Connor
T. Peterson

Energy Insights
1750 14th Street, Suite 200
Boulder, CO 80302

Principal Investigators
N. Lenssen
N. Enbar

This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Renewable Energy Technical Assessment Guide—TAG-RE: 2006. EPRI, Palo Alto, CA: 2007. 1012722.

PRODUCT DESCRIPTION

First published in 2000, the annual *Renewable Energy Technical Assessment Guide (TAG-RE)* provides a consistent basis for evaluating the economic feasibility of renewable generation technologies. The technologies include wind, solar photovoltaic (PV), solar thermal, biomass, geothermal, and emerging ocean energy conversion technologies. The 2006 edition is the sixth annual update of the EPRI *TAG-RE*.

Results & Findings

Based on rated capacity, the leading worldwide sources of renewable energy at the end of 2005 were wind (59 GW), biomass (22 GW), geothermal (9 GW), solar PV (5 GW), and solar thermal (0.4 GW). Counting hydroelectric generation as a renewable resource, renewable energy contributed about 6% of U.S. primary energy consumption and 9% of electricity generation during 2005, most of which was contributed by biomass and hydro. The 2006 edition of the EPRI TAG-RE provides new information for all renewable technologies. Most noteworthy is the new, detailed economic data for renewable electricity technologies in the wind, biomass, and solar thermal chapters.

Challenges & Objective(s)

Because so many conflicting and overly optimistic claims are made about the performance and economic potential of all energy sources—conventional fossil, nuclear, hydro, alternative fuel, and renewable—it is important to conduct careful and objective assessments of the status, performance, cost, environmental impacts, and other aspects of the technologies. The primary objective of this report is to provide timely and unbiased assessments of the status, performance, and cost of renewable generation technologies.

Applications, Values & Use

Renewable generation technology data reported in the EPRI *TAG-RE* are of value to system planners and others who make decisions about whether renewable technology belongs in the generation portfolio and who develop a long-term strategy and plan for a sustainable generation portfolio.

EPRI Perspective

An energy producer can use renewable energy to strengthen ties to the community, attract new customers, and diversify its portfolio. EPRI believes companies that have not yet incorporated renewables into their generation mix should consider these technologies to determine which ones might benefit their generation strategy. The information summarized in *TAG-RE* encompasses more than three decades of EPRI research on renewable technologies. The *Renewable Energy Technical Assessment Guide* will continue to be updated on an annual basis to ensure that EPRI members have access to the most current information on the technical and economic status of renewable technologies.

Approach

The research team collected and analyzed information and data from both EPRI and outside sources on the status, performance, cost, installed capacity, and markets for renewable energy generation technologies from a variety of sources. These sources included EPRI studies and U.S. government and other publicly available reports. The team then updated the information in each chapter of the previous edition of the *TAG-RE* (EPRI report 1010407, December 2005).

Keywords

Renewable energy
Alternative energy
Technology assessment
Economic analysis
Cost-benefit analysis
Wind energy
Biomass
Solar photovoltaic
Solar thermal
Geothermal
Ocean tidal energy
Ocean wave energy
Greenhouse gas emissions

ABSTRACT

The *Renewable Energy Technical Assessment Guide—TAG-RE 2006* provides a basic reference to inform the technical and economic assessment of renewable energy generation technologies. Design, cost, and performance information contained in this report will enable EPRI members to perform preliminary capital investment evaluations in a consistent and informed manner. Renewable technologies covered include: Wind, Biomass, Solar Photovoltaics, Geothermal, Solar Thermal, Ocean Tidal and Wave Energy, and Grid Integration—technologies that are commercially available or on the threshold of commercialization. Additional sections address the potential to reduce greenhouse gas emissions through the use of renewables.

CONTENTS

1 **INTRODUCTION 1-1**

1.1 Background 1-1

1.2 EPRI's Role 1-5

1.3 Objective 1-5

1.4 Definitions and Units 1-6

1.5 Scope 1-6

1.6 References 1-8

2 **ECONOMIC METHODOLOGY AND ASSUMPTIONS 2-1**

2.1 Regulated Utility Power Projects 2-1

2.1.1 Fixed Charge Rates 2-1

Annual Fixed Charge Rates 2-1

Nominal Levelized Annual Charges and Nominal Levelized Fixed Charge Rates 2-3

Real Levelized Annual Charges and Real Levelized Fixed Charge Rates 2-3

2.1.2 Example Annual Fixed Charge Rates for a 100-MW Wind Power Plant 2-5

2.1.3 Other Capital Expenses—Capital Additions 2-5

2.1.4 Calculating Costs per Kilowatt-Hour 2-5

Levelized Costs per Kilowatt-Hour 2-5

2.2 Non-Utility Generator Power Projects 2-8

2.2.1 Types of Non-Utility Generators 2-9

PURPA Cogenerators and Small Power Producers 2-10

Exempt Wholesale Generators 2-11

Merchant Power Plants 2-12

2.2.2 Development of an Economic Pro Forma for a Merchant Plant 2-12

Differences between Regulated Utility and Non-Utility Power Projects 2-13

Pricing 2-13

Income Taxes and Depreciation 2-13

Capital Expenditures 2-13

Debt Financing 2-13
Economic Methodology 2-14
2.2.3 Conceptualizing the Analysis 2-14
Total Capital Requirement 2-15
Construction Cost 2-15
Financing Cost 2-16
Development Cost 2-16
Other Costs 2-17
EPRI Capital Cost Definitions 2-18
Income Statement 2-18
Revenues 2-20
Operating and Maintenance Expenses 2-22
Income Taxes 2-22
Cash Flow Statement 2-23
Economic Measures 2-25
Busbar Cost 2-25
Net Present Value (NPV) 2-26
Internal Rate of Return (IRR) 2-27
Payback Period 2-27
Debt Coverage Ratios 2-28
Sensitivity Analysis 2-28
Project Risks and Financing 2-30
2.2.4 Limitations of Examples 2-32
2.3 Guidelines for Economic Evaluation of Renewable Energy Projects 2-32
2.3.1 Design/Cost Estimate 2-32
2.3.2 Accuracy Ranges 2-33
2.3.3 Definitions of Economic Terms 2-34
2.4 The EPRI Personal Computer Programs 2-36
2.5 References 2-37

***3* WIND POWER 3-1**
3.1 Introduction 3-1
3.2 Installed Wind Capacity 3-2
3.3 Technology Description 3-8
3.3.1 Wind Energy Principles 3-8

3.3.2 Turbine Designs 3-10
Constant-Speed Wind Turbines 3-12
Two-Speed Wind Turbines 3-13
Variable-Speed Wind Turbines 3-13
Direct-Drive Generators 3-14
3.4 Technology Trends and Status 3-15
3.4.1 2005 and 2006 Industry Trends 3-15
Cost Reduction and Efficiency Improvements 3-16
Evolving New Technology 3-19
3.4.2 Turbine Technology Trends 3-19
3.5 Cost and Economic Issues 3-22
3.5.1 Technology Performance and Cost Tables 3-22
3.6 Grid Integration 3-25
3.6.1 Production Variability 3-25
3.6.2 Ancillary Service Costs 3-26
3.6.3 Wind Energy Forecasting and Scheduling 3-27
3.6.4 Regulatory Update 3-28
3.6.5 Power Quality 3-28
3.7 Project Development Process and Market 3-29
3.7.1 Buy or Build Considerations 3-29
3.7.2 Project Development Process 3-29
Pre-Development Activities 3-30
Engineering Procurement and Construction Activities (EPC) 3-31
Operation and Maintenance Activities 3-33
3.8 Environmental Issues 3-35
3.8.1 Avian and Bat Issues 3-35
3.8.2 Noise 3-36
3.8.3 Visual Impact 3-38
3.9 Offshore Wind Development 3-39
3.9.1 Installed Capacity 3-40
Europe 3-40
United States 3-43
3.9.2 Offshore Wind Resource 3-43
3.9.3 Offshore Wind Turbine Technology 3-46

Current Technology 3-46
Future Deepwater Technology 3-49
3.9.4 Capital and O&M Costs 3-51
3.10 Equipment Markets and Key Participants 3-51
3.10.1 World Markets 3-52
Trend to Larger Turbines 3-53
Offshore Market in Europe 3-56
Market Forecast 3-56
2006 through 2010 3-57
2011 through 2015 3-57
3.10.2 Key Players in the Wind Power Industry 3-58
3.11 Internet Resources 3-60
3.12 References 3-62
3.12.1 DOE-EPRI Wind Turbine Verification Program Reports 3-64

***4* BIOMASS ENERGY 4-1**
4.1 Introduction 4-1
4.1.1 Basic Issues Associated with Biomass Fuel Utilization 4-2
4.1.2 Technology Considerations for Using Biomass Fuels 4-3
Commercially Available Technologies 4-3
Goal Technologies 4-4
Prospectus 4-5
4.1.3 Characteristics of Representative Biomass Fuels 4-5
4.2 Biomass Fuel Resources 4-5
4.2.1 Basic Properties of Solid Biomass Fuels 4-6
Proximate and Ultimate Analyses of Biomass Fuels 4-7
Structural Relationships and Heteroatoms 4-9
Inorganic Constituents in Biomass 4-10
4.2.2 Performance Characteristics of Biomass Fuels 4-14
Biomass Fuel Volatility 4-14
Fuel Nitrogen Characteristics of Biomass Fuels 4-21
Ash Reactivity, Slagging, and Fouling 4-30
4.2.3 Wastewater Treatment Gas and Landfill Gas 4-33
Gas Compositions 4-33
Utilization 4-34

4.3 Characteristics of Biomass Cofiring Technologies 4-34
4.3.1 Overview of Solid Biomass Fuel Cofiring Systems 4-35
4.3.2 Cofiring in Cyclone Boilers 4-37
Cofiring Systems Design for Cyclone Boilers 4-38
Capital Costs of Cofiring Systems for Cyclone Boilers 4-41
Cofiring Impacts in Cyclone Boilers 4-43
4.3.3 Cofiring in Pulverized Coal (PC) Boilers 4-45
Cofiring System Designs for PC Boilers 4-46
Capital Costs of Separate Injection PC Cofiring Systems 4-48
Impacts of Cofiring Biomass in PC Boilers 4-49
4.3.4 Cofiring Gaseous Biomass Fuels 4-51
4.3.5 Conclusions Regarding Biomass Cofiring 4-52
4.4 Stand-Alone Biomass Fired Systems 4-53
4.4.1 Wood-Waste-Fired Boilers 4-53
Typical Capacities of Wood-Waste-Fired Plants 4-54
Wood-Waste-Fired System Design 4-54
Fuel Handling 4-55
Boiler and Turbine-Generator Technology 4-56
Pollution Control Systems 4-60
Comparisons to Other Biomass-Fired Rankine Cycle Designs 4-60
4.4.2 Capital Costs for Wood Waste-Fired Boilers 4-61
4.4.3 Ownership Patterns and Institutional Issues 4-65
4.4.4 Alternative Systems for Gaseous Biomass Fuels 4-66
4.4.5 Near-Commercial Technologies 4-66
Wood Gasification for Power and District Heating in Güssing, Austria 4-67
Wood Gasification at Harboøre 4-68
Gasification of Wood Pellets at Skive 4-69
Co-firing Syngas at Ruien 4-70
Wood Gasification at Kokemäki 4-71
4.4.6 Non-Commercial Technologies 4-72
4.5 Cost and Performance Summary 4-73
4.5.1 Biomass Cofiring with Coal in Cyclone and Pulverized Coal Boilers 4-74
4.5.2 Biomass-Fired Stoker and Fluidized Bed Combustion Boilers 4-74
4.5.3 Biomass Direct Combustion for Compined Heat and Power 4-74

4.5.4 Landfill Gas Recovery and Power Generation 4-74
4.6 Conclusions 4-80
4.7 References 4-80

***5* SOLAR PHOTOVOLTAICS 5-1**
5.1 Introduction 5-1
Continued Focus on Distributed PV 5-2
5.2 Resources 5-3
5.2.1 Resource Assessment 5-4
5.2.2 Shipments and Installed Capacity 5-6
5.3 Technology Description 5-7
5.3.1 Building-Integrated Photovoltaics (BIPV) 5-9
5.4 Technology Status 5-10
5.4.1 Likely Development Pathways 5-10
5.5 Cost and Economic Issues 5-14
Japan 5-15
Germany 5-15
5.5.1 Example PV Project Costs 5-16
5.5.2 Technology Performance and Cost Tables 5-16
Distributed PV Performance and Cost 5-16
Utility-Scale Performance and Cost 5-17
5.5.3 Performance and Cost History and Projections 5-20
5.5.4 PV Performance and Cost Estimates 5-20
Resource Estimates 5-21
Distributed PV Cost and Performance Estimates 5-23
Hypothetical Case Studies 5-24
Central Station PV Cost and Performance Estimates 5-28
Example Performance Calculations 5-31
Example Capital and O&M Cost Calculations 5-32
5.6 Environmental Issues 5-33
5.7 Design and Deployment Issues 5-34
Utility-Scale Issues 5-36
5.7.1 Operating and Maintenance Labor Requirements 5-36
Utility-Scale Issues 5-36
5.7.2 Interconnection 5-36

5.7.3 Microgrids 5-38
Microgrid Economic Issues 5-39
5.8 Equipment Markets and Key Participants 5-39
5.8.1 Equipment Markets 5-40
5.8.2 Key Participants 5-42
5.8.3 Internet Resources 5-43
5.8.4 Applicable Codes and Standards 5-45
5.9 References 5-46

***6* GEOTHERMAL ENERGY 6-1**
6.1 Introduction 6-1
6.2 Resources 6-2
6.2.1 Geothermal Resource Assessment 6-3
U.S. Geothermal Resource 6-4
Resource Permeability 6-8
U.S. Supply Curve 6-9
6.2.2 Installed Geothermal Capacity 6-9
6.3 Technology Description 6-10
6.3.1 Hydrothermal 6-11
Major Common System Components and Features 6-12
Direct Steam 6-13
Flash Steam 6-14
Binary Power Plants 6-16
6.3.2 Hot Dry Rock (“Enhanced Geothermal Systems”) 6-18
6.3.3 Geopressured 6-20
6.3.4 Non-Electric (“Direct Use”) Geothermal 6-21
6.4 Technology Status 6-21
6.4.1 Recent Developments 6-23
6.4.2 Likely Development Pathways 6-24
6.5 Cost and Economic Issues 6-29
6.5.1 Example Geothermal Project Costs 6-30
Geothermal Power Cost Factors 6-30
Existing Geothermal Power Plants 6-32
Cost Estimates for Goal Technologies 6-33
6.5.2 Technology Performance and Cost Tables 6-34

6.5.3 Performance and Cost Projections 6-38
6.6 Environmental Issues 6-38
6.6.1 Land Use 6-39
6.6.2 Subsidence 6-40
6.6.3 Effects on Other Geothermal Phenomena 6-41
6.6.4 Emissions 6-42
6.6.5 Thermal Discharge 6-43
6.7 Design, Deployment, and O&M Issues 6-44
6.7.1 Industry Trends 6-45
6.7.2 Research Needs and Recommendations 6-45
6.8 Equipment Markets and Key Participants 6-46
6.9 References 6-49

7 SOLAR THERMAL 7-1
7.1 Introduction 7-1
7.1.1 Solar Thermal Technologies 7-1
7.2 Resources 7-3
7.3 Technology Description 7-4
7.3.1 Parabolic Trough 7-5
7.3.2 Central Receiver 7-7
7.3.3 Dish/Engine 7-12
Concentrators 7-13
Engines 7-14
7.4 Technology Status 7-15
7.4.1 Parabolic Trough 7-16
7.4.2 Central Receiver 7-19
7.4.3 Dish/Engine 7-20
7.5 Cost and Economic Issues 7-22
Central Receiver 7-26
Dish/Engine 7-26
7.6 Environmental Issues 7-27
7.6.1 Land Use 7-27
7.6.2 Water Use 7-27
7.6.3 Molten Salt for Central Receiver 7-28
7.6.4 Oil for Heat Transfer in Trough Applications 7-28

7.6.5 Potential for Greenhouse Gas Reduction 7-28
7.7 Design, Deployment and O&M Issues 7-28
7.7.1 Parabolic Trough 7-28
7.7.2 Central Receiver 7-31
7.7.3 Dish/Engine 7-33
7.8 Equipment Markets and Key Participants 7-34
7.8.1 Internet Resources 7-37
7.9 References 7-39

***8* OCEAN TIDAL ENERGY 8-1**
8.1 Introduction 8-2
8.1.1 What Is Ocean Tidal Energy? 8-2
8.1.2 How Can Tidal Energy Be Harnessed? 8-7
8.1.3 Will These Systems Survive Storms and Hostile Marine Environments? 8-9
8.1.4 Will These Tidal Power Plants Affect the Environment? 8-10
8.1.5 Will Regulatory Agencies Grant Permits for Offshore Tidal Power Plants? 8-10
8.1.6 Will Offshore Tidal Power Be Reliable and Cost-effective? 8-12
8.1.7 What Is the Installed and Planned Capacity? 8-12
8.1.8 What Other Introductory Information Is Important to Know? 8-14
8.2 Tidal Power and Energy Resource Characterization in United States and Canada 8-14
8.2.1 United States 8-14
Tidal Current Prediction Source - NOS 8-15
Current Reference Stations 8-15
U.S. Geographical Coverage 8-16
Characteristics of the Tidal Current Data 8-17
Example Tidal Current Data 8-19
8.2.2 Canada 8-20
8.2.3 Tidal Power Flux and Average Annual Energy 8-21
Site Screening 8-21
Mean Annual Power Density 8-22
Surface Current Velocities 8-23
Extrapolation of Velocity Time History to a Different Channel Section 8-25
Accounting for Depth Variations in Velocity 8-27
Accounting for Across-Channel Variations in Velocity 8-29
Channel Cross-Sectional Area 8-30

Available Resource 8-32
Extractable Resource 8-32
8.3 Tidal Energy Conversion (TISEC) Technology Description 8-35
8.3.1 Tidal Energy Conversion (TISEC) System Developers 8-35
8.3.2 Offshore Tidal Energy DT&E Projects 8-40
8.3.3 EMEC Tidal 8-41
8.4 Performance Prediction 8-42
8.5 Cost and Economic Issues 8-42
8.6 Deployment, Operation, and Maintenance 8-44
8.6.1 Placement 8-44
8.6.2 Anchoring Systems 8-45
8.6.3 Multi-Directional Current Capability 8-45
8.6.4 Monitoring and Maintenance 8-45
8.6.5 Transmission/Distribution Lines 8-46
8.7 Environmental Issues 8-46
8.7.1 Withdrawal of Tidal Energy 8-47
8.7.2 Interactions with Marine Life Including Underwater Noise 8-49
8.7.3 Atmospheric and Oceanic Emissions 8-49
8.7.4 Visual Impacts 8-49
8.7.5 Conflicts with Other Uses of Sea Space 8-49
8.7.6 Environmental Benefits 8-50
8.7.7 European Marine Energy Center (EMEC) Tidal Environmental Assessment 8-50
8.8 U.S. Regulatory Framework 8-50
8.8.1 Regulatory Agencies 8-50
8.8.2 Recent Tidal Energy Permitting History 8-53
The Long Island Project 8-54
Amesbury Project 8-54
Verdant East River Roosevelt Island Tidal Energy (RITE) Project 8-54
8.9 Conclusions 8-56
8.9.1 Internet Resources 8-57
8.10 References 8-57

_9_ OCEAN WAVE ENERGY 9-1
9.1 Introduction 9-2
9.1.1 Harnessing Wave Energy 9-2

9.1.2 Survival in Storms and Hostile Marine Environments 9-4
9.1.3 Effect of Wave Power Plants on the Environment 9-7
9.1.4 Permits for Offshore Wave Power Plants 9-7
9.1.5 Installed Capacity and Expected Growth 9-8
9.1.6 Other Important Considerations 9-8
9.2 Wave Power and Energy Resource 9-10
9.2.1 Data Sources 9-11
9.2.2 Wave Energy Scatter Diagrams 9-13
9.2.3 Wave Power Flux and Average Annual Energy 9-17
9.3 WEC Technology Description 9-21
9.3.1 WEC System Developers 9-21
9.3.2 European Marine Energy Center 9-26
9.3.3 American Marine Energy Center Pacific Northwest 9-27
9.4 Performance Prediction 9-28
9.5 Pilot and Commercial Scale Design, Cost, and Economic Issues 9-31
9.5.1 Sites 9-31
9.5.2 WEC Devices Studied 9-32
9.5.3 Pilot or Demonstration Plant Design (Oregon Example) 9-33
9.5.4 Commercial Scale Plant Design (Oregon Example) 9-35
9.5.5 Demonstration and Commercial Scale Plant Cost Estimates 9-37
9.5.6 Commercial Scale Plant Economic Assessment 9-39
9.6 Operation and Maintenance 9-40
9.7 Avoidance and Mitigation of Environmental Impact Concerns 9-41
9.7.1 Wave Projects Permitted and in Licensing Process (including pending) 9-42
9.7.2 Existing Environmental Studies 9-43
9.7.3 Environmental Benefits of Ocean Energy 9-44
Avoided emissions 9-45
9.7.4 Recommended Next Steps 9-45
9.8 Regulatory Issues 9-46
9.8.1 Chronology of Licensing Offshore Wave Energy Plants in the U.S. 9-46
9.8.2 MMS Rulemaking 9-47
9.8.3 Ocean Zones 9-48
9.8.4 Federal Permits, Licenses and Respective Agencies 9-49
9.8.5 California State and Local Government Agencies with Permitting and/or Review Authority 9-51

Coastal Zone Management Act/California Coastal Act 9-52
Submerged Lands Act/California State Lands Act 9-52
California Environmental Quality Act (CEQA) 9-53
The California Endangered Species Act (CESA) 9-53
9.8.6 Internet Resources 9-53
9.9 References 9-54

***10* RENEWABLE ENERGY GRID INTEGRATION TECHNOLOGIES 10-1**
10.1 Renewable Generation Integration Issues 10-2
10.1.1 Power System Planning and Operation 10-2
System Generation Fundamentals 10-2
Expectations Based on Traditional Generators 10-4
Typical System-Operating Strategy 10-5
Energy Balancing 10-6
Unit Commitment 10-6
Economic Dispatch 10-7
Role of Ancillary Services 10-7
Regulation 10-7
Voltage Control 10-9
Black Start 10-9
10.1.2 Technical Integration Issues of Intermittent Generation 10-10
Intermittency 10-10
Ramping Burdens 10-10
Fluctuating Power Output 10-10
Limited Reactive Power Control 10-11
Distributed Generation 10-11
Remote Location of Some Renewable Resources 10-11
10.1.3 Renewable Generation Technical and Associated Cost Impacts 10-12
10.1.4 Standards and Regulatory Actions 10-15
Connection Standards for Distributed Generation 10-15
Regulatory Treatment of Wind Power 10-15
FERC Order 888 10-15
FERC Order 2000 and Other Pending Rulings 10-16
10.2 Renewable Generation Integration Technologies 10-16
10.2.1 Generator Interface and Output Control 10-18

Constant-Speed Induction Generator with Direct Grid Connection 10-19
Variable-Speed Induction or Asynchronous Generator with Power Electronic Interface to Grid 10-20
Doubly Fed Induction Generator 10-20
Full-Converter Asynchronous or Induction Generator 10-21
Variable-Speed HVDC-Link to Grid 10-23
10.2.2 Ride-Through During Faults and Other Grid Disturbances 10-24
Adaptive Protective Relaying 10-24
Low-Voltage Ride-Through Circuits 10-24
10.2.3 Reactive Compensation Equipment 10-26
Distributed Constant Power Factor 10-27
Distributed Variable Power Factor 10-27
Substation Switched Capacitor Banks 10-28
Power Electronic Custom Power Devices 10-30
Static Shunt Compensator (DSTATCOM) 10-31
Distribution Static VAR Compensator (DSVC) 10-32
10.2.4 Wind Energy Forecasting Tools 10-35
10.2.5 Energy-Storage Technology 10-36
Energy Storage Applications and Benefits 10-37
Arbitrage Benefits 10-38
Ancillary Services Benefits 10-38
Other Energy Storage Benefits 10-39
Energy Storage Attributes and Costs 10-40
10.3 References 10-45
10.3.1 Endnotes 10-45
10.3.2 General 10-47
10.3.3 Renewable Generation Grid Impacts and Integration 10-48
10.3.4 Battery Energy Storage 10-48
10.3.5 Compressed Air Energy Storage 10-49
10.3.6 Pumped Hydro Energy Storage 10-49
10.3.7 Flywheel Energy Storage 10-50
10.3.8 SMES 10-50

***11* GREENHOUSE GAS EMISSIONS CONTROL 11-1**
11.1 Greenhouse Gases 11-1

11.2 Role of Renewable Energy Technology 11-2
11.3 Fossil Carbon Intensity of Fuels 11-2
11.4 CO_2 Emissions Offsets 11-4
11.4.1 Factors Affecting CO_2 Emissions Offset 11-4
Wind 11-4
Planting Trees and Other Fast-Growing Crops 11-5
11.4.2 Levelized CO_2 Emissions Offsets 11-5
11.5 Factors Affecting Generation Cost of Renewable Technologies 11-8
11.5.1 Wind 11-8
11.5.2 Biomass 11-11
11.5.3 Solar Photovoltaics 11-13
11.5.4 Geothermal 11-15
11.5.5 Solar Thermal 11-16
11.6 References 11-20

LIST OF FIGURES

Figure 1-1 Contributions of Renewable Energy and Other Sources to Total U.S. Energy Supply during 2005 (U.S. EIA, 2006 [1]) 1-2

Figure 1-2 Contributions of Renewable Energy and other Sources to Net U.S. Electricity Generation during 2005 (U.S. EIA, 2006 [1]) 1-3

Figure 2-1 Day-Ahead Prices for the California Power Exchange 2-20

Figure 2-2 Example Price Duration Curve 2-21

Figure 2-3 Components of Busbar Cost for Example 100-MW Wind Generation Plant..... 2-25

Figure 3-1 Historical (1982-2005) and Projected (2006-2010) Installed Wind Generation Capacity in the U.S., Europe, and Remainder of the World (Source: National Renewable Energy Laboratory, *Wind Power Monthly*, and BTM Consult ApS) 3-2

Figure 3-2 End-of-Year Operating Wind Capacity by Country and Region: 2004 and 2005 (Source: BTM Consult ApS, March 2005). 3-7

Figure 3-3 Installed Wind Generation Capacity in the U.S. by State as of December 31, 2006 (Source: American Wind Energy Association). 3-8

Figure 3-4 Rayleigh Probability Density Function for Wind Speed 3-9

Figure 3-5 Coefficient of Performance (Cp) vs. Tip Speed/Wind Speed Ratio 3-10

Figure 3-6 Clipper Windpower's 2.5 MW Liberty Series Wind Turbine Nacelle, with Four Modular Permanent-Magnet Generators and Integral (Source: Clipper Windpower Inc.) 3-20

Figure 3-7 Distribution of Average Wind Power in the United States. Source: Renewable Resource Data Center 3-32

Figure 3-8 The Number of O&M Personnel at a Wind Power Plant versus the Number of Turbines and Project Rating..... 3-34

Figure 3-9 Forecast Capacity Additions of Offshore Wind Through 2010 (BTM Consult Aps). 3-42

Figure 3-10 Wind Resource Map for New England Generated Using Mesoscale Weather Models (AWS Truewind, LLC)..... 3-44

Figure 3-11 Steel Monopile, Concrete Gravity, and Bucket Foundations for Offshore Wind Turbines in Shallow Water Less than 30-m Depth (EUREC and Risoe National Laboratory [60])..... 3-47

Figure 3-12 Location of 80 2-MW wind turbines at Horns Rev Offshore Wind Project (EUREC, Elsam, and Risoe National Laboratory [60])..... 3-47

Figure 3-13 Monopile Steel Foundation and Transition Section for Wind Turbine at Horns Rev Offshore Wind Project (EUREC, Elsam, and Risoe National Laboratory [60]) 3-48

Figure 3-14 Meteorological Tower and Wind Speed Frequency Data from Horns Rev Site (EUREC, Elsam, and Risoe National Laboratory [60])..... 3-48

Figure 3-15 Progression of Expected Wind Turbine Evolution to Deeper Water (Source: Musial and Butterfield, NREL/U.S. DOE, 2004) 3-50
Figure 3-16 NREL TLP and Dutch Trifloater Design Concepts for Floating Wind Turbine Platforms (Source: Musial and Butterfield, NREL/U.S. DOE, 2004) 3-50
Figure 3-17 Installed Wind Capacity and Forecast: 1990-2015 3-56
Figure 3-18 Wind Turbine Sales to Domestic and Export Markets: 2003-2005 3-60
Figure 4-1 Maximum Volatile Yield of Biomass Fuels Compared to Reference Coals (sources: Johnson et al., 2001; Johnson et al., 2002) 4-16
Figure 4-2 Low-Temperature Devolatilization Kinetics for Fresh Sawdust (Source: Johnson et al., 2001) 4-17
Figure 4-3 High-Temperature Devolatilization Kinetics for Fresh Sawdust (Source: Johnson et al., 2001) 4-18
Figure 4-4 Devolatilization Kinetics for Urban Wood Waste (Source: Johnson et al., 2002) 4-18
Figure 4-5 Devolatilization Kinetics for Fresh Switchgrass (Source: Johnson et al., 2002) 4-19
Figure 4-6 Devolatilization Kinetics for Weathered Switchgrass (Source: Johnson et al., 2001) 4-19
Figure 4-7 Devolatilization Kinetics for Black Thunder PRB Coal (Source: Johnson et al., 2001) 4-20
Figure 4-8 Devolatilization Kinetics for Pittsburgh Seam #8 Coal (Source: Johnson et al., 2001) 4-20
Figure 4-9 Fuel Nitrogen Concentrations for the Fuel Samples Analyzed in Detail (Source: Johnson et al., 2001; Johnson et al., 2002) 4-22
Figure 4-10 Distribution of Volatile and Char Fuel Nitrogen in Selected Biomass and Reference Coal Samples (Source: Johnson et al., 2001; Johnson et al., 2002) 4-23
Figure 4-11 Maximum Nitrogen Volatile Yields for Selected Biomass and Coal Samples (Source: Johnson et al., 2001; Johnson et al., 2002) 4-24
Figure 4-12 Volatile Nitrogen and Carbon Evolution from Fresh Sawdust 4-25
Figure 4-13 Volatile Nitrogen and Carbon Evolution from Urban Wood Waste 4-26
Figure 4-14 Volatile Nitrogen and Carbon Evolution from Fresh Switchgrass 4-26
Figure 4-15 Volatile Nitrogen and Carbon Evolution from Weathered Switchgrass 4-27
Figure 4-16 Nitrogen and Carbon Volatilization Normalized to Total Volatiles Formed from Sawdust 4-27
Figure 4-17 Nitrogen and Carbon Volatile Evolution from Weathered Switchgrass Normalized to Total Volatile Evolution 4-28
Figure 4-18 Nitrogen/Carbon Atomic Ratios for Biomass Chars Formed During DTR Pyrolysis at Various Temperatures 4-29
Figure 4-19 Normalized Nitrogen/Carbon Atomic Ratios for Biomass Solid Fuel and Char, Compared to Pittsburgh #8 Bituminous Coal and Black Thunder Powder River Basin Subbituminous Coal 4-29
Figure 4-20 Schematic of Biomass Cofiring with Coal in a Utility Boiler 4-35
Figure 4-21 Plan View of the Willow Island Biomass Cofiring System 4-40
Figure 4-22 Elevation View of the Willow Island Biomass Cofiring System 4-40

Figure 4-23 Receiving Sawdust at the Willow Island Generating Station 4-42
Figure 4-24 Influence of Cofiring in Cyclone Boilers on Furnace Exit Gas Temperature (Source: Tillman and Payette, 2004) 4-44
Figure 4-25 The Influence of Cofiring on Slag Viscosity. Fuels 2 to 9 are various cofiring scenarios using woody biomass, herbaceous biomass, and animal manures with eastern bituminous coals (Source: Miller et al., 2002). 4-45
Figure 4-26 Design of the Sawdust Injection System at Seward Generating Station 4-48
Figure 4-27 NO_x Reduction at the Albright Generating Station Test Program 4-51
Figure 4-28 Representative Wood Fuel Handling System 4-55
Figure 4-29 Schematic of Biomass-Fired Stoker Boiler Power Plant 4-56
Figure 4-30 Typical Boiler and Turbine-Generator Approach 4-57
Figure 4-31 Schematic of Biomass-Fired Atmospheric Fluidized Boiler Power Plant 4-58
Figure 4-32 Air Pollution Control System, Cooling Tower, and Demineralizer for a Typical Wood Waste-Fired Plant 4-60
Figure 4-33 Schematic of Biomass Gasification Application for Combined Heat and Power 4-68
Figure 4-34 Process Flow Diagram for the Vølund Gasifier at Harboøre 4-69
Figure 4-35 Fjernvarme Process Flow Diagram for Coproduction of 6 MW electric and 10 MW thermal. 4-70
Figure 4-36 Overall Configuration of the Biomass Gasifier at Ruien 4-71
Figure 4-37 Schematic of Biomass Gasification and Power Generation System at Kokomäki. 4-72
Figure 5-1 Distribution of Global Insolation in the U.S. (Wh/m^2 per day) (Source: U.S. DOE) 5-5
Figure 5-2 Worldwide Average PV Module Selling Price vs. Cumulative Sales 5-21
Figure 5-3 Schematic of a Simple Microgrid System 5-38
Figure 5-4 U.S. Shipments of PV by Market Sector and End Use in 2005 (Source: EIA [16]) 5-42
Figure 6-1 Map of U.S. Geothermal Resource Potential Map [Estimated Temperatures (°C) at 6 km Depth] (top), 2004 SMU Heat Flow Assessment (bottom) 6-5
Figure 6-2 Recent BLM Resources Potential Map of the Western States 6-6
Figure 6-3 Hydrothermal Power Plant at The Geysers, California 6-11
Figure 6-4 Dual-Flash (two-flash) Geothermal Power Plant 6-16
Figure 6-5 Binary Cycle Geothermal Power Plant (air-cooled design) 6-17
Figure 6-6 Steam Pipelines for the Ohaaki, New Zealand Plant Run through Land Used for Grazing and Agroforestry 6-41
Figure 7-1 Distribution of Direct-Normal Insolation in the U.S. (Wh/m^2/day) (Source: U.S. DOE) 7-4
Figure 7-2 Solar Trough Collector Field at Kramer Junction, California. Note the receiver tube at the reflectors' focal point that transports heat-transfer fluid. 7-6
Figure 7-3 Solar Two Central Receiver in Operation. The two tanks to the left of the tower base are the storage tanks for the hot and cold molten salt solutions 7-9

Figure 7-4 25-kW SAIC Dish/Engine System at the DOE Mesa Top Thermal Test Facility. (Source: NREL) 7-13
Figure 8-1 Earth, Moon and Sun's Influence on Tides 8-3
Figure 8-2 Schematic of the Tidal Bulge 8-4
Figure 8-3 Tide Generating Forces based on Earth-Moon Interactions 8-4
Figure 8-4 Diurnal, Semi-Diurnal and Mixed Semi-Diurnal Tides 8-5
Figure 8-5 Spring and Neap Tides 8-6
Figure 8-6 Global Distribution of Mean Tidal Range 8-6
Figure 8-7 Tidal Energy Conversion System Configurations 8-8
Figure 8-8 United States Tidal Current Reference Stations 8-17
Figure 8-9 Canadian Tide and Current Tables and Regions Covered by the Canadian Data 8-20
Figure 8-10 WebTide Ocean Model Regions 8-22
Figure 8-11 Annual Average Tidal Current Speed Probability Distributions for Cape Blomidon transect, Minas Passage, NS (East Coast) 8-23
Figure 8-12 Annual Average Tidal Current Speed Probability Distributions for Dog Island transect, Western Passage, ME (East Coast) 8-24
Figure 8-13 Annual Average Tidal Current Speed Probability Distributions for Point Evans Transect, Tacoma Narrows, WA (West Coast) 8-24
Figure 8-14 Annual-Average Tidal Current Speed Probability Distributions for Cairn Point Transect, Knik Arm, AK (West Coast) 8-25
Figure 8-15 Open-Channel Flow Theory: Energy Equation and Definition Sketch 8-26
Figure 8-16 Alternative Profile Formulations of Velocity Variability with Depth (1/10th-Power Law used) 8-28
Figure 8-17 Cross-Section of Tidal Channel (dotted lines show section boundaries) 8-30
Figure 8-18 Accounting for Tidal Range in Cross-Sectional Area Calculation 8-31
Figure 8-19 Digital Bathymetry for Tacoma Narrows, WA 8-31
Figure 8-20 Influence of Energy Extraction on Flow in a Tidal Channel 8-34
Figure 9-1 Wind Blowing Over Fetch of Water Produces Waves 9-3
Figure 9-2 Particle Motion in Different Water Depths 9-3
Figure 9-3 (a) Wave Energy Device Concepts and Principles of Operation, Point Absorber Wave Energy; (b) Device Concepts and Principles of Operation, Oscillating Water Column 9-5
Figure 9-4 New England Reference Stations (NDBC 44005 and 44008 are bright green squares) 9-12
Figure 9-5 West Coast Reference Stations (NDBC 46012 is green square; CDIP 0036 and 0037 are green circles) 9-12
Figure 9-6 Oahu HI Reference Station, (CDIP 0098 is green circle) 9-13
Figure 9-7 (a) Scatter Diagram for Point Makapuu, Oahu, Hawaii. 9-15
Figure 9-8 Scatter Diagrams for (a) Point Makapuu, Oahu, (b) Hawaii; Gray's Harbor, WA; (c) Half Moon Bay CA; and (d) Gulf of Maine 9-18

Figure 9-9 Wave Power Flux 9-19
Figure 9-10 Statistical Wave Distribution Matrix and Lines of Constant Wave Power and Gradient 9-20
Figure 9-11 U.S. Wave Energy Resources 9-20
Figure 9-12 Annual Wave Power Averages Worldwide in kW/m Wave Front 9-21
Figure 9-13 European Marine Energy Center (EMEC) 9-26
Figure 9-14 Permanent Magnet Linear Generator in a Conceptual Wave Park Vision 9-27
Figure 9-15 Preproduction Prototype Pelamis 9-32
Figure 9-16 Mooring Arrangement of the Prototype Pelamis Design 9-33
Figure 9-17 Energetech Preproduction Prototype OWC Device Showing Mooring Design 9-33
Figure 9-18 Electrical Interconnection of a Single Unit Pelamis Plant–Oregon Example 9-34
Figure 9-19 Electrical Interconnection of a Commercial-Scale Pelamis Plant–Oregon Example 9-35
Figure 9-20 Commercial Scale COE Breakdown–Oregon Example 9-39
Figure 9-21 Levelized COE Comparison to Wind–Oregon Example 9-40
Figure 9-22 Anchor Handling and Multi-Cat Vessels 9-41
Figure 9-23 Primary Maritime Boundaries Relevant to Coastal Development Permitting for WEC Project 9-48
Figure 10-1 Ancillary Services Are Distinguished by Their Deployment Times and Durations 10-9
Figure 10-2 Constant-Speed Induction Machine-Connected Wind Turbine Generator with Gear Box 10-19
Figure 10-3 Grid Interface for Peetz Table 30-MW Wind Farm 10-20
Figure 10-4 Variable-Speed Doubly-Fed Induction Machine Connected WTG with Gear Box 10-21
Figure 10-5 Variable-Speed, Direct-Drive Asynchronous Machine Converter-Connected WTG (no gear box) 10-22
Figure 10-6 Direct-Drive Synchronous Generator with Simple Rectifier at the WTG and Voltage-Source Converter Interface With the Utility Grid 10-22
Figure 10-7 One Leg, Single-Line Diagram of 12-Pulse HVDC System (Source: Siemens) 10-23
Figure 10-8 A Severe Voltage Sag to Less Than 30% Voltage Remaining Voltage for 100 ms (Upper Trace) and Wind Turbine with LVRT Recovering After the Event (Lower Trace) 10-25
Figure 10-9 Response of Four Commercially Available Wind Turbine Generators to a Large Voltage Sag 10-26
Figure 10-10 Illustration of Various Reactive Compensation and Voltage Control Mechanisms for Wind Farm Applications 10-27
Figure 10-11 Power Factor Curves for Example Wind Plant 10-28
Figure 10-12 Fixed and Switched Capacitor Bank Supporting a 2.8-MW Wind Farm in India (Source: Crompton Greaves Ltd.) 10-29

Figure 10-13 Conceptual Layout of a Dynamic VAR Device and Switched Capacitors Supporting a Wind Farm (Source: American Superconductor) 10-32
Figure 10-14 Simplified Schematic of a Static VAR (SVC) or Distribution Static Var Compensator (DSVC) 10-33
Figure 10-15 Configuration of Commercially Available DSVC Source: S&C Electric 10-34
Figure 10-16 Distribution Static VAR Compensator (DSVC) at Wind Site in India (Source: Crompton Greaves Ltd.) 10-34
Figure 10-17 Storage Operating Benefits in Different Ancillary Services Markets 10-39
Figure 10-18 Model for Evaluation of Energy Storage with Wind Power 10-44
Figure 11-1 Levelized CO_2 Emissions Offset vs. % Fossil Fuel Generation 11-6
Figure 11-2 Levelized CO_2 Emissions Control Cost vs. Cost Premium and CO_2 Emissions Offset 11-7
Figure 11-3 Levelized CO_2 Emissions Control Cost vs. Cost Premium and Fossil Fuel Mix at 50% Generation from Fossil Fuels 11-7
Figure 11-4 Levelized CO_2 Emissions Control Cost vs. Average Wind Speed at 50 m (top) and System Generation Cost (Bottom) for a 100-MW Wind Plant (Dec 2006 $) ... 11-10
Figure 11-5 Levelized CO_2 Emissions Control Cost vs. Delivered Fuel Cost (Top) and System Generation Cost (Bottom) for a 50-MW Stoker Boiler Biomass Power Plant (Dec-2006 $) 11-12
Figure 11-6 Levelized CO_2 Emissions Control Cost vs. Annual Insolation for a 5.0-MW fixed Flat-Plate Solar PV Plant vs. Annual Insolation (Top) and System Generation Cost (Bottom, Dec-06 $) 11-14
Figure 11-7 Levelized CO_2 Emissions Control Cost for 50-MW Flash-Steam and 20-MW Binary-Cycle Power Plants vs. Base System Generation Cost (Dec-06 $) 11-16
Figure 11-8 Levelized CO_2 Emissions Control Cost vs. Annual Insolation (Top) and System Generation Cost (Bottom) for an 80-MW Solar Thermal Parabolic Trough Power Plant (Dec-06 $) 11-18
Figure 11-9 Levelized CO_2 Emissions Control Cost vs. Annual Insolation (Top) and System Generation Cost (Bottom) for an 80-MW Solar Thermal Dish Stirling Engine Power Plant (Dec-06 $) 11-19

LIST OF TABLES

Table 1-1 U.S. Energy Consumption by Energy Source, 2001-2005 (in Quadrillion Btu) (Source: U.S. EIA, 2005 [1]) 1-2

Table 1-2 Installed Renewable Energy Generation Capacity (as of December 2005) 1-4

Table 2-1 Calculation of Annual Fixed Charge Rates 2-2

Table 2-2 Calculating Levelized Annual Charges 2-4

Table 2-3 Wind Power Generation—Nominal Dollar Terms 2-6

Table 2-4 Wind Power Generation—Constant Dollar Terms 2-7

Table 2-5 Sources and Uses of Construction Funds 2-17

Table 2-6 Example Income Statement ($1000) 2-19

Table 2-7 Example Cash Flow Statement ($1000) 2-24

Table 2-8 Example Sensitivity Analysis 2-29

Table 2-9 Confidence Rating Based on Cost and Design Estimate 2-33

Table 2-10 Accuracy Range Estimates for TAG Cost Data (Ranges in Percent) [1] 2-33

Table 2-11 TPC-TPI Adjustment Factors (AF) 2-35

Table 3-1 Operating Wind Generation Capacity: End of Year 1999–End of 2005 (Source: *Wind Power Monthly* and BTM Consult ApS, March 2006) 3-3

Table 3-2 Forecast Wind Generation Capacity Additions: 2006-2010 (Sources: BTM Consult ApS, March 2006) 3-6

Table 3-3 Wind Turbine Prototypes and Upgrades Announced during 2004 (Source: Renewable Energy World, February 2005) 3-17

Table 3-4 Technology Process Development Map: Wind Power Plants 3-21

Table 3-5 Cost and Performance Estimates for Horizontal-Axis Wind Turbine Power Plants (Dec. 2006 $) 3-23

Table 3-6 Wind Plant Performance and Levelized Cost of Electricity Estimates (Dec. 2006 $) 3-24

Table 3-7 Offshore Wind Farms, All Situated in Northern Europe 3-41

Table 3-8 Forecast for Offshore Wind Development 2006 to 2010 3-42

Table 3-9 U.S. Offshore Wind Energy Resource by Region for Shallow and Deep Water [59] 3-45

Table 3-10 Ten Largest Wind Turbine Markets during 2003-2005 3-52

Table 3-11 Growth Rates of Installed Wind Capacity in the Top-Ten Markets during 2005 3-53

Table 3-12 Annual Average Nameplate Ratings (kW) of Wind Turbines Installed by Country 3-53

Table 3-13 Commercial Megawatt-Class Wind Turbine Generators 3-55
Table 3-14 Global Wind Power Development Forecast: 2006-2010 3-57
Table 3-15 Global Participants in the Wind Power Industry 3-58
Table 3-16 Global Market Shares of Wind Turbine Manufacturers in 2003, 2004, and 2005 3-59
Table 4-1 Biomass Energy Consumption in the U.S. Economy by Sector and Type, 2004 (exajoules) 4-2
The data in the tables document the fact that all biomass, on a moisture and ash free (MAF) basis, has reasonably similar heating values. Differences are in the relative percentages of holocellulose (cellulose plus the hemicelluloses), lignin, and extractives. Table 4-2 Proximate and Ultimate Analyses for Typical Woody Biomass Fuels 4-7
Table 4-3 Proximate and Ultimate Analyses for Typical Herbaceous Biomass Fuels 4-8
Table 4-4 Proximate and Ultimate Analyses for Typical Manures 4-8
Table 4-5 Nitrogen and Ash Concentrations in Biomass Fuels (values in lb/10^6 Btu) 4-11
Table 4-6 Ash Analyses of Various Biomass Fuels Compared to Pittsburgh #8 Coal 4-11
Table 4-7 Ash Analyses of Switchgrass and Other Herbaceous Crops 4-12
Table 4-8 Slagging and Fouling Index for Selected Biomass Fuels 4-13
Table 4-9 Ranges in Concentrations of Trace Metals in Woody Biomass (mg/kg in dry wood) 4-14
Table 4-10 Ranges in Concentrations of Trace Metals in Woody Biomass Burned at a Pulp Mill in the Pacific Northwest (mg/kg in dry wood) 4-14
Table 4-11 Volatility Measures for Representative Biomass Fuels 4-15
Table 4-12 Devolatilization Kinetic Parameters for Biomass Fuels and Reference Coals (400-1700°C) 4-17
Table 4-13 Chemical Fractionation Analyses of Various Biofuel Ash Compared to Pittsburgh #8 Coal 4-31
Table 4-14 Chemical Fractionation of Potassium in Switchgrass for Four Samples 4-32
Table 4-15 Complete Chemical Fractionation of a Switchgrass Sample 4-32
Table 4-16 Composition and Characteristics of the Wastewater Treatment Gas Produced at the T.E. Maxson Treatment Facility in Memphis, TN 4-33
Table 4-17 Representative Biomass Cofiring Tests and Demonstrations 4-36
Table 4-18 Capital Cost of the Willow Island Cofiring Demonstration 4-42
Table 4-19 Capital Cost Summary for the Bailly Generating Station Cofiring System 4-43
Table 4-20 Estimated Capital Cost of the Albright Cofiring Demonstration if Constructed as a New Facility 4-49
Table 4-21 Typical Water Rates for Condensing Turbines in Wood Waste-Fired Plants 4-59
Table 4-22 Typical Water Rates for Backpressure Turbines in Wood Waste-Fired Plants 4-59
Table 4-23 Capital Cost Estimate for a Conceptual 25 MW_e Wood Fired Power Plant 4-63
Table 4-24 Total Costs for a 25 MW_e Wood Fired Power Plant 4-64
Table 4-25 Performance and Cost Estimates for Biomass Cofiring with Coal in Utility Boiler 4-76

Table 4-26 Performance and Cost Estimates for Biomass Stoker and CFB Boilers.....4-77
Table 4-27 Performance and Cost Estimates for Direct Combustion and Combined Heat and Power.....4-78
Table 4-28 Performance and Cost Estimates for Landfill Gas.....4-79
Table 5-1 U.S. PV Exports by Region (in 2005).....5-6
Table 5-2 Technology Monitoring Guide: Solar Photovoltaic Power Plants.....5-11
Table 5-3 Technology Process Development Map: Solar Photovoltaics.....5-13
Table 5-4 Utility-Scale Solar Photovoltaic Power Plant Costs for 2000 PV Technology in Carrisa Plains, California (Dec-03 $).....5-19
Table 5-5 Site Data for 27 Locations in the Continental U.S.....5-22
Table 5-6 Information Included in Clean Power Estimator Databases.....5-23
Table 5-7 Case Study Assumptions.....5-25
Table 5-8 Net Capital Cost.....5-26
Table 5-9 Energy Production and Emissions.....5-27
Table 5-10 First-Year Savings and Costs.....5-27
Table 5-11 Economic Analysis Results.....5-28
Table 5-12 Solar PV Power Plant Capital, O&M, and Lease Cost Projections for Fixed Flat-Plate Thin-Film Photovoltaic Power Plants (Dec-03 $).....5-29
Table 5-13 Solar PV Power Plant Capital, O&M, and Lease Cost Projections for One-Axis Tracking Crystalline Silicon Flat-plate Photovoltaic Power Plants (Dec-03 $).....5-30
Table 5-14 Solar PV Power Plant Capital, O&M, and Lease Cost Projections for Two-Axis Tracking High Concentration Photovoltaic Power Plants (Dec-03 $).....5-30
Table 5-15 Solar PV Power Plant Capital and O&M Cost Scaling Factors vs. Rated Plant Output Relative to a 5-MW_{ac} Plant.....5-31
Table 6-1 Proposed Resource Temperature Classification.....6-7
Table 6-2 Performance and Cost Ranges for Geothermal.....6-8
Table 6-3 Supply Curve for Geothermal in U.S. (Hydrothermal Only).....6-9
Table 6-4 Installed Geothermal Power Worldwide (2005) [28].....6-10
Table 6-5 New Added Generation in 2005-2006.....6-23
Table 6-6 Technology Monitoring Guide: Geothermal Power Plants.....6-25
Table 6-7 Technology Process Development Map: Geothermal Power Plants.....6-28
Table 6-8 Estimated Geothermal Development Costs (Dec 2005 $).....6-32
Table 6-9 Geothermal Power Costs (Dec-2005 $).....6-33
Table 6-10 Geothermal: Cost Estimates for “Goal” Technologies (Dec-2005 $).....6-34
Table 6-11 Current Status and Goals for Geothermal Technologies (Dec 2005 $).....6-35
Table 6-12 Land Area Requirements for Current Renewable Technologies.....6-40
Table 6-13 Averages of Four Significant Pollutants, as Emitted from Geothermal and Coal Facilities, Are Listed in the Table Below (source: GEA 2005 [27]).....6-43
Table 7-1 Central Receiver Demonstration Projects.....7-8
Table 7-2 Technology Monitoring Guide Solar Thermal Power Plants.....7-17

Table 7-3 Technology Process Development Map: Solar Thermal Power Plants 7-18
Table 7-4 Comparison between Solar Two and Solar Tres Projects 7-20
Table 7-5 Performance and Cost Estimates for Solar Thermal Technologies (Dec-06 $) 7-23
Table 7-6 Selected Data for Solar Trough Systems 7-24
Table 7-7 Peak Central-Receiver System Efficiency Components 7-32
Table 7-8 Annual Average Central Receiver System Efficiency Components 7-33
Table 8-1 List of Tidal In Stream Energy Conversion (TISEC) Projects in the FERC Database 8-12
Table 8-2 Installed and Planned U.S. Tidal Energy Capacity 8-13
Table 8-3 U.S. Tidal Current Site Characteristics 8-18
Table 8-4 Offshore Tidal Energy Conversion Device Developers Contacted 8-36
Table 8-5 Initial Screening of Responses 8-37
Table 8-6 TISEC Device Characterization Summary 8-39
Table 8-7 Selected Tidal Energy Development, Test and Engineering Projects 8-40
Table 8-8_Summary of Feasibility Evaluation Sites 8-43
Table 8-9_Cost Estimates for Feasibility Evaluation Sites 8-43
Table 8-10_Major Environmental Issues Facing Tidal In Stream Energy Projects 8-48
Table 9-1 Installed and Planned Wave Energy Capacity (as of December 1, 2006) 9-9
Table 9-2 Offshore Wave Energy Reference Measurement Stations 9-11
Table 9-3 Offshore Wave Energy Conversion Device Manufacturers 9-22
Table 9-4 Major WEC Device Manufacturers 9-25
Table 9-5 Key Site Parameters 9-31
Table 9-6 Estimated Performance of Pilot Demonstration Plants (Oregon Example) 9-34
Table 9-7 Estimated Performance of Commercial Plants 9-37
Table 10-1 Functions and Services Provided by Generation 10-4
Table 10-2 Summary of Integration Technical Impacts 10-13
Table 10-3 Summary of Integration Cost Impacts ($/MWh) 10-13
Table 10-4 Scheduling Provisions Beneficial to Wind 10-17
Table 10-5 Mapping Solution Categories with Wind Power Problems 10-18
Table 10-6 Types and Functions of Custom Power Devices per Draft IEEE Standard 1409 10-31
Table 10-7 Advantages and Disadvantages of Candidate Energy Storage Technologies to Support Wind Power Energy Intermittency and Output Fluctuations 10-42
Table 10-8 Performance and Cost Comparison of Energy Storage Technologies to Support Wind Energy Intermittency and Output Power Fluctuations 10-44
Table 11-1 Lifetimes in the Atmosphere and Relative Infrared Absorption Strengths of the Greenhouse Gases 11-1
Table 11-2 Fossil Carbon Intensity of Coal, Oil, Natural Gas and Wood Fuels 11-2
Table 11-3 Carbon Intensity of Generation Technologies 11-3

Table 11-4 Wind Plant Performance and Levelized Energy Cost vs. Wind Speed Class for a 100-MW Wind Plant ($/MWh, Dec-2006 $) 11-8
Table 11-5 Levelized Cost of Electricity for 50-MW Biomass-Fired Stoker and Fluidized Bed Boiler Power Plants ($/MWh, Dec-2006 $) 11-11
Table 11-6 Levelized Cost of Electricity for 5- and 50-MW Solar Photovoltaic Plants with Fixed Flat Plate Modules ($/MWh, Dec-06 $) 11-13
Table 11-7 Geothermal Power Energy Cost vs. Year of Commercial Order for 50-MW Flash-Steam and and 20-MW Binary-Cycle Geothermal Power Plants ($/MWh, Dec-06 $) 11-15
Table 11-8 Levelized Cost of Electricity for 80-MW Parabolic-Trough and Dish-Stirling Solar Thermal Power Plants (Dec-06 $) 11-17

1
INTRODUCTION

1.1 Background

Renewable energy technologies are those that utilize inexhaustible or naturally replenished resources to generate electricity with minimal environmental impact. Energy sources addressed in this edition of the *Technical Assessment Guide–Renewable Energy* (TAG-RE) include wind, biomass, solar photovoltaic, geothermal, solar thermal, and ocean tidal and wave energy.

Passage of the Public Utilities Regulatory Policies Act (PURPA) in 1978 was a turning point for domestic renewables. PURPA was drafted in response to the oil crisis of the early 1970s and guaranteed a market at some price for any energy an alternative provider could produce. Solar and wind power in particular made great strides during this period. However, to some extent, lower oil prices during the 1980s and 1990s lessened interest in, development of, and government support for renewable technologies.

Recent concerns about the long-term impacts of rising concentrations of atmospheric greenhouse gases, such as carbon dioxide, have brought renewed vigor to the industry. Although it now appears unlikely to be ratified by the United States, the 1997 Kyoto Protocol on Climate Change, in which industrialized nations agreed to a set of binding emission targets for six greenhouse gases, has been a critical driver of subsequent funding for renewable energy projects both in the U.S. and abroad. Germany, Japan, the U.K., and other European Union countries have set aggressive goals for meeting increasingly large percentages of their energy needs with renewable technologies, and have instituted policies and subsidies to encourage them. New concerns about energy security and independence in the wake of terrorist attacks have also renewed interest in developing domestic energy resources in the U.S., including non-fossil renewable options.

For a variety of regulatory, social, economic, and environmental reasons, interest in renewable energy continues to grow. As renewable energy technologies evolve and become more cost-competitive, and their environmental benefits become more valuable, they are being deployed with increasing frequency and public support.

Table 1-1 and Figures 1-1 and 1-2 show the relative contributions of renewable energy to total U.S energy supply and electricity generation during 2001 through 2005 and during 2005, based on data reported by the U.S. Department of Energy (DOE) Energy Information Administration (EIA) [1]. During 2005, renewable energy contributed about 6% of total energy and 9% of total electricity generation, of which most was contributed by hydroelectric and biomass energy.

Table 1-1
U.S. Energy Consumption by Energy Source, 2001-2005 (in Quadrillion Btu)
(Source: U.S. EIA, 2005 [1])

Energy Source	2001	2002	2003	2004	2005
Fossil Fuels					
Coal	21.914	21.904	22.321	22.466	22.830
Net Coal Coke	0.029	0.061	0.051	0.138	.044
Natural Gas [1]	22.906	23.628	23.069	23.036	22.640
Petroleum [2]	38.333	38.401	39.047	40.5940	40.441
Subtotal	83.121	84.297	84.388	86.234	85.955
Nuclear Electric Power	8.033	8.143	7.959	8.222	8.133
Renewable Energy					
Hydroelectric	2.242	2.689	2.825	2.690	2.715
Geothermal	0.311	0.328	0.339	0.341	0.352
Biomass	2.640	2.648	2.740	2.982	2.781
Solar	0.065	0.064	0.064	0.065	0.064
Wind	0.070	0.105	0.115	0.142	0.149
Subtotal	5.328	5.835	6.082	6.220	6.061
U.S. TOTAL	96.472	97.877	98.311	100.676	99.894

1. Natural gas data include supplemental gaseous fuels.
2. Petroleum products supplied, including natural gas plant liquids and crude oil burned as fuel.

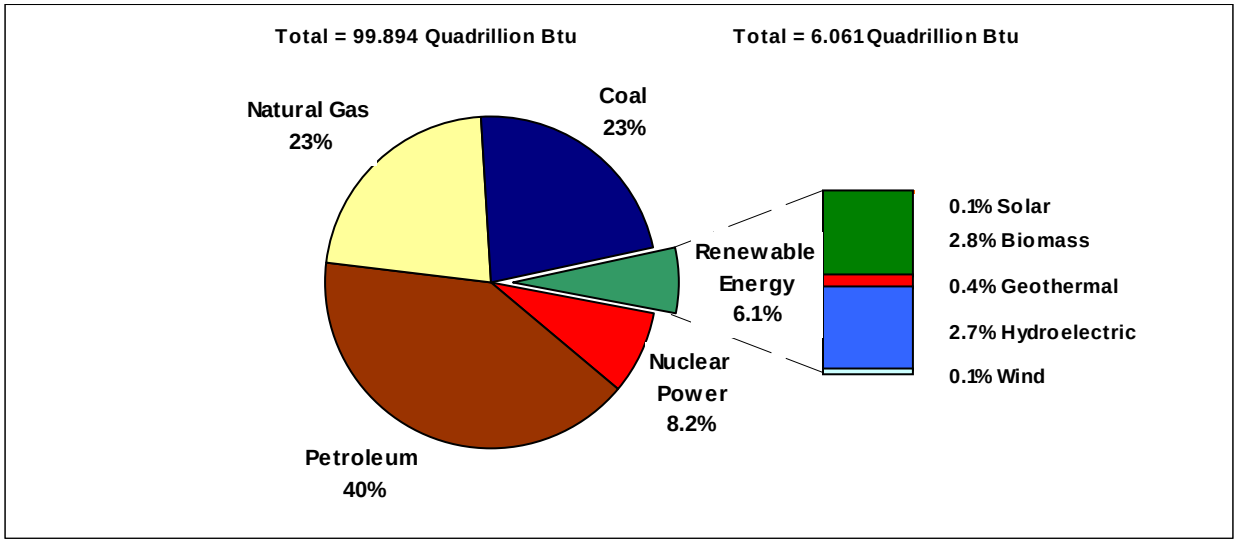


Figure 1-1
Contributions of Renewable Energy and Other Sources to Total U.S. Energy Supply during 2005 (U.S. EIA, 2006 [1])

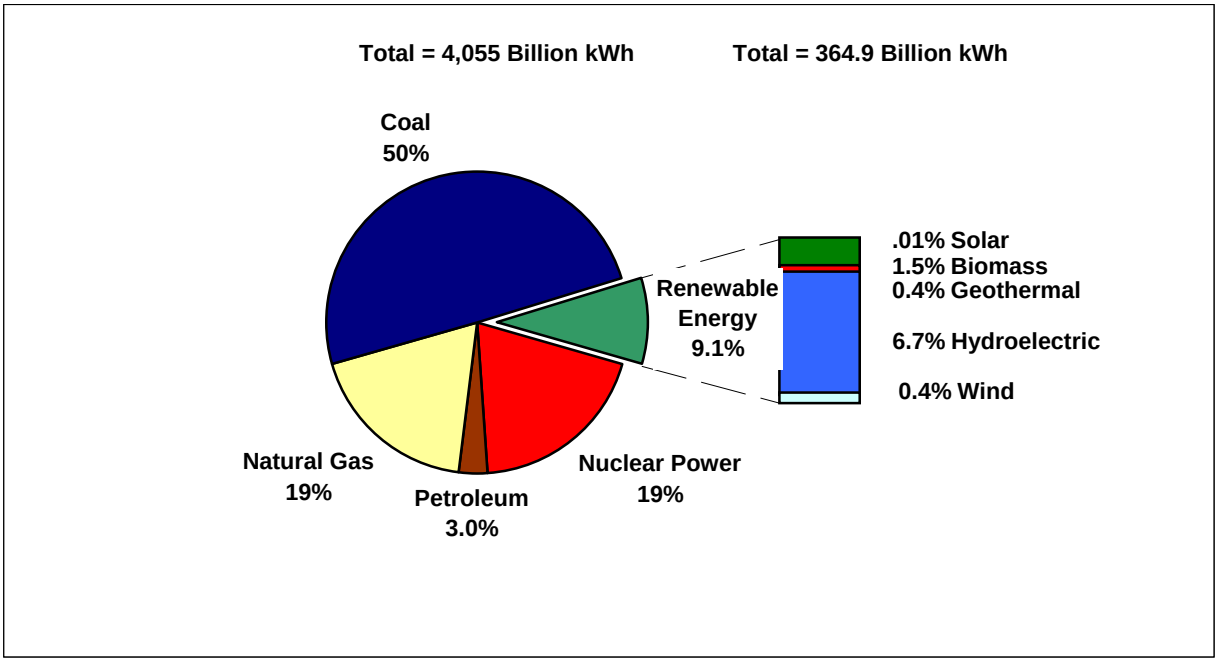


Figure 1-2
Contributions of Renewable Energy and other Sources to Net U.S. Electricity Generation during 2005 (U.S. EIA, 2006 [1])

Renewable energy resources are broadly available across the U.S. and throughout the world. Some resources are almost universally available; others are limited to particular areas. Locations with high annual insolation are obviously best suited to solar power. Solar energy can still be usefully and economically applied in locations with lower quality resources including, in some cases, extreme northern or southern latitudes. Wind energy is generally deployed along coastlines or mountain passes with reliable sustained winds. The upper plains of the American Midwest also host some of the world's best wind resources and a number of the newest and largest wind power projects. In addition, the Midwest is an excellent source of biomass, which can be grown through managed agricultural programs to provide a continuous supply of biomass fuels. Geothermal resources are concentrated in geologically active areas such along the Pacific "Ring of Fire" that includes the Philippines, Indonesia, and California. The resources for small hydroelectric systems exist in most countries.

Table 1-2 provides estimates of the installed capacity by generation source, including renewable technologies in the U.S. as of the end of 2005. Note, though, that some of these sources are growing rapidly. For example global wind capacity is estimate to have climbed from 59,267 MW at end of 2005 to some 75,000 MW by end of 2006.

Table 1-2
Installed Renewable Energy Generation Capacity (as of December 2005)

Technology	U.S. (MW)	Worldwide (including U.S.) (MW)
Wind	9,181	59,267
Biomass	9,700	22,400
Geothermal	2,828	8,933
Solar Photovoltaics[1]	550	5,200
Solar Thermal:		
Parabolic Trough	354	360
Dish/Engine	<1	<1
Central Receiver	<1	<1
Low-Impact and Emerging Hydro:		
Ocean Tidal Energy	0.07	<1
Ocean Wave Energy	0.04	<4

1. PV data reflect module sales; installed capacity is likely similar.

The benefits of using renewable energy are many and extend beyond issues of abundance and environmental impact. Diversifying energy resources provides security against economic or political events that may impact one particular resource. They offer some protection against risks associated with fluctuating fossil-fuel prices and supplies. Investment in renewable energy can contribute to local economic growth and employment. Many renewable energy plants can be built in a modular fashion proportionate to load growth patterns and local needs. In addition, renewable energy technologies are often ideal distributed resources that can be placed at or near the customer load, reducing transmission and distribution infrastructure costs.

The value of renewable energy is determined by a number of factors, including its ability to meet mandated renewable energy capacity requirements, respond to customer demands for renewable energy, and differentiate a power provider from its competitors. Renewables can also offer significant environmental benefits such as offsetting carbon dioxide, NOx, and SO_2 emissions. Some renewable energy technologies such as biomass and geothermal (and to a lesser extent some solar thermal technologies) are dispatchable, making them valuable generation assets. The output of non-dispatchable technologies such as solar PV can correspond well with summer afternoon load peaks. And EPRI's ongoing efforts to develop accurate forecasting models will improve the value of wind energy in a company's generation portfolio.

1.2 EPRI's Role

Since its inception in the 1970s, EPRI has conducted programs to assess, evaluate, and advance renewable power technologies. EPRI has published periodic updates to the *Technical Assessment Guide* (TAG) since the 1970s, a document containing the most up-to-date technical and economic data available on generation technologies. The EPRI TAG has become the recognized industry standard for information essential in preliminary planning for generation technology evaluation and application. Renewable energy technologies were addressed in the 1997 and earlier editions of the EPRI TAG as well as the 1997 joint EPRI-U.S. DOE report *Renewable Energy Technology Characterization* [2-8].

EPRI has also published several editions of its *Technical Assessment Guide–Distributed Resources* (TAG-DR) [8], which provides a consistent and credible set of cost and performance data involving distributed resources—defined as decentralized energy generation, storage, distribution, and end-use technologies in locations that benefit the electric system, specific customers, or both. The TAG-DR also addressed renewable technologies.

EPRI project managers concluded in 1999 that renewable energy technology had grown sufficiently and was developing and changing so rapidly that it would be worthwhile to prepare a dedicated *Technical Assessment Guide–Renewable Energy* (TAG-RE) and update it annually, beginning in 2000. The inaugural edition has been updated and expanded annually and subsequent editions were issued each year through 2005.

In addition to the major renewable energy technologies, the 2006 edition of the TAG-RE includes sections on Economic Methodology, Renewable Energy Grid Integration Technologies, and Greenhouse Gas Emissions. All sections have been thoroughly reviewed and updated to reflect new studies, project results, and cost and performance data gathered over the past year. In 2003, the content of the Low-Impact and Emerging Hydropower section became sufficiently large and complex to justify splitting it into two new sections, one covering in-stream and tidal energy generation technologies and the other covering ocean wave energy technologies.

1.3 Objective

As with other editions and versions of the TAG, the TAG-RE fulfills two roles. First, it serves as a one-stop information source for a wide variety of renewable energy technologies evaluated on a consistent basis. EPRI's experience and expertise, along with its reputation for objectivity and credibility, make TAG-RE a uniquely valuable reference. The various renewable technologies have been evaluated with sufficient technical depth to enable planners to conduct an accurate assessment of the renewable energy options that are available to them.

Second, the TAG-RE provides information to educate all interested parties in the key technology concepts, language, and issues related to renewables. It offers not only technical depth but also breadth of coverage across many disciplines including project planning, resource availability and management, regulatory processes, operating and maintenance requirements, market potential, and future developments.

The information summarized in TAG-RE encompasses more than three decades of EPRI research on renewable technologies and draws upon a large foundation of knowledge built by the U.S. DOE and other national and international experts. This information has been distilled and synthesized to provide the readers of TAG-RE the most up-to-date, accurate, practical intelligence available that they can use to investigate, plan, and deploy the latest renewable energy technologies.

1.4 Definitions and Units

Unless otherwise stated, all dollar figures cited in the TAG-RE are assumed to be U.S. dollars corrected for inflation to end-of-year 2004 values.

Throughout the TAG-RE, most notably the Biomass and Solar Thermal sections, the subscripts "e" (e.g., kWe or MWe) and "t" (e.g., kWt or MWt) are used to differentiate between electrical and thermal power, respectively. In the Solar Photovoltaic section, the terms kWp or MWp may be used to denote "peak" PV cell or module capacity.

1.5 Scope

The TAG-RE has 11 main sections. Following this Section 1: *Introduction*, they are:

Section 2: *Economic Methodology and Assumptions* provides a detailed discussion of the basis upon which data were gathered and presented.

Section 3: *Wind Power* covers one of the most widespread and economically competitive renewable energy technologies. Wind power systems progressed substantially through the past decades as a result of government incentives, with a steady trend of cost reduction. Wind power is particularly popular in Europe, due partly to aggressive government goals and public support, and is considered to be a commercially- established and competitive grid-power technology.

Section 4: *Biomass Energy* focuses on biomass fuel and combustion properties, direct combustion, gasification, and cofiring with coal in utility boilers. This section addresses resource availability, technology status, performance and cost history and projections, operating and maintenance labor requirements, environmental emissions, installed capacity, and cost and economic issues.

Section 5: *Solar Photovoltaics* (PV) addresses power systems that convert sunlight directly into electricity. These solid-state electronic devices have no moving parts, no fluids, no noise, and no emissions of any kind. These benefits have positioned PV to be the preferred power technology for many remote applications. In addition, developments on the horizon promise to significantly reduce the costs of PV and open up new markets for distributed applications, such as innovative building-integrated technologies.

Section 6: *Geothermal* provides the latest information on systems that generate electricity by tapping underground steam reservoirs. Although available in relatively few areas, geothermal power has been a practical reality in California, Italy, and Asia for decades. This section also discusses the potential in both developed and developing countries for the more common geothermal hot water and liquid-dominated hydrothermal resources.

Section 7: *Solar Thermal* focuses on solar power systems that use concentrated sunlight to heat a working fluid that generates electricity in a thermodynamic cycle. Such systems range in scale from a 25-kW reflector dish-generator system that can fit on the back of a large truck to the 10-MW Solar Two demonstration, that used hundreds of mirrors to focus sunlight onto a central receiver, and incorporated thermal storage through the use of a molten salt heat transfer fluid and a large storage tank.

Section 8: *Ocean Tidal Energy* addresses low-impact and emerging hydro systems that capture ocean tidal current energy to generate electricity. These systems are distinct from traditional hydroelectric installations, which typically generate electricity via a turbine powered by water impounded behind a dam. Many in-stream energy generation technologies are derived from analogous technologies in the wind turbine industry.

Section 9: *Ocean Wave Energy* addresses low-impact and emerging hydro systems that convert the kinetic energy of ocean waves into electricity.

Section 10: *Integrating Renewable Energy with the Grid* addresses power electronics, energy storage, and other technologies need to integrate large wind plants and other intermittent generation technologies into the electricity grid. Energy storage technologies such as batteries, pumped hydro, compressed air energy storage (CAES), flywheels, and superconducting magnetic energy storage (SMES) can be selected and designed to absorb short, intermediate, and longer-term fluctuations of output from seconds to days. Other integration technologies, such as line compensation, power electronics, integration with hydro, and solar and wind energy forecasting address short-term fluctuations.

Section 11: *Greenhouse Gas Emissions Control* discusses the role that renewable energy power technologies can play in greenhouse gas emissions reduction and includes example calculations showing how that role can be quantified.

1.6 References

1. *Annual Energy Review 2005*, U.S. Energy Information Agency, Washington, D.C.: July 2006: DOE/EIA-0384(2005).
2. *Renewable Energy Technical Assessment Guide–TAG-RE 2005*, EPRI, Palo Alto, CA: December 2005. 1010407.
3. *Renewable Energy Technical Assessment Guide–TAG-RE 2004*, EPRI, Palo Alto, CA: December 2004. 1008366.
4. *Renewable Energy Technical Assessment Guide–TAG-RE 2003*, EPRI, Palo Alto, CA: December 2003. 1004938.
5. *Renewable Energy Technical Assessment Guide–TAG-RE 2002*, EPRI, Palo Alto, CA: December 2002. 1004196.
6. *Renewable Energy Technical Assessment Guide–TAG-RE 2001*, EPRI, Palo Alto, CA: December 2001. 1004034.
7. *Renewable Energy Technical Assessment Guide–TAG-RE 2000*, EPRI, Palo Alto, CA: February 2001. 1000574.
8. *Renewable Energy Technology Characterizations*, EPRI, Palo Alto, CA, and the Office of Utility Technologies, U.S. Department of Energy, Washington, D.C.: December 1997. TR-109496.
9. *TAG Technical Assessment Guide, Distributed Resources-1997*, EPRI, Palo Alto, CA: November 1997. TR-105124-R1.

2
ECONOMIC METHODOLOGY AND ASSUMPTIONS

The economic methodology and assumptions presented here provide a uniform framework to evaluate the economic feasibility of alternative renewable energy projects on a consistent basis. Since both regulated utility and unregulated non-utility generators are developing renewable energy projects, this section presents separate methodologies to apply depending on the developer type.

The methodology descriptions presented below are excerpted from the 1999 TAG volume, *TAG® Technical Assessment Guide, Volume 3, Revision 8, Fundamentals and Methods-Electricity Supply* (EPRI TR-1000281-V3R8, November 1999), and the examples are based on a 100-MW wind project constructed during 2005 with operations beginning on January 1, 2007.

2.1 Regulated Utility Power Projects

The total annual cost of a regulated utility power project consists of the annual fixed charge on the capital investment plus the operation and maintenance costs. The latter costs include operation and maintenance labor and material, fuel, raw materials and utilities, waste disposal fees, and other costs.

2.1.1 Fixed Charge Rates

A very useful concept is the *capital fixed charge rate* or *fixed charge rate*. This rate represents the annual charges customers would have to pay each year so that the utility recovers its capital-related revenue requirements, and is expressed as a percentage of the booked cost of a plant. Fixed charge rates are typically measured in one of three ways:

- Annual fixed charge rate
- Nominal levelized fixed charge rate
- Real levelized fixed charge rate

Subsections 2.1.2 through 2.1.4 address these concepts and their derivation. The 1999 EPRI TAG report [1] describes the components and calculation of annual fixed charge rates in detail.

Annual Fixed Charge Rates

Annual fixed charge rates express the annual capital revenue requirements as a percentage of the booked cost. In Table 2-1, for example, the total present value of the annual capital charge or booked cost is $604.27 million, and the annual capital revenue requirements based on that booked cost are shown in Column (1). The annual fixed charge rates are the ratio of the annual

capital revenue requirements to the booked cost of $604.27 million and are shown in Column (2). The annual fixed charge rates decline over time as the annual capital revenue requirements decline. So, for example, in the first year, the annual fixed charge rate is 19.09% and declines to 5.32% by the end of the book life.

Table 2-1
Calculation of Annual Fixed Charge Rates

End of Year	Capital Revenue Requirements	Nominal Annual Fixed Charge Rates
	($ Million, Nominal)	(Percentage of booked cost)
	(1)	(2)
2007	$115.34	19.09%
2008	112.38	18.60%
2009	108.34	17.93%
2010	104.46	17.29%
2011	100.74	16.67%
2012	97.16	16.08%
2013	93.72	15.51%
2014	90.41	14.96%
2015	87.20	14.43%
2016	84.02	13.90%
2017	80.83	13.38%
2018	77.65	12.85%
2019	74.46	12.32%
2020	71.28	11.80%
2021	68.09	11.27%
2022	64.91	10.74%
2023	61.72	10.21%
2024	58.54	9.69%
2025	55.35	9.16%
2026	52.17	8.63%
2027	48.98	8.11%
2028	46.49	7.69%
2029	44.70	7.40%
2030	42.90	7.10%
2031	41.11	6.80%
2032	39.32	6.51%
2033	37.52	6.21%
2034	35.73	5.91%
2035	33.94	5.62%
2036	32.14	5.32%
Booked Cost ($ millions)	**$604.27**	

Nominal Levelized Annual Charges and Nominal Levelized Fixed Charge Rates

The second type of fixed charge is the nominal levelized fixed charge rate, which translates booked costs into a constant annual nominal dollar charge with the same present value as the actual annual capital revenue requirements. Calculating the nominal levelized annual charge can be thought of as a two-step process (see Example 2-1).

Example 2-1:

The first step is to calculate the present value of the annual capital revenue requirements. Column (1) of Table 2-2 below shows the annual capital revenue requirements in Table 2-1. Since the annual revenue requirements are in nominal terms, they must be discounted using the nominal discount rate. Column (2) shows the annual present value factors used to bring the costs from end-of-year to present value. Column (3) lists the real or constant dollar revenue requirements that have inflation factored out of the values (e.g., $\$115.34/(1.03)^1 = \$111.98$ for the year 2007). Column (4) lists the annual present value factors based on the real discount rate.

Once the present value has been calculated, the levelized annual charges and the fixed charge rates can be derived as noted in the table.

It is important to note that the levelized fixed charge rate depends on the capital structure and cost of money, tax depreciation, construction length, book life, and taxes.

Real Levelized Annual Charges and Real Levelized Fixed Charge Rates

The third type of fixed charge rate is real levelized fixed charge. It is the fraction of the booked cost, expressed in constant dollar terms that customers would have to pay annually over the book life of a plant to cover capital revenue requirements. The real levelized annual charge and fixed charge rate are calculated the same way as the nominal counterparts.

Real levelized fixed charges, however, have an important advantage over their nominal counterparts: they do not reflect general inflation. The nominal levelized charge reflects assumptions about future inflation. If a power contract is specified in nominal terms, there are risks associated with expected inflation. If inflation is less than expected, the buyer will pay too much and the seller will earn greater than anticipated profits. The opposite would be true if inflation were greater than anticipated. On the other hand, if a contract is specified in real terms, the risks to the buyer and seller can be avoided. The real levelized charge can be adjusted for actual inflation over the term of the contract.

How are levelized fixed charge rates used? Generating alternatives are often compared on the basis of levelized costs. With the appropriate levelized fixed charge rate, the booked cost of alternatives can be converted to levelized annual cost terms. The EPRI financial model computes levelized fixed charge rates, which can be used to evaluate generating and other utility investment options.

Table 2-2
Calculating Levelized Annual Charges

		Nominal Revenue Requirements		Real Revenue Requirements	
	End of Year	Capital Revenue Requirements ($ million)	Present Value Factors	Capital Revenue Requirements ($ million)	Present Value Factors
		(1)	(2)	(3)	(4)
	2007	$115.34	0.9193	$111.98	0.9469
	2008	112.38	0.8451	105.93	0.8966
	2009	108.34	0.7769	99.14	0.8490
	2010	104.46	0.7142	92.81	0.8039
	2011	100.74	0.6566	86.90	0.7612
	2012	97.16	0.6036	81.37	0.7208
	2013	93.72	0.5549	76.21	0.6825
	2014	90.41	0.5101	71.37	0.6462
	2015	87.20	0.4690	66.83	0.6119
	2016	84.02	0.4311	62.52	0.5794
	2017	80.83	0.3964	58.39	0.5486
	2018	77.65	0.3644	54.46	0.5195
	2019	74.46	0.3350	50.70	0.4919
	2020	71.28	0.3079	47.12	0.4658
	2021	68.09	0.2831	43.71	0.4411
	2022	64.91	0.2603	40.45	0.4176
	2023	61.72	0.2393	37.34	0.3954
	2024	58.54	0.2199	34.38	0.3744
	2025	55.35	0.2022	31.57	0.3546
	2026	52.17	0.1859	28.88	0.3357
	2027	48.98	0.1709	26.33	0.3179
	2028	46.49	0.1571	24.26	0.3010
	2029	44.70	0.1444	22.65	0.2850
	2030	42.90	0.1328	21.11	0.2699
	2031	41.11	0.1221	19.63	0.2556
	2032	39.32	0.1122	18.23	0.2420
	2033	37.52	0.1032	16.89	0.2291
	2034	35.73	0.0948	15.62	0.2170
	2035	33.94	0.0872	14.40	0.2054
	2036	32.14	0.0801	13.24	0.1945
Present Value of Annual Revenue Requirements [1]	($ million)	**$901.81**		**$901.81**	
Escalation Rate		3.00%		3.00%	
Discount Rate [2]		8.78%		5.61%	
Capital recovery factor notation		(A/P, 8.78%,30)		(A/P, 5.61%,30)	
Capital recovery factor value		0.0954		0.0696	
Levelized Annual Charges [3]	($ million)	**86.05**		**62.80**	
Booked Cost	($ million)	**$604.27**		**$604.27**	
Levelized Annual Fixed Charge Rates [4, 5]		**14.24%**		**10.39%**	

Notes:

1. The present value is at the beginning of 2007 and results from the sum of the products of the annual present value factors times the annual requirements.
2. The discount rate for real dollar analysis has inflation factored out: 1.0878/1.03 - 1
3. The levelized annual charges (end-of-year) result from the present value times the (A/P, i, n) factor.
4. The levelized annual fixed charge rate results from the levelized annual charges divided by the booked cost.
5. The real levelized annual charge is an end-of-year payment expressed in beginning of year 2006 real dollars.

2.1.2 Example Annual Fixed Charge Rates for a 100-MW Wind Power Plant

To illustrate how plant characteristics affect annual fixed charges, the 1999 TAG report presents several examples, including transmission; distribution; and renewable, nuclear, combined-cycle combustion turbine, simple-cycle combustion turbine, and fossil fuel generation. The examples differ with respect to construction period, tax life, and book life.

Tables 2-3 and 2-4 address the example of a 100-MW wind power plant. The tables present the capital cost of the plant, the construction period, book life, tax life, and, based on these data, the annual, cumulative, and levelized fixed charges. The fixed charges in Table 2-3 are expressed in nominal terms, while those in Table 2-4 are expressed in constant-dollar terms.

2.1.3 Other Capital Expenses—Capital Additions

Capital additions are investments in a plant after it is in service. They are treated as capital investments so the above discussion of capital-related revenue requirements applies to capital additions as well. The annual revenue requirements associated with specific capital additions depend on relevant book and tax depreciation schedules. For many analyses, it is sufficient to treat them as expenses, in which case customers are assumed to pay for them on an as-you-go basis. For the same level of capital additions, expensing them yields a smaller present value of revenue requirements than capitalizing them; capitalizing would include a tax component whereas expensing would not.

2.1.4 Calculating Costs per Kilowatt-Hour

Calculating costs on a per-kilowatt-hour basis provides a relatively easy way to compare new generating alternatives and their costs with those of one or more existing resources.

Levelized Costs per Kilowatt-Hour

Comparing costs on a levelized or a present-value-of-revenue-requirements basis is appropriate under the following conditions:

- When the benefits or revenues are the same between alternatives. For example, the revenues to a utility will be the same between alternatives that are all designed to produce 300 MW_{net}. Therefore, the most economical plant can be selected by minimizing the present value of revenue requirements.
- When alternatives have different benefits but the benefits remain the same for each year. For example, a 300-MW_{net} plant can be compared with a 200-MW_{net} plant by comparing ratios of levelized cost per kilowatt-hour (often referred to as levelized busbar costs).

Table 2-3
Wind Power Generation—Nominal Dollar Terms

Instantaneous Construction Cost ($/kW at mid-year of first year of construction)	
Total Plant Cost	1,400
Startup, Inventory, Land, Financing	267
Capital Cost ($/kW at commercial operation date)	
Total cash expended	1,667
AFUDC	0
Total Booked Cost (total capital requirement)	1,667
Time Frames and Economic Factors	
Plant Construction Period (years)	2
Tax Recovery Period (years)	5
Book Life (years)	30
Apparent escalation rate during construction[1] (%/year)	3.00
AFUDC Rate, nominal (%/year)	10.30
Discount Rates (%/year)	
Nominal	8.78
Real	5.61

	Fixed Charges		
End of Year	**Annual**	**Cumulative Present Value**	**Levelized[2]**
1	0.1920	0.1765	0.1920
2	0.1788	0.3277	0.1857
3	0.1595	0.4515	0.1777
4	0.1467	0.5563	0.1709
5	0.1378	0.6468	0.1653
6	0.1289	0.7246	0.1605
7	0.1230	0.7929	0.1564
8	0.1201	0.8541	0.1530
9	0.1171	0.9091	0.1503
10	0.1142	0.9583	0.1479
11	0.1113	1.0024	0.1458
12	0.1083	1.0419	0.1439
13	0.1054	1.0772	0.1422
14	0.1024	1.1087	0.1406
15	0.0995	1.1369	0.1392
16	0.0965	1.1620	0.1379
17	0.0936	1.1844	0.1366
18	0.0906	1.2043	0.1355
19	0.0877	1.2220	0.1344
20	0.0847	1.2378	0.1334
21	0.0818	1.2517	0.1325
22	0.0788	1.2641	0.1316
23	0.0759	1.2751	0.1308
24	0.0729	1.2848	0.1300
25	0.0700	1.2933	0.1293
26	0.0671	1.3008	0.1286
27	0.0641	1.3075	0.1280
28	0.0612	1.3133	0.1273
29	0.0582	1.3183	0.1268
30	0.0553	1.3228	0.1262

Note: The Total Plant Cost figure used in the above illustrative example is likely low for end-of-2006 wind energy installation costs.

Table 2-4
Wind Power Generation—Constant Dollar Terms

Instantaneous Construction Cost ($/kW at mid-year of first year of construction)	
Total Plant Cost	1,400
Startup, Inventory, Land, Financing	267
Capital Cost ($/kW at commercial operation date)	
Total cash expended	1,667
AFUDC	0
Total Booked Cost (total capital requirement)	1,667
Time Frames and Economic Factors	
Plant Construction Period (years)	2
Tax Recovery Period (years)	5
Book Life (years)	30
Apparent escalation rate during construction[1] (%/year)	3.00
AFUDC Rate, nominal (%/year)	10.30
Discount Rates (%/year)	
Nominal	8.78
Real	5.61

	Fixed Charges		
End of Year	**Annual**	**Cumulative Present Value**	**Levelized[2]**
1	0.1920	0.1765	0.1864
2	0.1736	0.3277	0.1777
3	0.1503	0.4515	0.1677
4	0.1342	0.5563	0.1591
5	0.1224	0.6468	0.1519
6	0.1112	0.7246	0.1455
7	0.1030	0.7929	0.1401
8	0.0976	0.8541	0.1354
9	0.0925	0.9091	0.1314
10	0.0875	0.9583	0.1278
11	0.0828	1.0024	0.1246
12	0.0782	1.0419	0.1216
13	0.0739	1.0772	0.1189
14	0.0697	1.1087	0.1164
15	0.0658	1.1369	0.1141
16	0.0620	1.1620	0.1119
17	0.0583	1.1844	0.1099
18	0.0548	1.2043	0.1080
19	0.0515	1.2220	0.1062
20	0.0483	1.2378	0.1045
21	0.0453	1.2517	0.1029
22	0.0424	1.2641	0.1014
23	0.0396	1.2751	0.1000
24	0.0370	1.2848	0.0987
25	0.0344	1.2933	0.0974
26	0.0320	1.3008	0.0963
27	0.0297	1.3075	0.0951
28	0.0275	1.3133	0.0941
29	0.0254	1.3183	0.0931
30	0.0235	1.3228	0.0921

Notes: 1. The apparent escalation rate represents the total annual rate of change of capital costs during construction. For this example, the inflation rate equals 3% and the real escalation rate equals 0%.
2. Levelized over the period from the first year through the current year. For example, the levelized fixed charge rate for a 25-year book life is 0.0974; for a 30-year book life, it is 0.0921. Values where the book life is less than the tax life should be considered as approximations only.
Note: The Total Plant Cost figure used in the above illustrative example is likely low for end-of-2006 wind energy installation costs.

Levelized busbar costs are calculated by the following steps:

- Calculate the present value of revenue requirements.
- Calculate the levelized annual revenue requirements by multiplying the present value by the capital recovery or (*A/P,i,n*) factor.
- Calculate the levelized busbar cost by dividing the levelized annual cost by the uniform annual generation in kilowatt-hours.

Frequently, alternatives need to be compared where the amount of generation changes each year. Sometimes analysts calculate alternative measures that may present analytical problems, such as:

- Levelizing the annual cost of generation. The annual cost of generation can be calculated by dividing the annual revenue requirement by the annual generation. Levelizing these rates (calculating a present value of the ratios and multiplying the result by an A/P factor) may lead to mathematical problems because it does not properly account for the amount of generation in each year.

- Dividing the present value of revenue requirements by the present value of kilowatt-hours. This can result in erroneous results under certain mathematical conditions.

For the case where annual generation varies, other analytical methods must be used. These methods include purchasing replacement power so that the generation remains constant over the years, applying more sophisticated approaches included in production cost models, or performing a net present value (or profitability) analysis that discretely evaluates the variations in revenue.

2.2 Non-Utility Generator Power Projects

Electricity from non-utility generators (NUGs) has played an increasingly important role in the electric utility industry since the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA). As electric utility industry restructuring continues, the role of non-utility generation is likely to increase. The recently enacted Energy Policy Act of 2005 modifies some of PURPA's mandatory purchase requirements that obligate utilities to purchase power from qualifying small power facilities, although the details of how the law will be implemented are not yet clear, pending actions by the Federal Energy Regulatory Commission (FERC).

One of the key goals of restructuring was to shift risk from electricity customers to both utility and non-utility power producers. Under the current regulatory structure, customers bear the risks associated with and benefit from prudent utility investment decisions. While giving up the potential for higher-than-expected profits as well as the potential for losses, electric utilities are guaranteed a return on their prudent investments. With restructuring, the risk associated with the generation portion of electricity production has shifted somewhat to power producers. The extent to which risks are shifted depends on the specifics of industry restructuring, which varies among states and regulatory jurisdictions.

As electric utility industry restructuring proceeds, utilities as well as non-utility power producers could construct and operate new generating units within a less-regulated environment. In fact,

many new power plants built in the past five years were "merchant plants" that are owned by non-utility generating companies. Merchant plants are generally characterized as those that have some commodity risk for electricity sales (i.e., the sale of electricity is not fully committed to long-term power sales agreements). However, most renewable energy power plants being built remain either utility-owned or, more commonly, privately-owned, with their output pre-sold to utilities at contractually-agreed upon rates.

The key differences between utility and non-utility power producers are:

- Obligation to Serve: Electric utilities have traditionally had an obligation to serve and to provide reliable electricity service. However, the obligation to serve is becoming less clear as the industry restructures the regulation of generating and distribution companies. Non-utility power producers develop projects for their potential economic rewards and have the option to sell their power on a wholesale basis to a utility, on a retail basis to a customer, or directly to a power pool.

- Rates/Prices: Rates for utilities are usually set using the revenue requirements approach. Non-utility power producers typically attempt to set prices as high as the market will allow.

- Risks and Benefits: Customers of electric utilities bear the risks associated with prudent investments. Since customers, not utilities, bear the risk, utilities earn a lower return on investments associated with a monopoly. Non-utility power producers, or utilities providing generation in competitive power markets, bear the risks associated with their investments but can mitigate them to the extent they can negotiate contracts for fuel purchases and energy sales.

The following subsections focus on the economic evaluation of non-utility or independent power projects. Subsection 2.2.1 provides a brief discussion of the various types of non-utility power producer projects.

Subsection 2.2.2 describes the development of an economic *pro forma* for an "example" merchant plant.

Subsection 2.2.3 summarizes a sensitivity analysis for the example merchant plant *pro forma*.

Subsection 2.2.4 provides a brief discussion of the major risks associated with financing merchant plants.

Subsection 2.2.5 provides a statement of caution on the limitations of the examples that are discussed.

2.2.1 Types of Non-Utility Generators

An understanding of the economic evaluation methods for non-utility projects requires an understanding of the potential economic rewards. Non-utility projects can be classified into the following types:

- PURPA Cogenerators and Small Power Producers

- Wholesale Generators Exempt from the Energy Policy Act of 1992
- Merchant Power Plants

PURPA Cogenerators and Small Power Producers

Title II of PURPA created a class of power producers called qualifying facilities (QFs) for which utility ownership is limited to 50%. Qualifying facilities—which can include cogenerators and small power producers—are exempt from certain state regulations, FERC regulations, and the recently repealed Public Utility Holding Company Act (PUHCA). The Energy Policy Act of 2005 (EPAct05) amended provisions within PURPA, however, that affect cogeneration and small power production facilities, including the elimination of the ownership limitation on utilities.

Cogenerators produce two forms of energy: electricity and steam (or heat). Two types of cogenerators have emerged. The first type comprises facilities designed primarily to meet the thermal requirements of an industrial host with electricity generation being a secondary consideration. The second type has become known as “PURPA machines,” which are designed primarily for the purpose of selling electricity to electric utilities while satisfying the thermal requirements under Title II of PURPA.

In 2006, The Federal Energy Regulatory Commission (FERC), in compliance with EPAct05, issued a decision that did not significantly change the definition of a Qualifying Facility. FERC decided not to dramatically tighten standards, impose new and higher efficiency rules, or restrict access to QF status. Instead, the Commission stated that CHP continues to be intrinsically more efficient than separate heat and power production, that current efficiency standards are appropriate, that case-by-case evaluate is called for rather than any one-size-fits-all numeric rule, that smaller cogenerators in particular present no risk of being "sham" projects to foist overpriced power onto utilities, and that cogenerators should continue to be able to self-certify as QFs. Small power producers continue to be qualifying facilities that use biomass, waste, geothermal resources or renewable resources such as wind, solar energy, or water. In addition to qualifying facilities, there are other non-utility generating units, but they are regulated under the Federal Power Act.

Power sales for qualifying facilities were typically based on a utility’s avoided cost rates. Avoided cost rates were generally specified as the cost of a utility’s next plant to be built. By purchasing power from a non-utility generator, the utility typically paid the non-utility generator the avoided cost for not building this plant. Consequently, ratepayers would be indifferent as to who supplied the power. Financing a qualifying facility was relatively straightforward because the credit worthiness of the project was tied closely with that of the utility (or power purchaser).

Power sales usually consisted of a capacity charge and an energy charge. The capacity charge frequently comprised a debt service portion that was not subject to escalation and a fixed operating and maintenance cost that may have been subject to inflation over time. The energy charge was typically based on the cost of fuel and variable operating costs and was subject to a negotiated inflation or escalation rate over time.

The economic incentive for qualifying facilities was reduced in the late 1980s and early 1990s when rates for some qualifying facilities were reduced below the local utility's avoided cost. In some states a qualifying facility's rates had to be low enough to win a competitive bid for a power solicitation.

The economic incentive for QFs was further reduced by competition from exempt wholesale generators, which resulted from the Energy Policy Act of 1992. Many long-term power purchase agreements for qualifying facilities have turned out to be significantly more expensive than the market price of power. There are efforts in some states to restructure or buy out these contracts.

As stated above, the Energy Policy Act of 2005 also modifies PURPA's mandatory purchase requirements for qualifying cogeneration and small power production facilities. The law states that no electric utility shall be required to enter into a new contract with an existing facility provided that certain competitive market conditions exist. In early 2006, FERC provided a preliminary interpretation for determining when electricity markets are adequately competitive that utilities within those markets need no longer bear any obligation to purchase power from or sell power to cogenerators as required by Section 210 of PURPA. Based on the FERC proposal, markets may be defined automatically as sufficiently competitive to exempt utilities from any obligations to engage with qualifying cogenerators even though those cogenerators have no reasonable or practical options to market power or obtain back-up power at reasonable rates.

FERC's rule asserts that several of FERC's own approved regional transmission and grid-operation organizations (MISO, PJM, NYISO, NEISO) currently meet the statutory standards and that utilities that are members of those therefore no longer need to offer or renew avoided-cost purchase or standby-power sales contracts with QFs. In addition, FERC asserts that any QF that has access through its local utility to a competitive wholesale market should have no ability to compel its utility to purchase its output, under either a new or a renewed contract, and that specific FERC-regulated wholesale markets are competitive.

FERC also opined that as long as bilateral contracts for capacity or long-term energy sales are permitted in a given jurisdiction, and the utilities have an Open Access Transmission Tariff ("OATT") that theoretically allows non-discriminatory wheeling of power under that contract, that is a sufficient demonstration that there is a competitive market to allow the utilities to refuse to participate as a purchaser or energy or capacity or seller of back-up energy to that cogenerator.

Exempt Wholesale Generators

The Energy Policy Act of 1992 (EPAct92) created another group of non-utility facilities called Exempt Wholesale Generators (EWGs), which was unaffected by EPAct05. The major characteristics of EWGs include:

- Ownership and operation is for wholesale delivery of electricity.
- Ownership by utilities is allowed to be 100%.
- There is no requirement for a thermal host.
- Wholesale rate approval is required from (FERC).

- Exemptions from the Securities and Exchange Commission (SEC) regulations under PUHCA are allowed.

Other major provisions of the EPAct92 include:

- FERC is empowered to order transmission access to third parties (such as EWGs).
- FERC is prohibited from ordering retail wheeling. However, states may choose to order retail wheeling which could further encourage the construction of non-utility generators.

EPAct92 allowed EWGs to develop large central power stations that have economy-of-scale advantages over smaller cogeneration plants. EPAct92 also opened the way for states to consider retail wheeling and the establishment of merchant power plants.

Merchant Power Plants

Merchant plants, which have arisen in the U.S. as electric wholesale competition has taken hold in many regions, are generally characterized as those that have some commodity risk for electricity sales (i.e., the sale of electricity is not fully committed to long-term power sales agreements). The power will either be sold on a spot market basis to the power pool or under contracts with varying terms to utilities. “Pure” merchant power more precisely refers to power sales that are not covered by conventional long-term agreements. The term “hybrid” merchant power refers to plants selling power under a combination of conventional power sales agreements and spot market sales where the power is at risk for prevailing market conditions. For the purposes of this report, the term “merchant power plants” will generally refer to those plants in which a “substantial” portion of the power sales (sometimes referred to as the “offtake”) is at risk.

Merchant power plants include existing, repowered, and greenfield units. Most currently operating merchant plants are existing plants that have recently been sold by electric utilities. These existing plants are either currently economical or represent a site that could be repowered to be economical (e.g., by adding a new combustion turbine at an existing site).

Greenfield power plants are those that are built at a new site. A large number of greenfield merchant power plants are being developed in areas where they will be able to produce power less expensively than existing older generation or in areas where additional power will be required to meet growing demand.

The economic analysis in this report centers on greenfield merchant power plants, but is broadly applicable to repowering projects and to other non-utility power plants.

2.2.2 Development of an Economic Pro Forma for a Merchant Plant

The revenue requirements method (as discussed in Section 2.1) is generally not applicable to the evaluation of non-utility projects. While there are a variety of methods to evaluate non-utility power projects, all methods depend on calculating cash flows. The cash flows represent all of the revenues from the sale of electricity less the sum of all expenses, debt service, and income taxes. The net cash flows represent cash available to equity holders. The major differences between the

two types of analyses are summarized below and followed by an example *pro forma* economic analysis for a non-utility plant.

Differences between Regulated Utility and Non-Utility Power Projects

Pricing

Regulated utilities are restricted in how they can set prices to recover costs of investments. The recovery of the total capital-related costs is determined using the revenue requirements approach described in Section 5 of the 1999 EPRI TAG report [1]. In particular, the recovery of capital-related costs depends on return on equity, interest on debt, book depreciation, income taxes, and property taxes and insurance. But taxes, in turn, depend on capital-related costs, interest on debt, tax depreciation schedules, and income tax rates. Thus capital-related revenues are determined by the underlying costs.

Non-utility power producers have more flexibility. They are not bound to the revenue requirements approach for determining how their costs will be recovered. Such flexibility is necessary for non-utilities to respond to changes in the market power prices. Whereas under the revenue requirements approach, capital-related revenues decline over the life of a project, this need not be the case for non-utility power projects. The prices of power for non-utility projects can rise, fall, or remain constant over the contract period depending on the needs of the purchaser and the internal requirements of the non-utility power producer.

Income Taxes and Depreciation

There are two types of depreciation for regulated utilities: book and tax (see Section 2.1). Under the revenue requirements method, book depreciation is used in determining revenues, and tax depreciation is used in calculating income taxes. For non-utility power producers, there is no such distinction. Tax depreciation is calculated to reduce income taxes, which directly affect cash flow. However, book depreciation (which may be needed for accounting purposes) does not affect cash flow. Cash flow drives the economic viability of non-utility projects.

Capital Expenditures

Revenue requirements reflect the cost of constructing a plant as well as the allowance for funds used during construction (referred to as interest during construction for non-utility projects). For non-utility power producers, only the debt portion of construction expenditures is typically capitalized. The equity portion of the interest during construction is recovered in the net cash flows and is not capitalized.

Debt Financing

Debt is a major source of financing for construction projects. Regulated utilities tend to borrow against their corporate balance sheet. Corporate stability and borrowing capability become important issues for utility financing.

Non-utilities finance projects through both corporate debt and project finance (as discussed later in this section). Corporate debt is becoming more common as the industry consolidates to fewer and larger companies through mergers and acquisitions. Nevertheless, there is a significant role for limited recourse project finance.

Economic Methodology

Regulated utilities typically evaluate potential projects using the present worth of revenue requirements methodology. Financial structure (debt and equity proportions) is implicitly included in the analysis by using an after-tax discount rate.

Non-utilities typically evaluate potential projects using a discounted net cash flow analysis. For project finance opportunities, specific financial parameters are included in the costs of the project. The after-tax net cash flows are then discounted with the owner's minimum acceptable rate of return.

2.2.3 Conceptualizing the Analysis

This section illustrates cash flow calculations through an example for a 100-MW merchant wind plant. General parameters for the example are described, followed by a discussion of income and cash flow statements. Economic results for evaluating the cash flows are also discussed.

In this 100-MW wind project example, the Total Plant Cost is assumed to be $1,600/kW. This represents a significant increase from the $1,000/kW used in the 2004 and earlier editions of the TAG-RE, and accounts for the recent cost increases for wind turbines and other components caused by high demand and higher steel prices.

A merchant plant needs to sell its power at a price sufficient to cover fuel costs, operating and maintenance costs, income and property taxes, debt service, working capital, and return on and recovery of the equity investment. This "price" is usually calculated at the busbar of the plant (essentially at the plant boundary on the high-voltage side of the transformer) and may be separated into capacity and energy components. Some regions of the country have a shortfall of generating capacity and, consequently, have both the capacity and energy components. Other markets only have an energy component. These payments can be further complicated by various risk-hedging business deals (from options to tolling agreements, which are not considered in this report) with power marketers, gas companies, or utilities.

For this 100-MW wind plant example, we have assumed the following parameters and costs:

- Time Frames
  - The durations of project development and permitting can vary widely and are not explicitly included here. Reasonable cost allowances for these activities are discussed below.
  - Duration of engineering, procurement, and construction: 12 months
  - Commercial operation date: January 1, 2007.

  - Service life of plant: 20 years
- Technical and Operating Parameters
  - Capability: 100 net MW at rated wind speed
  - Operation: intermittent
  - 100-MW wind plant composed of 50 x 2.0-MW wind turbines

Total Capital Requirement

The major categories of total capital requirement include construction, development, and financing costs. Table 2-5 displays general categories for the uses of the capital funds, as well as their sources, as described below. Capital costs can vary significantly as a function of variations in many items such as equipment type and cost, interconnection, site difficulties, and financing structure. This example is designed to illustrate a reasonable magnitude of "all-in" costs.

Construction Cost

The largest component of capital cost is usually engineering, procurement, and construction (EPC), which are included in the term "total plant cost" (TPC). TPC includes detailed design, equipment and materials procurement, and installation and construction costs. Typically, an EPC contractor supplies these services. TPC costs generally range from 60% to 90% of the total capital requirement depending on development difficulty and financing costs.

Other costs that are usually included with the total capital requirement include:

- Land (excluded for wind plant as land is leased)
- Operating and maintenance mobilization (or startup costs): This example assumes one month of operating labor and 0.5 months of full capacity fuel consumption as approximate cost allowances (no fuel is used by wind plant).
- Spare parts. Spare parts costs can range widely depending on the maintenance philosophy and remoteness for the plant. This example, assumes approximately 2% of the EPC cost for spare parts.

Financing Cost

Merchant plants can be financed either as a limited recourse project or through general corporate debt. Limited recourse project financing refers to those projects that are dependent on the specific cash flows of the project as defined in the project agreements. Qualifying facilities and exempt wholesale generators were commonly financed on a limited recourse project finance basis. Some merchant plant projects are also being financed on a limited recourse project basis. However, there is a trend for financing merchant plant projects with corporate debt (as discussed later in this section of the report). For the example, debt is assumed to be financed with limited recourse project financing. Assumed financing costs and parameters for a project-financed transaction include:

- Construction Loan:
  - 100% debt: Frequently, construction loans may require equity on a *pro rata* basis with the construction costs. However, a 100% debt construction loan is assumed to keep this example conceptually simple.
  - Interest rate during construction of 8.0%
  - Financial fees of approximately 2% of the loan amount
  - *Debt service reserve fund* of approximately six months of debt service. The lending institution may require that a debt reserve fund be included in the capital cost of a project. The fund is set up to pay the debt service for the term loan if unexpected conditions adversely affect the project revenues.
- Term Loan:
  - 60% debt / 40% equity
  - Commercial bank loan rate of 8.0% for a 10-year term

Development Cost

Development costs include a variety of costs that a non-utility generating company incurs to develop a project. Examples include security deposits, permitting (including construction permits and environmental permits), owner's engineering and general and administrative costs, development fees, legal fees, and easements and rights-of-way. These costs can vary widely depending on the complexity of the site, the financing, and the contracting with the EPC contractor and the equipment suppliers. For this example (Table 2-5), an approximate cost allowance of 5% of the TPC price was assumed for total development costs.

Table 2-5
Sources and Uses of Construction Funds

(Example assumes a 100% construction loan and 60% debt/40% equity financing at plant startup)

Commercial Operation: January 1, 2007

Description	Units	2004	2005	2006	*Total Capital* $1,000	$/kW	Proportion of Total
SOURCES OF FUNDS							
Equity	$1,000	0		67,023	67,023		40.0%
Debt	$1,000	0		100,534	100,534		60.0%
Total Project	$1,000	0		167,556	167,556		100.0%
USES OF FUNDS							
Land	$1,000	0	0	0	0	0	0.0%
Total plant cost	$1,000	0	0	140,000	140,000	1,400	83.6%
Operating and maintenance mobilization	$1,000	0	0	47	47	0	0.0%
Spare parts	$1,000	0	0	2,800	2,800	28	1.7%
Subtotal Construction Cost	$1,000	0	0	142,847	142,847	1,428	85.3%
Owner's Cost	$1,000	0	0	700	700	7	0.4%
Financial fees	$1,000	0	0	2,011	2,011	20	1.2%
Interest during construction	$1,000	0	0	5,714	5,714	57	3.4%
Reserves	$1,000	0	0	7,000	7,000	70	4.2%
Subtotal Owner's and Financing	$1,000	0	0	15,425	15,425	154	9.2%
Working capital	$1,000	0	0	2,143	2,143	21	1.3%
Contingency	$1,000	0	0	7,142	7,142	71	4.3%
Total Capital Requirement	$1,000	0	0	167,556	167,556	1,676	100.0%

Notes:
Construction escalation = 0.00% per month, 0.00% per year
Construction interest = 0.67% per month, 8.00% per year

Other Costs

A variety of other costs are frequently included in the total capital requirement, including:

- Working capital, which includes requirements for cash and inventories and for this example is assumed to equal one month of accounts receivables
- Contingency, assumed for this example to be 5% of the total cost

EPRI Capital Cost Definitions

Section 4 of the 1999 EPRI TAG report [1] provides capital cost definitions for regulated utilities. The three measures of capital cost are Total Plant Cost, Total Plant Investment, and Total Capital Requirement.

The *Total Plant Cost* (TPC) is the sum of process facilities capital, general facilities capital, engineering and home office overhead, and project and process contingencies. It is usually expressed in constant dollars and assumes overnight construction, i.e., the construction of the facility occurs instantaneously. When expressed in constant dollars, the total plant cost is also referred to by several terms: *real direct capital cost, overnight capital costs*, or *overnight construction costs*.

The *Total Plant Investment* (TPI) adjusts the Total Plant Cost to account for the fact that construction occurs over a period of years, and hence the costs are distributed over the same period and tend to escalate over time. In addition, the project allows for interest accrued on each expense from the date of the expense until the completion and commissioning of the facility. The accrued interest is called *allowance for funds used during construction* (AFUDC) and is also referred to as *interest during construction*. Total Plant Investment is the sum of the Total Plant Cost, an adjustment for the escalation of capital costs during construction, and AFUDC. Reference [1] provides formulas for calculating escalation and interest during construction as a function of the escalation rate, cost of money, and construction expenditure profile.

The *Total Capital Requirement* (TCR) is the sum of the Total Plant Investment and owner's costs such as land and property tax, insurance, pre-production, startup, and inventory costs.

These terms are maintained for consistency in this report. However, a project that is "project financed" typically organizes the capital costs into construction costs (sometimes referred to as "hard costs") and financing and development costs (sometimes referred to as "soft costs"). EPRI values for project and process contingencies are typically included within the TPC numbers that are guaranteed by the EPC contractor. An overall project contingency (based on development, financing, permitting, and the potential for EPC contractor overruns) is normally included by the banks and is calculated right before the total capital requirement is calculated.

Since the industry convention for summarizing capital costs varies somewhat from a regulated utility to a market-based plant, the cost components are identified in Table 2-5 for comparison with other cost breakdowns. For example, EPRI's value for total plant investment usually includes the sum of the total plant costs and the interest during construction. TPI is not shown in the table, but can be easily calculated.

Income Statement

The income statement summarizes the revenues and expenses for each year of the project. Table 2-6 presents an example income statement, which is discussed below.

Table 2-6
Example Income Statement ($1000)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2		**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
3	**Revenues**																					
4	Capacity Payments		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Energy Payments		18,856	19,327	19,810	20,306	20,813	21,334	21,867	22,414	22,974	23,548	24,137	24,741	25,359	25,993	26,643	27,309	27,992	28,691	29,409	30,144
6	Federal Production Tax Credit		5,971	6,120	6,273	6,430	6,591	6,756	6,925	7,098	7,275	7,457	0	0	0	0	0	0	0	0	0	0
7	Total Revenues		24,827	25,448	26,084	26,736	27,404	28,089	28,792	29,511	30,249	31,005	24,137	24,741	25,359	25,993	26,643	27,309	27,992	28,691	29,409	30,144
8	Avg. Electricity Rev. (cents/kWh)		6.2	6.3	6.5	6.6	6.8	7.0	7.1	7.3	7.5	7.7	7.9	8.1	8.3	8.5	8.7	8.9	9.1	9.4	9.6	9.8
9																						
10	**Fuel Costs**																					
11	Variable Fuel Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Fixed Fuel Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14																						
15	**Variable Operating Expenses**																					
16	Supplies and Consumables		48	49	50	52	53	54	56	57	58	60	61	63	65	66	68	70	71	73	75	77
17	Water & Water Treatment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Other		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Land Laease		453	464	475	487	500	512	525	538	551	565	579	594	609	624	639	655	672	689	706	723
20	Total		501	513	526	539	553	566	580	595	610	625	641	657	673	690	707	725	743	762	781	800
21																						
22	**Fixed Operating Expenses**																					
23	Operating labor		320	328	336	345	353	362	371	380	390	400	410	420	430	441	452	463	475	487	499	512
24	General and administrative		64	66	67	69	71	72	74	76	78	80	82	84	86	88	90	93	95	97	100	102
25	Maintenance labor and matl		820	841	862	883	905	928	951	975	999	1,024	1,050	1,076	1,103	1,130	1,159	1,188	1,217	1,248	1,279	1,311
26	Insurance		618	633	649	666	682	699	717	735	753	772	791	811	831	852	873	895	917	940	964	988
27	Property Taxes		1,545	1,584	1,623	1,664	1,705	1,748	1,792	1,837	1,882	1,929	1,978	2,027	2,078	2,130	2,183	2,238	2,294	2,351	2,410	2,470
28	Other		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total		3,367	3,451	3,537	3,626	3,717	3,809	3,905	4,002	4,102	4,205	4,310	4,418	4,528	4,641	4,757	4,876	4,998	5,123	5,251	5,383
30																						
31	**Total Operating Expense**		3,868	3,964	4,063	4,165	4,269	4,376	4,485	4,597	4,712	4,830	4,951	5,075	5,201	5,331	5,465	5,601	5,741	5,885	6,032	6,183
32	**Earnings Before Interest, Taxes,**																					
33	**Deprec. and Amortization (EBITDA)**		20,959	21,483	22,020	22,571	23,135	23,714	24,306	24,914	25,537	26,175	19,186	19,666	20,158	20,662	21,178	21,708	22,250	22,807	23,377	23,961
34																						
35	**Pro Forma Income Tax Calculations**																					
36	Tax Depreciation		7,468	7,975	7,377	6,824	6,312	5,839	5,401	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,709
37	**Earnings before Interest + Taxes**		13,491	13,508	14,643	15,747	16,823	17,875	18,905	19,839	20,462	21,100	14,111	14,591	15,083	15,587	16,103	16,633	17,175	17,732	18,302	18,252
38	Interest Paid		8,043	7,488	6,888	6,240	5,541	4,786	3,970	3,089	2,137	1,110	0	0	0	0	0	0	0	0	0	0
39	Interest Received (at 5.00% per year)		250	250	250	250	250	250	250	250	250	250	0	0	0	0	0	0	0	0	0	0
40																						
41	**Net Operating Loss**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	**Taxable Earnings**		5,699	6,271	8,006	9,757	11,532	13,339	15,186	17,000	18,575	20,241	14,111	14,591	15,083	15,587	16,103	16,633	17,175	17,732	18,302	18,252
43	State/Local Tax		285	314	400	488	577	667	759	850	929	1,012	706	730	754	779	805	832	859	887	915	913
44	Federal Tax		1,895	2,085	2,662	3,244	3,834	4,435	5,049	5,653	6,176	6,730	4,692	4,852	5,015	5,183	5,354	5,530	5,711	5,896	6,085	6,069
45	Total Tax Obligation		2,180	2,399	3,062	3,732	4,411	5,102	5,808	6,503	7,105	7,742	5,398	5,581	5,769	5,962	6,159	6,362	6,570	6,782	7,000	6,981
46																						
47	**Net Earnings after Taxes**		3,519	3,872	4,943	6,025	7,121	8,237	9,377	10,498	11,470	12,499	8,714	9,010	9,314	9,625	9,944	10,271	10,606	10,949	11,301	11,271

Revenues

Forecasting revenues over the service life of a merchant power plant is one of the most critical aspects of the economic analysis. Revenues for a utility generator are set by the revenue requirements method and approved by a state commission. However, there is no guarantee of revenues with a merchant plant because the price of power is set by the electricity markets. Section 2 of the 1999 EPRI TAG report [1] provides additional information.

A forecast of market prices for a deregulated power market varies with time-of-day and time-of-year as shown for a historical time period in Figure 2-1. Detailed forecasting of the market price for power typically requires the following steps:

- Project the cost of fuel for the generating units in the region.
- Evaluate the cost of generation from existing units.
- Project the cost of generation from planned units.
- Project the dispatch order of units that will comprise the market.
- Include variations in electricity consumption as a function of time-of-day, time-of-year, and weather.
- Develop a price duration curve for each year of the service life.

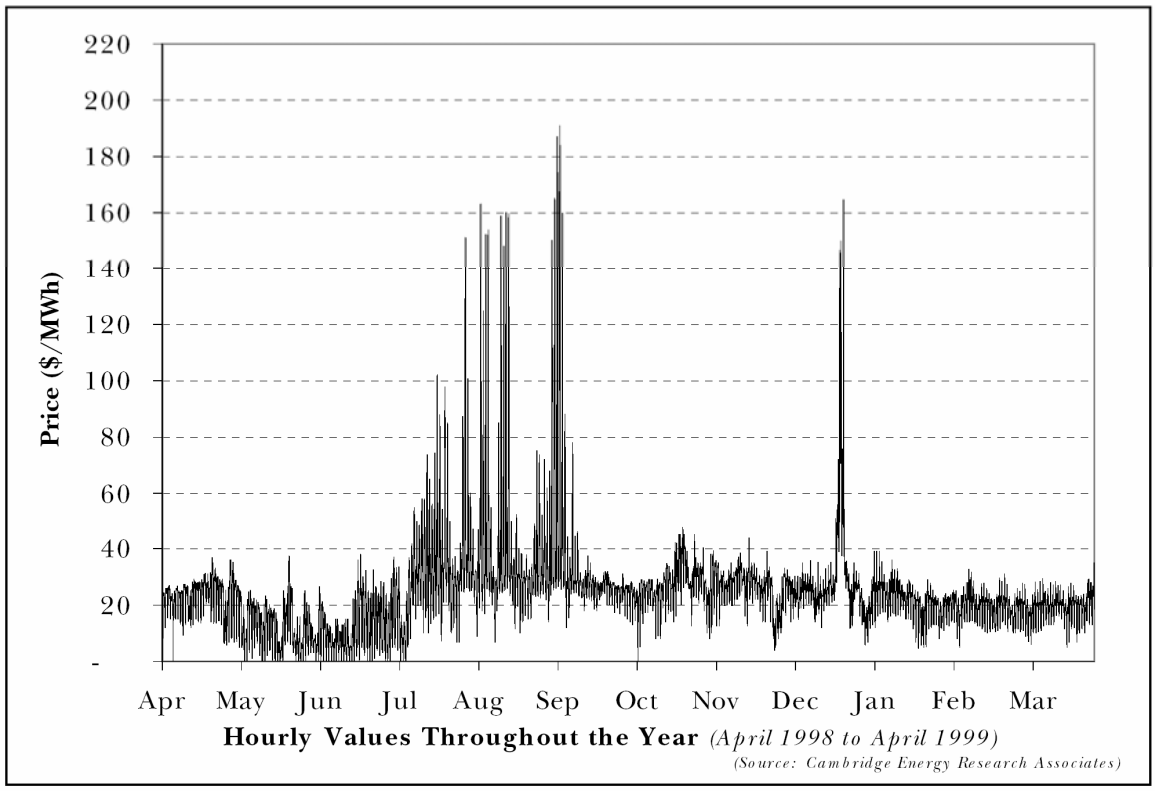


Figure 2-1
Day-Ahead Prices for the California Power Exchange

In an annual market price duration curve, data are arranged to show the fraction of a year that the market price is at or above a given level. An example of a price duration curve for 1998 is shown in Figure 2-2. For the California Power Exchange, the price was greater than or equal to approximately $29/MWh for 20% of the year. The integrated price duration curve shows the cumulative average for any given portion of a year. For example, a market utilization of 20% of the year would have resulted in an average price of $45/MWh. The average for the entire year was $24.4/MWh.

This information (appropriately adjusted for transmission costs) can then be used in the calculation of revenues for the merchant plant.

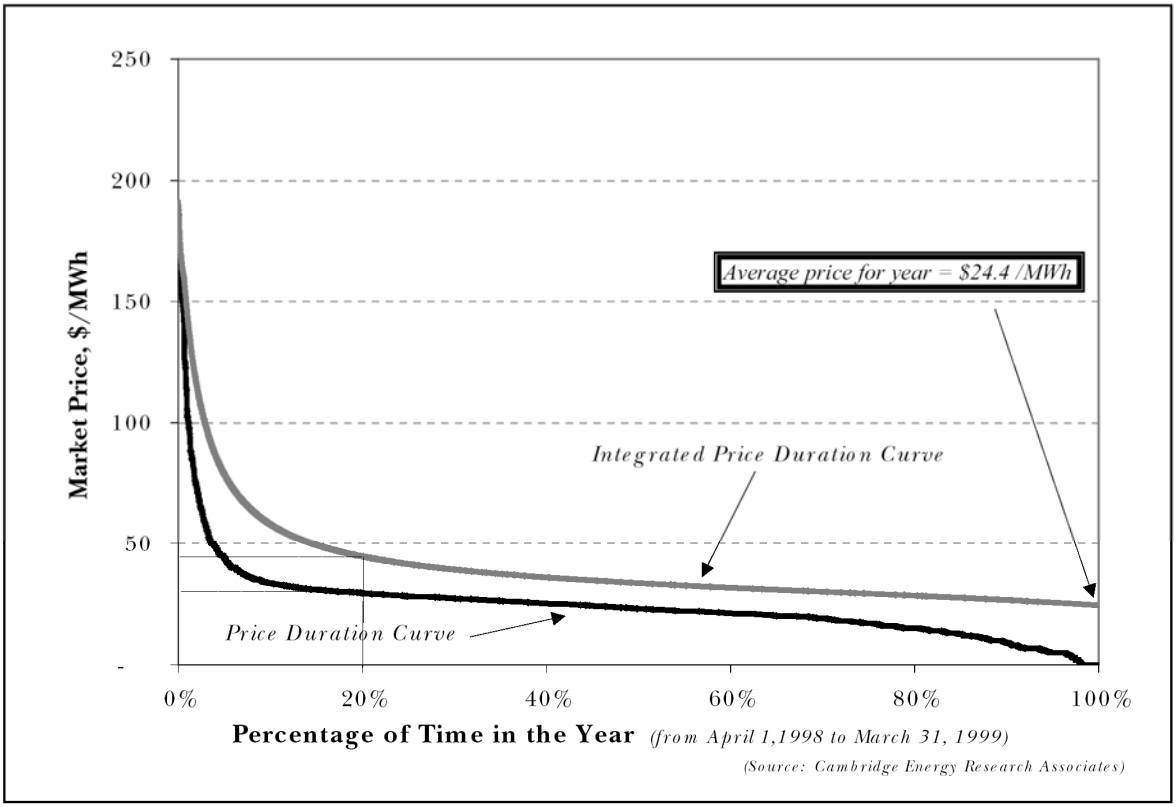


Figure 2-2
Example Price Duration Curve

For the example (not related to the California Power Exchange data), the revenue assumptions include:

- For simplicity, only an energy component is assumed for the price of electricity (see line 8 of Table 2-6). The energy component is based on average power sales and assumed to be approximately 6.0 cents/kWh in January 2007, escalating at 2.5% per year. For some projects, there would also be a capacity component (line 7 of Table 2-6) of revenues.
- In addition, it is assumed that the 100-MW wind plant qualifies for the 10-year Federal Production Tax Credit, which was increased to 1.9 cents/kWh by the 2005 Energy Policy Act, and is assumed to escalate at 2.5%/yr for 10 years.
- Average annual capacity factor: 35%

Operating and Maintenance Expenses

Operating and maintenance costs need to be projected for each year of the service life. For this example, the operating cost assumptions (included in lines 13 through 32 of Table 2-6) include:

- Average annual capacity factor: 35%
- Average annual net plant heat rate (lower heating value): N/A for wind plant
- Delivered price of natural gas: N/A for wind plant
- Variable operating costs: 0.05 mills/kWh (at Jan. 1, 2006)
- Annual land lease cost: 3% of electricity sale revenue.
- Labor: 5 employees at an average fully burdened wage rate of $30/hour (at Jan. 1, 2006)
- General and administrative expenses: 20% of operating labor
- Maintenance labor and material: $8/kW-yr (at Jan. 1, 2006)
- Insurance: 0.5% of the total capital requirement
- Property taxes: 1.25% of the total capital requirement
- All costs escalate at 2.5% per year (for simplicity)
- Income statements often include a book depreciation component for the calculation of book income. However, this income statement calculates earnings before interest, taxes, depreciation and amortization (EBITDA) to focus on the calculation of net cash flows (see the next subsection).

Income Taxes

Income taxes are included on a conceptual basis. For the example, key assumptions include:

- All of the depreciable capital investment qualifies for 20-year MACRS tax depreciation (line 36, Table 2-6) (for simplicity)
- Interest paid on the debt service is tax deductible (Line 38, Table 2-6)

- Interest received from the debt service reserve increases the taxable earnings (line 39, Table 2-6)
- A state income tax rate of 5% (line 43, Table 2-6)
- Marginal federal income tax rate of 35% (line 44, Table 2-6)
- This example assumes that the project structure includes a single purpose corporation. It is important to note that some projects are structured as partnerships. Although partnerships are not taxed directly under federal and most state laws, a tax computation is needed so that investors can compute their individual cash return from the project and also to compare it with other opportunities. In this case, the tax information needed by the partners is computed, but tax payments are excluded from the project's cash flow forecast.

Cash Flow Statement

The cash flow statement calculates the after tax net cash flow for the project. Table 2-7 presents an example cash flow statement.

The cash flow statement begins with the EBITDA (line 5 in Table 2-7) as brought forward from (line 33 of Table 2-6) and includes the following adjustments (lines 9-25, Table 2-7):

- Less income taxes
- Less debt service (principal and interest payments for the loan)
- Plus interest received from the debt reserve fund
- Less any new contributions to reserves (sometimes additional reserves may be required)
- Plus return of the reserves at the end of the debt service term (the reserve fund is returned if it has never been drawn down)
- Less any adjustments to working capital (growth in working capital requirements)
- Less equity investment during construction.

The net cash flows represent the cash flows associated with the equity investor (owner of the project). During the construction period, the cash flows are negative. Throughout the service life of the plant, the net cash flows are initially negative and become positive in the out years.

The net present value (line 31, Table 2-7) and the internal rate of return ("IRR" on line 32, Table 2-7) are economic measures of the project that reflect the present worth of profit over the service life and the profitability of the project, respectively. The cumulative IRR reflects the IRR for the relevant service life. For example, the IRR for a 20-year project life is projected to be 10.5%, while the IRR for the first 19 years of net cash flows is projected to be 10.0%. The meaning of these measures is discussed in the following section.

Figure 2-3 shows the variation of the components of busbar electricity sales price vs. year. The fixed costs represent the income taxes, debt service, and working capital. The fixed costs decline when the debt service for the loan ends (a 10-year loan in this example). The O&M component represents the fixed and variable operating and maintenance component. The net cash flow represents the capital recovery for the equity investor.

Table 2-7
Example Cash Flow Statement ($1000)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
1	**Commercial Operation: January 1, 2007**																								
2			**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
3			**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
4																									
5	**EBITDA**					20,959	21,483	22,020	22,571	23,135	23,714	24,306	24,914	25,537	26,175	19,186	19,666	20,158	20,662	21,178	21,708	22,250	22,807	23,377	23,961
6					0																				
7	Taxes Paid					2,180	2,399	3,062	3,732	4,411	5,102	5,808	6,503	7,105	7,742	5,398	5,581	5,769	5,962	6,159	6,362	6,570	6,782	7,000	6,981
8																									
9	**Cash Flow From Operations**				0	18,780	19,085	18,958	18,839	18,724	18,611	18,498	18,412	18,432	18,433	13,789	14,085	14,389	14,700	15,019	15,346	15,681	16,024	16,376	16,980
10																									
11	Debt Service					14,983	14,983	14,983	14,983	14,983	14,983	14,983	14,983	14,983	14,983	0	0	0	0	0	0	0	0	0	0
12	Interest Received					250	250	250	250	250	250	250	250	250	250	0	0	0	0	0	0	0	0	0	0
13	Contribution to Reseserves					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Disbursement (return) of Reserves					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15																									
16	**Additions to Working Capital**																								
17	Accounts Receivable					1,755	44	45	46	47	48	50	51	52	53	(515)	42	43	44	45	46	47	49	50	(2,043)
18	Fuel Stocks					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Spare Parts					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20																									
21	**Capitalized Refurbishments**																								
22																									
23	**Contributed Capital**		0	0	67,023																				
24																									
25	**Net Cash Flow Before Tax**		0	0	(67,023)	4,472	6,707	7,243	7,792	8,355	8,933	9,524	10,131	10,752	11,389	19,701	19,624	20,115	20,618	21,133	21,661	22,203	22,758	23,327	26,004
26	Cumulative		0	0	(67,023)	(62,551)	(55,844)	(48,601)	(40,808)	(32,453)	(23,520)	(13,996)	(3,865)	6,887	18,277	37,978	57,602	77,717	98,334	119,467	141,129	163,331	186,089	209,416	235,421
27																									
28	**Net Cash Flow After Tax**		0	0	(67,023)	2,292	4,308	4,181	4,060	3,944	3,831	3,716	3,628	3,648	3,647	14,304	14,043	14,346	14,656	14,974	15,299	15,633	15,976	16,326	19,023
29	Cumulative		0	0	(67,023)	(64,730)	(60,422)	(56,241)	(52,181)	(48,236)	(44,406)	(40,690)	(37,062)	(33,414)	(29,767)	(15,463)	(1,420)	12,925	27,581	42,555	57,854	73,487	89,463	105,789	124,812
30																									
31	**Net Present Value (at time = 0)**				(18,714)																				
32	**Cumulative IRR on Net Cash Flow After Tax**						-72.9%	-53.7%	-40.2%	-30.7%	-23.8%	-18.8%	-15.0%	-11.9%	-9.4%	-3.5%	-0.3%	2.0%	3.7%	5.0%	6.0%	6.9%	7.6%	8.1%	8.7%
33																									
34	**Coverage Ratios (before tax)**		**Minimum**	**Average**																					
35	Total Debt Service		1.40	1.57		1.40	1.43	1.47	1.51	1.54	1.58	1.62	1.66	1.70	1.75	na	na	na	na	na	na	na	na	na	na
36	Debt Service Including Reserves		1.73	1.87		1.73	1.77	1.80	1.84	1.88	1.92	1.96	2.00	2.04	1.75	na	na	na	na	na	na	na	na	na	na
37																									
38	**Reserves**																								
39	Contribution to Reserves				0	5,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Reserve Balance				0	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	0	0	0	0	0	0	0	0	0	0	0
41	Disbursement of Reserves					0	0	0	0	0	0	0	0	0	5,000	0	0	0	0	0	0	0	0	0	0
42	Operating Income with Reserves					25,959	26,483	27,020	27,571	28,135	28,714	29,306	29,914	30,537	26,175	0	0	0	0	0	0	0	0	0	0
43																									
44	**Working Capital Balances**																								
45	Accounts Receivable					1755	1,799	1,844	1,890	1,937	1,986	2,035	2,086	2,138	2,192	1,677	1,719	1,762	1,806	1,851	1,897	1,945	1,993	2,043	2,094
46	Fuel Stocks					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	Spare Parts					2000	2,050	2,101	2,154	2,208	2,263	2,319	2,377	2,437	2,498	2,560	2,624	2,690	2,757	2,826	2,897	2,969	3,043	3,119	3,197

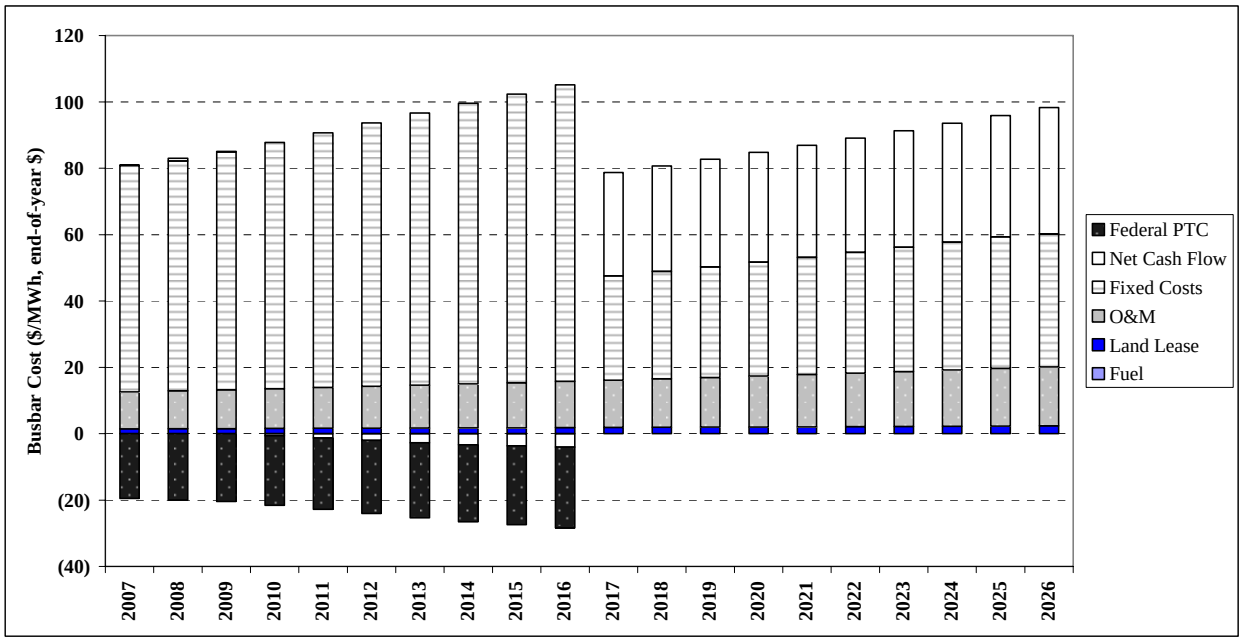


Figure 2-3
Components of Busbar Cost for Example 100-MW Wind Generation Plant

Economic Measures

Several common measures address the economic viability of a project. The busbar cost includes capital, O&M, fuel, and other costs of generating electricity. The profitability of the net cash flows is typically addressed by calculating the net present value (NPV) and the internal rate of return (IRR). Other common measures that address the riskiness of a project include the payback period and debt coverage ratios.

Busbar Cost

The busbar cost is the unit cost of generating one unit of electricity, e.g., one megawatt-hour (MWh), and is equal to the total annual costs minus credits received, divided by the total annual electricity generation. For the 100-MW wind plant example, the cost components include fixed and variable O&M cost, other fixed costs including income taxes and debt service, and other net cash flow. The credit is the 10-year federal Production Tax Credit (PTC), which is assumed to be 1.9 cents/kWh in 2005, escalates at 2.5%/yr for 10 years, and is zero after 10 years. Figure 2-3 illustrates how the various cost components and the PTC vary over the 20-year operating period of the wind plant. The 10-year PTC is shown as a negative contribution to the busbar cost during the first 10 years of operation, after which it is eliminated. The fixed cost component decreases after 10 years because the 10-year loan has been retired and the debt service component of fixed cost is eliminated. The average annual busbar cost increases from 6.2 cents/kWh in 2007 to 9.8 cents/kWh in 2026.

Net Present Value (NPV)

The net present value represents the present value (or present worth) of profit using the time value of money principles described in Section 3 of the 1999 EPRI TAG report [1]. This calculation results from discounting the net cash flows at the minimum acceptable rate of return for the equity investor. The method is also referred to as the discounted cash flow method.

The net present value must be defined at a certain point in time. Frequently, the NPV is calculated at the commercial operation date. In this case, the total capital requirement (at the commercial operation date) is subtracted from the net cash flows that are discounted or brought back to the same date. For the example provided, the total capital requirement is considered at the commercial operation date, since the construction loan was based on 100% of the capital investment and the interest during construction essentially includes the future worth of the construction expenditures at the commercial operation date.

The NPV may also be calculated at the beginning of the construction time period if equity is required to fund the construction expenditures (as opposed to a 100% construction loan). In any event, the NPV can be calculated at the point in time that makes the most sense for the evaluation.

In addition to determining the present value of cash flows for potential projects, the discounted cash flow method can be used in other ways as well. Up to this point, revenues from the project were assumed to be known. With an assumed rate of return, the discounted cash flow approach can then be used to compute the annual revenues, or rate structure, necessary to make the project a viable one. Essentially, this is what is done in the revenue requirements method.

Another application would be to use the discounted cash flow method to negotiate with a potential project constructor. If all the other variables are known (estimated), the discounted cash flow approach could be used to compute the initial cash outlay that would make the project feasible. Alternatively, the discounted cash flow method can be used to project values for *liquidated damages* if a contractor fails to meet specific targets on plant performance or capacity.

Other types of studies can include an assessment of capital/energy tradeoffs, such as an evaluation of the potential benefits from spending capital dollars to reduce heat rate. In many of the previously discussed cases, solutions are found using trial-and-error algorithms, and spreadsheets can find solutions for even complex problems very quickly.

Finally, a contract may cover a period that does not extend over the entire economic life of a project. There is, however, value to the project for the period beyond the life of the contract, which is referred to as the terminal value. Additionally, there may be a salvage value or a dismantling and decommissioning cost at the end of the service life. Analysts often omit these values or costs because they are subject to uncertainty since they occur far in the future, have relatively little impact on the results, are hard to estimate, and make the analysis slightly more conservative. However, there may be some cases in which it is appropriate to include the terminal value in calculating discounted cash flows.

Internal Rate of Return (IRR)

The internal rate of return addresses the profitability of a project. Mathematically, the IRR is defined as the discount rate that sets the present worth of the net cash flows over the service life equal to the equity investment at the commercial operating date.

An IRR of 20% does not necessarily mean that the net cash flows will represent 20% of the equity investment for each and every year of the service life. However, an IRR of 20% does mean that the equity investor will earn the equivalent of 20% of the outstanding equity balance each year. That balance will be reduced in some fashion over the life of the plant.

Many companies have a minimum acceptable rate of return that must be met before a potential project is seriously considered. This minimum acceptable return is known as the *hurdle rate*, which can be used to screen potential projects based on their internal rates of return. In the example above, the project would be viable if its 20% internal rate of return is greater than the hurdle rate.

There are several caveats to be aware of when calculating the IRR:

- The IRR solution is a trial-and-error solution that is typically solved by a convergence routine available in spreadsheet software.
- The solution is based on solving an nth-degree polynomial that may have multiple real, positive roots. More than one change in the sign of the coefficients of the net cash flows is an indication of possible multiple roots. The net cash flow line in the example in Table 2-7 has only one real positive root due to only one change in sign of the coefficients (negative net cash flow at the commercial operating date changing to positive net cash flows for the service life). A standard engineering economics textbook should be consulted for situations where multiple roots are suspected.
- Changes in the IRR are not scalar, and a small change in the cash flows can have a large effect on the IRR.
- Comparison of the IRR values may be misleading. While the internal rate of return allows investors to rank options based on their potential rate of return, it does not take into account a project's size. For example, it does not allow an analyst to compare a $1 million project with a 25% internal rate of return with a $10 million alternative having a 20% internal rate of return. An incremental analysis may be required. Again, a standard engineering economics textbook should be consulted for these situations.

Payback Period

The payback period represents how long it will take the net cash flows to recover the capital investment (i.e., how many years for the cumulative net cash flows to become positive). There are two versions of the payback period measure:

- The *simple payback period* typically represents the number of years for the net cash flows to payback the capital investment. The calculation requires summing the net cash flows for the preceding years. Time value of money considerations are not included.

- The *discounted payback period* represents the number of years for the *present worth* of net cash flows to recover the capital investment. Time value of money considerations are properly considered.

The discounted payback period is the preferred measure since it provides a proper economic signal for the importance of the net cash flows. The simple payback period can be misleading since cash flows in future years have the same apparent value as cash flows in the current year.

The payback period is a measure of secondary economic importance since it does not include consideration of all of the net cash flows over the life cycle of the project. Significant cash flows after the payback period are not included in the measure number. Nevertheless, the payback period remains a popular indicator of the risk level of the project.

Debt Coverage Ratios

For projects that are debt financed, debt coverage ratios address the level of risk for the project from the perspective of the lending institution. The *debt coverage ratio* is calculated as the earnings before interest, taxes, depreciation, and amortization (EBITDA), divided by the annual debt service. EBITDA represents the revenues minus expenses (not including book depreciation) on a before income tax basis. The debt service represents the principal and interest payments to service the loan. The ratio is designed to address the ability of the project's cash flows to service the debt; the higher the ratio, the lower the level of risk for the project.

The minimum debt coverage ratio should always be greater than 1.0. Depending on the risk of the project, banks may require that the minimum never go below a certain threshold such as 1.3 or 1.5.

Lending institutions also calculate the average debt coverage ratio over the life of the loan. This measure reflects the ability to service the loan over its term. Depending on the level of risk, the lending institution may require that the average over the life of the loan never drop below a certain threshold such as 1.7 or 2.0.

Sensitivity Analysis

Sensitivity analysis is important for understanding the key drivers for the economic *pro forma*. An economic analysis typically begins with specifying a base case as defined in the previous example. Sensitivity analysis is based on re-evaluating the economic analysis by changing input parameters by reasonable amounts. The analyst can then study the results to determine the key drivers in the *pro forma* model. The analyst can also determine what reasonable variations in input parameters may cause the project miss its financial goals.

Table 2-8 presents a sensitivity analysis for the previous example. The effects of reasonable variations in key input parameters on key economic results are shown. For example, a 20% decrease in the total plant cost (TPC) would cause the IRR to increase from 8.7% for the base case to 14.0% (the *pro forma* assumes that certain development costs are based on the TPC cost—these would decrease accordingly). Debt coverage ratios and payback periods would improve accordingly.

Table 2-8
Example Sensitivity Analysis

Parameter	Input Data % Change	Input Data Value	Case	After Tax IRR[1]	Net Present Value[2] $ million (Jan 2006) Result	Net Present Value[2] $ million (Jan 2006) % vs. Base	Senior Debt Coverage Ratios[3] Minimum	Senior Debt Coverage Ratios[3] Average	Simple Payback Period (years)	Discounted Payback Period (years)
CAPITAL COST		$ million, Dec. 31, 2006								
Total Plant Cost	*20%*	168,000	2	5.1%	(46,620)	-149%	1.17	1.31	15	15
	Base	140,000	1	8.7%	(18,714)	0%	1.40	1.57	13	13
	-20%	112,000	3	14.0%	9,192	149%	1.75	1.96	9	9
FINANCING										
Debt Proportion		40%	4	8.1%	(27,456)	-47%	2.11	2.36	12	12
	Base	60%	1	8.7%	(18,714)	0%	1.40	1.57	13	13
		80%	5	9.6%	(9,901)	47%	1.04	1.17	13	13
Loan Term		Years								
		8	6	6.2%	(34,564)	-85%	1.20	1.34	15	15
	Base	10	1	8.7%	(18,714)	0%	1.40	1.57	13	13
		12	7	9.8%	(12,150)	35%	1.42	1.59	11	11
Interest Rate		Rate								
		6.0%	8	9.4%	(14,452)	23%	1.53	1.72	12	12
	Base	8.0%	1	8.7%	(18,714)	0%	1.40	1.57	13	13
		10.0%	9	8.0%	(23,184)	-24%	1.28	1.44	13	13
REVENUES										
		cents/kWh, Jan. 1, 2007								
Power Revenue	*20%*	7.2	10	12.2%	1,146	106%	1.64	1.84	11	11
	Base	6.0	1	8.7%	(18,714)	0%	1.40	1.57	13	13
	-20%	4.8	11	4.9%	(38,574)	-106%	1.15	1.29	15	15
Capacity Factor		40%	12	11.8%	(1,269)	93%	1.63	1.83	11	11
	Base	35%	1	8.7%	(18,714)	0%	1.40	1.57	13	13
		30%	13	5.5%	(36,159)	-93%	1.17	1.31	15	15
Federal Production		cents/kWh, 2006								
Tax Credit		3.0	14	11.0%	(5,505)	71%	1.63	1.83	11	11
	Base	1.9	1	8.7%	(18,714)	0%	1.40	1.57	13	13
		0.0	15	5.3%	(41,529)	-122%	1.00	1.12	15	15

Notes

1. Internal rate of return on discounted net cash flow after tax.

2. Discount rate is 12%.

3. Senior debt coverage ratios are based on operating income (before tax, not including reserves) divided by debt service.

As can be seen from the table, the key drivers in the analysis are the power sales revenue, capacity factor, federal Production Tax Credit, and total plant cost. A 20% decrease in electricity revenues would cause the IRR to decrease from 8.7% to 4.9% and the debt coverage ratios to be low and possibly unacceptable depending on the goals of the project.

The sensitivity analysis provides a basis for beginning the probabilistic risk analysis that is described in Sections 8 and 9 of the 1999 EPRI TAG report [1].

Project Risks and Financing

Non-utility generating plants can be financed as limited recourse projects or through general corporate debt.

Limited recourse project financing refers to those projects that are dependent on the specific cash flows of the project as defined in specific project agreements. Limited recourse financing usually requires the formation of a special-purpose company to protect the exposure of the parent company. The financial exposure of the owner is typically limited to the equity invested in the physical and intangible assets of the project. However, the interest of the owner in the assets is junior to that of the lenders. This type of financing requires acceptable risk allocation through proper contract structuring with financially strong contractual parties, performance guarantees, and liquidated damages (intended to "backstop" guarantees provided by the parties to the various project contracts and agreements). The backstop for the guarantees can be assigned to the appropriate original equipment manufacturers.

Qualifying facilities (under PURPA) were commonly financed on a limited recourse project finance basis because these projects had a revenue stream that was secured by long-term power sales agreements. The ultimate risk of power sales became a function of the creditworthiness of the utility that had contracted to buy the power. Most utilities have been creditworthy because of their regulated monopoly status.

The regulatory restructuring of the industry has allowed the development of merchant power plants to sell power on a commodity basis (as previously shown in Figure 2-1). Limited recourse financing for a merchant plant requires more stringent assurances that the project can meet its goals. The amount of and type of limited recourse debt financing will be a function of:

- *A properly structured project ownership.* An appropriate legal structure and experienced and well-managed sponsors are fundamental requirements. Experienced contractors are required for engineering, procurement and construction.
- *The proportion of the plant's output that will be under contract.* It is expected that this percentage will vary widely between developers with different risk strategies. A sound security package in terms of the project agreements that will be designed to secure the appropriate cash flows with a low degree of volatility.

- *The competitiveness of a project in its region.* The project will have to be one of the lowest cost producers. However, being one of the lowest cost producers in a commodity-driven market has several implications:
  - Maximizing the capacity factor will become relatively less important than maximizing the profitability of the plant production.
  - The economics of a project may be driven by capacity payments in some areas of the country while other regions will be driven by energy payments.
  - Different plant types will have a niche based on the time of day or season of the year. For example, some natural gas combined-cycle units may be most profitable in the "shoulder" or intermediate peaking times of day. Simple-cycle natural-gas-fired plants and pumped storage plants are typically most economical for the time of day and season of the year when power is at peak demand. The economic viability of run-of-river hydro plants will depend on the hydrologically "wet" seasons.
- *The capabilities for understanding and forecasting market pricing.*
- *The ability of the project cash flows to cover the risks of power sales.* Many projects will have structural enhancements that take the following forms:
  - Methods to shift risk, such as subordinating fuel expenses to debt service payments, or to utilize a tolling agreement for fuel supply and power output
  - Methods to share risk, such as higher equity investments, limited parent guarantees, or subordinated debt provided by vendors and/or EPC contractors
  - Methods to account for the timing of risks, such as cash sweeps, reserve accounts and commodity swaps, and remarketing of unused fuel

Achieving an investment-grade rating for limited recourse project financing is difficult when power sales are subject to "commodity" risk. The volatility of commodity prices leads to risk that the plant may not be able to meet its financial goals. Consequently, lenders will require that projects have a greater equity proportion of financing to absorb the volatility risk (i.e., the risk that the cash flows will be insufficient to pay the debt service).

A typical merchant plant project that is project financed can be characterized as follows:

- Equity proportion of the capital structure of 30% to 50% depending on the risk of the project
- Average annual debt coverage ratios of at least 1.75 to 2.0 (probably closer to 2.0)
- Debt terms of 10 to 20 years with cash sweep provisions
- Relatively higher debt reserves than were required for qualifying facilities because of the seasonality of electricity pricing (Debt reserves of 6 to 12 months of debt service payments may be required, depending on the level of risk. Debt service reserves can take the form of cash that is financed, letters of credit, or other financial commitments.)
- Other financial structural enhancements such as subordinated debt, limited parent guarantees and commodity swaps
- A well-defined legal structure
- An internal rate of return on after tax equity that is typically at least 15%

As more equity is required for limited recourse project financing, the financing complexity and costs increase. Essentially, a premium is being paid for limited recourse debt even though the higher levels of equity are designed to absorb the risk of volatility in the cash flows. Consequently, large firms with healthy balance sheets and diversified assets may have an advantage in financing merchant power plants through general corporate debt. Corporate debt allows the company to avoid burdensome contractual arrangements and project security arrangements that are required for project financing and, in some cases, allows the company to tolerate more commodity-based risk.

The advantage of financing with corporate debt is one of the factors driving the industry to consolidate to larger companies. Large balance sheets (sometimes formed as a result of mergers and acquisitions) allow for financing through corporate debt. Large companies with diversified portfolios of power plant assets can also balance downside risks that occur in one regional market with upside risks that occur in another regional market. Financing with corporate debt may provide financing that is more flexible, has shorter lead-time, and often has reduced costs.

In conclusion, the financing of merchant power plants is evolving along several parallel paths. A framework for limited recourse project financing is developing in the financial community that requires significant proportions of equity investment. Additionally, there is an increasing trend for financing with corporate debt as the industry consolidates to larger firms.

2.2.4 Limitations of Examples

This section has outlined methods for evaluation of power projects developed by non-utility producers and provided comparisons to evaluations for utility projects. We have used many simplifying assumptions have that may not be appropriate for an actual project. The appropriate method for any entity to use in making economic decisions depends on many factors including its strengths and weaknesses, its strategic aim, its competitors, and the economic and legal environment. In addition, as electricity competition increases, industry participants will assess their missions and their risk profiles, and the distinctions between regulated and non-utility entities can be expected to blur.

2.3 Guidelines for Economic Evaluation of Renewable Energy Projects

2.3.1 Design/Cost Estimate

The rating system shown in Table 2-9 indicates the level of effort involved in the design and cost estimate.

Table 2-9
Confidence Rating Based on Cost and Design Estimate

Letter Rating[1]	Key Word	Description
A	Actual	Data on detailed process and mechanical designs Historical data from existing units
B	Detailed	Detailed process design (Class III design and cost estimate)
C	Preliminary	Preliminary process design (Class II design and cost estimate)
D	Simplified	Simplified process design (Class I design and cost estimate)
E	Goal	Technical design/cost goal (or value developed from literature data)

1. If complete design and cost-estimating methods and assumptions are not available, the rating is reduced by one unit.

2.3.2 Accuracy Ranges

Accuracy of cost estimates has been discussed in detail in many texts and papers on cost estimating. Table 2-10 presents estimates of the range of accuracy for the cost data presented in this report.

Table 2-10
Accuracy Range Estimates for TAG Cost Data (Ranges in Percent) [1]

Design & Cost Estimate Rating	A Mature	B Commercial	C Demo	D Pilot	E & F Lab & Idea
A. Actual	0	-	-	-	-
B. Detailed	-5 to + 5	-10 to + 10	-15 to + 20	-	-
C. Preliminary	-10 to + 10	-15 to +15	-20 to +20	-25 to +30	-30 to +60
D. Simplified	-15 to + 15	-20 to +20	-25 to +30	-30 to +30	-30 to +80
E. Goal	-	-30 to + 70	-30 to +80	-30 to +100	-30 to +200

1. This table indicates the overall accuracy for cost estimates. The accuracy is a function of the level of cost-estimating effort and the degree of technical development of the technology. The same ranges apply to O&M costs.

2.3.3 Definitions of Economic Terms

The following briefly defines various economic terms used throughout this TAG report:

Plant Size: Net electrical capacity of the unit that forms the basis for the cost estimates.

Available for Commercial Orders: Estimate of the earliest date that a commercial-size unit could be ordered with normal performance guarantees, if the technology is not already commercially available. This date assumes an orderly development program, with success at each step. Since most technology development programs have unexpected delays and unsuccessful steps that must be repeated, the actual commercial order date is likely to be later than the one shown. Furthermore, the very first commercial units will be somewhat more expensive (in constant dollars) than the mature unit designs that form the basis for the cost estimate.

First Commercial Service: Estimate of the earliest date that a commercial-size unit could be put into operation. The first commercial service date estimate is usually based on adding the idealized construction time plus an allowance for design time to the "available for commercial orders" date.

Hypothetical In-Service Year: Year in which the plant is assumed to be placed into service. In most cases this is the same as the "first commercial service."

Plant Capital Cost: Basis for the cost estimate in terms of the number of units included in the plant.

General Facilities and Engineering Fee: General facilities capital is the total construction cost of the general facilities, including roads, office buildings, shops, laboratories, etc. The engineering fee is the engineering and home office overhead and fee paid to the architect/engineering company and considered representative of the type of generating or storage unit.

Project and Process Contingency: Project contingency is a capital cost contingency factor covering the cost of additional equipment or other costs that are not apparent in the preliminary design and that would result from a more detailed design of a definitive project. Process contingency is a capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Total Plant Cost (TPC): Total of all direct and indirect construction costs at a single point in time. This item does not include the time value of money (interest, etc.) during the construction period. Capital cost estimates expressed at a single point in time are often referred to as instantaneous or overnight construction costs.

Total Cash Expended (TCE): Amount of money that would have been spent for all labor, materials, and indirect costs at the time the unit does into service. This item is expressed in mixed-year dollars accumulated over the construction period.

AFUDC (Allowance for Funds Used During Construction): Interest paid on the cash expended during the construction period. This interest is accumulated and compounded until the plant goes into service

Total Plant Investment (TPI): Sum of TCE and AFUDC. TPI is expressed in mixed-year dollars accumulated at the same point in time as total plant cost. For cases where the expenditure rate is uniform, total plant investment (TPI), total cash expended (TCE), and allowance for funds used during construction (AFUDC) can be calculated by multiplying total plant cost (TPC) by the appropriate adjustment factor (AF) shown in Table 2-11. That is:

$$TPI = TPC \times AF\ (TPI)$$

$$TCE = TPC \times AF\ (TCE)$$

$$AFUDC = TPC \times AF\ (AFUDC)$$

Owner Costs: This includes prepaid royalties, startup costs, inventory capital, catalyst and chemicals, and land.

Total Capital Requirement: All capital costs that would go into the rate base on a hypothetical in-service date. Since the technology may not be available until a much later point in time, the total capital requirement should be multiplied by the appropriate cost escalation factor for a future in-service date.

Total Capital Replacement: Capital cost that would be incurred by employing a particular technology; the total capital cost over the lifetime of the unit. This represents major replacement or refurbishing of equipment such as replacement of blades in a combustion turbine.

Table 2-11
TPC-TPI Adjustment Factors (AF)

Idealized Construction Time (years)	Adjustment Factors [1]		
	AF (TPI)	AF (TCE)	AF (AFUDC)
1	1.0	1.0	0
2	1.025	0.980	0.045
3	1.050	0.961	0.089
4	1.076	0.942	0.134
5	1.103	0.924	0.179
6	1.131	0.906	0.225
7	1.160	0.889	0.271
8	1.189	0.872	0.317

1. Based on 4.1% cost escalation and 9.2% AFUDC interest rate.

Operation and Maintenance (O&M) Costs: Costs are expressed at the same point in time as the total capital requirement and represent the costs for a normal year of operation. The extra costs associated with plant start-up in the first year are included in the total capital requirement. Incremental costs are broken down into variable and consumable components. Consumables are computed directly from the plant material balance. The variable component primarily represents variable maintenance and is estimated from an algorithm incorporating the units expected capacity factor.

Unit Availability: Fraction of time a generating unit is able to supply power at various capacity levels. Estimates are based on mature plants and are likely to be significantly more optimistic than the initial experience with first-of-a-kind plants.

Minimum Load: Estimate of the minimum load from which the unit could be ramped up to full load in a reasonable time (one hour or less).

Pre-construction, Licensing, and Design Time: Time periods for pre-construction activities depend on local regulations and conditions. The time period is intended to be a reasonable approximation, but actual times may range from one-half to two times the original time.

Idealized Plant Construction Time: The idealized construction time is intended to represent the *minimum* construction time required to build a plant under ideal conditions. Actual construction times will likely be somewhat longer due to labor strikes, weather, regulatory problems, etc.

Unit Life: Estimate of the book life of the plant. Maintenance costs include sufficient funds to replace minor equipment that wears out before the unit life shown.

Technology Development Rating and Design / Cost Estimate Rating: Rating systems designed to indicate the quality of the information used to develop the data.

2.4 The EPRI Personal Computer Programs

Two EPRI programs are available to assist users in conducting economic evaluations: the *EPRI Regulated Utility Power Project Costing Model* and the *EPRI Non-Utility Power Project Model*.

The *EPRI Regulated Utility Power Project Costing Model* helps determine total plant investment, depreciation, annual revenue requirements, annual carrying charges, and fixed charge rates. Inputs to the model are divided into three sections: Schedule, Project Costs, and Financing. In “Schedule,” a user specifies the construction schedule, construction cost, size of the project, and expected lifetime capacity factor. In “Project Costs,” the costs are entered. In “Financing,” the user enters capital structure, rates associated with each financial instrument, tax rates, and other rates.

Outputs from the model are blocked in sections. The first three sections summarize the input assumptions and provide preliminary calculations including the weighted cost of money before pre-tax and after-tax and construction expenditures in as-spent dollars with AFUDC. The fourth section shows construction costs, specifically more detail on total plant investment and the nominal and real levelized fixed charge rates. The fifth section provides annual book depreciation, tax depreciation, and annual deferred taxes by construction costs. The sixth and last

section displays key results—the allocation of book depreciation and deferred taxes by financing instrument, annual revenue requirements by component, the end-of-year annual carrying charges, and the annual levelized fixed charge rates.

The *EPRI Non-Utility Power Project Model* is a conceptual economic *pro forma* for evaluating non-utility projects for which the price of electricity is market-based. A spreadsheet tab (within the workbook) is set aside for input values for time frames, revenue data, capital cost data, financing parameters, fuel costs, and operating and maintenance costs.

Separate spreadsheet tabs are provided for a summary sheet, capital costs, an income statement, a cash flow statement, rates and prices, loans and tax depreciation, and construction costs by month.

2.5 References

1. *TAG® Technical Assessment Guide, Volume 3, Rev. 8: Fundamentals and Methods-Electricity Supply*, EPRI, Palo Alto, CA: November 1999. TR-100281-V3R8.
2. *Technical Assessment Guide, Electricity Supply-1993, Volume 1, Rev. 7*, EPRI, Palo Alto, CA: June 1993. TR-102275-V1R7.
3. U.S. DOE Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1994, July 1995, pp. 15, 27.
4. U.S. DOE Energy Information Administration, Annual Energy Outlook 1996, January 1996, p. 79.
5. U.S. DOE Energy Information Administration website, Status of State Electric Industry Restructuring Activity, http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html, July 2003.

3
WIND POWER

Installed Capacity (December 31, 2006)	73,900 MW Worldwide 11,603 MW in the United States
Technology Readiness	Mature, commercial High confidence in cost estimates and projections
Environmental Impact	Minimal during manufacturing and operation New technologies minimize avian mortality Sight and sound impacts must be considered in planning and operation
Economic Status	Competitive in many markets Tax and cash incentives still desirable to facilitate most projects
Policy Status	Encouraged by RPS and energy policies in most jurisdictions Encounters occasional resistance from the public, environmental groups and others concerned primarily with visual impact of turbines
Trends to Watch	Near-term capacity growth of approximately 25% per year Larger individual turbines (taller towers, longer blades) Larger aggregate wind farms Advanced materials and controls Rapid expansion into high wind resource areas (U.S. plains, North Atlantic, Asia) as costs becomes competitive in more markets Small, direct-drive turbines hybridized with gensets and energy storage

3.1 Introduction

Wind is generated by small regional differences in atmospheric pressure caused by solar heating of the Earth's surface, radiation cooling at night, the passage of air over warm or cold ocean water, the passage of fronts and storms, and other complex meteorological phenomena. Since the dawn of civilization, people have relied on the wind to propel sailing vessels and power grain grinding mills, saw mills, water pumps, electric generators, and other devices.

In recent years, the modern wind turbine has been developed and commercialized, principally in Europe and the United States, for electricity generation. Wind is now the fastest growing form of electricity generation in the world. During 2005 alone, more than 11,407 MW of new wind capacity was installed throughout the world. Projected wind capacity additions for 2006 total about 13,300 MW. As of the end of 2005, the installed wind generation capacity was about 9,180 MW in the United States and 59,267 MW worldwide.

This section of the TAG-RE addresses worldwide historical and projected installed wind generation capacity, wind turbine technology, likely development pathways, wind turbine performance and project cost estimates, operating and maintenance labor requirements, grid

integration, onshore and offshore project development process and market, environmental issues, potential for greenhouse gas reduction and evolving markets for equipment and services.

3.2 Installed Wind Capacity

The worldwide installed wind generating capacity continues to grow at a rapid rate. Figure 3-1 shows the historical installed wind generating capacity through 2005 and the projected capacity from 2006 through 2010 in the United States and the world. During 2005, installed capacity increased by about 24%, from 47,934 MW to 59,264 MW, and is forecast to nearly triple between 2006 and 2010 to 148,794 MW.

Table 3-1 presents the installed capacity by country at the end of each year during the period 1999 through 2005. As of the end of 2005, Germany led the world in installed wind capacity (18,445 MW), followed by Spain (10,027 MW), the United States (9,181 MW), and India (4,253 MW). The United States installed the most wind capacity during 2005 with 2,431 MW, followed by Germany (1,808 MW), Spain (1,764 MW), India (1,253 MW), Portugal (502 MW), and P.R. China (498 MW).

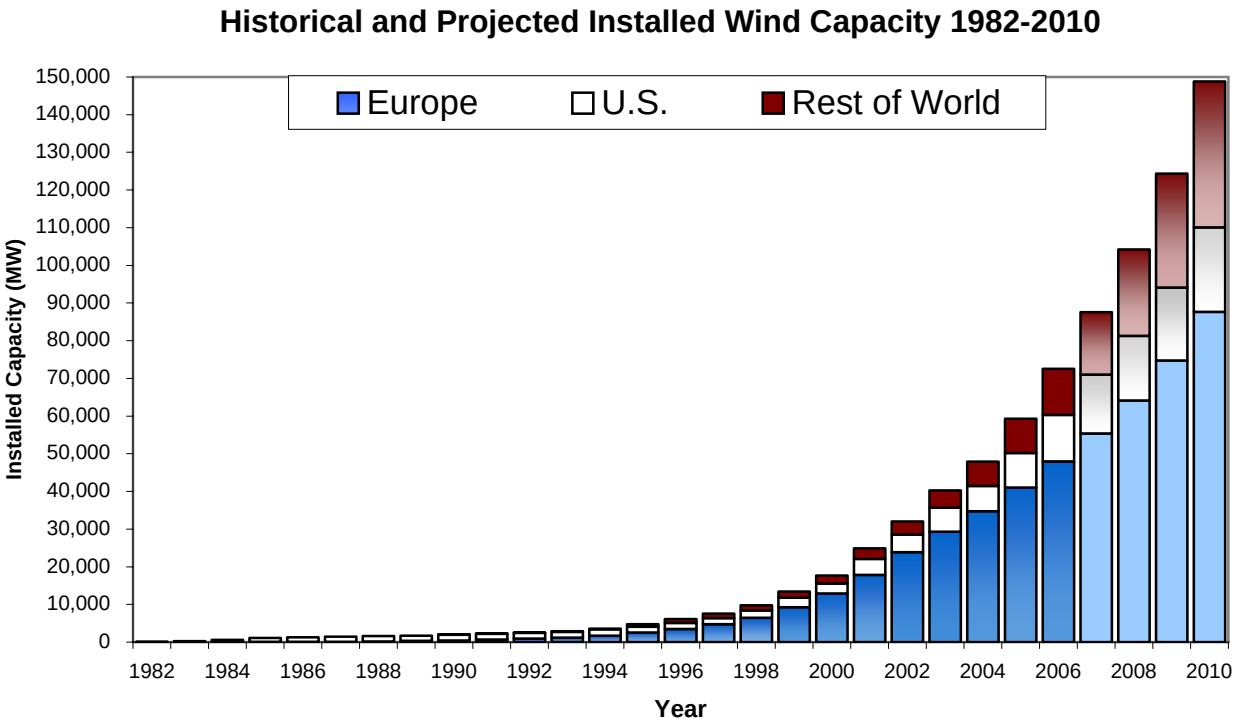


Figure 3-1
Historical (1982-2005) and Projected (2006-2010) Installed Wind Generation Capacity in the U.S., Europe, and Remainder of the World (Source: National Renewable Energy Laboratory, *Wind Power Monthly*, and BTM Consult ApS)

Table 3-1
Operating Wind Generation Capacity: End of Year 1999–End of 2005
(Source: *Wind Power Monthly* and BTM Consult ApS, March 2006)

	Operating Wind Capacity by Country (MW)						
Region/Country	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**End 2005**
Europe							
Germany	4,445	6,113	8,753	12,001	14,612	16,649	18,445
Spain	1,530	2,402	3,335	4,830	6,420	8,263	10,027
Denmark	1,742	2,297	2,556	2,889	3,076	3,083	3,087
Italy	211	389	697	785	922	1,261	1,713
UK	356	409	485	552	759	889	1,336
Netherlands	410	448	483	686	938	1,081	1,221
Portugal	60	100	127	194	311	585	1,087
Austria	42	78	95	139	415	607	820
France	23	79	85	147	274	386	775
Greece	87	189	272	302	538	587	705
Sweden	220	231	280	328	428	478	554
Ireland	73	118	125	137	230	339	498
Norway	13	13	17	97	101	158	275
Belgium	9	9	31	46	78	106	177
Rest of Europe (Other East European and Baltic countries)	na	na	na	na	na	75	132
Finland	38	38	39	41	53	83	85
Poland	7	7	28	58	55	55	65
Luxembourg	10	10	15	16	16	12	12
Turkey	9	20	19	19	20	20	20
Switzerland	3	3	5	5	6	8	11
Total Europe	**9,288**	**12,953**	**17,447**	**23,272**	**29,252**	**34,725**	**41,044**
North America							
United States	2,492	2,555	4,245	4,645	6,361	6,750	9,181
Canada	127	140	207	236	351	444	683
Total North America	**2,619**	**2,695**	**4,452**	**4,881**	**6,712**	**7,194**	**9,864**

Table 3-1 (continued)
Operating Wind Generation Capacity: End of Year 1999–2005
(Source: *Wind Power Monthly* and BTM Consult ApS, March 2006)

	Operating Wind Capacity by Country (MW)						
Region/Country	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**End 2005**
Asia							
India	1,095	1,220	1,507	1,702	2,125	3,000	4,253
China	182	340	399	468	571	769	1,264
Taiwan		3	3	3	8	16	72
Rest of Asia (Indonesia, N Korea, Malaysia, Philippines, Thailand, Vietnam, etc.)	na	na	na	na	na	4	28
Total Asia	**1,277**	**1,563**	**1,909**	**2,173**	**2,704**	**3,789**	**5,617**
South & Central America							
Costa Rica	46	51	71	71	71	71	79
Brazil	20	20	20	22	31	31	31
Argentina	14	14	24	26	30	30	31
Other Americas	na	na	na	na	50	54	54
Mexico	3	3	3	3	3	3	3
Total S. & Central America	**83**	**88**	**118**	**122**	**185**	**189**	**198**
Pacific Region							
Japan	68	150	300	384	761	991	1,159
Australia	11	34	73	103	239	421	717
New Zealand	37	37	37	37	55	167	167
South Korea	7	8	8	8	21	69	89
Total Pacific Region	**123**	**229**	**418**	**532**	**1,081**	**1,653**	**2,132**
Middle East & Africa							
Egypt	15	63	69	69	123	146	180
Middle East (Jordan, Iran, Iraq, Israel, Saudi Arabia, Syria, etc.)	na	na	na	na	72	101	101
Morocco	na	54	54	54	54	54	64
Tunisia	0	0	0	0	28	28	28
Rest of Africa (Algeria, Cape Verde, Ethiopia, Libya, S Africa,etc)	na	na	na	na	5	6	6
Total Middle East & Africa	**15**	**117**	**123**	**123**	**282**	**335**	**379**
Total World	**13,405**	**17,645**	**24,467**	**31,103**	**40,216**	**47,885**	**59,234**

The U.S. market fluctuates from year to year depending on the status of the federal production tax credit (PTC). The federal PTC expired on December 31, 2003 and was extended to December 2005 by tax legislation passed by Congress in September 2004, and then to December 2007 by the 2005 Energy Policy Act. It was further extended to December 2008 by Congress when it passed a tax and trade policy bill in December of 2006. As a result of the PTC extension, 2005 and 2006 wind capacity additions exploded in the United States, totaling about 2,430 MW and 2,750 MW respectively; new capacity additions are expected to reach 3,000 to 3,500 MW during 2007.

Table 3-2 presents the forecast annual capacity additions for 2006 through 2010 and the projected installed capacity at the end of 2010 by country. As discussed later, much of the new wind capacity in Europe will be installed at offshore, shallow water sites. From 2006 through 2010, the United States is expected to install the most new wind generation capacity (13,200 MW), followed by Spain (9,200 MW), Germany (8,050 MW), India (8,000 MW), P.R. China (6,500 MW), and the UK (6,400 MW). By the end of 2010, the countries with the largest projected installed wind generation capacity are expected to be Germany (26,495 MW), the United States (22,381 MW), Spain (19,127 MW), India (12,253 MW), and P.R. China (7,764 MW). Figure 3-2 compares the operating wind capacity in different nations and regions of the world at the end of 2004 and 2005, indicating both overall capacity growth and shifting shares of the total.

In the United States, most early wind turbine projects were constructed at three sites in California that demonstrated high average wind speed. Additional wind power sites are under development in Minnesota, Texas, Iowa, New York, Pennsylvania, Oregon, Washington, Kansas, and other states. Figure 3-3 shows the distribution of U.S. wind generation capacity among the states at the end of 2006.

As of the end of September 2006, 20 states contributed approximately 50 MW or more of wind power: Texas, California, Iowa, Minnesota, Oklahoma, Oregon, New Mexico, Washington, Kansas, Colorado, Wyoming, New York, Pennsylvania, Montana, North Dakota, Illinois, Nebraska, West Virginia, Wisconsin, and Hawaii. Forecasts of future U.S. wind capacity vary depending on different assessments of how planned projects will proceed. As shown in Table 3-2, BTM Consult ApS forecasts that cumulative U.S. wind capacity will reach approximately 12,381 MW in 2006.

Table 3-2
Forecast Wind Generation Capacity Additions: 2006-2010
(Sources: BTM Consult ApS, March 2006)

	Cum MW	Forecast Wind Capacity Additions (MW)						Cum MW
Region/Country	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**	**2010**
Europe								
Austria	820	200	200	250	250	250	1,150	1,970
Belgium	177	100	100	200	150	250	800	977
Denmark	3,087	20	50	250	300	100	720	3,807
Finland	85	50	50	50	100	100	350	435
France	775	500	800	800	1,200	1,500	4,800	5,575
Germany	18,445	1,500	1,200	1,300	1,550	2,500	8,050	26,495
Greece	705	150	150	200	200	250	950	1,655
Ireland	498	250	200	200	300	300	1,250	1,748
Italy	1,713	500	500	600	600	700	2,900	4,613
Netherlands	1,221	400	150	150	100	300	1,100	2,321
Norway	275	150	250	300	300	500	1,500	1,775
Poland	65	75	100	200	300	400	1,075	1,140
Portugal	1,087	600	700	700	800	800	3,600	4,687
Spain	10,027	1,500	1,500	1,700	2,200	2,200	9,100	19,127
Sweden	554	75	250	125	340	340	1,130	1,684
Switzerland	11	20	30	50	50	50	200	211
Turkey	20	50	150	150	200	200	750	770
UK	1,336	600	900	1,400	1,500	2,000	6,400	7,736
Other European Countries	144	125	200	100	150	250	825	969
Total Europe	**41,044**	**6,865**	**7,480**	**8,725**	**10,590**	**12,990**	**46,650**	**87,694**
North America								
United States	9,181	3,200	3,200	1,600	2,200	3,000	13,200	22,381
Canada	683	450	600	800	1,000	1,000	3,850	4,533
Total North America	**9,864**	**3,650**	**3,800**	**2,400**	**3,200**	**4,000**	**17,050**	**26,914**
Asia								
India	4,253	1,000	1,300	1,700	2,000	2,000	8,000	12,253
China	1,264	700	800	1,500	1,500	2,000	6,500	7,764
Other Asian Countries	100	50	150	200	200	200	260	388
Total Asia	**5,617**	**1,750**	**2,250**	**3,400**	**3,700**	**4,200**	**14,760**	**20,405**
South & Central America								
Total S. & Central America	**198**	**150**	**300**	**500**	**750**	**750**	**2,450**	**2,648**
Pacific Region								
Japan	1,159	250	300	400	400	600	1,950	3,109
Australia	717	300	300	400	500	500	2,000	2,717
New Zealand	167	50	75	100	100	100	425	592
South Korea	89	100	100	150	200	200	750	839
Total Pacific Region	**2,132**	**700**	**775**	**1,050**	**1,200**	**1,400**	**5,125**	**7,257**
Middle East & Africa								
Egypt	180	50	150	150	200	200	750	930
Morocco	64	40	40	50	50	50	230	294
Other African Counties	34	25	25	50	50	75	225	259
Middle East	101	20	30	50	50	150	300	401
Transition Economies	24	50	150	250	400	600	1,450	1,474
Rest of the World	**5**	**0**	**0**	**0**	**0**	**0**	**0**	**5**
Middle East, Africa and Rest	**408**	**185**	**395**	**550**	**750**	**1,075**	**2,955**	**3,363**
Total World	**59,264**	**13,300**	**15,000**	**16,625**	**20,190**	**24,415**	**89,530**	**148,794**

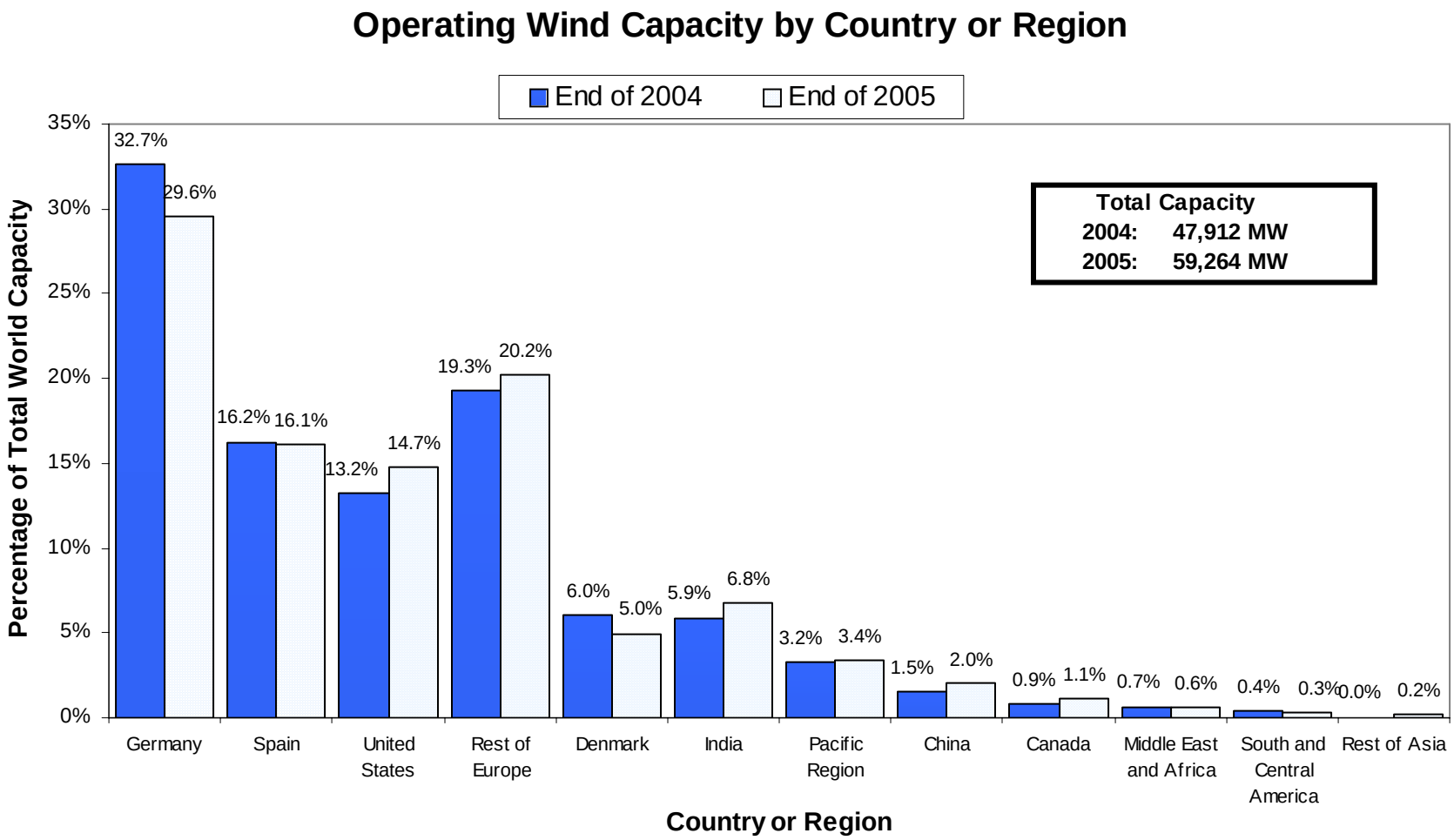


Figure 3-2
End-of-Year Operating Wind Capacity by Country and Region: 2004 and 2005 (Source: BTM Consult ApS, March 2005).

Wind Power Capacity State by State - December, 2006 Total: 11,603 MW

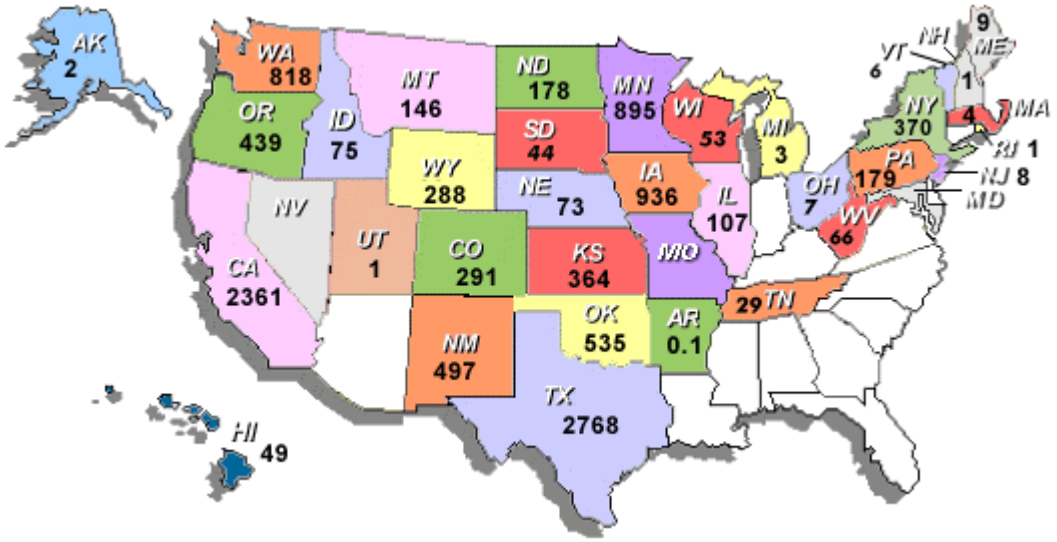


Figure 3-3
Installed Wind Generation Capacity in the U.S. by State as of December 31, 2006 (Source: American Wind Energy Association).

3.3 Technology Description

3.3.1 Wind Energy Principles

Capturing the wind's kinetic energy depends on the efficiency of the conversion process as well as the power of the wind, which can be expressed by the equation:

$$P_w = 1/2 \quad A V^3$$

where = density of the air, A = swept area of the rotor, and V = velocity of the wind.

It can be seen that the power in the wind varies proportionally with the cube of the wind speed, which has important bearing on the design and siting of wind turbines. As a result, even a small increase in wind speed can substantially boost the power available in the wind. For example, a 25% increase in wind speed approximately corresponds to a doubling in the power contained in the wind, which illustrates the importance of accurate resource assessment to a project's success.

Because of the strong link between wind speed and power, and because of the variable nature of the resource, the direct use of average wind speeds to estimate energy generation can lead to gross inaccuracies. Therefore, it makes sense to talk about the wind resource in statistical terms. For sites where resource measurements have not been taken over a significant period of time and actual distributions are unavailable, meteorologists have found that the Weibull probability

function provides a good approximation of the distribution of wind speeds over time. The Weibull function is:

$$f(v) = (k/V_c)*(V/V_c)^{(k-1)}*\exp((-V/V_c)^k)$$

where k is a shape parameter between 1 and 3, and V_c is the characteristic velocity defined as the weighted average wind speed at hub height. The Rayleigh distribution, shown in Figure 3-4, is a special case of the Weibull function in which k=2. It requires only the characteristic wind speed to define an approximate distribution.

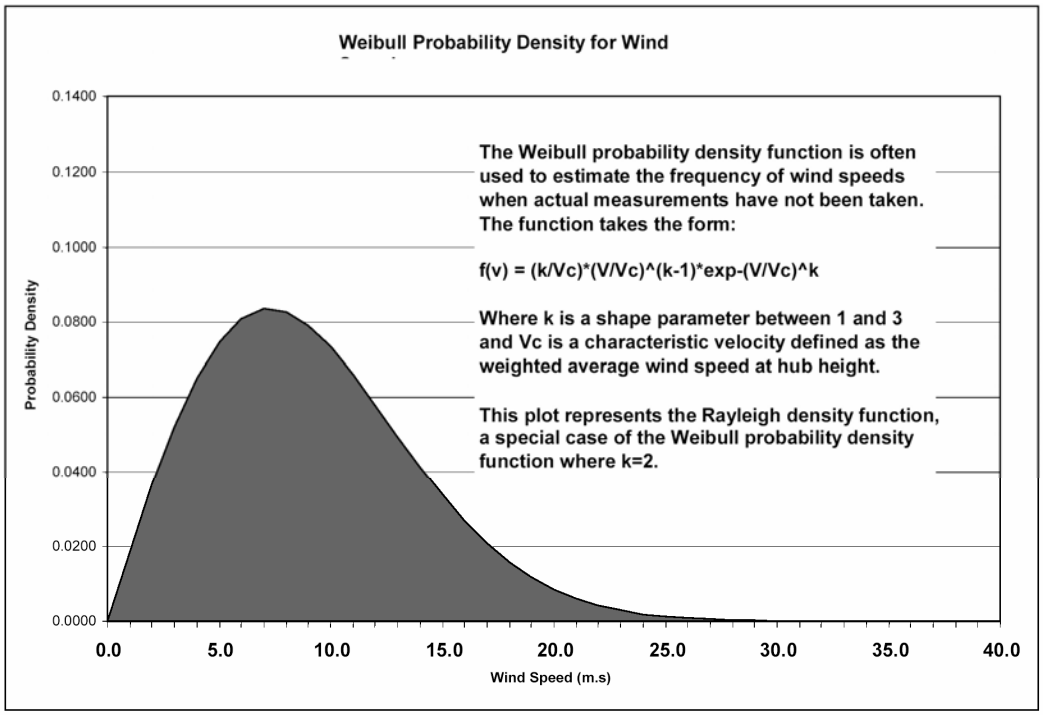


Figure 3-4
Rayleigh Probability Density Function for Wind Speed

Although the greatest power production occurs at higher wind speeds, most sites do not experience those high wind speeds with great frequency. Due to laws of conservation of mass and momentum, there is a theoretical limit to the fraction of energy in the wind that can be extracted by the rotor, called the Betz Limit. The theoretical limit of rotor energy collection efficiency is 59%. Since every other system in the turbine contributes losses as well, only a fraction of the power in the wind can be extracted by a practical wind turbine. The actual mechanical power output is:

$$P_m = Cp\ (1/2\quad A\ V^3) = Cp\ P_w$$

where Cp is the coefficient of performance and represents overall system efficiency.

The coefficient of performance, Cp, varies with wind speed and blade tip speed, and is often plotted as a function of the ratio of the blade tip speed to the wind speed because it clearly shows the optimum operating point and is applicable to both constant-speed and variable-speed wind turbines. Figure 3-5 illustrates a typical curve for the coefficient of performance vs. the tip speed/wind speed ratio.

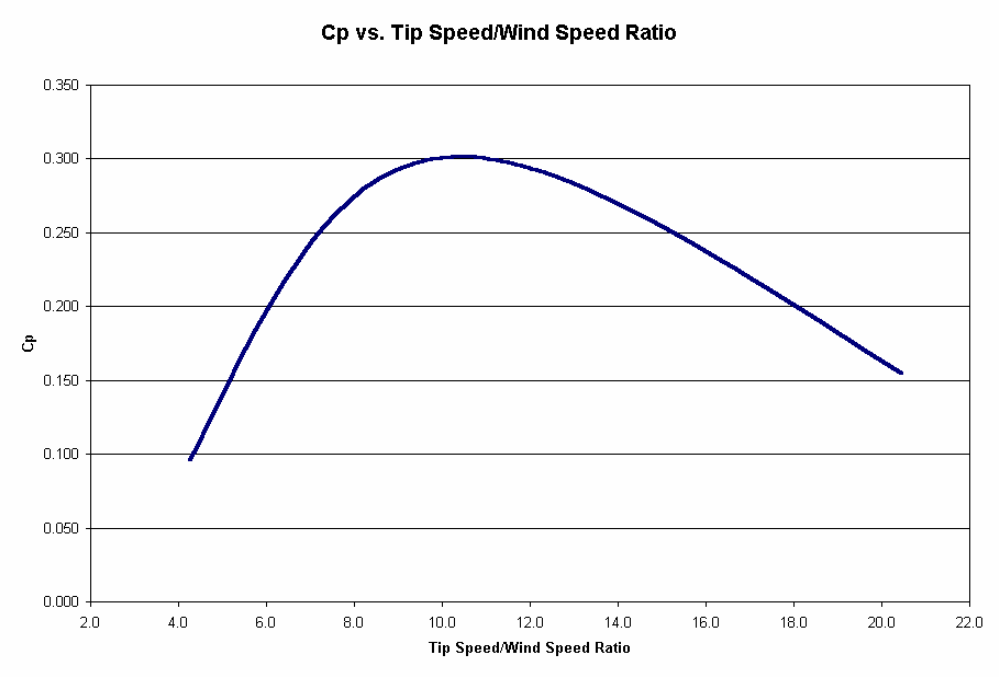


Figure 3-5
Coefficient of Performance (Cp) vs. Tip Speed/Wind Speed Ratio

3.3.2 Turbine Designs

Wind project development requires consideration of technical issues associated with turbine design, operation, and maintenance, including wind turbine reliability and maintainability; lightning protection; impact on power quality (especially in distributed generation applications); operation under extreme hot, cold, humid, or dusty environments; and operation and maintenance labor requirements. To address these issues, it is necessary to accurately assess the wind resource, temperature, humidity, winter icing, geotechnical, and lightning conditions at a site, and to develop design specifications for wind turbines and associated equipment that are appropriate for the site. The series of EPRI reports generated by the DOE-EPRI Wind Turbine Verification Program for eight utility wind projects, e.g., the December 2000 EPRI Report, *Wind Turbine Verification Project Experience: 1999* [2] and the companion reports [32-58], provide valuable information on each of these issues.

Over the last 20 years, numerous wind turbine design configurations have been proposed, including vertical axis and horizontal axis with upwind and downwind rotors. Rotors have been designed with one, two, and three blades to drive fixed-speed, two-speed, and variable-speed generators. Today, the most common configuration is the three-blade, upwind, horizontal-axis design.

Wind turbines are designed to function within a set wind speed range, which is defined by the "cut-in" and "cut-out" wind speeds. Below the cut-in wind speed, the energy in the wind is too low to be of use. Once the wind reaches the cut-in speed, the turbine comes on-line and power output increases with wind speed up to the speed for which it is rated. The turbine produces its rated output at speeds between the rated wind speed and the "cut-out" speed, at which the turbine shuts down to prevent mechanical damage.

Power output and stress on mechanical components at high wind speeds are controlled through active or passive yawing to track wind direction as well as stall or blade pitch regulation to control power output. Stall-regulated airfoils are designed to lose their lift at high wind speeds, and are therefore self-regulating. Pitch-regulated turbines vary the pitch of the blade to reduce lift and shave off power in high winds. If wind speed rises to the cut-out speed, the rotor blades feather and the turbine shuts down to avoid excessive loads on the rotor and other mechanical components. Pitch-regulated blades also provide a means for optimizing the power output at lower wind speeds. Other speed regulation methods include pitching only the blade tips, tip brakes, and ailerons.

The nameplate rating of a wind turbine is determined by the manufacturer. It can be approximated by the rating of the generator(s). The average nameplate rating of utility-grade turbines has increased from an average of about 50 kW in 1981 to roughly 1,300 kW (1.3 MW) today. Individual turbine rated capacities range from less than 1 kW for remote sites with low power needs up to 6 MW for offshore applications.

A wind turbine power plant, or wind farm, consists of one or more wind turbines arranged in rows or grids, with the longest dimension arranged perpendicular to the prevailing wind direction. Individual turbines are generally separated by 10 to 15 rotor diameters downwind and three to five rotor diameters in the direction perpendicular to the prevailing wind. Large wind farms consisting of more than five to 10 machines are typically connected to the transmission grid through a substation. Smaller distributed wind plants with fewer than five to 10 machines are often connected directly to the distribution grid without a substation.

Wind power plants typically operate unattended and are monitored and controlled via a Supervisory Control and Data Acquisition (SCADA) system, which communicates with a remote terminal at the utility control facility or other location via a telecommunications link. Under the control of on-board computers, wind turbines automatically start up when the wind speed reaches the cut-in velocity, shut down when the wind speed drops below the cut-in speed or exceeds the cut-out speed, and yaw into the wind as it changes direction. The control system is also designed to shut down the turbine when it detects a mechanical or electrical fault, such as over-speed operation, loss of hydraulic pressure, or excessive vibration. The operational status of each wind turbine in a wind farm is monitored continuously, and can be controlled from a remote location

to respond to changing operating conditions. Maintenance crews are dispatched only on an as-needed basis when alarms occur and indicate mechanical or electrical problems.

The predominant design categories for commercial wind turbines are discussed below. A listing of turbine model offerings by category and manufacturer appears in Section 3.10, "Equipment Markets and Key Participants."

Constant-Speed Wind Turbines

Many small wind turbines are designed for off-grid applications and are therefore free to respond to changes in wind speed by operating at variable speeds. However, as the speed of an induction generator changes, so does the voltage and frequency of the electricity output. Therefore, utility applications which require that generator output be synchronized with the grid place some restrictions on turbine operation. Many utility-scale wind turbines maintain the constant voltage and frequency required by the grid by simply operating at a constant speed. While this approach is effective and relatively straightforward from a mechanical and electrical standpoint, it has some inherent limitations.

First, at constant rotational speed and fixed blade pitch, the *apparent* wind speed—the vector sum of the actual wind speed and the blade speed—changes with wind speed. The effect is a corresponding change in the angle of attack, and therefore the lift generated by the blade and the torque produced by the rotor. Thus, constant-speed machines are designed for optimal performance within a very narrow range of wind speeds and, as a consequence, trade off some aerodynamic performance at all other wind speeds for reduced complexity in design. In addition, restricting the turbine to constant-speed operation imposes higher torque loads on the drive train as wind speed increases. In gusty conditions, high transient torque loads are also a problem. Therefore, the choice of constant-speed operation places additional design requirements on the drive train components.

Designers typically weigh the cost savings of designing and manufacturing a constant-speed turbine against the trade-off in performance and find that constant-speed operation is the most cost-effective option. Wind turbine technology has evolved over the years as manufacturers have gradually improved upon the basic constant-speed fixed-pitch design. One method in common use today is varying the pitch of the blade, either at the tip or, more typically, along the entire span of the blade. This approach addresses the aerodynamic limitations of fixed-pitch blades discussed above by allowing the blade to compensate for the changes in *apparent* wind speed by changing the angle between the blade and the direction of the wind, or the angle of attack. In doing this, blade performance is optimized over a much wider range of wind speeds. Pitch control also enables the turbine to reduce blade performance and torque in high winds—a safety feature that would otherwise be accomplished through such techniques as stall regulation, tip brakes, or ailerons.

Two-Speed Wind Turbines

Yet another approach to increasing the performance of constant-speed turbines is to address the problem from the generator side. The typical wind speed distribution shows that the highest wind speeds occur with relative infrequency, so the turbine only operates at its rated output a small percentage of the time. Because generators are inherently less efficient at part load, this means that the generator will operate most of the time under less than ideal conditions. One solution to this problem is dual-speed operation, in which the turbine starts up at a slow rotational speed and then switches over to a larger generator or another winding that operates at a higher rotational speed. The main generator or winding usually rotates about 30% to 50% faster than the low-speed generator or winding, and the switch-over usually occurs between wind speeds of 6 and 7 meters per second (m/s). This approach enables both generators to operate in a range where efficiency is higher, while also reducing noise (due to slower rotational speed) at low wind speeds.

Variable-Speed Wind Turbines

Variable-speed wind turbines (VSWT) vary the rotor speed as a function of wind speed to control the turbine rotor speed at the optimum tip speed/wind speed ratio and maximize the coefficient of performance (Cp). The technology was developed during the late 1980s in the United States by a consortium consisting of U.S. Windpower, Pacific Gas and Electric Company, Niagara Mohawk Power Corporation, and EPRI. In Europe, German manufacturer Enercon led a separate, parallel effort.

Under variable-speed operation, the rotor speed varies with wind speed, turning faster or slower in order to optimize rotor performance and reduce drive train torque. This was made possible by the development of a power electronic converter that transforms variable-frequency electricity from the turbine's generator into constant-frequency alternating current. A typical converter consists of a rectifier, which changes variable-frequency ac power into direct current and feeds it through a dc link to an inverter. The inverter then changes dc into high-quality ac at synchronous frequency.

Due to the fact that its rotor speed can vary, a VSWT generally has higher energy capture at low wind speeds near cut-in and at rated wind speeds. VSWTs also have a higher cut-out wind speed than corresponding variable-pitch or fixed-pitch constant-speed turbines, resulting in at least a 10% increase in energy capture. However, at high wind speeds, electrical losses due to the power electronic converters may exceed the additional energy capture and reduce performance relative to constant-speed machines.

Along with a larger operating envelope, one of the most important features of variable-speed operation is the ability to limit the drive train torque to a specific level by allowing the rotor to speed up to respond to wind gusts. For constant-speed wind turbine operation, angular velocity is constant since it is tied to the grid frequency, and the torque varies with the wind speed. However, for VSWT operation, both the angular velocity and the torque can vary which allows another degree of freedom, and makes it possible to both operate close to the maximum Cp and limit the drive train torque loads.

Other benefits of variable-speed operation include power smoothing, voltage and frequency control, reactive power control, and harmonic control. Because power electronic converters can prevent unwanted current fluctuations from entering the grid, the power output from a VSWT is much smoother than that from a constant-speed turbine. As the number of machines increases, the power output becomes even smoother. Plant operators can direct the turbines to vary their output to address fluctuations in either voltage or frequency. For instance, if grid voltage drops due to lagging reactive power, variable-speed machines with power electronic converters can supply leading reactive factors to compensate, and thereby raise the voltage. Since reactive power is available whether or not the wind is blowing, this form of voltage control is available at all times. However, to assist in frequency control, the turbines must be operating.

Variable-speed wind turbines with power electronic converters can deliver real and reactive power in combination up to the full rating of the turbine. At full-power operation, the power factor control limits usually range between 0.9 leading and lagging. Such reactive power control can reduce the need for operating load tap changers and other voltage control equipment. At the point of connection to the distribution system, wind turbines incorporating variable-speed technology can deliver a current waveform of very good fidelity and with few lower order harmonics. Low harmonic distortion that complies fully with IEEE 519 specifications is usually the result of high switching frequencies in the power electronic converters. In many cases, no traditional filters are required in addition to the power electronic converter to achieve good power quality.

Direct-Drive Generators

Direct-drive generators are used in variable-speed wind turbines designed by Germany's Enercon, as well as in other new wind turbine designs developed by Northern Power Systems in the United States. The generator uses a multipole design similar to the generators used in hydroelectric plants, which allows it to operate at a lower speed than the induction generators used in most commercial wind turbine designs. This makes it possible to couple the generator directly to the turbine rotor and thus eliminate the gearbox required for high-speed induction generators. Elimination of the gearbox reduces the weight of the wind turbine and the structural requirements of the tower, and also avoids the outages associated with gearbox bearing, lubrication, and gear wear problems that are typically significant contributors to turbine downtime.

With respect to offshore application of direct-drive generators, the reliability benefit of having no gearbox is offset by concerns surrounding the susceptibility of the open windings to a salt spray environment. Also, wound generators tend to be large and heavy, which offsets the benefits of design simplicity and reduced head weight that result from eliminating the gearbox.

One recent development that addresses these issues is the introduction of permanent-magnet generator (PMG) systems. Many direct-drive generators are synchronous ring generators with external excitation. These generators continuously consume 1% to 2% of the power output in generating and maintaining a magnetic field. The loss is attributed to the large diameter (up to 10 m) of ring generators. An advantage of PMG over external excitation designs is higher flux density at the poles, expressed in W/m^2. Therefore, PMG designs can be lighter and more compact for the same capacity range, and, because there is no external field excitation, less heat

is generated. This results in lower cooling demand and allows for the use of a fully enclosed generator. PMG designs are slightly more expensive to manufacture than external excitation systems but make up for their higher cost with higher efficiency during part-load operation.

Another recent PMG design approach to direct-drive generators is the use of high-voltage dc (HVDC) systems, which can contribute to lower operation and maintenance costs and increase generator reliability—an especially important consideration for offshore applications. HVDC also allows wind farms to be economically connected directly to large national grids.

3.4 Technology Trends and Status

Development of wind turbine technology continues for several distinct markets, including remote and village power applications, distributed generation, and large-scale wind farm applications for both onshore and offshore projects. For utility scale wind applications, two major goals are driving turbine equipment design: 1) reducing levelized cost of energy (LCOE), and 2) improving grid integration and power quality.

Key trends in the design of mainstream, commercial turbines are described in the February 2005 wind energy technology review published by Renewable Energy World [40].

3.4.1 2005 and 2006 Industry Trends

During 2005, key wind technology highlights included continuing advances in turbine size and technology and the acquisitions of Horizon Wind Energy (formerly Zilkha Renewable Energy) by Goldman Sachs Group, SeaWest Holdings by AES Corp., and Atlantic Renewable by PPM Energy. In addition, 2005 brought two initial public offers (IPOs) for Suzlon Energy of India and Clipper Windpower, which is based in the United States. Separately, GE Power Systems continued to develop its position as a leading supplier of wind turbines worldwide, even though GE's 2005 market share lagged Vestas, Gamesa, and Enercon's total 68% share.

MW-size turbines continue to increase in scale and now dominate the commercial market, comprising a 75% share. Three turbines larger than 3 MW are now commercial: the Vestas 3 MW and GE Wind's 3.2/3.6 MW units. GE Power Systems completed testing of seven 3.6 MW wind turbines installed in 2003 at the Arklow offshore project in the Irish Sea. The original design had a 104 m rotor, and the design has been optimized and is now offered as the 3.6sl Offshore turbine with a 111-m rotor. None of the 3.6 MW GE turbines were delivered to the market, however, in 2005. In addition to GE's flagship 1.5 MW turbines which have reached about 3300 units, the company began production of its new 2.x line of turbines in 2004 after testing a 2.5 MW prototype at the ECN test facility in the Netherlands. The company expected to install a 2.3 MW prototype at another site in the Netherlands during 2005.

A number of major manufacturers are now testing prototypes in the 5.0-MW range for offshore applications, including Enercon, REpower, and Multibrid.

Enercon reported in April 2005 that they had fully tested the fourth prototype of the E-112 direct-drive wind turbine at 6 MW nominal output at Emden, representing a 33% increase in output vs. the first E-112 rated at 4.5 MW. Both prototypes are fitted with the same 12-m diameter ring generator.

RE Power's 5M 5-MW turbine is fitted with a 126-m two-blade rotor and a conventional drive train with main shaft, three-stage gearbox, and a six-pole doubly-fed generator. The first two turbines will be supplied to the Beatrice offshore wind farm, in 40-44-m depth water, 25 km off the east coast of Scotland.

The 5-MW Multibrid M5000 turbine was developed by Aerodyn Energiesysteme of Germany. The turbine design uses a very compact integrated slow-rotating drive train. It consists of a single main bearing, single-stage gearbox, and a medium speed (58-147 rpm) synchronous permanent magnet generator. The company expects to test the first four prototypes on land during 2006 and 12 more at an offshore project during 2006 and 2007.

During 2007, it is anticipated that the industry will continue its consolidation, prototype testing, and product optimization activities and the high demand for wind turbines and related equipment and higher steel prices will continue to increase the cost of wind turbines into 2007 vs. 2004 prices.

Table 3-3 summarizes new wind turbine prototypes and upgrades announced during 2005.

Cost Reduction and Efficiency Improvements

To reduce levelized cost of energy (LCOE) over the typical 20-year certified turbine life, turbine manufacturers are working to decrease capital cost per kilowatt of installed capacity, improve energy capture efficiency, and lessen operation and maintenance (O&M) costs. The most visible trend over the past decade has been the drive to capture scale economies by increasing turbine capacity. In 1996, the nameplate ratings of new installed turbines ranged between about 300 and 600 kW worldwide and was about 500 kW in the United States. In 2005, small wind turbines (<750 kW) contributed only about 4% of new capacity. Wind turbines in the 750-1500 kW range contributed about 48% and MW-Class (1501 – 2500 kW) and Multi-MW Class turbines (>2500 kW) contributed the remaining 48% of new wind capacity. In addition, the market shares of MW-Class and Multi-MW Class turbines respectively increased from about 30% to 46.4% and 0.6% to 2.4% between 2002 and 2005.

However, current 1.5-to-1.8-MW model turbine nacelles have reached practical size and weight limits for land based wind projects, above which transportation and erection costs can increase rapidly.

Table 3-3
Wind Turbine Prototypes and Upgrades Announced during 2004 (Source: Renewable Energy World, February 2005)

Make and Type	Capacity (kW)	Rotor diameter (m)	Remarks
Ecotechnia 100	3000	100	
Fuhrlander FL 2500	2500	90	License product[e]
GE 1.5 xle	1500	82.5	New gearbox & blades
GE 2.3	2300	94	GE 2.5 MW in 2004
GE 3.6sl Offshore	3600	111	Upgrade
Leitner 1.5 MW	1500	na	Direct Drive PMG
Leitner 1.35 MW	1350	na	Direct Drive PMG
Mitsubishi MWT 92/ 2.4 MW	2400	92	VS & RCC versions
Nordic 2300	2300	90	Two blades
Nordic 3000	3000	90	Two blades
Scanwind 3000 xx	3000	na	Direct drive[b]
Suzlon S.52/600 kW	600	52	
Vestas V100-2.75 MW	2750	100	
Vestas V100-3 MW	3000	100	
Vestas V120-4.5	4500	120	

Nacelles for turbine ratings above about 2 MW must be transported in pieces and reassembled on site, which increases cost and subjects critical components to possible contamination. Blade lengths are also reaching the point where specialized transportation is required. Regarding installation, current turbine models up to 1.8 MW can be installed on towers up to 70 m in height at most sites using 500-ton crawler cranes with luffing boom attachments. In the United States, cranes of this size are broadly available. Heavier nacelles or taller towers will often require much larger cranes that have a much lower availability, adding substantially to costs and logistical difficulties. In Europe, larger cranes are more broadly available. For offshore installations, transport, crane size, and weight limitations are not applicable.

Accordingly, turbine manufacturers are working toward reducing top head weight through changes in design and materials. As an example, Vestas is continuing to test and has received several orders for a 3.0-MW turbine that maintains essentially the same envelope size and weight specifications as its current 1.8-MW model. The first Vestas 3.0 MW turbines in the U.S. were installed by Sacramento Municipal Utility District during 2006. GE's new 2.3-to-2.7-MW turbine models, currently in the prototype phase, are also expected to fall within similar size and weight limits. These new 2.0-to-3.0-MW range turbine models and others are expected to reduce equipment capital cost per kilowatt by approximately 10% over existing models.

Many new turbine models incorporate features meant to reduce O&M costs. Due to strong equipment availability histories and improved statistical performance tracking and monitoring, several leading manufacturers have reduced recommended scheduled maintenance visits from twice to once per year, per turbine. Larger turbines are incorporating on-board cranes capable of raising and lowering major components such as gearboxes and generators for repair or replacement. Without this feature, a large construction crane must be mobilized to the site for such repairs at costs often approaching $100,000 per visit.

Turbine manufacturers are also making major strides in improving the efficiency of energy capture for different types of sites. Turbine blade length and the ratio of swept area to generator capacity is increasing substantially with current model turbines, facilitated by improvements in airfoil shape and incorporation of lighter carbon fiber composite materials into blades. These higher ratios allow greater energy capture and are appropriate for lower wind sites, but can cause unacceptable torque loads at higher wind sites. Current turbine models are now frequently offered with a range of rotor sizes so that the ratio of swept area to generator capacity can be optimized for site wind conditions. Turbines have been delivered with rotors up to 126 m in diameter.

Taller turbine towers take advantage of wind shear, resulting in higher turbine capacity factors at the same turbine location. The average tower height for new turbines in the United States is currently 65 to 80 m, and 100 m and higher towers are sometimes used. However, taller towers add significantly to both delivered and installed tower cost and typically require either high wind shear or relatively high energy pricing to be cost-effective. In Europe, where large government price supports are common for wind power and maximizing output is highly valuable, turbine manufacturers are offering towers as high as 120 m for new models. Electrical efficiency is also improved by mounting step-up transformers in the nacelle versus placing them on the ground at the base of each turbine, thereby eliminating losses associated with low-voltage cabling run along the length of the tower.

Regarding power quality and grid integration, many turbine models are being offered with features that provide active VAR or voltage support, as well as disturbance ride-through capability to facilitate wind development on weak grids. This represents a major advancement over earlier turbine models, many of which were characterized by VAR consumption, high in-rush currents at start up, and poor ride-through capability.

Evolving New Technology

Clipper Windpower of Carpenteria, CA developed its 2.5 MW Liberty Series wind turbine design for low-wind speed applications under public-private partnerships with the U.S. Department of Energy and the California Energy Commission.

As shown in Figure 3-6, the turbine drive train consists of a forged steel main shaft integrated with the gear housing and bull gear that drives four permanent-magnet generators arranged around the housing. This configuration eliminates the conventional three-stage gearbox and spreads the torque loads across the four pinion gears. Other benefits included reduced weight per kilowatt of capacity, longer life, compact size, and quieter operation. Due to the modular design, individual generators and other components can be removed for repair or replacement and lowered to the ground by the integral crane-winch drive in the nacelle. In addition, the turbine can continue to operate during a generator outage. As a result, the turbine is expected to exhibit reduced downtime for maintenance, lower availability and energy losses, and lower O&M costs than conventional turbines of the same rated capacity.

The drive train is matched with advanced power electronics allowing for variable speed operation and providing full power quality management capability. The turbine is offered with three rotor diameters to match the wind speed class at the site, 89, 93, and 99 meters for Classes I, II, and III, respectively. Additional information and turbine specifications are available at http://www.clipperwind.com/pdfs/WebBrochure.pdf.

In early 2005, Clipper broke ground to install the first prototype 2.5 MW Liberty Turbine at Platte River Power Authority's Medicine Bow Wind Project near Medicine Bow, WY. In addition, the company set up a manufacturing plant in Cedar Rapids, Iowa to build the wind turbines for commercial projects. The company also plans to develop a marine version of the 2.5 MW Liberty turbine for the European offshore market.

3.4.2 Turbine Technology Trends

Table 3-4 is a technology process development "map" for wind turbine power generation. Forecasts suggest that near-term improvements in performance and cost for turbine designs that are already commercial will be derived from increased rotor diameters, improved scale economies, lighter weight designs, refinement of direct-drive generators, improved controls and power conversion technology, and higher towers. Given 8.5 m/s average hub height wind speeds, commercial turbines can already deliver energy at busbar power costs in the competitive range of 3 to 5 cents per kWh, including government incentives. However, the recent 15% to 20% cost increases for wind turbines and related equipment resulting from high demand and increasing steel prices will affect the energy costs. These costs should continue to drop, albeit more slowly, as conventional designs continue to be refined. Longer term, advanced new designs may lead to more pronounced cost improvements.



Figure 3-6
Clipper Windpower's 2.5 MW Liberty Series Wind Turbine Nacelle, with Four Modular Permanent-Magnet Generators and Integral (Source: Clipper Windpower Inc.)

Table 3-4
Technology Process Development Map: Wind Power Plants

	Constant-Speed Wind Turbines	Variable-Speed Wind Turbines	Direct-Drive Wind Turbines	Advanced Wind Turbines
Features and Advantages				
Technology Characterization	Tubular rolled steel tower. Off-the-shelf gearbox and induction generator. Digital controls and SCADA system.	Tubular rolled steel tower. Double high-speed gearbox shaft. Off-the-shelf induction generator. Digital controls and SCADA system.	Tubular rolled steel tower. No gearbox, reduced cost. Low-speed direct-drive generator. Improved controls and SCADA.	Tubular steel or composite tower. No conventional gearbox. Advanced low-speed direct drive or multi-generator drive. Advanced controls and SCADA.
Efficiency	Limited by fixed generator speed.	Slightly greater due to variable generator speed.	Slightly greater due to variable generator speed.	Slightly greater due to variable generator speed.
Resources	Remote sites w/ PNL Class 4 or greater wind speed near transmission lines.	Remote sites w/ PNL Class 4 or greater wind speed near transmission lines.	Remote sites w/ PNL Class 4 or greater wind speed near transmission lines.	Remote sites w/ PNL Class 3 or greater wind speed near transmission lines.
Challenges and Disadvantages				
Cost	Design for fluctuating torque load increases cost.	Full-span pitch control and power electronics increase cost.	Weight and cost of low-speed generator offset by absence of gearbox.	Optimize design to minimize cost.
Operation	Fatigue failure of parts due to fluctuating wind and torque loads.	Complexity of full-span pitch controls increases maintenance cost.	Durability of low-speed turbine under fluctuating loads.	Optimize design to minimize O&M cost and maximize reliability.
Technology Needs	Design for extreme loads to handle wind gusts.	Solid-state power electronics.	Low-speed generator design, new control system.	Optimization for reliability and low cost.
Markets				
Key Issues	Structural and load-bearing component reliability. Cost of energy. Moderate cost reduces prospects in competitive market.	Complex control system and power electronics, component reliability. Moderate cost reduces prospects in competitive market.	Complex control system, power electronics, cost and reliability of new generator. Lower cost improves prospects in competitive market.	Reliability, cost of energy. Low cost likely to result in significant market.
Impact on Technology Outlook	Established and mature: dominant market share in U.S.	Established: Enhanced performance leading to growing market share worldwide.	Maturing: reduced cost would improve worldwide market.	Emerging: low cost would result in large worldwide market.

3.5 Cost and Economic Issues

The principle issue is the recent increase of the installed wind plant cost from ca. 1200-1360 $/kW in 2005 to 1500-1800 $/kW in 2006. The cost increase is the result of the high demand for wind turbines and related equipment; a weaker dollar; and mounting commodity and energy costs. Availability losses also result in reduced power revenues. Improved designs and maintenance procedures will also reduce the cost of wind energy by improving availability and therefore wind plant capacity factors. Operating wind plants in tandem with existing hydroelectric, diesel, and other backup power resources and optimization using load and wind energy forecasting systems, will make the technology more competitive.

3.5.1 Technology Performance and Cost Tables

Tables 3-5 and 3-6 present the performance and capital, O&M, and levelized cost of electricity estimates for three wind plant rated capacities 16, 50, and 100 MW. The assumed individual turbine rating is 2.0 MW. The reference date of the cost estimates is December 2006.

The scope of the Total Capital Requirement cost estimates in Table 3-5 includes turbine procurement and transportation (wind turbines, blades, and towers), balance of plant/EPC, process and project contingencies, AFUDC, and owners costs (due diligence, permitting, legal, development, taxes and fees). The Total Capital Requirement is from 1753 to 2414 $/kW for 100- and 16-MW wind projects, respectively.

The Levelized Cost of Electricity estimates in Table 3-6 are presented for each combination of wind plant rated capacity and PNL wind speed classes 3 through 6. The scope of the levelized cost estimates includes capital, O&M, land lease and grid integration costs, and the estimates are presented both with and without the Federal Production Tax Credit (PTC). The PTC is assumed to be 19 $/MWh for the first 10 years, and zero after 10 years. The 20-year levelized value of the PTC is 10.9 $/MWh. The land lease cost is 3% of annual electricity revenues at $60/MWh or 1.8 $/MWh, and the grid integration cost is 3 $/MWh. For PNL Class 4 wind resources, the levelized cost of electricity ranges from 74.9 to 105.5 $/MWh with the 19 $/MWh PTC, and 85.8 to 116.4 $/MWh without the PTC.

Table 3-5
Cost and Performance Estimates for Horizontal-Axis Wind Turbine Power Plants (Dec. 2006 $)

Rated Capacity	**16 MW**		**50 MW**		**100 MW**	
Plant Size (number of units x unit size, MW)	8 x 2.0		25 x 2.0		50 x 2.0	
Nameplate Rating (MW)	16		50		100	
Technology Description	Upwind, Horizontal. Axis, DFIG		Upwind, Horizontal. Axis, DFIG		Upwind, Horizontal. Axis, DFIG	
Physical Plant						
Land under lease (flat, even terrain) , Acres	640		2,000		4,000	
Disturbed land area, Acres	32		100		200	
Unit Life, Years	20		20		20	
Scheduling						
Development time, Months	24-36		24-36		24-36	
Construction time, Months	6		11		14	
Capital Cost ($/kW)						
Month/Year Dollars	December, 2006		December, 2006		December, 2006	
Turbine Procurement (Advanced purchase)						
Turbine, Tower and Blades, fob factory/port	1,303		1,298		1,296	
Transportation and Freight to project site	80		75		70	
Balance of Plant/EPC						
Engineering	12		9		7	
Foundations	55		52		50	
Civil (roads, grading, fences)	115		75		50	
Power Collection System	147		95		60	
SCADA and Communications	20		10		6	
Turbine Erection	60		60		60	
Substation, Transmission, Interconnection	180		90		55	
O&M Facility, Met Towers, Sensors	30		13		9	
Construction Management	19		13		11	
Project and Process Contingency	18		12		9	
Total Plant Cost	2,039		1,802		1,683	
AFUDC (interest during construction)	0		0		0	
Total Plant Investment	2,039		1,802		1,683	
Owner Costs						
Due Diligence, Permitting, Legal, Development	375		130		70	
Tax and Fees	0		0		0	
Total Capital Requirement	2,414		1,932		1,753	
O&M Costs ($ per turbine per year)	Warranty	Out-of-W	Warranty	Out-of-W	Warranty	Out-of-W
Scheduled maintenance	80,000	80,000	60,000	60,000	60,000	60,000
Unscheduled maintenance	0	30,000	0	20,000	0	20,000
Unit Availability						
Equivalent Planned Outage Rate, %	—		—		—	
Equivalent Unplanned Outage Rate, %	—		—		—	
Equivalent Availability, %	97		97		97	
Confidence and Accuracy Rating						
Technology Development Rating	Commercial		Commercial		Commercial	
Design & Cost Estimate Rating	Simplified		Simplified		Simplified	

Table 3-6
Wind Plant Performance and Levelized Cost of Electricity Estimates (Dec. 2006 $)

PNL Wind Class	3	4	5	6
Average Wind Speed (m/s @ 50 meter measurement height)	6.8	7.3	7.8	8.4
Average Wind Speed (m/s @ 80 meter hub height)	7.2	7.8	8.4	9.0
Wind Shear Factor	0.14	0.14	0.14	0.14
Air density, kg/m3	1.09	1.09	1.09	1.09
Array and Energy Losses, %	8.0	8.5	9.0	9.0
Gross Capacity Factor, %	36.4	41.1	44.2	47.6
Net Capacity Factor, %	32.5	36.5	39.0	42.0
16 MW Project				
Net Energy Output (MWh/yr)	46,000	51,000	55,000	59,000
Levelized Energy Cost ($/MWh)				
Fixed Charge @12.5%/yr	106.0	94.4	88.3	82.0
O&M	19.3	17.2	16.1	14.9
Land Lease	1.8	1.8	1.8	1.8
Grid Integration	3.0	3.0	3.0	3.0
Subtotal	130.1	116.4	109.2	101.8
Production Tax Credit[1]	10.9	10.9	10.9	10.9
Net Total with PTC	119.2	105.5	98.3	90.9
50 MW Project				
Net Energy Output (MWh/yr)	142,000	160,000	171,000	184,000
Levelized Energy Cost ($/MWh)				
Fixed Charge @12.5%/yr	84.8	75.5	70.7	65.6
O&M	14.0	12.5	11.7	10.9
Land Lease	1.8	1.8	1.8	1.8
Grid Integration	3.0	3.0	3.0	3.0
Subtotal	103.7	92.8	87.2	81.3
Production Tax Credit[1]	10.9	10.9	10.9	10.9
Net Total with PTC	92.8	81.9	76.3	70.4
100 MW Project				
Net Energy Output (MWh/yr)	285,000	320,000	342,000	368,000
Levelized Energy Cost ($/MWh)				
Fixed Charge @12.5%/yr	77.0	68.5	64.1	59.6
O&M	14.0	12.5	11.7	10.9
Land Lease	1.8	1.8	1.8	1.8
Grid Integration	3.0	3.0	3.0	3.0
Subtotal	95.8	85.8	80.6	75.2
Production Tax Credit[1]	10.9	10.9	10.9	10.9
Net Total with PTC	84.9	74.9	69.8	64.3

[1]Federal Production Tax Credit is $19/MWh during first 10 years, zero after 10 years, and is levelized over 20-years.

The technology performance and cost estimates assume a 2.0-MW, horizontal-axis, variable-speed, variable-pitch, wind turbine technology available for commercial order in 2005. Other assumptions include 80-m hub height and 1.09-kg/m^3 air density. Economic assumptions include end-of-year 2006 dollars, 20-year constant-dollar levelized cost of electricity 12.5%/yr annual fixed charge, 3 $/MWh grid integration cost and 19 $/MWh Federal Production Tax Credit. The average wind speed for Class 3, 4, 5, and 6, wind resources are respectively 6.8, 7.3, 7.8, and 8.4 m/sec at 50-meter elevation and are adjusted to the 80-m hub height using a power law relation between wind speed and elevation and a 0.14 shear-factor exponent.

3.6 Grid Integration

3.6.1 Production Variability

While wind is an intermittent generation resource, generation output from wind farms is more stable than the term "intermittent" may suggest. Grid-connected wind farms typically have capacity factors ranging from 25% to 40% or more over the course of a year. A common misconception about wind power is that turbines are either on or off and sit dormant for much of the year. In actuality, wind turbines are capable of partial output, and most wind farms generate at some level during 70% to 90% of the year. Further, there are a number of factors that smooth the output of a wind farm relative to variations in actual wind speed.

First, wind turbines do not begin to generate power until winds reach cut-in speed, usually 4 to 5 m/s, and will generate at the rated capacity at or above the rated wind speed—typically 12 to 14 m/s. This creates a "floor" and a "ceiling" over the range of wind speeds at which wind turbine output will vary. In addition, the turbine rotor of variable speed machines acts like a flywheel, capturing the energy of sudden gusts and converting it to power more smoothly. Second, the wind at modern turbine tower heights is steadier than the winds closer to the ground. Third, geographic dispersion of wind turbines has a powerful mitigating effect on wind plant output variation. Several studies have demonstrated this fact with wind plant spread among multiple sites, but the smoothing effect of geographic dispersion also occurs within a single wind farm. Individual wind gusts are typically very local phenomena, with a breadth of 30 m or less. Since even a medium-sized project would be spread over several miles of land, individual turbines do not experience the same wind speed simultaneously and ramp up and down at differing rates.

Although variability over time due to wind speed changes can pose integration challenges, wind power generally varies less rapidly than customer demand. Experience to date has shown that at penetration levels of up to 10% to 20% of delivered total system load measured on an energy basis and for large interconnected electricity grids with no significant transmission bottlenecks, wind variability has little impact relative to the larger, shifting variability of utility system demand. In addition to systems with transmission constraints, island and other systems that are not interconnected may be affected at relatively low levels of wind penetration—especially those with low nighttime loads and combined heat and power generation. That being said, the more accurately these output variations can be anticipated and planned for, the more reliably and economically wind can be integrated into a large utility system. Alternately, energy storage and backup power generation resources at strategic locations in the electricity grid can help alleviate

some of the integration issues related to wind power. Application of energy storage and other integration technologies to wind and other renewable technologies is addressed in Chapter 10.

3.6.2 Ancillary Service Costs

In the last few years, several empirical studies have been performed in the United States analyzing the impacts and ancillary services costs of wind power plant integration into specific utility systems. Work is ongoing to establish methodologies for identifying integration costs more accurately. "Good utility practice" for integrating wind will evolve for some time. However, some initial conclusions can be drawn from work to date.

Recent studies—carried out in cooperation among NREL, other researchers, and utility operators and planners—analyze the impacts and costs to integrate wind power into several different utility systems, including Xcel Energy, PacifiCorp, and BPA. The results of the Xcel Energy evaluation are presented in the Utility Wind Interest Group report, *Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning, Excel Energy-North Case Study* (May 2003), also available from EPRI (EPRI 1004807, December 2003). The studies estimate ancillary service costs for a range of utility operations time frames including unit commitment and reserves, load following, and regulation. The methodologies vary to some extent between the studies' given differences in the wind regimes modeled, the degree of wind penetration, the mix of utility generation assets, and the cost structures. However, a common finding among all the studies is that, overall, impacts and costs are relatively low at low wind penetration levels. Total ancillary cost estimates ranged from negligible costs in the case of BPA's system, to 1-to-3 $/MWh for Xcel's Minnesota system, to a high of 5 to 6 $/MWh for Pacificorp's system to integrate 2,000 MW of wind generation—equal to nearly 20% of system capacity. A paper released in May 2003 summarizes these studies and provides references to the specific analyses [4].

Building on these studies, the California Energy Commission (CEC) sponsored a similar detailed study of the cost to integrate renewables into the state's larger power system in support of the California Public Utility Commission's (CPUC) RPS implementation efforts. The study is motivated by the RPS's "least-cost, best-fit" bid selection criterion which requires that indirect costs be considered in addition to the energy bid price when selecting eligible renewable projects. Accordingly, the three-phase study quantifies the costs of integrating various renewable technologies, including wind power. Phase I analyzes the costs to integrate existing renewables [5].

Phase II of the study identifies and analyzes the key attributes of renewable generators that affect integration cost. Phase III [http://www.energy.ca.gov/reports/500-04-054.PDF] provides a final methodology to model the characteristics and costs of renewables in California. Given the transparent and open approach of the study, broad participation, extensive data availability from the Cal-ISO, and depth of the analysis, the California study will likely serve as a benchmark for future efforts that attempt to accurately assess the integration costs for renewables, including wind power, into larger utility systems.

During 2004, two additional wind integration studies were completed in the U.S. One sponsored by the Minnesota Department of Commerce addressed the impacts of expected higher wind penetration in the future. The other, sponsored by the New York State Energy Research and Development Authority addressed the impacts of wind development on the New York State electricity system. Recent wind integration studies are summarized in the 2006 EPRI report, *Survey of Wind Power Integration Studies* (EPRI 1011883, 2006).

3.6.3 Wind Energy Forecasting and Scheduling

In recent years, the art of forecasting wind plant generation over the next zero to 48 or 72 hours has advanced rapidly. Current forecasting systems can provide system operators with information necessary to integrate intermittent wind generation in the most reliable and economic manner. Wind production forecasts can allow a system operator to schedule a wind plant's capacity and energy with some accuracy, effectively avoiding some capacity and fuel costs while maintaining reliability standards. These systems also help wind plant operators schedule turbine maintenance. Several companies and organizations in the U.S., Europe, and elsewhere in the world offer wind energy forecasting services and are providing next-hour, next-day, and extended forecasts to wind plant operators, utility system operators, and electric utilities.

Wind forecast systems integrate regional weather and project production models, utilizing real-time inputs from on-site and off-site weather stations and wind plant SCADA systems. They produce rolling output forecasts for periods of up to a month or more in advance, which can be updated as frequently as every hour. The accuracy of these forecasts increases dramatically with the proximity of the hour forecast. The week-ahead average forecast error is typically in the range of 20% of nameplate. The average error for a forecast provided 60 minutes ahead for the next hour is in the 8% range. Expected error for a forecast provided 30 to 40 minutes ahead of the next hour should be closer to 4%. These error ranges will vary depending on the specific wind regime and project layout.

During 2003 and 2004, EPRI published several reports on wind energy forecasting system development and testing at two wind plants in California and one in Texas [27, 28, 29, 30, 31]. These reports assessed the capability of current forecasting technology to predict hourly wind speed and energy generation over the next 48 hours. The mean absolute errors of the wind speed and wind energy generation were 30% to 40% and 50% to 60% of the annual average wind speed and energy generation, respectively.

During 2005, the California Energy Commission and EPRI completed development and testing of a regional wind energy forecasting system, designed to generate five-minute forecasts over a three hour period, updated every five minutes. In addition, the project evaluated improved technology for intermediate-term forecasting of hourly wind generation over a 48-hour period. The results are described in a four-volume final report published during 2006 [32, 33, 34, 35]

To date, most wind projects simply deliver energy into a utility's system on an unscheduled basis without the use of forecasting. However, wind production forecasting is increasingly being used for power scheduling purposes. Wind forecasting is now being used by the California ISO to forecast approximately 500 MW of wind generation across the state. Forecasting is also being

used extensively in the Pacific Northwest to schedule the output of individual projects, including the 300-MW Stateline project.

For utilities that are required to schedule generation with a control area operator, electronically delivered next-hour wind production forecasts can be automatically integrated into next-hour schedule modifications to minimize imbalances. As noted above, forecast error in these next-hour time frames is expected to be small and may be smaller than a utility's average control area load forecast error. Since these two errors are not correlated, the relatively small wind forecast error should make little net contribution to a utility's existing level of scheduling imbalances.

3.6.4 Regulatory Update

Although the rules governing scheduling and imbalance penalties for wind are not consistent throughout the United States, the Federal Energy Regulatory Commission (FERC) is promoting a new approach that should ease the addition of more wind capacity throughout the U.S. See Chapter 11 for discussion of the current status of these and other related topics.

3.6.5 Power Quality

In recent years, wind turbine manufacturers have placed increasing emphasis on improving the grid integration and power quality of wind turbine generators. This push is being driven largely by two factors. First, as wind economics have improved and wind power has reached higher penetration levels, expectations have increased for state-of-the-art performance and better power quality. Second, many growth opportunities for wind around the world are on weaker transmission systems where power quality is key for expansion. Slowing growth in the European onshore wind market is focusing European manufacturers on the large North American market. Unlike the European power grid, which is characterized by greater density of population, power generation, and transmission lines, the U.S. market, particularly in the West, is characterized by expansive geography and long distances between population centers and generation. Much of the wind resource is located in remote regions with access to only smaller, less robust transmission lines.

General Electric, the only major U.S. turbine manufacturer, has led the push for power quality in the U.S. market with its patented dynamic VAR system. This system regulates voltage in real time, supplying reactive power to the grid through each turbine's power electronics instead of through slower-acting capacitors or static VAR compensators. More recently, European manufacturers have developed similar systems that are just now being rolled out to compete effectively in North America.

In 2004, Danish manufacturer Vestas continued testing the V90, a 3.0-MW full variable-speed pitch regulated turbine that provides similar VAR support and ride-through benefits as the GE turbine. In 2005, the company received an order for 36 units for an offshore project near the Dutch coast. In addition to OEM-provided power quality systems, several after-market dynamic VAR support systems are available, specifically designed for use with wind generation.

3.7 Project Development Process and Market

3.7.1 Buy or Build Considerations

As wind energy costs continue to drop and utility experience with purchasing wind energy increases, more utilities are likely to consider developing, owning, and operating their own wind projects. Two important initial considerations are project scale and capital intensity. As is discussed in Section 3.5.1, wind project costs decline rapidly with project scale. In Class 5 and 6 wind regimes, projects of 100 MW and larger can typically deliver energy at costs below competing new thermal generation. However, at smaller scales, this advantage can quickly disappear. Smaller project costs are driven up by pre-development, financial transaction, and construction mobilization expenses that typically remain relatively flat regardless of project size. Also, wind projects are capital intensive, typically coming in near $1,150/kW before 2005 (now $1,500 to $1,800/kW) installed for a 100-MW project. For utilities that must carefully allocate capital across many competing uses, entering a power purchase agreement with a wind developer may provide more strategic benefit than committing to wind plant ownership.

For utilities that are interested in investing in a wind project, the question of balancing cost management and risk must be addressed at each project development stage. The pre-development stage is high risk. Pre-development companies typically invest up to a half million dollars into site pre-screening, resource assessment, land and easement acquisition, environmental review, and permitting on a specific site before viability can be determined. Generally, about one in four sites clears all required hurdles and demonstrates resource quality sufficient to produce energy in the target cost range. The high levels of in-house expertise maintained by experienced pre-development companies and consultants helps to reduce pre-development risk and improve the probability of identifying and successfully developing sites with the optimal resource in any given area. Utilities choosing to take on the pre-development task can avoid the significant fees charged by pre-development specialists for “packaged” sites, but may expose themselves to a high probability of project failure or disappointing results. Utilities may also hire experienced consultants to guide the pre-development process and manage sub-tasks in disciplines unfamiliar to utility personnel, thereby reducing risk.

3.7.2 Project Development Process

The vast majority of wind capacity on-line in the United States has been developed, financed, built, and operated by wind independent power producer companies, with the energy being sold under long-term power purchase agreements with utilities. This arrangement stems from the complexity of wind project development and project operation. Specialized activities require expertise across a range of disciplines, a number of which do not fall within the areas of expertise of typical electric utilities. In addition, equipment procurement and operations are subject to substantial economies of scale. A small but growing portion of U.S. wind capacity is owned and operated by utilities. Much of the utility-owned facilities have traditionally comprised small wind installations with less than five turbines and been operated by municipal and public utilities. However, large-scale. Multi-MW utility wind ownership is on the upswing. MidAmerican Energy recently completed a 310-MW project in its Iowa territory, and intends to embark on future projects totaling 545 MW. Other investor-owned utilities—including

Oklahoma Gas & Electric, Kansas City Power & Light, Puget Sound Energy, WE Energy, and Nebraska Public Power District—have either already invested in or have announced plans to own and develop wind projects.

Pre-Development Activities

The project development process falls into three distinct stages: 1) pre-development; 2) engineering, procurement, and construction (EPC); and 3) operations. Primary pre-development tasks include resource assessment, transmission access evaluation, land acquisition, permitting, pre-engineering/costing, marketing, and sometimes, finance.

Wind resource quality can vary significantly from site to site. Obviously some locations are windier than others, but even within a known wind resource area, the wind resource can vary substantially between adjoining land parcels, depending on topography. This is further complicated by the fact that for a given site, wind resources generally exhibit seasonal, diurnal, and hourly variations. Accordingly, optimizing site selection for resource quality is perhaps the most important and difficult pre-development task. Wind resource quality is characterized by wind speed and direction—typically expressed as frequency distributions, the wind shear or variation of wind speed with elevation, and the turbulence intensity.

Prior to final site selection, the wind resource is measured for an extended period of time—at least one year, and usually two to three years—to statistically quantify the resource. If the data collected show a high correlation to a nearby meteorological tower with a longer operating history—at an airport, for example—a shorter period of data collection may be acceptable.

A meteorological tower or mast is erected at one or more locations to continuously measure wind speed, direction, temperature, and sometimes, other weather parameters. The measurements are made at multiple elevations above the ground (typically 10, 30, and 50 meters) to allow the wind shear to be estimated. As a rule of thumb, meteorological tower height should be at least two-thirds the planned turbine hub height.

The recent trend toward turbine towers 80 m and taller will likely engender broader use of new 60 m meteorological towers and SODAR, sonic detection, and ranging technology that uses sound to passively profile the vertical shear from the ground up to several hundred meters. The resulting data are stored on site by a data logger and periodically downloaded on site or remotely by modem. Data are analyzed to resolve erroneous values; and calculate average wind speeds, directions, and temperatures over annual, seasonal, monthly, and hourly time intervals. The information is often expressed in wind speed frequency distributions and wind roses, which graphically show the relative frequency of wind speed and direction, and wind energy.

Most regions of the United States have specific locations where significant wind resources exist, especially on mountain passes, ridges, and coastal areas near oceans and large lakes. Figure 3-7 shows the distribution of wind power in the United States. Wind speed class characterizes the wind resource, with the darkest areas representing high-speed Class 7 winds and the lightest representing low-speed Class 1 winds. In the last few years, more detailed wind maps have been generated for most of the country that show the wind resource distribution in finer detail than

was available in previous maps. A listing and web links to these updated wind maps is available from the DOE at http://www.eere.energy.gov/windandhydro/windpoweringamerica/

For cost-effective wind power generation, a wind power plant must be located at a site with high wind speeds and must use reliable, efficient wind turbines. Generally, Class 3 is representative of a low-to-moderate wind resource and Classes 4 through 6 are considered to be the most desirable for commercial wind projects.

Site selection is typically an iterative screening process where the pros and cons for a large number of potential sites are evaluated with increasing levels of scrutiny until the highest viability site or sites are selected for further pursuit. Pre-engineering, costing, and output projection also include many variables and components that are unique to wind generation and require specialized knowledge.

In today's market, the wind project pre-development stage is often conducted by small, regionally-,focused, independent wind pre-development companies that actively seek out sites and, in turn, sell a completed pre-development package to large energy companies that self-finance, build, own, and operate multiple wind projects. A completed pre-development package typically includes: fully-documented wind resource studies, land leases, land use entitlements (permits), an interconnection agreement, and a power purchase agreement. The build, own, operate (BOO) companies typically also maintain in-house pre-development groups that actively seek and pre-develop sites and market output to utilities or other buyers.

Engineering Procurement and Construction Activities (EPC)

At the EPC stage, there is also a range of cost and risk considerations that should be evaluated. Wind generation technology and associated power management equipment is fully commercial but still evolving rapidly. Advances are made annually in improving project engineering, layout, equipment, and material choices. Accordingly, to achieve optimal project performance, engineers with substantial and current wind generation experience should be utilized.

During the 1980s and 1990s, most wind projects were developed by independent pre-development companies that also managed EPC tasks and project finance, tapping financial markets for debt and equity. However, over the past several years, large utility or oil and gas company affiliates have consolidated dominant wind development market share using a balance sheet finance approach. The independent project finance model may re-emerge in the later half of this decade as the broader financial markets recover their confidence in electricity generation investments.

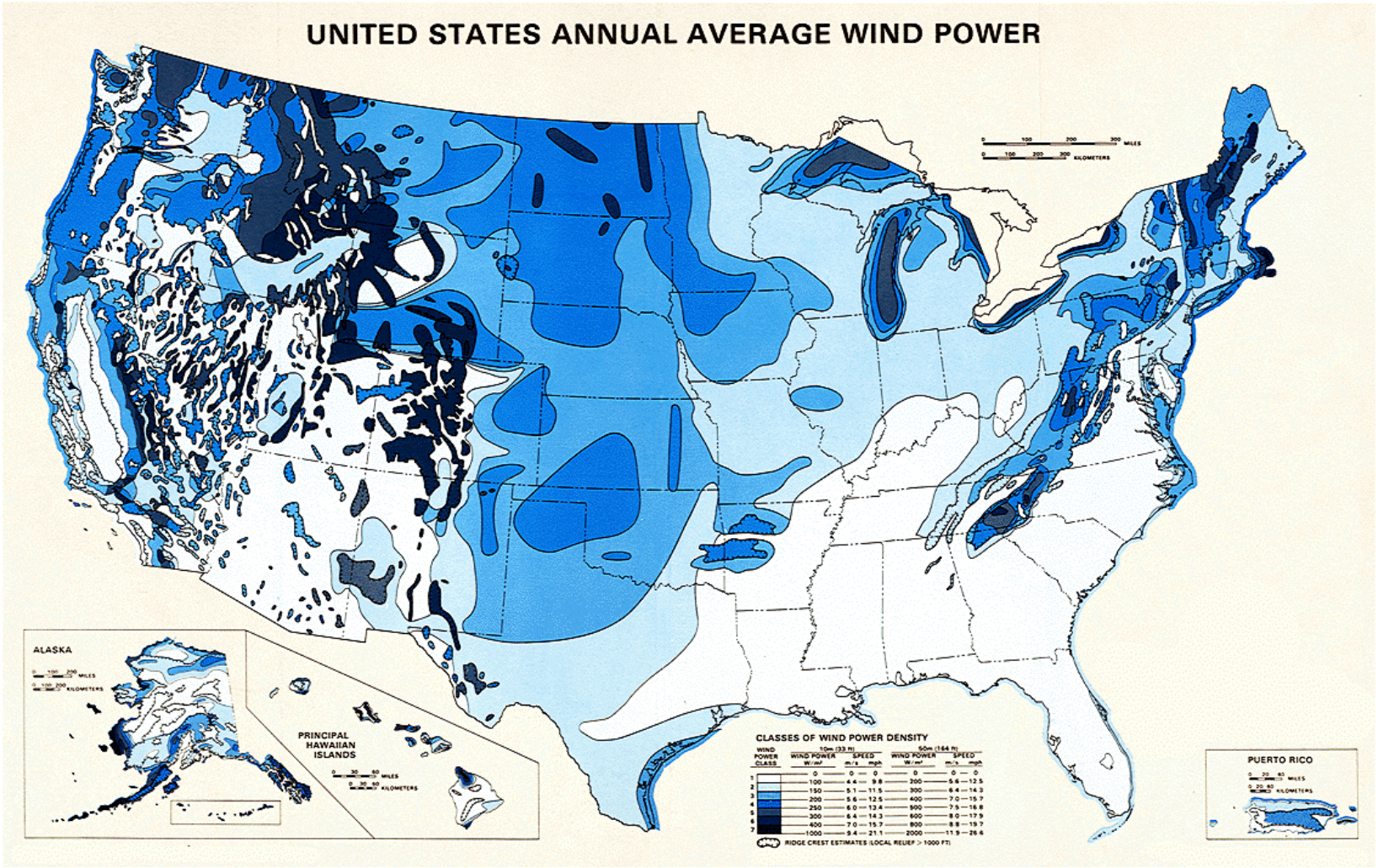


Figure 3-7
Distribution of Average Wind Power in the United States. Source: Renewable Resource Data Center

At the procurement level, economies of scale in purchasing can be important. Large wind BOO companies often maintain multi-year bulk purchasing agreements with major equipment vendors, which can allow them to gain the pricing benefit of very large purchase orders and spread them across numerous projects, both large and small. Utilities and developers purchasing equipment and services for single projects do not have this advantage. Nevertheless, the wind turbine market in the United States is extremely competitive and has the benefit of a diversity of high quality manufacturers all competing to increase market share. Turbine equipment, which typically accounts for approximately 75% of total project cost, can often be purchased in smaller volumes at competitive prices, particularly if the purchaser can allow for flexible lead times. Purchase order timing is important because the supply/demand balance in the U.S. turbine market can be subject to discontinuities related to tax incentive deadlines. Also, long lead-time orders allow turbine manufacturers to order major turbine components for just-in-time delivery, saving inventory costs.

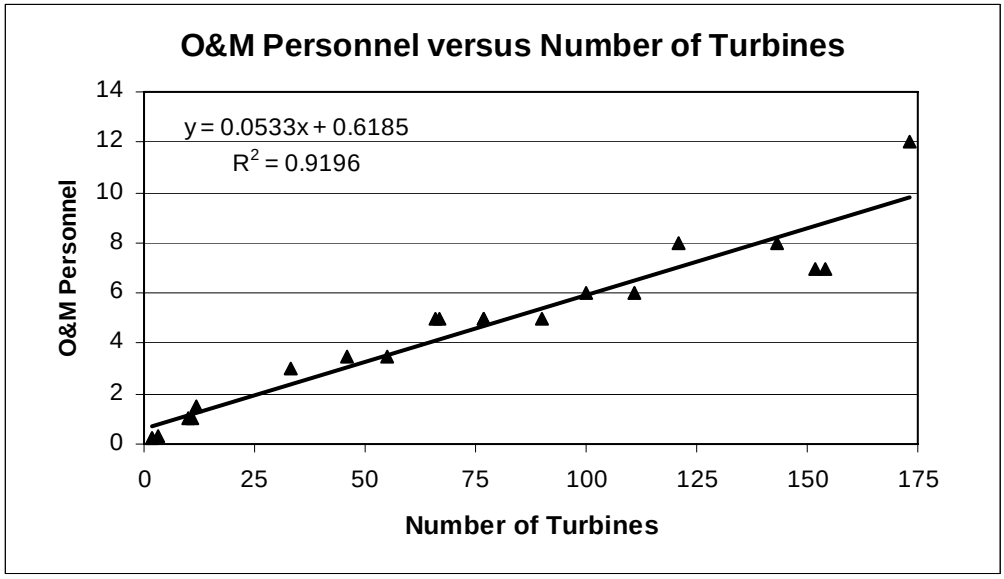
Regarding construction, wind projects are highly modularized and the major tasks of pouring foundations and erecting turbines can be accomplished very efficiently in a production line manner, as long as the work is properly staged, equipment deliveries are timely, and weather is cooperative. Typically, crews can erect one turbine per day. Large projects may employ multiple crews. This allows even very large wind projects in the 200-MW range to be completed within six months from first ground breaking to commercial start-up. However, because high crane work and regular crane movement are major components of the job, excessive wind, rain, snow, or other *force majeure* events can cause substantial delays and cost overruns. Accordingly, allocation of construction risk should be a key consideration when evaluating a “buy or build” decision.

Operation and Maintenance Activities

Wind project operations and maintenance are following the trends in other generating technologies and are becoming increasingly systematized. More sensors are being used to gather statistical performance data on turbines and subcomponents and around-the-clock remote monitoring is becoming the norm. Wind turbine manufactures typically offer full-wrap warranty service contracts for up to five years and on-going support and service relationships are available from both turbine manufacturers and wind O&M companies. Generally, current wind turbine technology is highly reliable, with the historical fleet availability for leading manufacturers in excess of 97%. Well-established turbine models typically show availability in excess of 98%. However, because wind technology is still evolving rapidly and new turbine models are being introduced annually, technology risk can be a factor.

With advanced instrumentation and SCADA systems, modern wind power plants are capable of operating unattended, and on-site labor is required only for routine scheduled maintenance and periodic troubleshooting. Figure 3-8 includes two graphs: one of O&M personnel vs. number of turbines and one of O&M personnel vs. size of facility. Both graphs include data from the TVP projects as well as a number of other commercial projects. Some of the commercial projects are based on proposals rather than actual experience; however, because the data for these planned projects did not appear to distort the results, they are included in the graphs.

The graphs show a strong relationship between the number of O&M personnel at a wind power plant and the number of turbines ($r^2 = 0.92$). Although there also appears to be a relationship between the number of people and the size of the project ($r^2=0.70$), the size of the maintenance crew is more dependent on the number of turbines than on the rated capacity of the project. This is due to the fact that, although some of the maintenance activities on larger wind turbines may require more time or different equipment to complete repairs, many maintenance activities require the same level of effort regardless of turbine size.



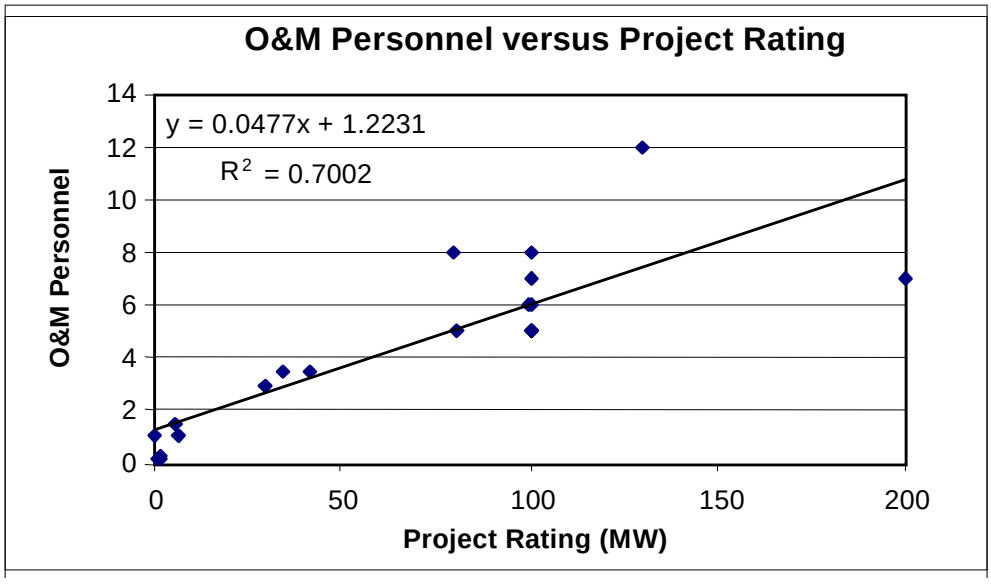


Figure 3-8
The Number of O&M Personnel at a Wind Power Plant versus the Number of Turbines and Project Rating

Wind projects benefit from the substantial federal production tax credit incentive (PTC), which was extended through 2007 by the 2005 Energy Policy Act, and then to 2008 by recent legislation. The PTC is now worth 1.9 cents per kWh for the first 10 years of production. This tax credit may or may not be useful to investor-owned utilities and is typically not useful to publicly-owned utilities. There is also a federal wind incentive for publicly-owned utilities called the REPI that is of similar value to the PTC. However, REPI funding is subject to annual Congressional appropriations and, therefore, introduces substantial risk into the public financing structure. Wind developers offering a utility a power purchase agreement typically integrate the value of the PTC into their financial structure and their power price offer.

3.8 Environmental Issues

Environmental and social issues associated with wind energy include public acceptance, permitting, land use, soil erosion, visual and noise impacts, and impacts on resident and migratory bird and animal populations. These issues are addressed in the 1999 National Wind Coordinating Committee report, *Permitting of Wind Generation Facilities* [17].

Experience in the DOE-EPRI Wind Turbine Verification Program indicates that, through vigorous public outreach and involvement programs and a proactive approach to assessing environmental impacts, it is possible to address community concerns and, ultimately, receive support and foster a sense of ownership by the community.

3.8.1 Avian and Bat Issues

Avian interaction with wind facilities became a central issue for the wind industry in the late 1980s, when bird carcasses were first reported in the Altamont Pass wind resource area in northern California. More recently, concerns endangered bat species have been raised by observations of increased bat mortality at the Mountaineer wind project in West Virginia and other wind projects.

Since numerous birds are killed each year by man-made structures such as buildings, communication towers, and bridges, not to mention cars, trucks, and airplanes, the idea that local bird populations might be affected was not new to the wind industry. However, the presence of raptor carcasses drew attention to the issue in the Altamont Pass, and the fact that the state's golden eagle population could potentially be affected raised the stakes.

In 1989 the California Energy Commission, along with the counties of Solano, Alameda, and Contra Costa, contracted with BioSystems to conduct the first extensive study of bird fatalities in the Altamont Pass. The results from that initial research were published in 1992. While it left many questions unanswered, the BioSystems study did indicate that wind turbines were indeed killing birds, particularly raptors, and in numbers significant enough to cause concern. It also marked the beginning of the debate over what has become the most contentious environmental issue to face the wind industry.

Since 1992, much more research has been done at the Altamont Pass, as well as numerous other wind resource areas, to identify the species found in each area and define their use and mortality rates; understand why raptors seem particularly susceptible to collisions with wind turbines; and identify the factors that lead to bird deaths (i.e., turbine designs, placement, geography, vegetation, and prey availability at the site; habitat encroachment in surrounding areas; and interaction behaviors such as flying, perching, hunting, etc.). To date, this body of research suggests that biological resource and risk factors vary significantly from site to site, and that results from the Altamont Pass are not necessarily representative of other sites. In fact, all research to date on sites in the United States indicates that significant bird mortality rates are only correlated with one commercial wind energy facility—Altamont Pass. However, this does not mean that the issue can be dismissed.

In 1999, the National Wind Coordinating Committee published a definitive report, *Studying Wind Energy/Bird Interactions: A Guidance Document* [16]. The report provides extensive information on designing and conducting field avian studies to better understand the risk that wind facilities create to local avian populations. If widely adopted and implemented, this report will lead to a body of research that will produce "credible and comparable results." The report stresses that, while a general protocol for conducting research should be adopted, each site must be evaluated on the basis of its unique set of parameters.

The current wind industry trend toward larger wind turbines is also considered to be beneficial to reducing the avian mortality risk at wind facilities. Relative to the small 50- to 200-kW wind turbines installed during the 1980s at Altamont Pass and other wind areas, the large wind turbines being installed today typically use taller towers and operate at much lower rotor speeds, typically 20 to 30 rpm. This may elevate the turbine rotor above the elevation of much of the avian habitat, while slower rotor speed should reduce the probability of striking birds. In addition to new wind projects, repowering projects in California are replacing large numbers of small turbines with fewer large machines, which should reduce the avian risk at existing wind projects.

The industry must continue to take this issue seriously and strive to minimize avian and bat risk at all wind facilities through ongoing research and proper siting. The National Wind Coordinating Committee continues to take a lead role in coordinating and disseminating research on biological impacts of wind farms and is an excellent resource for information on this subject [9].

3.8.2 Noise

Although wind generation facilities generate noise during both construction and operation, it is the long-term operating noise that receives the most attention during permitting. In August 2002, the National Wind Coordinating Committee issued an update to their report, *Permitting of Wind Generation Facilities,* which addresses noise characteristics, impacts on receptors, prediction and measurement, and mitigation strategies [17].

The noise produced by operating wind generation facilities is much different in both level and character from the noise generated by large power plants and other industrial facilities. It is generally considered to be low-level noise and consists of both mechanical and aerodynamic components.

Mechanical noise is typically only tonal noise at discrete frequencies, e.g., noise caused by wind turbine mechanical components, vortex shedding from blades, and unstable flows over holes or slits. Mechanical components that generate noise include gearboxes, yaw drives, brakes, and cooling fans for generators. Mechanical noise can increase as components move out of alignment and gears and bearings wear over time.

Aerodynamic noise is caused by airflow over and past the turbine blades and tends to increase with rotor speed and wind speed. It consists of three components: broadband, impulsive, and low-frequency noise. *Broadband noise* is characterized by a continuous distribution of sound pressure with frequencies greater than 100 Hertz (Hz) and is often caused by the interaction of turbine blades and atmospheric turbulence, producing the familiar "swishing" or "whooshing" sound. *Impulsive noise* typically appears as a thumping noise as the wind turbine blades of downwind turbines pass through the wind shadow of the tower. *Low-frequency noise,* in the range 20 to 100 Hz, is also associated with older downwind turbines and results from interactions between the blades and wake turbulence caused by towers and nearby wind turbines.

In general, the more the noise from a new source exceeds the background level or generates a different tonal characteristic than background noise, the more it will be unacceptable to the local community. The perception of wind generator noise by a receptor depends on the noise intensity, frequency, frequency distribution, and pattern; background noise level; proximity of the receptor to the wind turbine; terrain and vegetation between the wind generator and the receptor; and the nature of the receptor. Background noise tends to increase with wind speed and thus mask the wind generator noise. Therefore wind generator noise is generally most noticeable at lower wind speeds. If the receptor is at a location where the wind speed is lower than at the wind turbine, e.g., in a hollow or depression in the terrain, then the background noise will also be lower there. In general, a wind turbine is likely to be heard at twice the distance in hilly terrain as in flat terrain.

Although no federal and few state noise standards exist, the U.S. Environmental Protection Agency has promulgated noise guidelines. Many local governments have enacted local noise ordinances that must be considered when siting wind facilities.

The NWCC Permitting Handbook cites two proposed noise measurement techniques for wind energy systems, one prepared by the Solar Energy Research Institute (now NREL) in 1987, *A Proposed Metric for Assessing the Potential of Community Annoyance*; the other prepared by the American Wind Energy Association (AWEA) in 1989, *Procedure for Measurement of Acoustic Emissions from Wind Turbine Generator Systems, Tier 1 – 2.1.* In addition, the International Electrotechnical Commission (IEC) proposed a standard in 1988 that was rejected in the balloting process.

Turbine noise studies should include separate measurements of low frequency and A-weighted noise levels across a range of wind speeds, turbulence conditions, distances from the turbine, and locations of the receptor relative to wind direction. Preferably before the wind project is installed, background noise measurements should be conducted at representative dwellings up to one-quarter mile from the site for flat terrain, and up to one-half mile for uneven terrain. Receptors at less windy locations should be emphasized.

Several software packages are available that predict noise level profiles for the area around a wind facility. However, prediction of wind generator noise levels at a given site is difficult because conditions vary between sites. For example, the variations of wind turbulence and noise with wind speed depend on wind direction, terrain, vegetation, and other site variables and are rarely the same at two sites. Thus, the measured noise levels at one site are not necessarily representative of the noise levels that would occur at another site. Noise mitigation measures include requirements for noise setbacks of 400 to 1,000 meters from the edge of the property line; installation of sound insulation and baffles in the turbine nacelle; use of low-speed cooling fans, special finishing of gear teeth, vibration isolators and soft mounts for major components; and design of wind turbine rotors for low noise. If local residences are shielded from the wind, a larger setback may be required than in an exposed location.

3.8.3 Visual Impact

Wind projects are usually located in rural and remote areas, and their visual impacts are somewhat different from those of conventional power plants. Visual impact considerations during permitting typically focus on the impact of the wind project on the "viewshed," or visual appearance of the project setting from different locations. They include the impacts on the natural terrain and landscape; the form, line, color, and texture of the viewshed; and the visibility and appearance of landmarks in the area. In addition, the compliance of the project with public preferences, local goals, policies, and guidelines regarding visual quality is crucial toward gaining acceptance.

The elements of wind projects that affect visual impact include the relative elevations of the site and the surrounding area; the presence of dense woodland or other vegetation cover at the site; the number of wind turbines; wind turbine spacing and uniformity; height and color of the wind turbine nacelle, tower, and rotor; the type of tower used (lattice or tubular steel); markings and lighting required for FAA approval; roads built on slopes; and the locations and sizes of service buildings, substations, electrical switchgear, transmission lines, and other on-site facilities. In general, deploying fewer and wider-spaced turbines of uniform type, color, tower design, and rotational direction enhances a project's visual appearance and makes it more likely to gain public acceptance.

In a March 2003 study, the Renewable Energy Policy Project found that property values within the viewshed of recently constructed commercial-scale wind farms have not been negatively impacted [10]. The study assembled a database covering every wind development that had come online in the United States after 1998 with 10-MW installed capacity or greater. REPP then compared actual property sales records for all land within the viewshed and for a comparable community not within the viewshed. The report found that for the great majority of projects, property values actually rose more quickly in the viewshed than they did in the comparable community. Moreover, values increased faster in the viewshed after the projects came on-line than they did before. In all, 30 cases were analyzed; in 26 of them, property values in the affected viewshed increased more than those in other areas without wind turbines.

3.9 Offshore Wind Development

Offshore wind development is relatively new to the industry, but offshore wind resources are quite large and virtually untapped. Given the size of the resource and the fact that offshore noise and visual impact concerns are lower, it is likely that significant new wind capacity will be developed offshore over the next one to two decades—particularly in Europe, where the first projects have already been installed in Denmark, the Netherlands, Sweden, and the UK

As of December 2005, offshore wind capacity in Europe totaled 679 MW, and is forecast to contribute 12.5% of that continent's market by the end of 2010. In the immediate term, offshore development of between 3000 and 4000 MW has been delayed by several years, largely as a result of technical concerns and rising project costs. Increasing turbine prices have also been a factor, with some offshore projects buyers claiming to have met price increases of up to 30%. All told, global offshore capacity contributed a modest 90 MW to the market in 2005, and is expected to make-up 8.5% of the overall market. Although no offshore wind projects have been developed in the United States, four projects have been proposed in the U.S., two off the northeast U.S. coast, one off the southeast coast, and one off the Gulf coast. There is also interest in wind development in the Great Lakes region.

The rapid growth of the offshore market in Europe is driven both by the European countries' ambitious targets for renewable energy development and the declining availability of good wind sites on land, especially in Denmark, Germany, and the UK.

Offshore wind turbines offer several advantages versus onshore turbines, including higher maximum turbine ratings and economies of scale, fewer concerns about visual and noise impacts, higher wind speeds and less turbulent wind resources, and proximity to high population areas that need power [59]. Onshore, the turbine rated capacity is restricted by size and weight limits on transporting wind-turbine tower, blade, and nacelle components to the site via local highways; the load limits of land-based cranes; and site conditions such as steeply sloping terrain and unstable soil. Offshore, it is easier to transport the large components of multi-megawatt wind turbines to the site, and the size and lifting capacities of marine shipping and handling equipment still exceed the requirements for the largest wind turbines available today.

Onshore, particularly in Europe and populated regions of the United States, there may be public objections to the visual and noise impacts of wind projects. At sufficient distance from the coast—beyond three to five kilometers—offshore wind turbines are less visible under most conditions and turbine noise should not be an issue. Higher and less turbulent winds offshore result in both higher power generation per unit rotor swept area and less wear and tear on turbine components. Location of offshore wind projects near population centers reduces the distance and cost of transporting wind energy to power customers compared to remote onshore sites. On the negative side, capital and O&M costs are significantly higher for offshore sites due to higher foundation and erection costs, underwater cable connection, limited accessibility for turbine maintenance, and addition of salt-water corrosion protection to the design requirements.

3.9.1 Installed Capacity

Europe

Table 3-7 lists offshore wind projects operating in Europe as of December 2005. The 160-MW Horns Rev project, installed in 2002 in the North Sea off of Denmark, consists of 80 x 2-MW turbines and was the first large offshore wind project in Europe. Three projects were developed during 2003: the 165.6-MW Nysted Offshore Wind Farm (DK) with Bonus 2.3-MW turbines, the 60-MW North Hoyle facility (UK) with Vestas 2.0-MW turbines, and the 25-MW Arklow Bank facility (Ireland) with GE Wind 3.6-MW turbines. During 2004, a 60-MW facility with Vestas 2.0 MW turbines was developed in the UK. Also in the UK, the Crown State has launched its second round for offshore proposals, with room for 7,200 MW within three appointed areas. Several companies have applied for projects with rated capacities up to 1,200-MW. The first round awarded licenses for 18 projects, of which 12 have begun installation. One of these projects was installed during 2004, the 60 MW Scroby Sands project. Most recently, the 90-MW Kentish Flat project (UK), consisting of 30 x 3-MW Vestas turbines, was completed in 2005. Additional offshore projects are expected to be built in the 2006-2008 timeframe in Sweden, the UK, Germany, and the Netherlands. Other countries such as Belgium, Spain, and France are also considering offshore developments.

As shown in Table 3-8 and Figure 3-9, the installed offshore wind capacity in Europe is projected to grow from 679 MW at the end of the 2005 to 7,588 MW in 2010, representing an average growth rate of roughly 60% per year. All projects incorporate megawatt-class machines.

Table 3-7
Offshore Wind Farms, All Situated in Northern Europe

Location	WTG's	MW	Foundations	Year of Installation
Vindeby (DK)	11 x 450 kW, Bonus	5	Concrete caisson	1991
Lely (NL)	4 x 500 kW, NedWind	2	Driven monopile	1994
Tuno Knob (DK)	10 x 500 kW, Vestas	5	Concrete caisson	1995
Dronten Isselmeer (NL)	28 x 600 kW, Nordtank	16.8	Driven monopile	1996
Bockstigen (S)	5 x 550 kW, Wind World	2.8	Driven monopile	1997
Utgrunden (S)	7 x 1.5 kW, ENRON	10.5	Driven monopile	2000
Blyth (UK)	2 x 2 MW, Vestas	4	Driven monopile	2000
Middelgrunden (DK)	20 x 2 MW, Bonus	40	Concrete caisson	2000
Yttre Stengrund (S)	5 x 2 MW, NEG Micon	10	Driven monopile	2001
Horns Rev (DK)	80 x 2 MW, Vestas	160	Driven monopile	2002
Palludan Flak (DK)	10 x 2.3 MW, Bonus	23	Driven monopile	2002
Nysted Havmollepark (DK)	72 x 2.3 MW, Bonus	165.6	Concrete caisson	2003
Arklow Bank Phase I (IRL)	7 x 3.6 MW, GE Wind	25.2	Driven monopile	2003
North Hoyle (UK)	30 x 2 MW, Vestas	60	Driven monopile	2003
Scroby Sands (UK)	30 x 2 MW, Vestas	60	Driven monopile	2004
Kentish Flat (UK)	30 x 3 MW, Vestas	90	Monopile	2005
Total	**Number of WTGs: 351**	**679.8 MW**		

Source: BTM Consult ApS – March 2006

Table 3-8
Forecast for Offshore Wind Development 2006 to 2010

Country	Cum (MW) 2005	Installed (MW) 2005	2006	2007	2008	2009	2010	Installed 2006-2010	End 2010
Belgium	0	0	0	0	100	0	100	200	200
Denmark	398	0	0	0	200	200	0	400	798
France	0	0	0	0	0	105	0	105	105
Germany	0	0	0	0	60	240	1,300	1,600	1,600
Ireland	25	0	0	0	0	0	0	0	25
Netherlands	19	0	108	0	0	0	200	308	327
Norway	0	0	0	0	0	0	200	200	200
Spain	0	0	0	0	20	0	200	220	220
Sweden	23	0	0	182	44	270	270	766	789
UK	214	90	90	318	934	768	1,000	3,110	3,324
Canada	0	0	0	20	0	0	0	20	20
USA	0	0	0	0	0	0	430	430	430
Others	0	0	0	0	50	100	200	350	350
Total	**679**	**90**	**198**	**520**	**1,408**	**1,683**	**3,900**	**7,709**	**8,388**

Source: BTM Consult ApS – March 2006

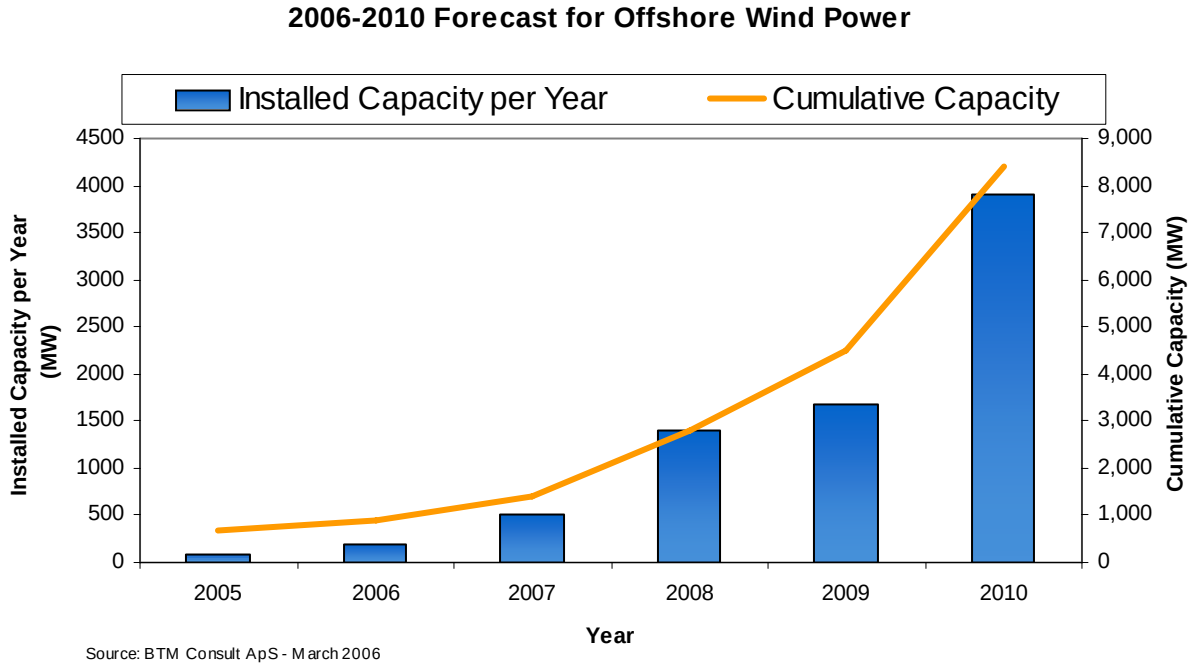


Figure 3-9
Forecast Capacity Additions of Offshore Wind Through 2010 (BTM Consult Aps).

United States

Offshore wind development is just beginning in the United States. The 420-MW Cape Wind project, proposed off the Cape Cod shore in Massachusetts, would be the first offshore wind farm in the country. The project would incorporate 130 turbines spread out over a 28-square-mile area. However, the project has faced considerable opposition, primarily by a group called "The Alliance to Protect Nantucket Sound," which believes the project would disturb fish, fisherman, and birds in the area. The group is also concerned that the presence of turbines would have a negative aesthetic impact on the natural beauty of the area. In 2003, Cape Wind Associates, the project developer, won two court challenges that sought to prevent erection of a meteorological tower offshore and proceeded to install the tower. As of October 2005, substantial wind resource data have been collected, but the developers are still trying to get approval to begin installation and development of the project.

The Long Island Power Authority (LIPA) is also pursuing an initiative to develop 100 MW of offshore wind turbines, and issued formal requests for proposals for the project in late 2002. LIPA has identified the most feasible site as a narrow band paralleling the south shore of Long Island extending from 4.8 to 10 km (3 to 6 miles) offshore in water 15 to 30 meters deep (50 to 100 feet). A preliminary assessment of the project prepared by AWS Scientific and published in April 2002 [3] concluded that a 100-MW offshore wind farm would cost from $150 million to $180 million to install and would produce energy at a cost of 6 to 9 cents/kWh. LIPA issued an RFP and selected a wind developer to install and operate the project during 2004.

During 2005, Southern Company and Georgia Tech University announced plans to conduct a one-year engineering and economic feasibility evaluation of developing an offshore wind project near Savannah, Georgia. In addition, Wind Energy Systems Technologies recently announced plans to monitor the wind resource and eventually build a 150 MW offshore project in the Golf of Mexico, seven miles away from Galveston Island, TX.

3.9.2 Offshore Wind Resource

Offshore resources differ in some fundamental ways from wind resources on land, and these differences are reflected in turbine designs for offshore projects. Offshore wind speeds are typically higher, calm periods less frequent and, because of the relatively flat surface of the sea, the wind is less turbulent and wind shear is much lower. These features translate into lower tower heights and larger generators to capture the additional available energy.

Mesoscale weather prediction models have been adapted by several meteorological consultants and organizations in the United States, Europe, and elsewhere to forecast short-term (minutes to hours) and long-term (months to years) average wind speed and wind energy generation for both individual wind projects and wind resource regions. One of the leading providers is the U.S. company, AWS Truewind, which has generated detailed wind resource maps for most of the states on the United States' east and west coasts as well as for several countries outside of the United States. Figure 3-10 is an example of a wind resource map for New England showing the predicted annual average wind speed in m/sec at 50 m elevation. Other wind resource maps are available from the AWS Truewind website at:
http://www.awstruewind.com/inner/windmaps/windmaps.htm.

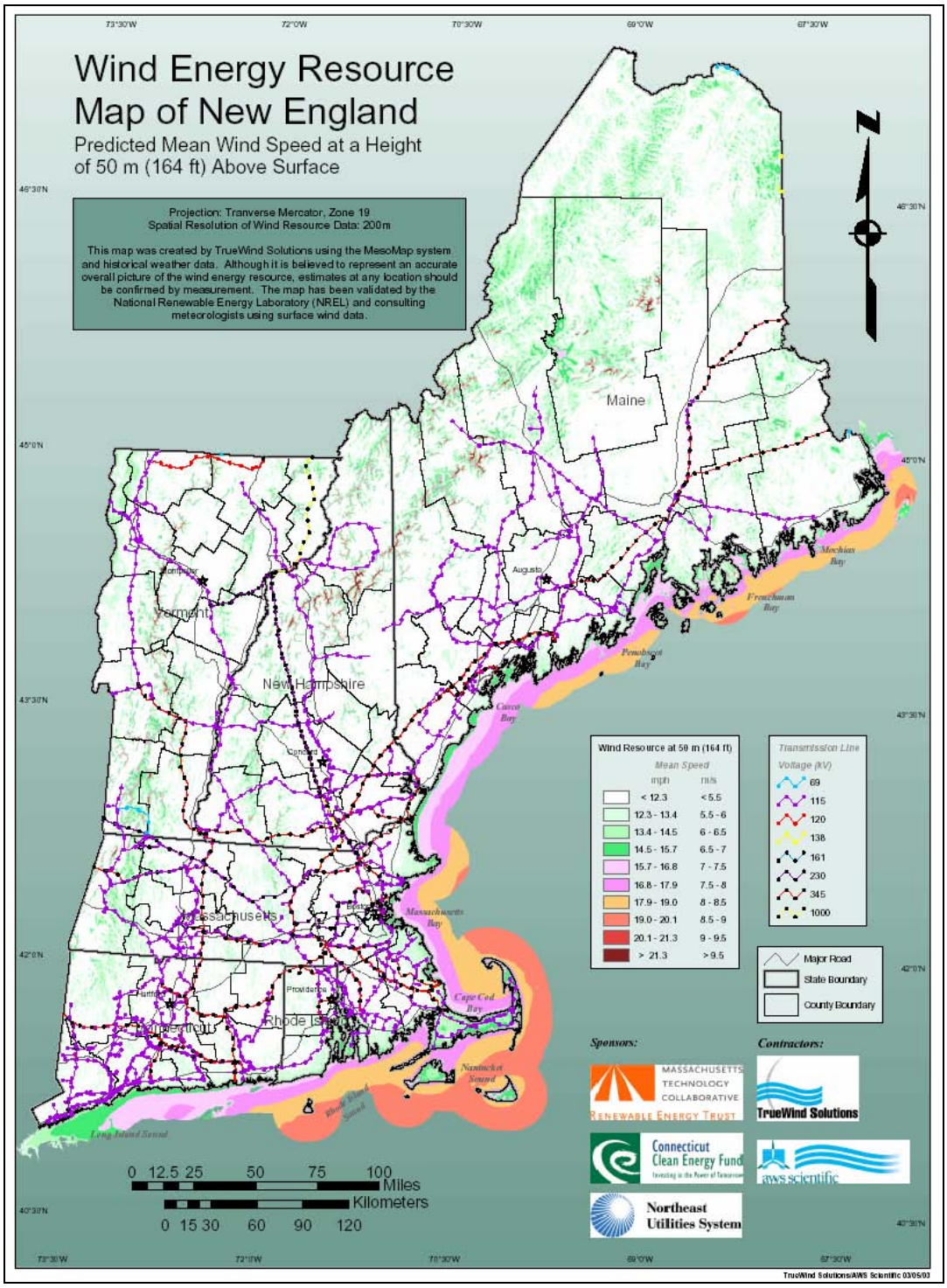


Figure 3-10
Wind Resource Map for New England Generated Using Mesoscale Weather Models (AWS Truewind, LLC)

Although mesoscale wind resource models are new and have not been fully validated, they do provide useful information on the relative strength of wind resources versus location and are considered to be more accurate than earlier boundary layer prediction methods.

Wind resource maps indicate that there are significant areas that exhibit Class 5, 6, and some Class 7 winds at distances from 5 to 50 nautical miles (nm) offshore. Table 3-9 shows preliminary estimates of the offshore wind potential for the United States generated by the National Renewable Energy Laboratory [59]. The analysis assumes that sites within 5 nm of the coast are 100% excluded from consideration due to concerns about visual impacts from onshore locations and potential damage to the rich ecosystem near shore. In addition, between 5 and 20 nm of the coast, 67% of the potential area is excluded, and between 20 and 50 nm, 33% is excluded. In both cases, the exclusions allow for environmentally sensitive areas, shipping routes, fishing, various animal habitats, and other restricted areas. The 67% exclusion for sites within 5 to 20 nm of the coast is more restrictive than that used in previous analyses of offshore wind potential.

Table 3-9
U.S. Offshore Wind Energy Resource by Region for Shallow and Deep Water [59]

Offshore Resource Estimates Resource in MW						
	5-20 Nautical Miles			20-50 Nautical Miles		
Region	Shallow <30m	Deep	% Exclusion	Shallow <30m	Deep	% Exclusion
New England	9,900	41,600	67%	2,700	166,300	33%
Mid Atlantic States	46,500	8,500	67%	35,500	170,000	33%
California	2,650	57,250	67%	0	238,300	33%
Pacific Northwest	725	34,075	67%	0	93,700	33%
Totals	59,775	141,425	67%	38,200	668,300	33%

Source: Musial, W. and S. Butterfield, National Renewable Energy Laboratory, U.S. Department of Energy, NREL/CP-500-36313, June 2004.

The total wind potential estimated by Musial and Butterfield [59] is 907 GW for both shallow (<30 m) and deep (>30m) water depths. For shallow waters, the wind generation potential totals almost 60 GW between 5 and 20 nm from the coast, and almost 40 GW more between 20 and 50 nm from the coast. Most of the shallow water potential in the United States is off the Mid-Atlantic states (New York, New Jersey, Delaware, and Virginia). The offshore wind generation potential is an order of magnitude greater in waters greater than 30 m depth, totaling about 140 GW between 5 and 20 nm from shore, and almost 670 GW between 20 and 50 nm from shore. The largest potential for deep-water offshore wind is off the California coast.

3.9.3 Offshore Wind Turbine Technology

Current Technology

Offshore wind projects installed to date are typically sited in shallow 5-m to 15-m water depths and use “marinized” conventional land-based turbine designs that have been upgraded to withstand the corrosive and severe conditions of the marine environment. In addition, due to economies of scale and the high cost of foundations and underwater electrical cables, offshore wind turbines are typically larger than their onshore counterparts. The 25 MW Arklow project off the southeast coast of Ireland has seven GE 3.6-MW turbines, and is the first project to use wind turbines larger than three-MW rated capacity. Future large offshore wind projects are likely to use even larger wind turbines.

In shallow water, the turbine towers are typically mounted on concrete bases or steel monopole foundations anchored to the seabed. Figure 3-11 illustrates three types of foundations used in shallow water. They include steel monopiles, gravity structures, and buckets. Steel monopiles are used when the subsea structure is such that the monopole can be driven into and supported by the seabed. Concrete gravity structures consist of steel monopole mounted in a massive concrete structure that rests on the bottom and is used when the subsea structure is bedrock or unable to support a monopole. Bucket foundations are large-diameter hollow steel structures that are partially driven into the subsea structure by suction and filled with soil and rock to stabilize the foundation.

Undersea cables connect the wind turbines to an offshore substation, which boosts the voltage to transmit the power onshore via another undersea cable. Power transmission to shore can be via either high-voltage ac or dc transmission line. High-voltage dc (HVDC) transmission is a new technology that may be favored for offshore projects located far offshore, because the line losses are lower than those for high-voltage ac transmission. However, dc transmission requires ac-to-dc conversion offshore and then back to ac onshore, which introduces rectifier and inverter losses.

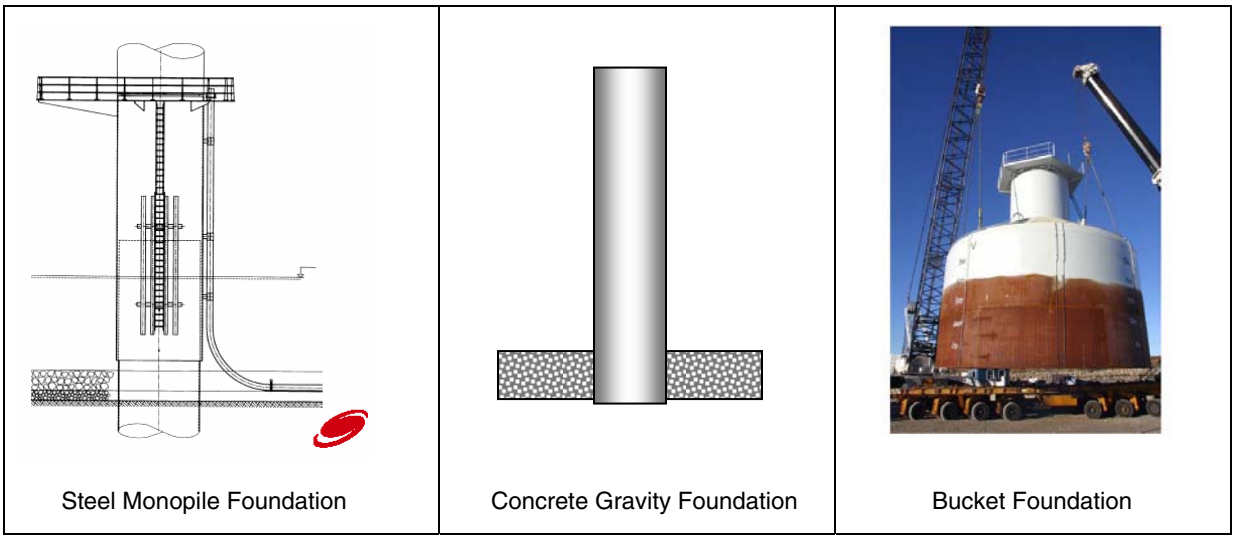


Figure 3-11
Steel Monopile, Concrete Gravity, and Bucket Foundations for Offshore Wind Turbines in Shallow Water Less than 30-m Depth (EUREC and Risoe National Laboratory [60])

An example of a recently-constructed large offshore wind project is the 160-MW Horns Rev project, located 14 to 20 km off the west coast of Denmark. Figure 3-12 illustrates the arrangement of the 80 2-MW wind turbines on a rectangular grid, with 560 m spacing between wind turbines. The turbine towers are mounted on steel monopoles and transition pieces in water depths of 6 to 14 meters (Figure 3-13). An onsite meteorological tower collects wind resource data from the site and provides average wind speed and frequency distribution data vs. wind direction (Figure 3-14). The average wind speed at the site is 9.7 m/sec and the projected annual wind generation is 600 GWh/year—equivalent to a 43% annual capacity factor at the 160-MW nameplate rating.

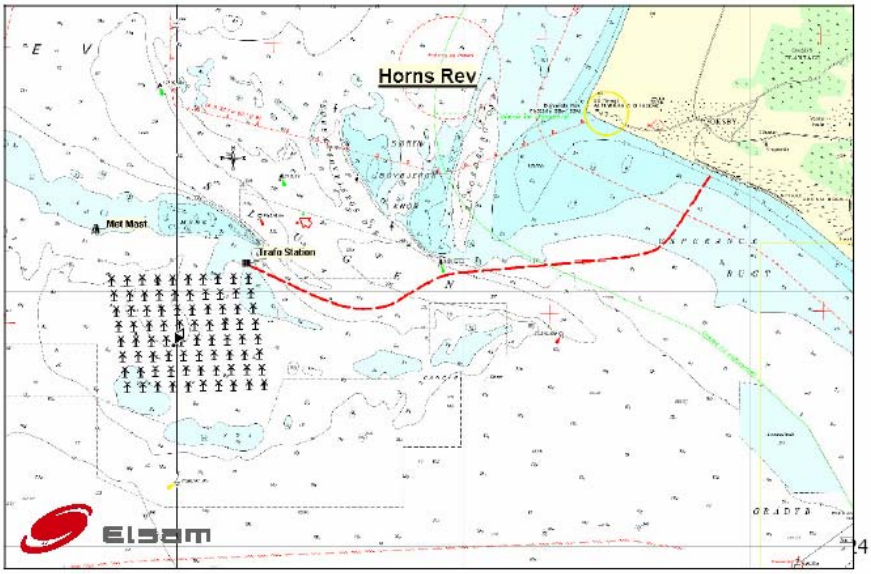


Figure 3-12
Location of 80 2-MW wind turbines at Horns Rev Offshore Wind Project (EUREC, Elsam, and Risoe National Laboratory [60])



Figure 3-13
Monopile Steel Foundation and Transition Section for Wind Turbine at Horns Rev Offshore Wind Project (EUREC, Elsam, and Risoe National Laboratory [60])

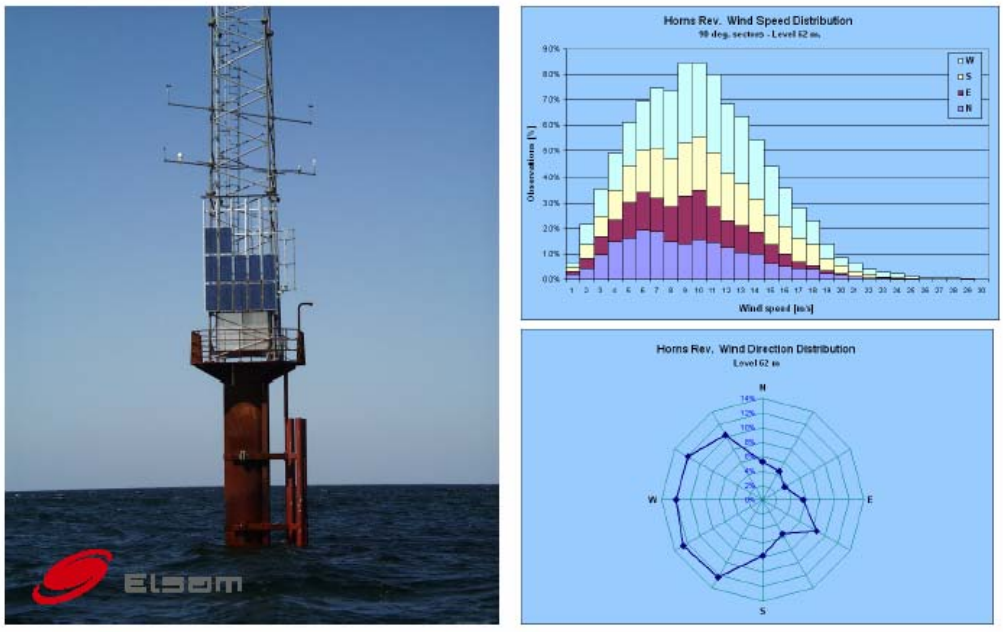


Figure 3-14
Meteorological Tower and Wind Speed Frequency Data from Horns Rev Site (EUREC, Elsam, and Risoe National Laboratory [60]).

Construction of large-scale offshore wind farms and maintaining high availability may be the most challenging task for the wind power industry over the next decade. Specific challenges include: developing foundations for offshore applications, devising smart solutions for erecting turbines, and providing sufficient equipment and tools for supporting the service and maintenance of turbines in operation.

The offshore climate represents its own challenge. In many areas, accessibility to turbines may be limited in bad weather, which can include high waves, high winds and, in some cases, ice. To address such conditions, redundant systems as well as advanced remote control and preventive operation and maintenance schemes will need to be developed and implemented.

Many potential offshore projects are planned for development in Europe through 2008, most of which are still waiting for approval of their project plans and environmental impact assessments (EIA). For offshore projects, the approval process is typically long and costly. The reason is that offshore wind power plants are a relatively new development at sea. Also, there are many different interests related to a given project site to consider, including fishing, ship traffic, bird life, marine ecology cultures existing on the sea bed, etc. Public administration of the sea area is often divided among many separate government agencies, and approval procedures are inconsistent.

Future Deepwater Technology

Due to economies of scale, future offshore wind projects throughout the world are likely to use larger turbines above the 2- to 4-MW range used today. Offshore projects in the United States and other locations outside of Europe are likely to encounter more challenging conditions, with more severe ocean wind, current, and wave conditions, and deeper water.

For water depths greater than about 30 meters, more complicated turbine foundation structures will be needed, using support cables, tripods, and truss towers for transitional water depths (30 m to 50 m) and floating foundations moored to the bottom by cables for deep water sites (50 m to 200 m). Figure 3-15 shows the expected evolution of wind turbine applications at offshore sites. Figure 3-16 shows two conceptual floating platform design concepts for deepwater offshore projects—the NREL TLP and the Dutch Tri-Floater designs [59].

At deepwater sites, the floating structure will replace the conventional steel monopole, bucket, and concrete structures used at shallow water sites. The floating structure must provide sufficient buoyancy to support the weight of the foundation, turbine tower, nacelle and rotor, electrical conversion, and underwater cable. The top of the structure should be below the water surface to minimize the impact of surface waves and swells. The mooring cables and anchors to the seabed must be designed for long life and resistance to the elements. The oil and gas industry has proven application of floating platforms for drilling and production rigs in water depths from 500 to 2,500 meters, which far exceeds the highest water depths expected for offshore wind.

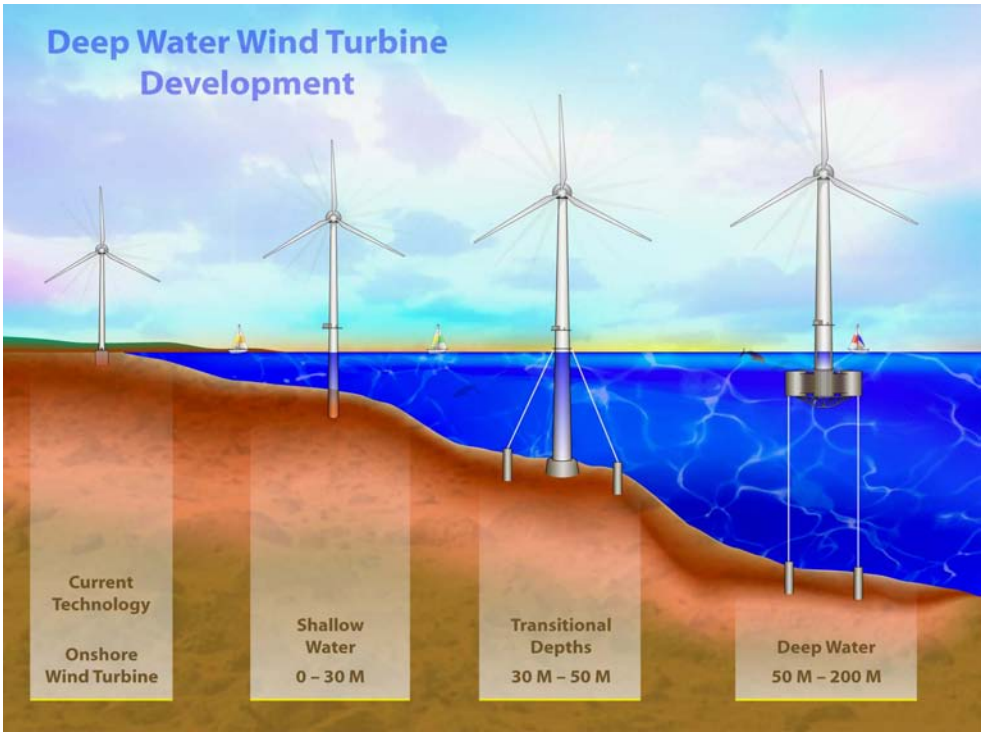


Figure 3-15
Progression of Expected Wind Turbine Evolution to Deeper Water (Source: Musial and Butterfield, NREL/U.S. DOE, 2004)

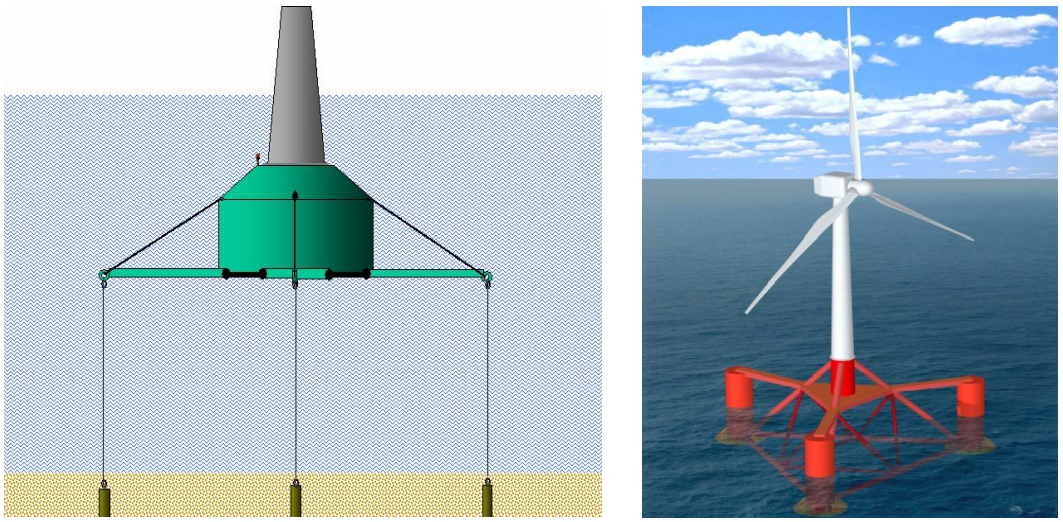


Figure 3-16
NREL TLP and Dutch Trifloater Design Concepts for Floating Wind Turbine Platforms (Source: Musial and Butterfield, NREL/U.S. DOE, 2004)

3.9.4 Capital and O&M Costs

Due to the higher costs of foundations, underwater power cables and connections, marinization, and the difficult conditions for construction, the total cost of offshore wind projects is typically 50% to 100% higher than the cost of equivalent onshore wind projects. For example, the total cost of the 160-MW Horns Rev project was 270 million Euros or almost 1700 Euros/kW, which is about 60% to 70% higher than the cost of an onshore project [57]. According to Risoe data, the project cost distribution was 48% wind turbines, 21% foundations, 14% substation and main underwater cable, 6% internal grid, 6% design and project management, 4% environmental studies and R&D, and 1% miscellaneous [60].

Higher costs for foundations, underwater cables to shore, and offshore maintenance also influence the move toward economies of scale for offshore projects. Designs for offshore applications lean toward megawatt-scale machines that use variable-pitch blades for power control rather than passive stall regulation. The higher costs of foundations, maintenance, and grid connection are at least partially offset by the more energetic offshore wind resource, shorter towers, and less turbulent winds leading to lower transient torque loads.

Due to more limited access to wind turbines when seas are calm and the more difficult marine environment, O&M costs are typically 80% to 150% higher for offshore projects than for onshore projects.

Studies sponsored by the European wind industry indicate that advances in foundation designs and the development of large wind plants in the 120- to 150-MW range will lead to electricity costs in the 4 to 5 cents/kWh range using current turbine technology. Fewer constraints on noise and visual impact are also likely to contribute to the appeal of offshore wind. In addition, initial studies conducted by Danish offshore projects indicate no significant impact on bird behavior resulting from wind farms. Clearly, more avian interaction studies will need to be conducted, but initial data are encouraging.

3.10 Equipment Markets and Key Participants

The world market for wind turbine equipment and services is growing at a high rate, and the rapid growth is expected to continue into the 21st century. According to the annual report, *International Wind Energy Development, World Market Update 2005, Forecast 2006-2010* (BTM Consult ApS, Denmark, March 2006), installed world wind capacity grew at an average annual rate of 21% per year during 2000 through 2005, and total installed capacity is expected to more than double from 59,264 MW to about 148,794 MW between 2006 and 2010. At the same time, the world turbine market is expected to grow. The cumulative wind turbine market is valued at around $53 billion over the coming five years.

The drivers for this rapid growth include growing electricity demand throughout the world, the declining cost of wind energy, and government mandates for clean energy and CO_2 emissions reduction—especially in the European Community. In the United States, the extension of the Production Tax Credit to the end of 2007 and the establishment of renewable portfolio standards in a growing number of states will continue to stimulate the U.S. market. The German Bundestag passed a new renewable energy incentive law (REFIT) in February 2000. This action is expected

to further stimulate the German market, which is currently the leading market for wind energy in the world. Similar incentives have been enacted in Spain.

3.10.1 World Markets

Table 3-10 summarizes the 10 largest wind turbine markets by country in 2003, 2004, and 2005. During 2005, the top 10 installed 9,839 MW of new capacity, which represented about 86.3% of the total world market for that year. The largest markets were in the United States (2,431 MW), Germany (1,808 MW), Spain (1,764 MW), and India (1,253 MW).

Table 3-11 presents the growth rates of installed wind capacity for the top 10 wind turbine markets in 2005. The highest 2004-2005 growth rates occurred in P.R. China (64.5%), the UK (50.3%), and India (41.8%); and the highest three-year average growth rates occurred in P.R. China (38.8%), India (35.7%), and Japan (33.6%). The 2004-2005 and three-year growth rates for the top 10 markets were 20.9% and 20.8%, respectively.

Two ongoing trends that will continue to shape the market are the increasing size of new wind turbine generators and the shift of new installations in Europe to offshore applications. The trend toward larger wind turbines is driven both by the economies of scale of larger machines and the need for larger machines in offshore applications.

Table 3-10
Ten Largest Wind Turbine Markets during 2003-2005

Country	2003	2004	2005
USA	1,687	389	2,431
Germany	2,674	2,054	1,808
Spain	1,377	2,064	1,764
India	423	875	1,253
Portugal	107	274	502
P.R. China	98	198	498
Italy	116	357	452
UK	195	253	447
France	91	138	389
Australia	50	182	296
Total	**6,818**	**6,784**	**9,839**
Percent of World	81.7%	83.2%	86.3%

Source: BTM Consult ApS – March 2006

Table 3-11
Growth Rates of Installed Wind Capacity in the Top-Ten Markets during 2005

	Installed Capacity (MW)				Growth Rate (%/yr)	
Country	**End 2002**	**End 2003**	**End 2004**	**End 2005**	**2004-2005**	**3-Year Avg.**
Germany	11,968	14,612	16,649	18,445	10.8%	15.5%
Spain	5,043	6,420	8,263	10,027	21.3%	25.7%
USA	4,674	6,361	6,750	9,181	36.0%	25.2%
India	1,702	2,125	3,000	4,253	41.8%	35.7%
Denmark	2,880	3,076	3,083	3,087	0.1%	2.3%
Italy	806	922	1,081	1,713	35.8%	28.6%
UK	570	759	889	1,336	50.3%	32.8%
P.R. China	473	571	769	1,264	64.5%	38.8%
Netherlands	727	938	1,081	1,221	13.0%	18.9%
Japan	486	761	991	1,159	17.0%	33.6%
Total "Ten"	**29,329**	**36,545**	**42,735**	**51,686**	**20.9%**	**20.8%**

Sources: *Wind Power Monthly,* BTM Consult ApS 2006

Trend to Larger Turbines

Table 3-12 shows the average nameplate ratings of wind turbine generators installed between 2001 and 2005 in eight countries. The average turbine rating was about 853 kW in 2001 and increased to about 1,368 kW in 2005. Megawatt-class wind turbines continued to gain an increasing share of the overall market in 2005, and the average turbine rating surpassed 1 MW in the UK (2,172 kW), Germany (1,667 kW), the United States (1,499 kW), Denmark (1,381 kW), Spain (1,371 kW), and Sweden (1,126 kW).

Table 3-12
Annual Average Nameplate Ratings (kW) of Wind Turbines Installed by Country

Year	China	Denmark	Germany	India	Spain	Sweden	UK	USA
2001	681	850	1,281	441	721	1,000	941	908
2002	709	1443	1,397	553	845	1,112	843	893
2003	726	1,988	1,650	729	870	876	1,773	1,374
2004	771	2,225	1,715	767	1,123	1,336	1,695	1,309
2005	899	1,381	1,667	780	1,367	1,126	2,172	1,499

Source: BTM Consult ApS – March 2006

The noticeable increase in ever-larger turbines as a major proportion of the market prompted BTM Consult Aps to redefine the ranges associated with the various market segments for 2004. The new ranges are still being used for 2005: 0-750 kW for small turbines, 750-1500 kW for mainstream turbines, 1500-2500 kW for megawatt-class turbines, and >2500 kW for multi-megawatt class turbines. Using these definitions, the 2005 market shares were 3.6% for small

wind turbines, 47.6% for mainstream turbines, 46.4% for megawatt-class turbines, and 2.49% for multi-megawatt class turbines. It is expected that the small turbine market share will continue to decrease, the mainstream turbine market will decrease slightly, and the megawatt-scale market will continue to increase.

The installed capacity of small wind turbines (<750 kW) decreased to 3.6% (404 MW) of total capacity between 2004 and 2005. Mainstream turbines (750-1,500 kW) decreased to 47.6% (5,331 MW), and megawatt-class turbines (1,501-2,500 kW) increased modestly to 46.4% (5,198 MW) of total capacity. A new "Multi-Megawatt Class" (> 2,500 kW) turbine emerged during 2002, and its installed capacity reached nearly 2.4% (271 MW) of total capacity during 2004 and 2005.

During 2005, the leading suppliers of the redefined megawatt-class machines (>1500 kW) included Vestas Wind Systems, Enercon, Gamesa, Siemens, and REpower. The market shares for megawatt-class turbines were: Vestas (41.2%), Enercon (23.0%), Gamesa (14.4%), Siemens (9.0%), and REpower (4.5%).

Table 3-13 presents selected data for commercial megawatt-class wind turbine generators offered by the major suppliers. Of the manufacturers producing multi-megawatt turbines, Enercon leads the way, with development and testing of a 4.5-MW machine, followed by GE Wind with a 3.6-MW turbine, Vestas with a 3.0 MW turbine, and Nordex with a 2.5-MW wind turbine. Two new models that have been announced by Vestas are the V-100 (2.75/3.0 MW) and V-120 (4.5 MW).

Table 3-13
Commercial Megawatt-Class Wind Turbine Generators

Manufacturer/Turbine Model	Rating (kW)	Rotor Dia. (m)	Control Features	Comments
Bonus 2 MW	2000	70-77	Active Stall (C)	2-Speed CombiStall
Bonus 2.3 MW	2300	82.4	Active Stall (C)	CombiStall
DeWind 1.25 MW	1250	62	Pitch (V)	IGBT-Inverter
DeWind 2 MW	2000	80	Pitch (V)	IGBT-Inverter
Ecotechnia 1.67 MW	1670	74	Pitch (V)	
Enercon E 66, 1.8 MW	1800	70	Pitch (V)	Multipoled Ring Generator
Enercon E 66, 2.0 MW	2000	71	Pitch (V)	Multipoled Ring Generator
Enercon E 70, 2.0 MW	2000	70	Pitch (V)	Multipoled Generator
Enercon E112, 4.5 MW	4500	112/114	Pitch (V)	Multipoled Generator
Fuhrlander MD77	1500	77	Pitch (V)	
Nordex N60/N62	1300	60/62	Stall (C)	2-Speed Switchable Poles
Nordex S70/77	1500	70/77	Pitch (V)	
Nordex N90, 2.3 MW	2300	90	Pitch (V)	
REpower MM70	2000	70	Pitch (V)	
REpower MM82	2000	82	Pitch (V)	IGBT Inverter
GAMESA G80	2000	80	Pitch (V)	IGBT Inverter
GAMESA G83	2000	83	Pitch (V)	IGBT Inverter
GAMESA G87	2000	87	Pitch (V)	IGBT Inverter
GE TW 1.5	1500	70.5-77	Pitch (V)	IGBT Inverter
GE Wind 2.3	2300	82	Pitch (V)	IGBT Inverter
GE TW 3.6	3600	104	Pitch (V)	IGBT Inverter/Offshore Application
VESTAS NM70 C-1500	1500	72	Active Stall ©	1 or 2 Speed
VESTAS V82	1650	82	Active Stall (C)	1 or 2 Speed
VESTAS V80	2000	80	Pitch (V)	Variable Frequency Control System
VESTAS V90-1.8/2MW	2000	90	Pitch (V)	Variable Frequency Control System
VESTAS V90	3000	90	Pitch (V)	Variable Frequency Control System

Source: BTM Consult ApS – March 2006
(C) = Constant-Speed Turbine; (V) = Variable-Speed Turbine

Offshore Market in Europe

The growing offshore market in Europe is driven by the declining availability of good sites on land, especially in Denmark. Installation of large megawatt-class machines on offshore foundations and pilings is economically attractive due to both the economies of scale of larger machines and the availability of wind resources with more uniform wind speeds and less wind turbulence. Assessments of potential resources and feasibility of European offshore wind show that the market can develop very fast. The exploitable offshore wind resource in Europe is approximately 300 TWh/year. Together with an identified onshore potential of approximately 600 TWh/year, the total wind power potential in Europe is 900 TWh/year, equaling almost one-third of the total electricity consumption in Europe today.

Market Forecast

Figure 3-17 presents the BTM Consult forecasts of wind power development for 2006 to 2010 and 2011 to 2015. The forecast is based on an analysis of a number of technical, economic, and political factors in each country. The factors include national energy plans, government support for renewable energy, present market for wind turbines, new project announcements, wind resource assessment, and expected technology development and cost reduction.

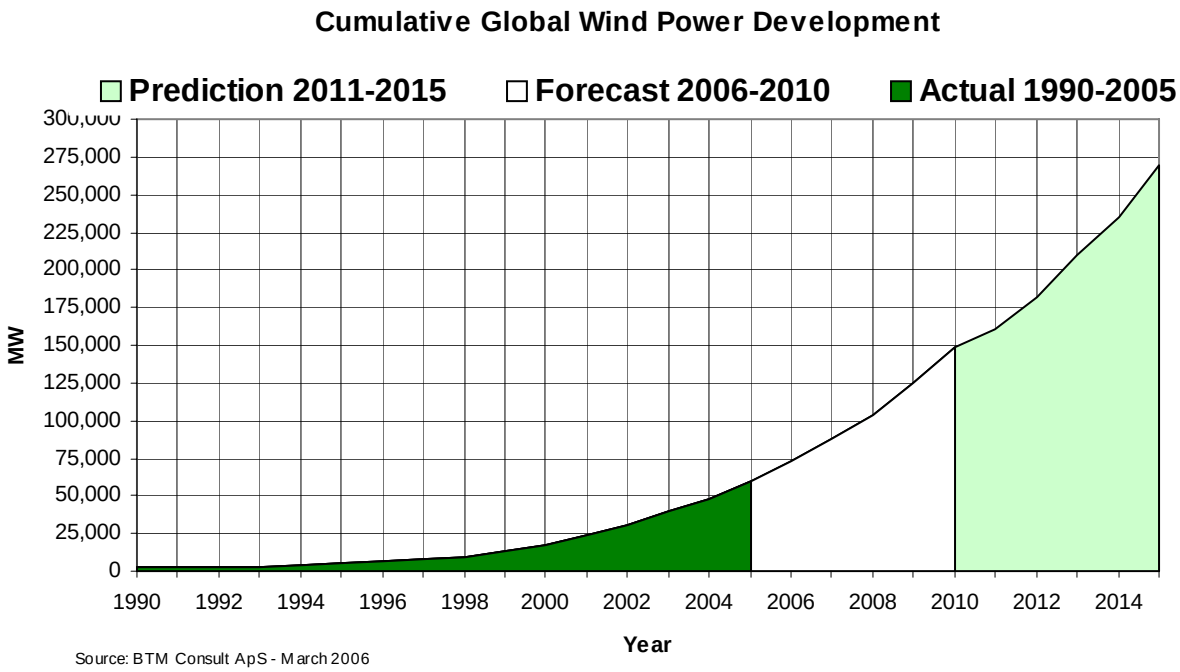


Figure 3-17
Installed Wind Capacity and Forecast: 1990-2015

2006 through 2010

Installed world wind capacity is expected to reach 72,564 MW during 2006 and grow to 148,794 MW in 2010. Over the same period, U.S. wind capacity is expected to reach 12,381 MW and grow to 22,381 MW. The United States' 18% share of worldwide wind capacity is expected to remain constant through 2010.

Table 3-14 presents the global forecast of installed wind capacity for 2006-2010. The installed capacity is forecast to grow to 26,562 MW in the Americas, 87,694 MW in Europe, 20,918 MW in South and East Asia, 7,257 in the OECD-Pacific region, and 3,362 MW in the rest of the world.

Table 3-14
Global Wind Power Development Forecast: 2006-2010

Region	Cum MW	Inst'd MW	Forecast Installed MW: 2006-2010						Cum MW
	2005	2005	2006	2007	2008	2009	2010	Total	2009
Total Americas	10,062	2,671	3,800	4,100	2,900	3,950	4,750	19,500	29,562
Total Europe	41,044	6,372	6,865	7,480	8,725	10,590	12,990	46,650	87,694
Total South and East Asia	5,618	1,836	1,750	2,250	3,400	3,700	4,200	15,300	20,918
Total OECD-Pacific	2,132	484	700	775	1,050	1,200	1,400	5,125	7,257
Total other areas	407	44	185	395	550	750	1,075	2,955	3,362
Total New MW		11,407	13,300	15,000	16,625	20,190	24,415	89,530	**148,794**
Cum MW	59,264		72,564	87,564	104,189	124,379	**148,794**		

Source: BTM Consult ApS – March 2006

2011 through 2015

As shown in Figure 3-17, the installed world wind capacity is predicted to grow from about 148,794 MW in 2010 to about 298,291 MW in 2015. The forecast is based on an assessment of global trends in energy consumption, economic growth, restructuring of the utility markets, and the eventual impacts of the Kyoto Protocol and future agreements concerning global climate change.

It is anticipated that the wind power growth will no longer be dependent on environmental regulations and will instead be driven by traditional market drivers, including energy demand growth, declining cost of wind energy, and the expansion of offshore wind generation in Europe.

Assuming that the forecast market grows to 13,200 MW/yr by 2010, the predicted market beyond 2010 assumes stabilization of growth in Europe from 12,990 MW/year in 2010 to around 13,000 MW/yr by 2015; rapid growth in America of 4,720 MW/yr in 2010, growing to 9,500

MW/yr by 2015; rapid growth in Asia of 5,700 MW/yr in 2010, growing to 10,000 MW/yr by 2015; and rapid growth in the rest of the world, of 1,000 MW/yr in 2010, growing to 2,000 MW/yr by 2015.

3.10.2 Key Players in the Wind Power Industry

Table 3-15 lists the major global participants in the wind power industry. They include wind turbine manufacturers, component suppliers, and project developers.

Table 3-15
Global Participants in the Wind Power Industry

Wind Turbine Manufacturers	Component Suppliers	Wind Project Developers
Vestas Wind System A/S Enercon GmbH NEG Micon A/S GE Wind Systems Gamesa Eolica Bonus Energy Nordex-Borsig Energy MADE Energias Renovables Mitsubishi Heavy Industries MHI REpower Systems AG Ecotecnia Suzlon Energy DEWIND GmbH Desarrollos Fuhrlander GmbH Jeumont Industrie Lagerway the Windmaster Nordic Windpower AB Turbowinds NV Wincon West Wind	*Blades* LM Glasfiber A/S Polymarin Aerpac BV Abeking & Rasmussen NOI Rotortechnik *Gearboxes* Jahnel Kestermann Getriebewerke Winergy AG Metso Drives Tehnology Hansen Transmission *Generators* ABB Elin Siemens Weier Elektromotrenwerk GmbH Winergy AG *Towers* KGW Schweriner Maschinenbau GmbH Chemieanlagenbau Stassfurt AG Omnical Borsig Energy GmbH Pfleiderer AG Bladt Industry A/S Valmont Wind Energy Erik Roug A/S	WKN Windkraft Nord AG FPL Energy LLC National Wind Power Ltd. Renewable Energy System Elsam A/S EnXco SeaWest WindPower, Inc. Winkra GmbH Umweltkontor GmbH REG Entwicklungs KG Das Grune Emissionshaus Italian Vento Power Corp. EHN Plambeck Neue Energien AG Gesellschaft fur Energie un Oekologie EnergieKontor Jysk Vindkraft A/S SEAS Wind Energy Centre TechWise Viking Wind farms A/S AIRICOLE AB Espace Eolien Developpement (EED) Greentech Energy Systems A/S

Table 3-16 presents the global market shares of the leading manufacturers of wind turbines in 2002, 2003, and 2004. During 2005, the five market share leaders were Vestas (27.9%), GE Wind(17.7%), Enerco (13.2%), Gamesa (12.9%), and Suzlon (6.1%). In most years, the total market shares do not add to 100% due to an imbalance between turbine sales and installations.

Table 3-16
Global Market Shares of Wind Turbine Manufacturers in 2003, 2004, and 2005

Manufacturer	MW Sales 2003	% Market Share	MW Sales 2004	% Market Share	MW Sales 2005	% Market Share
Vestas (DK)	1,812	25.1%	2,783	33.4%	3,186	27.9%
GE WIND (US)	1,503	20.8%	918	11.0%	2,025	17.7%
Enercon (GE)	1,218	16.9%	1,288	15.4%	1,505	13.2%
Gamesa (ES)	956	13.2%	1,474	17.7%	1,474	12.9%
Suzlon (Ind)	178	2.5%	322	3.9%	700	6.1%
Siemens (DK)	552	7.6%	507	6.1%	629	5.5%
REpower (GE)	291	4.0%	276	3.3%	353	3.1%
Nordex (GE)	242	3.3%	186	2.2%	298	2.6%
Ecotecnia (ES)	48	0.7%	214	2.6%	239	2.1%
Mitsubishi	218	3.0%	214	2.6%	233	2.0%
NEG Micon (DK)	855	11.8%	na	na	na	na
Others	215	3.0%	334	4.0%	567	5.0%
Total	**8,088**	**112%**	**8,513**	**102%**	**11,207**	**98%**

Source: BTM Consult ApS – March 2006

Figure 3-18 shows the sales of each wind turbine manufacturer to their respective domestic and export markets from 2003 through 2005. Manufacturers that exported most of their turbine sales to other countries were: Vestas, Siemens, REpower, Nordex, and, Mitsubishi. The remaining manufacturers sold mostly to their respective domestic markets.

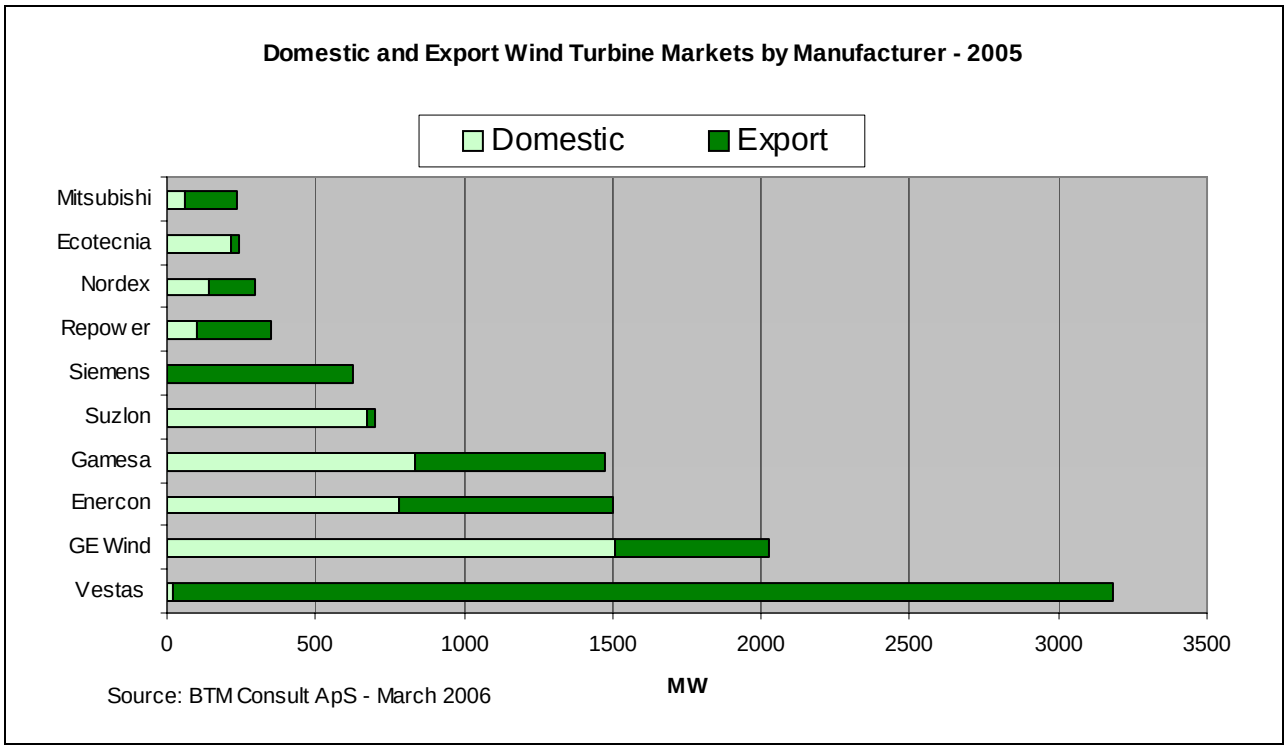


Figure 3-18
Wind Turbine Sales to Domestic and Export Markets: 2003-2005

3.11 Internet Resources

In addition to the manufacturers, vendors, and organizations listed above, the reader is referred to the following Internet websites. Note that while these sites contain information and contacts that may be of interest, EPRI cannot vouch for the accuracy or quality of all of their content.

U.S. Department of Energy Wind Energy Program
Located within the Office of Power Technologies in the Office of Energy Efficiency and Renewable Energy, the DOE Wind Energy Program includes a comprehensive wind energy research effort involving national laboratories as well as support for utilities, industry, and international wind energy projects.

http://www.eere.energy.gov/windandhydro

National Renewable Energy Laboratory—National Wind Technology Center
NREL's Golden, Colorado facilities host the NWTC, the U.S.'s only full-service wind turbine testing center and the U.S. DOE's lead laboratory in wind technology research and development.

www.nrel.gov/wind

Sandia National Laboratories
Sandia performs applied wind research in aerodynamics, structural dynamics, fatigue, materials, manufacturing, controls, and systems integration to solve technical problems encountered by the wind industry.

www.sandia.gov/wind

Utility Wind Integration Group
The Utility Wind Integration Group (UWIG) is a non-profit corporation whose mission is to accelerate the appropriate integration of wind power for utility applications through the coordinated efforts and actions of its members, in collaboration with public and private sector stakeholders.

www.uwig.org

National Wind Coordinating Committee
A consensus-based collaborative formed in 1994, the NWCC comprises representatives from the utility, wind, environmental, consumer, regulatory, power marketing, government, and other interested sectors interested in encouraging U.S. wind power deployment.

www.nationalwind.org

American Wind Energy Association
Established in 1974, AWEA is a trade and advocacy organization based in Washington, D.C. The association represents the U.S. wind energy industry and individuals who support wind power in the legislative, regulatory, public relations, and international arenas. AWEA hosts the annual Windpower conference that features technical papers, research and news from around the world.

www.awea.org

European Wind Energy Association
EWEA is a nonprofit, non-governmental association with a total membership of more than 15,000, including most major wind turbine manufacturers and research centers. Its objective is to disseminate information about the status and value of wind power, to provide a forum to discuss wind energy issues, to organize related workshops and conferences, and to promote the use of wind power.

www.ewea.org

Danish Wind Industry Association
The Danish Wind Industry Association is a nonprofit organization founded in 1981 to promote wind energy in Denmark—one of the world leaders in wind turbine deployment—and abroad. The association is engaged in energy policy issues, economics, standardization, and R&D.

http://www.windpower.org/en/core.htm

Windpower Monthly Magazine
Based in Denmark, *Windpower Monthly* is the world's leading wind energy new magazine, with correspondents in 16 countries and offices in Europe and the U.S.

www.windpower-monthly.com

Center for Renewable Energy and Sustainable Technology
The Center for Renewable and Sustainable Technology provides excellent background information and extensive links to other websites.

http://www.crest.org

3.12 References

1. American Wind Energy Association (AWEA) news release, August 20, 2003, available at http://www.awea.org/news/news030820nmw.html

2. *Wind Turbine Verification Project Experience: 1999*, EPRI, Palo Alto, CA: November 2000. 1000961.

3. *Long Island's Offshore Wind Energy Development Potential: A Preliminary Assessment*, Long Island Power Authority and the New York State Energy Research and Development Authority, April 2002.

4. B. Parsons & M. Milligan, B. Zavadil & D. Brooks, B. Kirby, K. Dragoon, and J. Caldwell, "Grid Impacts of Wind Power: A Summary of Recent Studies in the United States," June 2003 presented at the EWEA Conference in Madrid, Spain.

5. California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis, Phase I: One-Year Analysis of Existing Resources, Results and Recommendations, Final Report, Oct. 9, 2003. See http://cwec.ucdavis.edu/rpsintegration/RPS_Int_Cost_PhaseI_pubrev1.pdf

6. M. Milligan. *Modeling Utility-Scale Wind Power Plants, Part 2: Capacity Credit.* NREL/TP-500-29701. Golden, Colorado: National Renewable Energy Laboratory, 2002.

7. MAPP Reliability Handbook, Section 3, Sub-section 4.7.2.7, "Procedures for setting Monthly Net Capability for Variable Capacity Generation."

8. NEPOOL Manual for Installed Capacity, Manual M-20, Supplement D.

9. Updated research and information on current activities is available at NWCC's website at http://www.nationalwind.org/

10. *The Effect of Wind Development on Local Property Values*, REPP, Washington, D.C., May 2003. See www.repp.org/articles/static/1/binaries/wind_online_final.pdf

11. *Planning Your First Wind Power Project: A Primer for Utilities*, EPRI, Palo Alto, CA: December 1994. TR-104398.

12. *Building Community Support for Local Renewable and Green-Pricing Projects*, EPRI, Palo Alto, CA: December 1999. TR-114203.

13. *Renewable Energy Technology Characterizations*, U.S. Department of Energy and EPRI, Palo Alto, CA: December 1997. TR-109496.

14. *Power-Electronic, Variable-Speed Wind Turbine Development: 1988-1993*, EPRI, Palo Alto, CA: September 1995. TR-104738.

15. Gipe, P., *Wind Energy Comes of Age*, John Wiley & Sons, Inc., New York, NY, 1995, pp. 216-219.

16. *Studying Wind Energy/Bird Interactions: A Guidance Document*, National Wind Coordinating Committee, Washington, D.C.: December 1999.

17. *Permitting of Wind Facilities*, National Wind Coordinating Committee, Washington, D.C.: August 1999.

18. Windicator, *Wind Power Monthly*, Knebel, Denmark: October 2005.

19. *International Wind Energy Development, World Market Update 2004*, BTM Consult ApS, Ringkobing, Denmark, March 2005

20. *"Stretching the Boundaries – Wind Energy Technology Review 2004-2005," Renewable Energy World Magazine*, February, 2005.

21. www.re-focus.net . March 2002.

22. *Offshore Wind Could Quadruple UK Wind Energy*, Renewable Energy World Magazine, May-June 2001.

23. *Wind Turbine Productivity Improvement and Procurement Guidelines*, EPRI, Palo Alto, CA: March 2002. TR-104738.

24. *Wind Power For Pennies*, Technology Review, July/August 2002.

25. *Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning, Xcel Energy-North Case Study*, Final Report, Utility Wind Interest Group, December 2003: 1004807.

26. *California Wind Energy Forecasting System Development and Testing Phase 1: 12-Month Testing,* EPRI, Palo Alto, CA, California Energy Commission, Sacramento, CA: March 2003. 1007338.

27. *California Wind Energy Forecasting System Development and Testing Phase 2: 12-Month Testing,* EPRI, Palo Alto, CA, California Energy Commission, Sacramento, CA: July 2003. 1007339.

28. *Texas Wind Energy Forecasting System Development and Testing, Phase 1: Initial Testing*, EPRI, Palo Alto, CA, U.S. Department of Energy, Washington, DC: December 2003. 1008032.

29. *Wind Energy Forecasting Applications in Texas and California: EPRI - California Energy Commission - U.S. Department of Energy Wind Energy Forecasting Program: EPRI - California Energy Commission - U.S. Department of Energy Wind Energy Forecasting Program*, Palo Alto, CA: December 2004. 1004038.

30. *Texas Wind Energy Forecasting System Development and Testing, Phase 1: 12-Month Testing*, EPRI, Palo Alto, CA, U.S. Department of Energy, Washington, DC: September 2004. 1008033.

31. *Wind Energy Forecasting Technology Update: 2004*, Palo Alto, CA: April 2005. 1008389.

32. *California Regional Wind Energy Forecasting System Development, Volume 1: Executive Summary,* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013262.

33. *California Regional Wind Energy Forecasting System Development, Volume 2: Wind Energy Forecasting System Development and Testing and Numerical Modeling of Wind Flow over Complex Terrain,* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013263.

34. *California Regional Wind Energy Forecasting System Development, Volume 3: Wind Tunnel Modeling of Wind Flow over Complex Terrain,* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013264.

35. *California Regional Wind Energy Forecasting System Development, Volume 4: California Wind Generation Research Dataset (CARD),* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013265

3.12.1 DOE-EPRI Wind Turbine Verification Program Reports

36. *Tennessee Valley Authority Buffalo Mountain Wind Power Project First- and Second-Year Operating Experience: 2001-2003*, EPRI, Palo Alto, CA: December 2003. 1008031.

37. *Tennessee Valley Authority Buffalo Mountain Wind Power Project Development*, EPRI, Palo Alto, CA: January 2003. 1004207.

38. *Big Spring Wind Power Project Third- Through Fifth-Year Operating Experience: 2001-2004*, EPRI, Palo Alto, CA: October 2004. 1008384

39. *Big Spring Wind Power Plant Second-Year Operating Experience: 2000-2001*, EPRI, Palo Alto, CA: December 2001. 1004042.

40. *Big Spring Wind Power Plant First-Year Operating Experience: 1999-2000*, EPRI, Palo Alto, CA: December 2000. 1000958.

41. *Project Development Experience at the Big Spring Wind Power Plant*, EPRI, Palo Alto, CA: December 1999. TR-113919.

42. *Lessons Learned at the Iowa and Nebraska Public Power Wind Projects*, EPRI, Palo Alto, CA: October 2000. 1000962.

43. *Iowa/Nebraska Distributed Wind Generation Projects First- and Second-Year Operating Experience: 1999-2001*, EPRI, Palo Alto, CA: December 2001. 1004039.

44. *Project Development Experience at the Iowa and Nebraska Distributed Wind Generation Projects*, EPRI, Palo Alto, CA: December 1999. TR-112835.

45. *Kotzebue Electric Association Wind Power Project Third-Year Operating Experience: 2001-2002*, EPRI, Palo Alto, CA: December 2002. 1004206.

46. *Kotzebue Electric Association Wind Power Project Second-Year Operating Experience: 2000-2001*, EPRI, Palo Alto, CA: December 2001. 1004040.

47. *Kotzebue Wind Power Project Initial Operating Experience: 1998-2000*, EPRI, Palo Alto, CA: December 2000. 1000957.

48. *Project Development Experience at the Kotzebue Wind Power Project*, EPRI, Palo Alto, CA: December 1999. TR-113918.

49. *Wisconsin Low Wind Speed Turbine Project Third-Year Operating Experience: 2000-2001*, EPRI, Palo Alto, CA: December 2001. 1004041.

50. *Wisconsin Low Wind Speed Turbine First and Second Year Operating Experience: 1998-2000*, EPRI, Palo Alto, CA: November 2000. 1000959.

51. *Wisconsin Low Wind Speed Turbine Project Development*, EPRI, Palo Alto, CA: December 1998. TR-111438.

52. *Green Mountain Power Wind Power Project Third Year Operating Experience: 1999-2000*, EPRI, Palo Alto, CA: December 2000. 1000960.

53. *Green Mountain Power Wind Power Project Second Year Operating Experience: 1998-1999*, EPRI, Palo Alto, CA: December 1999. TR-113917.

54. *Green Mountain Power Wind Power Project First Year Operating Experience: 1997-1998*, EPRI, Palo Alto, CA: December 1998. TR-111437.

55. *Green Mountain Power Wind Power Project Development*, EPRI, Palo Alto, CA: December 1997. TR-109061.

56. *Central & South West Wind Power Project Third Year Operating Experience: 1998-1999*, EPRI, Palo Alto, CA: December 1999. TR-113916.

57. *Central & South West Wind Power Project Second Year Operating Experience: 1997-1998*, EPRI, Palo Alto, CA: December 1998. TR-111436.

58. *Central & South West Wind Power Project First Year Operating Experience: 1996-1997*, EPRI, Palo Alto, CA: December 1997. TR-109062.

59. *Central and South West Wind Power Project Development*, EPRI, Palo Alto, CA: December 1996. TR-107300.

60. DOE-EPRI Wind Turbine Verification Program TVP MI-112231 Status Report, 1998.

61. DOE-EPRI Wind Turbine Verification Program TVP MI-112231 Status Report, 2001.

62. Review of Operation and Maintenance Experience in the TVP Program, Report No. LP-500-28620, 2000.

63. Musial, W. and S. Butterfield, "Future for Offshore Wind Energy in the United States," National Renewable Energy Laboratory NREL/CP-500-36313, presented at EnergyOcean 2004, Palm Beach Florida, June 28-30, 2004.

64. Frandsen, Stan, "Design of Offshore Wind Turbines," Professional Course, *Developing Offshore Wind Energy*, European Renewable Energy Centres Agency (EUREC), June 2003.

4
BIOMASS ENERGY

Installed Capacity (est.)	22,400 MW worldwide 9,700 MW in United States
Technology Readiness	Near commercial, widespread High confidence in cost estimates and projections for combustion systems Moderate to low confidence in cost estimates and projections for gasification systems
Environmental Impact	Atmospheric and solid emissions from combustion and gasification technologies controllable using commercial technology When fuel is grown sustainably, no *net* increase in CO_2 emissions Can help meet local solid waste disposal challenges
Economic Status	Competitive or near-competitive in many markets Particularly attractive in cogeneration applications Cost of securing and transporting fuel remains a challenge on case-by-case basis
Policy Status	Not always addressed by state RPS or energy policies (except digester gas and ethanol production) Combustion technologies can encounter resistance from the public, policymakers, and environmental groups; education is needed Policies and government R&D investment tend to favor biomass to liquid fuels over other biomass energy European Union policies and regulations have produced a robust and growing biomass-to-power industry
Trends to Watch	New emission control technologies Progress toward more efficient and economical gasification Dedicated fuel crops

4.1 Introduction

Biomass fuels produced by living plant and animal matter provide electric utilities and other electricity generators with *dispatchable* renewable power. For the most part, biomass fuels can be produced, concentrated, and stored for use when it is economic to do so. The U.S. Energy Information Agency (USEIA) estimates that biomass currently supplies 3.0 Exajoules (EJ) or 2.854×10^{15} Btu (Quads) of energy to the U.S. economy per year. Altogether, biomass supplies some 20 EJ to the world's economy—largely in North America, Scandinavia, China, and numerous developing economies. Over the past decade, annual biomass consumption in the U.S. has ranged from 2.79 EJ to 3.21 EJ (2.66 to 3.06 Quads) depending upon economic activity among the wood products industries, agribusinesses, electric utilities, and other industries. Biomass consumption in the U.S. economy has been generally quite stable.

Biomass fuels are largely industrial fuels. Data from USEIA indicates the distribution of biomass energy consumption shown in Table 4-1. These data do not include the 0.313 EJ of biomass used in transportation, largely in the form of ethanol added to gasoline.

Table 4-1
Biomass Energy Consumption in the U.S. Economy by Sector and Type, 2004 (exajoules)

Biomass Type	Economic Sector			
	Residential and Commercial	Industrial	Electricity	Total
Wood and Wood Waste	0.394	1.532	0.177	2.105
MSW/Landfill Gas	0.045	0..093	0.330	0.468
Other Biomass	0.005	0.089	0.029	0.122
Total	**0.444**	**1.714**	**.536**	**2.695**

Source: USEIA

4.1.1 Basic Issues Associated with Biomass Fuel Utilization

Biomass fuels exhibit certain fundamental differences from other fossil fuels. Typically, biomass fuels are either gathered up or harvested from diffuse sources and concentrated at a given location. Consequently, there are practical limitations on the quantities that can be obtained at any location without experiencing significant cost pressures. This phenomenon limited the capacities of the early iron furnaces fueled by charcoal in Pennsylvania and other states in the late 18th century and early 19th century [1], and remains an issue today. This is in distinct contrast to the fossil fuels that are produced in centralized locations—e.g., coal—and distributed to users such as power plants.

Biomass fuels currently used as fuels are, almost exclusively, residues from other processes. They may be wood processing residues such as hog fuel, bark, sawdust, or spent pulping liquor. They may be agricultural and agribusiness residues such as bagasse. They may be wastewater treatment gas or landfill gas. These are commodities that are presently outside the commercial mainstream. In many cases these commodities have both material and energy value. Wood waste markets, for example, can include mulch for urban areas, bedding for livestock and poultry, feedstocks for materials such as particleboard, and feedstocks for niche chemical and related products. As a result, fuel pricing is highly sensitive to locale and the competitive pressures of local and regional economies.

Significant efforts have also been made to develop short-rotation biomass crops to be used exclusively as fuel or energy feedstocks. To date, these have not produced competitively-priced fuels.

4.1.2 Technology Considerations for Using Biomass Fuels

Biomass-to-power technologies can be divided into two basic categories: 1) existing technologies that are either commercialized or nearly ready for commercial implementation, and 2) goal technologies that have been proposed and are of long-term interest. It is important to focus on the first category, for which economics are reasonably well defined. Time frames for commercial availability and costs associated with goal technologies are more speculative in nature and can only be discussed in such terms.

Commercially Available Technologies

Commercially available technologies include stand-alone condensing power plants, such as those owned by electric utilities and independent power producers. Stand-alone power plants fired by wood waste and certain agricultural wastes were developed extensively during the early years of the Public Utilities Regulatory Policies Act (PURPA). Stand-alone power plants fired with municipal solid waste (MSW) and landfill gas have also been developed. Landfill gas, for example, is used to fuel a 50-MW_e steam boiler installation at the Puente Hills, Los Angeles landfill. The energy installation at Puente Hills also includes a combustion turbine and internal combustion engines.

Equally significantly, commercially available technologies include Rankine cycle cogeneration installations such as those owned and operated by companies in the forest products industry, the sugar industry, and other manufacturing interests. Such installations couple a medium-pressure boiler with main steam conditions, typically 600 psig/750°F, 850 psig/825°F, 1250 psig/950°F, and 1450 psig/1005°F to either backpressure turbines or automatic extraction turbines. Process steam is typically generated at 50 psig, 150 psig, or 450 psig depending upon application. The energy released when steam is expanded from throttle conditions to exhaust conditions is used to generate electricity. In selected cases such as the Snohomish, Washington Public Utility District, utilities team with forest products industry firms to jointly develop such cogeneration capabilities.

Biomass cofiring technologies have been employed at several locations. For example, wood waste can be blended with coal on the main belt leading to the Willow Island Generating Station #2 boiler, a 188-MW_e cyclone boiler owned and operated by Allegheny Energy Supply Co., LLC. Sawdust and other biofuels have been ground and separately injected into the 105-MW_e boiler at Greenidge Station in a project developed in the mid-90s by New York State Electric and Gas (NYSEG) and continued by AES, the current plant owner. Southern Company has pioneered numerous cofiring approaches at Plant Hammond, Plant Yates, Plant Gadsden, and other installations. Previously, Northern States Power implemented biomass cofiring at its Allen S. King Generating Station. Numerous vendors now offer commercial systems.

An example of coupling atmospheric gasification of biomass to electricity-generating Rankine cycle installations is the Kymijarvi power plant in Lahti, Finland, owned and operated by Lahden Lampovoima Oy. The Lahti gasification project—an EU Thermie demonstration—involved numerous partners including Lahden Lampovoima Oy, Foster Wheeler Energia Oy, VTT (the Technical Research Center of Finland), Elkraft Power Co., Ltd. of Denmark, and Plibrico Ab from Sweden. The project involved installing a Foster Wheeler atmospheric circulating fluidized

bed gasifier capable of converting sawdust, bark, wood chips, plywood trim, particleboard trim, and recycled fuel (REF) into a producer gas for firing in the coal-fired boiler used for generating electricity and district heat. Based upon the success of that project and other gasification projects, atmospheric circulating fluidized bed boilers can now be procured commercially for such cofiring projects used to generate electricity.

For each of these commercially available technologies, the issues of fuel cost and the availability of fuel in significant quantities remain driving issues. The process of gathering and concentrating the fuel in a single location is a primary consideration. All of these commercially available technologies exhibit technical advantages and disadvantages associated with using biomass fuels. Such technical considerations, along with economics, are discussed in subsequent sections of this report.

Goal Technologies

Those technologies that have long-term promise, but remain beyond current technical and economic feasibility on a proven basis, are many and varied.

The practice of raising silvicultural or agricultural crops as a fuel supply is one such technology. This technology was employed, as mentioned previously, by the initial iron industry in the fledgling U.S. It has appeared significantly in the literature since the early 1970s (see, for example, Szego and Kemp [2], Bethel et al. [3] and Henry [4]). Government research in this area has been significant over a long period of time. To date, however, experience has shown that biomass cannot be grown and harvested at costs even close to those associated with alternative combustible resources. Further, there are significant economic issues associated with competition for the resource, once grown, that make this a goal technology rather than a near-term commercial reality. In the United Kingdom, however, government policies are in place which may offer a significant role for dedicated biomass. The success of this program will be watched carefully in the coming years.

A program in the United States will also be watched carefully. In May, 2006, the Biomass Investment Group announced they had signed a power purchase agreement for 130 MW of power derived from the gasification of a dedicated herbaceous crop (called E-Grass by the developer). Florida was identified as the site of this development, and the species of E-Grass was not identified in public documents. No further information was available at the time of this writing.

Pressurized gasification with hot or warm gas clean-up, coupled with combustion turbines in integrated gasification combined-cycle (IGCC) applications, also remains a long-term possibility. Scale limitations severely constrain the economics of this technology. Further, hot or warm gas clean-up remains an elusive target. Pyrolysis to produce liquid fuels is yet another goal technology, but with serious practical problems.

Atmospheric (or near-atmospheric) gasification with warm gas cleanup in a configuration that provides fuel to reciprocating engines and district heating is also considered a goal technology, though is much nearer to commercial readiness than pressurized biomass gasification used in combined cycle mode.. Demonstrations at Skive, Denmark, featuring the Carbona gasifier

technology, Güssing, Austria, featuring the Repotec gasifer technology, and Harboøre, Denmark, featuring the Vølund gasifer provide evidence of approaching commercial deployment. This technology category is addressed in more detail in 4.4.5.

Prospectus

Within this framework, the generation of electricity from biomass can be evaluated. In order to make such an evaluation, this chapter considers the physical and chemical characteristics of various biomass fuels, and the technical characteristics and costs of various biomass technologies.

4.1.3 Characteristics of Representative Biomass Fuels

Biomass is commonly defined as material derived from living organic matter (e.g., trees, grasses, animal manure). While there are alternate political/regulatory definitions of biomass, from the physical and chemical perspectives (including the biochemical perspective) this definition appears to be most accurate. The consequence is that fractions of municipal solid waste—paper, wood waste, food waste, yard waste—are forms of biomass fuel. This definition also supports the inclusion of both residues and potential energy crops as biomass fuel. Consequently, biomass includes wood and wood waste, herbaceous crops and crop wastes, agribusiness wastes (e.g., food processing wastes such as bagasse), animal manures and methane-rich gas from anaerobic digestion of such fecal mater, methane-rich gases generated from wastewater treatment plants and landfills, and miscellaneous related materials.

4.2 Biomass Fuel Resources

Numerous national studies of biomass availability have been conducted (see, for example, Walsh et al. [5]). Such studies estimate the availability of biomass as a function of price. Oak Ridge National Laboratory estimates that over 5 EJ (or 5 Quads) of biomass as residue could be available at a price of $50/dry ton (approximately $3/GJ or $3/$10^6$ Btu) nationally. This study focused upon forestry and wood residues, crop residues, and energy crops. It did not address animal manures, landfill gas, wastewater treatment gas, or biomass components of municipal solid waste. If those wastes are added in, the estimated quantity of residue-based biomass fuel available at some price could well be on the order of 10 EJ (10 Quads).

As a practical matter, national estimates have policy implications but are otherwise not useful to utilities and generating stations that require local availability estimates when considering firing biomass singly or in combination with fossil fuels. Local estimates are based upon forest industry or agricultural industry activity, plus local markets for forest industry residues. Such residues include bark, sawdust, shavings, chips, hog fuel, logging residues, silvicultural residues (e.g., pre-commercial thinnings) dead and diseased timber, and fire-damaged timber that can not be salvaged. Local residues may also include an array of agricultural materials such as:

- Corn stover
- Corn cobs

- Out-of-date corn seed
- Wheat straw
- Rice straw
- Rice hulls
- Vineyard prunings
- Orchard prunings
- Oat hulls
- Bagasse

Determination of locally available biomass depends upon local forest industry or agricultural activity, local competing markets for the material, and transportation systems available. Local conditions vary substantially. In the Chicago area, for example, bark commands a premium price as mulch. In some areas with high concentrations of poultry farms, sawdust and rice hulls both command good prices as bedding material. Chips command prices beyond fuel prices in areas that are within economic haul distances of pulp mills or manufacturers of oriented strand board (OSB), medium density fiberboard (MDF), or related products. Other competing uses that have been encountered include manufacturing charcoal, manufacturing particleboard, and specialty products.

When considering agricultural residues, seasonality becomes a concern. For wastewater treatment gas, the population served by the wastewater treatment plant is the primary factor and can include industries as well as residential populations. Similarly, landfill gas utilization depends upon landfills serving large populations. As a consequence, California has more than 200 MWe of generation from landfill gas [6]. In all cases, however, local resource availability is the governing factor.

Local resource availability is critical because biomass fuels have limited transportability. Green wood wastes typically have bulk densities of 0.21 to 0.26 kg/m^3 (16 to 20 lb/ft^3). This compares to coals with bulk densities of 0.68 to 0.78 kg/m^3 (52 to 60 lb/ft^3). Crop wastes can have bulk densities of 0.11 to 0.13 kg/m^3 (5 to 8 lb/ft^3). Landfill and wastewater treatment gases are typically saturated with water, and have heating values that are about half of that associated with natural gas (on a dry gas basis). Further, landfill and wastewater treatment gases are not compressed while natural gas is transported under significant pressure. The typical estimated maximum haul distances for woody biomass are on the order of 50 to 75 miles (80 to 120 km.); economical transport distances for other biomass fuels are significantly lower.

4.2.1 Basic Properties of Solid Biomass Fuels

Fuel properties can be characterized in terms of proximate and ultimate analyses, reactivity measurements, ash elemental analyses, ash reactivity, and trace metal composition.

Proximate and Ultimate Analyses of Biomass Fuels

Research at The Energy Institute of Pennsylvania State University (PSU) has led to characterization of a broad array of biomass fuels, including the proximate and ultimate analyses shown in Tables 4-2 through 4-4.

Note that the sawdust in Table 4-2 is mixed hardwood-softwood sawdust. As a practical matter the difference between softwood and hardwood is insignificant from a fuels perspective, unless a fuel loaded with extractives—e.g., slash pine—is used. The urban wood waste is clean and does not include pentachlorophenol or copper chromium arsenate (CCA) treated wood. The switchgrass shown is from the Plant Gadsden tests of Southern Company.

The data in the tables document the fact that all biomass, on a moisture and ash free (MAF) basis, has reasonably similar heating values. Differences are in the relative percentages of holocellulose (cellulose plus the hemicelluloses), lignin, and extractives. Table 4-2 Proximate and Ultimate Analyses for Typical Woody Biomass Fuels

Parameter	Fuel				
	Pine Chips	**Pine Shavings**	**Red Oak Shavings**	**Fresh Mixed Sawdust**	**Urban Wood Waste (*)**
Moisture %	45.0	45.0	28.8	40.0	30.8
Proximate Analysis (wt % dry basis)					
Volatiles	84.7	84.7	79.5	80.0	76.0
Fixed Carbon	15.2	15.2	19.0	19.0	18.1
Ash	0.1	0.1	1.5	1.0	5.9
Ultimate Analysis (wt % dry basis)					
Carbon	49.1	49.1	51.6	49.2	48.0
Hydrogen	6.4	6.4	5.8	6.0	5.5
Nitrogen	0.2	0.2	0.5	0.4	1.4
Sulfur	0.2	0.2	0.0	<0.1	0.1
Oxygen	44.0	44.0	40.6	43.0	39.1
Ash	0.1	0.1	1.5	1.0	5.9
HHV (Btu/lb)	8502	8502	8069	8400	8364

Sources: Miller et al., 2000; Johnson et al., 2001; Tillman, 2001.

Note: (*) Urban Wood Waste shown is from the Bailly Generating Station Tests.

Table 4-3
Proximate and Ultimate Analyses for Typical Herbaceous Biomass Fuels

Parameter	Fuel			
	Fresh Switchgrass	Weathered Switchgrass	Reed Canary Grass	Mulch Hay
Moisture %	15	15	65.2	19.5
Proximate Analysis (wt % dry basis)				
Volatile Matter	76.18	81.8	76.1	77.6
Fixed Carbon	16.08	14.8	4.1	17.1
Ash	7.74	3.4	19.8	5.3
Ultimate Analysis (wt % dry basis)				
Carbon	46.73	49.4	45.8	46.5
Hydrogen	5.88	5.9	6.1	5.7
Nitrogen	0.54	0.4	1.0	1.7
Sulfur	0.13	0.3	0.1	0.2
Oxygen	38.99	40.6	42.9	40.6
Ash	7.74	3.4	4.1	5.3
HHV (Btu/lb)	7750	8150	7103	8058

Sources: Miller et al., 2000; Johnson et al., 2001.

Table 4-4
Proximate and Ultimate Analyses for Typical Manures

Parameter	Fuel				
	Dairy tie-stall manure	Dairy free-stall manure	Poultry Litter	Sheep manure	Swine waste
Moisture %	64.7	69.8	20.0	47.8	97.8(*)
Proximate Analysis (wt %, dry basis)					
Volatiles	76.0	30.1	55.3	65.2	59.6
Fixed Carbon	18.1	7.4	7.7	14.0	7.3
Ash	6.0	62.5	17.0	20.9	33.1
Ultimate Analysis (wt %, dry basis)					
Carbon	48.6	22.6	38.1	40.6	38.0
Hydrogen	5.8	2.9	5.6	5.1	5.5
Nitrogen	1.4	1.1	3.5	2.1	3.2
Sulfur	0.1	0.1	0.6	0.6	0.6
Oxygen	38.1	10.8	30.9	30.7	19.6
Ash	6.0	62.5	17.0	20.9	33.0
HHV (Btu/lb)	8203	3644	6399	6895	7328

Source: Miller et al., 2000; Miller et al., 2002
Note: (*) Swine waste is liquefied for transportation and disposal.

Structural Relationships and Heteroatoms

The proximate and ultimate analyses relate directly to summative analysis—the distribution of cellulose, hemicelluloses (e.g., galactoglucomannans, arabinogalactan), lignin, and extractives (e.g., pinoresinol). Typical distributions of these compounds in softwoods are as follows (extractive-free basis): cellulose, 45% to 50%; hemicelluloses, 25% to 35%; lignin, 25% to 35%. Extractives comprise 1% to 5% of softwoods. Hardwoods are characterized by somewhat lower concentrations of lignin. Herbaceous materials also are characterized by lower lignin concentrations. These combinations yield fuels that are highly reactive with little aromaticity and a significant concentration of functional groups such as hydroxyl and methoxyl functionalities. Aromatic structures, where they occur, exist as single aromatic rings rather than fused aromatic clusters. All of this contributes to the high volatility indicated by the proximate analyses (e.g., the volatile/fixed carbon ratio).

Structurally, carbon 13 nuclear magnetic resonance (^{13}C NMR) research has shown that woody and herbaceous biomass has an aromaticity of about 8% in sawdust and 10% in weathered switchgrass (Johnson et al. [7], Tillman [8]). This contrasts with 57% aromaticity in Black Thunder PRB coal and 73% aromaticity in Pittsburgh #8 coal. Biofuels typically contain six aromatic carbons per aromatic cluster while the PRB coals contain approximately 10 aromatic carbons per cluster and the eastern bituminous coals contain 13 to 15 aromatic carbons per cluster [7]. Further, structural research shows that the concentration of methoxy functionalities ($-OCH_3$) represents 8.67% of the carbon atoms in sawdust and 7.87% of the carbon atoms in weathered switchgrass. Methoxy functional groups provide a useful measure of fuel reactivity. As a comparison, 4.21% of the carbon atoms in Black Thunder PRB coal are contained in methoxy functional groups and 2.27% of the carbon atoms in Beulah lignite are contained in the $-OCH_3$ groups; this percentage drops to 0.79% for western bituminous coals and to 0% for eastern and Midwestern bituminous coals [7].

The structural analysis is consistent with the coalification results reported by Jenkins et al. [9] and numerous other authors. Biomass is at the extreme upper right hand corner on the typical coalification diagrams plotting hydrogen/carbon atomic ratios on the X-axis and oxygen/carbon ratios on the Y-axis.

Heteroatom analysis shows significant variability. Nitrogen concentrations, for example, can vary dramatically. Generally, the woody biofuels have lower fuel nitrogen contents; however, urban wood waste with high concentrations of glues is a notable exception. Herbaceous materials tend to have higher nitrogen concentrations, while manures have extremely high nitrogen concentrations, commonly in the form of free ammonia. Concentrations of inorganic matter (ash) are typically lowest in woody biomass and highest in manures as well. Sulfur contents can vary significantly, with very low concentrations in woody and herbaceous materials and higher concentrations in some manures though even these materials contain less than 1% sulfur.

The high concentrations of nitrogen in urban wood waste are a function of glues such as urea-formaldehyde. Such glues are used in the manufacture of various grades of plywood, OSB, and MDF. They are used in particleboard as well. The higher concentrations of nitrogen in herbaceous crops result more from fertilization practices. Common fertilizers such as 30-30-30 are high in nitrogen concentration, along with potassium and phosphorus.

Note the extremely high concentrations of inorganic material—ash—in some of the dairy manure and in the swine waste. The concentrations of fuel nitrogen and ash, expressed in $lb/10^6$ Btu, are shown in Table 4-5.

Inorganic Constituents in Biomass

Ash composition is of considerable significance in addressing concerns associated with slagging and fouling. Traditional ash analyses are presented in Tables 4-6 and 4-7 for representative biomass fuels, and Pittsburgh #8 coal is included in Table 4-6 for comparison purposes.

Table 4-5
Nitrogen and Ash Concentrations in Biomass Fuels (values in lb/10^6 Btu)

Fuel	Nitrogen (lb/10^6 Btu)	Ash (lb/10^6 Btu)
Pine Chips	0.24	0.12
Pine Shavings	0.24	0.12
Red Oak Shavings	0.61	1.86
Fresh Mixed Hardwood-Softwood Sawdust	0.47	1.19
Urban Wood Waste	1.67	7.05
Fresh Switchgrass	0.70	9.99
Weathered Switchgrass	0.49	4.17
Reed Canary Grass	1.41	5.77
Mulch Hay	2.11	6.58
Dairy Tie-stall Manure	1.71	7.31
Dairy Free-stall Manure	3.02	171
Poultry Litter	5.47	26.6
Sheep Manure	3.04	30.31
Swine Manure	4.37	45.0

Source: Miller et al., 2000

Table 4-6
Ash Analyses of Various Biomass Fuels Compared to Pittsburgh #8 Coal

Parameter	Fuel				
	Pittsburgh #8 Coal	Pine Shavings	Reed Canary Grass	Dairy Tie-Stall Manure	Poultry Litter
Al_2O_3	25.34	13.4	1.66	2.26	9.14
BaO	--	0.15	0.05	0.02	0.05
CaO	2.28	8.75	9.57	23.3	12.7
Fe_2O_3	18.34	5.94	1.47	1.37	4.04
K_2O	2.22	4.94	18.1	10.7	9.94
MgO	0.82	3.35	5.29	8.91	4.01
MnO	--	0.49	0.11	0.14	0.36
Na_2O	0.25	1.38	2.34	7.04	3.60
P_2O_5	0.4	1.44	13.8	14.7	14.0
SiO_2	48.2	57.2	43.0	26.0	39.4
SO_3	0.67	0.05	0.02	0.14	2.58
SrO	--	0.80	0.11	0.11	0.03
TiO_2	--	1.16	4.99	5.08	0.51
Base/Acid Ratio	0.325	0.339	0.741	1.539	0.699

Source: Miller et al., 2002; Miller and Miller, 2002.

Table 4-7
Ash Analyses of Switchgrass and Other Herbaceous Crops

Parameter	Fuel				
	Switchgrass	Switchgrass	Alfalfa Stems	Wheat Straw	Rice Straw
SiO_2	65.18	65.42	1.44	55.70	73.00
Al_2O_3	4.51	6.98	0.60	1.80	1.40
TiO_2	0.24	0.34	0.05	0.00	0.00
Fe_2O_3	2.03	3.56	0.25	0.70	0.60
CaO	5.60	7.14	12.90	2.60	1.90
MgO	3.00	3.17	4.24	2.40	1.80
Na_2O	0.58	1.03	0.61	0.90	0.40
K_2O	11.60	7.00	40.53	22.80	13.50
P_2O_5	4.50	2.80	7.67	1.20	1.40
SO_3	0.44	2.00	1.60	1.70	0.70
CO_2	0.00	0.00	17.44	0.00	0.00
Base/Acid Ratio	0.33	0.30	28.00	0.51	0.24

Source: Prinzing, 1996; Baxter et al., 1996a; Bryers, 1993.

Note that the potassium oxide content is always approximately 10%—or greater—for herbaceous biomass and manures. The woody biomass, on the other hand, typically has lower potassium content unless it is short-rotation woody crop grown with an aggressive regime for fuel or fiber purposes. The higher concentrations of potassium and phosphorus in the herbaceous crop residues and in the animal manures again result from fertilization practices.

The consequence of the high alkali metal concentrations in the herbaceous materials and manures is the potential for formation of slagging and fouling deposits. Miles et al. [10] posit a useful measure of slagging and fouling potential for biomass fuels as follows:

- <0.4 lb alkali ($K_2O + Na_2O$)/10^6 Btu, low slagging and fouling potential
- 0.4 – 0.8 lb alkali/10^6 Btu, probable slagging and fouling
- >0.8 lb alkali/10^6 Btu, certain slagging and fouling.

Table 4-8 presents the Miles et al. [10] slagging and fouling index for selected biomass fuels. Note the comparison of the manures—tie stall dairy manure and chicken litter—to woody biomass and herbaceous biomass.

Trace metal concentrations in biomass are typically lower than in coal. This has been shown with repeated testing (see Tillman [8][11], Payette et al. [12], and Hus and Tillman [13]). In particular, mercury concentrations—expressed as lb/10^6 Btu or mg/kg—are significantly lower for biomass than for coal [12].

Table 4-8
Slagging and Fouling Index for Selected Biomass Fuels

Fuel	Index (lb/10^6 Btu of K_2O and Na_2O)
Pine Shavings and Chips	0.01 – 0.02
Fresh Mixed Hardwood/Softwood Sawdust	0.08 – 0.12
Clean Urban Wood Waste	0.45
Alfalfa Stems	3.38
Fresh Switchgrass	0.80 – 1.22
Weathered Switchgrass	0.33 – 0.51
Reed Canary Grass	1.18
Tie Stall Manure	1.30
Chicken Litter	3.60

Sources: Miller et al. (2002); Prinzing (1996); Baxter et al. (1996a); Miles et al. (1993).

Trace metals in wood waste, agricultural materials, and other biomass fuels are a reflection of where they came from. Trees grown in areas where there are high concentrations of trace metals will exhibit somewhat elevated concentrations of same. Herbaceous crops will exhibit metal concentrations associated with fertilization practices. Urban wood waste will exhibit metal concentrations associated with glues, laminates, paints, coatings, and related materials (see Tillman [14]). Recent studies have shown that mercury concentrations in sawdust are typically 0.001 to 0.002 mg/kg in the as-received wood, or 0.002 to 0.004 mg/kg (parts per million) in the wood waste on an oven dry basis [15]. Studies of urban wood waste have shown the following trace metal concentrations in mg/kg of fresh material [13]:

- Arsenic: 2.143 mg/kg
- Chromium: 6.570 mg/kg
- Lead: 2.923 mg/kg
- Mercury: 0.012 mg/kg
- Nickel: 2.643 mg/kg
- Vanadium: 3.06 mg/kg

Previous studies [16] have shown wide ranges in trace metal concentrations, as shown in Table 4-9. These ranges reflect differences in the originating environment of the wood and wood waste. Table 4-10 shows ranges measured for wood waste burned at a pulp mill in the Pacific Northwest.

Table 4-9
Ranges in Concentrations of Trace Metals in Woody Biomass (mg/kg in dry wood)

Metal	Mean	Range
Arsenic	6.5	3 – 10
Barium	---	0.5 – 910
Cadmium	10.4	3 – 26
Chromium	31.4	9.1 – 92
Lead	72	38 – 127
Nickel	36.6	11.6 – 50
Vanadium	53	27 – 79
Zinc	500	200 - 794

Source: Campbell, 1990

Table 4-10
Ranges in Concentrations of Trace Metals in Woody Biomass Burned at a Pulp Mill in the Pacific Northwest (mg/kg in dry wood)

Metal	Mean	Range
Arsenic	0.475	BDL – 1.8
Barium	51.5	43 – 66
Beryllium	BDL	BDL
Cadmium	BDL	BDL
Chromium	128.4	16 – 524
Chromium +6	0.063	BDL – 0.3
Lead	2.71	1.1 – 6.1
Nickel	137.3	BDL – 556
Zinc	99	35 – 207

Source: Tillman, 1994

Trace metals in herbaceous crops and animal manures exhibit the same wide variability. Again, the originating and processing environments govern trace metal concentrations.

4.2.2 Performance Characteristics of Biomass Fuels

Performance characteristics of biomass fuels are critical to understanding their behavior in energy production systems. Fuel volatility, nitrogen evolution patterns, and ash characteristics are among the parameters of most significance.

Biomass Fuel Volatility

Biomass fuels exhibit significant volatility measured through conventional analyses by the volatile/fixed carbon (V/FC) ratio of the proximate analysis and the hydrogen/carbon (H/C) and oxygen/carbon (O/C) atomic ratios derived from the ultimate analysis. Representative biomass

fuels exhibit a highly consistent, very volatile pattern. Typical volatility measures for the fuels shown in Tables 4-2 through 4-4 are presented in Table 4-11.

Table 4-11
Volatility Measures for Representative Biomass Fuels

Volatility Measure	Statistical Measure		
	Average	Standard Deviation	95% Confidence Interval
Volatile/Fixed Carbon Ratio	5.14	1.27	2.65 – 7.63
Hydrogen/Carbon Atomic Ratio	1.51	0.12	1.27 – 1.75
Oxygen/Carbon Atomic Ratio	0.59	0.10	0.39 – 0.79

There is a reasonably consistent pattern of volatility measured through conventional techniques. Further, these measures are significantly higher than the volatility measures for the range of coals burned in the U.S. and throughout the world. Eastern bituminous coals from the Pittsburgh Seam typically have V/FC ratios of 0.40, H/C ratios of 0.69, and O/C ratios of 0.03. Illinois basin coals have V/FC ratios of 0.70, H/C ratios of 0.81, and O/C ratios of 0.06. PRB coals from Wyoming can have V/FC ratios of 0.84, H/C ratios of 0.85, and O/C ratios of 0.19 [17].

Alternative fuel analyses provide significantly more information concerning the volatility of biomass fuels in relation to coal. These analyses are directly related either to the chemical structure of the fuel or to their performance in combustion environments. Such alternative measures include:

- Maximum volatile yield in drop tube reactor (DTR) experiments, in an inert environment, including both the percentage yield and the temperature at which that yield was obtained
- Devolatilization kinetic parameters for Arrhenius equations as derived from drop tube experiments
- Aromaticity as measured in carbon 13 nuclear magnetic resonance (^{13}C NMR) experiments
- Concentrations of methoxy (-OCH_3) functional groups measured during ^{13}C NMR experiments

DTR experiments conducted at The Energy Institute of Pennsylvania State University [7][18] and reported by Tillman [8][19] measured the maximum volatile yield of four biomass fuel samples. Drop tube reactor temperatures varied from 752°F (400°C) to 3092°F (1700°C). All DTR experiments were conducted in an argon atmosphere. In addition to the biomass fuels, Pittsburgh Seam #8 coal and Black Thunder PRB coal were tested as representative fossil fuels. The results of these tests are shown in Figure 4-1.

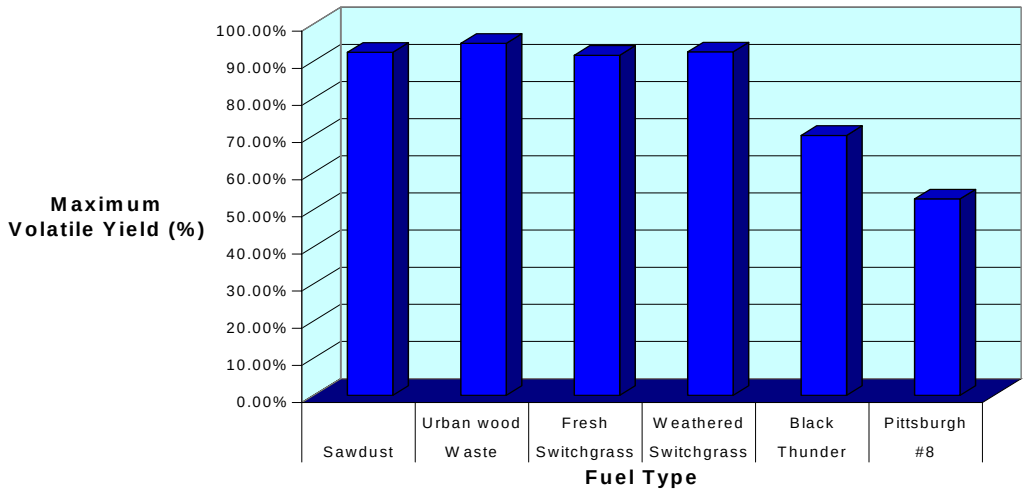


Figure 4-1
Maximum Volatile Yield of Biomass Fuels Compared to Reference Coals (sources: Johnson et al., 2001; Johnson et al., 2002)

All biomass fuels exhibit maximum volatile yields of about 90+%. This compares with the lower maximum volatile yields for the two representative coals. It is also significant to note that the fresh sawdust and fresh switchgrass achieved maximum volatile yields at 1,832°F (1,000°C) while the urban wood waste and weathered switchgrass required temperatures of 2,732°F (1,500°C) to achieve maximum volatile yield.

The DTR experiments were conducted to obtain devolatilization kinetics, using the following equations:

$$R = (V/V^{*})/t_r \qquad \textbf{Eq. 4-1}$$

Where R is reactivity, V is percentage weight loss of the particle at a given temperature, V^{*} is the maximum percentage weight loss, and t_r is residence time in the DTR. V is further defined by equation [4-2]:

$$V = [(w_f - w_c)/w_f] \times 100 \qquad \textbf{Eq. 4-2}$$

Where w_f is weight of fuel being fed and w_c is weight of char produced by the DTR experiment.

The DTR kinetics are summarized in Table 4-12, and illustrated in Figures 4-2 through 4-8. Note that the fresh sawdust shows a two-stage devolatilization mechanism with much of the pyrolysis occurring below 1112°F (600°C). This is consistent with the evolution of extractives and holocellulose (cellulose plus the hemicelluloses). Research by Shafizadeh and DeGroot [20][21] indicates that significant pyrolysis of woody cellulose occurs at less than 570°F (300°C). Research by Broido [22] also confirms the low temperature at which woody cellulose pyrolysis

occurs, and—more significantly—confirms the multi-stage process of woody cellulose devolatilization. Two-stage devolatilization also characterizes many coals.

Table 4-12
Devolatilization Kinetic Parameters for Biomass Fuels and Reference Coals (400-1700°C)

Fuel	Pre-exponential Constant A (1/sec)	Activation Energy E (kcal/mol)
Fresh Sawdust (400-600°C)	1.17	0.681
Fresh Sawdust (600-1000°C)	5.74	3.42
Urban Wood Waste	3.53	2.41
Fresh Switchgrass	4.01	2.67
Weathered Switchgrass	1.91	1.35
Black Thunder PRB Coal	59.1	9.53
Pittsburgh Seam #8 Coal	66.2	10.3

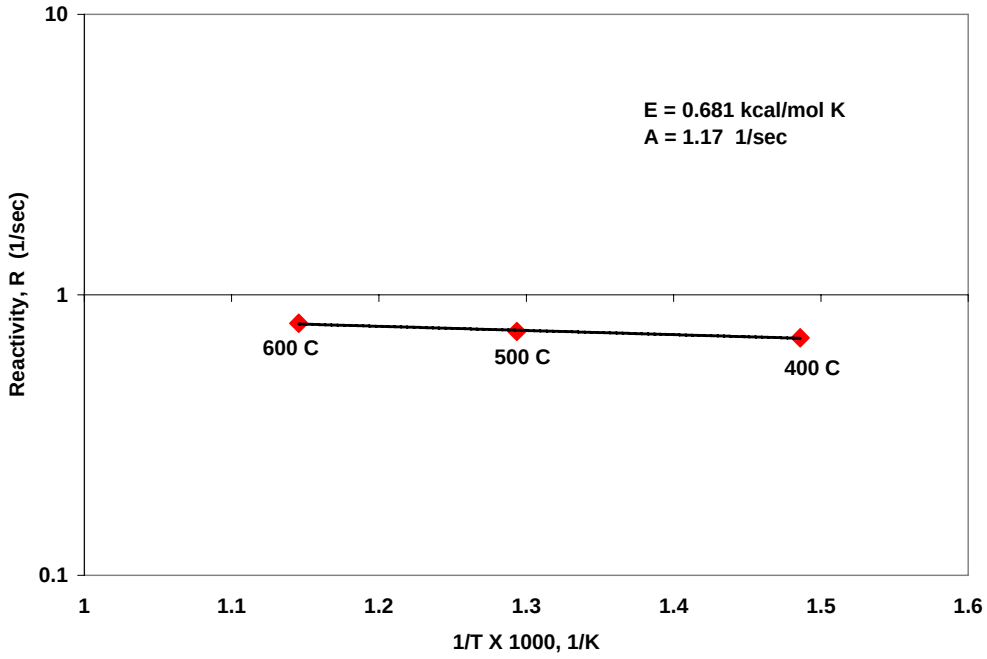


Figure 4-2
Low-Temperature Devolatilization Kinetics for Fresh Sawdust (Source: Johnson et al., 2001)

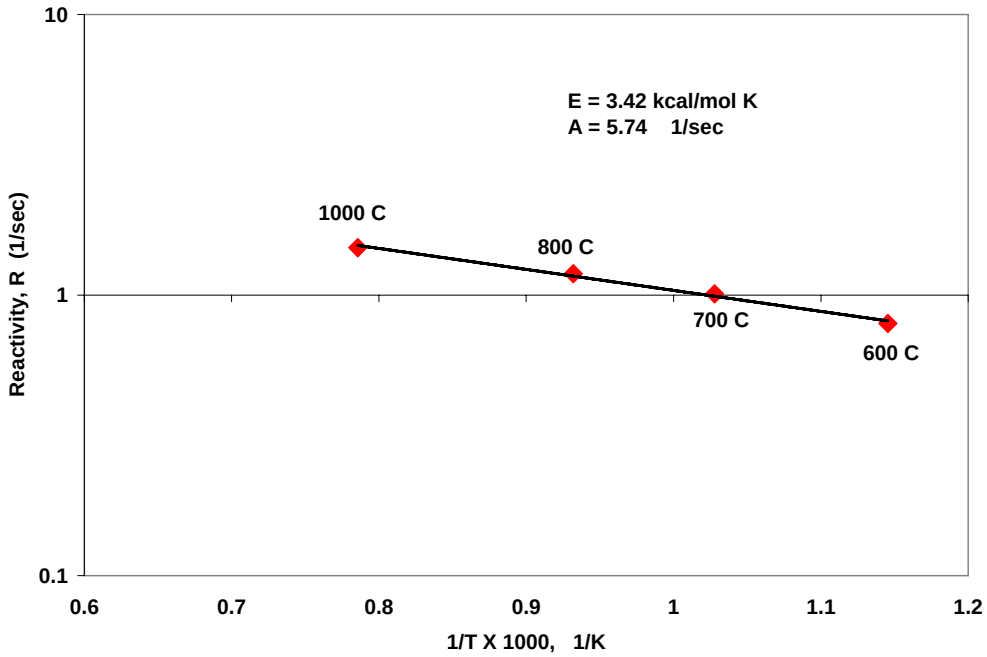


Figure 4-3
High-Temperature Devolatilization Kinetics for Fresh Sawdust (Source: Johnson et al., 2001)

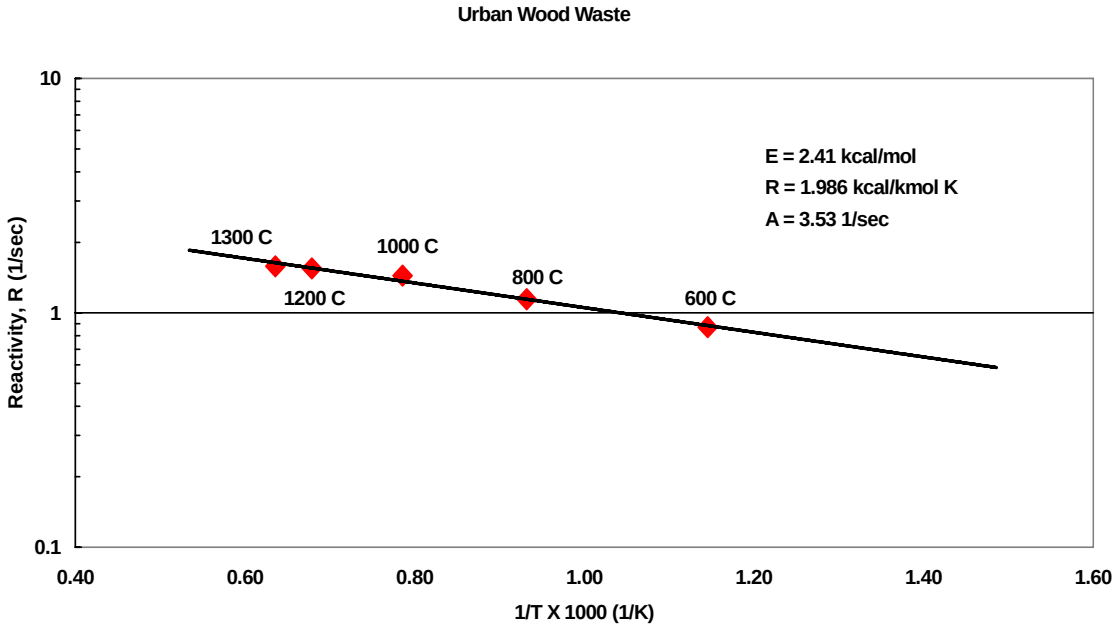


Figure 4-4
Devolatilization Kinetics for Urban Wood Waste (Source: Johnson et al., 2002)

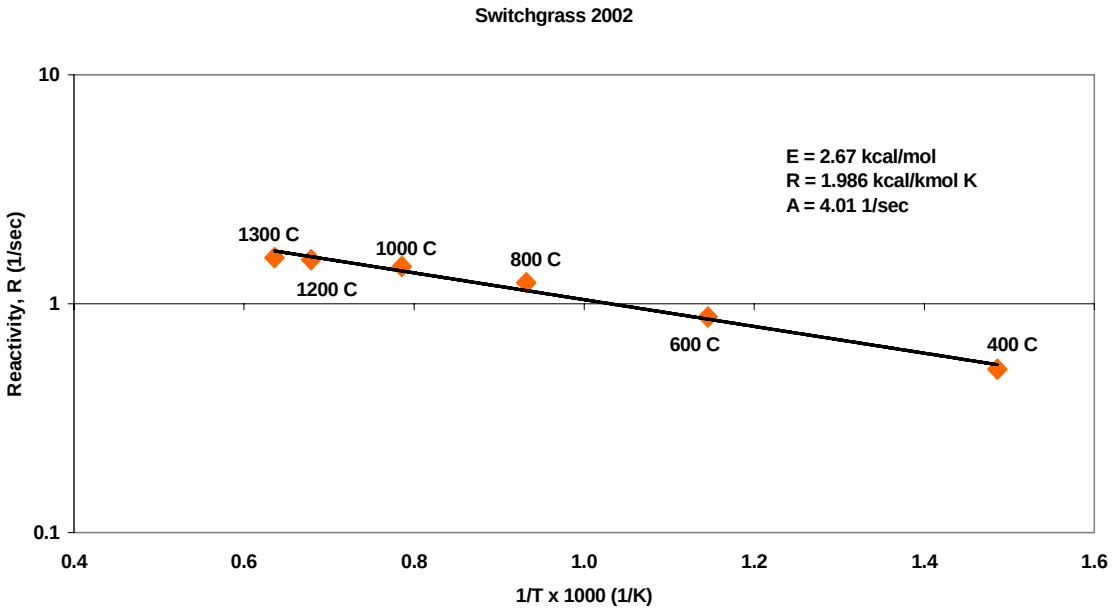


Figure 4-5
Devolatilization Kinetics for Fresh Switchgrass (Source: Johnson et al., 2002)

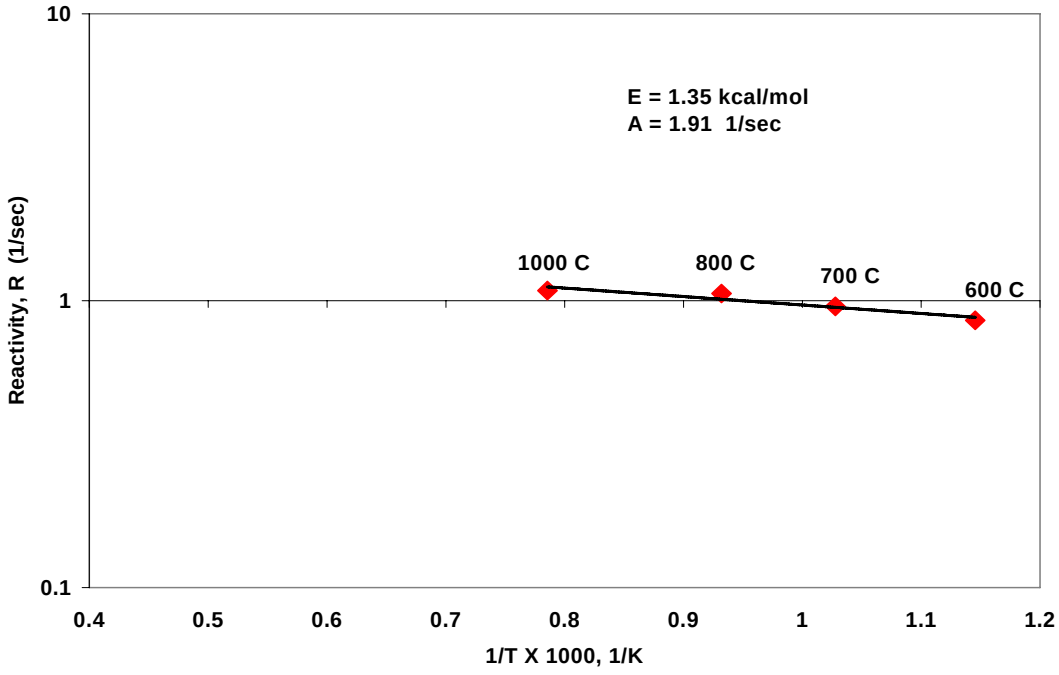


Figure 4-6
Devolatilization Kinetics for Weathered Switchgrass (Source: Johnson et al., 2001)

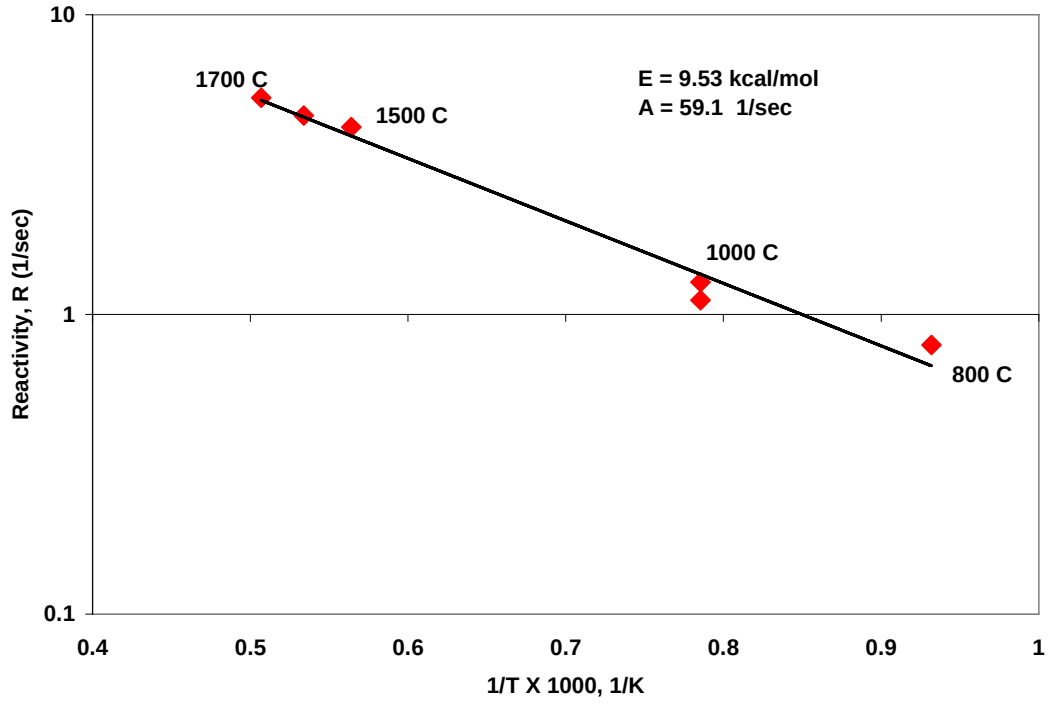


Figure 4-7
Devolatilization Kinetics for Black Thunder PRB Coal (Source: Johnson et al., 2001)

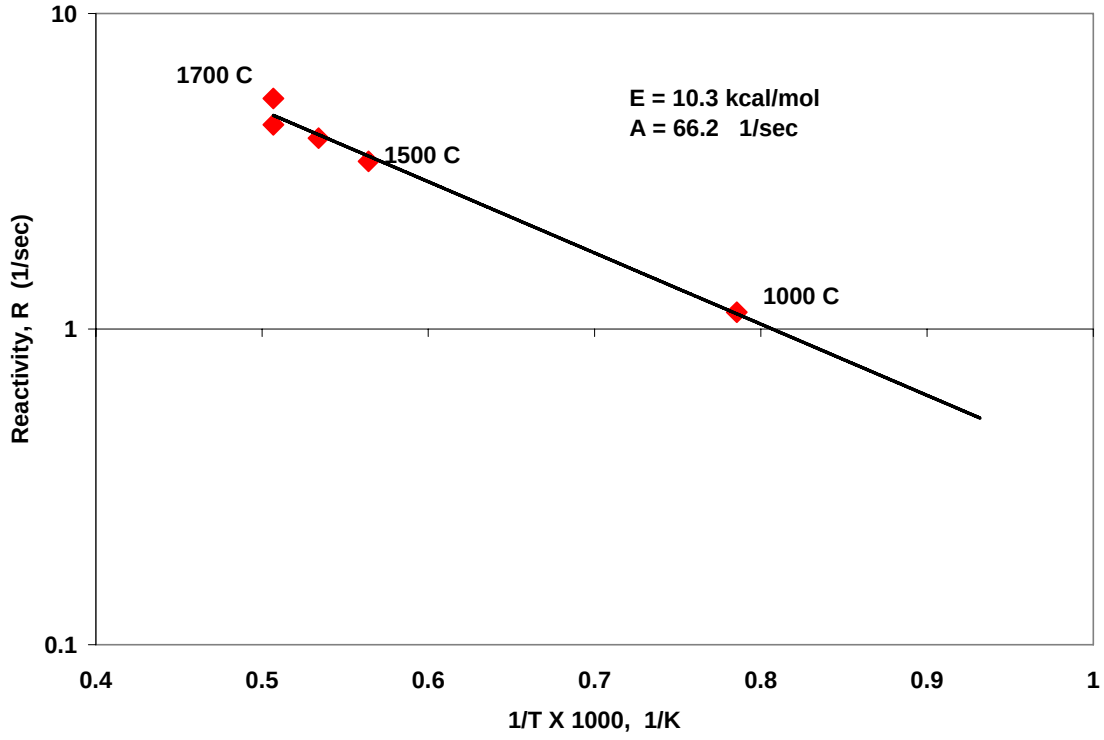


Figure 4-8
Devolatilization Kinetics for Pittsburgh Seam #8 Coal (Source: Johnson et al., 2001)

^{13}C NMR experiments also highlight the fundamental differences in reactivity, or volatility, between biomass fuels and coals. Aromaticity—calculated by equation [4-3]—is the first measure of volatility.

$$Ar = (C_{aromatic}/C_{total}) \times 100 \quad \textbf{Eq. 4-3}$$

Where Ar is aromaticity, expressed as a percentage, $C_{aromatic}$ is the number of aromatic carbon atoms in the sample, and C_{total} is the total number of carbon atoms in the sample. Aromaticities measured by the Energy Institute of Pennsylvania State University are as follows:

- Sawdust: 8%
- Weathered switchgrass: 10%
- Black Thunder PRB coal: 57%
- Pittsburgh #8 eastern bituminous coal: 70%

In all cases, the biomass contained an average of six aromatic carbons per cluster, resulting from single aromatic ring structures. The Black Thunder coal averaged 10 aromatic carbons per cluster, indicating an average of two fused aromatic rings per cluster. The Pittsburgh seam eastern bituminous coal had an average of 15 aromatic carbons per cluster, indicating an average of three to four fused aromatic rings per cluster.

Aromaticity is directly related to devolatilization kinetics, according to equation [4-4]:

$$E_{act} = 1.91 + 17.23(Ar) - 2.00(AC/Cl) \quad \textbf{Eq. 4-4}$$

Where E_{act} is activation energy in the Arrhenius equation in kcal/mol, Ar is aromaticity, and AC/Cl is the measured number of aromatic rings/cluster. This equation was developed over a broad range of fuels including biomass, lignite, subbituminous coals, eastern and Midwestern bituminous coals, and petroleum coke. It has an r^2 of 0.87 and a significance >0.999. It clearly relates biomass structure to its reactivity, and places the biomass reactivity into the overall context of solid fuels.

The final measure of reactivity is the presence of methoxy functional groups in a given solid fuel. Some 8.7% of the carbon atoms in fresh sawdust are in the form of $–OCH_3$ functionalities. Switchgrass has 7.9% of its carbon atoms in methoxy functional groups. In contrast, Black Thunder coal has 4.2% of its carbon atoms in the form of $–OCH_3$ groups, and Pittsburgh seam bituminous coal contains no such functionalities.

Fuel Nitrogen Characteristics of Biomass Fuels

The overall reactivity of biomass fuels is clearly established. The reactivity of nitrogen from the various biomass fuels significantly impacts its ability to influence NO_x formation—or NO_x control. Key measures include fuel nitrogen in $lb/10^6$ Btu as well as the following:

- Maximum fuel nitrogen volatility, paralleling the maximum fuel volatility
- Distribution of volatile fuel nitrogen and char-bound fuel nitrogen

- Pattern of volatile fuel nitrogen evolution

These parameters are important in that the volatile fuel nitrogen is more readily reduced to N_2 through staged fuel and staged air mechanisms. However, it is important to recognize that not all nitrogen volatiles are identical, and they evolve at different time histories. Nitrogen volatiles that evolve more rapidly are more likely to be released from the fuel particle in a fuel rich region of the furnace; nitrogen volatiles that are slow to evolve are more likely to be released in a fuel lean environment, where surplus oxygen exists.

Fuel nitrogen concentrations for four biomass fuels extensively analyzed, along with reference coals, are shown in Figure 4-9. Note the high concentration of fuel nitrogen in the urban wood waste. Total fuel nitrogen concentration in the sample analyzed is consistent with that measured in the urban wood waste cofired at the Bailly Generating Station [11]. It results largely from glues in the plywood and particleboard, OSB, and MDF components of the urban wood waste. It also results from coatings and coverings including paints and laminates. The nitrogen contents in the fresh and weathered switchgrass samples vary significantly, with the weathered switchgrass showing less fuel nitrogen.

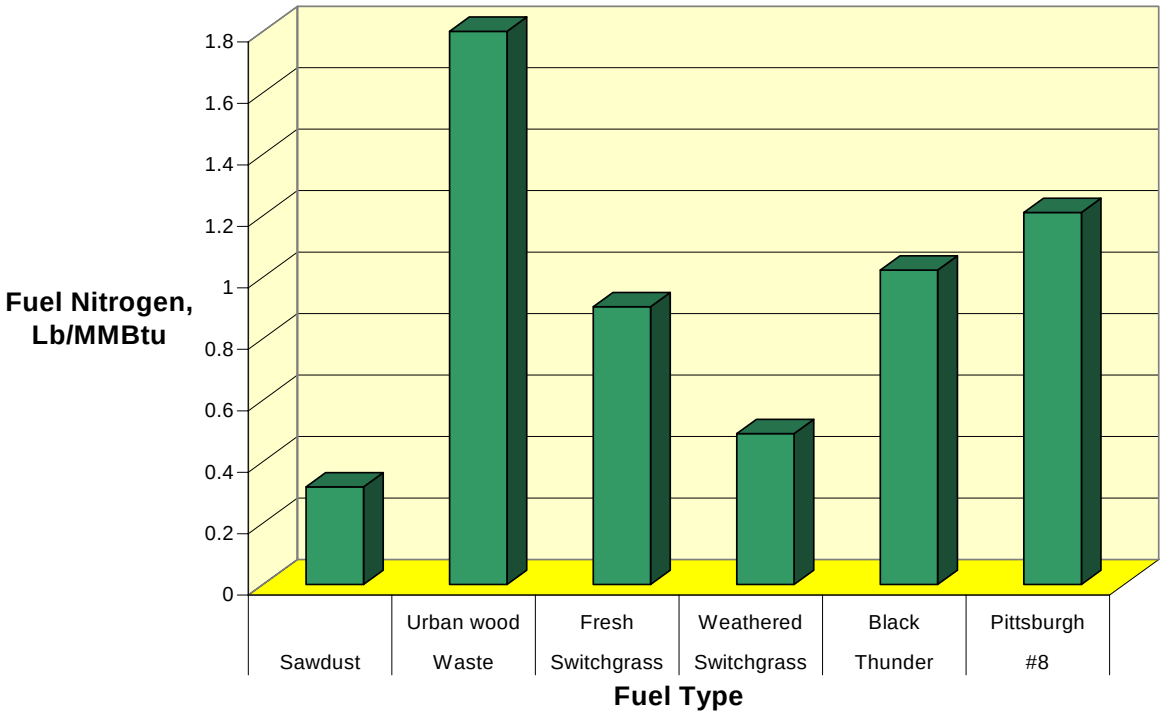


Figure 4-9
Fuel Nitrogen Concentrations for the Fuel Samples Analyzed in Detail (Source: Johnson et al., 2001; Johnson et al., 2002)

The distribution of nitrogen—in volatile or in char form—is shown for these fuels in Figure 4-10. Note that the sawdust contains virtually no char nitrogen. Nitrogen in sawdust has been shown to comprise largely amine functional groups in the living portion of the wood. The char nitrogen is virtually identical for the two switchgrass samples and for the urban wood waste. Clearly some of the nitrogen in the glues does not evolve in volatile form, but remains in the char form. Note, also, that the char nitrogen for biomass is significantly lower than that for the reference fuels. The Black Thunder PRB coal shows increased char nitrogen, and the Pittsburgh Seam coal shows the highest concentration of fuel nitrogen in char form. These data for coals are well correlated to the degree of difficulty in controlling NO_x emissions during pulverized coal combustion.

Maximum volatile nitrogen yield significantly impacts NO_x management. It ties structural considerations to fuel behavior in combustion settings. Figure 4-11 shows maximum nitrogen volatile yield as a function of fuel sample. Note that sawdust shows the highest maximum nitrogen volatile yield while Pittsburgh Seam coal shows the lowest nitrogen volatile yield. Weathered switchgrass shows the lowest nitrogen volatile yield among the biomass fuels. These data are consistent with those previously presented in terms of overall fuel volatility and distribution of fuel nitrogen.

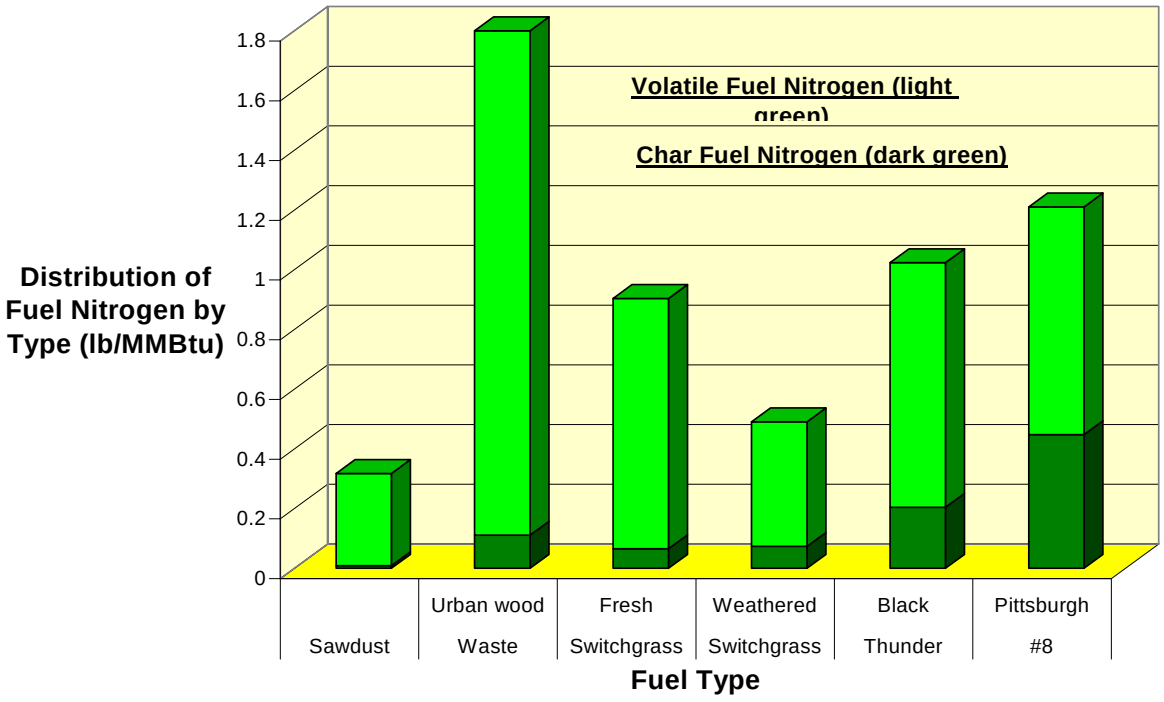


Figure 4-10
Distribution of Volatile and Char Fuel Nitrogen in Selected Biomass and Reference Coal Samples (Source: Johnson et al., 2001; Johnson et al., 2002)

Given these data, it is critical to evaluate the behavior of nitrogen volatiles in biomass and to compare that behavior to the nitrogen volatiles from reference coals. Baxter et al. [23][24] initiated investigations into the rate of nitrogen volatile release from coal particles during the pyrolysis or devolatilization phases of combustion. These investigations recognize that fuel nitrogen in all coal can come in pyrrole, substituted pyrrole, and pyridine forms, and can come in amine and aniline forms in the lower rank coals (e.g., lignites) to a very limited extent. These various forms of nitrogen in fuel volatilize at different temperatures and at different time histories, as the particle is heated and devolatilized. Volatiles that evolve most rapidly are also most easily controlled. They tend to evolve in fuel-rich or oxygen-deficient regions of the combustion system. Nitrogen volatiles retained for longer times in the fuel particle are more likely to be released in fuel-lean regions of the combustion zone, where excess oxygen is available to the volatile nitrogen.

Experiments by Johnson et al. [7][18] in the drop tube reactor document volatile nitrogen evolution patterns for four biomass fuel samples evaluated: sawdust, urban wood waste, fresh switchgrass, and weathered switchgrass. Nitrogen volatilization patterns are shown as a function of temperature, recognizing that the temperature history of the particle is a reasonable substitute for the time history of the fuel particle during the devolatilization phase. In these experiments, the volatile nitrogen evolution rate was compared to the volatile carbon evolution rate, and to the total volatile matter evolution rate. These volatilization patterns were developed over the entire temperature range of 400°C to 1,700°C.

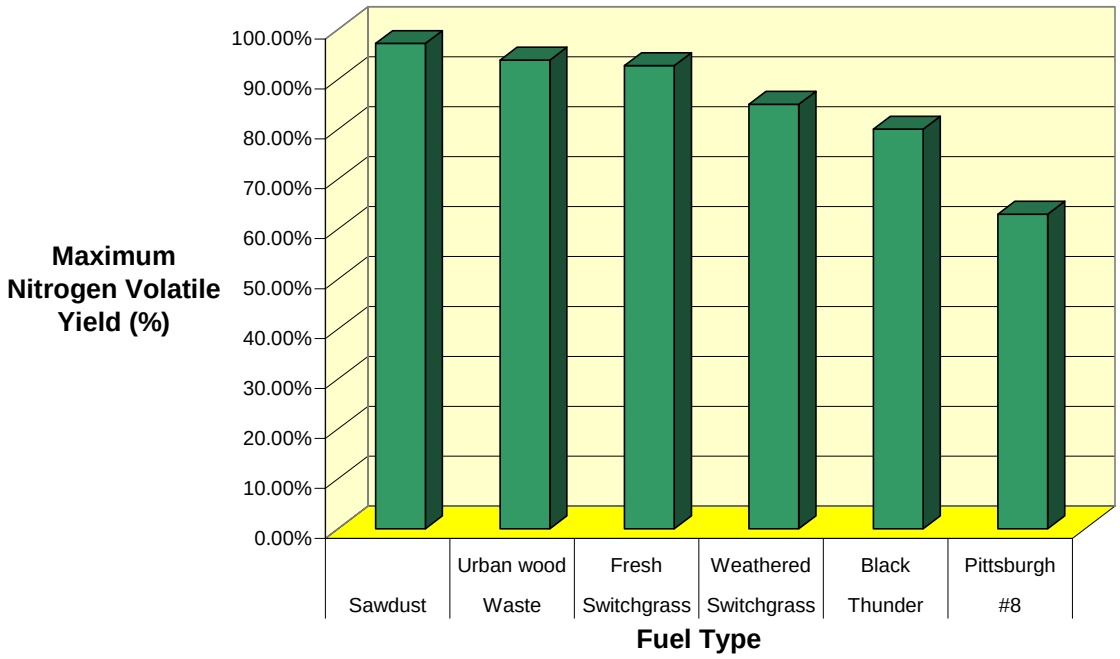


Figure 4-11
Maximum Nitrogen Volatile Yields for Selected Biomass and Coal Samples (Source: Johnson et al., 2001; Johnson et al., 2002)

Figures 4-12 through 4-15 present the volatile nitrogen and carbon evolution rates for representative biomass fuels. Among these samples, nitrogen volatiles evolve most rapidly for sawdust, where nitrogen volatiles evolved more rapidly than the carbon volatile matter, particularly during the initial stages of pyrolysis. For urban wood waste, the nitrogen evolution rate essentially parallels the carbon volatile evolution rate. The nitrogen volatile evolution rate lags just slightly behind the volatile carbon evolution rate for fresh switchgrass. This result is quite similar to the result for urban wood waste. The nitrogen volatile evolution lags significantly behind the carbon volatile evolution for the weathered switchgrass, indicating the potential for more difficulty in using this fuel to reduce NO_x emissions from biomass combustion.

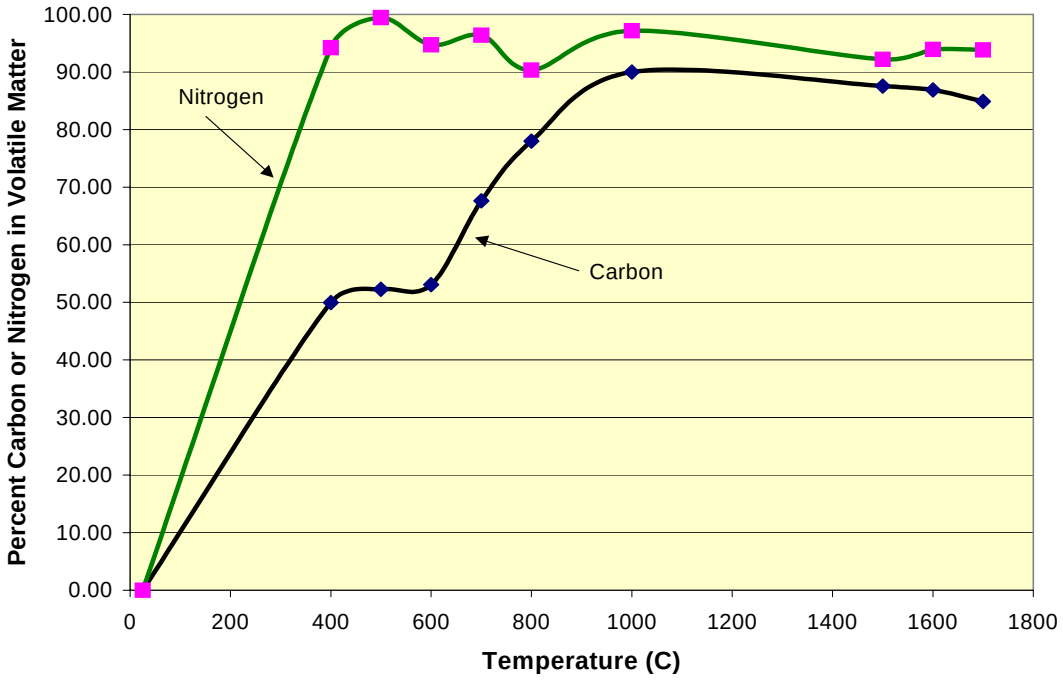


Figure 4-12
Volatile Nitrogen and Carbon Evolution from Fresh Sawdust

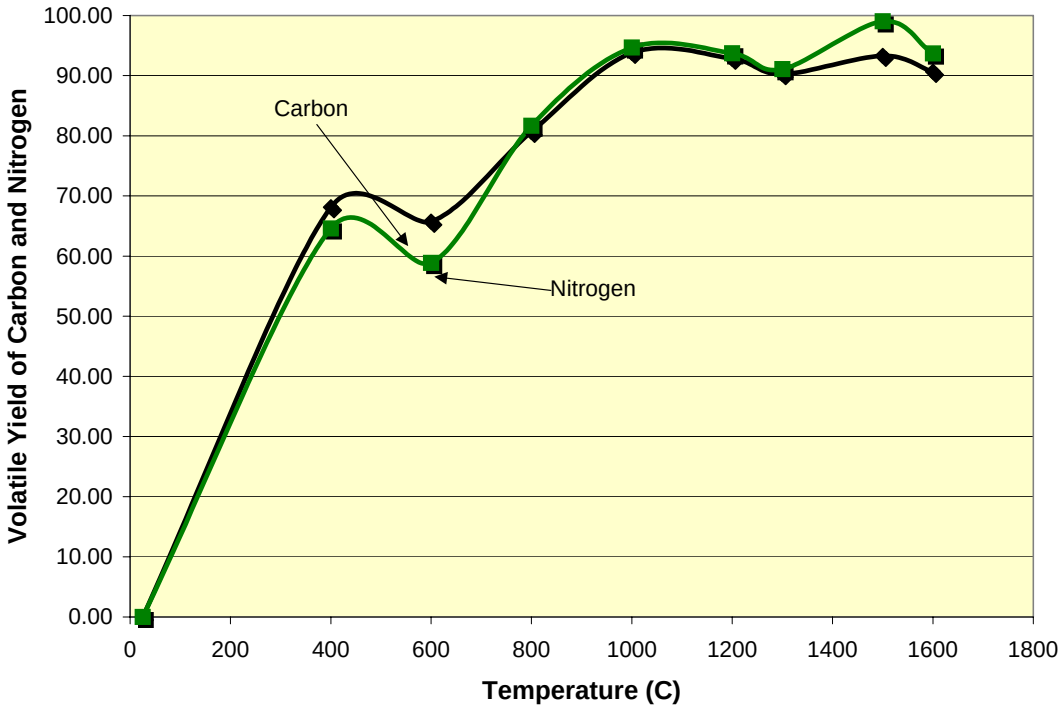


Figure 4-13
Volatile Nitrogen and Carbon Evolution from Urban Wood Waste

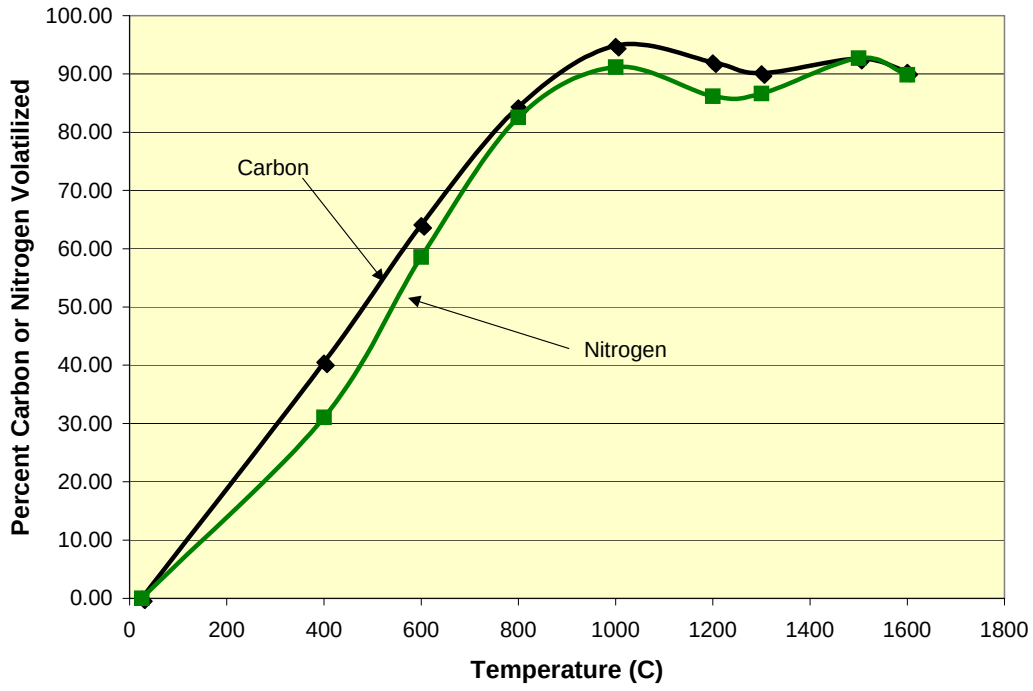


Figure 4-14
Volatile Nitrogen and Carbon Evolution from Fresh Switchgrass

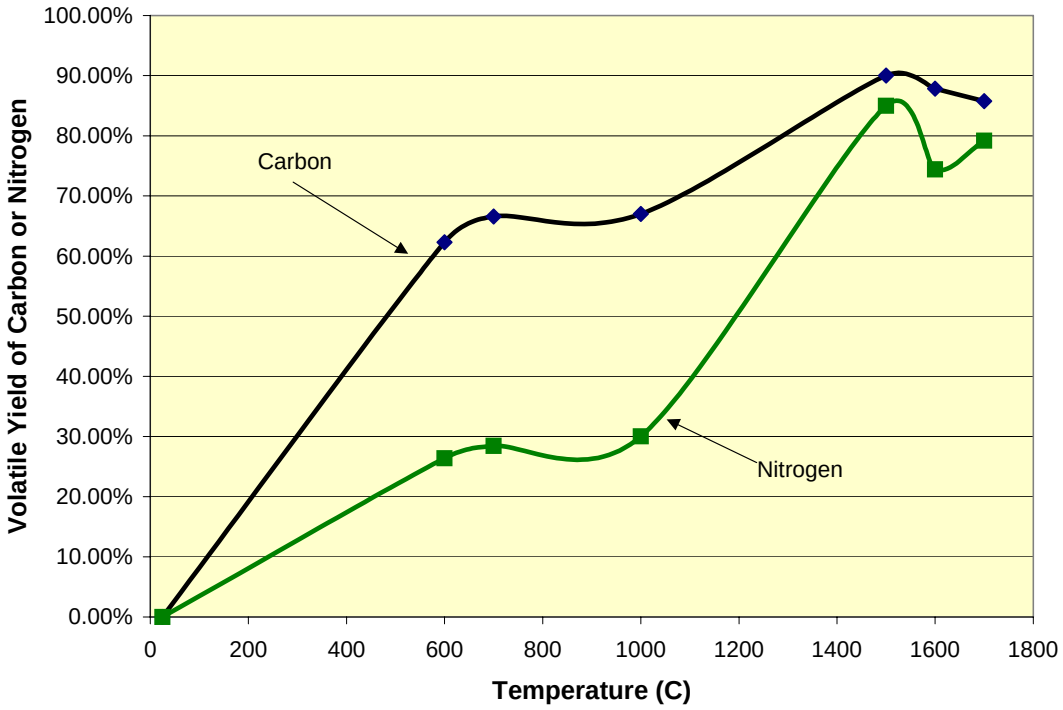


Figure 4-15
Volatile Nitrogen and Carbon Evolution from Weathered Switchgrass

The data presented above can also be normalized to total volatile evolution, as is shown in Figures 4-16 and 4-17 for the sawdust and weathered switchgrass. Normalizing the data to proximate analysis, consistent with the Baxter analysis [23][24], provides a means for relating volatile nitrogen evolution to traditional fuel analyses. Further, it provides a means for relating the nitrogen evolution data to typical information used in burner design and operation.

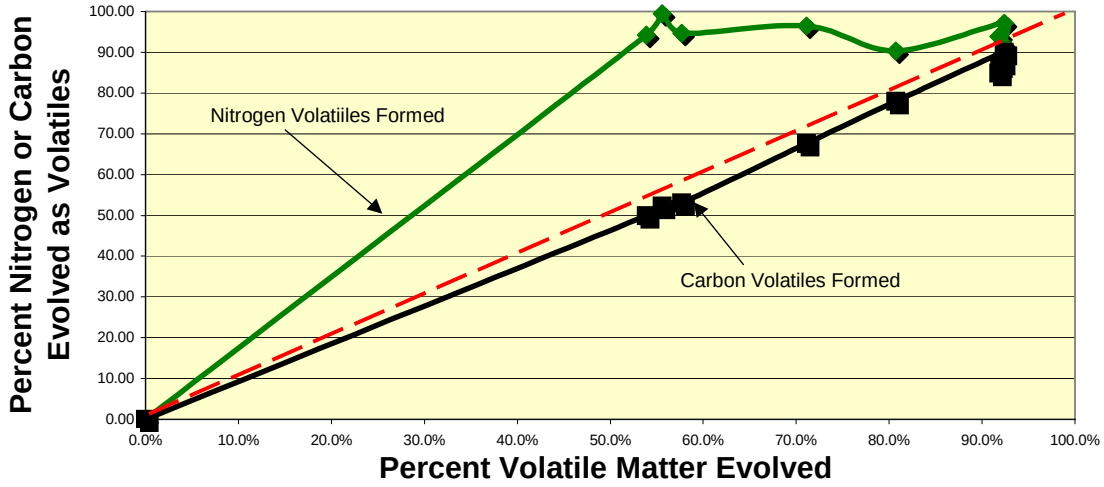


Figure 4-16
Nitrogen and Carbon Volatilization Normalized to Total Volatiles Formed from Sawdust

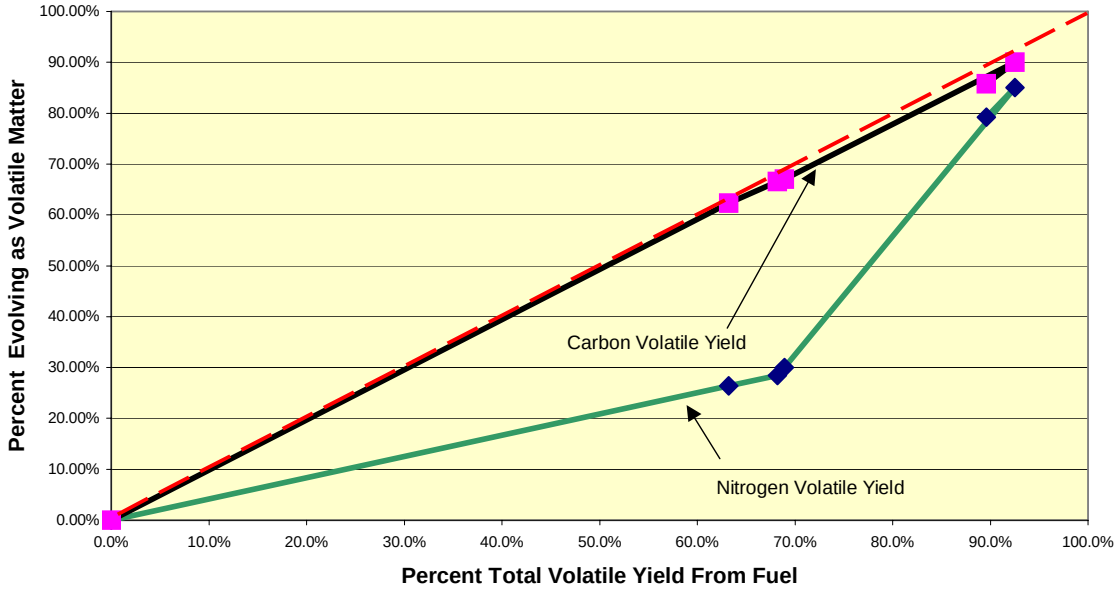


Figure 4-17
Nitrogen and Carbon Volatile Evolution from Weathered Switchgrass Normalized to Total Volatile Evolution

The normalized data demonstrate that the carbon volatile evolution and the total volatile evolution are virtually identical, with only a slight lag in the carbon volatile evolution caused by the hydrogen in the fuel.

An alternative approach to evaluating these data is to calculate the nitrogen/carbon (N/C) atomic ratios of the char remaining from pyrolysis or devolatilization at given temperatures. If the N/C ratio is declining, then the nitrogen volatiles are evolving more rapidly than the carbon volatiles. Alternatively, if the N/C ratio is increasing, then the nitrogen is preferentially being retained in the char. These data can be presented as calculated N/C ratios. These data can also be presented on a normalized basis, where the initial N/C ratio of the fuel is considered 1.0. N/C ratios in the char can then be related to the N/C ratio in the fuel on a proportional basis. Both approaches are presented in Figures 4-18 and 4-19. In Figure 4-19, where normalized data are presented, Black Thunder and Pittsburgh #8 coals are also presented for comparative purposes. The sawdust shows the only initial decline in N/C ratios, indicating the preferential evolution of nitrogen volatiles. The urban wood waste and fresh switchgrass data show that the nitrogen volatiles evolve at a rate just slightly slower than the carbon volatiles. The weathered switchgrass data show that the nitrogen volatile evolution lags significantly behind carbon volatile evolution at the early stages of combustion. The coal data show that the more reactive Black Thunder coal nitrogen volatile evolution pattern essentially mirrors the carbon volatile evolution pattern, while there is a significant lag in the nitrogen volatile evolution relative to the carbon volatile evolution for the Pittsburgh #8 coal.

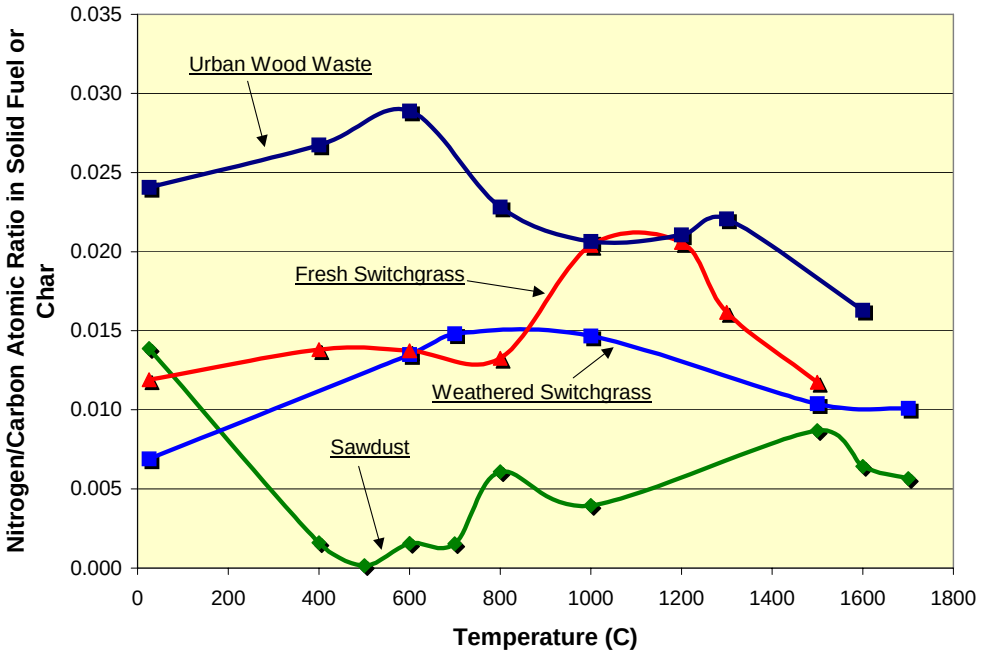


Figure 4-18
Nitrogen/Carbon Atomic Ratios for Biomass Chars Formed During DTR Pyrolysis at Various Temperatures

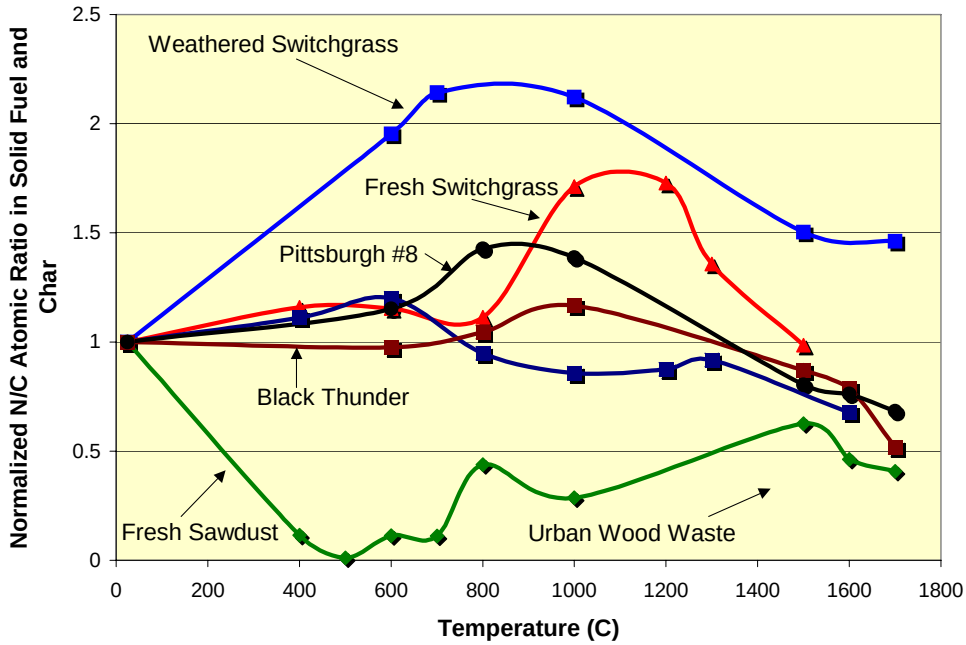


Figure 4-19
Normalized Nitrogen/Carbon Atomic Ratios for Biomass Solid Fuel and Char, Compared to Pittsburgh #8 Bituminous Coal and Black Thunder Powder River Basin Subbituminous Coal

The result of the nitrogen evolution analysis is an assessment of the relative desirability of the four biomass fuels tested. Sawdust clearly has the lowest potential for generating NO_x emissions. Weathered switchgrass has the most potential to be problematic. Fresh switchgrass and urban wood waste are about on equal footing with respect to nitrogen evolution; however, fresh switchgrass has the advantage of a lower fuel nitrogen content. Actual impact on NO_x emissions will vary significantly, though, depending on the fraction of biomass burned, pre-existing combustion conditions, etc.

Ash Reactivity, Slagging, and Fouling

Ash reactivity, slagging, and fouling also provide significant concerns for biomass fuel utilization. Ash elemental analyses have been previously presented. More significant data can be obtained from chemical fractionation of the ash, however. In this procedure (see Miller et al. [25][26] and Miller and Miller [27]), the fuel is successively leached in water, ammonium acetate, and hydrochloric acid (HCl). The successive leaching provides insights into the reactivity of a given inorganic constituent by revealing mineral associations of the cations. Matter leached with water and ammonium acetate is highly reactive; matter leached in HCl is less reactive while the residue from this procedure is considered to be relatively unreactive. Baxter et al. [24] and Bryers [28] have used this procedure to evaluate a wide array of biomass fuels, and a very similar technique is used to assess the deposition probabilities of coals and other mineral effects..

Table 4-13 presents chemical fractionation of an array of biomass fuels developed by Miller et al. [25]. This includes wood, herbaceous material (Reed Canary grass), and manure samples.

Table 4-13
Chemical Fractionation Analyses of Various Biofuel Ash Compared to Pittsburgh #8 Coal

Parameter	Fuel				
	Pine Shavings	Reed Canary Grass	Sheep Manure	Dairy Tie-Stall Manure	Poultry Litter
Potassium					
Water soluble and ion exchangeable	65	97	97	96	41
Acid soluble	0	2	1	1	
Insoluble	35	1	2	3	20
Sodium					
Water soluble and ion exchangeable	77	98	96	99	90
Acid soluble	0	0	2	0	0
Insoluble	23	2	2	1	10
Calcium					
Water soluble and ion exchangeable	92	92	58	68	41
Acid soluble	6	7	41	31	58
Insoluble	2	1	1	1	1
Magnesium					
Water soluble and ion exchangeable	72	95	77	90	69
Acid soluble	10	4	21	9	19
Insoluble	18	1	2	1	12
Aluminum					
Water soluble and ion exchangeable	30	25	32	12	0
Acid soluble	0	3	0	13	0
Insoluble	70	72	68	75	100
Silicon					
Water soluble and ion exchangeable	29	55	0	0	0
Acid soluble	0	0	0	0	0
Insoluble	71	45	100	100	100

Source: Miller et al., 2002b.

Table 4-14, from Baxter et al. [24], presents chemical fractionation of switchgrass.

Table 4-14
Chemical Fractionation of Potassium in Switchgrass for Four Samples

Parameter	Switchgrass Sample			
	A	B	C1	C2
Water Soluble	52	68	70	72
Ion Exchangeable	35	24	20	16
Acid Soluble	9	0	0	2
Residual	4	8	10	10

Source: Baxter et al., 1996b

Baxter, as reported by Miles et al. [10], performed one complete analysis of switchgrass as shown in Table 4-15. These results show the high reactivity of the alkali, and alkali earth minerals along with the low reactivity of the silica, alumina, and titanium dioxide.

Table 4-15
Complete Chemical Fractionation of a Switchgrass Sample

Ash Component	Chemical Fraction (wt %)			
	Water Soluble	Ion Exchangeable	Acid Soluble	Residual
SiO_2	0	0	0	100
Al_2O_3	0	0	0	100
TiO_2	0	0	0	100
Fe_2O_3	0	0	40	60
CaO	2	80	10	8
MgO	32	48	7	13
Na_2O	52	0	0	48
K_2O	70	20	0	10
P_2O_5	70	8	15	7
SO_3	26	69	5	0

Source: Miles et al., 1993

Chemical fractionation provides key insights into the reactivity of ash and its potential to cause slagging and fouling. It provides insights into potential combustion problems of various biomass fuels when used in conjunction with total ash concentration. Reactivity places a premium on low-ash biomass fuels and demonstrates some of the difficulties with the herbaceous materials. It also demonstrates that trees grown for fuel with high doses of fertilizer containing potassium could generate significant slagging and fouling deposits.

4.2.3 Wastewater Treatment Gas and Landfill Gas

Unlike solid biomass fuels, gaseous fuels (generated by anaerobic digestion either in a wastewater treatment reactor or in an enclosed landfill cell) exhibit considerable utility and energy density. All of these gases are produced at atmospheric pressure, and therefore must be compressed before use in internal combustion engines or in combustion turbines. Further, all of these gases are saturated with water and should be dehydrated to some extent before use.

Gas Compositions

Wastewater treatment gas, resulting from the digestion of human matter, has a typical composition of greater than 50% methane on a dry basis, and contains some ammonia, nitrogen, and oxygen depending upon the integrity of the system.

Table 4-16 presents the composition of wastewater treatment gas produced at the T.E. Maxson Wastewater Treatment Plant in Memphis, Tennessee. This gas has been fired in the Allen Fossil Plant of TVA. Note that ammonia was not detected in the analysis. Ammonia concentrations can be significant when animal wastes are digested.

Table 4-16
Composition and Characteristics of the Wastewater Treatment Gas Produced at the T.E. Maxson Treatment Facility in Memphis, TN

Parameter	Value
Gaseous Composition (volume percent, dry basis)	
CO_2	31.4
O_2	0.4
N_2	4.1
CH_4	64.1
Molecular Weight	25.32
Higher Heating Value (Btu/ft^3)	647.7
Lower Heating Value (Btu/ft^3)	584.6
Ultimate Analysis	
Carbon	45.21
Hydrogen	10.17
Oxygen	40.17
Nitrogen	4.45
Higher Heating Value (Btu/lb)	10,002

Landfill gas typically has a lower calorific value, with CO_2/CH_4 ratios in the 48/50 to 52/48 range. Heating values are accordingly lower than those shown in Table 4-16. Landfill gas composition is a function of the age of the landfill, the moisture migration through the cells, and the composition of the material placed in the cells.

Utilization

Because these biomass gases are low in pressure and have modest heating value, they are not readily transported significant distances. They can be cleaned of particulate, moisture, and other contaminants, however, and under such circumstances can be used in numerous generation technologies. Their reactivity—or rate of combustion—is governed by the kinetics of methane oxidation. The many combustion issues associated with using solid biomass fuels do not arise for these fuels.

Use of wastewater treatment gas and landfill gas requires obtaining sufficient quantities in a single location to make the process economical.

4.3 Characteristics of Biomass Cofiring Technologies

Currently the technologies that are commercially available, or commercially offered, include various forms of cofiring along with stand-alone (100% biomass-fired) Rankine cycle generating systems. Cofiring refers to the practice of firing one or another biomass fuels as a supplement to coal (or very rarely, gas). Stand-alone biomass plants may either supply superheated steam to condensing turbines where the only product is electricity; or they may supply steam to backpressure or automatic extraction turbines in cogeneration (also known as combined-heat-and-power or CHP) applications.

Cofiring systems are most readily adapted to electric generating stations. Biomass can be integrated with the fuel supply to existing boilers designed to utility standards. The biomass can be used in large reheat boilers where steam is used most efficiently. Such systems are less expensive than stand-alone power plants on a $/kW supported by biomass basis. If the biomass is unavailable temporarily, the operation of the unit is not compromised. However, integrating biomass fuel into the coal stream still involves complex issues of materials handling and control. Further, cofiring does not contribute additional capacity; instead it displaces coal fuel at the unit. When gaseous biomass fuels (e.g., landfill gas, wastewater treatment gas, producer gas) are fired, additional considerations and benefits are available. Figure 4-20 represents a typical configuration of biomass cofiring in a coal-fired utility boiler.

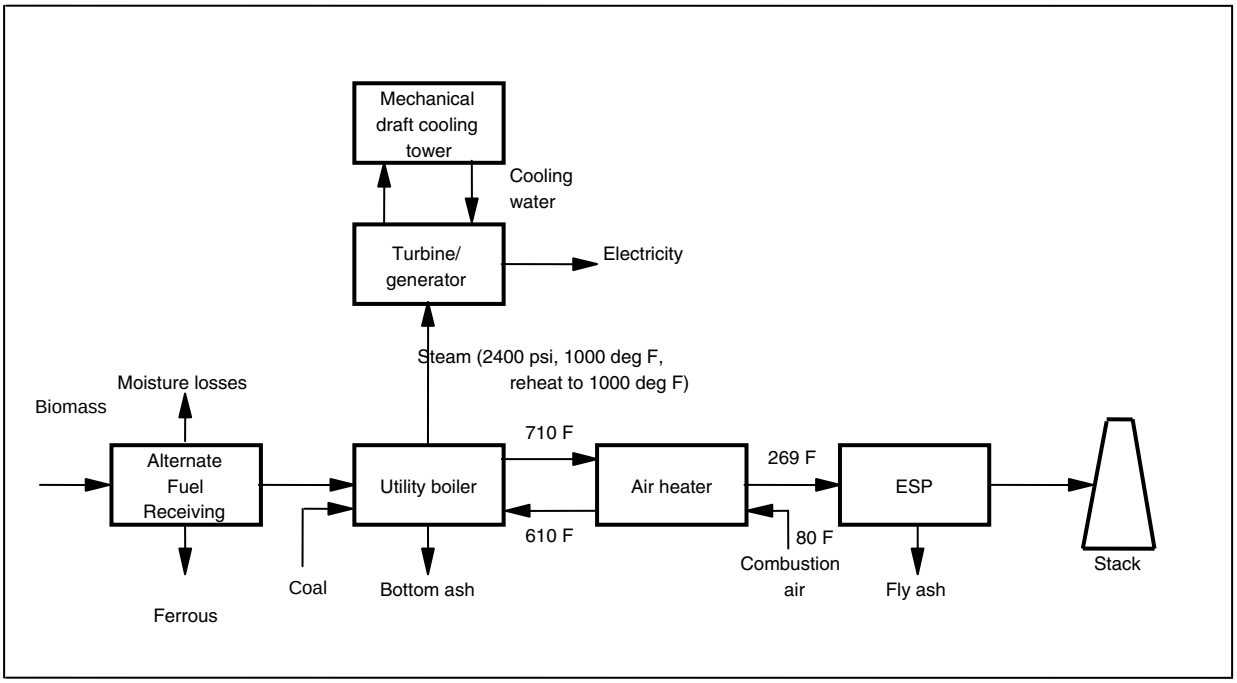


Figure 4-20
Schematic of Biomass Cofiring with Coal in a Utility Boiler

4.3.1 Overview of Solid Biomass Fuel Cofiring Systems

Biomass cofiring refers to a family of technologies designed to introduce these renewable fuels into fossil fuel-fired systems. The common approach is to fire solid or gaseous biomass fuels in coal-fired boilers. Differences in applicable technology are a function of the following issues:

- The biomass fuel being fired (woody biomass, herbaceous biomass, gaseous fuel from a landfill, a wastewater treatment facility, or an atmospheric gasifier)
- The type of boiler (cyclone, tangentially-fired pulverized coal, wall-fired pulverized coal, fluidized bed)
- The percentage cofiring sought
- The design and operating parameters of the unit (e.g., the presence of spare pulverizer capacity, the use of low-NO_x burners)

There are certain combinations that are highly useful, but others simply do not work. Technology selection is based upon putting the most appropriate combination in place.

Numerous facilities have demonstrated cofiring (Table 4-17). Of these, cofiring has continued at the Greenidge Station, the Big Stone Plant, Plant Gadsden, and the Willow Island Generating Station at a minimum. It was previously practiced for many years at the King Generating Station of Northern States Power and several other locations.

Table 4-17
Representative Biomass Cofiring Tests and Demonstrations

Plant	Owner at Time of Demo	Boiler Type	Biomass Fired	Responsible Agency
Allen Fossil Plant	TVA	Cyclone	Sawdust	TVA/EPRI/USDOE-NETL
Kingston Fossil Plant	TVA	T-fired PC	Sawdust	TVA
Colbert Fossil Plant	TVA	Wall-fired PC	Sawdust	TVA
Plant Hammond	Southern Co	Wall-fired PC	Sawdust	Southern Co.
Plant Kraft	Southern Co	T-fired PC	Sawdust	Southern Co.
Plant Gadsden	Alabama Power	T-fired PC	Switchgrass, sawdust	Southern Co., DOE, EPRI
Shawville Generating Station	GPU Genco	Wall-fired PC T-fired PC	Sawdust	GPU/EPRI/USDOE -NETL(2)
Seward Generating Station	GPU Genco	Wall-fired PC	Sawdust	GPU/EPRI/USDOE -NETL(2)
Greenidge Station	NYSEG/AES(1)	T-fired PC	General wood waste	NYSEG/ NYSERDA(3)
Blount St. Station	MG&E	Wall-fired PC	Switchgrass	USDOE/EPRI
Michigan City Generating Station	NIPSCO	Cyclone	Urban wood waste	EPRI/USDOE-NETL(2)
Bailly Generating Station	NIPSCO	Cyclone	Urban wood waste	EPRI/USDOE-NETL(2)
Albright Generating Station	Allegheny Energy	T-fired PC	Sawdust	Allegheny Energy/USDOE-NETL(2)/EPRI
Willow Island Generating Station	Allegheny Energy	Cyclone	Sawdust	Allegheny Energy/USDOE-NETL(2)/EPRI
Dunkirk Generating Station	Niagara Mohawk	T-fired PC	Sawdust/ SRWC	USDOE-GFO(4)
Ottumwa Generating Station	Alliant Energy	T-fired PC	Switchgrass	USDOE-GFO(4)
Polk County Generating Station	TECO	Coal gasifier IGCC	SRWC	USDOE-NETL(2)
Plant Gadsden	Southern Co	T-fired PC	Switchgrass	USDOE-GFO(4)
Studstrup(5)	Midkraft	Wall-fired PC	Straw	Elsamprojekt
Lahti (gasification)	Lahden Lampovoima Oy	Wall-fired PC	General wood waste	FWOy/EU Thermie Program

1. Many of these units have changed hands since the demonstration (e.g., AES has purchased the Greenidge Station formerly owned by NYSEG)
2. NETL is the National Energy Technology Laboratory of USDOE
3. NYSERDA is the New York State Energy Research and Development Agency
4. GFO is the Golden Field Office of USDOE
5. One example of many European cofiring demonstrations

4.3.2 Cofiring in Cyclone Boilers

Cyclone firing demonstrates that the key issues associated with cofiring—either in cyclone boilers or pulverized coal (PC) boilers—are issues of fuel handling. Combustion considerations dictate many of the environmental and technical consequences of cofiring. Materials handling concerns have the major impact on economics.

Cyclone boilers are commonly considered most appropriate for cofiring dissimilar solid fuels—biomass fuels, tire-derived fuel (TDF), petroleum coke, and other opportunity fuels. In cyclone firing, fuel crushed typically to ⅜-inch x 0-inch (9.5 mm x 0 mm) is put up in bunkers. The outfeed from the bunkers falls by gravity through the downcomers to the feeders—typically Stock gravimetric feeders—and is then fed by gravity to the cyclone burners. The fuel is burned in a cyclone, forming a slag layer on the cyclone barrel rather than being burned in suspension.

The flow of fuel to the bunkers, Stock feeders, and cyclones is appropriate for granular and regularly shaped particles. Wood waste such as sawdust at 18 lb/ft^3 works well in cyclone boilers. However, cyclone technology is not suitable for switchgrass and other herbaceous materials. Jenike and Johanson of Westford, Massachusetts, as reported by Bush et al. [29], state that, in evaluating co-feeding and co-milling switchgrass and coal at Plant Gadsden for Southern Co., they analyzed blends of switchgrass and Pratt Seam coal. Their research documented that a blend of 5% switchgrass and 95% coal on a mass basis would not flow from the bunker. The needle-like characteristics of the switchgrass particles, combined with the low bulk densities of switchgrass (e.g., 5 to 7 lb/ft^3), resulted in continuous bridging. As a consequence of the handling characteristics of herbaceous materials, all cyclone demonstrations have been on woody biomass.

Cyclone firing is unique in that the coal is not pulverized, combustion occurs at very high peak temperatures (e.g., 3,300°F to 3,550°F), and inorganic matter is largely converted into a liquid slag, which is then tapped from the furnace bottom. Cyclone firing typically results in about 70% of the mineral matter in the coal or fuel mass being removed as bottom ash or slag. Only 30% of the mineral matter typically exits the boiler as fly ash. Slag or bottom ash is typically sold frequently for sandblasting grit, roofing granules, and other like products.

Cyclone firing can generate high concentrations of NO_x. NO_x emissions of 1.2 to 2.0 $lb/10^6$ Btu have been generated depending upon boiler size and configuration (front wall vs. opposed wall configurations of the cyclone barrels). More recently, numerous cyclone boilers have been equipped with overfire air systems to reduce NO_x emissions to the 0.3 to 0.8 $lb/10^6$ Btu range. No new cyclone boilers have been built since about 1975, due in large part to the NO_x emissions associated with these units.

Cyclones, originally designed for slagging coals of the Midwest, have had success in firing a range of coals. Consequently cyclone boilers were adapted to the cofiring of petroleum coke (see [19]), tire-derived fuel or TDF [30], and other opportunity fuels with coal. In the 1970s, some experiments were conducted cofiring refuse-derived fuel (RDF) with coal in these boilers. In the 1990s, Northern Indiana Public Service Co. (NIPSCO) cofired tar-laden soils from manufactured gas plants with coal in one cyclone boiler. In the early 1990s, Northern States Power also began cofiring dry wood waste from Andersen Windows with PRB coal at its 600 MW_e King Generating Station.

Cofiring Systems Design for Cyclone Boilers

With the exception of the King Station, where dry sawdust was blown into the secondary air system of three cyclone barrels (out of 12), all demonstrations have blended woody biomass with coal and/or other opportunity fuels on the coal pile or on the conveyor leading to the bunker system. Consequently the cofiring system has to have sufficient transport capacity to load the entire requirement for biomass within a two- to four-hour time window depending upon loading schedules at the plant.

Critical variables associated with cyclone cofiring systems include:

- Project design life
- Degree of automation desired
- Space available, including both location and acreage
- Soil conditions where the cofiring system is intended to go
- Plant standards and preferences

Project design life can be between three and 10 years, since the cofiring system addresses existing plants built before 1975. This impacts the robustness of the design. Degree of automation is critical. If the plant accepts a low degree of automation, the capital cost can be minimized; however, labor requirements increase.

At a minimum, cofiring requires a pile and a reclaim conveyor connected to the main belt conveyor feeding the bunkers or silos. This requires a truck unload location and a conveyor with a belt scale for control. One to two workers are necessary to operate successfully. It also requires accepting the risk of tramp material in the biomass. Absent accepting this risk, a magnet must be installed somewhere on the conveyor. This system can be enhanced by a pole barn or similar structure to contain biomass dust. At the other extreme, the system can be built to accept any type of truck and automatically screen biomass for oversized particles, with a grinder for oversized particles, a stock-out bin, a reclaim system, and controls to manage the blend automatically. This may require one-quarter to one-half of a worker. Space available dictates whether a hydraulic truck unloader can be successfully installed. It also dictates conveyor lengths, conveyor selection, and ease of operation. Soil conditions can be critical in determining whether spread footings are acceptable or whether pile construction is required. Plant standards dictate whether or not the electrical installation must be explosion-proof, the extent to which fire suppression systems are required, the method and degree of system controls, and the extent to which redundancy is built into the system. All of these are issues with significant economic consequences.

An example of a cyclone cofiring system is the Willow Island Generating Station boiler #2 demonstration hosted by Allegheny Energy Supply Co., LLC. Willow Island Generating Station #2 boiler, located in Willow Island, West Virginia, is a 188-MW_e (net) unit equipped with five cyclone barrels, all located in two rows or elevations on the front wall of the boiler. The boiler operates in a positive pressure mode. The cyclones are equipped with scroll feeders. Willow Island #2 boiler burns a washed Pittsburgh Seam coal. Limestone is periodically added to the coal to enhance the slag-forming properties of the fuel. The plant is equipped with a “hot side”

electrostatic precipitator (ESP) for particulate control. Overfire air (OFA) was recently added to the #2 boiler to help reduce NO_x emissions.

The design criteria for the Willow Island cofiring system included the following:

- The capability to blend 15% sawdust with coal (mass basis) on the main coal belt, recognizing that normal operation would involve blending 10% sawdust with coal on the main belt.
- The capability to receive and process at least 150 to 200 tons (six to eight truckloads) of sawdust daily in walking floor vans.
- The capacity to store more than three days of sawdust on-site in order to supply the boiler with biomass during weekends, including holiday weekends.
- The construction of a facility with a design life of more than three years.
- The capability to screen the entire mass of biomass fuel in order to protect the crushers and cyclone barrels from undesirable material.
- The capability to grind oversized particles to a fuel specification of less than ¼-inch particles, consistent with maximizing the volatile matter release in the cyclone barrels.
- The capability to meter the flow of biomass to the cyclone barrels in order to measure the blends being put up in the bunkers.
- In addition, the design was robust in order to minimize maintenance commitments.

The system design is shown in Figures 4-21 and 4-22. In this system, walking floor vans discharge their load to a live bottom hopper. The bottom of the hopper is a conveyor belt carrying the sawdust to a 50-ton/hr disc screen capable of producing a fuel of ¼-inch x 0-inch sawdust particles. Oversized material received is discharged from the screen to a slow speed/high torque grinder that reduces the wood particles to the desired size. Acceptable particles are then carried by mechanical conveyor to a 408-ton live bottom storage bin. This bin accepts the material through three openings. It has the capability to level the storage pile of sawdust using three leveling screws at the top of the bin. The floor of the bin is a “walking floor” capable of moving the entire mass of sawdust in the bin.

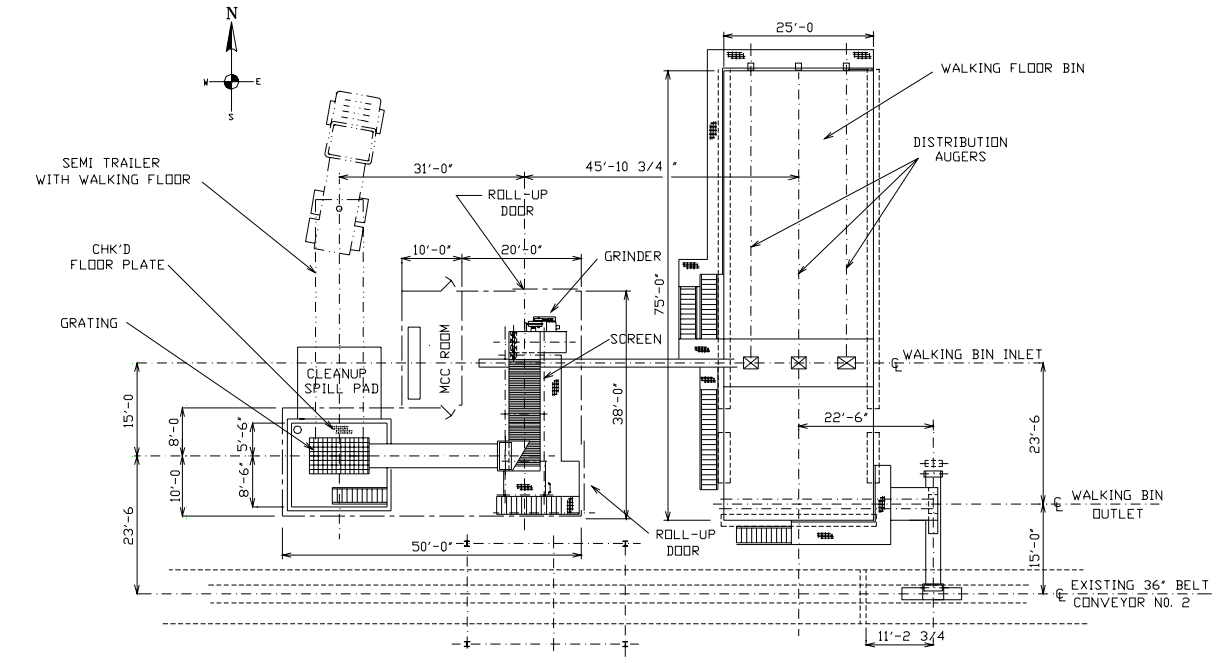


Figure 4-21
Plan View of the Willow Island Biomass Cofiring System

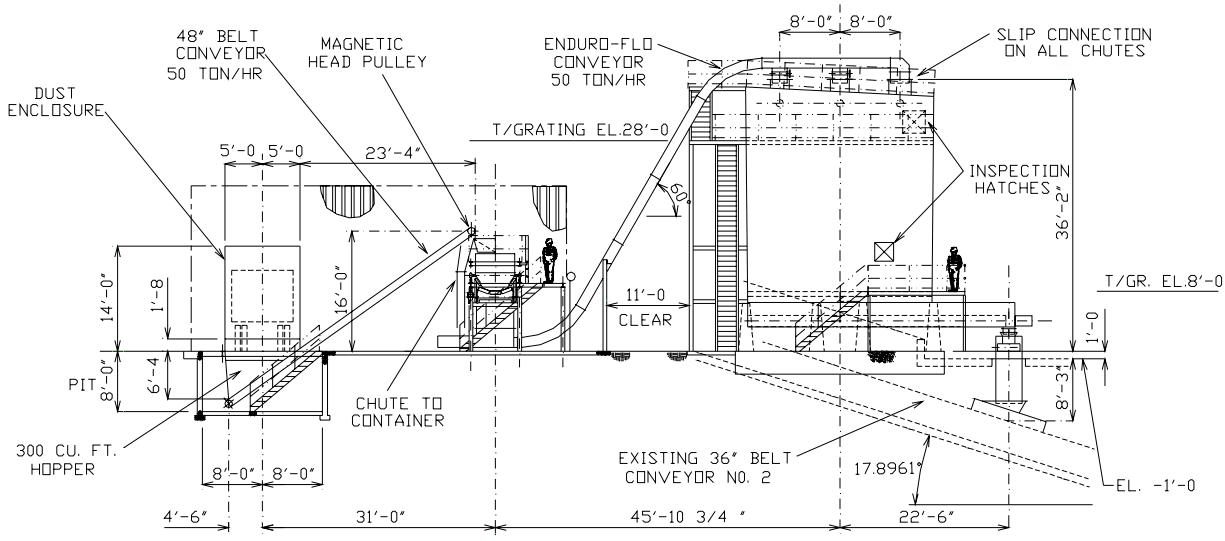


Figure 4-22
Elevation View of the Willow Island Biomass Cofiring System

Sawdust is discharged from the bin by twin counter-rotating augers conveying the material to a weigh belt conveyor. The augers operate at variable speed and meter the sawdust to the weigh belt conveyor. The weigh belt conveyor carries sawdust to the main coal conveyor from the crusher house to the power plant bunkers. The system is designed to convey up to 75 ton/hr of sawdust to the main coal conveyor. Sawdust is added to the conveyor belt before the automatic belt samplers. TDF is added to the conveyor belt separately, after the belt samplers.

The design was based upon walking floor van truck transportation. Value engineering dictated that walking floor vans are used due to the costs of hydraulic chip van dumpers. Further, dust management issues made use of trailer dump trucks less than desirable. Finally, there was insufficient space at the Willow Island site to house a truck dump other than a walking floor receiving hopper.

The design then focused upon screen selection. The disc screen provided an acceptable particle for combustion without generating the levels of dust associated with trommel screens. Further, disc screens experience little blinding. Covered mechanical conveyors, selected both for maintenance and dust management reasons, were used to load the bunker, rather than pneumatic conveyors previously used to feed silos.

The walking floor bin was chosen over a silo due to storage requirements and height considerations, in addition to consequent maintenance concerns when dealing with the head pulley of the conveyor feeding the bin. There were ample reasons for using either type of storage system, and customer preference issues ultimately influenced the choice of the storage facility. Covered, contained storage of the prepared fuel is always employed at power plants due to dust management considerations.

Some additional features were incorporated into the design. A small permanent vacuum system was added to facilitate general site clean-up. Dock seals were added around the truck unloading hopper to minimize sawdust spillage at that location. An inspection door was added to the twin auger conveyor moving sawdust from the walking floor bin to the weigh belt metering conveyor. These features improve the overall performance of the system.

The system was installed on a site requiring extensive piling, which added considerably to the cost. The system also met plant requirements for an explosion-proof electrical system. Figure 4-22 depicts this system.

Capital Costs of Cofiring Systems for Cyclone Boilers

The capital costs associated with the Willow Island Generating Station are shown in Table 4-18. Since this unit was built with the potential to supply 75 ton/hr to the main coal belt—equal to 15% of the coal feed on a mass basis, or 7% of the coal feed on a thermal input basis—it had the capacity to support 13 MWe (net). Normal operation was between 5% and 10% of the total coal input on a mass basis, or 2.2% to 4.5% on a thermal input basis. Given those numbers, the capital cost of the Willow Island system was approximately $180/kW supported by wood if total cofiring capacity is used as the basis. If one assumes a normal operating capacity of 50 ton/hr to

the coal bunkers—or 10% of the total coal flow on a mass basis—then the capital cost of this system is $275/kW supported by biomass.



Figure 4-23
Receiving Sawdust at the Willow Island Generating Station

Table 4-18
Capital Cost of the Willow Island Cofiring Demonstration

Number	Description	Capital Cost
1	Process Equipment	$920,200
	Walking floor bin	
	Outfeed conveyor from bin	
	Cross feed weigh belt conveyor	
	Scale	
	Sawdust receiving hopper	
	Conveyor to disc screen	
	Disc screen	
	Overs grinder	
	Outfeed conveyor	
	Vacuum system	
	Motor control center	
2	Engineering Studies	$194,400
	Soils Studies	
	Engineering	
3	Construction	$1,114,400
4	Home Office Support and Other	$86,800
	TOTAL	$2,315,800

Source: Tillman and Payette, 2004

The capital cost of the Willow Island cofiring system can be compared with that required to construct the Bailly Generating Station cofiring system, as shown in Table 4-19. The Bailly Generating Station cofiring system—consisting of a pole barn, a trommel screen, a pad and aboveground reclaimer, and a metering conveyor belt—cost $1.18 million. It had the capacity to supply 10% of the mass feed, or 5% of the thermal input, for Bailly Generating Station #7 boiler, a 165-MWe cyclone unit. On that basis, the capital cost of the Bailly cofiring system was $140/kW supported by biomass.

The cost range of $140 to $180/kW supported by biomass is a reasonable representation of the capital costs associated with cofiring in cyclone boilers, particularly at the 8- to 12-MW_e range. Because these systems are largely materials handling systems, the exponential scale factor for estimating larger systems would be 0.65 to 0.8. The $1.18 million cost of the Bailly system could well represent a minimum cost for cofiring at smaller scales.

Table 4-19
Capital Cost Summary for the Bailly Generating Station Cofiring System

Number	Description	Capital Cost
1	Process Equipment	$587,700
	Trommel Screen	
	Above Ground Reclaim	
	Air Slide Metering Conveyor	
2	Engineering and Installation	$327,400
3	Home Office Support and Other	$266,500
	TOTAL	$1,181,600

Source: Tillman, 1999

The differential in operating costs associated with automation is due to additional labor requirements. Annual maintenance costs can be estimated at about 4% to 5% of the initial capital investment.

Cofiring Impacts in Cyclone Boilers

Cofiring in cyclone boilers has been tested and demonstrated in a significant number of plants including the Allen Fossil Plant of TVA, the Bailly Generating Station of NiSource, the Michigan City Generating Station of NiSource, and the Willow Island Generating Station of Allegheny Energy.

Efficiency impacts have been modest. At the Willow Island cofiring demonstration, 10% cofiring (mass basis) resulted in an increase in the net station heat rate (NSHR) of 30 Btu/kWh. Efficiency penalties of up to 0.5% have been measured when cofiring at 10% mass basis (5% thermal basis) at the Allen Fossil Plant, the Bailly Generating Station, and the Michigan City Generating Station. This is about equal to 50 Btu/kWh [11].

Operationally, cofiring increased the duty on the coal feeders to the cyclones, as would be expected. In no case did cofiring limit unit capacity. Flame temperatures were largely unaffected. Further, flame intensity of sawdust and finely divided biomass equals that of coal. Furnace exit gas temperatures (FEGT) decreased in all cofiring tests at Willow Island and at the other cyclone demonstrations. Figure 4-24 depicts this phenomenon at Willow Island.

Cofiring can also reduce the viscosity of slag formed in the cyclone barrel, increasing the flexibility of coal chosen. Figure 4-25 depicts the influence of cofiring on slag viscosity as determined by FACTSAGE modeling performed by Miller et al. [25]. Note the significant change in viscosity from 100% bituminous coal to various cofiring approaches.

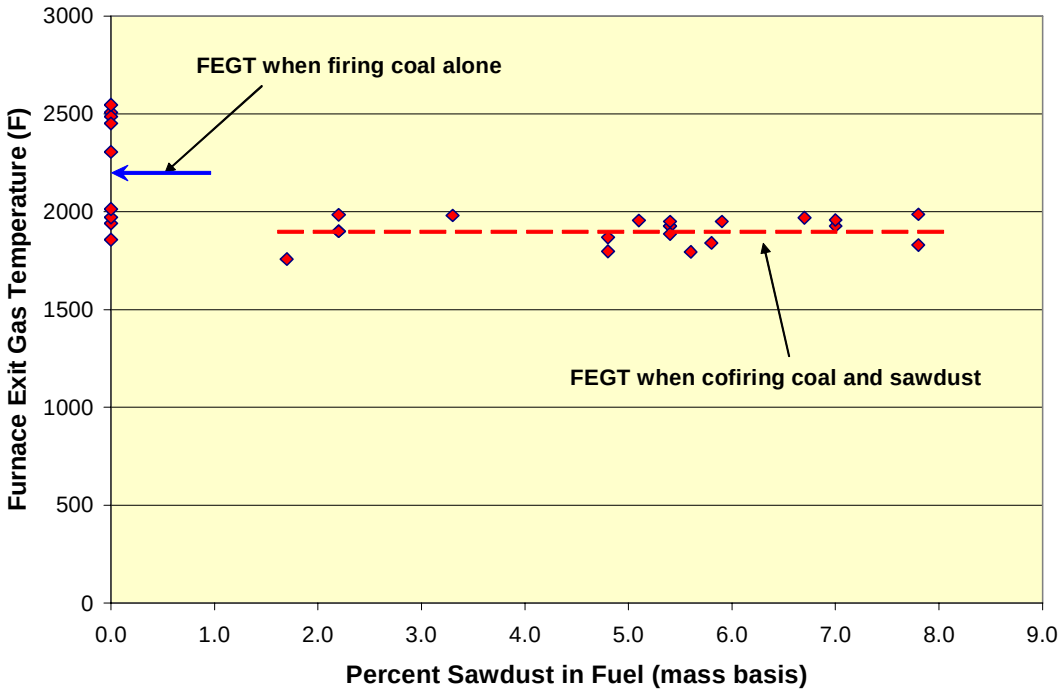


Figure 4-24
Influence of Cofiring in Cyclone Boilers on Furnace Exit Gas Temperature (Source: Tillman and Payette, 2004)

Typically, cofiring has reduced NO_x emissions; however, this has not always occurred. At Bailly Generating Station, NO_x reductions of about 0.1 lb/10^6 Btu occurred when cofiring at 10% wood (mass basis), and were far more dramatic when blending petroleum coke with wood and coal. NO_x emissions reductions at Allen Fossil Plant were up to 0.2 lb/10^6 Btu when cofiring at 10% (mass basis) depending upon the base coal employed. At Willow Island Generating Station, NO_x emissions did not decrease or increase. SO_2 emissions decreased as a function of wood substitution for coal in the boiler.

Testing at Bailly Generating Station [11] demonstrated that carbon monoxide and hydrocarbon emissions did not increase or decrease as a function of biomass cofiring. The influence on SO_3 emissions was inconsequential (approximately 2 ppmvd @ 3% O_2).

In all cases, mercury (Hg) emissions decreased as a function of the concentration of Hg in the feed fuels.

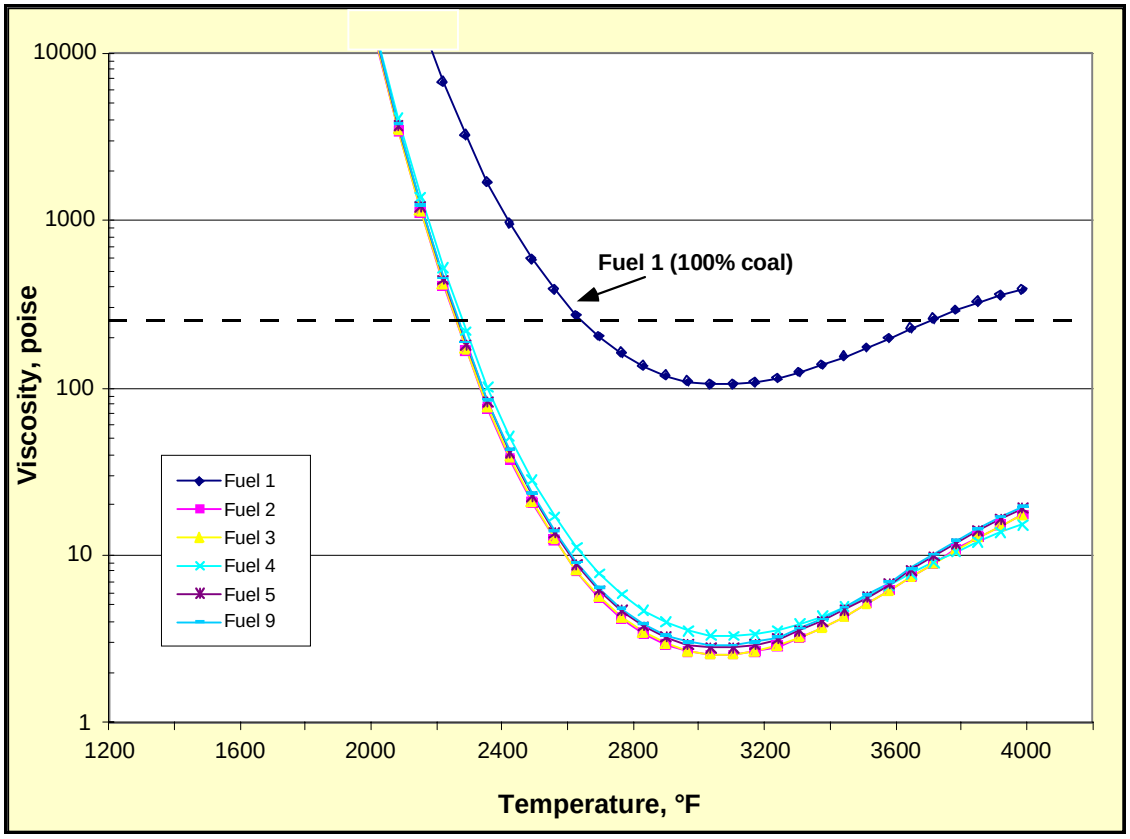


Figure 4-25
The Influence of Cofiring on Slag Viscosity. Fuels 2 to 9 are various cofiring scenarios using woody biomass, herbaceous biomass, and animal manures with eastern bituminous coals (Source: Miller et al., 2002).

4.3.3 Cofiring in Pulverized Coal (PC) Boilers

Cofiring in PC boilers can be accomplished either by blending biomass with coal on the main belt feeding the coal bunkers or by separately injecting biomass directly into the furnace equipped with either burner modifications or specially designed biomass burners. Blending on the belt is limited to woody biomass. Herbaceous biomass such as switchgrass causes significant problems in this application, as previously discussed (see also [29]). With woody biomass, initial research by TVA showed that the percentage of biomass in the feed to the bunkers must be less than 5% (mass basis) in order to minimize problems with the mills. Testing at Shawville Generating Station of GPU Genco (now Reliant Energy) demonstrated that pulverizers were negatively impacted even at 3% biomass (mass basis). If boilers are equipped with Riley Atritta mills, the maximum biomass percentage may be about 8%.

Most demonstrations of PC cofiring—both tangentially fired boilers and wall-fired boilers—have focused upon separately preparing and injecting biomass into the primary furnace. Examples of domestic tests and demonstrations include:

- Greenidge Station
- Blount St. Station
- Seward Generating Station
- Gadsden Station
- Ottumwa Generating Station
- Albright Generating Station
- Dunkirk Generating Station

Cofiring System Designs for PC Boilers

There have been several cofiring demonstrations using separate injection. Of these, the Albright Generating Station of Allegheny Energy Supply Co., LLC provides key insights into design and cost considerations.

The process design for the Albright Generating System cofiring demonstration somewhat paralleled the design for Willow Island in concept. However, numerous differences occurred in equipment selection, largely due to the following factors:

- Moving to an existing demonstration at Seward Generating Station, where equipment had already been selected based upon different project criteria
- Favoring pneumatic conveyance of sawdust, rather than mechanical conveyance of sawdust
- Injecting the sawdust directly into the boiler, requiring changes in the final handling and control approaches

The Albright design involved accepting sawdust through a walking floor receiver. This receiver is slightly wider than a walking floor van, and can hold the entire load of a single truck. This provides for surge capacity in the unloading process. The discharge of the walking floor unloader is a series of screw conveyors transporting the sawdust to a 30-ton/hr disc screen.

A disc screen was chosen for Albright Generating Station, rather than a trommel screen or deck screen. Dust management was the critical issue, and a disc screen with covers generates less dust in the work area than a trommel screen. Disc screens have been successfully deployed in the forest products industry as well as the waste-to-energy industry. This screen produces a product for suspension firing at less than 6.35 mm (<¼-inch). The size chosen was based upon extensive research conducted from 1992 to 1995, and the success of both TVA and Southern Company firing <6.35 mm (<¼-inch) sawdust in PC boilers.

The <6.35 mm (<¼-inch) sawdust from the screen was deposited in a bin and then pneumatically transported to the top of the agricultural silo. Material rejected as being oversized was originally ground in a research grinder; when that proved unsuccessful in a commercial application, it was returned to the vendor and the oversized material—less than 5% of the incoming feedstock—was disposed of. Some employees used a portion of this as mulch on their own property, while some was landfilled. Eventually a two-stage grinder and associated dust management system was purchased to achieve particle size reduction of oversized product.

From the silo, sawdust was reclaimed on demand, fed through a surge hopper and onto a weigh belt conveyor feeding a live bottom bin. The live bottom bin discharged sawdust into two rotary airlocks, each supported by blowers. This arrangement transported sawdust to opposite corners of the T-fired boiler. Processing equipment was housed in a metal building in order to manage the entire process. The building also housed the motor control center and all other electrical systems.

The Albright system delivered up to 6 tons/hr to the boiler, supporting the generation of approximately 6.0 MW_e or about 4.3% of the net generation of the #3 boiler. Injection into the boiler was accomplished with two specially designed injectors capable of following the burner tilts. The boiler has four rows of burners, with the injectors installed between the B and C rows. The burners and sawdust delivery system were designed with a tip velocity of 25.5 m/s (5,000 ft/min) and with an air/fuel mass ratio of 2 kg air/kg fuel. This achieved a sub-stoichiometric air/fuel ratio and a fuel speed sufficient to overcome the flame speed of biomass. The first consideration was essential for NO_x control; the second consideration was a safety issue.

The system used two independent control systems: one to manage the flow of fuel to the silo and a second to manage the flow of sawdust to the boiler. The second set of controls allows the system operator to set the flow of sawdust—up to 5.5 tonnes/hr (6 tons/hr) to the boiler—at his discretion. It also permits the operator to shut down the flow of sawdust with an emergency stop if, for any reason, the operator believes that such action is in the best interest of the boiler and the power plant.

The design for Seward Generating Station, also using sawdust, was virtually identical to Albright with one exception; instead of having a separate biomass injector, the Seward wall-fired burners were modified to fire sawdust into the center of the coal burner. The sawdust and the coal interacted in the flame envelope (Figure 4-26).

Both Albright and Seward used separate blowers and separate transport lines for each biomass injection point. An alternative used at both Plant Gadsden and Dunkirk Generating Station acquired biomass from the bin using an eductor and a single transport line. This transport line then employed a splitter to convey the biomass to individual burners.

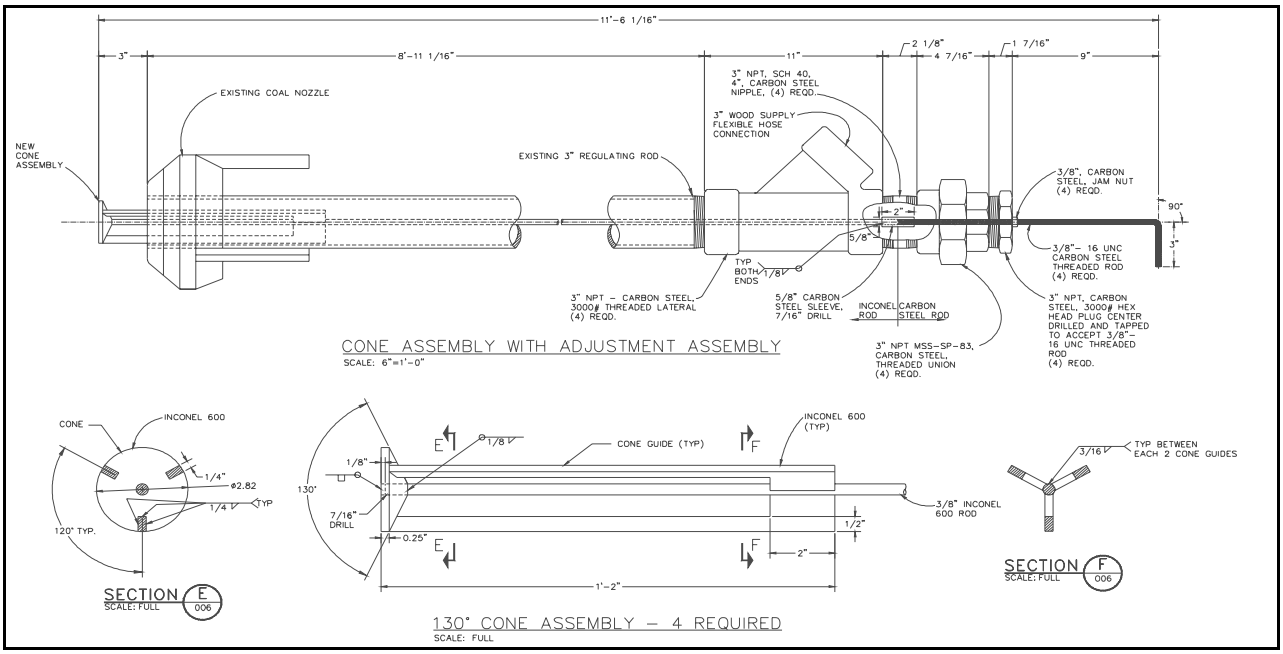


Figure 4-26
Design of the Sawdust Injection System at Seward Generating Station

Capital Costs of Separate Injection PC Cofiring Systems

The capital costs associated with cofiring in PC boilers via blending on the main coal belt—as demonstrated at Colbert Fossil Plant and Kingston Fossil Plant of TVA, Shawville Generating Station of GPU Genco, and Pickway Station of American Electric Power—are comparable to those of cofiring in cyclone boilers. The capital costs associated with separate injection are somewhat higher.

Table 4-20 summarizes the capital costs for the Albright project, assuming that it would be constructed from completely new equipment. Given that the system could support 6.0 MW_e, the installed capital cost was $300/kW output supported by biomass. It may be surprising that the cost of reasonably automated cofiring systems for cyclone and separate injection PC boilers are separated by only about $120/kW. However it must be remembered that cyclone systems must deliver 24 hours of fuel in a two- to three-hour span (while bunkers are filling). Separate injection systems deliver significantly lower quantities of biomass to the boiler (or bunkers) on a per-hour basis.

Capital costs associated with herbaceous crop cofiring systems are likely to be substantially higher than those associated with biomass. Experience at the Ottumwa Generating Station, as well as at the Grena, Avedore, and Studstrup Power Plants of DONG Energy in Denmark, demonstrate the need to commit significant resources to dry storage of the biomass and to extensive grinding systems. Further, because herbaceous biomass is largely a seasonal product, investments are required to provide this material on a year-round basis.

Table 4-20
Estimated Capital Cost of the Albright Cofiring Demonstration if Constructed as a New Facility

Number	Description	Capital Cost
1	Process Equipment	$882,700
	Burners	
	Disc Screen	
	Overs 2-stage grinder	
	Dust control for grinder	
	Screw conveyor	
	Sawdust receiving bin, blower, And cyclonet	
	Storage silo and unloader	
	Paddle conveyor	
	Surge hopper and live bottom bin	
	Weigh belt feeder	
	Rotary airlocks and blowers	
	Walking floor unloader	
	Motor starters, Motor Control Centers, and Related	
	System controls	
2	Engineering Studies	$82,100
3	Construction	$710,000
4	Home Office Support and Other	$135,600
	TOTAL	$1,810,400

Source: Tillman and Payette, 2004

Impacts of Cofiring Biomass in PC Boilers

The impacts of separate injection cofiring solid biomass fuels in PC boilers are distinct and separate from those for cofiring in cyclone boilers. Biomass cofiring does not reduce boiler capacity. In winter, when wet coal reduces capacity, biomass cofiring can facilitate recovery of some of the lost capacity as demonstrated at Seward Generating Station [8][19][31].

Efficiency penalties can be very modest or somewhat significant depending upon system design and operation. Typically, biomass is introduced with ambient air. This reduces the combustion air passing through the air heater and raises the temperature of the gaseous combustion products exiting the air heater. Further, like cofiring in cyclone boilers, moisture in the fuel along with hydrogen in the fuel exerts a minor penalty on boiler efficiency. At Albright Generating Station,

for example, the efficiency penalty was about 3.5 Btu/kWh per mass percentage sawdust cofired. This resulted in a penalty of 35 Btu/kWh at 10% cofiring.

Emissions impacts are clear, and significant. SO_2 emissions decline as a function of biomass Btu substitution in the boiler. Similarly, Hg emissions decrease as a function of Btu substitution. CO and opacity emissions are not impacted by cofiring, assuming the test results at Albright Generating Station can be generalized to all units. NO_x emissions decrease, particularly as a function of targeting the location of the biomass injection.

At Seward Generating Station, NO_x emissions decreased dramatically when cofiring sawdust, and the data are represented by equation [4-5]:

$$NO_x = 0.030 + 0.0017(L) + 0.082(EO2) - 1.917(W_h) \quad \textbf{Eq. 4-5}$$

where NO_x = oxides of nitrogen, lb/10^6 Btu, L = load measured as main steam flow in kpph, EO2 = excess O_2 reported in the control room (total basis), and W_h = wood cofiring percentage, heat input basis. The r^2 for equation [4-5] is very high at 0.93. Further, the probability that any term is a random occurrence is extremely small. These probabilities:
L = 2.09×10^{-5}; EO2 = 2.53×10^{-5}; W_h = 8.39×10^{-7}; and the equation as a whole = 4.36×10^{-6}.

NO_x can also be expressed on a mass basis, as is shown in Equation 4-6:

$$NO_x = 0.026 + 0.0017(L) + 0.083(EO2) - 0.899(W_m) \quad \textbf{Eq. 4-6}$$

where W_m = wood cofiring percentage, mass basis. Again the $r^2 = 0.93$. The probabilities in equation 4-6 are essentially identical to those of equation 4-5.

The NO_x reduction at Albright Generating Station indicated in Figure 4-27 is represented by the equation:

$$NO_x = 0.361 - 0.0043(C_{m\%}) + 0.022(EO_2\%) - 0.00055(SOFA) \quad \textbf{Eq. 4-7}$$

where NO_x is measured in lb/10^6 Btu, EO_2% is percent excess oxygen in the flue gas leaving the furnace (total basis), and SOFA is the total position of the three SOFA damper systems. Alternatively, the equation is

$$NO_x = 0.157 - 0.002(W\%) + 0.009(O_2\%) - 0.00024(SOFA) \quad \textbf{Eq. 4-8}$$

where NO_x is measured in kg/GJ.

As indicated in these equations, Albright Unit #3 was equipped with a low-NO_x firing system, including three levels of separated overfire air (SOFA). The SOFA values used to create these equations ranged from 15% to 240%, representing a 0% to 100% opening for each SOFA level. The mechanisms yielding NO_x reduction at Albright included reducing the loading on the pulverizers, improving their performance; creating a reducing zone in the center of the fireball; and improving the ability to use the SOFA system. With cofiring, SOFA dampers were opened up to 240% without increasing unburned carbon or loss on ignition (LOI) in the fly ash.

Experience from the Studstrup plant, which fires 20 tph straw continuously into a 350-MW unit, indicates little or no impacts in NO_x, LOI in ash, corrosion, or heat rate. Other European cofiring experience, such as that in the UK and Netherlands, similarly suggests little adverse impact on boiler operations, emissions, or byproducts.

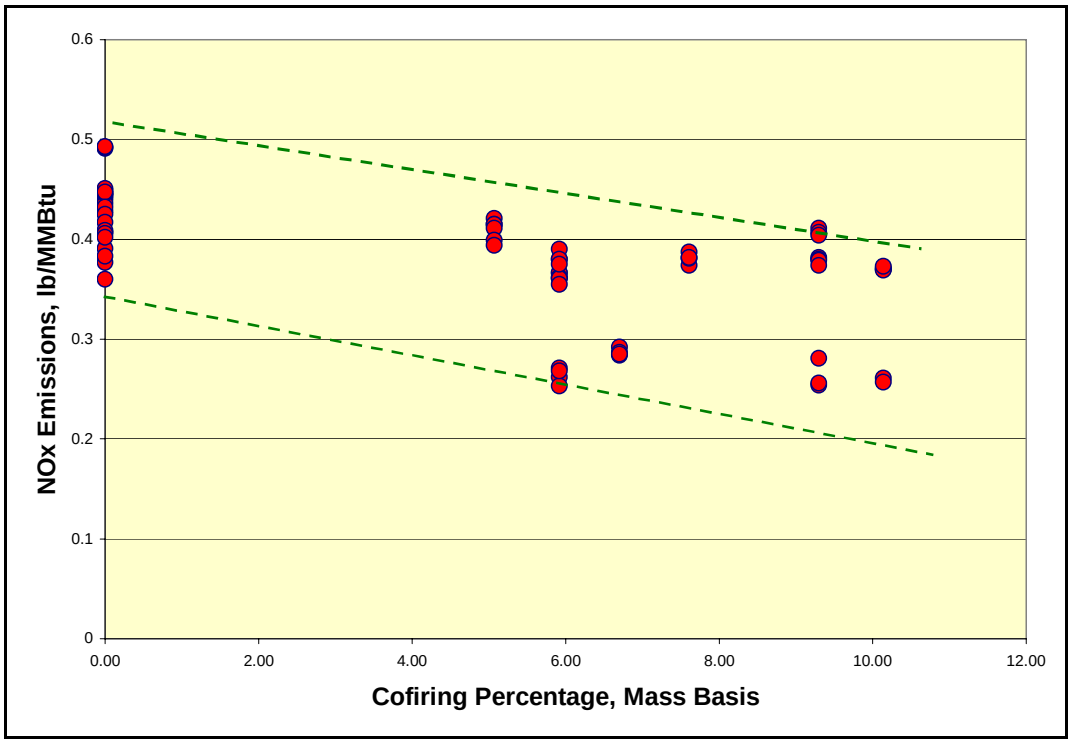


Figure 4-27
NO_x Reduction at the Albright Generating Station Test Program

4.3.4 Cofiring Gaseous Biomass Fuels

Gaseous biomass fuels can be cofired in coal-fired boilers, natural-gas-fired boilers, or combined-cycle power plants. In the latter case, the design with the most near-term potential introduces biomass gas in a duct burner between the combustion turbine and the heat recovery steam generator (HRSG). Both producer gas from biomass gasification and natural gaseous biomass fuels can be used in these applications.

The most frequently reported example of producer gas cofiring was installed at the Kymijarvi power plant in Lahti, Finland. The power station is a district heating plant that also generates electricity. This coal-fired generating station has capacity to produce 167 MW_e and 240 MW_{th} of district heat. The utility, Lahden Lampovoima Oy, owns and operates the plant. The Lahti gasification project involved installing a Foster Wheeler atmospheric circulating fluidized bed gasifier capable of converting sawdust, bark, wood chips, plywood trim, particleboard trim, and recycled fuel (REF) into a producer gas for firing in the coal-fired boiler. The REF consists of plastics, paper, cardboard, and wood. The gasifier has also blended tire-derived fuel (TDF) into the overall feedstock.

In this project, biomass fuels are brought to a central processing facility where they are shredded and prepared as feedstock for the gasifier. The atmospheric CFB gasifier itself is very simple. The system consists of a reactor where the gasification takes place, a cyclone to separate the circulating bed material from the gas, and a return pipe for returning the circulating material to the bottom part of the gasifier.

The hot gas, as produced at 1,520°F to 1,580°F (827° C to 860° C), is then fed directly to the boiler, using both the chemical energy and sensible heat of the gas. In tests on the unit, the gasifier supplied 12% to 16% of the total heat input to the boiler. The gasifier was put on line in September 1998 and has been operational ever since. It has an average availability approaching 88%, with its highest monthly availability slightly above 95% (Raskin et al., 2001). A similar system is used by Electrabel at their Ruein Unit 5 to contribute 17 MWe out of 540 MWe.

Other utilities have studied similar applications, using gasifiers supplied by a variety of vendors. Various feasibility studies have estimated the capital costs for such systems as approximately $600/kW supported by biomass. Such capital costs include both the material handling systems for biomass fuels, the gasifier and the hot gas piping. If gas cooling and clean-up are required, the capital costs increase.

Use of wastewater treatment gas and landfill gas is also frequently proposed. Such gaseous products, at low pressure and at 500 to 650 Btu/scf, can be attractive if the gas is used in immediate proximity to a suitable power plant. This gas can be used in coal-fired boilers, natural-gas-fired boilers, or in combined-cycle applications. Again it is most suitable as a duct burner fuel in a combined-cycle application. One such installation exists south of Sacramento, California.

Wastewater treatment gas is fired in the Allen Fossil Plant, generating green power for TVA. In this application, wastewater treatment gas from the Maxson Wastewater Treatment Plant serving the south side of Memphis, Tennessee. Gas is introduced in separate burners above the cyclone barrels. Although the Allen Fossil Plant approach does not make special use of the gas, landfill gas or wastewater treatment gas could well be employed as reburn gas if that technology is favored.

The database for these applications is insufficient to provide estimates of capital cost or operating and maintenance costs. Quantities of gas available, specific application, piping distances, and the degree of gas clean-up required make each case unique. It is sufficient to note that this approach can be quite cost-effective depending upon the individual situation.

4.3.5 Conclusions Regarding Biomass Cofiring

Biomass can be cofired in numerous applications—such as cyclone boilers, wall-fired and tangentially fired PC boilers, and natural gas boilers and combined-cycle plants—depending upon the biomass available and the technology of choice. These systems can be cost-effective depending upon the plant, the supply and cost of the biomass, and the design employed. Cofiring is the least-cost approach to biomass utilization in electricity generation.

Research is ongoing to address the impact of biomass cofiring on the life of deNOx catalysts and on fireside corrosion. In both cases, the alkali/alkaline earth constituents prevalent in the biomass may adversely impact catalyst poisoning or corrosion reactions.

4.4 Stand-Alone Biomass Fired Systems

Stand-alone biomass-fired systems designed to produce electricity include a myriad of designs including but not limited to:

- Stand-alone wood or wood-waste-fired generating stations producing electricity as an exclusive product or producing both electricity and process steam in cogeneration or combined-heat-and-power (CHP) applications.
- Spent pulping liquor (e.g., black liquor from Kraft pulping) combustion systems designed to recover pulping chemicals while producing steam for both electricity generation and process heat applications.
- Bagasse-fired boilers used to generate electricity in the sugar industry.
- Other agribusiness systems with biomass either fired directly in a boiler or gasified and gas fired in a waste heat boiler with steam subsequently used for electricity generation.
- Boilers fired with landfill or wastewater treatment gas, designed to produce electricity.
- Combustion turbines fired with landfill or wastewater treatment gas.
- Internal combustion engines, typically diesel engines, fired with landfill gas, wastewater treatment gas, or producer gas from woody or herbaceous biomass gasification.

Of these, wood-waste-fired boilers and chemical recovery boilers are the dominant sources of biomass electricity today. Black liquor from Kraft pulp mills is used to produce more electricity than any other form of biomass, followed closely by wood waste.

Chemical recovery boilers and associated systems are specific to the pulp and paper industry, and are not considered further here. The wood-waste-fired boiler is the focus of this discussion, as it provides the most promise for electricity generation.

4.4.1 Wood-Waste-Fired Boilers

Wood-waste-fired boilers, also known as hog fuel boilers, have long been used in the forest products and pulp and paper industries to generate process steam and to cogenerate both electricity and process steam. Major integrated forest products mills producing a product mix including Kraft pulp, plywood, and dimension lumber commonly installed such boilers as power boilers. Examples abound, including the Longview #11 boiler at the Weyerhaeuser complex in Longview, Washington and comparable power boilers at Weyerhaeuser facilities in Columbus, Mississippi, Plymouth, North Carolina, and New Bern, North Carolina. Georgia Pacific, International Paper, and others have similar installations.

Electric utilities and independent power producers also constructed wood-waste-fired boilers to generate electricity as their sole product. Large units have been constructed by Washington

Water Power at Kettle Falls, Washington, Burlington Electric at the McNeil Generating Station in Burlington, Vermont, and at other locations. Independent power producers built similar systems to fire wood waste and wood-like biomass fuels. Large numbers of such systems were built in California, Maine, and elsewhere in response to the Public Utilities Regulatory Policies Act (PURPA), the need for capacity in certain areas of the country, and localized availability of materials. The Shasta Generating Station in Anderson, California is a prime example of such facilities.

Typical Capacities of Wood-Waste-Fired Plants

While coal is produced at a central location such as a mine and distributed to users, wood waste is produced as a diffuse resource and collected or gathered into a user location. This fundamental distinction highlights one capacity limitation impacting biomass systems. The second limitation results from the typical fuel characteristics:

- 15 to 20 lb/ft^3 bulk density
- 40% to 50% moisture
- 8 x 10^6 to 10 x 10^6 Btu/ton as-received

These factors combine to limit boiler and generating capacity. Given typical transportation distances for wood fuel of up to 50 miles (80 km.), wood-fired boilers have been limited to a nominal 100 to 125 ton/hr firing rate (nominally 10,000 ft^3/hr of fuel), or 50 to 70 MW_e depending on system design and operation. This capacity limitation carries with it significant implications:

- It is difficult to economically justify more than three turbine extractions for feedwater heaters; the three extractions are typically for a low-pressure heater, the deaerater, and a high pressure heater. In some cases only one extraction (deaerater) is justified.
- Reheat cycles that significantly improve cycle efficiencies are not economic at the size plants available for wood firing.
- Depending on staffing philosophies, such units will achieve ratios of 0.5 to 2.0 MW_e per worker, depending upon unit capacity and staffing approach. This contrasts with conventional coal-fired staffing ratios of 3 to 6 MW_e/worker.

Typical stand-alone wood-fired power plants have been built at capacities ranging from 11 MW_e to 70 MW_e, with the larger plants proving most successful.

Wood-Waste-Fired System Design

Numerous wood-waste-fired systems have been developed for the current market. In order to evaluate system design, a generic plant has been configured. It represents standard practices in wood-waste-fired technology. Variations on this approach are also discussed.

Fuel Handling

The standard approach to fuel handling is shown in Figure 4-28. Loaded trucks of wood waste are received and unloaded by hydraulic unloaders that raise the truck sufficiently to dump the load into a hopper and feed it to a disc screen. Oversized particles are hogged using hammer hogs or (rarely) knife hogs. The entire fuel pile is then stocked out. Wood waste or hog fuel is then reclaimed and transported to the plant where it is discharged into bunkers.

Because typical truckloads contain 20 to 25 tons of wood waste, large plants such as McNeil Generating Station or Kettle Falls Generating Station require a significant commitment to wood fuel handling. A 50-MWe plant burning 80 to 100 tons/hr requires four to five trucks/hr, 24 hrs/day, seven days/wk. Burlington Electric chose another approach to keep truck traffic out of the plant neighborhood. They receive wood waste off site, load it into open hopper railroad cars, and bring the biomass in to be discharged through a trestle arrangement. This has plant benefits, but increases the cost of materials handling.

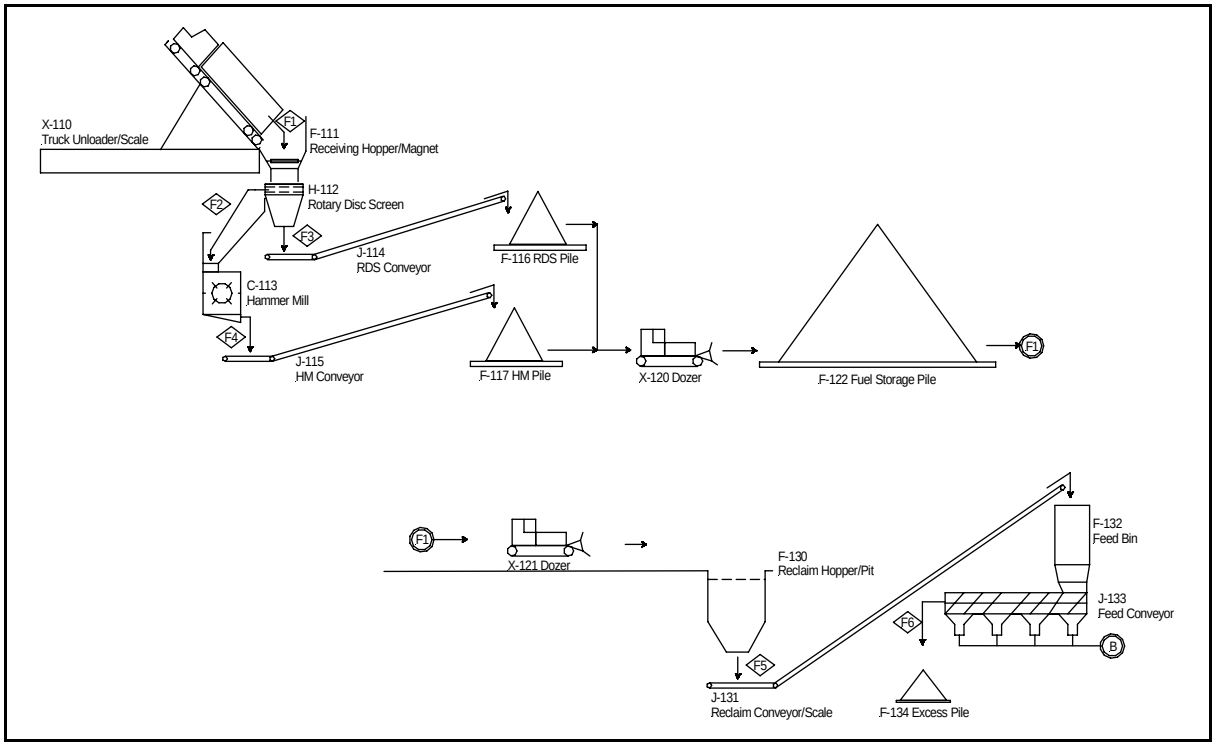


Figure 4-28
Representative Wood Fuel Handling System

Weyerhaeuser at Longview, Washington, uses a wood fuel stacker-reclaimer arrangement instead of bulldozer reclaiming. This helps manage the 100+ tons/hr burned in its #11 boiler.

Numerous studies have addressed the addition of drying systems to the materials handling as a means for improving boiler efficiency. These are not generally employed. Dryers require energy to operate, consequently reducing the efficiency gain. Further, drying technologies introduce the potential for fires, which have been experienced at installations that have used fuel dryers.

Consequently, the general approach is to use the boiler as the most efficient dryer unless site-specific circumstances favor drying technology.

Boiler and Turbine-Generator Technology

The traditional wood-fired boiler used in electricity generation is a spreader-stoker. Figure 4-29 shows a typical flowsheet for a stoker boiler. Wood is discharged from the surge bin via a twin counter-rotating auger system and fed to a stoker. Unlike the typical coal stoker, which is a paddle wheel device, a wood fuel stoker is an air-swept design that throws the wood fuel onto the grate. Figure 4-30 depicts a typical boiler and turbine-generator system, along with feedwater heaters, pumps, and fans.

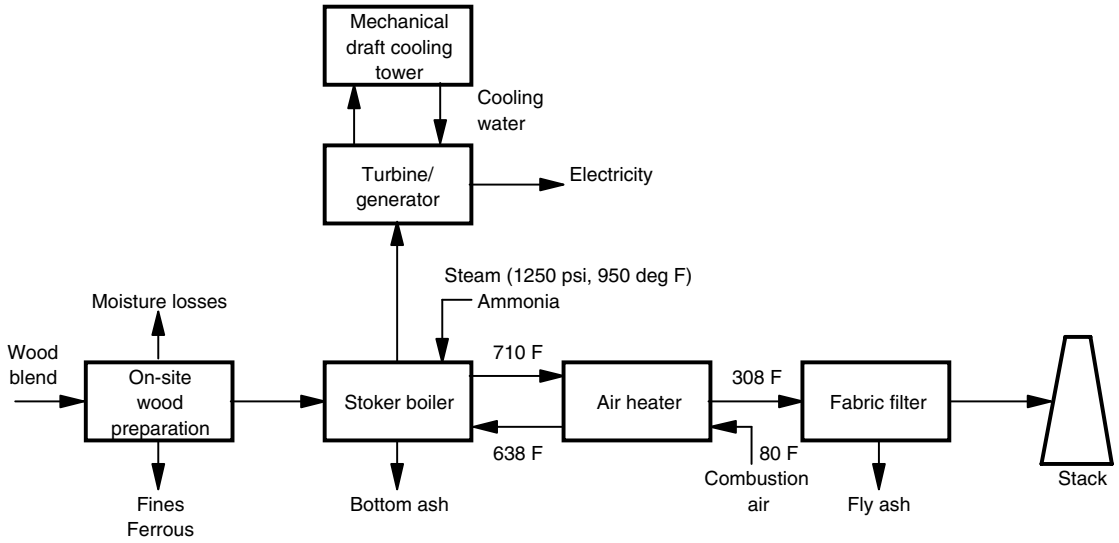


Figure 4-29
Schematic of Biomass-Fired Stoker Boiler Power Plant

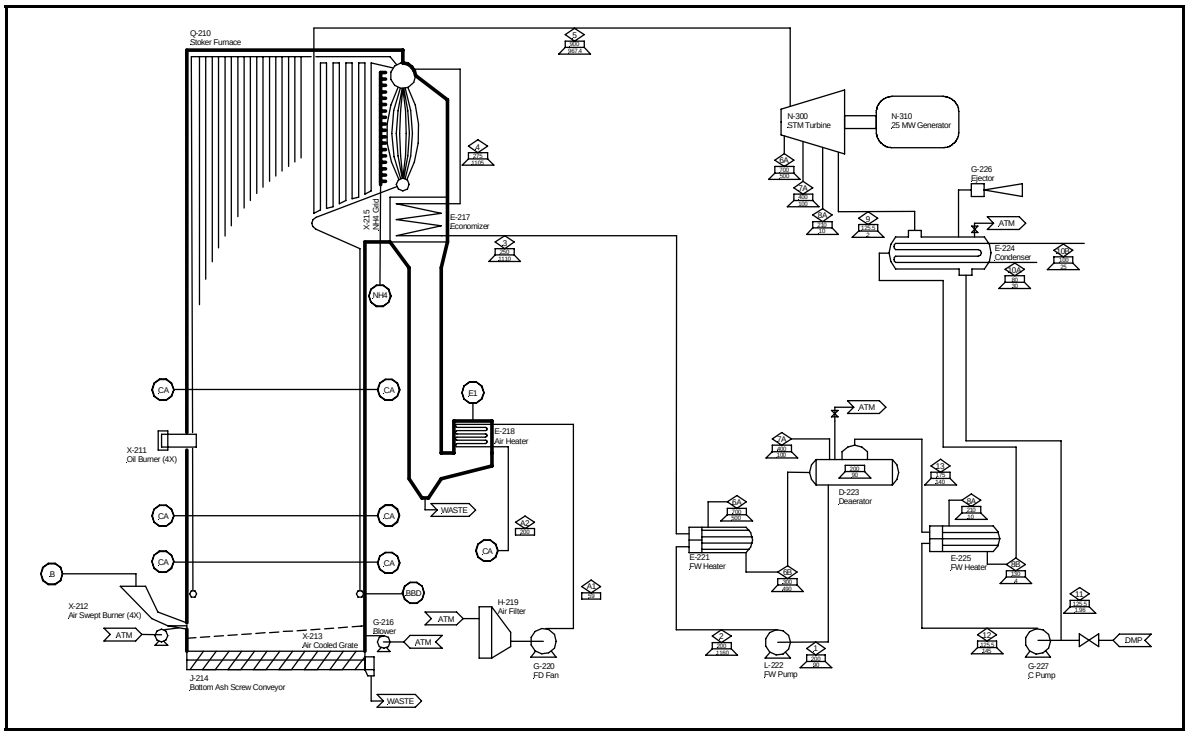


Figure 4-30
Typical Boiler and Turbine-Generator Approach

Because wood waste is highly volatile as well as high in moisture content, the typical heat release parameters for these boilers are somewhat different than those associated with coal-fired stoker boilers. Typically the coal-fired stoker boiler operates with 80% of the combustion occurring on the grate. In contrast, a wood-waste-fired boiler may experience only 10% to 20% of combustion on the grate. Finer particles such as sawdust and fines from the grinding process may never touch the grate; rather, they are burned in suspension as they are entrained in the gaseous combustion products and combustion air leaving the grate area.

The plan area heat release for wood waste-fired boilers is typically on the order of 750 x 10^3 to 1 x 10^6 Btu/ft^2-hr. Most coal-fired stokers are in the 500 x 10^3 to 750 x 10^3 Btu/ft^2-hr range. The volatility of the wood fuel permits this change in parameter. The furnace volumetric heat release for wood waste is typically 13,000 to 20,000 Btu/ft^3/hr, compared to coal at 20,000 to 25,000 Btu/ft^3/hr. The lower calorific value of the wood fuel, plus its moisture content, causes this reduction in volumetric heat release. Moisture moving from condensed phase to vapor phase can consume significant furnace volume.

Grate selection is of consequence. The generic design presented here uses a water-cooled grate design such as the Detroit Stoker Hydrograte™. Alternatives include air-cooled pinhole grates, where primary or undergrate air not only provides oxidant to fuel on the grate, but also cools the grate bars themselves.

Steam conditions are a function of the design capacity of the boiler. For lower capacity boilers (e.g., 250,000 lb/h steam), 600 psig/750°F conditions are common. For medium-sized boilers, 850 psig/825°F conditions are frequently the design conditions, while the larger capacity units typically use 1,250 psig/950°F and 1,450 psig/1,000°F as design conditions. The larger units more readily accommodate the use of more feedwater heaters to improve the cycle efficiency of the unit.

Alternative steam generators—circulating and bubbling fluidized-bed boilers and gasifiers coupled to waste heat boilers—may be used. Figure 4-31 shows a typical fluidized bed combustion power plant flowsheet. Selection of a steam generator depends upon the type and quality of biomass available as well as the site and project-specific economics. For example, the Tacoma Steam Plant #2 repowering used two bubbling bed steam generators coupled to existing boilers used as waste heat boilers. The use of bubbling bed technology was based upon the blend of fuel used: Tacoma Public Utilities fueled the units with a mixture of wood waste, refuse-derived fuel (RDF), and coal.

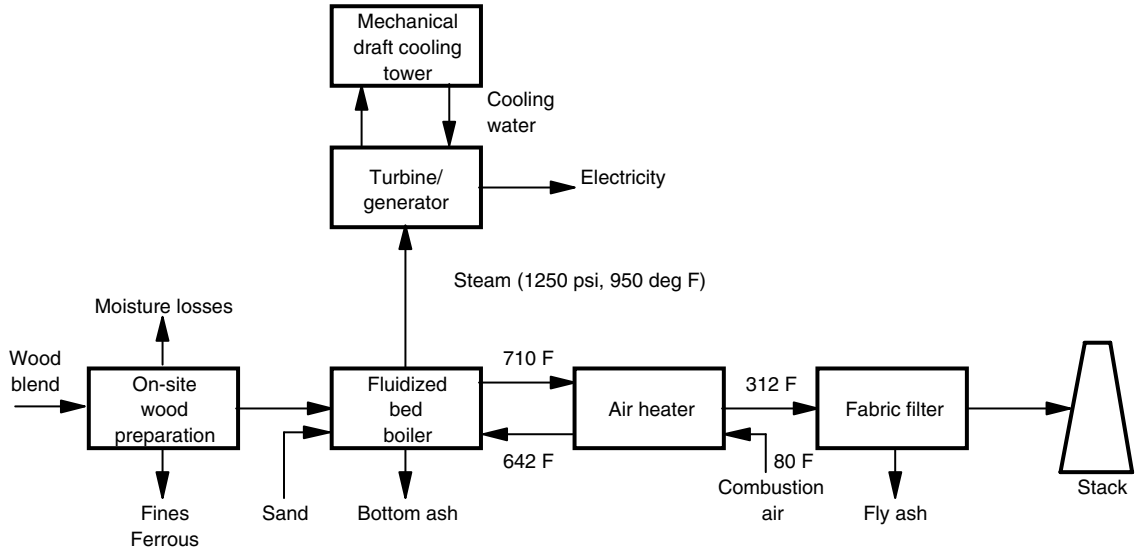


Figure 4-31
Schematic of Biomass-Fired Atmospheric Fluidized Boiler Power Plant

Turbines are selected based on unit capacity and whether the system is designed as a stand-alone power-only plant, or whether it is a cogeneration or CHP plant. Steam turbines can be designed with automatic extractions for process steam or as backpressure turbines exhausting process steam at 50 psig, 150 psig, or other conditions depending upon the plant requirements. Alternatively the turbines can be designed and supplied to exhaust steam at 2 to 3 in HgA if power is the exclusive product. Typical water rates (lb steam/kWh) for Rankine cycle turbines used in wood-waste-fired power plants are shown in Tables 4-21 and 4-22. Table 4-21 shows water rates for condensing turbines while Table 4-22 presents water rates for backpressure cogeneration turbines.

Table 4-21
Typical Water Rates for Condensing Turbines in Wood Waste-Fired Plants

Turbine Throttle Pressure		Water Rate	
Psig/°F	Atm/°C	lb steam/kWh	kg steam/kWh
600/750	41/400	9.8	4.4
850/825	58/440	8.7	3.9
1250/950	85/510	8.3	3.8
1450/1000	102/540	8.0	3.6

Note: Assumes 3-inch HgA turbine exhaust

Source: Tillman, Rossi, and Kitto, 1981

Table 4-22
Typical Water Rates for Backpressure Turbines in Wood Waste-Fired Plants

Turbine-Generator Cap.	Turbine Throttle Pressure		Water Rate	
	Psig/°F	Atm/°C	lb steam/kWh	kg steam/kWh
15	600/750	41/400	31.6	14.3
15	850/825	58/440	23.6	10.7
15	1250/950	85/510	18.4	8.3
20	600/750	41/400	30.9	14.0
20	850/825	58/440	23.4	10.6
20	1250/950	85/510	18.1	8.2
25	600/750	41/400	30.6	13.9
25	850/825	58/440	23.2	10.5
25	1250/950	85/510	17.9	8.1

Note: Assumes 10.2 Atm or 150 psig exhaust pressure.
}Source: Tillman, Rossi, and Kitto, 1981

Given the typical boiler efficiencies of well-run wood-waste-fired boilers, the net station heat rates (NSHR) for small condensing wood-fired plants are typically in the 15,000 to 17,000 Btu/kWh range, while the NSHR values for the 40+ MW_e units are typically in the 13,000 to 14,000 Btu/kWh range. NSHR values depend upon the capital investments made in such equipment as economizer and air heater surface, feedwater heaters, and like equipment. Balance of plant becomes a critical concern for these systems. For more severe steam conditions, feedwater treatment requirements become more substantial.

The incremental net station heat rate for cofiring systems is far more attractive. For backpressure turbines with throttle steam conditions of 1250 psig/950°F and exhaust conditions of 50 or 150 psig, the NSHR appropriate for the power generation element is on the order of 4,500 to 5,000 Btu/kWh. This is based upon the fact that many process uses of steam capitalize on the heat of vaporization. Consequently, losses associated with the heat of vaporization are ascribed to the process user. The losses attributed to cogeneration are related to boiler efficiency (or boiler thermal losses) and turbine efficiency (or turbine losses). With cogeneration systems based upon extraction steam, NSHR values can be on the order of 7,500 Btu/kWh or more, depending on the proportion of steam used in cogeneration applications and the proportion of steam condensed in power generation application.

Pollution Control Systems

Air pollution equipment for solid biomass-fired systems includes either fabric filters (FF) or electrostatic precipitators (ESP) and either selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) systems. Acid gas scrubbers are not required due to the compositions of typical solid biomass fuels. For the purposes of this analysis, an ESP was assumed, with multi-clones installed ahead of the ESP. Multi-clones are useful in scavenging any stray glowing embers should they leave the economizer and air heater sections of the steam generator "hot." A SNCR system was also assumed, as firing wood waste typically generates less NO_x than firing coal in larger utility boilers.

Figure 4-32 depicts the air pollution control system along with a mechanical cooling tower and a demineralizer system for feedwater treatment.

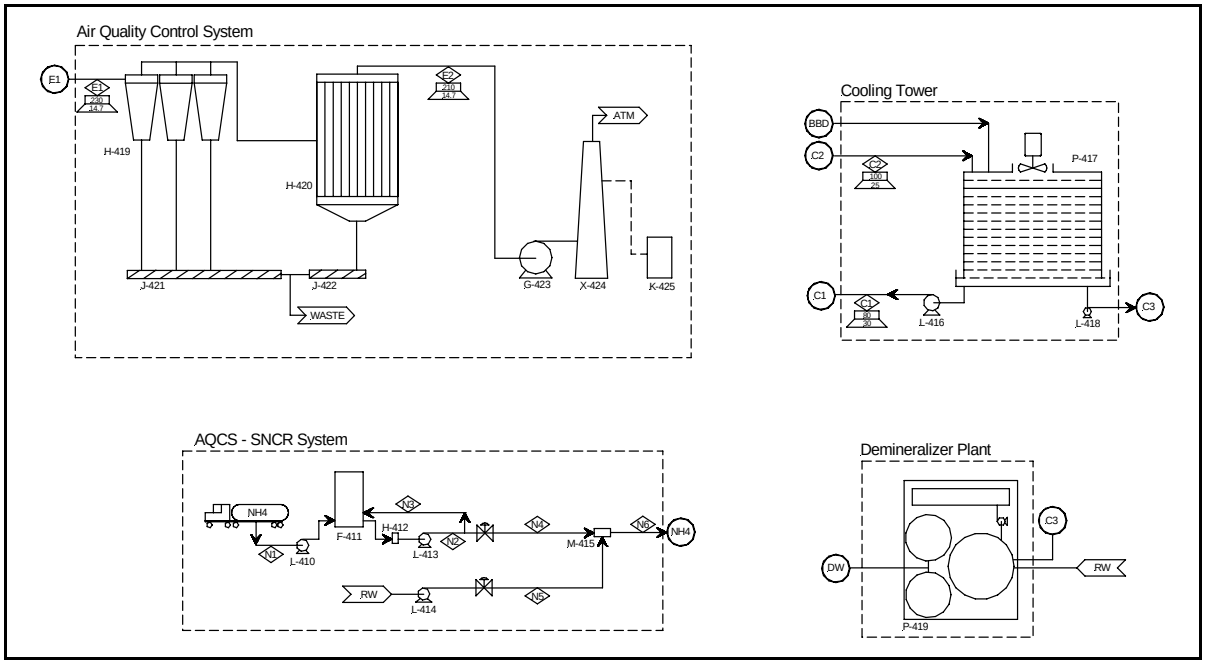


Figure 4-32
Air Pollution Control System, Cooling Tower, and Demineralizer for a Typical Wood Waste-Fired Plant

Comparisons to Other Biomass-Fired Rankine Cycle Designs

Boilers comparable to the wood waste-fired boilers described above have been used for agricultural wastes. Such wastes include nut hulls and shells, stone fruit pits, vineyard prunings, orchard prunings, rice hulls, corn stover, spent corn cobs, and a host of other materials. Wheat straws and comparable materials have been fired in stokers and fluidized-bed boilers in both the U.S. and Europe. All of these materials can be fundamentally different from wood waste as follows:

- Compositions higher in nitrogen than wood waste.
- Compositions higher in chlorine than wood waste.

- Compositions higher in inorganic matter than wood waste, with the wood waste containing significantly higher concentrations of calcium, potassium, sodium, and phosphorus than wood waste ash—particularly on a lb contaminant/10^6 Btu of fuel basis.
- Lower bulk densities of the biomass fuel with the exception of the stone fruit pits (e.g., peach pits).

Designers of boilers firing such materials must take into account the significantly higher slagging and fouling propensities of these materials when compared to typical wood waste (see Baxter et al. [23][24]). Experience in the Central Valley of California and elsewhere have shown that the combination of ash chemistries and chlorine has caused particular difficulties with deposition. Some of these biomass materials have been sufficiently different in characteristics that special systems have been used. Rice hulls, for example, have been suspension fired. They have also been gasified and the product gas fired in a waste heat boiler for steam generation and subsequent power generation.

Rankine cycle generation has also been used in firing landfill gas and wastewater treatment gas. The 10 million ton/yr Puente Hills landfill, for example, has a 50-MWe Rankine cycle generating station. Similar boilers include Spadra and Coyote Canyon, also built in the Los Angeles County area.

Primary differences include fuel handling and pollution control. The gaseous fuel is produced at low pressure and saturated with water vapor. Further, it can contain solid contaminants and some chlorinated compounds. Gas treatment for such biogas-burning boilers may include gas dehydration, particulate scavenging, and other gas treatments depending upon the design principles used. Flue gas treatment focuses more on NO_x removal than particulate capture.

4.4.2 Capital Costs for Wood Waste-Fired Boilers

Solid fuel biomass-fired boilers are not inexpensive. Tables 4-23 and 4-24 present a current capital cost estimate for a wood-fired boiler based on a confidential case study. The design basis used to generate this estimate is as follows:

- Stand-alone plant generating only electricity
- 25 MW_e rated capacity
- 850 psig/825°F throttle steam
- No costs allocated to site selection or site work
- No effort to estimate on the basis of site conditions (e.g., spread footings vs. piling)
- Full truck dump
- Three feedwater heaters and a steam turbine with three extractions

It is recognized that other designs exist. Steam conditions could vary in severity. The full truck dump could be replaced with simple unloading if the plant uses only walking-floor chip vans for fuel delivery. The truck dump can be replaced with the more expensive trestle system used by Burlington Electric. The three feedwater heaters could be reduced to a single feedwater heater—a deaerater. These changes, and many more potential design changes, could impact plant costs. These costs are generally consistent with the generic TAG-RE cost estimates in Tables 4-23 and 4-24.

Table 4-23
Capital Cost Estimate for a Conceptual 25 MW_e Wood Fired Power Plant

			Capacity or		Purchase Equipment
	Equipment Identification	**Number**	**Size Specifications**		**Cost (Base Materials)**
	FUEL HANDLING SYSTEM				
	Truck Scale/Unloader	X-110	60	Tons	$ 100,000.00
	Receiving Hopper/Magnet	F-111	8500	ft^3	$ 8,000.00
	Rotary Disc Screen/Hopper	H-112	200	Tons/hr	$ 35,000.00
	Hammer Mill/Hopper	C-113	100	Tons/hr	$ 230,000.00
	RDS Conveyor	J-114	100	Tons/hr	$ 45,000.00
	HM Conveyor	J-115	100	Tons/hr	$ 45,000.00
	Dozer #1	X-120	18.4	yd^3	$ 400,000.00
	Dozer #2	X-121	18.4	yd^3	$ 400,000.00
	Reclaim Hopper	F-130	150	Tons	$ 5,500.00
	Reclaim Conveyor	J-131	50	Tons/hr	$ 50,000.00
	Feed Bin	F-132	150	Tons	$ 5,500.00
	Feed Conveyor	J-133	50	Tons/hr	$ 40,000.00
	STOKER STEAM GENERATOR		350000	lb/hr	$ 12,000,000.00
	Structural Steel				$ 2,500,000.00
	Furnace	Q-210			-
	No. 2 Oil Burners (4X)	X-211	75	mmBtu/hr	$ 550,000.00
	Swept Air Burners (4X)	X-212	40	Tons/hr	-
	Air Cooled Grate	X-213		Btu/ft^2	-
	Bottom Ash Screw Conveyor	J-214		Tons/hr	-
	Underair Blower/Motor	G-216		acfm	-
	Economizer	E-217		ft^2	-
	Air Preheater	E-218		ft^2	-
	Air Filter	H-219		acfm	-
	Forced Draft Air Fan	G-220		acfm	-
	Feedwater Heater #1	E-221		ft^2	-
	Feedwater Pump	L-222		gpm	-
	Deaerator	D-223		gal	-
	Condenser	E-224		ft^2	-
	Feedwater Heater #2	E-225		ft^2	-
	Hogger Jet	G-226		lb/hr	-
	Condensate Pump	L-227		gpm	-
	AIR QUALITY CONTROL SYSTEM				
	NOx Control - SNCR		450	mmBtu/hr	$ 1,150,000.00
	Injection Grid	X-215	20	gpm	-
	Unloading Pump	L-410	100	gpm	-
	Storage Tank	F-411	10,000	gal	-
	Cartridge Filter	H-412	100	ft^2	-
	NH4 Feed Pump	L-413	20	gpm	-
	RW Feed Pump	L-414	100	gpm	-
	Static Mixer	L-415	20	gpm	-
	PM Controls				-
	Multiclone	H-419			-
	Electrostatic Precipator	H-420			-
	Multiclone Screw Conveyor	J-421			-
	ESP Screw Conveyor	J-422			-
	Induced Draft Fan	G-423			-
	CEMS	K-425			$ 250,000.00
	Stack	X-424	120	ft	$ 270,000.00
	COOLING TOWER	p-417	25000	GPM	$ 2,400,000.00
	STEAM TURBINE/GENERATOR SET		25	MW	$ 5,000,000.00
	Steam Turbine	N-300			-
	Generator	N-310			-
	DEMINERALIZER PLANT	P-419	0.04	m^3/s	$ 150,000.00
	TOTAL EQUIPMENT COST (TEC)				$ 25,634,000.00

Table 4-24
Total Costs for a 25 MW_e Wood Fired Power Plant

COMPLETION OF CAPTIAL COST ESTIMATE INCLUDING LABOR, MATERIALS, AND OTHER COSTS			
Equipment Labor	**8% of TEC**		
Process Materials			
Concrete Substructures	7.5% of TEC	$1,922,550	
Piping	12.5% of TEC	$3,204,250	
Electrical	5% of TEC	$1,281,700	
Insulation	2.5% of TEC	$640,850	
Process Structural	10% of TEC	$2,563,400	
Instrumentation	7.5% of TEC	$1,922,550	
Paint	0.5% of TEC	$128,170	
Total Process Materials			**$11,663,470**
Process Material Labor	**46%**		
Concrete Substructures	7.5% of TEC	$1,922,550	
Piping	11.25% of TEC	$2,883,825	
Electrical	10% of TEC	$2,563,400	
Insulation	5% of TEC	$1,281,700	
Process Structural	6% of TEC	$1,538,040	
Instrumentation	3.75% of TEC	$961,275	
Paint	2.5% of TEC	$640,850	
Total Process Materials			**$11,791,640**
Total Direct Costs			**$23,455,110**
Home Office Expense (w/Overhead)	**37.5% of TEC**	**$9612,750**	
Field Expenses (w/Overhead)	**17.5% of TEC**	**$4,485,950**	
Contractor Fees	**7.5% of TEC**	**$769,020**	
Total Indirect Costs			**$14,967,720**
Total TEC, DC, IDC			**$63,956,830**
Contingency Fee	**30% of TEC**		**$19,187,049**
Capital Cost Estimate			**$83,143,879**

The cost estimate yields a capital cost on the order of $3,300/kW of capacity. Recognizing that many design options can be employed, this cost could be reduced or increased by 20%. However, it provides a benchmark concerning wood-fired electricity generation.

The exponential scale factor for such plants can be estimated at 0.65. On this basis, a 50-MW_e generating station would have a capital cost on the order of 2,100/kW. Likewise, a 70-MW_e generating station would have a capital cost on the order of $1,700/kW.

Operating and maintenance costs for wood-waste-fired generation are typically site-specific, depending on the owner, the location, and its proximity to related facilities. For example, a project located on the site of an integrated forest products mill can share certain maintenance facilities and costs. An independent plant must bear the entire cost of operations and maintenance.

Typically, a wood-fired plant requires about 20 to 30 employees, including a plant manager, engineer, business manager, secretary, four shifts with three employees/shift, two fuel yard employees, and a maintenance crew with both millwrights and electricians. Nominally, a crew of about 25 is adequate for plant operations. However, larger stations (e.g., 40+ MW_e) generally are more heavily staffed to handle increased fuel receipts and the increased complexity of the unit. Alternatively, outsourcing can be used to manage the staffing complement. For smaller generating stations—those up to 15 MW_e capacity—staffing is consistent with about 0.5 MW_e capacity/worker. Larger units may achieve better ratios such as 1 to 2 MW_e capacity/ worker.

Maintenance requirements are comparable to those associated with coal-fired generating stations; the same types of problems occur. Annual maintenance costs can be estimated at 4% to 5% of the total capital cost of the facility. However, this is a generalized number, and site-specific maintenance costs vary significantly.

4.4.3 Ownership Patterns and Institutional Issues

Traditionally, biomass-fired generating stations are owned either by a utility (e.g., Burlington Electric, Washington Water Power), by a non-utility generator or NUG (e.g., a forest products company), or by an independent power producer. Independent power producers built over 1,000 MW_e of wood waste-fired capacity in California in response to PURPA and the California Standard Offer #4 (SO4). As SO4 expired, construction of new facilities was halted and several smaller units were shut down.

An alternative ownership pattern has been used by selected utilities located where large forest industry and pulp and paper complexes exist. The utility owns the turbine-generator within the site of the forest industry mill and its cogeneration installation. The utility purchases high-pressure steam from the boiler and sells low-pressure process steam back to the pulp mill or integrated complex. The utility has a lower capital investment and a lower net station heat rate. The turbine is dispatched by the forest industry, consistent with its needs. Such ownership arrangements are niche applications that are mutually beneficial.

Other institutional issues include regulatory constraints and incentives. There is currently considerable uncertainty in the regulatory and incentive arenas, which makes definitive observations difficult if not impossible to make. There are some who would, for political reasons, consider wood waste as "not renewable." Others argue whether wood waste in various forms is "green" or "clean" power. Regulatory constraints are equally uncertain.

4.4.4 Alternative Systems for Gaseous Biomass Fuels

Alternative systems for gaseous biomass fuels—landfill gas and wastewater treatment gas—include internal combustion engines, microturbines, and larger (e.g., 5,000 kW) combustion turbines. Wastewater treatment gas includes the product of municipal wastewater treatment plants as well as anaerobic digestion of animal manures. Traditionally, wastewater treatment plants have used internal combustion engines if appropriate for power generation. These systems can be installed in 1-MWe increments, although both smaller and larger systems are employed for both landfill gas and wastewater treatment gas. Such installations require gas compression and are frequently backed up with either natural gas or propane.

More recently fuel cells and microturbines have been applied to these gaseous biomass fuels on a somewhat experimental basis. Small 1- to 5-MW_e combustion turbines also have been installed. Again, the Puente Hills landfill has pioneered the use of these small combustion turbines for electricity generation. For all systems, attention must be paid to concentrations of hydrogen sulfide (H_2S) at 100 to 2,000 ppmv, particularly in wastewater treatment/digester gas. Siloxanes also are a contaminant with significant potential for causing combustion and environmental issues.

The capital costs of these alternatives have been documented by CH2M Hill and others (see Kitto and Green [32]), and are estimated as follows:

- Internal combustion engine: $3,000/kW (1-$MW_e$ system basis)
- Fuel cell: $9,000/kW (300-kW system basis)
- Microturbine: $4,000/kW (30-kW system basis)
- Combustion turbine: $1,000/kW (5-$MW_e$ system basis).

The combustion turbine, in particular, is penalized (relative to natural gas turbines) by the small scale of the equipment and by the need for gas cleaning and compression.

Operating and maintenance costs for these systems can be both site specific and technology specific.

4.4.5 Near-Commercial Technologies

Hundreds of biomass gasifiers are deployed world-wide (there are at least 50 suppliers), but almost all of them are unsuitable for utility power applications. There are three primary reasons for this. First, almost all of them are too small for utility application—most are rated at less than 1 MW thermal, and would consequently have high operating costs. Second, the gas quality of many of the small gasifiers is quite low—suitable for direct combustion as required for process

heat or district heating (or in some cases running small reciprocating engines, with associated high maintenance costs). And finally, while small gasifiers have been shown to be robust operationally, scale-up to utility sizes (approaching 10 MW and greater) would be problematic.

Demonstrations of larger-scale gasification technology, coupled with district heating are underway throughout Europe and show promise both technically and economically. These are demonstrations of gasifiers that are either already at utility scale, or could easily be scaled to larger configurations. Larger configurations reduce the operating cost by spreading fixed costs (i.e., operations staff) over a larger output. Economies of scale help keep variable operating costs somewhat lower, and reduce the required capital directly.

The following section briefly describes some key demonstrations of atmospheric gasification in Europe, and their role in power production. With the exception of the gasifier at Ruien, the projects highlighted below (and several more) are first-of-a-kind demonstrations. Consequently, cost and performance information is difficult to acquire and interpret. Other demonstrations, such as the biomass gasification/combined cycle demonstration at Värnamo have been completed and provide a reasonable technical backdrop, but little cost information. At the time of this writing, there are no active biomass gasification-to-power demonstrations in the United States.

Wood Gasification for Power and District Heating in Güssing, Austria

The Güssing Gasifier is a 2 MW electrical, 4.5 MW thermal, circulating fluid bed gasifier. Wood harvested from local forests is the fuel. The village of Güssing has 56 km of district heating, supplying local hardwood flooring industry, other industries, as well as a residential heating network. Repotec owns the gasifier technology, developed by the Technical University of Vienna, and has built a larger unit at Heiligenkreuz, Austria. The Heilegenkreuz unit is designed to produce 11 MW electric/6 MW thermal, and was to be commissioned in late 2006.

The overall process flow diagram is shown in Figure 4-33. The dimensions of the gasifier vessel are 2.5-m ID, and 5.5-mOD, and 8-m tall. The vessel is refractory lined and has an external combustion zone, or combustion leg, operating at nominally atmospheric pressure, with steam injection in the bottom of the vessel to keep the N_2 levels low. The ash is stored, and at some point in the future is expected to be cleared by environmental authorities to be spread on fields. It takes about 12 to 15 hours to start up the gasifier, and two days to shut down, mostly due to thermal stress limitations on the refractory. The gasifier could be scaled up easily, according to the staff at the site, but would require multiple combustion legs around the central gasifier rather than a single combustion leg as currently configured. The bed temperature is 850 C and about 830 C at the gasifier exit.

The syngas reports to the gas cooler, where it is cooled to 150 C (the heat goes to the district heating network). The cooled gas goes to the baghouse, where most of the particulates are taken out and reintroduced into the combustion leg. The baghouse is pulsed with nitrogen. The particulate-free gas reports to the scrubber, which uses biodiesel to scrub tars and condense H_2O. Incoming tar levels are 500 ppm, and less than 20 ppm is in the product gas. Then the cleaning liquid is separated, and the middles (tar/water/biodiesel) are introduced into the combustion leg. The gas composition is 22% CO, 23% CO_2, 40% H_2, 10% CH4, 4% N_2.

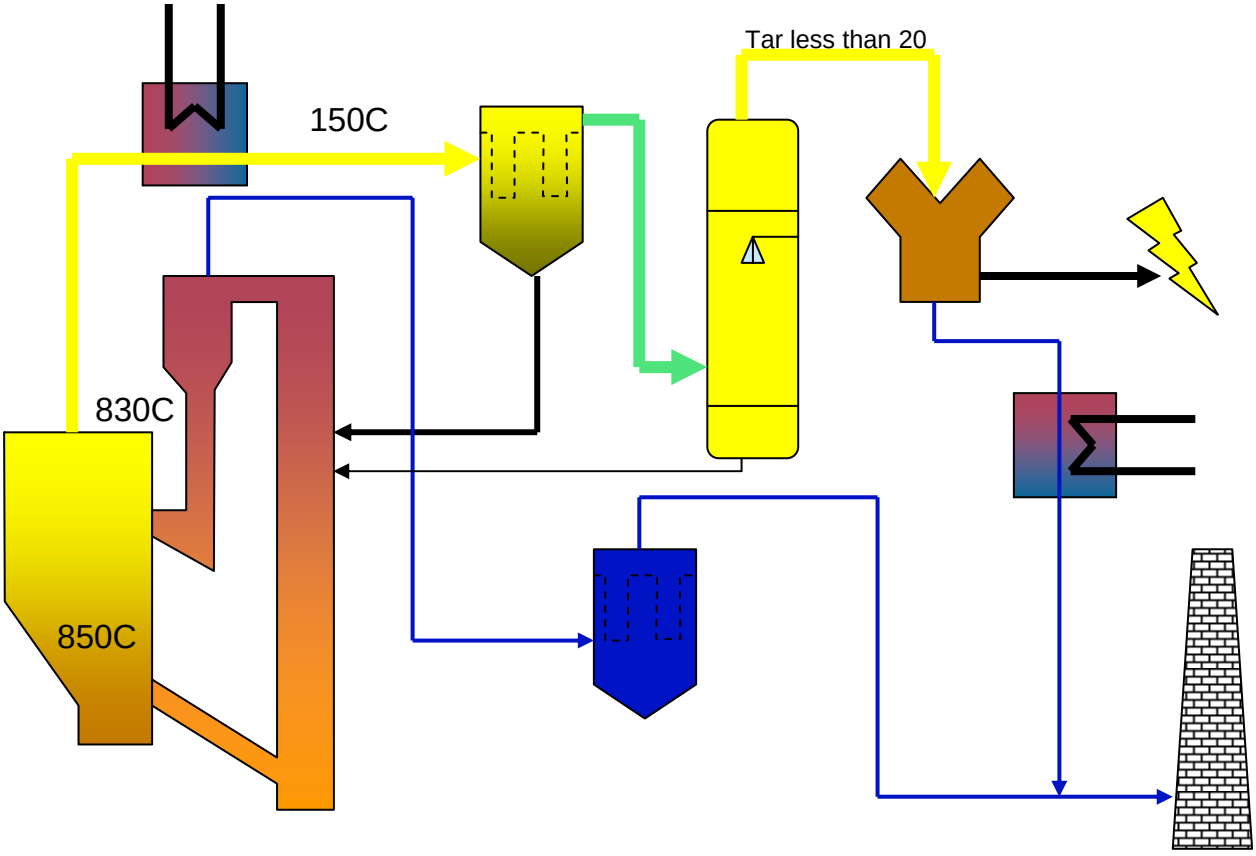


Figure 4-33
Schematic of Biomass Gasification Application for Combined Heat and Power

Wood Gasification at Harboøre

A Vølund-designed updraft gasifier has been installed and operated at Harboøre in western Denmark since 1988. Figure 4-34 shows a process flow diagram of the system. The gasifier dimensions are about 2.2-m ID and 12-m high. It is operated at atmospheric pressure. The feedstock is green wood chips, nominally 40mm, delivered from local suppliers. The unit consumes 1 ½ t/h at maximum load. The chips are delivered to top of the gasifier, where a spreader turning in the middle distributes the chips. When the torque on the spreader decreases, more wood is added. At the bottom of the gasifier, humidified air enters for the gasification which consumes 3 to 4 NM^3 water per day. The temperature is 1200 C at the bottom of the gasifier vessel and the product gas leaves the top of the gasifier at 75 C. The gas composition is 30% CO, 20% H_2, 5% methane, 8% CO_2, 3% N_2, with a heating value of 6 MJ/nm^3, compared to natural gas at about 40 MJ/nm^3. This does not include the dilution of the humidified air. The gas contains 100 g/nm^3 of tar. For firing the gas in IC engines, its tar content needs to be less than 50 mg/nm^3. Ash is drawn out of the bottom, and the annual production is about 50 t/year.

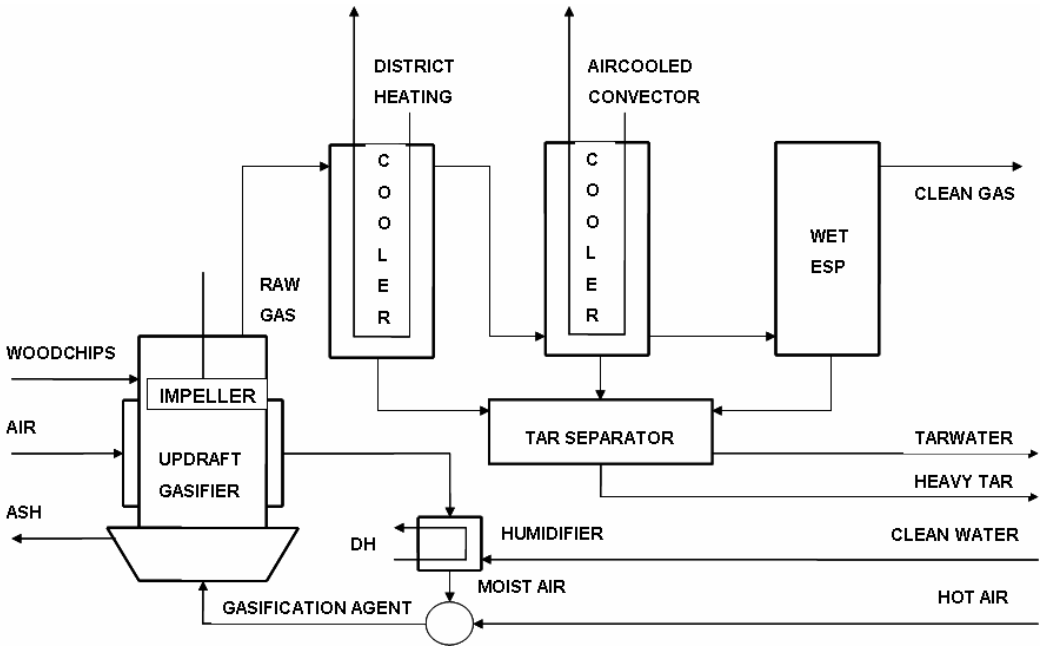


Figure 4-34
Process Flow Diagram for the Vølund Gasifier at Harboøre

The gas is cooled in two stages to 35 C, and then enters a wet ESP. The product gas is clean enough to be burned in Jenbacher engines. The ESP effluent, a water/tar/particulate mixture, reports to a settling vessel. The heavy tar is stored in a recirculated, heated vessel for combustion during the winter months as "peaking heat". The water/soluble tars are heated until vaporized, then combusted for additional district heating capacity.

The electric capacity of the unit is 1.3 MW and the thermal service is up to 3 MW. The supplier, Babcock and Wilcox Vølund, has indicated that it should be feasible to scale this gasification process to about 20MW total energy output.

Gasification of Wood Pellets at Skive

In Skive in northern Denmark, the local utility, Fjernvarme, has an extensive district heating network, currently fired predominantly by wood pellets and natural gas. There is some electricity generation as well. The heating network encompasses 8,000 homes and is growing. To meet that growth, Fjernvarme is building a wood gasifier at their Thorvej site. The gasifier will produce 6 MW electric power in three 2-MW Jenbacher engines, and 20 MW of heat in two 10-MW boilers. Figure 4-35 shows the process flow diagram for the plant.

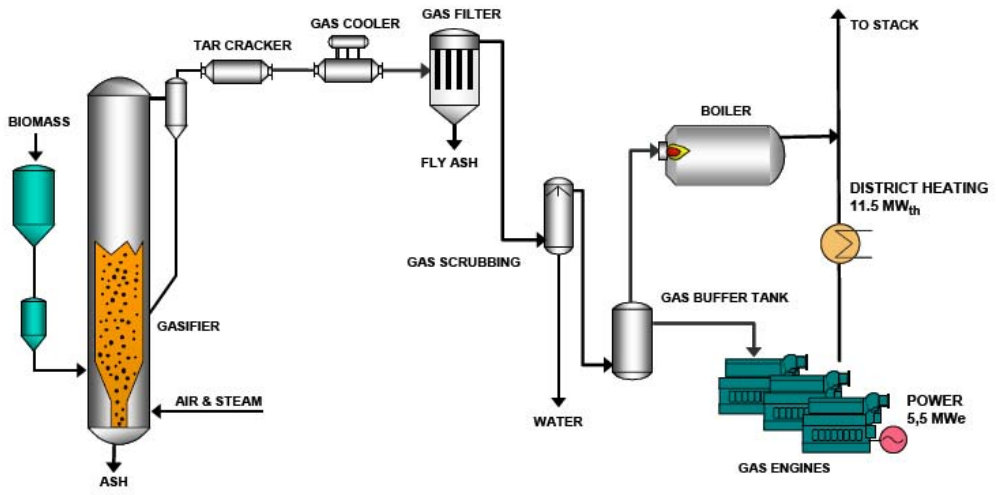


Figure 4-35
Fjernvarme Process Flow Diagram for Coproduction of 6 MW electric and 10 MW thermal.

The gasifier is a Carbona slightly pressurized gasifier. One of the unique features of this gasifier is a tar cracker to address the tar problems that other gasifiers have had. Fjernvarme is producing electricity primarily due to government mandate and would prefer to concentrate on producing hot water.

The Thorsvej site already has two large stoker boilers on site, fired with wood pellets, so the handling storage and infrastructure is already largely in place.

The gasifier at Skive was under construction at the time of this writing. Originally, the unit was to have been commissioned in summer 2006, but business issues with the constructor have introduced delays.

Co-firing Syngas at Ruien

In western Belgium, Electrabel's Ruien power station has begun to embrace biomass fuels as part of their drive to displace coal-based carbon. One part of that strategy is a Foster-Wheeler type atmospheric fluid bed gasifier providing syngas to the boiler. The gasifier operates on sized green wood. The feed is generally coarse wood chunks, 50 mm or so. Wood is delivered via walking floor truck, screened for oversize and tramp material, and conveyed to a covered storage area. The wood is extracted and conveyed to the gasifier. Figure 4-36 shows the particulars of the gasification at Ruien. Note that the gasifier has only particulate removal for gas cleanup. This is all that is required, since the gas is directly injected into the boiler. The injection of the fuel gas occurs below the lowest coal firing level of Unit 5. The syngas contributes about 17 MW to the 190-MW rated capacity of the unit.

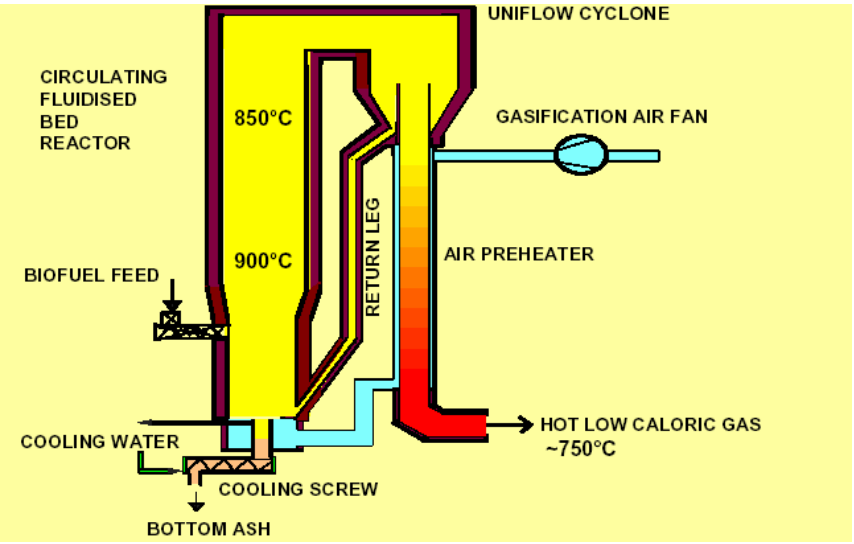


Figure 4-36
Overall Configuration of the Biomass Gasifier at Ruien

While there have been a few issues with this unit, it has mostly operated very smoothly. There are indications that using dry wood causes more operational problem than fresh, green wood, and consequently, Electrabel strives to have mostly fresh wood delivered.

Wood Gasification at Kokemäki

The town of Kokemäki, Finland, is the site of a demonstration of the Condens Oy "Novel" gasifer. The gasifier is a fixed bed unit, and is fueled by local wood supply. The unit has an electrical output of 1.8 MW and a thermal output of 4.3 MW. The electricity is generated by syngas-fired reciprocating engines. The unit has been in operation since 2005. The vendor indicates that capacity could be increased to 10 MW or greater. Figure 4-37 shows a schematic of the Kokemäki gasification system.

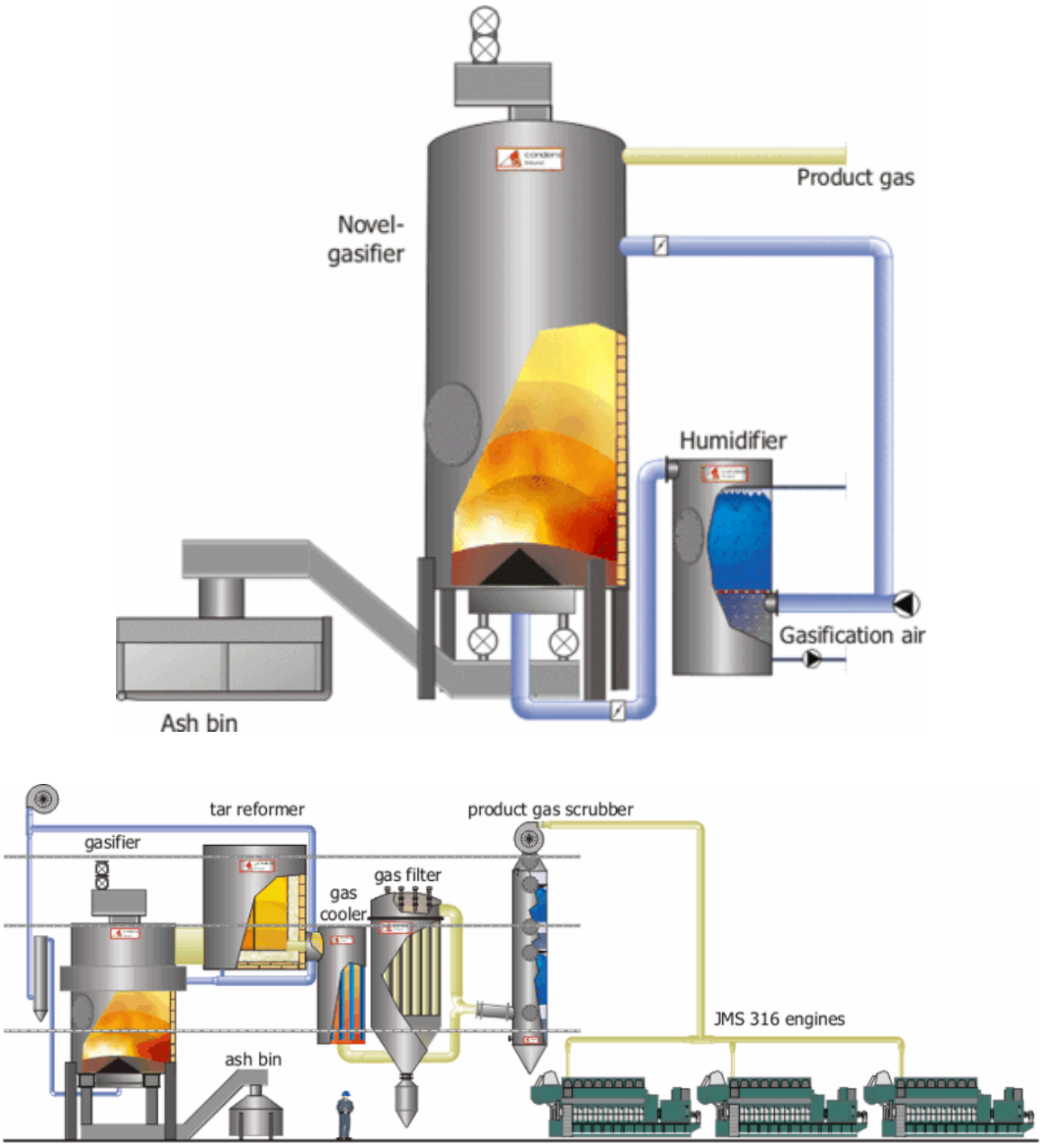


Figure 4-37
Schematic of Biomass Gasification and Power Generation System at Kokomäki.

4.4.6 Non-Commercial Technologies

A host of technologies are commonly proposed for biomass, either to supply fuel or to utilize that fuel successfully. These technologies include (but are not limited to):

- Energy farms to produce woody biomass.
- Energy farms to produce herbaceous biomass.
- Direct combustion or gasification of animal manures.

- Pressurized biomass gasification for use in integrated gasification/combined-cycle combustion turbine systems with or without coal gasification systems.
- Technologies for production and utilization of heavy pyrolysis liquids
- Indirect liquefaction of biomass fuels by Fischer-Tropsch or other technologies based upon gaseous feedstocks from landfills, wastewater treatment plants, and producer gasifiers.

To date, each of these technologies has encountered significant technical, economic, and institutional barriers sufficient to inhibit implementation on a commercial utility scale. Further, the traditional commercial test—the ability of vendors to give guarantees—has not been met. Consequently, the technical and economic information available to provide performance or cost data is somewhat speculative at this time.

Some of these technologies may never achieve commercial status. Many biomass technologies have already been developed but have not succeeded commercially, including:

- Cyclone combustion of wood with the addition of inorganic material
- Various gasification systems
- Mobile pyrolysis in a medium temperature reactor
- Many others.

It is not the purpose of this report to project which technologies will attain commercial status. Rather, it is our purpose to provide utilities with sufficient information to understand the commercially available technologies and near-term potentials.

4.5 Cost and Performance Summary

Biomass is unique among renewable resources. Although the capital costs of biomass technologies can be lower than those of many other renewable technologies, biomass power technologies must also account for fuel costs that other renewables such as solar, wind, and (for the most part) geothermal largely avoid.

Except for landfill gas, municipal solid waste (MSW), and a few other special cases in which the fuel is free or even comes at a negative cost due to disposal credits, the cost of a biomass feedstock is a significant fraction of the total cost of generating electricity. And, compared to coal and natural gas, biomass power plants have relatively high capital costs and low efficiencies, especially versus natural gas. Hence, the ability to find a low-priced, abundant fuel is critical to the success of biomass power generation.

4.5.1 Biomass Cofiring with Coal in Cyclone and Pulverized Coal Boilers

Table 4-25 presents cost and performance information for two generic biomass cofiring cases in which wood fuel provides 10% of the heat input for two types of utility boilers:

- a 200-MWe (net) pulverized-coal (PC) boiler that generates 10% by heat input from cofiring biomass (sawdust wood fuel of about 30% moisture) as 10% by heat through a *separate feed* system to generate 20 MWe from the biomass fraction
- a 200-MWe (net) cyclone boiler that also generates 10% by heat from biomass (wood sawdust at 30% moisture), but via *a blended feed* system, to generate 20 MWe (net) from the biomass fraction

While many aspects of cofiring are considered commercial, as of 2003, only one project can be considered "commercial" at the 5% to 10% cofiring level: the Greenridge station of AES in Dresden, New York. Southern Company and TVA have commercial cofiring operations at several plants in which small fractions (2% or less) of the heat input to the boiler comes from biomass.

4.5.2 Biomass-Fired Stoker and Fluidized Bed Combustion Boilers

Table 4-26 presents similar performance and cost data for two 50-MW direct combustion boiler technologies: the standard stoker-grate and fluidized bed combustion (FBC) boilers. Both technologies are considered to be commercial and are applied throughout the world. Fluidized bed combustion is considered the new state-of-the-art leader and offers several advantages vs. stoker firing, including higher combustion efficiency and its capability of operating over a wide range of variation of the fuel moisture and ash contents.

The estimated total capital requirements of the stoker and FBC boiler plants are 3,390 and 3,495 $/kW, respectively (Dec 2006). The scope of the cost estimates includes.

4.5.3 Biomass Direct Combustion for Compined Heat and Power

Table 4-27 presents performance and cost data for direct combustion of biomass and combined heat and power. The biomass-fired stoker boiler generates steam for both power generation and process heat or district heating. The design rating is 50 MW electric and 44 MW thermal. The unit delivers 100,000 lb/hr of steam, saturated at 100 psig.

4.5.4 Landfill Gas Recovery and Power Generation

Table 4-28 presents performance and cost data for a 5-MW generating unit fired by landfill gas. The plant scope includes the landfill gas collection field, gas cleanup facility to remove sulfur and other compounds, a flare and five 1-MW internal combustion engines.

According to the U.S. Environmental Protection Agency's Landfill Municipal Outreach Project (Reference 42), solid waste landfills are the largest source of human-related methane emissions

in the United States, accounting for about 25 percent of the total emissions in 2004. The landfill gas composition is typically 50% methane, 50% carbon dioxide, and small amounts of other organic compounds. Landfill gas is extracted from landfills using a series of wells and a blower/flare (or vacuum) system. This system directs the collected gas to a central point where it can be processed and treated depending upon the ultimate use for the gas. From this point, the gas can be simply flared or used to generate electricity, replace fossil fuels in industrial and manufacturing operations, fuel greenhouse operations, or be upgraded to pipeline quality gas.

Table 4-25
Performance and Cost Estimates for Biomass Cofiring with Coal in Utility Boiler

Rated Capacity	Cyclone	Pulverized Coal
Coal Plant size (units x unit size, MW)	1 x 200	1 x 200
Biomass Fuel Feed System	Blended	Separate Injection
Fraction of plant output from biomass, %	10	10
Equivalent power output , MW	20	20
Physical Plant (Biomass Facility)		
Unit Life, Years	10 to 20 (host dependent)	10 to 20 (host dependent)
Land Requirement, Acres	1	5
Scheduling		
Available for Commercial Orders, Year	2001	1997
First Commercial Service, Year	2002	1999
Hypothetical In-Service Date	July 1, 2008	January 1, 2009
Preconst., License & Design Time, Years	1	1
Idealized Plant Construction Time, Years	0.5	1
Capital Costs, $/kW (kW biomass)		
Month/Year Dollars	December, 2006	December, 2006
Fuel Handling/Prep	192	310
Boiler Modification	3	38
Balance of Plant	55	55
General Facilities and Engineering Fee	15	20
Project and Process Contingency	40	63
Total Plant Cost	305	486
AFUDC (Interest during Construction)	0	0
Total Plant Investment (includes AFUDC)	305	486
Owner Costs, $/kW		
Due Diligence, Permitting, Legal, Development	10	10
Tax and Fees	0	0
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	315	496
O&M Costs (Cofiring Systems only)		
Fixed, $/kW-yr (kW biomass)	11.6	11.6
Variable, $/MWh (MWh biomass)	1.2	1.6
Performance/Unit Availability		
Change in Net Heat Rate for 90 % coal, 10 % biomass (Full Load), %	+1.5%	+1.5%
Equivalent Planned Outage Rate, %	No change vs. 100% coal-fired	No change vs. 100% coal-fired
Equivalent Unplanned Outage Rate, %	No change vs. 100% coal-fired	No change vs 100% coal-fired
Equivalent Availability, %	No change vs, 100% coal-fired	No change vs. 100% coal-fired
Duty Cycle	Baseload	Baseload
Minimum Load, %	40	40
Emissions Offsets vs. 100% Coal		
CO_2 (derived from coal), %	-8	-8
NOx, %	-0 to -20 (boiler dependent)	-0 to -20 (boiler dependent)
SOx, %	-8	-8
Mercury, %	—	—
Confidence and Accuracy Rating		
Technology Development Rating	Commercial	Commercial
Design & Cost Estimate Rating	Simplified	Simplified

Table 4-26
Performance and Cost Estimates for Biomass Stoker and CFB Boilers

Rated Capacity	Stoker Boiler	CFB Boiler
Plant Size (no. of units x unit size, MW)	1 x 50	1 x 50
Physical Plant		
Unit Life, Years	30	30
Land Requirement, Acres	—	—
Scheduling		
Available for Commercial Orders, Year	1984	1996
First Commercial Service, Year	1986	1998
Hypothetical In-Service Date	July 1, 2010	July 1, 2010
Preconst., License & Design Time, Years	1.5	1.5
Idealized Plant Construction Time, Years	2	2
Capital Costs, $/kW		
Month/Year Dollars	December, 2006	December, 2006
Fuel Handling/Prep	106	106
Boiler and air quality control	700	782
Steam Turbine and Auxiliaries	554	554
Balance of Plant	220	220
General Facilities and Engineering Fee	1,026	1,026
Project and Process Contingency	97	100
Total Plant Cost	2,703	2,788
AFUDC (Interest during Construction)	122	125
Escalation during Construction		
Total Plant Investment (inc. AFUDC)	2,825	2,913
Owner Costs, $/kW		
Due Diligence, Permitting, Legal, Development	565	582
Tax and Fees	0	0
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	3,390	3,495
O&M Costs		
Fixed, $/kW-yr	88.4	91.0
Variable, $/MWh	3.6	4.1
Performance/Unit Availability		
Net Heat Rate, Btu/kWh (Full Load)	12,500	12,300
Equivalent Planned Outage Rate, %	4	4
Equivalent Unplanned Outage Rate, %	6	6
Equivalent Availability, %	90	90
Duty Cycle	Baseload	Baseload
Minimum Load, %	40	40
Emission Rates		
CO_2, lb/MMBtu	220	220
NOx, lb/MMBtu	0.15	0.08
SOx, lb/MMBtu	0.10	0.04
Mercury, lb/MMBtu	—	—
Confidence and Accuracy Rating		
Technology Development Rating	Commercial	Commercial
Design & Cost Estimate Rating	Simplified	Simplified

Table 4-27
Performance and Cost Estimates for Direct Combustion and Combined Heat and Power

Rated Capacity	**Stoker Boiler**
Plant Size (no. of units x unit size MW)	1 x 50 electric, 42MW thermal
Cogen steam output (1,000 lb/hr)	100
Cogen steam conditions	100 psig, saturated
Physical Plant	
Unit Life, Years	30
Land Required	—
Scheduling	
Available for Commercial Orders, Year	1984
First Commercial Service, Year	1986
Hypothetical In-Service Date	July 1, 2010
Preconst., License & Design Time, Years	1.5
Idealized Plant Construction Time, Years	2
Capital Costs, $/kW	
Month/Year Dollars	December, 2006
Fuel Handling/Prep	115
Boiler & Air Quality Control	760
Steam Turbine and Auxiliaries	629
Balance of Plant	220
General Facilities and Engineering Fee	1,026
Project and Process Contingency	102
Total Plant Cost	2,852
AFUDC (Interest during construction)	128
Total Plant Investment (inc. AFUDC)	2,980
Escalation During Construction	
Owner Costs, $/kW	
Due Diligence, Permitting, Legal, Development	596
Tax and Fees	0
Total Capital requirement, Hypothetical In-Service year (includes AFUDC)	3,576
O&M Costs	
Fixed , $/kW-yr	90
Variable, $/MWh	3.7
Performance/Unit Availability	
Net Heat Rate, Btu/kWh, Full Load	14,250
Equivalent Planned Outage Rate, %	4
Equivalent Unplanned Outage Rate, %	6
Equivalent Availability, %	90
Duty Cycle	Baseload
Minimum Load, %	40
Fluid Return Conditions	
Flow, (1000 lb/hr)	100
Temperature, F	59
Pressure	Atmospheric
Overall thermal efficiency, %	44
Emission Rates	
CO_2, lb/MMBtu	220
NOx, lb/MMBtu	0.15
SOx, lb/MMBtu	0.10
Mercury, lb/MMBtu	—
Confidence and Accuracy Rating	
Technology Development Rating	Commercial
Design & Cost Estimate Rating	Simplified

Table 4-28
Performance and Cost Estimates for Landfill Gas

Rated Capacity	5 MW Reciprocating Engine Plant
Plant Size (no. of units x unit size, MW)	5 x 1.0
Physical Plant	
Unit Life, Years	20
Land Required	—
Scheduling	
Available for Commercial Orders, Year	—
Hypothetical In-Service Year	January 1, 2009
Preconst., License & Design Time, Years	1
Idealized Plant Construction Time, Years	1
Capital Costs, $/kW	
Month/Year Dollars	December, 2006
Gas Conditioning and Compressor	189
Power conversion equipment	900
General Facilities and Engineering Fee	151
Project and Process Contingency	186
Total Plant Cost	1,426
AFUDC (Interest during construction)	0
Total Plant Investment (inc. AFUDC)	1,426
Owner Costs, $/kW	
Due Diligence, Permitting, Legal, Development	285
Tax and Fees	0
Total Capital requirement, Hypothetical In-Service year (includes AFUDC)	1,711
O&M Costs	
Fixed , $/kW-yr	52
Variable, $/MWh	13
Performance/Unit Availability	
Net Heat Rate, Btu/kWh, Full Load	13,500
Equivalent Planned Outage Rate, %	4
Equivalent Unplanned Outage Rate, %	11
Equivalent Availability, %	85
Duty Cycle	Baseload
Minimum Load, %	50
Emission Rates	
CO_2, lb/MMBtu	227
NOx, lb/MMBtu	0.2
SOx, lb/MMBtu	0.1
Mercury, lb/MMBtu	—
Confidence and Accuracy Rating	
Technology Development Rating	Commercial
Design & Cost Estimate Rating	Simplified

4.6 Conclusions

Biomass fuels are many and varied, with distinct characteristics. While there are institutional and political questions concerning the classification of wood waste and other waste products as biomass or renewable, technically they are biomass resources that are derived from living plants.

Most biomass fuels permit utilities to generate dispatchable renewable power. The fuels can be extracted and/or stored and then used to meet electricity demand. Utilization systems can capitalize upon the characteristics of these fuels. They are modest in heating value, highly reactive, low in nitrogen and sulfur, and of varying ash characteristics. Of the biomass fuels available, woody biomass is the most commonly used material.

Numerous technologies are available for biomass fuel utilization, including both cofiring options and stand-alone options. Cofiring provides a means for incorporating biomass utilization into electricity generating technologies with the lowest cost and the least risk. Cofiring can be used to enhance combustion and, in most cases, reduce SO_2 and NO_x emissions. The lack of sulfur in biomass fuels, coupled with low nitrogen concentrations, reactive nitrogen, and reactive fuel as a whole, provides the basis for this enhanced combustion.

The forest products and pulp and paper industries, as well as some electric utilities and independent power producers, have built stand-alone plants. These systems are not inexpensive. However, they provide a basis for using biomass to generate electricity. They can be economically justified depending upon localized economics and their use in addressing customer needs. Institutional arrangements that provide partnerships between industries and utilities can be particularly useful in such circumstances.

In summary, biomass is dispatchable renewable power. It can come in solid or gaseous form, and can be exploited using a wide variety of technologies to supply electricity to internal customers or to the grid.

4.7 References

1. Walker, Joseph. 1966. Hopewell Village: The Dynamics of a Nineteenth Century Iron-Making Community. Philadelphia. University of Pennsylvania Press.

2. Szego, G.C. and C.C. Kemp. 1973. Energy Forests and Fuel Plantations. CHEMTECH. May.

3. Bethel, J. et al. 1976. The Potential of Lignocellulosic Material for the Production of Chemicals, Fuels, and Energy. National Academy of Sciences. Washington, D.C.

4. Henry, J.F. 1979. The Silvicultural Energy Farm in Perspective. in Progress in Biomass Conversion, Vol 1. (Sarkanen, K.V. and D.A. Tillman, eds.) Academic Press, New York. pp. 215 – 256.

5. Walsh, M.E. et al. 2000. Biomass Feedstock Availability in the United States: 1999 State Level Analysis. Oak Ridge National Laboratory, Oak Ridge, TN.

6. SCS Engineers. 2002. Economic and Financial Aspects of Landfill Gas to Energy Project Development in California. California Energy Commission. Sacramento, CA. 500-02-020F

7. Johnson, D.K., D.A. Tillman, B.G. Miller, S.V. Pisupati, and D.J. Clifford. 2001. Characterizing Biomass Fuels for Cofiring Applications. Proc. 2001 Joint International Combustion Symposium. American Flame Research Committee. Kuai, Hawaii. Sep 9 – 12.

8. Tillman, D.A. 2001. Final Report: EPRI-USDOE Cooperative Agreement: Cofiring Biomass with Coal. Contract No. DE-FC22-96PC96252. Electric Power Research Institute, Palo Alto, CA.

9. Jenkins, B.M., L.L. Baxter, T.R. Miles, Jr., and T.R. Miles. 1996. Combustion Properties of Biomass. Proc. Biomass Usage for Utility and Industrial Power. An Engineering Foundation Conference. Snowbird, UT. April 28 – May 3.

10. Miles, T.R., et al. 1993. Alkali Slagging Problems with Biomass Fuels. Proc. First Biomass Conference of the Americas. Aug 30 – Sep 2. Burlington, VT. pp. 406-421.

11. Tillman, D.A. 1999. Biomass Cofiring: Field Test Results. Electric Power Research Institute, Palo Alto, CA. Report TR-113903.

12. Payette, K., T. Banfield, T. Nutter, and D. Tillman. 2002. Emissions Management at Albright Generating Station through Biomass Cofiring. Proc. 27th International Technical Conference on Coal Utilization and Fuel Systems. Clearwater Florida, March 4 – 7.

13. Hus, P.J. and D.A. Tillman. 2000. Cofiring multiple opportunity fuels with coal at Bailly Generating Station. Biomass and Bioenergy. 19(6):385-394.

14. Tillman, D.A. 1994. Trace Metals in Combustion Systems. Academic Press, San Diego, CA.

15. Tillman, D.A. 2004. Opportunity Fuel Cofiring at Allegheny Energy: Final Report. EPRI. Palo Alto, CA. Report 1004811.

16. Campbell, A.G. 1990. Recycling and Disposal of Wood Ash. TAPPI. Sep. pp. 141 – 145.

17. Prinzing, D.E. 1996. EPRI Alternative Fuels Database. Electric Power Research Institute, Palo Alto, CA. Report TR-107602.

18. Johnson, D.K., et al. 2002. Report to Foster Wheeler on Pyrolysis of Urban Wood Waste and Fresh Switchgrass. Private communication. Pennsylvania State University, University Park, PA.

19. Tillman, D.A. 2002a. Petroleum Coke as a Supplementary Fuel for Cyclone Boilers. Proc. 27th International Technical Conference on Coal Utilization and Fuel Systems. Clearwater Florida, March 4 – 7.

20. Shafizadeh, F., and W. DeGroot. 1976. Combustion Characteristics of Cellulosic Fuels, in Thermal Uses and Properties of Carbohydrates and Lignins (Shafizadeh, F., K. Sarkanen, and D. Tillman, eds.). Academic Press, New York. pp. 1-18.

21. Shafizadeh, F. and W. DeGroot. 1977. Thermal Analysis of Forest Fuels, in Fuels and Energy from Renewable Resources (Tillman, D., K. Sarkanen, and L. Anderson, eds). Academic Press, New York. pp. 93 - 114.

22. Broido, A. 1976. Kinetics of Solid-Phase Cellulose Pyrolysis. in Thermal Uses and Properties of Carbohydrates and Lignins (Shafizadeh, F., K. Sarkanen, and D. Tillman, eds.). Academic Press, New York. pp. 19-36.

23. Baxter, L.L. et al. 1996a. The Behavior of Inorganic Material in Biomass-Fired Power Boilers: Field and Laboratory Experiences. Proc. Biomass Usage for Utility and Industrial Power. Engineering Foundation Conference. Snowbird, UT. April 28-May 3.

24. Baxter, L.L. et al. 1996b. The Behavior of Inorganic Material in Biomass-Fired Power Boilers—Field and Laboratory Experiences: Vol II of Alkali Deposits Found in Biomass Power Plants. SAND96-8225 Volume 2 and NREL/TP-433-8142.

25. Miller, S.F., B.G. Miller, and D. Tillman. 2002. The Propensity of Liquid Phases Forming During coal-Opportunity Fuel (Biomass) Cofiring as a Function of Ash Chemistry and Temperature. Proc. 27th International Technical Conference on Coal Utilization and Fuel Systems. Clearwater Florida, March 4 – 7.

26. http://www.epa.gov/lmop/overview.htm#methane

27. Miller, B.G., S.F. Miller, C. Jawdy, R. Cooper, D. Donovan, and J. Battista. 2000. Feasibility Analysis for Installing a Circulating Fluidized Bed Boiler for Cofiring Multiple Biofuels and Other Wastes with Coal at Penn State University. Second Quarterly Technical Progress Report . Work Performed Under Grant No. DE-FG26-00NT40809.

28. Miller, S.F. and B. G. Miller. 2002. The Occurrence of Inorganic Elements in Various Biofuels and its Effect on the Formation of Melt Phases During Combustion. Proc. International Joint Power Generation Conference. Phoenix, AZ. June 24 – 27. (IJPGC2002-26177).

29. Bryers, R.W. 1993. Analysis of a Suite of Biomass Samples. Foster Wheeler Development Corporation, Livingston, NJ. Report FWC/FWDC/TR-94/03.

30. Bush, P. V. et al. 2001. Evaluation of Switchgrass as a Co-Firing Fuel in the Southeast. USDOE Cooperative Agreement No. DE-FC36-98GO10349. Southern Research Institute, Birmingham, AL.

31. Harding, N.S. 2002. Co-Firing Tire-Derived Fuel with Coal. Proc. 27th International Technical Conference on Coal Utilization and Fuel Systems. Clearwater Florida, March 4 – 7.

32. Tillman, D.A. 2002b. Cofiring Technology Review. Report to USDOE – NETL. Pittsburgh, PA.

33. Kitto, B. and D. Green. 2003. Electricity Generation Using Digester Gas at Clean Water Services. Proc. 28th International Technical Conference on Coal Utilization and Fuel Systems. Clearwater Florida, March 5 – 8.

34. Green, A. 2003. Opening Remarks. International Conference on Co-Utilization of Domestic Fuels. Gainesville, FL. Feb 5 – 6.

35. Tillman, D.A., A.J. Rossi, and W.D. Kitto. 1981. Wood Combustion: Principles, Processes, and Economics. Academic Press. New York.

36. Thimsen, D, Lindgren, G. *Assessment of Biogas-Fueled Electric Power Systems,* EPRI, Palo Alto, CA: 2004. 1009450

37. www.iea.gov

38. www.volund.dk

39. www.repotec.at

40. www.condensoy.fi

41. www.repp.org/discussions/gasification/supplier.html

42. www.epa.gov/lmop

5
SOLAR PHOTOVOLTAICS

Installed Capacity (est.)	5,200 MW worldwide 550 MW in United States
Technology Readiness	Early commercial (flat-plate crystalline and some thin-film types) Demonstration (concentrator modules, thin-film) Research (emerging materials and manufacturing processes) Moderate-high confidence in cost estimates and projections
Environmental Impact	Manufacturing: Manageable waste streams Installation: Minimal; potential visual and land-use issues Operation: Minimal Decommissioning: Material recycling and disposal needs
Economic Status	Currently competitive only in high-value applications; cost (without subsidy) remains several times that of grid power in most areas. As cost drops, the number of potential markets and uses increases Tax and cash incentives still necessary to facilitate most projects
Policy Status	Encouraged by RPS and energy policies in most jurisdictions
Trends to Watch	Short-term supply constraints from silicon shortage Near-term capacity growth perhaps down to 10% per year, rebounding to 30%+ per year by 2008 or 2009 Emergence of thin-film technology More building-integrated PV (BIPV) and energy-efficiency bundling Continued growth as a distributed resource, including microgrids Increasingly automated manufacturing leading to lower cost Significant R&D investment by major international petroleum (BP, Shell) and electronics (Kyocera, Sharp, GE) companies

5.1 Introduction

Solar photovoltaic modules, also known as “photovoltaics” (PV), are solid-state semiconductor devices that convert sunlight into direct-current electricity. PV was initially developed for the space program in the 1950s to power the first satellites, an application where simplicity and reliability were tremendously important, and cost was of much lesser consequence. In the early 1970s, PV began to be used for terrestrial power applications, which led to a shift in R&D goals and funding sources away from the space program to private/public sector collaborative efforts. This work, led primarily by the U.S., Europe, and Japan, has resulted in a generally steady, dramatic decrease in module costs and a concurrent near-doubling in energy conversion efficiency. The average module sales price (in 2004 dollars) dropped from $67,000/kW in 1976 to $3,600/kW in 2004, while high-end commercial modules increased in performance from 8% conversion efficiency to about 17%. Since 2004, a short-term constriction in high-purity silicon feedstock plus ongoing strong demand have pushed up module prices by about 10%. The

feedstock shortage is widely thought to be ending no later than 2009, but it has fueled faster growth in the thin-film PV sector already.

In 2005, annual global module sales exceeded 1,400 MW [20], which translates into a billions-of-dollars-per-year business for both module production and system installation. Recent mergers and acquisitions, which are consolidating PV manufacturing companies and system integrators into large multinational energy companies, may mark PV's emergence into the mainstream. With growing environmental concerns and the emerging green-power market, PV appears to be entering a new era in which it will play an increasingly important role in meeting the world's energy needs.

The growth of PV applications since 1992 has been in three major application groups: remote off-grid commercial PV, grid-connected PV, and indoor consumer applications such as watches, calculators, and other household electronics. Data compiled by Strategies Unlimited through 2002 [14] clearly indicated the tremendous growth in grid-connected PV since the mid 1990s. This trend has continued such that the grid-connected market segment was 80% of all installations by 2004 [23] and continuing to grow. Based on market and policy considerations, grid-connected PV systems for commercial, industrial, and residential uses appear to be entering a period of long-term, accelerated growth.

According to CLSA Asia-Pacific Markets' 2005 solar power sector outlook [18], future capacity growth will grow by 30% through the end of the decade, though it is likely to initially slow to 20% annual growth possibly through 2008 due to a very tight silicon feedstock market. Given current annual growth assumptions, the organization expects the industry to reach approximately 3.5 GW by 2010.

Continued Focus on Distributed PV

This edition of the TAG-RE continues the shift in focus begun in the 2002 edition from emphasizing the use of PV in large utility-scale applications to relatively small-scale distributed generation at the residential, commercial, industrial, institutional, business park, and subdivision scales. The National Center for Photovoltaics (NCPV) and others project that, by 2020, approximately half the PV market will consist of distributed generation applications, one-third will consist of traditional remote and high-value applications, and only one-sixth will consist of wholesale utility-scale grid generation. Large-scale bulk-power PV facilities remain uncompetitive with other intermediate and peaking supply technologies, and it seems unlikely that very many centralized PV facilities larger than 10 MW (ac) will be built in the near future.

In contrast, new PV technologies and policies that allow and even encourage (through rebates, subsidies, and tax incentives) distributed generators to interconnect to the grid will make small-scale on-site generation increasingly competitive, practical, and attractive. For a growing number of applications, straightforward economics favor PV when compared to the projected cost of grid power over a PV system's lifetime. Building-integrated PV (BIPV) strengthens the economic argument by incorporating PV into building components such as roofs, windows, or facades that would be necessary in any case and represent a significant portion of a structure's initial cost. Such distributed generation options offer energy companies and their customers many potential benefits.

Thus, while this section continues to provide updated information on large utility-scale PV facilities, it also includes and emphasizes new information on small-scale deployment, interconnection, and microgrid configurations. In addition, this section addresses solar resource assessment, likely development pathways, PV module performance and cost history and projections, operating and maintenance labor requirements, environmental issues, potential for greenhouse gas reduction, installed capacity history and projection, and evolving markets for equipment and services that are common to both distributed and centralized PV projects.

5.2 Resources

The solar energy resource at a given location is characterized by the solar radiation per unit area (or "insolation," also called "solar irradiance") expressed in units of kilowatt-hours or megajoules per square meter per year (kWh/m^2/yr or MJ/m^2/yr). The insolation reaching the earth's surface varies with latitude, altitude, time of day, and season, as well as with local weather and air clarity. The sunlight's path through the atmosphere is effectively lengthened or shortened by all of these factors, meaning that varying amounts of the incoming light are transmitted. The lower latitude regions of the world and especially those with dry climates, such as in the southwestern U.S., typically exhibit the highest average insolation.

As light passes through the atmosphere, some is reflected, some is absorbed, and some is scattered. On clear days around noon, the direct normal-beam radiation reaching the earth is typically 900-1,000 W/m^2. This varies as discussed above. However, it is always at least 30% less than the irradiance present outside our atmosphere.

Insolation reaches a PV module either directly ("direct-normal radiation"), after being scattered ("diffuse radiation"), or after being reflected from the ground. This is an important distinction, because not all PV module designs can use all types of solar radiation. Figure 5-1 shows the distribution of insolation in the U.S., including both the direct-normal and diffuse components.

There are two principal types of PV array: flat-plate and concentrator. Concentrator designs use lenses or mirrors to increase the amount of sunlight that reaches the active PV device. However, concentrator designs having more than a few-fold sunlight concentration must use precise, two-axis (east-west and north-south) tracking to always be perpendicular to the sun's rays, because they can only concentrate the direct-normal insolation.

Because flat-plate arrays can use both direct and diffuse sunlight, they can be mounted in a fixed orientation but they can also benefit from either one-axis (east-west) or two-axis tracking. An array mounted on a properly functioning one-axis tracker receives about 20% more solar radiation annually than it would on a fixed-tilt mount, while an array on a two-axis tracker would capture approximately 30% more.

5.2.1 Resource Assessment

As shown in Figure 5-1, typical insolation throughout the U.S. is within about plus or minus 35% of 5 kWh/m^2 per day (1,800 kWh/m^2/year). The standard variation from the average for any particular location is about 5%. Average insolation values for a given location, such as those given in Figure 5-1 and Table 5-5, can be used for rough calculations, but measurements taken over the course of at least one entire year at a particular power plant site are needed to accurately predict the output and, therefore, the energy cost of a PV system. (See Section 5.5.4, "PV Performance and Cost Estimates" for an example of using site-specific insolation data to evaluate PV projects.)

On a typical day, the insolation falling on a surface oriented perpendicular to the sun's rays reaches a maximum of about 1 kW/m^2 at solar noon. Today's typical 50- to 200-watt commercial solar modules operate at up to about 15% conversion efficiency to dc electricity under standard test conditions and should therefore output up to 150 W/m^2 dc. The maximum ac power available after packing-factor, module-mismatch, wiring, dc-ac conversion, and thermal derating losses are factored in is approximately 50 W/m^2. Thus, a large number of modules and large area are required to generate significant electric power. For example, a 100-MW power plant would consist of about one million modules and cover more than one-half square mile (130 hectares). Since PV power output is proportional to the incident insolation, it is not dispatchable without energy storage. However, PV technology fits in well with the peaking needs of utilities with early to mid-afternoon summer peaks, such as some in California.

While PV is most economical in regions of intense sunlight such as the southwestern U.S., it can be an effective technology in other climates and latitudes. As far north as Iceland and Alaska, PV is a practical power generation technology for some remote or building-integrated applications—particularly for summer-seasonal loads.

The National Renewable Energy Laboratory (NREL) maintains the National Solar Radiation Database, available at its "Solar Radiation Resource Information" website at http://rredc.nrel.gov/solar. In addition to solar data dating back to 1961, the site also provides U.S. solar resource maps, data collection archives, standard solar spectra, many publications, and access to solar codes, algorithms, models, and calculators.

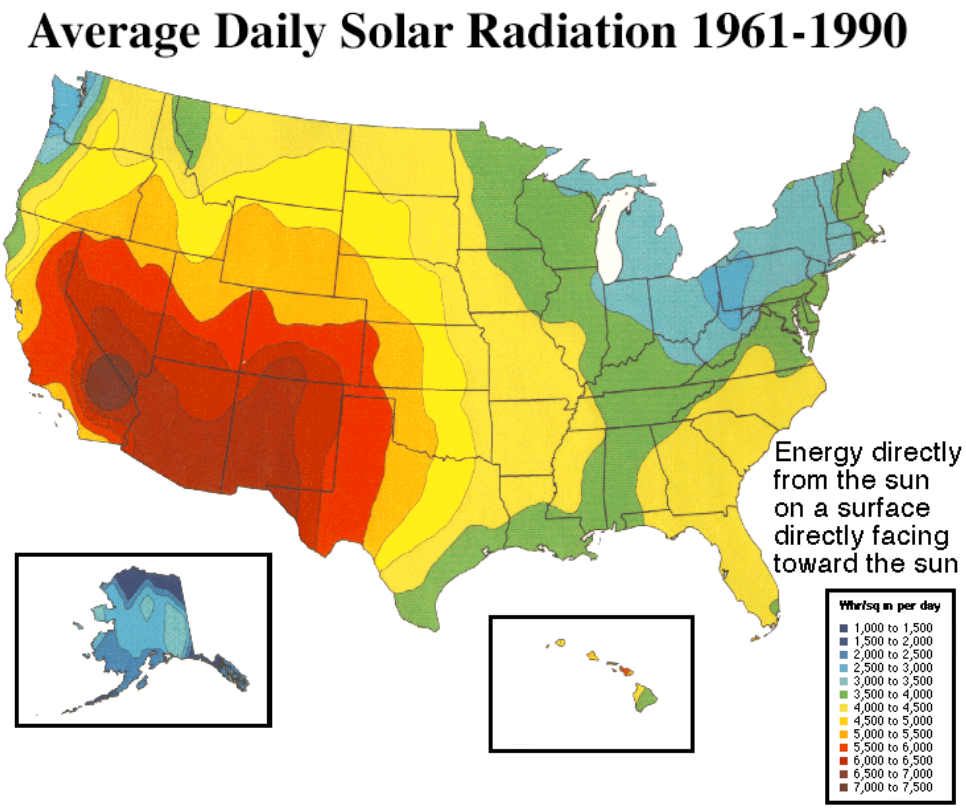


Figure 5-1
Distribution of Global Insolation in the U.S. (Wh/m^2 per day)
(Source: U.S. DOE)

NASA's Earth Science Enterprise Program (http://eosweb.larc.nasa.gov/sse/) provides data on more than 100 satellite-derived solar energy and meteorology parameters culled from more than a decade of observations, including global solar energy data for 1,195 ground sites. The website can produce data tables for any location, with color plots available on both global and regional scales. Information available includes seasonal and daily solar geometry, parameters for sizing and pointing solar panels and solar thermal devices, parameters for sizing batteries or other energy storage systems, and historic wind and cloud cover. These NASA data may also be used with the RETScreen renewable energy project analysis software, available from National Resources Canada at www.retscreen.net.

The European Union has established a website that provides satellite-derived data for solar resource estimation at http://www.satel-light.com/core.htm. The site offers solar radiation and daylight data for all Europe that were derived from two years of Meteosat Satellite images (1996-1997) and cover the continent at an average resolution of 5 km by 7 km.

5.2.2 Shipments and Installed Capacity

The world market for PV cells and panels in 2005 exceeded 1,407 MW (dc capacity), according to estimates by Navigant Consulting [20]. The majority of U.S. PV module production has been exported, with more than two-thirds of recent production going overseas. Table 5-1 summarizes U.S. PV exports by country of destination in 2005 as reported by manufacturers to the U.S. Energy Information Administration [16]. Note that, driven by large government subsidy programs for grid-connected systems, Germany and the Netherlands alone received two-thirds of the PV shipped from the U.S.

Table 5-1
U.S. PV Exports by Region (in 2005)

Country (by Continent)	Peak Megawatts	Percentage of U.S. Exports
Europe		
Germany	49.25	53.3
Netherlands	12.00	13.0
Other	5.76	6.2
Asia and Middle East		
Hong Kong	2.94	3.2
Japan	1.09	1.2
Singapore	8.56	9.3
China	1.94	2.1
Other	2.63	2.8
Africa		
South Africa	0.55	0.6
Other	0.39	0.4
North and Central America		
Canada	3.23	3.5
Mexico	1.07	1.2
Other	0.86	0.9
South America		
Peru	0.36	0.4
Brazil	0.46	0.5
Other	0.28	0.3
Australia and Oceania	1.07	1.2
TOTAL	92.45	100%

(Source: U.S. EIA)

According to the latest available figures on regional demand from Navigant Consulting's 2006 Solar Outlook, nearly a gigawatt-and-a-half of PV modules were shipped globally in 2005. Japan accounted for about 51%, Europe 29%, U.S. 9%, and the remaining 11% was divided among the rest of the world—where most of the two billion people without electricity today live [20].

Cumulative installed PV capacity in the U.S. in 2005 was approximately 550 MW, much of it still in little-documented small off-grid installations. However, at the current pace of grid-tied addition, those installations will soon dwarf the country's off-grid installed base. Worldwide, cumulative installed capacity surpassed the 1-GW benchmark in 1999, passed 2 GW in 2002, and reached beyond 5 GW in 2005.

5.3 Technology Description

Photovoltaic cells, the smallest PV generating units, are formed from a semiconductor material, usually silicon, which is doped with other elements having either one more or one less valence electron to alter the conductivity of the host material. For example, if the silicon is doped with an element having one more valence electron, such as phosphorus, then the resulting material will have an extra electron available for conduction. This material is called an n-type semiconductor. Conversely, when the silicon is doped with an element having one less valence electron, such as boron, then the p-type semiconductor that is produced has an electron vacancy, or hole. When adjacent layers of n-type and p-type materials are illuminated, a voltage develops between them, which can cause a dc electric current to flow in an external circuit.

A typical silicon solar cell today is about 100 cm^2 in area and produces about three amps at 0.5 volts. Individual cells are combined into modules and connected in series and parallel to provide higher voltage and current levels. The active areas of the modules range from 0.1 to 2 m^2, and the modules are typically connected together in flat arrays. Three array configurations are used: fixed-tilt arrays facing the equator, single-axis tracking of the sun from east to west, and two-axis tracking of the sun to remain perpendicularly oriented to the sun's rays. The dc power generated is converted to ac by a power-conditioning unit, if necessary. It is important to understand the different sorts of "watts" that are used in describing PV systems to correctly anticipate the field performance of such systems versus the module-label rating in "dc watts at STC" (Standard Test Conditions, which are 1,000 W/m^2 illumination and 25°C module temperature). The STC are clearly "laboratory" conditions that seldom occur in the field and the actual module output varies as illumination and temperature change. Typically, modules operate 20 to 40 C° hotter than STC on very sunny days and, therefore, they output 10% to 20% less power at 1-kW/m^2 illumination than their labels say. Other derating factors include imperfect use of the array's land area (packing-factor loss), electrical losses because of module-mismatch (no two modules have precisely the same current-voltage characteristics) and field wiring resistance, and less than 100% inverter dc-ac conversion efficiency. As mentioned earlier, these losses altogether amount to about 33% derating of plant ac output versus the sum of the modules' dc ratings.

New materials and manufacturing techniques have been sought throughout the history of PV to increase efficiency and lower costs. Overall, these efforts have been very successful, and new materials and techniques continue to promise significant further improvements. The key to reducing the cost of crystalline silicon cells has been improved manufacturing techniques to speed mass production while also reducing material consumption and improving efficiency.

To date, crystalline silicon cells have achieved the greatest efficiency, but the manufacturing process remains relatively slow and difficult to automate. Nevertheless, because crystalline silicon cells have the most highly-developed manufacturing processes, they remain at the low end of the PV cost spectrum.

Crystalline silicon cells can be made from single crystals, produced by slowly drawing a "boule" from molten silicon, or from polycrystalline silicon, made by cooling a graphite mold filled with molten silicon. The resulting blocks must then be cut into wafers to produce cells, a time-consuming process that wastes a significant amount of expensive material, turning it into sawdust.

Some manufacturers skip the sawing step by pulling "ribbons" of silicon from the melt, or by solidifying wafer-thin layers of silicon onto a supporting ceramic substrate. These both eliminate the inherent waste of the wafering processes, but neither produces as high conversion efficiency as the wafer-based modules. Consequently, so far, ribbon and "film silicon" cell modules are not significantly less expensive than wafered-cell ones on a dollars-per-watt basis.

Another approach that addresses the drawbacks of crystalline cells is to use various processes to deposit very thin films of amorphous silicon, copper indium diselenide (CIS), cadmium telluride (CdTe), or other novel semiconductors on a low-cost substrate, such as plastic, glass, or metal foil. These "thin-film" cells have several key advantages over crystalline silicon cells. They use considerably less raw material and their manufacturing techniques are well suited for mass production. To date, thin-film cells have not achieved the efficiencies of crystalline cells, but they show potential for doing so. Meanwhile, their greater application flexibility promises to accelerate their marketplace acceptance.

Several thin-film PV technologies are currently undergoing significant development efforts, including amorphous silicon, CIS, CdTe, TiO_2/dye (a novel device, called the "nanostructure" or Graetzel cell [named after its Swiss inventor, Michael Graetzel], involving sintered titania, an organic dye, and a liquid electrolyte), and even various silicon-film techniques. All of these technologies show real promise for ultimately replacing crystalline silicon as the PV workhorse technology. Indeed, CIS, CdTe, and TiO_2/dye are all in some form of commercial-scale production, and amorphous silicon continues as a strong competitor while struggling to maintain its 5% market share in today's robust PV market.

Looking to the future, a number of concepts show promise for advancing the performance of PV devices by a factor of two or three from those in present-day commercial modules. Collectively, these advanced devices are known as "Third Generation Photovoltaics."[24] Although most of the Third Generation concepts have not even reached the stage of laboratory demonstration, the one known as the "multijunction cell" can be found in some of today's commercial amorphous silicon modules. This concept involves making a device with two or more working junctions that are stacked one atop the other so that the sunlight reaches the lower junction(s) after being filtered through the upper one(s). This structure provides the possibility of higher conversion efficiency because it allows the more energetic photons of the solar spectrum to be harvested separately from the lower-energy ones. In theory, multijunction PV devices may be up to 86% efficient at converting sunlight to dc power. In practice, multijunction amorphous silicon modules have shown higher efficiency and (more importantly) greater stability than single-junction amorphous silicon modules. Multijunction concentrator cells made using semiconductor alloys related to gallium arsenide and indium antimonide hold the present world's record for solar energy conversion efficiency at nearly 40%.

5.3.1 Building-Integrated Photovoltaics (BIPV)

Still in the early stages of commercialization, thin-film PV offers several advantages over crystalline technology. In contrast to heavier and more brittle crystalline PV, thin-film PV can be manufactured as flexible lightweight sheets or rolls. It can also be incorporated into building materials such as roofing, window glass, or facades. Such PV systems—where the very materials of which a building is made contribute to meeting its energy demand—are termed building-integrated PV (BIPV).

BIPV strengthens the economic argument for PV by incorporating the technology into building components that would be necessary in any case and represent a significant portion of a structure's initial cost. A building designed for BIPV from the start can be constructed so that its architecture, placement, landscaping, and physical plant optimize its solar energy capture and efficiency. Another advantage of BIPV is aesthetic: while many find standard rooftop PV modules and mounting hardware to be visually unattractive, incorporating PV into a structure can make PV unnoticeable or even an attractive design element.

Both commercial and residential buildings are likely candidates for building-integrated technologies. On the residential side, roofing shingles or tiles are the primary candidates, while commercial options include other roofing systems, curtain walls, and glass for windows and skylights.

Several project developers are increasing the value of solar power by bundling BIPV with other energy efficiency measures. For example, the 1.18-MW PowerLight installation at the Santa Rita Jail in Dublin, California, was deployed as part of an overall energy efficiency plan that took advantage of the rooftop system's thermal insulating properties in addition to a comprehensive upgrade of the facility's central plant, cooling equipment, and controls. The combined solar and energy efficiency improvements reduce the jail's peak summer demand consumption of grid-generated electricity by 25% and are expected to save the county approximately $15 million over the system's estimated 25-year life. Another PowerLight project, deployed atop the Moscone Conference Center in San Francisco, similarly combines rooftop PV with broader energy efficiency measures to leverage the benefits of both. The project's PV modules, manufactured by Shell Solar and Sanyo, have a capacity of 675 kW and are expected to generate 825,000 kWh per year. The energy efficiency improvements are expected to save an additional 4.5 million kWh per year.

Another method of significantly improving the economics of PV may be by applying solar electricity in non-traditional dc power applications such as adjustable-speed motor drives, lighting systems, appliances with switch-mode power supplies, heating systems, and uninterruptible power supplies. Applying the dc energy generated by PV directly to such loads can reduce cost and equipment requirements by improving efficiency and eliminating the need for an inverter and interconnection equipment, which represent about 25% of a system's capital cost. PV applications that avoid the need for inverters benefit not only from lower capital costs, but also from lower maintenance costs and improved reliability. Taken together, these factors can mean a 30% reduction in the life cycle cost of PV energy compared to a traditional PV inverter approach.

5.4 Technology Status

PV technology is still evolving and has not reached mature commercial status. It is presently best suited economically to small installations (several watts to a few kilowatts) in special applications, including electrical switching and lighting at remote locations, billboard lighting and emergency telephones along highways, and other special applications where, in fact, PV often can provide service at the lowest cost. Other important present markets for PV include those derived from growing public interest in "green power," such as residential and commercial rooftop retrofit installations of 1 to 500 kW each. This market force will also help to stimulate the growth of BIPV throughout the first decade of this century. BIPV includes roofing materials and building facades, generally installed only during new construction. As noted in the Introduction, large-scale bulk-power PV facilities are not now competitive with other intermediate and peaking supply technologies and it is unlikely that many large centralized PV facilities will be built in the near future, unless specifically incentivized by policy-driven subsidies.

5.4.1 Likely Development Pathways

Table 5-2 is a monitoring guide of the leading developers and technical issues in solar photovoltaic power generation. The technologies addressed include: flat-plate silicon cells, high-concentration silicon and III-V semiconductor tandem cells; thin-film multijunction amorphous silicon cells; thin-film single-junction polycrystalline cells; optics for concentrators; and electronic, controls, sensors, and power conditioners.

Table 5-3 is a development "map" for solar photovoltaic power generation. Solar PV cell technology ranges from wafered silicon cell technology, to high-concentration silicon cell technology, to thin-film PV technology.

Table 5-2
Technology Monitoring Guide: Solar Photovoltaic Power Plants

Leading Developers of the Science or Technology								
Technologies	**R&D Intensity**	**Government Organizations**	**Nonprofit Organizations**	**Industrial Firms**	**Leading Vendors**	**Major Trends**	**Changes to Watch for**	**Unresolved Issues**
Flat-Plate Silicon Module	Moderate	DOE/NREL MITI	Georgia Tech	SolarWorld BP Solar Kyocera GE Energy Sharp	SolarWorld BP Solar Kyocera GE Energy Sharp	Improving performance and lowering manufacturing cost	Ongoing incremental decreases in module costs, increased efficiencies	Supply of purified silicon for large-scale, low-cost production
High-Concentration Silicon or III-V Tandem Cell	Low	DOE/NREL	Univ. New South Wales	Amonix SolarSystems SunPower Emcore Spectrolab	Amonix SolarSystems SunPower Emcore Spectrolab	Innovative designs with greatly lowered cost 40% cells	Commercial competition and deployments	Lack of infrastructure for large-scale marketing and distribution
Thin-Film Multijunction Amorphous Silicon Module	Moderate	DOE/NREL MITI	Many universities worldwide	United Solar Ovonic (Uni-Solar)	United Solar Ovonic (Uni-Solar)	Improving performance and manufacturers' yield of multi-junction thin-film modules		
Thin-Film Single-Junction Polycrystalline Module	Moderate	DOE/NREL Germany MITI European U.	Many universities worldwide	First Solar Global Solar Energy	First Solar Global Solar Energy	Very promising progress in laboratory cell performance	Multi-megawatt-per-year module production with rapidly falling costs	Manufacturing yield and average module performance
Advanced Thin-Film Multijunction Polycrystalline Module	Low	DOE/NREL European U.	Univ. Delaware Univ. So. Florida Univ. New South Wales			Exploratory materials research to identify and solve issues	Laboratory prototypes	Feasibility of monolithic construction for poly-crystalline thin-film modules

Table 5-2 (continued)
Technology Monitoring Guide: Solar Photovoltaic Power Plants

Leading Developers of the Science or Technology								
Technologies	**R&D Intensity**	**Government Organizations**	**Nonprofit Organizations**	**Industrial Firms**	**Leading Vendors**	**Major Trends**	**Changes to Watch for**	**Unresolved Issues**
Optics (for concentrators)	Moderate	NREL	U.C. Merced	3M SolarSystems SolFocus Energy Innovations	GE B&L EG&G Japanese companies	Use mirrors or novel lens designs	Field demonstration of reliable, long life with low O&M	Reliability under field conditions
Electronic Controls (for trackers)	Low	DOE/Sandia		as above	GE TI	Higher functionality, smaller units	PC-based systems	Reliability under field conditions
Sensors (for trackers)	Low	NASA DOE/Argonne		as above	EG&G Allen-Bradley	High sensitivity, more rugged	Greater integration into control systems	Reliability under field conditions
Power Conditioners	Medium	DOE/Sandia		Ballard Omnion SatCon SMA Xantrex	Ballard Omnion SatCon SMA Xantrex	Higher reliability, greater intelligence	Module-integrated designs Longer warranties	

Table 5-3
Technology Process Development Map: Solar Photovoltaics

	Flat-Plate Silicon Cell	High-Concentration Silicon, III-V Tandem Cell	Amorphous Silicon Thin-Film	Thin-Film Single-Junction Polycrystalline	Advanced Polycrystalline Multijunction Thin-Film
Features and Advantages					
Technology Characterization	Wafered silicon	Single-crystal silicon or III-V semiconductor	Thin-film multijunction amorphous silicon	Thin-film polycrystalline compound	Thin-film multijunction polycrystalline compound
Efficiency	12-18%	25–40%	7–15%	6–18%	25%
Resources	High annual sunlight, low-cost silicon availability	High annual direct sunlight location	Moderate-to-high annual sunlight location	Moderate-to-high annual sunlight location	Moderate-to-high annual sunlight location
Challenges and Disadvantages					
Cost	High cost of high-grade silicon	Complexity of two-axis tracking	Relatively low efficiency to date	Relatively low efficiency to date	Unknown manufacturing technologies
Operation	Non-dispatchable without storage	Non-dispatchable without storage	Non-dispatchable without storage	Non-dispatchable without storage	Non-dispatchable without storage
Technology Needs	Achieving 15% efficiency at $100/m^2	Achieving 25% system efficiency and array cost <$250/m^2	Achieving 15% module efficiency at cost of $50/m^2	Achieving equivalent field performance to amorphous Si at lower cost	Achieving 25% module efficiency at cost of $60/m^2
Costs					
Relative Capital	Medium	Medium-Low	Medium-Low	Medium-Low	Low
Relative O&M	Very Low	Low	Very Low	Very Low	Very Low
Busbar	15-30¢/kWh	10-20¢/kWh	7-15¢/kWh	6-8¢/kWh	<7¢/kWh
Development Timeframe					
Research	1970s–present	1976–present	1983–present	1980–present	1994–2010
Development	1985–present	1995–1997	1993–present	1990–present	2005–2012
Demonstration	1992–1994	1997–1999	1995–1998	1997–present	2015–2020
Commercialization	1990s	1999–present	1998–present	2000–present	2017–2020
Markets					
Key Issues	Established Goal: achieving 15% efficiency at cost of $100/sq meter	Goal: achieving 25% system efficiency and array cost of <$250/sq meter	Goal: achieving 15% module efficiency at cost of $50/sq meter	Goal: achieving equivalent field performance to amorphous Si at lower cost	Emerging Goal: achieving 25% module efficiency at cost of $60/sq meter
Impact on Technology Outlook	PV prospects helped by higher natural gas prices, but not by absence of limits on fossil fuel use and greenhouse gas emissions.	PV prospects helped by higher natural gas prices, but not by absence of limits on fossil fuel use and greenhouse gas emissions.	PV prospects helped by higher natural gas prices, but not by absence of limits on fossil fuel use and greenhouse gas emissions	PV prospects helped by higher natural gas prices, but not by absence of limits on fossil fuel use and greenhouse gas emissions	Emerging tech needs demonstration of feasibility; no vendor activity

5.5 Cost and Economic Issues

This edition of the *Renewable Energy TAG* continues to reflect a stronger emphasis on relatively small-scale distributed PV as opposed to utility-scale centralized PV that a utility might, for example, build near a substation to provide grid support. While EPRI believes that the latter option will eventually prove practical as the cost of PV falls, it will likely not be competitive with other intermediate and peaking supply technologies before 2010. Current activity in the marketplace and among policymakers focuses almost entirely on the distributed option.

Though the fundamental PV technology may be the same, cost and economic considerations related to distributed PV are significantly different from those related to centralized utility-owned PV. In the former case, some or all of the cost may be born by customers interested in benefiting from on-site distributed generation and supporting a clean, renewable technology. Depending on local electricity prices and any rebates, subsidies, or incentives available, the payback period for a typical residential-scale PV system often exceeds a decade. A distributed PV system may also be owned by an energy company interested in providing grid support in critical areas, exploiting new business opportunities, or complying with policy demands such as renewable portfolio standards. Because PV is highly modular, distribution companies can precisely deploy it in optimal locations and capacities—or work with customer-owners to do so. Other purchase or lease arrangements may be beneficial to customers, utilities, or both.

The federal government, acting through the DOE, has instituted several programs through the years to support PV research and development, subsidize its use, and plan for its future. The federal “Million Solar Roofs” initiative, begun under the Clinton administration, aims to install one million solar energy systems—including PV, water heating, and space heating—on the rooftops of American homes and businesses by 2010. The initiative includes federal procurement programs, technology grants, and lending programs. Several states also have programs encouraging the development of renewable energy. In many cases, a combination of state and federal incentive, rebate, or loan programs can pay a significant share of a PV system’s cost. Most notably, California's Emerging Renewables Program (ERP) and Self-Generation Incentive Program (SGIP) have led to an estimated installed grid-connected PV capacity totaling one-quarter of the nation's 550 MW of installed PV in 2005. California’s PV momentum was further boosted in 2006 by the passage of SB-1 (Senate Bill 1) and formation of the California Solar Initiative, a $3 billion program to incentivized installation of 1 million solar rooftops by 2017. In addition, solar requirements embedded in renewable portfolio standards are also fueling PV development. The National Database of State Incentives for Renewable Energy (DSIRE) at www.dsireusa.org provides up-to-date information on state financial and regulatory incentives that are designed to promote renewable energy technologies.

Other nations, such as Germany and Japan, have active and generous government-sponsored incentive programs. As a result of their aggressive programs, Germany currently ranks first in the world in installed PV capacity with over 1,600 MW as of the end of 2005, while Japan ranks second, with over 1,400 MW installed. The U.S., with far more land and sunshine than either of the leaders, is an increasingly trailing third.

Japan

Japan had approximately 320 MW of PV in place at the end of 2000, with more than two-thirds of it installed through a residential capital cost buy-down program that began in 1994 and was administered by the New Energy Foundation, part of the Ministry of Economy, Trade, and Industry (METI) until the program's termination in 2005 [15]. In the following five years, another 1.1 GW was installed, nearly all under the METI program, launched in the late 1990s and run by METI's New Energy and Industrial Technology Development Organization (NEDO), which aimed to develop a full range of new energy technologies, including PV, by subsidizing both R&D and market penetration to bring costs down.

METI PV systems are grid-connected and net-metered, which increases their attractiveness given Japan's high-priced electricity. The maximum subsidy provided to system buyers, which was initially about 50% of installed costs and has decreased annually, reaching 10% in 2003, and was phased out completely in 2005. Despite the decline and eventual termination of end-user incentives, the program remained popular and successful to its end, in part because net prices in Japan have continued to fall, aided by ongoing Japanese government market-development assistance to the industry. NEDO budgeted ¥3.5 billion in 2003 to develop advanced PV power generation, a drop from the ¥4.5 billion budgeted in 2002 [21].

Although federal rebates in Japan expired in 2005, some regional and municipal governments are continuing to support local projects. Just what the lack of federal support means for future PV projects in Japan is unclear, though it may be the first real market test of how well the model program has worked. Looking ahead, Japan' latest goal is to have a cumulative capacity of 5 GW installed by 2010, and it is considering instituting a 100 GW goal by 2030.

Germany

Germany had approximately 110 MW of PV installed as of the end of 2000. Beginning with a "1,000 Solar Roofs" program in 1989, Germany progressed to a "100,000 Solar Roofs" program in 1999 with the goal of installing 300 MW of PV by 2004. The program provides 10-year low-interest loans that feature no money down and no interest payment for two years toward the installation of rooftop PV systems. Over the term of the program that ended in June 2003, loans for approximately 350 MW were approved.

Germany's Renewable Energy Sources Act, which took effect in April 2000, also encouraged PV development by offering high financial incentives. The act established a PV feed-tariff which initially offered solar power producers roughly 0.5062 per kWh ($0.66 at April 2006 exchange rates), guaranteed for 20 years. Since 2002, this guaranteed price has been reduced by 5% to 6.5% per year—depending on the type of system— to encourage cost reductions New regulations that took effect in January 2004 provide a tiered incentive structure ranging from 45.7 to 62.4 Eurocents/kWh of PV generation, depending upon the system size and whether it is free-standing, rooftop, or building-integrated. In addition to national incentives, some individual German municipalities offer production incentives as high as 2 DM/kWh ($1/kWh), funded by surcharges on utility bills. All told, these programs have helped catapult the country's annual solar power installations from 83 MW in 2002 to 366 MW in 2004 and to 832 MW in 2005.

5.5.1 Example PV Project Costs

As solar photovoltaic technology continues to evolve, significant cost reductions are expected to continue as a result of improving power conversion efficiencies, development of low-cost cell fabrication processes, and increasing cell production volume with attendant economies of scale.

The procedure and data tables presented below provide a methodology to estimate solar PV power plant performance and cost at a given location for both current technology and projected future solar PV technology. The resulting estimates represent technology available for commercial order in a given year and site conditions that include annual insolation, average ambient temperature, and a city cost index. The projections are based on the EPRI Solar Calculator, which is in turn based on the 1997 DOE/EPRI Technology Characterization for solar photovoltaic power plants [1] and other EPRI reports [2, 3], updated by EPRI staff judgment.

5.5.2 Technology Performance and Cost Tables

The following subsections, which address the performance and cost of PV technologies, take a two-track approach. Distributed and utility-scale PV systems demand very different economic and technical considerations. In particular, distributed PV systems—whose costs are typically assumed by a building owner or operator with, in most cases, significant support in the form of rebates or tax credits—require a more flexible and tailored approach. The information and examples that follow are intended to illustrate some of the variables involved and an approach to estimating system performance and cost through a range of options.

Distributed PV Performance and Cost

Many customers considering installation of a distributed PV system are relatively sophisticated energy consumers. In many cases, they have investigated their energy consumption patterns, taken measures to improve energy efficiency and reduce usage, and developed a working knowledge of PV operating principles, utility interconnection practices, net metering tariffs, and financial incentive programs for solar electric power.

Nonetheless, due to the complexity (and novelty) of PV production models and financial calculations, their investment decisions are often made without a complete understanding of the true economic effects. To accurately evaluate the costs and benefits of a possible PV project, the consumer must:

- Obtain detailed cost and performance data from the PV system or module manufacturer
- Acquire meteorological data from a representative ground station
- Simulate the production of the PV system, taking into account sun angles and module orientation
- Determine hourly impacts on utility consumption
- Calculate monthly energy and/or demand savings using their specific utility tariff structure
- Calculate the financial impacts and applicability of various buy-down programs, tax credits, and financing terms

Because the factors involved vary so widely, it is impractical to attempt to construct a single table representative of all distributed PV systems. One consumer tool that has been designed to overcome these difficulties is the "Clean Power Estimator." Section 5.5.4 provides sample calculations using the Estimator.

Utility-Scale Performance and Cost

Table 5-4 presents performance and cost data for several large, centralized, utility-scale projects hypothetically located at Carrisa Plains, California. This location is chosen to represent the base case because, while PV can operate beneficially in many latitudes and climates, its early large-scale applications are most likely to be pursued in high-insolation areas near load centers such as Arizona and southern California. Cost data are adjusted to end-of-year 2003 dollars based on both the U.S. Producer Price Index (PPI), which best represents changes in the cost of the metal, glass, and semiconductor materials that comprise a PV system, and the Consumer Price Index (CPI), which best represents the cost of labor and retail goods. Over the past few years, the PPI has been slightly deflationary while the CPI has been modestly inflationary, resulting in little net change.

The table's first two columns present data for 5-MW and 50-MW fixed flat-plate PV plants. The plants use thin-film copper indium diselenide (CIS) technology. Thin-film technology was chosen for this example because, although commercial silicon cell technology is available today with greater than 12% system efficiency and lower cost than available thin-film PV technology, its projected efficiency and cost-per-unit-area improvements are not expected to keep up with those of thin-film systems in the post-2010 timeframe for which this example is assumed to be of most interest.

The 50-MW flat-plate PV plant example assumes the following:

- 2,880 fixed south-facing arrays oriented at a 25-degree angle vs. horizontal
- Each array contains 160 modules
- Modules have about 1.1 square meters of active area comprising 123 thin-film PV cells in series
- Configured in 10 5-MW subfields, each with a dc-ac inverter
- Land area required is 255 acres
- Cost and performance data based on technology available for commercial order in 2002, albeit not in the quantity needed for a 50-MW plant
- Solar-to-dc electric conversion efficiency of CIS PV cells is 12% at 25 C cell temperature and 8.7% at the operating temperature (57 C)

This design, based on CIS technology, is also generically representative of other thin-film PV technologies that are expected to become available in the future, including multijunction amorphous silicon and CdTe.

The middle two columns of Table 5-4 present performance and cost data for 5-MW and 50-MW one-axis tracking flat-plate PV plants using crystalline silicon. The system is identical to the

fixed flat-plate system except in the 50-MW plant the arrays track the sun along one axis, oriented at a 25-degree angle vs. horizontal in the north-south direction.

The final two columns present performance and cost data for 5-MW and 50-MW Fresnel lens high-concentration PV (HCPV) plants.

The 50-MW HCPV plant example assumes the following:

- 2,110 two-axis tracking arrays, spaced sufficiently to avoid excessive shadowing in the early morning and late afternoon
- Configured in 10 5-MW subfields, each with a dc-ac inverter
- Each array contains 84 modules and 4,032 Fresnel lens/silicon cell combinations designed for a 250:1 solar concentration ratio
- Required land area with the assumed array spacing is 700 acres
- Solar-to-dc electric conversion efficiency of the silicon cells is 27.4% at 25°C cell temperature and 23.1% at operating temperature (70ºC).

The design is based on the integrated array system developed by EPRI's Renewable Energy Program, and the contractor estimates were adjusted using data available for this design. The design integrates the Fresnel lens parquet and backplate containing the cells into the array structure, which both reduces the weight of the array and simplifies the PV module manufacturing process.

Table 5-4
Utility-Scale Solar Photovoltaic Power Plant Costs for 2000 PV Technology in Carrisa Plains, California (Dec-03 $)

	Fixed Flat-Plate		One-Axis Tracking		Two-Axis Tracking	
Plant Size (no/ of units x unit size, MW)	1 x 5	10 x 5	1 x 5	10 x 5	1 x 5	10 x 5
Available for Commercial Orders, Year	2001	2001	2001	2001	2001	2001
First Commercial Service, Year	2002	2002	2002	2002	2002	2002
Hypothetical In-Service Year	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04
Plant Capital Cost ($/kW)						
Month/Year Dollars	Dec-03	Dec-03	Dec-03	Dec-03	Dec-03	Dec-03
PV Cells					418	384
PV Modules	4,033	3,700	4,011	3,680	1,338	1,228
Trackers			42	39	560	514
Power Conditioning Unit						
Balance of Plant	2,825	2,592	1,317	1,208	1,923	1,765
General Facilities and Engineering Fee	686	629	537	493	424	389
Project and Process Contingency	754	692	591	542	466	428
Total Plant Cost	8,299	7,614	6,497	5,961	5,130	4,707
Total Cash Expended (mixed year $)	8,299	7,614	6,497	5,961	5,130	4,707
AFUDC (Interest during construction)	0	0	0	0	0	0
Total Plant Investment (includes AFUDC)	8,299	7,614	6,497	5,961	5,130	4,707
Owner Costs	249	228	195	179	154	141
Total Capital Requirement, Hypothetical						
In-Service Year (includes AFUDC)	8,548	7,842	6,692	6,140	5,284	4,848
Operation and Maintenance Costs						
Costs for Hypothetical In-Service Year						
Fixed, $/kW-yr	18.8	13.5	10.6	7.5	62.7	44.9
Power Generation						
Annual Energy (M kWh/yr)	11.1	111	13.4	134	13.8	138
Capacity Factor	25.4%	25.4%	30.5%	30.5%	31.5%	31.5%
Unit Availability						
Equivalent Planned Outage Rate, %	3.8	3.8	3.8	3.8	3.8	3.8
Equivalent Unplanned Outage Rate, %	3.0	3.0	3.0	3.0	3.0	3.0
Equivalent Availability, %	93.3	93.3	93.3	93.3	93.3	93.3
Capability Ratio	1.03	1.03	1.03	1.03	1.03	1.03
Minimum Load, %	5	5	5	5	5	5
Preconst., License & Design Time, Months	12	12	12	12	12	12
Idealized Plant Construction Time, Months	12	12	12	12	12	12
Unit Life, Years	30	30	30	30	30	30
Technology Development Rating	Pilot	Pilot	Pilot	Pilot	Pilot	Pilot
Design & Cost Estimate Rating	Goal	Goal	Goal	Goal	Goal	Goal

5.5.3 Performance and Cost History and Projections

Figure 5-2 shows the evolution of worldwide PV module average selling price from 1976 through 2004 in constant year-2004 dollars [22]. The figure presents these data in the form of an "experience curve," where the average sales price is plotted versus cumulative installed capacity. This format was chosen to show the clear power-law behavior of historical module prices, where the average selling price has declined by about 20% with each doubling of capacity. Note that the right end of the figure's abscissa, at 1,000 GW, is about equal to the total installed U.S. electric generation capacity today.

In the 30-year timeframe of the historic data in Figure 5-2, the total market size has grown over a thousand fold, while prices have fallen more than 90%, and typical system efficiency has roughly doubled. Straightforward extrapolation of this trend for only the next 30 years, while by no means guaranteed to be an accurate forecast, implies another efficiency doubling and order-of-magnitude cost reduction while reaching terawatts of PV deployments. For specific projections of future costs and performance, see Tables 5-12 to 5-14.

5.5.4 PV Performance and Cost Estimates

The procedure and data tables that follow provide a methodology to estimate solar PV power plant performance and cost at a given location for both current technology and projected future solar PV technology. Methods and data are presented for estimating the performance and cost of typical fixed flat-plate, one-axis, and two-axis systems. Tracking systems maximize the power output of a particular PV array but also add to its cost and mechanical complexity.

The resulting estimates represent technology available for commercial order in a given year and site conditions that include annual insolation, average ambient temperature, and a city cost index. The projections are based on the EPRI Solar Calculator, which is in turn based on the 1997 DOE/EPRI Technology Characterization for solar photovoltaic power plants [1] and other EPRI reports [2, 3], updated based on the experience and judgment of EPRI staff.

Because solar PV technology is still developing, the projections are based on an assumed future technology development and market scenario. Hence, these performance and cost projections are subject to considerable positive and negative uncertainty, especially in the out years.

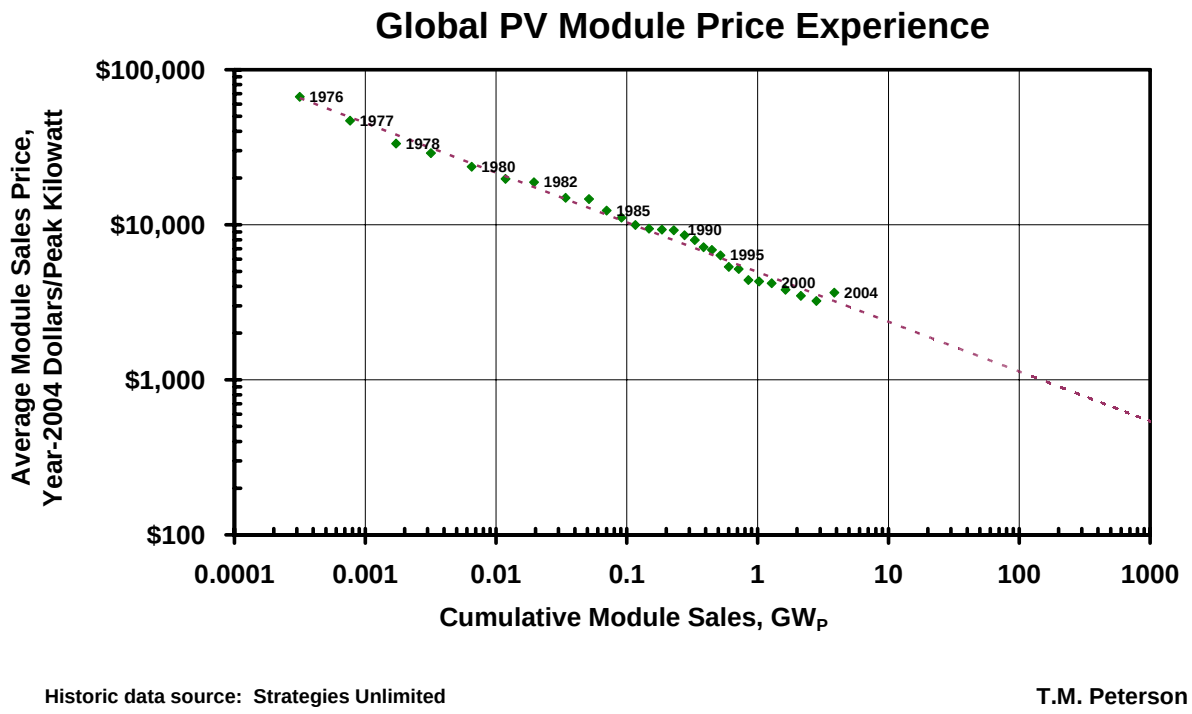


Figure 5-2
Worldwide Average PV Module Selling Price vs. Cumulative Sales

Resource Estimates

Location is a fundamental consideration when estimating PV performance and cost. Table 5-5 presents site data, as described below, for 27 representative locations in the continental U.S.

The **global latitude-tilt insolation rates** (kWh/m^2/yr) represent the annual solar energy that reaches an equator-facing solar array oriented at the latitude tilt angle relative to horizontal; i.e., the angle equals the latitude coordinate of the site.

The **global one-axis tracking insolation rates** are 20% higher than the latitude-tilt rates, to include the additional energy collected as the solar panel rotates around a single axis to follow the sun. The axis is oriented in the north-south direction at the latitude tilt angle relative to horizontal.

The **direct-normal insolation rate** excludes diffuse solar energy and includes only the direct solar energy that can be collected by a concentrating lens and solar module that tracks the sun via a two-axis tracking system.

Other site conditions include: **dry-bulb temperature**, which affects the PV cell operating temperature and therefore conversion efficiency; **maximum wind speed**, which affects design of the structural components; and the **city cost factor**, which affects capital and O&M costs.

Table 5-5
Site Data for 27 Locations in the Continental U.S.

	Solar Insolation			Average Ambient Temperature				
Location	**Global Latitude Tilt ($kWh/m^2/yr$)**	**Global 1-Axis Tracking ($kWh/m^2/yr$)**	**Direct Normal ($kWh/m^2/yr$)**	**Maximum Wind Speed (mph)**	**Dry Bulb (C)**	**Wet Bulb (C)**	**City Cost Factor**	**City Index**
El Paso, TX	2434	2921	2631	70	17.4	20.5	0.850	1
Albuquerque, NM	2401	2881	2566	90	13.8	18.9	0.927	2
Phoenix, AZ	2394	2873	2496	75	21.3	24.4	0.977	3
Carrisa Plains, CA	2345	2814	2445	70	20.1	26.5	1.100	4
Ely, NV	2230	2676	2377	74	6.7	15.6	1.062	5
Fresno, CA	2169	2603	2243	43	16.8	22.2	1.112	6
Dodge City, KS	2055	2466	2103	78	12.7	23.3	0.950	7
Santa Maria, CA	2039	2447	1947	60	13.8	18.3	1.130	8
Fort Worth, TX	1877	2252	1764	68	19.0	25.6	0.951	9
Columbia, MO	2058	2470	1552	54	12.5	25.6	0.987	10
Apalachicola, FL	1866	2239	1639	67	19.8	26.6	0.900	11
Brownsville, TX	1868	2242	1587	106	18.2	26.7	0.860	12
Omaha, NE	1767	2120	1652	109	9.7	25.6	0.950	13
Great Falls, MT	1715	2058	1641	82	7.2	17.8	0.952	14
Bismark, ND	1707	2048	1641	72	5.2	22.8	0.880	15
Medford, OR	1699	2039	1582	60	11.6	21.1	1.080	16
Cape Hatteras, NC	1747	2096	1504	110	16.5	25.5	0.820	17
Miami, FL	1802	2162	1418	132	24.1	26.1	0.930	18
Charleston, SC	1690	2028	1354	76	18.2	27.2	0.836	19
Lake Charles, LA	1652	1982	1285	69	20.2	26.7	0.920	20
Nashville, TN	1589	1907	1279	73	15.2	25.6	0.843	21
Madison, WI	1554	1865	1304	77	7.2	25.0	0.939	22
Washington, DC	1559	1871	1287	78	12.1	25.6	0.970	23
Caribou, ME	1418	1702	1183	76	3.8	21.7	0.885	24
Boston, MA	1421	1705	1160	87	10.7	23.9	1.073	25
New York, NY	1402	1682	1087	113	12.5	24.4	1.127	26
Seattle, WA	1299	1559	999	65	10.6	19.7	1.051	27

Distributed PV Cost and Performance Estimates

As described in Section 5.5.2, the Clean Power Estimator evaluates energy investments for a variety of technologies, including PV, wind, solar thermal, energy efficiency, and fuel cells. Although the discussion that follows focuses on the Estimator, EPRI is not endorsing this particular tool over similar products that serve the same purpose. However, it provides a useful illustration of the methods and variables involved.

The Estimator takes into account the specific characteristics of the customer purchasing the system (such as the utility rate structure, local solar and environmental conditions, and local, regional, and federal financial incentives) to provide a directly relevant "personalized" analysis.

A critical aspect of evaluating economic feasibility is obtaining the correct solar resource, utility tariff, and incentive data applicable to the specific customer. The Estimator contains databases for this purpose that have been developed over a four-year period and are regularly updated to ensure that Estimator licensees are using accurate data. Table 5-6 describes the contents of the Estimator databases.

Table 5-6
Information Included in Clean Power Estimator Databases

Database	Description
Solar Resource	Hourly "typical" solar irradiance by month (12 x 24 values); U.S. database is derived from the TMY-2 data and includes 237 locations
Utility Incentives	The "buy-down" and incentives provided by utilities; can include a variety of cost, size, and tax treatment constraints
State Incentives	Incentives provided by state governments or other jurisdictions below the federal level
Federal Incentives	Incentives provided at the federal level
Electricity Tariffs	Over 1,300 tariffs for residential and commercial customers, including net metering tariffs; provides wide flexibility in capturing the range of tariff structures, including seasonal variations, time of day variations, metering charges, energy pricing, demand pricing, energy and demand tiers, sell-back pricing, fuel cost adjustments, public programs, and other special charges; tariffs are updated using the Estimator's semi-automated monitoring tools
Electricity Load Profiles	Hourly profiles based upon independent utility research showing consumption patterns for various locations and customer types, such as all-electric heating, gas water heating, etc.
State Income Tax Rate Schedules	Tax rate schedules reflect tax filing status, such as personal income for married couples filing jointly, individuals, corporations, etc., for all states
Federal Income Tax Rate Schedules	Similar information as above, except for federal taxes.
Depreciation Schedules	Depreciation schedules such as the Modified Accelerated Cost Recovery System (MACRS) of the US tax code used by businesses to depreciate their PV capital investment
Environmental Emissions Factors	Air emissions (CO_2, SO_2, and NO_x) offset rates by state based on regional mix of sources, such as coal, gas, diesel, hydro, and nuclear

Many of the Estimator databases are indexed to locations. Once a location is selected, the databases provide available utility tariffs for that location. The Estimator is normally configured to use a default tariff, but it allows the user to select from all tariffs offered by the utility. In addition, the selected location determines the available federal, state, and utility economic incentive programs, the solar resource data, income tax rates, and air emissions rates.

The case studies below show how cost estimates are derived for two PV systems in different geographical, regulatory, and tariff situations: one in the service territory of the Long Island Power Authority (LIPA) in New York and another in the territory of Salt River Project (SRP) in Arizona. These examples demonstrate the importance of factors such as rate structure in deciding to deploy a distributed PV system.

Hypothetical Case Studies

The Estimator methodology was applied to four case studies. These case studies represent two different meteorological conditions and corresponding utilities (New York/LIPA and Arizona/SRP), and two different ownership scenarios (residential and commercial) with corresponding difference in tax computations. For example, the commercial installations will be able to take advantage of accelerated depreciation and the 10% federal tax credit. All dollar figures in the following case study discussion are in end-of-year 2000 U.S. dollars. Although the incentives and relevant taxes may have changed since these scenarios were generated, they still demonstrate that the financial details often can dominate technical considerations and lead to counterintuitive results.

For illustration purposes, the assumed utility tariffs represent a wide range of elements, including seasonal and time-of-day variations and even energy tiers that depend upon maximum monthly demand. The PV systems represent a range of orientations, including horizontal on flat commercial roofs and sloped residential systems. The four cases are defined in Table 5-7 along with their basic assumptions.

The two larger commercial systems are assumed to have a slight cost advantage over the smaller residential systems: \$6,500/kW_{dc} versus \$8,000/kW_{dc}. O&M costs are assumed to be \$200 per year (approximately 1 cent/kWh) for the commercial systems. O&M is assumed to be negligible for the residential systems due to their smaller sizes and the likelihood that homeowners would perform some of the maintenance themselves so that there would be no labor costs.

Table 5-7
Case Study Assumptions

	LIPA Residential	LIPA Commercial	SRP Residential	SRP Commercial
Tariff	Net Metered Residential Service (Rate 180, 183, 186)	Large Gen. and Ind. Service with Multiple Rate Periods—Secondary (Rate 284)	SRP, Basic Plan (Rate E-23)	SRP, General Service (Rate E-36)
System Size	2 kW (dc)	10 kW (dc)	2 kW (dc)	10 kW (dc)
Orientation	4:12 roof pitch, south facing	Horizontal flat roof	4:12 roof pitch, southwest facing	Horizontal flat roof
Installed Cost	$8,000/kW$_{dc}$	$6,500/kW$_{dc}$	$8,000/kW$_{dc}$	$6,500/kW$_{dc}$
System Life	30 yr	30 yr	30 yr	30 yr
O&M Cost	$0/yr	$200/yr	$0/yr	$200/yr
Electric Bill (w/o PV)	$1,200/yr	$100,000/yr	$1,200/yr	$10,000/yr
Financing	Home Equity Loan, 30 years, 7%	Commercial Loan, 15 years, 7%	Home Equity Loan, 30 years, 7%	Commercial Loan, 15 years, 7%
Tax Status / Taxable Income	Married filing jointly; $100,000	Corporation; $1,000,000	Married filing jointly; $100,000	Corporation; $500,000

The capital cost calculations shown in Table 5-8 include equipment, shipping, installation labor, sales tax, utility interconnection, and all related costs necessary to install the respective systems. These costs are then adjusted to account for available incentives that vary by state and tax status (personal versus corporate income taxes). Some of the incentives are taxed, so the increased tax liabilities are included as one-time costs. From these, the net capital cost is calculated, and the effective cost per kW is included for reference.

At a net cost of $1,282/kW$_{dc}$, the LIPA commercial system is the lowest cost of the four. This is due primarily to the generous buy-down program offered by LIPA valued at $50,000, the maximum available amount from the program. In addition, as a commercial customer, the 10% federal tax credit, accelerated depreciation, and the New York Green Building tax credit are applicable. The highest cost system is the SRP commercial case at $5,800/kW$_{dc}$. The only incentive available to commercial customers in Arizona is the 10% federal tax credit.

Table 5-8
Net Capital Cost

	LIPA Residential	LIPA Commercial	SRP Residential	SRP Commercial
Size	2 kW_{dc}	10 kW_{dc}	2 kW_{dc}	10 kW_{dc}
Capital Cost	$16,000	$65,000	$16,000	$65,000
Incentives				
LIPA Buydown	$ (10,000)	$ (50,000)		
NY Tax Credit	$ (1,500)			
NY Green Bld Tax Credit		$ (675)		
AZ Tax Credit			$ (1,000)	
Federal Tax Credit		$ (1,500)		$ (6,500)
Total Incentives	**$ (11,500)**	**$ (52,175)**	**$ (1,000)**	**$ (6,500)**
Taxes on Incentives				
NY Tax Credit	$413			
AZ Tax Credit			$275	
Total Taxes on Incentives	$413		$275	
Net Capital Cost				
Total	**$4,913**	**$12,825**	**$15,275**	**$58,500**
$/$kW_{dc}$	**$2,456**	**$1,282**	**$7,638**	**$5,850**

The summary results of energy production and emissions calculations are shown in Table 5-9. Kilowatt ac ratings are calculated from dc ratings based upon typical assumptions for mismatch losses, inverter losses, and module operating temperatures higher than standard conditions.

Capacity factors reflect the superior solar resource in Arizona over New York and the impacts of system orientation. For the New York sites, the south-facing sloped roof provides a 14% improvement in capacity factor over a horizontal system. For the two Arizona systems, the effect is not as significant (7% improvement) since the residential system is oriented towards the southwest.

Table 5-9
Energy Production and Emissions

	LIPA Residential	LIPA Commercial	SRP Residential	SRP Commercial
Ratings				
kW dc	2	10	2	10
kW ac	1.7	8.6	1.7	8.6
Production				
Annual Energy (kWh)	2,574	11,453	3,357	15,817
Capacity Factor (%)	17.3	15.2	22.5	21.0
Emissions Offsets				
CO_2 (lb/yr)	4,321	19,229	4,163	19,613
SO_2 (lb/yr)	12	53	11	54
NO_x (lb/yr)	4	18	7	33

The economic results consider year-by-year savings in the electric bill, loan payment amounts, O&M costs, and the tax impacts of these and depreciation. Table 5-10 illustrates the first-year savings and costs for the four case studies. Note that tax liability for the residential cases is only affected by interest in loan payments since these systems are financed by home equity loans (for which interest is tax deductible). For simplicity, other years are not shown, but these are included in the final economic results.

Table 5-10
First-Year Savings and Costs

	LIPA Residential	LIPA Commercial	SRP Residential	SRP Commercial
Electric Bill	324	1,920	216	1,205
Tax Savings (Utility Bill)		(831)		(508)
Loan Payment	(392)	(1,383)	(1,219)	(6,310)
Tax Savings (Loan Interest)	111	382	329	1,696
O&M Cost		(200)		(200)
Tax Savings (O&M Cost)		87		84
Tax Savings (Depreciation)		2,577		11,456
Total Cash Flow	43	2,551	(675)	7,424

Several economic tests are calculated and are summarized in Table 5-11. Simple payback is the net cost divided by the first year savings. Net present value (NPV) discounts the net cash flows in each year to the current date using the loan interest rate as the discount rate. A positive net present value indicates that the present value of benefits is greater than the present value of costs. Cost of energy is the NPV (excluding utility bill savings and taxes on utility bill savings) divided by the present value energy savings (kWh). It can be interpreted as the after-tax cost of purchased electricity that would make the system break even.

Table 5-11
Economic Analysis Results

	LIPA Residential	LIPA Commercial	SRP Residential	SRP Commercial
Simple Payback (years)	11	5	28	14
NPV ($)	269	9,198	(9,235)	(17,398)
Cost of Energy ($/kWh)	0.117	0.031	0.287	0.132

By all of these measures, the LIPA commercial case is the most economical system. While this system had the lowest capacity factor, the incentives were significantly higher than the other cases. Only the New York cases resulted in positive NPV.

Central Station PV Cost and Performance Estimates

To evaluate the economics of central station PV, three possible technologies are evaluated below and each is evaluated for various years. For fixed flat-plate PV systems, this example assumes a scenario of thin-film PV technology evolution, based initially on single-junction copper indium-gallium diselenide or cadmium telluride technology and evolving to multi-junction technology involving copper indium diselenide, cadmium telluride, and perhaps other materials in later years. The overall system efficiency (solar energy to ac power) will increase from approximately 7.7% in 2006 to 14.2% by the year 2030. This assumes that the commercial module efficiency increases from 10% in 2006 to 17% by 2030. The rated output of the plant increases from 8,000 kW_{ac} in 2005 to 16,000 kW_{ac} by 2030.

For the one-axis tracking flat-plate PV systems, the development scenario assumes crystalline silicon PV technology. The overall system efficiency (solar energy to ac power) will increase from 13.8% in 2006 to 16.7% by the year 2030. This assumes that the commercial module efficiency increases from 16% in 2006 to 20% by 2030. The rated outputs of the plants increase from 8,000 kW_{ac} in 2006 to 16,000 kW_{ac} by 2030. Note that the addition of one-axis tracking also increases the solar input by 20%, relative to the fixed flat-plate system.

For the two-axis tracking, high-concentration PV system, the development scenario assumes that the technology progresses from a two-axis tracking, point-focus silicon cell system with 400x concentration in 2006 to a two-axis tracking, point-focus, gallium arsenide cell system with 1,000x concentration after 2010. The overall system efficiency will increase from 17.1% in 2005

to 26.3% by 2030. The corresponding cell efficiencies range from 21% in 2006 to 40% in 2030. The rated outputs are 8,500 kW_{ac} in 2005 and 68,000 kW_{ac} in 2030.

The capital cost of solar PV power plants is a function of the performance of the solar collectors, the plant rating and number of modules, and the delivered cost of the modules, arrays, trackers, controls, power conversion system, and the other balance-of-plant components. O&M cost is a function of the solar collector area, the complexity of the solar tracking and control system, and the failure and replacement rates of the plant components. As the technology advances over time, performance improves, component costs drop, and the market for PV technology will grow, significantly reducing unit capital and O&M costs.

Tables 5-12 through 5-14 provide estimates of cost and performance for the each the three PV system examples as a function of the year of commercial order. System cost data are adjusted to end-of-year 2003 dollars based on both the Producer Price Index, which reflects changes in the cost of materials, and the Consumer Price Index, which reflects changes in the cost of labor and retail goods. Performance data include system conversion efficiencies and rated outputs (W_{ac}/m^2). Cost data include collector area and projections of total plant cost ($/m^2$ and $/$kW_{ac}$), O&M cost ($/m^2$/yr and $/$kW_{ac}$/yr), and land lease cost (% of revenues, $/kWh) for two kW_{ac} output ratings: 1) the nominal output rating of plants to be installed in a given year; and 2) scaled to an output rating of 5 MW_{ac}. Table 5-15 lists scaling factors that are used to scale the solar collector area, total plant cost, and O&M cost estimates to different plant ratings.

Table 5-12
Solar PV Power Plant Capital, O&M, and Lease Cost Projections for Fixed Flat-Plate Thin-Film Photovoltaic Power Plants (Dec-03 $)

Commercial Order Year:	**2005**	**2010**	**2020**	**2030**
System Efficiency:	7.7%	10.6%	13.2%	14.2%
Rated Output (W_{ac}/m^2):	77	106	132	142
Plant Size (kW_{ac}):	8,000	16,000	16,000	16,000
Collector Area (m^2):	104,092	150,461	121,065	112,716
Total Installed Cost ($/m^2$)	$443	$320	$181	$135
TPC ($/$kW_{ac}$):	$5,764	$3,010	$1,366	$950
O&M ($/m^2$/yr):	$0.57	$0.46	$0.34	$0.34
O&M ($/$kW_{ac}$/yr):	$7.40	$4.34	$2.58	$2.39
Costs Scaled to 5 MW				
Collector Area (m^2):	65,058	47,019	37,833	35,224
Total ($/$kW_{ac}$):	$5,866	$3,144	$1,427	$992
O&M ($/$kW_{ac}$/yr):	$7.93	$5.14	$3.05	$2.83
Land Lease, % of Revenues:	3%	3%	3%	3%

Table 5-13
Solar PV Power Plant Capital, O&M, and Lease Cost Projections for One-Axis Tracking Crystalline Silicon Flat-plate Photovoltaic Power Plants (Dec-03 $)

Commercial Order Year:	**2005**	**2010**	**2020**	**2030**
System Efficiency:	13.8%	14.7%	15.7%	16.7%
Rated Output (W_{ac}/m^2):	138	147	157	167
Plant Size (kW_{ac}):	8,000	16,000	16,000	16,000
Collector Area (m^2):	58,169	108,666	101,950	95,808
Total Installed Cost ($/$m^2$)	$701	$494	$349	$248
TPC ($/$kW_{ac}$):	$5,098	$3,354	$2,224	$1,486
O&M ($/$m^2$/yr):	$0.69	$0.55	$0.42	$0.42
O&M ($/$kW_{ac}$/yr):	$5.00	$3.74	$2.68	$2.51
Costs Scaled to 5 MW				
Collector Area (m^2):	36,356	33,958	31,859	29,940
Total ($/$kW_{ac}$):	$5,188	$3,503	$2,323	$1,552
O&M ($/$kW_{ac}$/yr):	$5.36	$4.43	$3.17	$2.97
Land Lease, % of Revenues:	3%	3%	3%	3%

Table 5-14
Solar PV Power Plant Capital, O&M, and Lease Cost Projections for Two-Axis Tracking High Concentration Photovoltaic Power Plants (Dec-03 $)

Commercial Order Year:	**2005**	**2010**	**2020**	**2030**
System Efficiency:	17.1%	21.7%	24.3%	26.3%
Plant Size (kW_{ac}):	8,500	17,000	34,000	68,000
Collector Area (m^2):	58,500	92,200	164,600	304,200
Rated Output (W_{ac}/m^2):	145	184	207	224
Concentration Ratio	400	1000	1000	1000
Total Installed Cost ($/$m^2$)	$363	$359	$280	$250
TPC ($/$kW_{ac}$):	$2,501	$1,947	$1,355	$1,117
O&M ($/$m^2$/yr):	$4.59	$4.59	$4.01	$2.87
O&M ($/$kW_{ac}$/yr):	$31.66	$24.95	$19.37	$12.81
Costs Scaled to 5 MW				
Collector Area (m^2):	34,412	27,118	24,206	22,368
Total ($/$kW_{ac}$):	$2,611	$2,152	$1,584	$1,381
O&M ($/$kW_{ac}$/yr):	$34.07	$29.57	$25.28	$18.41
Land Lease, % of Revenues:	3%	3%	3%	3%

Table 5-15
Solar PV Power Plant Capital and O&M Cost Scaling Factors vs. Rated Plant Output Relative to a 5-MW_{ac} Plant

	Total Plant Cost Factor			O&M Cost Factor		
Rated Output (kW_{ac})	Fixed Flat Plate	1-Axis Flat Plate	2-Axis HCPV	Fixed Flat Plate	1-Axis Flat Plate	2-Axis HCPV
10	2.33	2.33	2.55	2.75	2.75	2.51
50	1.87	1.87	2.00	2.12	2.12	1.98
100	1.70	1.70	1.80	1.89	1.89	1.78
500	1.37	1.37	1.41	1.45	1.45	1.41
1000	1.24	1.24	1.27	1.30	1.30	1.27
1500	1.18	1.18	1.20	1.22	1.22	1.20
2000	1.13	1.13	1.15	1.16	1.16	1.15
5000	1.00	1.00	1.00	1.00	1.00	1.00
10,000	0.97	0.97	0.95	0.90	0.90	0.91
20,000	0.95	0.95	0.89	0.82	0.82	0.82
50,000	0.92	0.92	0.83	0.72	0.72	0.73

Example Performance Calculations

As described in the steps below, the annual power generation is calculated by multiplying the annual insolation estimate for the site from Table 5-5 by the system efficiency from Tables 5-12 through 5-14. The system efficiency allows for soiling, energy collection, power conversion, step-up transformer, availability, and other losses within the power plant, but excludes substation losses.

The performance estimating procedure involves the following steps:

1. Obtain insolation and other site data from Table 5-5 and the system efficiency and rated output corresponding to the PV technology and year of commercial order from Table 5-12 for fixed flat-plate, Table 5-13 for one-axis tracking flat-plate, and Table 5-14 for two-axis tracking concentrator technologies.
2. Calculate the required solar Collector Area (m^2) by dividing the kW rating of the plant at standard conditions (kW_{ac}) by the Rated Output (W_{ac}/m^2) corresponding to the year of commercial order:

   Collector Area (m^2) = [(Plant Rating, kW_{ac})/(Rated Output, W_{ac}/m^2)] x 1,000
3. Calculate the annual power generation by multiplying the annual insolation ($kWh/m^2/yr$) by the System Efficiency (%) and the Collector Area (m^2):

   Annual Power Generation (kWh/yr) =
   (Annual Insolation, $kWh/m^2/yr$) x (System Efficiency, %) x (Collector Area, m^2)

For a 1,500-kW_{ac} one-axis tracking flat-plate solar PV power plant, ordered in 2005 and a plant site near El Paso, Texas:

1. The one-axis tracking insolation rate for El Paso is 2,921 $kWh/m^2/yr$ % (from Table 5-5). For the one-axis tracking flat-plate PV system ordered in 2005, the Rated Output is 138 W_{ac}/m^2 and the system efficiency is 13.8% (from Table 5-13).
2. The required solar collector area is:

   Collector Area (m^2) = (1,500 kW_{ac})/(138 W_{ac}/m^2) x 1,000 = 10,870 m^2
3. The net annual power generation is:

   Annual Power Generation (kWh/yr) =
   (2,921 $kWh/m^2/yr$) x (13.8%) x (10,870 m^2) = 4,381,500 kWh/yr

Example Capital and O&M Cost Calculations

The Total Plant Cost includes all direct and indirect construction costs, sales tax, engineering and procurement costs, and contingencies. The O&M cost includes all labor and material required to operate and routinely maintain the plant as well as allowances for periodic repair and replacement of failed modules and other components. If applicable, the lease cost covers the cost of leasing the land for the plant site.

The cost estimating procedure involves the following steps:

1. Estimate the Total Plant Cost (TPC, $/$kW_{ac}$) by multiplying the base Total Plant Cost (Base TPC, $/$kW_{ac}$) corresponding to the PV technology and year of commercial order (from Table 5-12 for fixed flat-plate, Table 5-13 for one-axis tracking flat-plate, and Table 5-14 for two-axis tracking concentrator technologies) by the City Cost Index from Table 5-5 and the TPC Scale Factor from Table 5-15:

   TPC ($/$kW_{ac}$) = (Base TPC, $/$kW_{ac}$) x (City Cost Index) x (TPC Scale Factor)
2. Estimate the total O&M Cost ($/$kW_{ac}$/yr) by multiplying the Base O&M Cost ($/$kW_{ac}$/yr) from Tables 5-12, 5-13, or 5-14 by the City Cost Index from Table 5-5 and the O&M Scale Factor from Table 5-15:

   O&M ($/$kW_{ac}$/yr) = (Base O&M, $/$kW_{ac}$/yr) x (City Cost Index) x (O&M Scale Factor)
3. If the land is leased by the project, estimate the annual land lease cost by multiplying the average power revenue rate ($/kWh) by the lease rate from Tables 5-12 through 5-14:

   Lease Cost ($/kWh) = (Power Revenue, $/kWh) x (Lease Rate, %)

Back to the example for a 1,500-kW_{ac} one-axis tracking flat-plate solar PV power plant, ordered in 2005, and a plant site near El Paso, Texas:

1. The City Cost Index for El Paso is 0.850 (from Table 5-5) and the TPC and O&M Scale Factors are 1.18 and 1.22 (from Table 5-15).
2. For a 2005 commercial order, one-axis tracking flat-plate technology, and 5,000-kW_{ac} uniform plant rating, the Total Plant Cost is \$5,188/kW_{ac}, the O&M cost is \$5.36/kW_{ac}/yr, and the annual land lease cost is 3% of power revenue (from Table 5-13). Thus:

   TPC (\$/kW_{ac}) = (\$5,188/kW_{ac}) x (0.85) x (1.18) = \$5,203/kW_{ac}

   O&M (\$/kW_{ac}/yr) = (\$5.36/kW_{ac}/yr) x (0.85) x (1.22) = \$5.56/ kW_{ac}/yr
3. Assuming the power revenue averages \$0.05/kWh or \$50/MWh, the land lease cost is:

   Land Lease (\$/MWh) = (\$50/MWh) x (3%) = \$1.50/MWh .

5.6 Environmental Issues

Although PV operation emits no gases or sounds and generally presents less environmental impact per deployed megawatt than any other known generation technology, it is not completely free from impacts and potential hazards. Most notably, some impacts may be expected during system manufacture involving handling of potentially toxic or flammable materials. These resemble the hazards encountered in the semiconductor industry, and the PV industry has taken advantage of many of the approaches demonstrated there. Other issues exist for polycrystalline thin-film systems in terms of ultimate disposal or recycling. These issues may prove problematic for deployment of those specific PV technologies in BIPV applications in the long term, but for large-scale utility deployments they may be readily addressed in “cradle-to-cradle” recycling schemes, as outlined in [4].

One significant benefit of PV is its lack of noise. PV is a solid-state technology that operates completely silently, making it unique among generation options and particularly among competing distributed generation technologies. The fact that PV does not require noise abatement could, in some cases, help offset its cost or argue for its use when other generation technologies would not be permitted or desirable.

Land-use concerns for most PV deployments are minimal. In operation, PV produces no liquid or solid waste and requires no fuel handling. In most applications, PV is installed on a building’s rooftop, a parking structure, or available nearby land. Building-integrated PV is incorporated directly into a building’s roofing, siding, or glass work.

Only large utility-scale, industrial, or military PV installations demand large areas of dedicated land. In most cases, such land consists of inhospitable, desert-like terrain of little use for alternative development. Impacts on native plant and wildlife can be minimized with proper planning and management.

Interestingly, the land-use impacts of PV can compare very favorably with those of other generation options such as hydroelectric power. For example, one can contrast the output of Hoover Dam to that of a hypothetical PV installation occupying the same land area as Lake Mead (which is formed by the Colorado River behind Hoover Dam and provides the water to turn its turbines):

(Typical Annual Insolation Value)(PV Module Efficiency)(Area of Lake Mead) =

(2,000 kWh/m^2)(10%)(688.6 million m^2) = 138 billion kWh per year

Hoover Dam generates an average of 4 billion kWh per year; its maximum annual net generation was 10.35 billion kWh in 1984. Thus, on average, Hoover Dam/Lake Mead produces just 3% as much electricity as would PV occupying an equivalent amount of land. (This comparison is merely illustrative of the potential energy that could be generated using a given amount of land area, and obviously does not take into account the many other costs and benefits involved.)

5.7 Design and Deployment Issues

Since distributed and utility-scale PV systems employ essentially the same technology at different scales, many of their design and deployment issues are the same. Several fundamental details must be considered when planning a PV project of any scale:

- *Project size.* For most power generating technologies, large systems are more cost-effective per unit. However, economies of scale have a much smaller effect on PV system cost than on the cost of conventional power plants such as combustion turbines.

- *Demonstration versus production systems*. Demonstration projects are more expensive per unit of capacity than production systems and, because they are research oriented and employ new or untested equipment, can have lower reliability as well.

- *Overall project plan*. While most structures with the proper orientation and design (roof support, drainage, etc.) can be readily retrofit to accept PV, it is preferable to design a building, subdivision, or business park to optimize the placement of PV from the start. Structures can be designed with the future deployment of PV in mind even if it is not included at the time of construction. While it is also possible to retrofit structures for building-integrated PV (incorporated into roofing materials, window glass, facades, etc.), its full economic and technological benefits are best realized when it is included from design through completion.
- *Type of installation.* Ground-mounted systems may benefit from economies of scale because they can be larger and heavier than roof-mounted systems. However, roof-mounted systems or building-integrated PV may benefit from savings in land costs or provide ancillary benefits such as shade or insulation. More sophisticated mounting systems that move a PV array to track the sun's motion on either one axis or two axes can increase the array's power output but also add to its cost and mechanical complexity.
- *PV technology*. Alternative technologies should be evaluated to determine which best suit the system needs.

- *Inverter technology.* Because PV devices generate dc power, electronic interfacing devices (inverters) are used to convert the power into ac for connection to the grid. Inverter reliability has been an issue for grid-connected PV systems for the past two decades, making inverter replacement or repair a leading O&M cost component. There is anecdotal evidence that this situation has been improving, but careful selection of the specific inverter for any large installation is warranted.
- *Use of storage.* Because PV is an intermittent resource, storage technologies are necessary to produce dispatchable or "firm" solar power, but they add cost to the system. Where net metering policies are in place, grid-tied systems often forego storage because they can transfer excess energy to the grid, essentially using it as a 100%-efficient storage system.
- *Type of developer*. PV projects can be designed and installed by electric utilities, energy service companies, solar companies, and private individuals. The system developer's background and experience can have a significant effect on a project's success. For example, an experienced system integrator using high-quality components and proper installation practices can improve the likelihood that a project will be trouble free.
- *Ownership and advocacy*: PV has a variety of champions. It makes a difference who initiated the project under consideration and who are the project owners and team members.
- *Non-energy benefits (ancillary benefits):* Beyond power, PV can provide additional value in some applications. Building-integrated photovoltaics can provide insulation, shading, hot water, and extended roof life among other benefits.
- *Distribution system issues.* Utility distribution companies have concerns about the safety and power-quality effect of connecting PV to distribution feeders. These interconnection questions involve such issues as islanding protection, fault contributions, and voltage regulation. For most small PV systems, recent IEEE and state utility commission standards have made interconnection more straightforward.
- *Interconnection and inspection requirements.* Though they are increasingly standardized, such requirements still vary greatly among utilities and jurisdictions. Some critics contend that utility distribution companies and some jurisdictions create barriers to PV by imposing unnecessarily stringent interconnection and inspection requirements.
- *Availability and competitive cost of grid-supplied electricity.* PV is recognized as cost-effective for many off-grid energy applications that are remote from a distribution line. The technology has advanced to the point where some on-grid applications may also prove cost-effective in high-price utility locations when coupled with various tax incentives.
- *Financial Assumptions*. PV system energy cost is impacted by issues involving insurance, taxes, incentives, rebates, green pricing, return on investment, O&M, and capital costs. For example, depending on the lifespan assumptions, maintenance assumptions, and the discount rate used in an analysis, PV energy costs can vary by as much as a factor of two for the same basic system design at the same location. Costs must be compared on an equivalent basis. Of course, the local cost of utility-supplied electricity is also frequently part of the economic analysis as mentioned above.

Utility-Scale Issues

The design and deployment of utility-scale PV systems resembles a simple distribution system construction project in terms of wiring complexity and civil engineering. The main differences are that most of the wiring involved is at lower voltages and currents than those in typical distribution systems. Modern inverters typically do not require an additional transformer, at least up to tens of kilowatts; however, for larger-scale and higher-than-distribution-level voltages, a transformer is desirable.

5.7.1 Operating and Maintenance Labor Requirements

Distributed and utility-scale PV systems share many of the same O&M requirements. In general, PV is the lowest-maintenance generation technology available. PV modules have a lifetime of several decades and have no moving parts that require service or replacement. A typical rooftop PV system located on a home or business could operate with literally no maintenance for years. As mentioned above, inverter replacement or repair can be a leading contributor to O&M cost.

Accumulation of dust and grime can significantly reduce PV system output in some environments. However, in most climates and locations, natural washing by precipitation limits such losses to on the order of 10% to 15%. PV modules are manufactured to withstand a hail-impact test. For glass-encapsulated modules, the primary environmental hazard is vandalism, if its potential is not minimized by the site design.

Utility-Scale Issues

Except for tracking systems, which may require periodic inspections to ensure proper operation of a few moving parts, PV hardware generally has no significant scheduled maintenance. The primary problems noted have generally been related to installation errors and component infant mortality. Following installation and initial wiring checkout, the modules require no service, except for replacement due to breakage (for example, from lightning or vandalism); similarly, the power-conditioning equipment needs only occasional checks to confirm that it is operational.

Experience to date indicates that O&M costs for a well-designed system should be substantially less than 0.5 cents/kWh. Therefore, assuming 0.1 cents/kWh in labor at $40,000 per year, we would expect PV plants to require about one full-time employee per 22 MW.

5.7.2 Interconnection

Only a very small proportion of PV-equipped facilities operate completely disconnected from the electric grid, most often for reasons of distance, cost, or the owner's personal philosophy. Most PV systems deployed residentially, industrially, or commercially retain a grid connection. The interconnection between a distributed resource and the larger utility grid is a critical determinant of a project's safety and financial and technological viability. The 2003 promulgation of IEEE 1547, the "Standard for Distributed Resources Interconnected with Electric Power Systems," provided a universal standard to help resolve the current patchwork of interconnection practices, which currently vary from utility to utility and project to project.

Local, state, and federal policies increasingly allow and even encourage interconnecting distributed generation with the grid. Net metering programs in many states allow PV owners to feed short-term excess power they generate to the grid—colloquially called "running the meter backward." It is important to note that net metering policies vary greatly among jurisdictions and that most do not allow customers to "sell" electricity back to their host utility—that is, to receive payment should they generate more power than they consume. Some programs offer payment or credit at rates less than the retail price, such as the avoided cost rate. Net metering is best understood as a method for customers to store self-generated energy that must be consumed within a relatively short time, typically on the order of one month. —effectively permitting these customers to use the grid as a cost-free, 100%-efficient storage battery

Some distribution companies have taken an understandably conservative approach to supporting distributed photovoltaic systems. Several potential safety and power quality problems may result from customer-sited PV projects. Specific power quality challenges associated with interconnecting PV and other distributed generation (DG) to the utility T&D system include unintentional islanding, changes in radial feeder power flows, reverse power flow in distribution networks, loss of effective voltage regulation, harmonic injection and distortions, voltage fluctuation and flicker, and overcurrent-protective device coordination.

Unintentional islanding is perhaps the most significant and commonly raised concern with respect to DG, primarily because it can endanger the safety of line workers and the public. Islanding is a situation in which a portion of the utility system operates separately from the rest of the system. Line crews working on a section of line they believe to be de-energized may unexpectedly encounter line voltage and could be electrocuted. Similar danger extends to the public in situations with downed conductors or other live wires within reach that would have normally been de-energized by upstream utility switchgear had an island not developed. The most common way to prevent unintentional islanding is to use voltage and frequency relays on DG units, set to trip whenever voltage or frequency migrate outside a selected window. This form of islanding protection is called "passive" protection, and prevents islanding in most cases. Other potential issues related to interconnection include changes in radial feeder power flows, possible reverse power flow in distribution networks, loss of effective voltage regulation, harmonic injection and distortions, voltage fluctuation and flicker, and overcurrent protective device coordination. All such issues may be successfully addressed by appropriate regulatory policies and interconnection practices.

Most existing and proposed interconnection requirements stem from fundamental issues related to providing a compatible interface. These include safety, reliability, quality, and potentially damaging interactions. Some requirements originate with distribution system operators and take the form of interconnect agreements, permits, or public service commission rulings. Industry standards, such as those promulgated or being developed by IEEE, may be adopted in whole or in part through such rulings. Local inspection authorities fulfilling their obligation to protect the public and comply with building and electric codes may impose other requirements. Five basic functions—electrical isolation via power transformer, controlled connection and disconnection, a visible and secure disconnect, short-circuit protection, and surge protection—are common to most interconnection policies or agreements.

5.7.3 Microgrids

The maturing microgrid concept offers new applications and advantages to distributed generation owners, operators, and utilities. Microgrids have the potential to improve the reliability of power delivery while reducing the cost of maintaining the wider power system. For the purposes of this discussion, a microgrid might be envisioned as a residential neighborhood, business park, or commercial district encompassing several on-site distributed generators—not necessarily all PV—networked together and interconnected to the grid at a single distribution-level point (Figure 5-3).

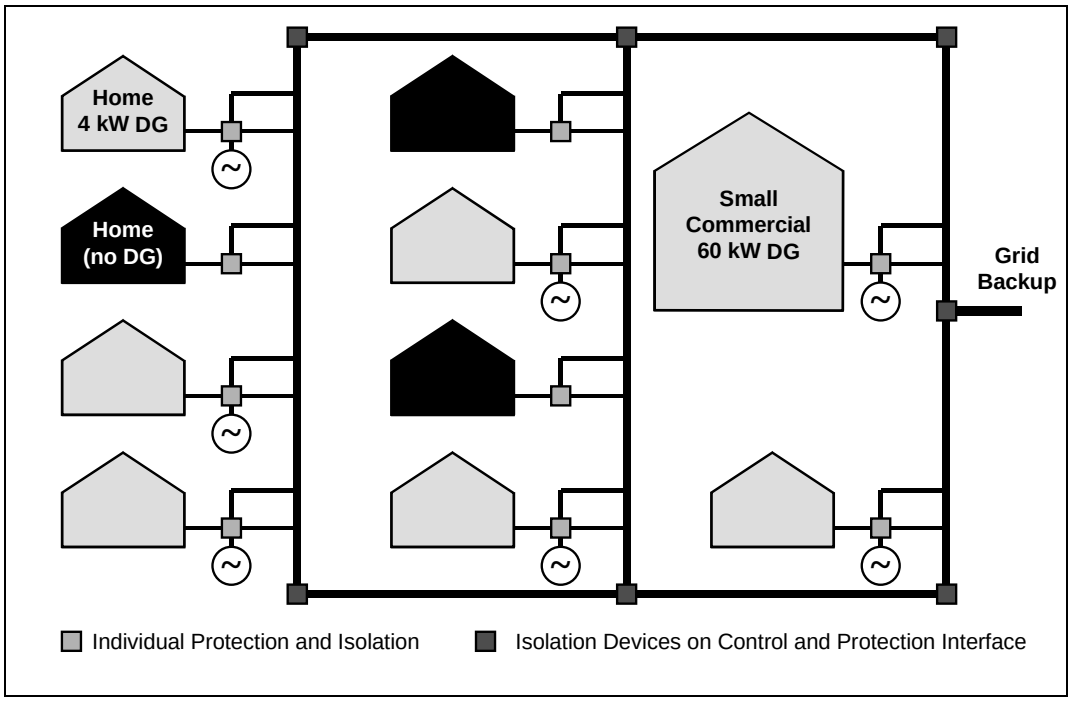


Figure 5-3
Schematic of a Simple Microgrid System

A microgrid is electrically isolatable from the utility macrogrid and would most often have sufficient cumulative capacity to meet the energy needs of those within it, although most microgrid concepts also specify a utility backup. Some microgrids could operate as full-time islands, while others could operate as part of the macrogrid during normal operation and only separate into an island during service interruptions.

Microgrids pose several challenges to infrastructures built around existing distribution control and protection practices. Microgrid control structures would require frequency and voltage regulation as well as protection equipment at each generator and at the point of grid interconnect. A microgrid would need protocols for blackstart and system restoration following disruptions, and would likely demand a high degree of sophisticated automation. Microgrids with intermittent generation sources, such as a PV-equipped neighborhood whose net output could vary substantially due to sun angle or weather, pose additional challenges.

The heart of the microgrid concept is the notion of a controllable interface between the microgrid and the macrogrid. This interface can separate the two sides electrically while it connects them economically. Within the microgrid, the conditions and quality of service would be determined by its component customers, while flows across the dividing line would be motivated by the prevailing valuation of energy and other services available on either side at any instant. In its simplest form, the interface could be a simple barrier that permits the microgrid to island itself and resynchronize with the macrogrid as desired. It would allow the microgrid to perform as a "good citizen" of the larger electric grid.

Microgrids offer customers and utilities many of the same benefits of distributed generation in general. For customers, they can result in lower costs, improved reliability, economic flexibility, and energy self-sufficiency. For energy companies, they can allow postponement of costly T&D system upgrades, better local voltage control and overall power quality, more reliable service, reduced transmission losses, and less congestion via peak load shaving.

Microgrid Economic Issues

Although a small number of premium power parks have been built to serve businesses with specialized energy needs, the economic viability of and outlook for microgrids in general is uncertain. One attempt to assess the potential economic benefits of microgrids was recently funded by the U.S. DOE and carried out by the Consortium for Electric Reliability Technology Solutions (CERTS) [12]. Their findings are summarized here less for their value as a useful assessment of actual microgrid viability than as an illustration of one approach to the problem.

CERTS developed customer adoption models that analyzed typical load curves for four customer types: a grocery, a restaurant, an office, and a shopping mall. By combining data from those four types, CERTS simulated a microgrid system. The study made simple assumptions and made no allowance for the potential benefits of improved reliability, power quality, or ancillary applications. Model customers were allowed to buy and sell power under several different scenarios; under these assumptions, typical customers adopted some on-site generation under all scenarios.

The study found that typical annual electricity cost savings for microgrid customers were approximately 20% to 25%. Model customers typically provided a significant share of their own energy requirements, often over 90%, while installed capacity tended to provide only approximately 50% to 70% of peak load. In other words, on-site generation tended to fill a baseload role; in none of the scenarios did customers meet their own peak load sufficiently to disconnect entirely from the grid.

5.8 Equipment Markets and Key Participants

The PV market is evolving rapidly. Industry deregulation and the anticipated promulgation of uniform interconnection standards that in most cases allow net metering tend to make the PV market more attractive to manufacturers, investors, and potential buyers. Some companies have established business units to target specific markets, such as southern California and particularly San Diego, which suffered the greatest retail price jumps during California's difficulties with

electricity cost and availability. In some cases, demand has outstripped supply and resulted in transient delays and price increases. This situation was repeated on a global scale in 2005 and 2006, as module demand outstripped the world's current production capacity of polysilicon feedstock for wafers. However, prices were evidently already moderating by late 2006, according to SolarBuzz consultants [<http://www.solarbuzz.com/moduleprices.htm>].

Shipments of PV modules and cells reported by U.S. manufacturers to the Energy Information Administration (EIA) in 2002 reached a record level of 112.1 MW_p but then dropped to 109.4 MW in 2003 because of BP Solar's shuttering of its thin-film PV plants and the bankruptcy of AstroPower [16]. Shipments subsequently rebounded in 2004, although the U.S. continued to lose global market share. Exports in 2005 were 92.45 MW, accounting for 41% of total shipments (compared to 60% in 2002). Sales to wholesale distributors rose from 106 MW in 2004 to 130 MW in 2005, or 60% of total shipments; meanwhile, sales to installers nearly doubled to 67 MW. (See Figure 5-4.)

5.8.1 Equipment Markets

In the domestic PV market, six major market sectors can be identified [7]:

1. Grid-connected residential, commercial, and industrial rooftop or building-integrated applications. According to the EIA, the commercial sector jumped ahead of the residential and industrial sectors in 2003 sales, with the three combined comprising nearly 77% of the market for PV cells and modules in 2003.

2. U.S. DOE plus other civilian government agencies committed to using PV and renewables through efforts such as the Federal Energy Management Program and the Million Solar Roofs program.

3. U.S. Department of Defense, which has been installing both grid-independent and grid-connected PV systems at military facilities for years. Total PV capacity installed by DOD is usually a few megawatts per year, many of them PV-battery-engine hybrid systems that range in size to over 100 kW.

4. Grid-independent buyers of PV systems for off-grid homes, ranches, or farms. An estimated 100,000 off-grid residential PV installations are operating today, most of them supplied by retail companies, service providers, system integrators, or mail-order organizations.

5. Grid-independent commercial buyers, which typically use PV to power remote communications installations, environmental measurement and monitoring sites, and security systems.

6. PV commercialization programs, such as the Utility PhotoVoltaic Group (UPVG, now SEPA) TEAM-UP program, through which approximately 2,000 new PV installations totaling 8 MW were deployed from 1995 through 2000. Similar programs have included DOE's Commercialization Ventures and PV-BONUS programs. Most such ventures involve utilities as the venture lead or participants. A number of grid-connected systems have also been installed by electric utilities independent of any federal subsidy program.

Figure 5-4 illustrates how PV cells and modules made in the U.S. are distributed by market sector and end use. According to the EIA, the total amount of PV produced for all uses in the U.S. in 2005 totaled 226.9 MW_p [16]. In the first chart, the “Other” category includes PV used for small consumer goods, healthcare, cooking, desalinization, distillation, etc. In the second chart, "Other" also includes water pumping and transportation.

Internationally, the World Bank, the Global Environmental Facility, regional development banks, and other national and international programs have made funds available for developing renewable technology systems, particularly in developing countries such as Indonesia and Brazil. This financial and technical support has helped provide PV-based systems to areas where electric service has never been available. The international PV market served by domestic suppliers has historically been two or three times the size of the domestic PV market, and it still is somewhat larger, a fact that can have significant impact on domestic supply, price, and delivery times.

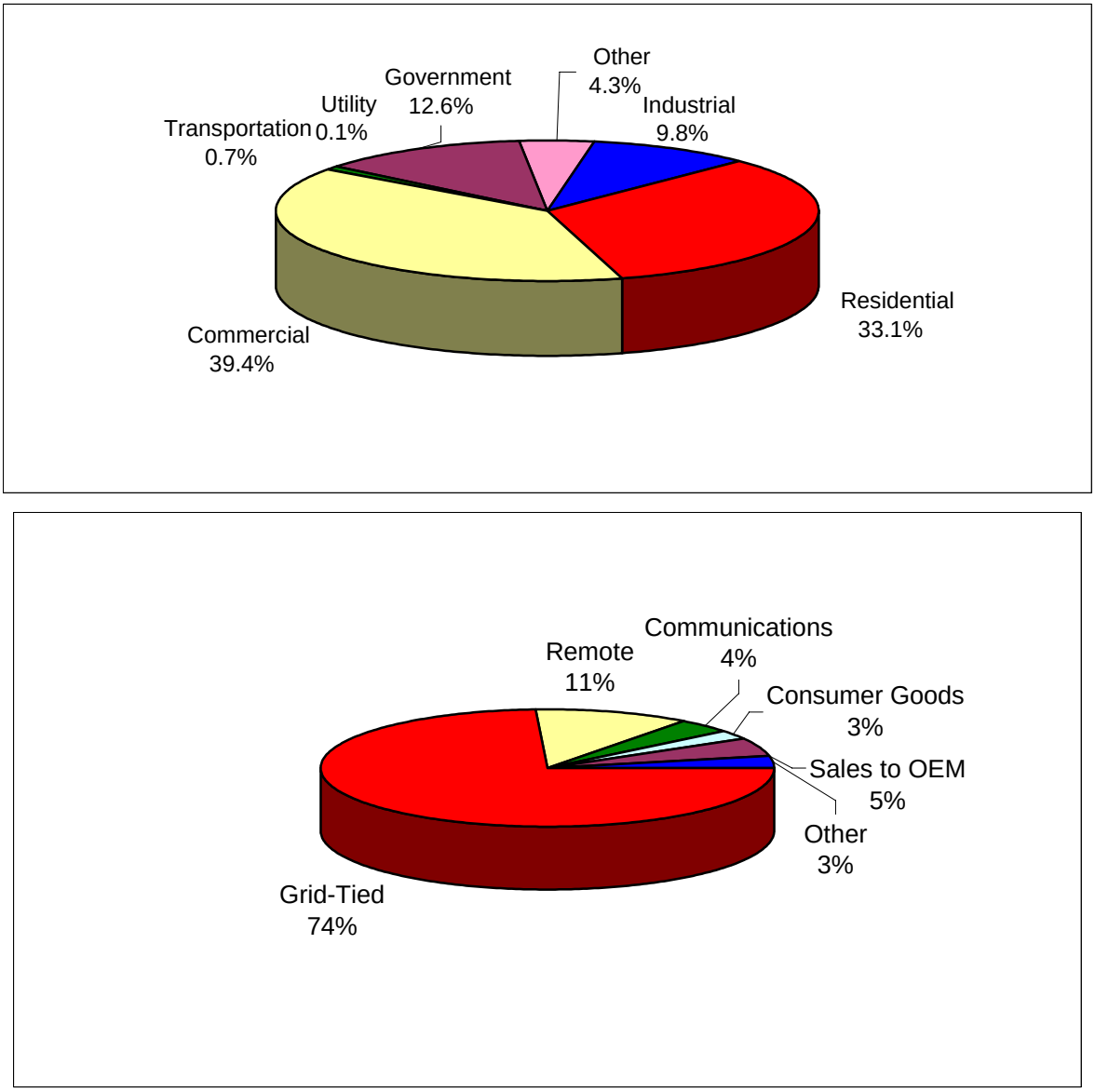


Figure 5-4
U.S. Shipments of PV by Market Sector and End Use in 2005
(Source: EIA [16])

5.8.2 Key Participants

The PV industry is made up of a large number of organizations that can be separated into two categories: component manufacturers and infrastructure organizations. The first category designs and fabricates PV cells, modules, and balance-of-system hardware. The second category consists of integrators that help identify customers, design and install systems, and provide maintenance services. There may be a few hundred such companies nationwide. Most serve off-grid customers, but the number and size of those involved in the grid-connected market is growing.

Today, more than 50 PV manufacturers and suppliers are providing components to customers around the world. The majority are located in Europe, Japan, and the U.S. Many are vertically-integrated organizations that refine basic cell materials, produce cells, and assemble modules. Another type of organization is the module assembly firm that purchases PV cells from various manufacturers and adds value by producing modules.

Table 5-2 in Section 5.4.1 is a technology monitoring guide of the leading developers and technical issues in solar photovoltaic power generation. That table provides a detailed list of government organizations, nonprofit organizations, industrial firms, and leading vendors working in solar photovoltaics.

5.8.3 Internet Resources

In addition to the vendors and organizations listed in the monitoring guide, the reader is referred to the following Internet websites. Note that while these sites contain information and contacts that may be of interest, EPRI cannot vouch for the accuracy of their content.

Solar Electric Power Association
Formerly the Utility PhotoVoltaic Group (UPVG), SEPA is a collaboration among utilities, energy service providers, and the PV industry working to create and encourage commercial use of new solar electric power technology and business models. www.solarelectricpower.org

American Solar Energy Society
ASES is a national organization dedicated to advancing the use of solar energy for the benefit of U.S. citizens and the global environment. The society sponsors conferences and publishes a magazine and white papers on the subject. ASES is the U.S. section of the International Solar Energy Society. www.ases.org

Center for Renewable Energy and Sustainable Technology
The Center for Renewable Energy and Sustainable Technology provides excellent background information and extensive links to other websites.

http://www.crest.org

National Center for Photovoltaics
NCPV is headquartered at the National Renewable Energy Laboratory (NREL) in Colorado. Its primary members comprise PV researchers affiliated with NREL and Sandia National Laboratories. www.nrel.gov/ncpv

University Centers of Excellence for Photovoltaics Research and Education
The U.S. DOE established PV centers of excellence at Georgia Tech and the University of Delaware to improve the fundamental understanding of the science and technology of advanced PV devices, create breakthrough PV technology, provide training, and give the U.S. a competitive edge in PV development.

www.ece.gatech.edu/research/UCEP
www.udel.edu/iec/

Million Solar Roofs Program
The federal government established the program in 1997 with the goal of installing solar systems—both PV and thermal—on one million U.S. rooftops by 2010. It is administered by the DOE's Energy Efficiency and Renewable Energy Network.

www.millionsolarroofs.com

Solar Energy Industries Association
SEIA is a national trade association of solar energy manufacturers, dealers, distributors, contractors, and installers. Its membership includes more than 500 companies operating in 22 states.

www.seia.org

Note: the companies listed below are the four largest PV manufacturers in 2005 with a combined worldwide market share of about 50%. They are included in this list of contacts for informational purposes only; no endorsement is implied.

Sharp Solar
Based in Osaka, Sharp initially focused its PV product line on the Japanese domestic market, but has more recently begun dramatic expansion of its production together with more significant U.S. and European marketing. Its residential PV systems employ both single-crystalline and polycrystalline technology.

http://sharp-world.com/solar/index.html

Kyocera
Based in Japan, Kyocera bills itself as the "world's largest vertically-integrated producer and supplier of solar energy products." The company has more than 1,500 distributors and dealers.

www.kyocerasolar.com

Q-Cells AG
This is a fast-growing German-based company that jumped from nowhere into the top tier in just the past 3 years, more than doubling production between 2004 and 2005.

http://www.q-cells.com/

Schott Solar
Schott Solar is a subsidiary of the German technology firm, Schott. It's production of solar PVs grew more than 50% in 2005, moving it up from sixth to the fourth largest PV company, producing both crystalline silicon and thin-film technologies.

http://www.schott.com/solar/english/index.html?c=bL

5.8.4 Applicable Codes and Standards

Both customers and distribution companies anticipate that adoption of universal standards will address interconnection requirements, ease the introduction of PV into the marketplace, and eliminate the complex and sometimes time-consuming or expensive tangle of practices currently followed. Several respected organizations are leading the drive to create such standards, including IEEE, Underwriters Laboratories (UL), and the Federal Energy Regulatory Commission (FERC).

The list below summarizes the content and status of key interconnection standards already promulgated or under development. Each standard relies on the precedents the others have set. In many instances, standards issued by different organizations have been developed cooperatively. More information about these and other relevant standards is provided in Chapter 10.

IEEE 929-2000: the "IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic Systems," which describes the interface, functions, and requirements necessary to interconnect a PV power system with the electric grid. It also describes acceptable and safe practices for accomplishing those functions.

UL 1741: the "Standard for Safety for Static Inverters and Charge Controller for Use in Photovoltaic Power Systems," is closely related to IEEE 929-2000. In fact, UL and IEEE worked together to ensure that testing procedures described in UL 1741 ensure inverter compliance with the guidelines established in IEEE 929-2000.

IEEE 1547: the "Standard for Distributed Resources Interconnected with Electric Power Systems." Its recent passage is seen as a critical milestone for the DG industry. IEEE 1547 provides a uniform interconnection standard that states and energy companies throughout the U.S. and the world are expected to use as the basis for their own interconnection practices. The recently passed Energy Policy Act of 2005 also includes language encouraging states to adopt IEEE 1547 as the basis for their interconnection standards.

5.9 References

1. *Renewable Energy Technology Characterizations,* EPRI and U.S. Department of Energy: December 1997. TR-109496.

2. *Engineering and Economic Evaluation of Central-Station Photovoltaic Power Plants*, EPRI, Palo Alto, CA: December 1992. TR-101255.

3. "Capital Requirement and Economic Summary, 50 MW Photovoltaic Fresnel Lens Concentrator Plant," Scientific Analysis, Inc., EPRI Project RP 2948-8, March 5, 1991.

4. Moskowitz, P.D., National PV Environmental, Health and Safety Information Center: Bibliography, Brookhaven National Lab, Upton, NY: 1993. Report 11973.

5. *Renewable Energy 2000: Issues and Trends*, U.S. Energy Information Administration: February 2001. DOE/EIA-0628.

6. *Renewable Energy Annual 2000*, U.S. Energy Information Administration: March 2001. DOE/EIA-0603.

7. *Renewable Power Industry Status Overview*, EPRI, Palo Alto, CA: December 1998. TR-111893.

8. *Photovoltaic Five-Year Market Forecast 2000-2005*, Strategies Unlimited: April 2000. Report PM-48.

9. *2000 Photovoltaic Industry Competition Analysis*, Strategies Unlimited: July 2000. Report PC-11.

10. "Annual Solar Thermal and Photovoltaic Manufacturing Activities Tables, 2000," U.S. Energy Information Administration, www.eia.doe.gov.

11. *Distributed Renewable Energy Generation Impacts on Microgrid Operation and Reliability*, EPRI, Palo Alto, CA: February 2002. 1004045.

12. *CERTS Customer Adoption Model*, Consortium for Electric Reliability Technology Solutions, prepared for the Transmission Reliability Program, Office of Power Technologies, U.S. Department of Energy by Lawrence Berkeley National Laboratory, Berkeley, California: March 2001. LBNL-47772.

13. *Assessment of Rooftop and Building-Integrated PV Systems for Distributed Generation*, EPRI: March 2003. 1004204.

14. *Photovoltaic Manufacturer Shipments 2000-2002*, Strategies Unlimited: August 2002. Report PM-51.

15. Bolinger, M., and Wiser, R., "Support for PV in Japan and Germany," Case Studies of State Support for Renewable Energy, Lawrence Berkeley National Laboratory, September 2002.

16. *Solar Thermal and Photovoltaic Collector Manufacturing Activities 2005*, U.S. Energy Information Administration: August 2006. http://www.eia.doe.gov/fuelrenewable.html.

17. Hoff, T.E., *TAG Case Studies for Clean Power Estimator Model of Distributed PV*, Draft report to EPRI, Clean Power Research, October 2002.

18. *Sun Screen II: Investment Opportunities in Solar Power*, Credit Lyonnais Securities Asia: July 2005.

19. *Case Studies of Grid-Connected Photovoltaic Systems, Volume 2*, EPRI, Palo Alto, CA: April 2003. 1004203.

20. *Solar Outlook*, Navigant Consulting: June 2006. Issue 2006-1.

21. Sharp, T., "New Energy for Japan," *Cogeneration & On-Site Power Production*, James & James Ltd., London, U.K.: September-October 2003.

22. *Photovoltaic Manufacturer Shipments & Profiles*, Strategies Unlimited: September 2003. SUPM 53.

23. *Photovoltaic Balance-of-Systems and U.S. Grid-Connected System Price Analysis 2005*, Strategies Unlimited: June 2005. Report PM 56.

24. Green, M.A., *Third Generation Photovoltaics: Advanced Solar Energy Conversion*, Springer-Verlag, Berlin (2003).

6
GEOTHERMAL ENERGY

Installed Capacity (est.)	8,933 MW worldwide 2,828 MW in U.S.
Technology Readiness	Mature, commercial (hydrothermal). Early research (hot dry rock). Moderate-low confidence in cost estimates and projections.
Environmental Impact	Some atmospheric emissions and solid waste that can be controlled. Unknown long-term impacts on local hydrology and subsidence. Can help meet local wastewater disposal challenges by pumping treated water to recharge subterranean aquifers.
Economic Status	Hydrothermal is competitive in many markets, although limited geographically to the western states Binary technology has potential to be more widespread and economical, but needs further experience. Re-injection of treated water into geothermal reservoir has shown to be economically feasible to prolong life of the wells. Hot dry rock remains unlikely to be competitive in the near future until improvements in resource development and deep drilling can be done at lower cost.
Policy Status	Currently being assessed as a small portion with potential growth available to add capacity to western states RPS. Included with other non-hydro renewables.
Trends to Watch	Improved drilling technologies. Lower cost for binary-cycle conversion technologies. Better characterization and identification of geothermal resources Enhancing the geothermal systems waste water re-injection to increase capacity of current plants. Limited growth potential in near future mainly driven by economics, permitting challenges, and the lack of economically feasible resources near transmission facilities. New energy bill have increased incentives to add geothermal capacity in the near term to fulfill increase in RPS availability.

6.1 Introduction

Electric power generation from geothermal steam reservoirs has been a commercial reality in the U.S., Italy, Mexico, and New Zealand for more than 45 years. Geothermal power production is a mature technology with a worldwide operating capacity of approximately 8,933 MW [28]. In California, nearly 2,492 MW of geothermal power plants provide over one-third of the state's non-hydro renewable capacity [3] exceeding that of every country in the world.

However, high-grade pure steam (i.e., not water-steam) reservoirs have been largely exploited. Future geothermal power generation will depend on locating and tapping additional water-steam, hot pressurized water, and hot dry rock (HDR) resources.

Geothermal power plants are dispatchable and range in size from 0.5 MWe to 180 MWe, with 30 to 60 MW considered standard for steam or flashed-steam plants. For binary cycle plants, smaller sizes are more common, in the range of 15 to 45 MW. Ramp rates of 5 MW per hour are typical of all geothermal power plants. Energy production is not affected by daily or seasonal resource supply fluctuations. Atmospheric emissions are low or non-existent and solid wastes are readily managed by conventional techniques. In addition to use for electric power generation technologies, which are the subject of this report, hot geothermal fluids can be used directly in aquaculture, greenhouses, space heating, wood drying, and vegetable drying. Today the U.S. non-electric energy uses consists of a very small portion of geothermal usage compared to electric power applications.

A major limitation factor in geothermal power development is the permitting and the high cost of resource exploration and development, particularly when geothermal power competes against lower-cost fossil fuels. Another crucial limiting factor is the proximity of the resource and ability to tie in to the generation grid, which is not always economically feasible. Reduced costs through better technical performance, improved materials and coatings to increase equipment's useful life, improved drilling techniques to fully identify a site's potential and speed up the exploration process, and expanded and standardized markets will all improve the prospects for geothermal power in the U.S. and abroad.

6.2 Resources

Geothermal energy is literally energy in form of heat contained within the Earth. It arises from the heat of the Earth's molten interior and occurs mainly in geologically active areas where the planet's continental plates meet. It is most accessible in the "Ring of Fire" that bounds the Pacific Ocean. These regions are often characterized by volcanism, earthquakes, hot springs, and/or geyser activity.

As a general rule, geothermal resources are classified in three categories: hydrothermal-convection, geopressured, and hot dry rock (HDR) resources. Hydrothermal-convection resources are subdivided further into vapor- and liquid-dominated resources, which produce mostly steam and hot water, respectively. They occur as a result of heat transfer from geologically active high-temperature belts to aquifers in close proximity. Geopressured resources are hot water containing dissolved methane under a high subsurface pressure about twice that of normal hydrostatic pressure. HDR resources are hot rock masses that lack fluid content but are close enough to the surface to have potential for commercial heat extraction.

Currently, hydrothermal-convection resources account for all electricity generation from geothermal energy in the United States. Geopressured wells produce methane, dissolved in and produced with the hot brine, and are therefore a source of natural gas, albeit an expensive source.

Geopressured resources are natural deposits of hot brine found in conjunction with oil and gas deposits. Methane gas dissolved in the hot brine, plus the heat of the brine itself, gives these deposits value as potential energy and power resources. Use of geopressured resources depends upon the economics of natural gas. This is because the low temperature of the hot brine produced and the great depth and pressure (and, hence, expense) of the producing wells drilled into geopressured zones make electricity generation alone uneconomic. In the U.S., geopressured resources are found for the most part in the Texas-Louisiana coastal region near the Gulf of Mexico. These geopressured resources are expensive to exploit and the power generation potential associated with them is only a fraction—perhaps 20%—of the estimated U.S. hydrothermal potential [5, 12].

HDR resource use is still in the experimental stage. Under the designation "Enhanced Geothermal Systems," the U.S. Department of Energy (DOE) has continued its 2006 R&D program in HDR at a relatively low level of funding. An enormous amount of potential geothermal energy is available. By some estimates, just 1% of the heat contained in the uppermost 10 km of the Earth's crust equals 500 times the energy contained in all oil and gas resources. The U.S. Geological Survey (USGS) estimates the known, accessible hydrothermal resource in the U.S. to be about 25,000 MW capacity for 30 years and the as-yet-undiscovered accessible hydrothermal resource to be approximately 95,000 MW to 150,000 MW for 30 years [4, 5, 6].

Although the potential of HDR resources has been studied less, and is therefore not as well-understood, it is believed to be much larger than that of the hydrothermal resource. The resource is characterized by man-made reservoirs of hot water created by fracturing geothermally-heated hot rock formations at depths of 2,000 to 5,000 meters[9]. Surface water is then pumped into the hot fractures and most of that water is recovered through production wells, as in a natural hydrothermal power system. By some estimates, more than two million MW could be generated from high-grade HDR in the U.S., with perhaps 17 million MW (more than 20 times the current installed electric capacity in the U.S.) available for less than 6 cents per kWh by 2020 [10, 11].

For comparison, the total generating capacity in the U.S. today from all sources is more than 900,000 MW. Coal provides about 33% of this capacity and hydro about 10%, or approximately 80,000 MWe [7, 8]. As a baseload source, coal generates slightly more than half of the total 3,800 billion kWh electric energy generated in the U.S. Hydro, as an intermediate source, generates about 10% of the electricity. Geothermal capacity runs at a higher capacity factor than baseload coal, and generates about 0.5% of the electricity, despite accounting for less than 0.4% of the installed capacity in the U.S. [8].

6.2.1 Geothermal Resource Assessment

Estimates of the resource base, as well as the cost of generating power from the major components of that resource base, yield a very rough (only four categories) "supply curve" for geothermal power in the U.S. In the following discussion, domestic geothermal power is divided into four resource/technology categories. Note that this supply curve addresses the hydrothermal type of geothermal resource only. The supply curve does not include the very much larger HDR resource, nor does it include the smaller geopressured resource. In this section, HDR technology is discussed under the heading "Enhanced Geothermal Systems" as well as "Hot Dry Rock."

U.S. Geothermal Resource

Accounting only for those resource sites already identified, the hydrothermal resource base is estimated to be 23,000 MWe. According to one estimate [5], another 20,000 to 30,000 MWe may eventually be developed, and the estimated hydrothermal power potential from "identified plus unidentified resources" in the U.S. is 95 to 150 GWe [5, 6].

The major physical characteristics of the resources—which determine the cost of bringing new electricity generation on line from these hydrothermal resources—are their temperatures and depths, plus the ease with which hot water flows from the hydrothermal aquifer into wells drilled into a subsurface geothermal reservoir (permeability).

Figure 6-1 is a map produced by DOE's Office of Energy Efficiency and Renewable Energy (EERE) indicating geothermal resource temperatures at a depth of six kilometers and a recent assessment of heat flow in the U.S. by Southern Methodist University (SMU).

A recent study of geothermal resources identified 271 cities and communities in 10 western states that could potentially use geothermal energy in some way; 70 of these communities are in California. Very few of these sites have been evaluated, much less developed, because of poor economic viability and lack of interest in developing small (<10 MW) resources. Some of these sites may be ideal candidates for small geothermal power projects where treated wastewater from nearby communities could be injected deep into subterranean reservoirs to make additional power. Injection technology is currently used at The Geysers in northern California using wastewater from Lake County and the city of Santa Rosa. As injection technology matures, it may be applied to other geothermal resources. Binary-cycle systems may play a significant role in the development of these resources due to their generally low temperature, and because a market for electricity as well as heat can enhance the economic viability of these projects.

A previous resource assessment, reported by the U.S. Bureau of Land Management (BLM) and shown in Figure 6-2, provides a better indication of the availability of high potential geothermal resources in the west.

Resource Temperature

How a resource is developed depends on its temperature: hot, defined as >400°F (204°C); moderate, 300-400°F (149-204°C); or low, 250-300°F (121-149°C). Hot resources are generally developed via "dual flash" (two-stage flash) technology, in which steam is generated at two pressures by first dropping the pressure from reservoir value to the "high" pressure steam inlet of the turbine and then again from "high" to "low" for entry to the low-pressure stages of the steam turbine. At each stage, the hot water "flashes" to form steam and the steam is injected into a dual-entry steam turbine.

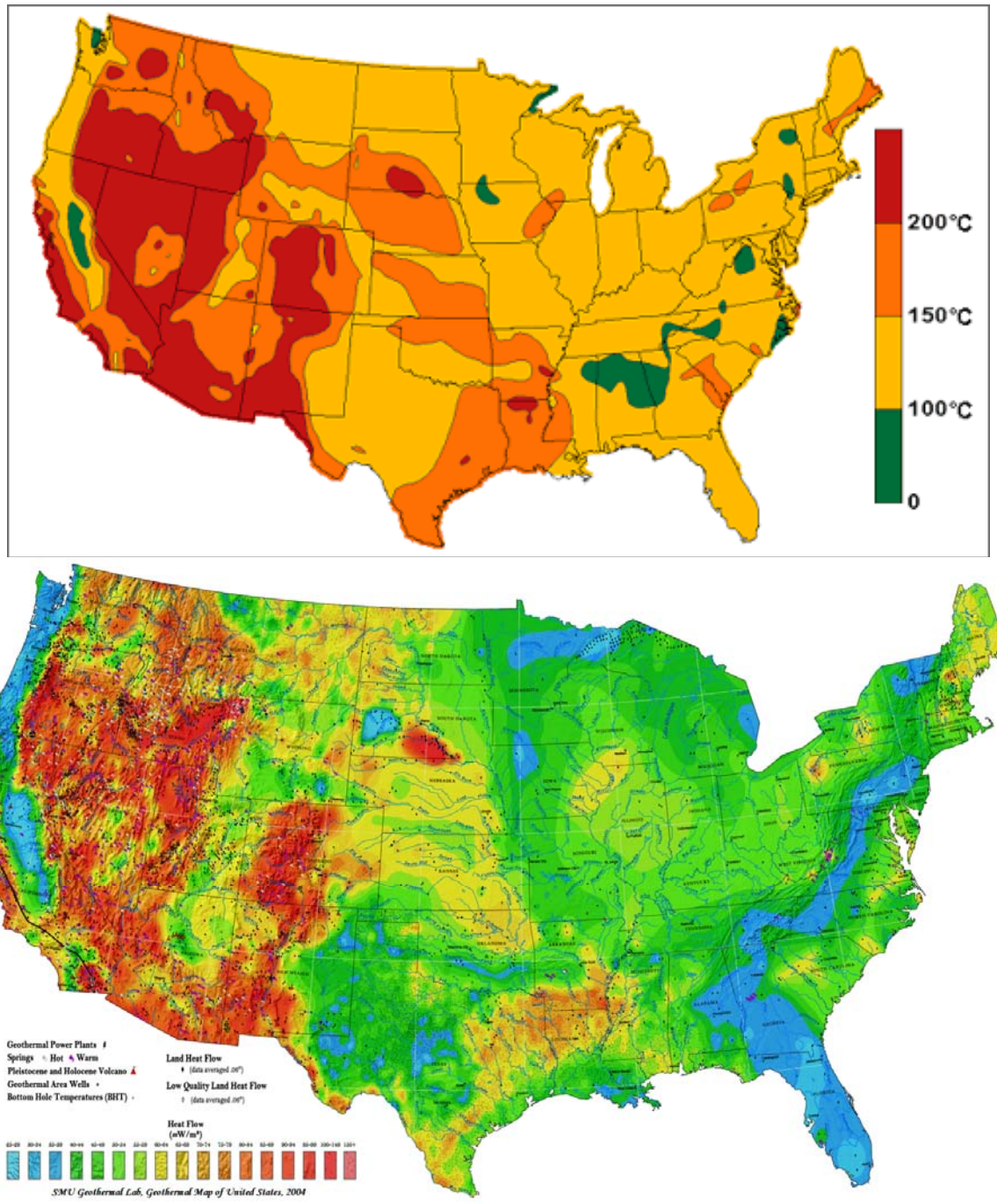


Figure 6-1
Map of U.S. Geothermal Resource Potential Map [Estimated Temperatures (°C) at 6 km Depth] (top), 2004 SMU Heat Flow Assessment (bottom)

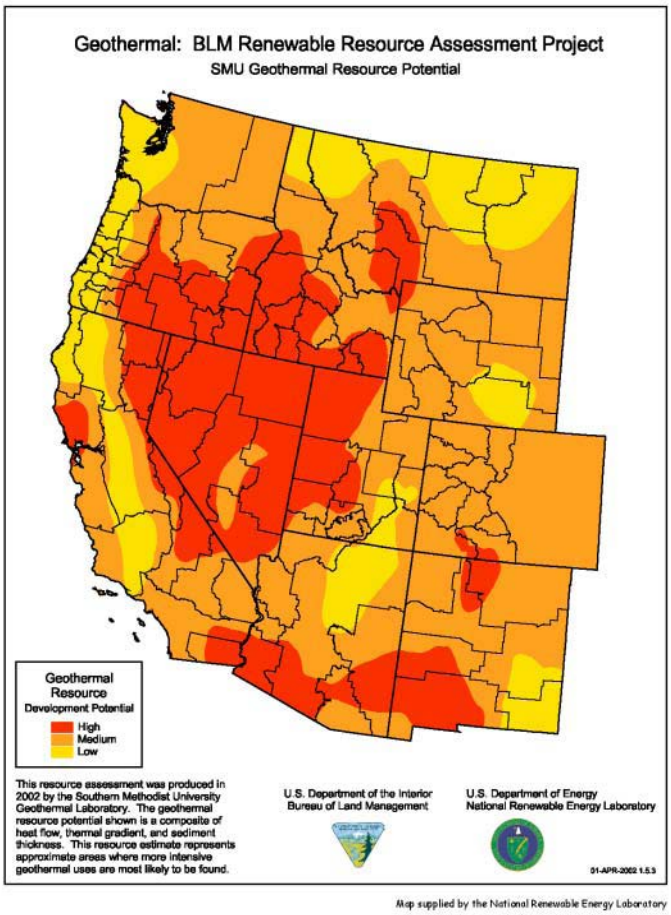


Figure 6-2
Recent BLM Resources Potential Map of the Western States

All low-temperature and many moderate-temperature resources will be developed via "binary" technology. In a binary cycle, water and steam are not used as the working fluid for the turbine; instead, heat is transferred from the hot water of the geothermal reservoir into a second fluid with better thermodynamic properties for power generation than water/steam at the low temperatures of these resources.

In 2005, an effort is underway to create a new classification based on temperature [29] requested by the Geothermal Energy Association (GEA) and DOE. With a new national resource assessment in the horizon, this proposal would further subdivide the resource temperatures into seven categories as shown on Table 6-1.

Table 6-1
Proposed Resource Temperature Classification

	Class of Resource	Reservoir Temperature	Mobile Fluid Phase in Reservoir	Production Mechanism	Fluid State at Wellhead	Well Productivity and Controlling Factors other than Temperature	Applicable Power Conversion Technology	Unusual Development or Operational Problems
1	Non-electrical Grade	< 100 deg C	Liquid water	Artesian self-flowing wells;	Liquid water	Well productivity dependent on reservoir flow capacity	Direct Use	
2	Very low Temperature	100 deg C to < 150 deg C	Liquid water	Pumped wells	Liquid water (for pumped wells); steam-water mixture(for self-	Typical well capacity 2 to 4 Mwe; dependent on reservoir flow capacity and gas content in water; well productivity	Binary	
3	Low Temperature	150 deg C to < 190 deg C	Liquid water	Pumped wells; self-flowing wells (only at the higher temperature end of the range)	Liquid water (for pumped wells); steam-water mixture(for self-flowing wells)	Typical well capacity 3 to 5 Mwe; dependent on reservoir pressures, reservoir flow capacity and gas content in water; productivity of pumped	Binary; Two-stage Flash; hybrid	Calcite scaling in production wells and stibnite scaling in binary plant are occasional problems
4	Moderate-Temperature	190 deg C < 230 deg C	Liquid Water	Self-flowing wells	Steam-water mixture(enthalpy equal to that of saturated liquid at reservoir	Well productivity highly variable (3 to 12 Mwe); strongle dependent on reservoir flow capacity	Single-stage Flash; Two stage Flash; Hybrid	Calcite scaling in production wells and occasional problem; alumino-silicate scale in injection system a
5	High Temperature	230 deg C to < 300 deg C	Liquid water; Liquid-dominated two phase	Self-flowing wells	Steam-water mixture (enthalpy equal to or higher than that of saturated liquid at reservoir	Well productivity highly variable (up to 25 Mwe); dependent on reservoir flow capacity and steam saturation	Single-stage Flash; Hybrid	Silica scaling in injection system occasionally corroison; occasionally high NCG content
6	Ultra High Temperature	300 deg C +	Liquid-dominated two phase	Self-flowing wells	Steam-water mixture (enthalpy equal to or higher than that of saturated liquid at reservoir condition); saturated steam;	Well productivity extremely variable (up to 50 MWe); dependent on resrvoir flow capacity and steam saturation	Single-stage Flash	High NCG content; silica scaling in injection system; occasionally corrosion; silica scaling potential in production wells at lower wellhead
7	Steam Field	240 deg C (33.5 bar-a pressure;	Steam	Self-flowing wells	Saturated or superheated steam	Well productivity extremely variable (up to 50 Mwe); dependent on reservoir flow	Direct Steam	Occasionally high NCG content or corrosion

The seven possible classes in Table 6-1 are based on temperature as the primary criterion, and steam fraction in the mobile fluid phase in the reservoir (but not necessarily steam saturation in the reservoir) as a secondary criterion. The reservoir temperature limits suggested in the table can be shifted by 5° to 10°C without disrupting the logical structure of the scheme. The attributes of the reservoirs in the various classes, as listed in Table 1, reflect general industry experience.

Depth

Resource development also depends on the depth to which wells must be drilled to tap underground reservoirs of hot water or steam as well as the permeability of the rock formation that constitutes the reservoir and, therefore, the rate of flow from the reservoir rock into the wells. Depth may range from less than 1,000 feet (300 m) to over 7,000 feet (2,000 m). The combined effect of permeability and well design/performance can be measured as flow rate per unit of pressure difference that drives the flow.

Based on these two major cost-determining factors and the technology performance and cost data in the Renewable Energy Technology Characterizations (RETC) report [10], the matrix in Table 6-2 estimates supply versus cost for four categories of geothermal power generation.

Table 6-2
Performance and Cost Ranges for Geothermal

High Temperature > 400°F (> 204 C)	Moderate Temperature 300-400°F (149-204 C)	Low Temperature 250-300°F (121-149 C)
Good Production $800-$1,100/kW 2,000 MWe	Good Production $1,300-$1,600/kW 10,000 MWe	Not used for power generation
Moderate Production $1,000-$1,300/kW 3,000 MWe	Moderate Production $1,800-2,100/kW 20,000 MWe	Not used for power generation

Resource Permeability

Although not a parameter used in the “supply curve” tables here, the permeability of a hydrothermal reservoir has a significant impact on the economics of geothermal energy projects. Low resistance to fluid flow (hot water or steam) from the hydrothermal aquifer to the well bore(s) results in high well production rates and therefore, lower unit costs to deliver hot fluid to the geothermal power plant or heat-using facility. Permeability is a function of the degree of fractures in the rock and the porosity of the rock matrix. Geothermal resources are associated with volcanic and seismic regions of the Earth. Therefore, fractures due to seismic (i.e., earthquake) faults are often associated with hydrothermal reservoirs and can often be important to their permeability. Often, the pattern of productive wells in a hydrothermal geothermal field follows a fault line—for example, at Roosevelt Hot Springs near Milford, Utah, where PacifiCorp has its 20-MWe Blundell Geothermal Plant. Or, the limit of the production zone of a geothermal field may be defined by a rather pronounced line where the change in rock type at a fault ends the zone of a permeable rock formation containing the water and/or steam.

U.S. Supply Curve

Table 6-3 shows the resulting "supply curve" for power generation from geothermal resources in the U.S. Note that the goal numbers for geothermal in the RETC report [10] yielded lower O&M costs than those adopted here. [RETC 1997 cost inflation to 2002 dollars]

Table 6-3
Supply Curve for Geothermal in U.S. (Hydrothermal Only)

	Group 1	Group 2	Group 3	Group 4
Temperature Class	High	High	Moderate	Moderate
Production Class	Good	Good	Moderate	Moderate
Capital Cost	$1,000/kW	$1,200/kW	$1,500/kW	$2,000/kW
Resource Potential	2 GWe	3 GWe	10 GWe	20 GWe
Capacity Factor	85%	85%	85%	85%
Annual Generation	15 TWh/yr	22 TWh/yr	74 TWh/yr	149 TWh/yr
Capital cost, $MWh	$28.00	$34.00	$42.00	$57.00
O&M cost, $/MWh	$8.00	$12.00	$15.00	$20.00
Fuel cost, $/MWh	none	none	none	None
Total, $/MWh	$36.00	$49.00	$54.00	$77.00

Here, the higher costs for Groups 2 through 4 ($12 to $20/MWh) relative to those for the goal cases of the RETC report ($6 to $8/MWh) reflect adverse conditions that can be and have been encountered in geothermal fields. The term "field" usually refers to the rock, reservoir, well, and pipeline components that deliver heat to the geothermal power plant. Contingencies are reflected as higher O&M costs in Table 6-2 and include extra labor and material to overcome problems of scale deposition, corrosion, down-well pump replacement and production well work-over, and even the drilling of new wells at an accelerated pace. Note also that Table 6-2 addresses hydrothermal resources only, and does not address HDR resources ("Enhanced Geothermal Systems") or geopressured resource figures.

6.2.2 Installed Geothermal Capacity

In 2005, the World Geothermal Congress (WGC2005) estimated that the total geothermal capacity in the U.S. was 2,564 MWe, generating 17,917 GWh and operating at a capacity factor of 0.67 [28].

In fact, the dry steam resource at The Geysers has run at a lower capacity factor than the hot water resources due to different business arrangements: i.e., there is no requirement that the utility buy all the electricity that can be generated. Many geothermal plants typically can achieve annual capacity factors of 0.85, 0.90, or higher [3, 10, 13].

Table 6-4 summarizes worldwide installed geothermal generating capacity by country as of 2005, with nations listed in decreasing annual power generation order [28].

Table 6-4
Installed Geothermal Power Worldwide (2005) [28]

Country	Installed MW	Annual Energy Produced (GWh/y)
U.S.	2,564	17,917
Iceland	202	14,838
Philippines	1,931	9,253
Mexico	953	6,282
Indonesia	797	6,085
Italy	791	5,340
Japan	535	3,467
New Zealand	435	2,774
Costa Rica	163	1,145
Kenya	129	1,088
El Salvador	151	967
Nicaragua	77	271
Guatemala	33	212
Turkey	20	105
France (Guadalupe)	15	102
China	28	96
Portugal (Azores)	16	90
Russia	79	85
Papua New Guinea	6	17
Austria	1.2	3.2
Thailand	0.3	1.8
Germany	0.2	1.5
Australia	0.2	0.5
Ethiopia	7.3	not operating
TOTAL	**8,933**	**56,786**

6.3 Technology Description

As noted, hydrothermal power generation involves well-established systems and technology with decades of practical experience. Most of this discussion will therefore focus on hydrothermal technologies. Geopressured and HDR systems have both shown promise in early research; however, the specific technologies, available geothermal resources, and economics involved are uncertain. In the case of geopressured resources, the economics do not appear favorable, even over a 10- to 20-year time frame. Natural gas prices, and hence the value of the methane dissolved in the geopressured fluid, may have to be very high, well above $5.00/MBtu, perhaps,

to enable a geopressured well to recover the very high costs associated with drilling and completing it. Also, the geopressured resource base is rather limited in size—perhaps 2-6 GWe [5, 12, 14]. In contrast, the HDR resource base is very large—perhaps 500 GWe to as much as 3,000 GWe [4, 9].

6.3.1 Hydrothermal

Hydrothermal power is generated from steam and hot water withdrawn from geologic structures relatively close to the Earth's surface. A geothermal hydrothermal system consists of a geothermal reservoir, wells, and a power plant (Figure 6-3). The set of producing wells are often referred to as the field, or the well field. Sites using direct steam for power generation are located in the U.S., Italy, and Japan. Geothermal hot water or brine is used for generation in the U.S., Philippines, New Zealand, Mexico, Japan, El Salvador, Nicaragua, Kenya, Turkey, Iceland, and the other countries listed in Table 6-4, above [2, 10].



Figure 6-3
Hydrothermal Power Plant at The Geysers, California

In general, geothermal fluids are tapped through wells, also referred to as "bores" or as "bore holes," and are similar to oil wells due to the borrowed drilling technologies for the oil and gas. Well depths typically range from 200 to 3,500 meters. The fluids surging out of the wells are then piped out to the power plant. One or more wells may be connected to feed the steam to the turbine. The geothermal hot water, steam, or vaporized secondary working fluids then impel a turbine, which in turn transfers the energy by spinning the generator to create electricity. Waste heat from the process, mainly due to efficiency of heat conversion, is then put through a heat exchanger or directly ejected to the atmosphere through condensers and cooling towers. Remnant geothermal liquids, including any excess condensate, are generally pumped back into the reservoir through injection wells. In some systems outside the U.S., cooled liquid leaving the plant is disposed of on the ground surface or in streams. This "cooled" liquid is, of course, "hot" relative to ground surface, stream, or river temperatures.

If present, non-condensable gases are removed from the system by gas ejection equipment and released to the atmosphere after any treatment mandated by emission regulations. Some emission control systems may produce sludge or solids that are disposed of either on reclaim fields or in landfills.

The nominal plant size used in most system characterizations and industry comparisons is 50 MWe. Real-world systems range in size from 0.5 MWe to 180 MWe [3, 10]. The technology driver affecting design, performance, and cost of these systems is directly linked to the reservoir temperature. In general, the higher the temperature, the lower the cost of the electricity. This is because higher temperature fluid has more energy per unit mass and because the second law of thermodynamics states that higher temperatures are converted into useful work more efficiently than lower temperatures. To allow for these variations, this discussion addresses high-temperature reservoirs (flashed-steam systems) and moderate-temperature reservoirs (binary systems). Although abundant, low-temperature systems are typically not adequate for power generation and are mostly developed for direct use applications.

In high-temperature geothermal systems with temperatures greater than 302 °F (150 °C), the reservoir fluid consists of hot water and/or steam. These higher temperature systems typically flash the hot water into steam to drive steam turbines and are typically the better contenders for power plant electricity generation.
The intermediate-temperature systems have temperatures between 194 and 302°F (90 and 150 °C) and usually require the use of binary fluid for power production. These power plants require a closed-loop heat exchange technology that allows transfer of the heat from the geothermal fluid to a secondary fluid that vaporizes at lower temperature also flashed to drive the turbine.

The 1996 DOE/EPRI Next Generation Geothermal Power Plant (NGGPP) study [13] provides substantial performance and a robust set of cost data for a wide range of reservoir conditions and power plant technologies. Additional general background information on geothermal electric technologies and resources is available in references [9], [15], [16], and [27].

Major Common System Components and Features

- **Reservoir:** A geothermal hydrothermal reservoir consisting of hot rock with substantial permeability, and aqueous fluid *in situ*. The temperature of the fluid ranges from 212°F to 752°F (100°C to 400°C). The fluid may contain substantial amounts of dissolved solids and non-condensable gases (particularly carbon dioxide and hydrogen sulfide).
- **Exploration/Confirmation:** An exploration and reservoir confirmation process to identify and characterize the reservoir. This process is usually complex and can add substantial front-end cost to a hydrothermal project. Such costs are usually borne out of developer's equity and can be a large barrier to exploration projects. Those costs are accounted for in this discussion but are not represented in the system schematics. In the long run, the costs of exploration and confirmation must be included in payments made to developers of geothermal fields or to producers of geothermal fluids or power.

- **Wells:** Wells for production and injection of geothermal fluids. These range in total depth from 200 to 3,500 meters at producing U.S. hydrothermal reservoirs. The wells are drilled and completed using technology for deep wells that has been incrementally adapted from oil and gas well technology since the 1960s. The produced fluids range from totally liquid to liquid-vapor mixtures (with two-phase flow at the wellhead). In a dry steam field the wells produce only steam (with, perhaps, very small amounts of liquid condensate). Injection wells, to return "spent" (heat removed) geothermal fluid to the underground reservoir, are part of fields at which such re-injection is practiced.
- **Reservoir Design and Management:** A reservoir design and management process has the goal of optimizing the production of electricity from the reservoir to at least cost over the life of the system. Those costs are accounted for in this discussion but are not represented in the system schematics.
- **Surface Piping System:** Surface piping that transports fluid between the wells and the power plant equipment.
- **Power Conversion System (Power Plant):** A powerhouse that converts heat (and other energy) from the geothermal fluid into electricity. Power plants comprise: a) one or more turbines connected to one or more electric generators; b) a condenser to convert the vapor exiting from the turbine (water or other working fluid) to a liquid; c) a heat rejection subsystem to move waste heat from the condenser to the atmosphere. Most systems use cooling towers (wet or dry), and others use cooling ponds; d) electrical controls and conditioning equipment, including a step-up transformer to match transmission line voltage; e) an injection pump that pressurizes the spent geothermal liquid from the power plant to return it to the geothermal reservoir through the injection wells. Representative power-conversion (power plant) technologies are described below.
- **Operation and Maintenance:** Activities and costs related to the operation and maintenance of the system over a typical 30-year useful life of an individual power plant and a 40- to 100-year production life of a reservoir as a whole.

Direct Steam

Dry steam (also called "direct steam" or "vapor-dominated") power plants draw from underground reservoirs of steam. Conventional steam turbines are used with hydrothermal fluids that are wholly or primarily steam. The plant gathers steam from wells and routes it directly to a turbine, which drives an electric generator. It rejects waste heat to the atmosphere through a condenser and cooling tower, and returns remaining geothermal liquids to an underground reservoir via injection wells. These dry steam resources are rare. The Geysers geothermal field in northern California (Figure 6-3) is an important example of such a reservoir and accounts for approximately half of today's U.S. geothermal capacity. However, geothermal developers do not expect to find any more such fields in the U.S. The only other major dry steam geothermal field in the world is the Larderello field in Italy, site of the world's first geothermal power plants, first installed in about 1904 and then again in the 1920s.

In some situations "vapor-dominated" reservoirs can produce two-phase water/steam mixtures. The vapor-dominated term applies to the governing pressure and flow driver in the reservoir. Sometimes the transition from nearly all-liquid production to increasingly higher fractions of

steam entering along with the liquid water (or "brine") can indicate that the reservoir is reaching an advanced stage of depletion. The higher steam fraction may increase the power generating capacity for a brief time, but the well is near depletion and a replacement well will soon be needed. EPRI supported a method of assessing changes in reservoir conditions and predicting changes in the steam/water ratio [26]. The technique is based on the higher mobility of radon gas in the steam phase than in the liquid phase.

Flash Steam

Facilities that use hydrothermal fluids above 360°F (180°C), primarily water, usually use flash steam technology. This method uses very hot water that flows through wells under its own pressure. Flash steam systems include one or two (for single- or double-flash, respectively) large vessels called flash tanks, in which part of the geothermal fluid vaporizes into steam at pressures below that of the reservoir. These vessels can be located at the power plant or at the individual wells (at the "wellhead") or at both, depending on whether single-phase or two-phase transmission pipelines move the fluids from wells to power plant. The steam, typically 18% to 25% of the mass of the fluid from the reservoir (for double flash plants), is sent to the high-pressure and low-pressure inlets of a conventional turbine-generator. Steam volume depends on conditions in the reservoir and the designs of the production wells and power plant. The remaining liquid ("brine") from the second flash tank, containing 75% to 82% of the original mass, is injected through a well back into the geothermal reservoir.

Three-stage flash power plants that were built and operated in New Zealand in the 1970s were shut down in the 1980s due to resource depletion. Three stages of flash enable heat to be converted to electricity with higher efficiency than the double-flash approach, which is, in turn, more efficient than the single-flash approach. The added expense of each additional stage of flash, and the added costs of dealing with lower-pressure/higher-volume steam flows, must be traded off against efficiency and environmental considerations. One figure of merit that improves as a design goes to more stages of flash and lower temperatures of spent fluid is the "hot-water rate" or "brine rate" measured in mass (tons) of geothermal fluid extracted per unit (MWh) of electricity generated. Lower rates mean that less geothermal fluid required to generate a unit of electricity. In general, the less fluid produced, the lower the total cost of the production system and the less its environmental impact. Equipment present in all or most flashed-steam systems includes:

- One or two large vessels—flash tanks—in which part of the geothermal fluid vaporizes ("flashes") into steam at pressures less than the pressure in the reservoir. The turbine in the dual flash system shown in Figure 6-4 has dual inlets to admit high-pressure steam from the first flash tank and low-pressure steam from the second flash tank. The flash tanks can be located at the wellhead, at the power plant, or at both locations—e.g., the first stage at the wellhead(s) and second stage at the power plant. At Cerro Prieto in Mexico, just south of the U.S./Mexico border near Mexicali, the original single-flash system uses flash separators at the wellheads. A subsequent modification generates power from a second-stage flash and features a central low-pressure flash steam facility and adjacent power plant., The liquid from the first separation (wellhead separators) is flashed to generate the low-pressure steam that drives the added turbine/generator.

- Special features related to minimizing the deposition of silicate scale. For the plant depicted in the system diagram, which is similar to some but not all U.S. flash plants, the geothermal brine contains substantial amounts of dissolved silica, which tends to precipitate upon equipment walls as hard scale if not treated. Mitigation measures include:

  Elevating the conversion cycle's brine exit temperature above that optimal for maximum power production, which tends to keep some of the silica in solution (This is the method of choice when silica presents a small to moderate problem.)

  Using a crystallizer-clarifier system, which consists of a brine solids clarifier and a return line that injects silica seeds into the first flash tank to prevent the precipitation of amorphous silica on the walls of the vessel and connecting pipes

  Using a pH modification system, which injects small quantities of acid upstream of the first flash tank to reduce the pH of the geothermal fluid

- Environmental control measures. At reservoirs where the concentration of non-condensable gases (e.g., CO_2) is high, substantial gas ejection equipment is attached to the condenser. Steam or electricity drives the ejectors. If hydrogen sulfide in the gases requires abatement, H_2S control equipment is added downstream of the ejectors. H_2S removal is a significant environmental control system, when such removal is necessary to prevent odor nuisance at sites. Other environmental control measures can include settling and cooling ponds, water and solid waste containment and disposal system, and other measures if appropriate or required for local situations.

Descriptions of flashed steam geothermal power plants are presented in the RETC [10]. The NGGPP report [13] provides a range of process and cost information. Figure 6-4 is a schematic diagram of a dual flash geothermal power plant.

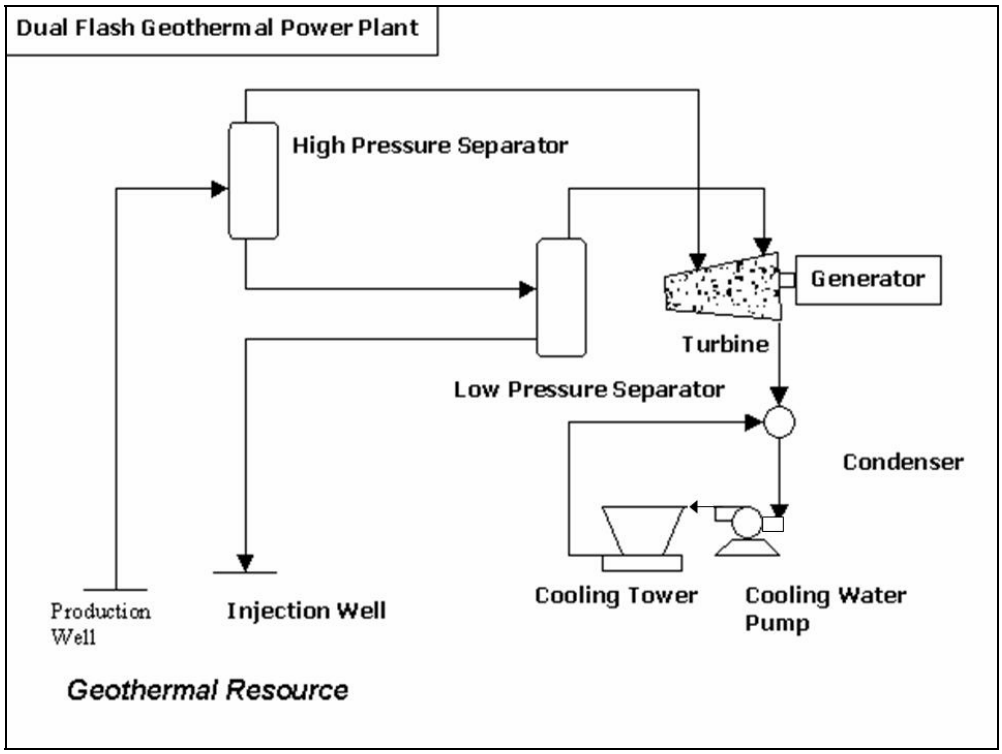


Figure 6-4
Dual-Flash (two-flash) Geothermal Power Plant

Binary Power Plants

For hydrothermal fluids with temperatures below 360°F (180°C), binary cycle technology is generally most cost-effective. Binary cycles are also applied together with a flash cycle in "hybrid" or "bottoming cycle" configurations, where the binary cycle generates power from the lower-temperature liquid that remains after one or two flash steps upstream have exploited the higher-temperature heat. In this application, the binary cycle is an alternative to the second or third stage of flash. Thus, the binary cycle is another way to use more of the heat and increase the megawatt-hours of electricity generated from a ton of the geothermal fluid brought to the power plant from the well field.

In a binary cycle power system, the natural geothermal fluid flows in one of two loops that make up the "binary" system. Figure 6-5 is a schematic diagram of a binary cycle geothermal power plant. Hydrothermal fluid passes through a heat exchanger where it vaporizes a secondary fluid, usually an organic compound with a low boiling point, such as isopentane, which drives a specially-designed turbine. Having given up its heat, the water is returned to the geothermal reservoir using a deep injection well. Low-pressure vapor from the turbine is liquefied in the condenser and re-pressurized by the hydrocarbon pump. Waste heat is ejected to the atmosphere through a condenser and cooling tower. The water and working fluid are confined to separate closed loops during the whole process, so there are few or no air emissions.

Makeup water is required for the heat rejection system if wet cooling towers are used, but not if dry cooling towers are used. The binary system characterized here is one with dry cooling ("air-cooled"). However, wet cooling will usually be less expensive than dry cooling, if cooling water is available.

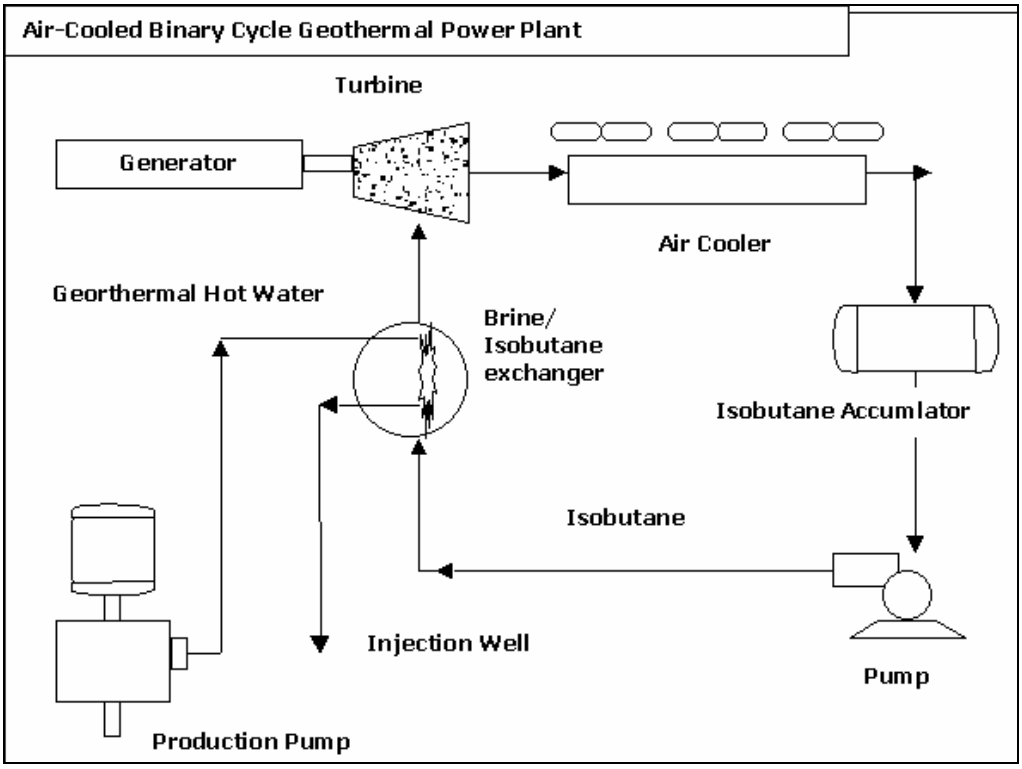


Figure 6-5
Binary Cycle Geothermal Power Plant (air-cooled design)

Technical descriptions of binary-cycle or Organic Rankine Cycle (ORC) power systems and other systems proposed for moderate-temperature reservoirs can be found in the NGGPP report [13]. The RETC report [10] references others such as binary systems, vacuum-flash, and ammonia-based cycles.

Equipment present in most binary systems includes:

- Downhole production pumps in the production wells. These keep geothermal fluid from vaporizing in the wells or in the power plant, and enhance the production well flow rate.
- A working fluid pump, the "main cycle pump," that pressurizes the low-boiling-temperature liquid working fluid to drive it around the power-conversion loop.
- A primary heat exchanger, where heat is extracted from the geothermal fluid and transferred to vaporize the binary working fluid (isobutane in the case shown in Figure 6-4).
- A turbine that converts energy in the high-temperature high-pressure working fluid vapor to shaft energy, driving a generator.

- A condenser and cooling system, receiving the low-temperature low-pressure isobutane vapor exhausted from the turbine and condensing it to a liquid for re-pressurization by the working fluid pump. The heat extracted from the working fluid in the condenser is rejected to the atmosphere via a wet or dry cooling system (the "cooling tower").

Most geothermal binary plants consist of a number of smaller modules, each having a capacity of 1 to 12 MWe net. EPRI has extensively documented the largest binary power system ever built, the nominal 48-MWe (net) Heber Binary Project, built by DOE and San Diego Gas and Electric Company as a demonstration project in the 1980s. [17]

The trend in binary-cycle technology since the mid-1980s has been toward binary cycles of relatively small size despite the lower cost of electricity that would be expected to result from economies of scale at larger sizes. The reasons for this are that binary cycles lend themselves well to smaller sizes and to modular construction techniques, and the economics of financing favors smaller sizes. For instance, in New Zealand, the large unit size that launched Wairakei at over 100 MWe more than 40 years ago is no longer seen as the preferred path, because field development in smaller increments of 20 MWe or less enables a well developer to establish a revenue stream sooner, without the cost and risk of proving a 50- or 100-MWe resource in the ground. The 100-MWe unit size was developed in New Zealand when there was a national government-owned power generation and distribution corporation. Now, with smaller, private, competing power generation companies in charge of generating electricity, smaller increments of capital and less time from first exploration to power sales take priority. The new priorities have led to the choice of binary cycles at 20- to 24-MWe or smaller unit size as the preferred technology during the past decade.

6.3.2 Hot Dry Rock ("Enhanced Geothermal Systems")

HDR resources are relatively deep masses of rock that contain little or no steam or water and are not very permeable. They exist where geothermal gradients—the vertical profile of changing temperature—are well above average (>50°C/km). Rock temperature reaches commercial usefulness at depths of about 4,000 meters or more. The potential energy to be derived from HDR is enormous. The U.S. Geological Survey estimates that there are between 3 million EJ and 18 million EJ of accessible HDR energy in the U.S.—enough to satisfy current U.S. energy consumption for tens of thousands of years [4].

To exploit HDR, site developers first create a permeable reservoir by hydraulic fracturing in a "construction" phase [3]. Then, in the "operating" phase, water from the surface must be pumped through the fractures to extract heat from the rock [10]. At sufficient temperature, the water can be flashed to steam and used to generate power. Alternatively, the injected water can be held at sufficient pressure to maintain it in liquid form for use in a binary or a flash/binary hybrid cycle. The technical challenges lie in the sub-surface elements of the system, not the power cycle, notably related to deep drilling (2 to 3 miles, or 3 to 5 km) and *in situ* fracturing [9, 15].

Although the potential of HDR resources has been studied less than hydrothermal resources, and is therefore less understood, it is believed to be much larger. By some estimates, more than 2 million MW could be generated from high-grade HDR in the U.S., with perhaps 17 million MW (more than 20 times the current installed electric capacity in the U.S.) available for less than 6 cents per kWh by 2020 [10, 11].

Flash steam or binary cycle technologies could both be used with HDR resources depending on the temperature of geothermal fluid produced. However, because of constraints imposed by high well costs, most of the accessible HDR resource would likely produce wellhead fluids in the moderate temperature range best suited for binary cycle technology [9].

To date, HDR resources have not been developed commercially in the U.S. Well costs increase exponentially with depth; because HDR resources are much deeper than hydrothermal resources, they are much more expensive to develop. Also, although the technical feasibility of creating HDR reservoirs has been demonstrated at experimental sites in the U.S., Europe, and Japan, operational uncertainties regarding the resistance of the reservoir to flow, thermal drawdown over time, and water loss have so far made commercial development unacceptably risky. Lower-cost resource assessment and drilling technologies will help bring these HDR systems into commercial use [3, 4, 9].

HDR resource use is still in the experimental stage. The only major U.S. experiments were conducted at Fenton Hill, New Mexico, near the Los Alamos National Laboratory from 1973-1996.

DOE has aptly named its effort to investigate the potential for increasing the amount of electricity generated from geothermal sources “enhanced geothermal systems” (EGS). As the name suggests, EGS technology could be used to enhance and extend hydrothermal geothermal production zones. The same technology that fractures HDR formations and allow them to heat water that can flow to the surface to a geothermal power plant could also be applied to extend the life, flow rate, and size of the production zone of a hydrothermal geothermal field. Such technology could enhance or restore the permeability of rock formations and bring in new sources of water, such as the treated wastewater from the fringes of The Geysers field in northern California. It could also help maintain production at sites where natural geothermal steam and water are depleted or insufficient natural permeability is encountered.

HDR experiments were also performed at two sites in Japan during the 1980s and 1990s. These experiments included work similar to that of DOE EGS program, namely enhancing a poor or declining conventional hydrothermal hot-water-producing field through targeted rock fracturing in zones where more permeability is needed. The most significant experiment in the world since 1994 was the European project at Soultz, France, where two fracture zones have been completed, one deeper and hotter than the other. The deep zone could be the source of sufficiently high-temperature hot water to drive an electric power generation station. Circulation tests have been performed, from injection well to hot rock fractured by high-pressure injection, to the production well, and back to the surface. The wells were stimulated by adding salt and near-by lake water to provide initial brine. During the 2001 to 2004 period, a pilot plant was built using the previously drilled and stimulated three-well system. In the current 2005 to 2008 phase, an initial 1.5 MW

power plant is planned for operation using the short circulation loop now under construction and eventually a medium circulation loop of 26 gal/s [100 l/s].

In mid-2003, Geodynamics Ltd. of Australia began drilling to build the world's first commercial HDR plant. The well will extend approximately 3 miles (5 km) under South Australia's Cooper Basin to tap a promising geothermal region in which rocks achieve temperatures of about 550°F (290°C). HDR geothermal exploration in South Australia alone cover an area of 991 square kilometers and have potential future capacities in the thousands of MWe. The near 1000-square-kilometer HDR resource is equivalent to 50 billion barrels of oil or 10.3 billion tonnes of coal. This is 20 times larger than all the known Australian oil reserves and equivalent to 40 years of their current black coal production.
Geodynamics has secured the rights to another HDR field in the Cooper Basin and two others in the Hunter Valley in New South Wales. After developing an initial demonstration HDR plant in the 10- to 15-MWe range, the company plans to build a commercial-scale power plant capable of generating hundreds of megawatts.

Currently, the hot chili pepper-named plants Habanero 1 & 2, Geodynamic's first two geothermal wells, have produced good results. The company has successfully completed the riskiest task of the project, hydraulic stimulation of the underground wells and heat exchanger. In 2005, the firm reported that—using a large than expected heat exchanger—it has exceeded all expectations. An initial water circulation test in spring 2005 lasted 40 hours and reached temperatures of 389°F (198.5°C). Habanero #2 produced about 10MW of thermal power during diagnostic flow tests. The flow test in April 2005 found some potential for power production, but concluded that a dropped plug was restricting the connection to the geothermal reservoir. The company's attempt to drill another sidetrack had one problem after another and was concluded in June 2006 when the drill pipe became stuck. Currently a new well Habanero #3 is in the planning.

The development to date indicates that there is a very good potential for economic energy extraction in the future. This potential has been considerably enhanced by the discovery of the overpressures in the granite fracture network, which could add a large convective heat component into the original design. Geodynamics estimates that a 300-MWe plant will cost $770 million Australian (approximately $600 million U.S.) to complete.

Overall, EGS Technology has the potential to provide a sizeable addition to current geothermal production. According to the GRC (bulletin 33) [31], about 40,000 MW of resource could be made economic in the 2020-2040 timeframe by improving EGS technology.

6.3.3 Geopressured

Geopressured resources are natural deposits of hot brine found in conjunction with oil and gas deposits. Methane gas dissolved in the hot brine, plus the heat of the brine itself, gives these deposits a role as potential energy and power resources. As mentioned above, the extent of this resource amounts to only about 20% of the hydrothermal resource and appears to be expensive to exploit, except for a niche involving wells drilled for other purposes and used to provide geothermal heat and dissolved methane as an alternative to being plugged and abandoned [12]. Geopressured resources are found for the most part in the Texas-Louisiana coastal region near the Gulf of Mexico [5, 12]. Use of geopressured resources depends upon the economics of natural gas. This is because the low temperature of the hot brine produced and the great depth

and pressure (and, hence, expense) of the producing wells drilled into geopressured zones make the production of electricity alone uneconomic.

6.3.4 Non-Electric ("Direct Use") Geothermal

In addition to the electric power generation technologies, which are the subject of this report, hot geothermal fluids can be used directly in aquaculture, greenhouses, space heating, wood drying, and vegetable drying. In the U.S., non-electric energy uses are very small relative to electric power applications. District-heating projects exist in Idaho and other states, and there are a few new projects in the proposal stage. If the price of energy, especially natural gas, continues to rise, similar projects will evolve.

As an energy conservation measure, geothermal heat pump (GHP) systems have been marketed and deployed to reduce the cost of heating and cooling with electricity, gas, and fuel oil, especially in new housing or commercial developments. These heat pump systems exchange heat by means of shallow wells, usually within 100 feet (30 m) of the surface and drilled into rock or soil. GHPs take advantage of the constant temperature that exists at these shallow depths but differ from basic geothermal technology in that they do not extract heat from the earth's core. Sometimes called ground-source heat pumps, GHPs operate best in climates with extreme temperature changes between summer and winter. The market for these units is adversely affected by high initial cost, but they can be competitive with conventional heating/cooling units in the long run. The DOE geothermal research and development program addresses these non-electric and energy-conservation aspects of geothermal energy in addition to its major emphasis on electricity generation.

6.4 Technology Status

While geothermal (hydrothermal, not HDR) is generally considered a mature technology, there are many opportunities for improvement through research and development. Geothermal projects are very capital intensive. Continued research and development will be useful on many fronts, particularly in developing improved geophysical methods to detect geothermal reservoirs and resources, decreasing the cost of drilling geothermal wells, decreasing the cost of power production by reducing maintenance cost, increasing the conversion effectiveness of power plants sited at low-temperature reservoirs, and decreasing O&M costs of wells, field equipment, and power plant equipment performance. Recent work carried out by the EIA, the Environmental Impacts of Geothermal Energy Development study, involved improvements in subsidence modeling, enabling a more reliable basis for forecasting and possible mitigation. A project investigating EGS-induced seismicity was initiated in 2004 to examine subsidence effects.

Technologies for exploration, drilling, and reservoir analysis and management are essentially the same for all types of geothermal systems. There is substantial room for improvement in most aspects of these technologies, including both the fluid-production (exploration, wells, and reservoir management) and electricity-conversion (power plant) components. Improvement in drill bit technology is expected to help reduce the cost of drilling deep geothermal wells by about 20% over the next decade. The cost of conversion technologies should decrease substantially over the next decade for lower-temperature systems such as binary cycle plants, but may not

decrease much for higher-temperature flash systems. The main thrusts for reducing power plant costs involve [10, 13]:

- Substantial changes in the basic conversion cycle designs used in the plants, including the addition of "topping" and "bottoming" cycles, improved working fluids, and the used of various hybrid cycles. An example of a topping cycle is the Rotary Separator Turbine (RST) developed by Douglas Energy and previously by Biphase Energy Systems, with major testing support from EPRI during 1978-1984 and from Utah Power & Light during 1981-1987. Subsequent testing has been done at Cerro Prieto, the geothermal field in Mexico just south of the California border, with support from the California Energy Commission and DOE. The RST extracts added electric power at the high-temperature side of a flash process by having the flash and separation take place in a rotary separator designed to capture the kinetic energy that the flashing steam imparts to the liquid phase. Examples of bottoming cycles include the third stage of flash in use in New Zealand, a binary cycle added at the low-temperature side of a flash cycle, and a special low-temperature water-ammonia binary cycle (the Kalina Cycle™ of Exergy Inc.) added below a flash or a binary cycle.
- Efforts on the part of system operators to reduce O&M costs, especially by reducing the number of staff employed at each system and site. This is being accomplished through increased automation of controls and monitoring. An example is the operation and maintenance of the Wairakei and Ohaaki-Broadlands fields by Contact Energy in New Zealand. The central control system at the Wairakei plant also controls the Ohaaki plant 15 km away, and a roving operator performs monitoring and maintenance tasks for both plants.
- Gradual reduction in complex instrumentation and controls as operations are streamlined and engineers learn what components are safe to omit.

The consensus in the industry is that characterizing the commercial potential of identified geothermal reservoirs is a high priority [3]. Techniques such as fracture mapping, more accurate thermal gradient wells, and other untested methods should be evaluated and refined if appropriate. The objective is to be able to measure the temperature, fluid characteristics, and permeability of the resource prior to committing to expensive production wells and generation equipment.

Industry comments suggest that structured, integrated tests and experiments by industry, in collaboration with public agencies such as DOE, are essential to ensure further development of commercial geothermal power [3]. In the near term, such work will focus on:

- Techniques for improving the cost-effective definition of resources as discussed above
- Reducing the costs of drilling production wells
- Improving the efficiency of geothermal facilities
- Understanding the results of wastewater injection and improving this process
- Investigating environmental impacts of geothermal energy developments.

6.4.1 Recent Developments

Recent interest in geothermal energy in particular and renewable energy in general, has precipitated expansion of the geothermal electricity market. There are upcoming projects in Alaska, Nevada, Idaho, and Arizona.

In Alaska, the Chena Hot Springs Resort developed its first geothermal power project, which pairs the direct use of geothermal energy with on-site geothermal electricity generation. In the coming years, Arizona will develop its first geothermal plant. Idaho, in the meantime, will have its first geothermal power project at Raft River come online and potentially demonstrate new higher-efficiency power generation technology. The area of largest growth in 2006 was in Nevada, where the Nevada Renewable Portfolio Standard is stimulating new projects. With over 200 MW of new geothermal power (Table 6-5), the state will be doubling its current geothermal generation.

Table 6-5
New Added Generation in 2005-2006

Plant Identification	State	Net Summer Capability (MW)	Year OnLine
Puna (Expansion)	Hawaii	7.6	2006
Rye Patch	Nevada	11.9	2005
Hot Sulphur Springs	Nevada	23.8	2005
Galena I (Orni I Steamboat)	Nevada	19	2006
Desert Peak II, III	Nevada	38.4	2006
TOTAL		**100.7**	

New Mexico has direct-use applications of geothermal energy to fish farming that have notably increased fish production and sales and have provided economic opportunities for rural communities. California, where geothermal is a major non-hydro renewable power source, has set an aggressive RPS goal for expanded renewable power production. The state expects that geothermal production will at least double in the next decade, with 2000 MW or more generated from new geothermal power plants. Currently in Oregon, geothermal stakeholders and utilities are meeting to discuss development possibilities, and—depending on the results of these meetings—we may see the fastest growth in geothermal energy in this state. In addition, Hawaii, Washington, Colorado, Montana, Texas, and Wyoming also are eager to explore their potential geothermal power. The EIA's AEO2005 report [7] estimates significant increases in electricity generation from geothermal, particularly in the West, where geothermal output could increase from 13 billion kWh in 2003 to 33 billion kWh in 2025.

6.4.2 Likely Development Pathways

At present, hydrothermal-convection resources account for all electricity generation from geothermal energy. Hydrothermal-convection resources are subdivided further into vapor- and liquid-dominated resources, which produce mostly steam and hot water, respectively. Use of geopressured and HDR resources is currently in the experimental stage.

Table 6-6 is a technology monitoring guide of the leading developers and technical issues in geothermal power generation. The issues and the organizations involved in geothermal energy development are grouped based on broad technology categories, namely 1) exploration and resource development, 2) drilling and production, 3) reservoir management, 4) chemistry and materials, 5) dual-flash steam geothermal, 6) binary-cycle geothermal, and 7) HDR geothermal (or “Enhanced Geothermal Systems”).

Based on the major technology groups of dry steam (vapor-dominated), flashed steam (liquid-dominated and using steam cycles for power generation), binary cycle (liquid-dominated and using binary cycles for power generation), and HDR, Table 6-7 presents a development map for geothermal power generation technologies. With the new energy bill, R&D intensity is likely to increase in the government organizations.

Table 6-6
Technology Monitoring Guide: Geothermal Power Plants

Leading Developers of the Science or Technology								
Technologies	**R&D Intensity**	**Government Organizations**	**Nonprofit Organizations**	**Industrial Firms**	**Leading Vendors**	**Major Trends**	**Changes To Watch For**	**Unresolved Issues**
Exploration and Reservoir Assessment	Low	DOE, USGS, State geologists, NREL, INEEL	U. of Utah – Energy & Geoscience Inst. (EGI), LBL (Berkeley, CA), Inst. Inves. Elec. (IIE, Mexico) SMU Sandia National Laboratory	GeothermEx, SAIC, Geothermal Development Associates (GDA)		Slim hole methods	Reservoirs Modeling Assessment	
Drilling and Production	Low	DOE, NREL	Sandia National Laboratory	Cal. Energy Co., Calpine, Coso Operating Co., Unocal		Pumped wells		
Reservoir Management	Moderate	DOE, NREL, INEEL BLM	Stanford U., Los Alamos Nat. Lab. (John Rowley), Inst. Inves. Elec. (IIE, Mexico)	GeothermEx, SAIC, ThermaSource, CalEnergy Co., Coso Operating Co.		Cooperation among operators	Unitized operation	Resource risk
Chemistry and Materials	Moderate	DOE, NREL	Brookhaven & Sandia National Labs, Inst. Inves. Elec. (IIE, Mexico)	GeothemEx, Thermochem		Development of geothermal brine chemistry models	Better cements and coatings	Addition of NH_3 and H_2S to brine chemistry models

Table 6-6 (continued)
Technology Monitoring Guide: Geothermal Power Plants

Leading Developers of the Science or Technology								
Technologies	**R&D Intensity**	**Government Organizations**	**Nonprofit Organizations**	**Industrial Firms**	**Leading Vendors**	**Major Trends**	**Changes To Watch For**	**Unresolved Issues**
Dual Flash Steam Geothermal	Low	DOE, NREL	NREL IIE (Mexico)	Calpine, Cal Energy, Bibb and Assoc. (Pasadena, CA), Barber-Nichols (Arvada, CO), Stone&Webster, CFE (Mexico)	Mitsubishi, Hydrothermal Power (Elmira, NY), Elliott Company (Jeanette, PA)	Utilization of lower quality resources (lower temperature) Sub-atmospheric stage of flash? Kalina cycle for bottoming?	Tighter environmental regulations, more economical plants, hybrids with natural gas	Resource management
Binary-Cycle Geothermal	Moderate	DOE, NREL	NREL Oregon Inst. of Technology (Klamath Falls, OR)	Calpine, Bibb and Assoc. (Pasadena, CA), Barber-Nichols, Stone&Webster, Exergy (Fremont, CA) on Kalina Cycle, Advanced Thermal Systems (Reno, NV)	Ormat (Sparks. NV), Mitsubishi, Barber-Nichols, Elliott Company (Jeanette, PA)	Utilization of lower quality resources, dry cooling, 25-MW size, more binary systems	Tighter environmental regulations, more economical plants, hybrids with natural gas	Resource management Low temperature bottoming cycles, such as the Kalina Cycle (water/ammonia blends)

Table 6-6 (continued)
Technology Monitoring Guide: Geothermal Power Plants

Leading Developers of the Science or Technology								
Technologies	**R&D Intensity**	**Government Organizations**	**Nonprofit Organizations**	**Industrial Firms**	**Leading Vendors**	**Major Trends**	**Changes To Watch For**	**Unresolved Issues**
Hot Dry Rock Geothermal (also "Enhanced Geothermal Systems")	High (Europe) Low (U.S.) Moderate (Japan)	European Union (EU) DOE, NREL, INEEL NEDO (Japan)	Los Alamos National Lab. (Don Brown)	California Energy Co. (CalCo), Kiewit (Pasadena, CA), Stone & Webster Barber-Nichols (Arvada, CO) Geodynamics Ltd. (Australia)	Mitsubishi Hydrothermal Power (Elmira, NY) Barber-Nichols (Arvada, CO)	Utilization of lower quality resources, dry cooling, 25 MW size, more binary systems	Tighter environmental regulations, more economical plants, hybrids with natural gas	Resource management Drilling into hot rock at great depths Heat transfer from rock to the injected water and heat flow in rock to the water over life cycle of the power plant and well field

Table 6-7
Technology Process Development Map: Geothermal Power Plants

	Vapor-Dominated Dry Steam	Liquid-Dominated Flash	Liquid-Dominated Binary	Hot Dry Rock
Features and Advantages				
Technology Characterization	Steam drives conventional turbine Advantage is simplicity	Use liquid resource that flashes into steam at reduced pressure	Closed-loop operation Zero emissions, lower resource temperature	Potential widespread applicability
Efficiency	15-17%	11-16%	10-11%	5-15%
Resources	Dry geothermal steam source	Liquid geothermal steam source, brine disposal site	Liquid-dominated geothermal resource	Hot dry rock resource close to surface
Challenges and Disadvantages				
Cost	Limited resource	O&M costs	High capital costs	High capital costs
Operation	Environmental: H_2S emissions	Reliability H_2S emissions Brine disposal	VOC emissions Working fluid loss	Water consumption Injection well flow control
Technology Needs	H_2S abatement, resource management	Steam quality, NCG disposal	High efficiency turbines	Flow impedance predictions
Costs				
Relative Capital	Low	Low-Medium	Medium	High
Relative O&M	Low	Medium	Medium	Medium
Busbar	3-5¢/kWh	5-8¢/kWh	5-8¢/kWh	5-10¢/kWh
Development Timeframe				
Research	--	--	--	--
Development	--	--	--	1992-1993
Demonstration	--	1959	1967	2004
Commercialization	1960	1959	1979	2005-2010
Markets				
Key Issues	Resource is declining Only such resource in U.S. is The Geysers except for off-limits, unexplored national parks	Strong competition to sell to project developers led to lower capital costs in 1990s	Attractive closed loop with no fluid or gas discharge on surface or in air Extension to lower temperatures and shallow reservoirs could lower costs	Resource is abundant Technology needs demonstration Technical feasibility promising but not proved Drilling, fracturing, reservoir design, and proof of heat transfer and reservoir life and productivity are key
Impact on Technology Outlook	Expect little growth in U.S. Expansion or, at least, preservation of The Geysers via water injection	Can revive in U.S. with higher electricity prices or special demand for renewable, non-fossil, domestic energy	Can revive in U.S. with higher electricity prices or special demand for renewable, non-fossil, domestic energy	Watch Soultz project in Europe and Geodynamics in Australia Look for advance by enhancing hydrothermal

6.5 Cost and Economic Issues

Geothermal power systems couple fuel supply and power conversion systems into one. The geothermal fluid serves as the equivalent of fuel. Unlike fuel-fired power systems, in a geothermal plant, the fuel supply (the geothermal resource) and electricity generation (the power plant) are integrated and are physically connected. As a result, power plant cost is even more site-specific than for other power generation technologies. The cost is affected not only by the size and design of the power plant, but also the geothermal resource temperature and pressure, steam, impurity and salt content, and well depth.

This close and direct link is emphasized in the cost breakdowns provided here by 1) assuming a fuel cost of zero, and 2) including the capital and operating costs of the geothermal field as part of the costs of the power plant itself. In this way, geothermal is treated with the same type of cost breakdown as solar and wind energy. In contrast, biomass is treated as having a fuel supply that is separate from the power plant system analogous to a coal-, gas-, or oil-powered plant, which results in a fuel cost line item in the cost breakdowns given in the TAG-RE.

Geothermal power plants are able to generate energy at all times, except during planned and unplanned maintenance and repair episodes. Experience has led to longer periods between major overhauls, with many operators achieving five-year time spans. Because of the strong economic incentive to stay on-line, unplanned maintenance outages are kept to a minimum through the application of highly reliable equipment and adequate spare parts inventories. Some facilities are achieving capacity factors of 85% to 95%. Plant operators prefer to run their plants baseload because the fixed costs of operation far exceed the variable costs. An exception to this preference occurs when the fuel supply (steam) is less than that needed to satisfy the power plant's capacity. In such a case, the plant will operate at or near full capacity during peak-use periods (highest price for electricity) and then back down during off-peak periods.

Experiments have shown that some geothermal power plants, such as the dry steam plants at The Geysers facility in northern California, can be cycled to follow system load in the intermediate-baseloaded area of the utility time-demand curve, thereby increasing their value in certain applications. It is likely that load following would be more difficult for flash and binary cycle plants than for dry steam plants. Current contract capacity factors are on the order of 80%, but capacity factors for many operating plants are close to 100%. A capacity factor greater than 100% is possible, because some plants operate above their design and nameplate rating nearly all the time.

During the 1990s, competition from low-cost electricity generated from natural gas hurt the economic competitiveness of geothermal electric systems, slowing their development and deployment. During the early 1990s, geothermal power developers expected to compete successfully against 6 to 7 cent/kWh power in the western U.S. By the end of the decade, they instead found themselves competing against 2.5 to 3.5 cent/kWh electricity. This situation may be improving because of the rise in natural gas prices since 2002 and changing public and private preferences for more diverse sources of electricity supply, particularly from renewable and fossil-carbon-free sources. Future RPS demands in the western states take into account an increase in renewable energy supplied by geothermal power.

Recent cost reductions in flash power plants may enhance their competitiveness in the U.S. In the international market, geothermal development in regions such as Indonesia and the Philippines may be about to return to the strong growth that began in the early 1990s [2].

In California—site of the vast majority of U.S. geothermal power production—recent geothermal development picked up momentum, and geothermal-related research received R&D incentives in 2005. Ormat Technologies, Inc. broke ground on a new 10 MW geothermal power plant at its 40 MW Heber Geothermal Facilities Complex in southern California's Imperial Valley. Ormat is also modifying its existing Heber facilities to generate an additional 8 MW of power. Ormat plans to add an additional 125 MW of generating capacity over the next two to three years. Also in 2005, Ormat's new geothermal project "Galena 1," a part of the company's Steamboat geothermal power complex in Nevada, will soon be brought on-line. The project will incorporate developments in Ormat's binary technology, including turbines and power plant equipment that can be operated either on site or remotely.

The two factors most frequently cited for limited geothermal development are permitting issues and the high cost of resource exploration and development. Several proposed projects have been severely delayed in the permitting process, and market prices have just recently been sufficient to encourage more substantial project developments [3, 27].

U.S. geothermal power development is also limited by the availability of economically feasible resource sites located near transmission grids. While market participants do not generally cite transmission constraints as a restriction on development, the U.S. Forest Service’s denial of permits for transmission lines and the high costs of alternate routing have delayed several planned projects in California [3].

The current state of many aspects of geothermal technology was fairly well documented in the 90’s. The 1996 *Next Generation Geothermal Power Plants* (NGGPP) study, prepared for DOE, EPRI, BPA, and SCE by The Ben Holt Company, characterizes conventional flash and binary technology and evaluates new technologies proposed for the next generation of geothermal power plants [13]. Prior to this study, it had been difficult to obtain current cost and performance data for geothermal power plants because of the proprietary nature of this information. Newer cost models still reference this document for their base case comparisons [1, 24, 30]. For HDR, the cost estimates provided for creating a HDR reservoir, as well as its performance, were based on assessments made by scientists at Los Alamos National Laboratory, where HDR had been studied for the previous 25 years [11].

6.5.1 Example Geothermal Project Costs

Geothermal Power Cost Factors

The power cost in this subsection represents levelized cost (in cents per kilowatt-hour) over the project life. The capital cost is amortized over 30 years; and royalties, tax burden, and tax credits are ignored. Plants in the range of 5 to 150 MW size are considered for this subsection. The economy of scale in both capital cost and O&M cost, as well as the higher productivity decline

rate due to increased installed capacity, are taken into account. Currently factors affecting the power cost of geothermal power technology are divided into six categories:

- Capital cost
- Operations and maintenance (O&M) cost
- Make-up well drilling cost
- Resource characteristics (well productivity and its rate of decline)
- Development and operational options (installed plant capacity, number of years of make-up well drilling, and project life)
- Macro-economic climate (interest and inflation rates)

A recent cost model [30] indicates geothermal power costs can be reduced significantly by maintaining full generation capacity and drilling make-up wells for at least the first 10 years or so following plant start-up. Though the cost of make-up wells can be reduced, continuing make-up well drilling beyond about 20 years probably does not reduce power costs any further. The minimum achievable power cost is on the order of 3.4¢/kWh and is insensitive to plant capacity.

Power costs are most sensitive to unit O&M costs, followed by unit capital costs, interest rates, and inflation rates in decreasing order. Power costs are also relatively insensitive to well productivity, drilling cost per well, or the well productivity decline rate. Long-term site-specific experience, resource management, and power plant operation throughout a project's life can yield great insight in cost optimizations.

In addition, operating small power plants beyond their typical amortization period of 30 years can substantially reduce life-cycle power costs. This reduction is insignificant for plants of 50 MW or larger capacity. Power cost does not decline significantly with increasing plant capacity except in the unlikely situation of well productivity decline being insensitive to plant capacity.

Based on the experience of GeothermEx [30] and data presented by Entingh and McVeigh (2003), the smallest hydrothermal project size (5 MW) would have a unit capital cost of $2,500/kW and the largest project size of 150 MW would have a cost of $1,600/kW.

Data specific to California and Nevada, from a 2005 assessment by the California Energy Commission [32], suggest that the capital cost of incremental generation capacity averaged about $3,100 per installed kilowatt (kW) (See Table 6-8). For California sites alone, the average capital cost of incremental generation capacity was somewhat lower, at about $2,950 per installed kW. These cost estimates include the following components:

- Exploration (up to siting of the first deep, commercial-diameter well)
- Confirmation drilling (up to achieving 25% of required capacity at the wellhead)
- Development drilling (up to achieving 105% of required capacity at the wellhead)
- Construction of the power plant (including ancillary site facilities)
- Transmission-line costs.

Table 6-8
Estimated Geothermal Development Costs (Dec 2005 $)

Region	Most Likely Incremental Capacity (Gross MW)	Average Development Cost Per kW Installed
California	3,000	$2,950
Western Nevada	1,300	$3,450
Total	4,300	$3,100

For the purposes of the study values listed in Table 6-8, a capital cost of $2,400 per kW or less is considered competitive with other renewable resources. The amount of incremental geothermal capacity available at or below $2,400 per kW is about 1,700 gross MW. Such available capacity represents a significant opportunity for commercial geothermal energy development to meet the needs of electricity markets in the western U.S.

Existing Geothermal Power Plants

Some existing geothermal power plants can generate electricity at rather low and competitive costs because their capital investment is low, having been recovered in previous years. Table 6-9 presents cost estimates (in end-of-year 2005 dollars) for both low-cost and high-cost existing plants, as well as information regarding potential costs for future new geothermal power plants. As in the "supply curve" cases earlier in this sub-section, the values in Table 6-6 use higher O&M costs than were adopted in the RETC report in 1997 [10], reflecting the more adverse conditions that can be and have been encountered in geothermal fields.

Table 6-9
Geothermal Power Costs (Dec-2005 $)

Case Label	Exist. 0.2 Binary	Exist. 20 Binary	Exist. 50 Flash		Goal 0.2 Binary	Goal 20 Binary	Goal 50 Flash
Size MWe	0.2	20	50		0.2	20	50
Capital $/kW	6750	3930	2410		4766	1898	1265
CRF per year	0.107	0.130	0.137		0.130	0.130	0.130
$ per yr cap recover $M	$0.1445	$10.22	$16.51		$0.12	$4.93	$8.22
No. of staff	0.07	20	32		0.07	20	32
$ per yr each staff	40,000	40,000	40,000		40,000	40,000	40,000
Oper per yr $M	$0.0028	$0.80	$1.28		$0.0028	$0.80	$1.28
Maint fract of cap per yr	0.025	0.025	0.040		0.025	0.070	0.120
Maint per yr $M	$0.0338	$1.97	$4.82		$0.0238	$2.66	$7.59
Fuel cost $/MBtu	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00
Heat rate Btu/kWh	30,000	30,000	30,000		30,000	30,000	30,000
Capacity factor	0.7	0.85	0.9		0.7	0.85	0.9
Hours per year	6132	7446	7884		6132	7446	7884
Fuel in $M per yr	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00
Total $M per yr	$0.1810	$12.98	$22.61		$0.1506	$8.39	$17.09
GWh per year	1.226	149	394		1.226	149	394
COE in $/MWh	$147.59	$87.18	$57.35		$122.76	$56.34	$43.36
Breakdown of COE:							
capital $MWh	$117.78	$68.61	$41.88		$101.05	$33.13	$20.86
operation $/MWh	$2.28	$5.37	$3.25		$2.28	$5.37	$3.25
maint $MWh	$27.52	$13.20	$12.23		$19.43	$17.84	$19.25
fuel $MWh	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00
total $MWh	$147.59	$87.18	$57.35		$122.76	$56.34	$43.36

Cost Estimates for Goal Technologies

Table 6-10 shows the cost goals for 10-MWe to 50-MWe unit sizes for the two technologies and two resource combinations adopted here. Again, as in the earlier "supply curve" cases, the geothermal goal data use higher O&M cost estimates than presented in the 1997 RETC report [10]. The higher O&M costs reflect the more adverse conditions that have been and can be encountered in geothermal fields. Contingencies are included in the O&M costs to allow for extra labor and material to overcome scale deposition, corrosion, down-well pump replacement and production well work-over, and drilling of new wells at an accelerated pace. The resulting O&M costs are $14-23/MWh, which is higher than those in the RETC ($6-8/MWh).

Table 6-10
Geothermal: Cost Estimates for "Goal" Technologies (Dec-2005 $)

	Flash	Flash	Binary	Binary
	Resource: high temp. and good production	Resource: high temp. and moderate production	Resource: moderate temp. and good production	Resource: moderate temp. and moderate production
Size MWe	50	50	30	10
Capital $/kW	$1,035	$1,150	$1,150	$1,264
CRF per year	0.21	0.21	0.21	0.21
$ per yr cap recover $M	$10.65	$11.84	$7.10	$2.60
No. of staff	30	30	30	12
$ per yr each staff	$80,492	$80,492	$80,492	$80,492
Operation per yr $M	$2.36	$2.36	$2.36	$0.94
Maint fract of cap per yr	0.06	0.07	0.06	0.07
Maintenance per yr $M	$3.04	$3.95	$2.01	$0.86
Fuel cost $/MBtu	$0.00	$0.00	$0.00	$0.00
Heat rate Btu/kWh	30,000	30,000	30,000	30,000
Capacity factor	0.85	0.85	0.85	0.85
Hours per year	7,900	7,900	7,900	7,900
Fuel in $M per yr	$0.00	$0.00	$0.00	$0.00
Total $M per yr	$16.05	$18.15	$11.47	$4.40
GWh per year	395	395	237	79
Breakdown of COE:				
Capital $MWh	$26.96	$29.97	$29.96	$32.91
Operation $/MWh	$5.97	$5.97	$9.96	$11.90
Maint $MWh	$7.70	$10.00	$8.48	$10.89
Fuel $MWh	$0.00	$0.00	$0.00	$0.00
Total COE $MWh	$40.63	$45.95	$48.40	$55.70

6.5.2 Technology Performance and Cost Tables

Table 6-11 presents cost breakdowns in greater detail for flash and binary hydrothermal geothermal power systems. Data are derived from the RETC [10] and have been adjusted for inflation to December 2005 dollars.

Table 6-11
Current Status and Goals for Geothermal Technologies (Dec 2005 $)

		Flash (two-flash)		Binary Cycle	
	UNITS	**2002 Status**	**2030 Goal**	**2002 Status**	**2030 Goal**
Plant Size	MW	47.9	47.9	50	50
Performance					
Levelized Capacity Factor	%	89	97	92	97
Annual Energy Production	GWh/Year	390	425	403	425
Power Plant Net Effectiveness	Wh/kg fluid	26.4	13.9	11.8	13.9
Average Flow/Well	1,000 kg/hr	304	454	337	454
Average Cost/Well	$1,000	1911	955	544	401
Capital Costs					
Wildcat Exploration	$/kW	56	15	24	4
Site Confirmation, Well Costs	$/kW	123	52	34	21
Site Confirmation, Soft Costs	$/kW	22	16	21	15
Siting and Licenses	$/kW	78	78	78	78
Land (@$5,000/ha)	$/kW	1	1	1	1
Producing Wells & Spares	$/kW	312	110	161	79
Dry Production Wells	$/kW	78	18	25	9
Injection Wells	$/kW	134	45	74	36
Field Piping	$/kW	58	27	39	18
Production Pumps	$/kW	0	0	52	36
Power Plant	$/kW	770	770	1,796	1,419
Owner's Costs	$/kW	132	132	132	132
Total Overnight Capital Cost	$/kW	1,763	1,266	2,439	1,851

Table 6-11 (continued)
Current Status and Goals for Geothermal Technologies (Dec 2005 $)

		Flash (two-flash)		Binary Cycle	
Operations and Maintenance Costs					
Field, General O&M & Rework	$/kW-yr	39.7	26.3	31.3	22.6
Makeup Wells	$/kW-yr	15.0	4.9	8.1	2.7
Relocate Injection Wells	$/kW-yr	3.39	0.51	1.95	0.1
Power Plant O&M	$/kW-yr	60.08	35.84	54.74	36.25
Total Operating Costs	$/kW-yr	118.1	67.06	96.13	61.93
Cost of Electricity (COE)					
Net Capacity	MW	49.7	49.7	50	50
Capacity Factor		0.92	0.97	0.92	0.97
Capital Charge	$/kW	0.23	0.23	0.23	0.23
Total Plant Cost 2005 $	$/kW	1,717	1,233	2,375	1,802
O&M Cost 2005 $	$/kW-yr	105.78	66.45	101.47	65.32
Capital Charge	$/MWh	25.88	18.49	39.95	28.76
O&M Cost 2005 $	$/MWh	118.1	67.06	96.13	61.93
Fuel	$/MWh	0	0	0	0
Total (COE)	$/MWh	59.12	38.21	73.54	51.63
		Flash (two-flash)		**Binary Cycle**	
	UNITS	**2002 Status**	**2030 Goal**	**2002 Status**	**2030 Goal**
Plant Size	MW	47.9	47.9	50	50
Performance					
Levelized Capacity Factor	%	89	97	92	97
Annual Energy Production	GWh/Year	390	425	403	425
Power Plant Net Effectiveness	Wh/kg fluid	26.4	13.9	11.8	13.9
Average Flow/Well	1,000 kg/hr	304	454	337	454
Average Cost/Well	$1,000	1861	930	530	390

Table 6-11 (continued)
Current Status and Goals for Geothermal Technologies (Dec 2005 $)

		Flash (two-flash)		Binary Cycle	
Capital Costs					
Wildcat Exploration	$/kW	52	14	22	4
Site Confirmation, Well Costs	$/kW	114	49	31	19
Site Confirmation, Soft Costs	$/kW	20	15	19	14
Sitting and Licenses	$/kW	72	72	72	72
Land (@$5,000/ha)	$/kW	1	1	1	1
Producing Wells & Spares	$/kW	289	102	149	73
Dry Production Wells	$/kW	72	17	23	9
Injection Wells	$/kW	124	42	69	33
Field Piping	$/kW	53	25	36	17
Production Pumps	$/kW	0	0	49	33
Power Plant	$/kW	714	714	1,665	1,315
Owner's Costs	$/kW	123	123	123	123
Total Overnight Capital Cost	$/kW	1,634	1,174	2,261	1,715
Operations and Maintenance Costs					
Field, General O&M & Rework	$/kW-yr	36.8	23.7	29	20.9
Makeup Wells	$/kW-yr	13.9	4.6	7.5	2.5
Relocate Injection Wells	$/kW-yr	3.1	0.5	1.8	0.1
Power Plant O&M	$/kW-yr	55.7	33.2	50.7	33.6
Total Operating Costs	$/kW-yr	109.5	62.2	89.1	57.4
Cost of Electricity (COE)					
Net Capacity	MW	47.9	47.9	50	50
Capacity Factor		0.92	0.97	0.92	0.97
Capital Charge	$/kW	0.21	0.21	0.21	0.21
Total Plant Cost 2005 $	$/kW	1,634	1,174	2,261	1,715
O&M Cost 2005 $	$/kW-yr	98	61.54	94.05	60.51
Capital Charge	$/MWh	23.94	17.14	37.03	26.65
O&M Cost 2005 $	$/MWh	109.5	62.2	89.1	57.4
Fuel	$/MWh	0	0	0	0
Total (COE)	$/MWh	57.79	37.35	71.89	50.47

Plant construction period is assumed to require 0.8-1.5 years.

Column sums and totals may differ because of rounding.

Source: DOE/EPRI Renewable Energy Technology Characterizations (RETC), EPRI TR-109496, 1997.

6.5.3 Performance and Cost Projections

As with other renewable energy electric supply technologies, the "accuracy" of projected improvements in geothermal cost effectiveness is very important because, in many instances, use of the technologies at specific locations will not be cost effective until the technologies are improved. Projections of cost and performance improvements for hydrothermal and HDR technologies are a synthesis of what various experts believe is possible.

The projections for improvements in hydrothermal technology are based on trends in performance and cost since about 1985, when U.S. firms first started constructing many hydrothermal power systems. It has been apparent that for both wells and power plants, the earliest forms of the technologies—borrowed more or less wholly from other industries and uses—have been constantly analyzed, rethought, and improved.

The five years between 1992 and 1997 saw much new attention focused on improving the cost effectiveness of power plants through changes in the underlying process cycles and conditions used to convert heat to electricity. The single major exception to this trend of apparent improvements has been in the area of industry's ability to locate and target high-permeability zones for fluid collection and delivery. But here, too, there is constant theoretical progress, which is soon likely to result in practical progress.

The estimates for current and projected HDR cost and performance are more speculative than those for hydrothermal technology because HDR technology is much less mature and has not been applied commercially. With HDR technology, the stated estimates are for the best cost and performance that is reasonably possible; estimated uncertainty values reflect the possibility of lower performance and less improvement in the technology. The projections are predicated on various assumptions about factors that will affect the timing and extent of improvements in the technologies. These include the levels of funding for hydrothermal and HDR R&D in several countries, as well as fossil fuel drilling and well completion R&D, supply and demand in electricity markets, supply and demand in petroleum markets (which greatly influences drilling costs and private funding of drilling research), public policy (especially regarding energy and the environment) in several countries, currency fluctuations, and technological progress in other electric supply technologies.

6.6 Environmental Issues

While geothermal energy is a renewable energy technology, it is not free of environmental concerns. These concerns include land use issues in addition to emissions and chemicals that may be entrained in the steam that must be captured and processed. Also, geothermal energy generation has resulted in land impacts such as subsidence.

6.6.1 Land Use

Land use issues are similar to those experienced by conventional power plants. Geothermal power plants are sized according to the volume, temperature, and chemistry of the geothermal reservoir underlying the project. Typical generating capacities range from 10 to 50 MW. The largest unit in the world is 130 MW.

Land use patterns for geothermal power plants vary with site design and type of installation. While a well field may cover 100 to 200 acres, heat is tapped by drilling slant wells from a single above-ground location. A typical 50-MW plant and related well sites may occupy one or two acres of land. In some cases, a single plant can require multiple wellhead locations. In that case, aboveground lines carry the resource to the power plant.

A table developed for the EPRI report *Greenhouse Gas Reduction with Renewables* [8], based on land use figures in the DOE/EPRI *RETC* report [10], compares and quantifies the land use requirements of the various renewable energy resources and technologies. The result is displayed here in Table 6-12. Note that geothermal energy and solar energy are more land-area-effective, measured in kWe per acre, than wind and biomass. The area for a geothermal power plant itself is very small, about two acres for a 50-MW plant, but the value most relevant to the comparison is the area of the entire geothermal field, not just the site of the power plant. When doing such comparisons of land use, two points should be kept in mind:

1. Both wind and geothermal energy production are compatible with other simultaneous uses of much of the same land. This is especially true of wind, as shown in photographs of agricultural land with wind turbines on “islands” within fields of crops or grazing cattle. In the geothermal case, the pipelines to move geothermal fluids from wellhead to power plant and the wellhead sites themselves disrupt other land uses. In New Zealand geothermal fields, cattle or sheep can be seen grazing on land in between the well sites and pipelines (see Figure 6-6).

2. In the U.S., and in many other countries as well, land is not the limiting factor in most settings. This is especially important in considering biomass energy, where the land comparison should be made not to the land use of other energy sources but rather to the land used for agriculture and forestry.

Table 6-12
Land Area Requirements for Current Renewable Technologies

	Unit Size (MWe)	Area to Support Unit Size (acres)*	Power per Unit of Area (kW/acre)	Land Area for 100 GWe	
				Area (10^6 acres)	Fraction of U.S.**
Solar Thermal	75	408	180	0.54	0.028%
PV, Residential	0.0026	0***	NA	0	0
PV, Utility-Scale	2.4	24	100	1	0.053%
Wind	50	3,707	14	7.4	0.39%
Geothermal	50	420	120	0.84	0.044%
Biomass	50	39,400	1.3	78.7	4.1%

*** To convert acres to hectares, multiply by 0.4.**
** Fraction is of the 1.9 billion acres of the continental U.S.
*** No land is required for residential PV systems, which are typically installed on existing structures.

6.6.2 Subsidence

Land above or adjacent to a subsurface geothermal reservoir may drop in elevation, or "subside," due to the extraction of geothermal fluid from the reservoir. Subsidence is not always easy to detect and may be of no consequence.

Several areas of subsidence have been detected in the New Zealand fields. At Wairakei, the oldest geothermal field in New Zealand and one that has operated at close to 170-MWe capacity for approximately 40 years, one area of subsidence has created a pond at a low spot in a stream. Another has been detected over an area of approximately 1 km^2 and could eventually lead re-routing a section of roadway. A series of elevation surveys, conducted every several years throughout the region of the Wairakei field and environs, made it possible to detect this rather inconspicuous subsidence.



(Evan Hughes for EPRI)

Figure 6-6
Steam Pipelines for the Ohaaki, New Zealand Plant Run through Land Used for Grazing and Agroforestry

In anticipation of geothermal development expansion, biennial surveys of elevations in and near the Imperial Valley (California) geothermal fields were performed in the 1970s. Because of a gravity flow "ditch irrigation" system in a low desert valley, the economy of which depends upon agriculture, the surveys were needed to ensure that no harm was caused by geothermal production and to alert and correct the situation if adverse trends developed. Several hundred megawatts of generating capacity have been installed and operated in the Imperial Valley over the past two decades, and there has been no significant subsidence.

6.6.3 Effects on Other Geothermal Phenomena

Since ancient or pre-historic times, natural geothermal anomalies have created sites that people use for special religious and recreational purposes. The extraction of geothermal fluids to generate electric power can affect natural geothermal phenomena such as geysers, fumaroles, boiling mud holes, and hot springs.

Geothermal exploration is not allowed near Yellowstone National Park in the northwestern corner of Wyoming due to concern that discovery and eventual exploitation of such discovery could decrease the natural geothermal phenomena that are the single most important attraction of the park. In Japan, most of the potential geothermal energy resources of the country are near natural geothermal phenomena that have provided settings for religious and recreational sites and national parks. As a result, although Japan possesses a large geothermal energy resource base, the country has developed very little of that base.

New Zealand provides examples of the disappearance or decrease of some natural geothermal phenomena and the appearance of new phenomena at sites that previously did not display such phenomena, including boiling mud pots, hot pools, fumaroles, etc. (but not geysers). Geysers have disappeared or been threatened by both electric power development and expanded domestic and recreational development of geothermal resources. Near the geothermal resort city of Rotorua in New Zealand, government action to require and enforce closure of many small privately owned geothermal wells used for domestic heat and recreation led to the restoration of the full natural performance of a geyser that had declined and was trending toward extinction. At the Wairakei geothermal field, which began producing more than 100 MWe in 1958, electric power generation from the reservoir led to the disappearance of a geyser and other phenomena at one site and the appearance of geothermal phenomena at another site. After 40 years, the valley continues to be the site of hot springs, hot pools, boiling mud pots, and fumaroles.

It should be noted that geothermal phenomena are subject to natural change. They appear, function for a time and then disappear, all due to purely natural causes without any human-related disturbance. Some such natural changes occur relatively quickly, over periods of years or decades, while others—especially hot or warm springs, though probably not geysers—have lasted hundreds or even thousands of years.

6.6.4 Emissions

The environmental impacts of generating electricity from geothermal resources are benign relative to conventional power generation options. Geothermal power generation does not produce the federally-regulated air contaminants commonly associated with other power generation, such as sulfur dioxide, particulates, carbon monoxide, hydrocarbons, and photochemical oxidants. Some hydrothermal fluids contain hydrogen sulfide and/or high levels of dissolved solids such as sodium chloride (salt). Hydrogen sulfide emissions are abated, when necessary, with environmental control technology. Emissions factors are typically in the range of 45 kg/MWh for carbon dioxide and 0.0145 kg/MWh for hydrogen sulfide. Hydrogen sulfide is now routinely abated at geothermal power plants, resulting in the conversion of over 99.9 percent of the hydrogen sulfide from geothermal noncondensable gases into elemental sulfur, which can be made into non-hazardous fertilizer feedstock. Since 1976 hydrogen sulfide emissions have declined from 1,900 lbs/hr to 200 lbs/hr or less, while at the same time the geothermal power production has increased from 500 MW to over 2,500 MW. Another hazardous element found in a few geothermal plants is mercury. Although mercury is not present in each geothermal resource, where it is present, mercury capture equipment typically reduces emissions by 90 percent or more. The comparatively “highest” mercury emitters, two facilities at The Geysers in California, release mercury at levels that do not trigger any health risk analyses under California regulations.

The visible plumes seen rising from some geothermal power plants are in fact water vapor (steam). A case study by GEA [27] showed that a coal plant updated with scrubbers and other emissions control technologies emits 24 times more carbon dioxide, 10,837 times more sulfur dioxide, and 3,865 times more nitrous oxides per megawatt hour than a geothermal plant. Averages of four significant pollutants, emitted by geothermal and coal facilities, are presented in Table 6-13 below. Following the table is a brief discussion of other emissions that have sometimes been associated with geothermal development. Issues revolving around groundwater

contamination are avoided through protective well completion practices. The geothermal industry has developed various methods to mitigate chemical emission concerns.

Table 6-13
Averages of Four Significant Pollutants, as Emitted from Geothermal and Coal Facilities, Are Listed in the Table Below (source: GEA 2005 [27]).

Emission	Nitrogen Oxides (NOx)	Sulfur Dioxide (SO_2)*	Particulate Matter (PM)	Carbon Dioxide (CO_2)
Geothermal emissions (lb/MWh)	0	0 - 0.35	0	0 - 60
Coal emissions (lb/MWh)	4.31	10.39	2.23	2191
Emissions Offset by Geothermal Use (per yr)	32 thousand tons	78 thousand tons	17 thousand tons	16 million tons

* While geothermal plants do not emit sulfur dioxide directly, once hydrogen sulfide is released as a gas into the atmosphere, it eventually changes into sulfur dioxide and sulfuric acid. Therefore, any sulfur dioxide emissions associated with geothermal energy derive from hydrogen sulfide emissions.

Generally, there is less likelihood of adverse environmental impacts from binary-cycle generation than from flash steam generation because the hotter geothermal fluids (steam and water) used in flash plants tend to contain greater concentrations of chemical contaminants than do the cooler geothermal fluids (water) typically used in binary plants. In general, hotter water will dissolve more mineral from a rock formation than will cooler water. Also, in binary plants that employ dry, rather than wet, cooling systems, the geothermal fluid remains in a closed system and is never exposed to the atmosphere before it is injected back into the reservoir. The potential environmental impact of a HDR binary system is likely to be even lower. This is because the water used in such a system originates from a shallow groundwater well or other source with low levels of dissolved solids and no hydrogen sulfide to begin with, and because the limited contact time of the injected surface water with the hot rock will in most cases limit the level of dissolved mineral (including dissolved gas) to below that of chemical equilibrium.

In some situations, geothermal operations offer novel benefits to the environment. For example, operators of The Geysers complex in northern California are injecting treated municipal wastewater into underground steam-generating reservoirs whose natural stores are being depleted. This technique helps meet the generation facility's resource challenges in addition to mitigating the waste disposal problems of nearby communities.

6.6.5 Thermal Discharge

Geothermal power plants are intrinsically less efficient than fossil-fuel-fired power plants. This is because high-temperature steam can be converted into work at higher thermal efficiency than low temperature steam. Temperatures of steam produced in fossil fuel boilers are in the range of 800-1000°F (400 to 500°C), much higher than the 300-600°F (150-300°C) of geothermal steam and hot water. Less heat converted to work and electricity means more heat "wasted" and subject

to discharge into the environment. Fossil fuel steam plants have thermal efficiencies in the 32% to 38% range, nuclear plants close to 30% to 32%, and geothermal plants as low as 5% to 17%.

For this reason, geothermal power plants have very large cooling systems relative to the power generator. The Ohaaki Power Station in New Zealand installed a natural-draft cooling tower, one that appears comparable to those seen at nuclear power plants or at some of the larger fossil fuel power plants located on U.S. rivers (Figure 6-6). The reason for the cooling tower at Ohaaki is the same as that at U.S. nuclear or fossil plants: to avoid the discharge of relatively large amounts of waste heat into a stream, river, or estuary of limited capacity and the resulting increasing in water temperature.

6.7 Design, Deployment, and O&M Issues

Many geothermal developers acquire the rights to a geothermal resource and rely on service companies for exploration, drilling, well testing, reservoir engineering, and power plant design and construction. However, most developers handle their own power plant operation.

For domestic power projects, coated corrosion-resistant pipe and heat exchangers are typically obtained from U.S. manufacturers. However, virtually all steam turbines are purchased from Japanese manufacturers. A few U.S. companies manufacture their own small binary and hybrid power plant equipment. One important developer, Ormat, is the U.S. arm of an Israeli company that uses the Israeli Ormat assembled, skid-mounted, and modular equipment.

Most of the necessary drilling and well testing equipment is adapted from the oil and gas industry. However, some of this equipment has been specifically refined for the hotter and more corrosive environments of geothermal drilling. While DOE's geothermal research and development program is working on geothermal-specific improvements to some power plant equipment, in general, the pipe, heat exchangers, turbines, and cooling towers come from the fossil fuel power plant industry.

Technology is expected to improve incrementally over the coming years. Industry is working with DOE's geothermal R&D program to improve exploration, drilling, reservoir engineering, and energy conversion technology. R&D success in fracture detection and fracture permeability studies could give the industry important new tools to improve geothermal exploration and reservoir engineering effectiveness, and also drive down project costs. As discussed above under EGS, these fracture and permeability enhancements of natural hydrothermal hot water reservoirs could be the start of commercial activity in the so-called "hot dry rock" geothermal systems. Better materials and coatings for power plant equipment are being researched to reduce the high maintenance costs. On the energy conversion front, R&D also continues on binary geothermal systems that use a secondary working fluid to produce energy from the more abundant moderate- to low-temperature geothermal resources.

6.7.1 Industry Trends

Since the 1990s, there has been relatively little domestic geothermal development. Near the end of the 1990s, many U.S. geothermal power plants began falling over the "PURPA cliff," when plants entering their 11th year of operation began receiving a much lower price for their energy output. This drove owners and operators to find ways to cut O&M costs markedly, mainly through staff reductions. Until recently, the general employment rate for U.S. geothermal power plants was about one full-time equivalent staff per megawatt of capacity—approximately three to five times the rate for coal plants.

The late 1990s saw much of the U.S.-led geothermal development in Asia suddenly slow down and, in some cases, halt. The Indonesian government, in particular, canceled a number of geothermal power sales agreements, including some for plants that had just been completed. The main problem cited was a lack of hard currency with which to pay back equity investors and lenders. By mid-1998, most of the U.S. geothermal industry's exploration and development activity was focused on Central America. Investors believe that Indonesia could re-emerge as a key market within a few years.

Domestically, California will remain the primary market for geothermal energy. The state's recent problems with implementing deregulation make predicting future trends difficult. Social and policy issues such as the potential size of green energy markets and the application of renewable portfolio standards and trading credits will also impact the development of geothermal resources both within and outside of California. In 2005, the California Energy Commission made R & D funds available for projects furthering geothermal development and innovative ideas.

The primary world market for U.S. geothermal electric project development services will remain Asia, especially the Philippines and Indonesia. In those countries, under-served demand together with high-quality hydrothermal resources will drive continued geothermal development, although local economic perturbations may delay it. U.S. firms will continue to develop modest projects in Central America, where they will face competition from Mexican developers. New Zealand, Italy, and Japan will also remain formidable competitors of U.S. companies for providing goods and services in worldwide geothermal markets.

6.7.2 Research Needs and Recommendations

While geothermal is considered a mature technology, there are many opportunities for improvement through research and development. Geothermal projects are very capital intensive. Discussions with industry leaders suggest that that future geothermal R&D programs should focus on reducing the cost of finding and developing new geothermal resources.

The industry consensus is that characterizing the commercial potential of identified geothermal reservoirs is a high priority. Techniques such as fracture mapping, more accurate thermal-gradient wells, and other, untested methods should be evaluated and refined, if appropriate. The objective is to be able to measure the temperature, fluid characteristics, and permeability of the resource prior to committing to expensive production wells and generation equipment.

Industry comments suggest that structured, integrated tests and experiments by industry in collaboration with the California Energy Commission and DOE are essential to ensure further development of commercial geothermal power. In the near term, this work should focus on the following areas:

- Reducing life-cycle costs of electrical power generation
- Improving geothermal facility efficiencies
- Finding techniques to more cost-effectively define resources
- Supporting funding to reduce production drilling costs and develop direct-use demonstration and commercial projects
- Improving technology and technical support for geothermal direct-use projects
- Reducing geothermal heat pump (GHP) initial costs
- Improving professional training and consumer education campaigns for GHP
- Supporting financing programs for residential applications for GHP
- Understanding and improving wastewater injection
- Improving public awareness about the benefits of geothermal power, direct-use, and GHP.

6.8 Equipment Markets and Key Participants

Table 6-6 in Section 6.4.1 provided a technology monitoring guide of the leading developers and technical issues in geothermal power generation. Included in the table is a detailed list of government organizations, nonprofit organizations, industrial firms, and leading vendors working in geothermal energy field.

In addition to the vendors and organizations listed in the monitoring guide, the reader is referred to the following Internet websites. Note that while these sites contain information and contacts that may be of interest, EPRI cannot vouch for the accuracy or quality of all of their content.

DOE Geothermal Energy Program
The DOE administers its geothermal energy efforts through its Energy Efficiency and Renewable Energy Network.

www.eere.energy.gov/geothermal

NREL Geothermal Technologies Program
This National Renewable Energy Laboratory program supports activities of DOE's Geothermal Energy Program and works with DOE and industry partners in geothermal R&D efforts.

www.nrel.gov/geothermal/

Sandia Geothermal Research Department
Sandia National Laboratory hosts a Geothermal Research Department focused on developing well construction technologies to reduce the cost of geothermal wells. Hard rock drill bit technology, high-temperature instrumentation, rig instrumentation, and data management are among the projects it pursues.

www.sandia.gov/geothermal/

Idaho National Engineering and Environmental Laboratory
This laboratory's Geothermal Energy website serves as a repository for some DOE technical data related to geothermal energy, including maps and graphics, information about U.S. laws and standards, annual research program summaries, proposal solicitations, and other information.

http://geothermal.id.doe.gov/

Stanford University Geothermal Program
Stanford's geothermal program has conducted geothermal reservoir engineering research for more than 20 years, completing some 150 projects. Study areas have included well test analysis of fractured and multiphase reservoirs, design and interpretation of tracer tests in fractured reservoirs, experimental measurements of fluid flow parameters, and optimization of production and reinjection strategies.

http://ekofisk.stanford.edu/geotherm.html

Southern Methodist University
SMU has the most up-to-date data currently available for resource assessment based on the 1978 USGS data and other information collected since then.

www.smu.edu/geothermal/georesou/georesourcesmap.htm

Geocrack
This website provides information on the computer modeling of fluid flow in geothermal reservoirs, including technical papers, progress reports, and downloadable software.

www.mne.ksu.edu/~geocrack/

European Deep Geothermal Energy Programme
This website describes a hot dry rock research program funded by a consortium of European government, research, and utility organizations in Soultz-sous-Forêts, France. The multiyear project aims to develop a scientific pilot plant by 2006 and a subsequent commercial plant that could produce approximately 25 MW.

www.soultz.net

Geothermal Energy Association
GEA is a trade association composed of U.S. companies that support the expanded use of geothermal energy and are developing geothermal resources worldwide for both electric power generation and direct-heat uses.

www.geo-energy.org

Geothermal Resources Council
The GRC is a nonprofit educational association formed in 1970 to encourage geothermal research and development, and to serve as an informational conduit among researchers, industry, and the public.

www.geothermal.org

International Geothermal Association
Based in Italy with members in 63 nations, IGA's objective is to encourage research, development, and utilization of geothermal resources worldwide by compiling, publishing, and disseminating scientific and technical information.

http://iga.igg.cnr.it/index.php

Center for Renewable Energy and Sustainable Technology
The Center for Renewable and Sustainable Technology provides excellent background information and extensive links to other websites.

www.crest.org/geothermal/index.html

Calpine Corp.
Founded in 1984, Calpine operates The Geysers in northern California and is the largest producer of geothermal electricity in the world.

www.calpine.com

Unocal Geothermal
Unocal operates three of the world's largest geothermal electricity projects, Tiwi and Mak-Ban in the Philippines and Gunung Salek in Indonesia, which together have a combined installed generating capacity of 1,100 MW.

www.unocal.com/geopower

The World Bank

The World Bank provides a source of financial and technical cost data for geothermal development in countries around the world.

http://www.worldbank.org/html/fpd/energy/geothermal/assessment.htm#economic

GeothermalBiz.com

Geothermal Biz website provide general information on state government agencies, for example state energy offices, relevant legislation, e.g., for renewable portfolio standards (RPS) and public benefits funds. Also included is information on state, local, and utility incentives that promote geothermal energy such as tax incentives, grants, loans, rebates, and utility green pricing programs.

http://www.geothermal-biz.com

6.9 References

1. *Renewable Energy Annual 2003*. Contains data for 2002 and is also available on the web at http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/rea_sum.html, EIA, Washington, D.C.: December 2004. DOE/EIA-0603(99).

2. G. Huttrer, "The Status of World Geothermal Power 1995-2000." A paper prepared for the World Geothermal Conference and the DOE Geothermal Power Program, as an update of the 1995 status report on geothermal power deployment, based on the "Country Update" papers submitted to the World Geothermal Conference held in Japan, May-June 2000. Paper prepared by Gerald W. Huttrer of Geothermal Management Co., Frisco, Colorado: May 2000.

3. *Market Assessment of Renewable Energy in California*, EPRI report to the California Energy Commission, EPRI, Palo Alto, California: July 2001. 1001193.

4. Duffield, W.A., Sass, J.H., and Sorey, M.L., "Tapping the Earth's Natural Heat," U.S. Geological Survey Circular 1125, 1994.

5. *Assessment of Geothermal Resources of the U.S.–1978*. Editor: L.J.P. Muffler, USGS Circular 790, 1978.

6. *Geothermal Energy in the Western U.S. and Hawaii: Resources and Projected Electricity Generation Supplies*, EIA: September 1991. DOE/EIA-0544.

7. *Annual Energy Outlook 2005*, EIA: June 2005.

8. *Greenhouse Gas Reduction with Renewables*, EPRI, Palo Alto, California: December 2000. TR-113785.

9. *Economic Predictions for Heat Mining: A Review and Analysis of Hot Dry Rock (HDR) Geothermal Energy Technology*, by Tester, J.W., and H.J. Herzog, Massachusetts Institute of Technology: July 1990.

10. *Renewable Energy Technology Characterizations*, EPRI and DOE, EPRI, Palo Alto, California: December 1997. TR-109496.

11. Brown, D. and Duchane, D., Los Alamos National Laboratory, personal communication to Lynn McLarty (one of the authors of the RETC [10] above), November 5, 1996.

12. "Assessment of Geopressured Energy Resources on the Gulf Coast of the U.S." Report to EPRI by Southwest Research Inst. (San Antonio, TX). EPRI, Palo Alto, California: 1983.

13. Brugman, J., Hattar, M., Nichols, K., and Y. Esaki, *Next Generation Geothermal Power Plants*, EPRI: February 1996. TR-106223.

14. Proceedings of the 10th EPRI Geothermal Conference and Workshop, San Diego, June 1986. EPRI, Palo Alto, California: December 1986. AP-5059-SR.

15. Armstead, H.C.H. and Tester, J.W., *Heat Mining: A New Source of Energy*, E.&F.N. Spon Ltd. University Press, London: 1987.

16. Mason, T.R., "Improving the Competitive Position of Geothermal Energy," Proceedings of Geothermal Program Review XIV, DOE: April 1996. Report DOE/EE-0106.

17. Heber Binary Cycle Geothermal Demonstration Power Plant, EPRI, Palo Alto, California: August 1998. AP-5787-SR. (Note: This was the last in a series of several reports published by EPRI during the development and implementation of the Heber Project between 1978 and 1988.)

18. Los Alamos National Laboratory. "Proceedings of the 3rd International Hot Dry Rock Energy Forum," Santa Fe, New Mexico: May 13-16, 1996.

19. *EPRI Technical Assessment Guide Electricity Supply Volume 1, Rev. 7*, EPRI, Palo Alto, California: June 1993. TR-102275-V1R7.

20. Annual Energy Outlook 1996, EIA: August 1996. DOE/EIA-0603(96).

21. Entingh, D.J., *Technology Evolution Rationale for Technology Characterizations of U.S. Geothermal Hydrothermal Electric Systems*, BNF Technologies Inc., Alexandria, Virginia, Draft Report: March 1993.

22. *Renewable Power Industry Status Overview*, EPRI, Palo Alto, California: December 1998. TR-111893.

23. *Annual Energy Outlook 1998 with Projections Through 2020,* EIA, Office of Integrated Analysis and Forecasting, Washington, D.C. 20585: December 1997. DOE/EIA-0383 (98), Distribution Category UC-950.

24. *Annual Energy Outlook 2002 with Projections Through 2020,* EIA, Office of Integrated Analysis and Forecasting, Washington, D.C. 20585: December 2001.

25. Hunt, Trevor, geophysical and geothermal consultant in Taupo, New Zealand. Personal communication to Evan Hughes, October 2003.

26. *Radon as an In Situ Tracer in Geothermal Reservoirs*, Project 1992-1, Final Report to EPRI by Professor Paul Kruger of Stanford University: August 1987. EPRI AP-5315.

27. A Guide to Geothermal Energy and the Environment, Geothermal Energy Association by Alyssa Kagel, Diana Bates, and Karl Gawell, Earth Day 2005.

28. World Geothermal Generation 2001-2005 State of the Art by R. Bertani, 2005. Prepared for World Geothermal Congress 2005 Turkey.

29. Classification of Geothermal Systems – A Possible Scheme by Subir K. Sanyal, 2005. Prepared for Thirtieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California: January 31-February 2, 2005. SGP-TR-176.

30. Cost of Geothermal Power and Factors that Affect It by Subir K. Sanyal, 2005. Prepared for Thirtieth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California: January 26-January 28, 2005. SGP-TR-175.

31. Geothermal Bulletin Volume 33 Number 3, June 2004. Geothermal Resource Council.

32. New Study Highlights Geothermal Resources Available for Development in California and Nevada by Jim Lovekin, December 2004. GRC Bulletin p. 242.

33. New Geothermal Site Identification and Qualification: April 2004. CEC Publication No. P500-04-051,

7
SOLAR THERMAL

7.1 Introduction

Solar thermal electric power technology has received substantial development attention since the early 1970s. Government energy research programs in the developed countries have invested several billions of dollars (U.S. equivalent) over the past three decades aimed at its advancement and commercial introduction. U.S. development efforts were particularly strong during the 1980s, and resulted in deployment of a significant amount of experimental and commercial hardware during that decade.

Attention subsided in the 1990s, primarily because conventional energy prices seemed to stabilize at affordable levels. Also, primary interest in the solar power community shifted from large-scale wholesale power to smaller-scale retail power, due in part to the emerging electric sector restructuring movement. Key elements of that movement included increased emphasis on dispersed, distributed generation and retail competition for electricity supply. In addition, development issues had surfaced for the solar thermal options, and the resources to resolve those issues were not forthcoming because of the market's proclivities at the time. Nonetheless, several major field deployment and advancement activities were carried out in the 1990s, resulting in important new contributions that enhanced the prospects for these technologies.

The new century found the restructuring movement slowing and industry interest in central-station power plants increasing, driven by looming capacity shortfalls. Together with growing public interest in renewable energy, fueled by renewed concerns over energy prices and security, these trends seem to have put solar thermal electric generation back into serious consideration. In the past few years, there have been indications that the time has come for significant new investments in these technologies with construction of several hundred-megawatt-scale generation plants on the drawing boards.

7.1.1 Solar Thermal Technologies

There are three common types of solar thermal power systems: parabolic trough, central receiver or power tower, and dish/engine. Because these technologies all involve a heat-driven engine, they can be readily hybridized with fossil fuel and in some cases adapted to use thermal storage. The primary advantage of hybridization and thermal storage is that the technologies can provide dispatchable power and operate during periods when solar energy is not sufficient. Thus, hybridization and thermal storage can enhance the economic value of the electricity produced.

Parabolic trough systems use banks of trough-shaped mirrors with a parabolic cross-section to focus sunlight on highly absorbing receiver tubes that contain a heat-transfer fluid (HTF). This fluid, typically a synthetic oil, is heated and pumped through a series of heat exchangers to produce superheated steam that powers a conventional turbine generator to produce electricity. Nine trough systems, built in 1984 to 1990, are generating 354 MW in southern California. These 14- to 80-MW systems are hybridized to derive up to 25% of their output from natural-gas firing and provide dispatchable power independent of the solar energy available.

Central receiver systems, also referred to as power towers, use a field array of large mirrors called "heliostats" that track the sun and focus its light onto a central receiver mounted on top of a tower. The first central receiver in the United States, Solar One, was installed in southern California and operated in the mid-1980s. It used water as HTF and generated steam directly to power a 10-MW steam turbine. In 1992, a consortium of U.S. utilities, DOE, and EPRI formed to retrofit Solar One and demonstrate a system, aptly named Solar Two, that incorporated molten salt as the HTF and energy storage medium. In this system, molten salt was pumped from a "cold" tank and cycled through the receiver, where it was heated and returned to a "hot" tank. The hot salt could then be used to generate electricity when needed. Current designs allow storage times ranging from 3 to 13 hours. Such thermal storage capability makes central receivers the most flexible of solar technologies, promising dispatchable power with load factors of up to 65%—in principle, even 100%. Solar Two operated from April 1996 to April 1999.

Dish/engine systems use an array of mirrors made from stretched membranes or flat glass facets to form a parabolic dish that focuses solar energy onto a receiver located at the focal point of the dish. A HTF, typically helium or hydrogen, is heated in the receiver tube and used to generate electricity in a small engine attached directly to the receiver. Current designs employ a Stirling engine, but future designs could use Brayton-cycle (turbine) engines or dense arrays of high-efficiency photovoltaic cells.

Long-term cost projections for trough technology are higher than those for power towers and dish/engine systems due in large part to the lower solar concentration involved, which results in lower temperatures and efficiency. However, with 15 to 20 years of operating experience, continued technology improvements, and O&M cost reductions, troughs are likely to be the least expensive, most reliable solar thermal electric technology for near-term deployment.

This section of the Renewable Energy Technical Assessment Guide addresses solar resource assessment, technology overview and status for utility-scale solar thermal electric applications. It also discusses likely development pathways, performance and cost history and projections, operating and maintenance labor requirements, environmental issues, and potential for greenhouse gas reduction.

7.2 Resources

The solar energy resource at a given location is characterized by the solar radiation per unit area (or "insolation") expressed in units of kilowatt-hours or megajoules per square meter per year (kWh/m^2/yr or MJ/m^2/yr). The insolation reaching the Earth's surface varies with latitude, altitude, time of day, and season, as well as with local weather and atmospheric conditions arising from natural particulates or air pollution. The sunlight's path through the atmosphere is effectively lengthened or shortened by all of these factors.

As light passes through the atmosphere, some is reflected, some is absorbed, and some is scattered. Because of these losses, the amount of energy that actually reaches the Earth never exceeds about 70% of that present outside our atmosphere. Lower latitude regions in the southern U.S., and especially those with dry climates in the Southwest, typically exhibit the highest average insolation in the country.

Insolation reaches a solar collector either directly ("direct-normal radiation"), after being scattered ("diffuse radiation"), or after being reflected from the ground. These are important distinctions because all solar thermal designs employ optical concentration and can use only direct-normal solar radiation.

Figure 7-1 shows the distribution of direct-normal insolation in the U.S. Direct-normal insolation is most abundant in the Southwest, and the largest regions of highest-quality resource are in Nevada, Arizona, California, and New Mexico. Average insolation values for a given location, such as those shown in Figure 7-1, are adequate for rough calculations, but to accurately predict the output and, therefore, the energy cost of a solar thermal system, measurements should be taken over the course of at least one year at a potential power plant location.

To assess the potential solar resource overall, it is important to know the geographic regions where insolation is generally high, but the truly available resource is also constrained by both land topology and prior claims on it for other purposes. CSP plants cannot be easily built in the mountains and they would be unwelcome in many places such as national parks, military reservations, and urban areas. An NREL study used GIS screening techniques to identify the land comprising the premium sites suitable for CSP power plant deployment in the U.S. southwest. [11] The study began with all land having over 6.75 kWh/square meter of average insolation and filtered out unsuitable areas using the following criteria: military bases with a one-mile buffer; national wilderness areas with a five-mile buffer; Fish and Wildlife Service land with a one-mile buffer; National Park Service land with a five-mile buffer; National Forest Service land; cropland; major highways with a half-mile buffer; navigable waterways with a half-mile buffer; lakes with a two-mile buffer; major urbanized areas with four-mile buffer; railroads with a 500-foot buffer; and locations 9,000 feet above sea level with a 4.5-mile buffer around each point. The study concluded that using only 3% of the land area that remained after filtering could provide over one million GWh of CSP-generated electricity annually.

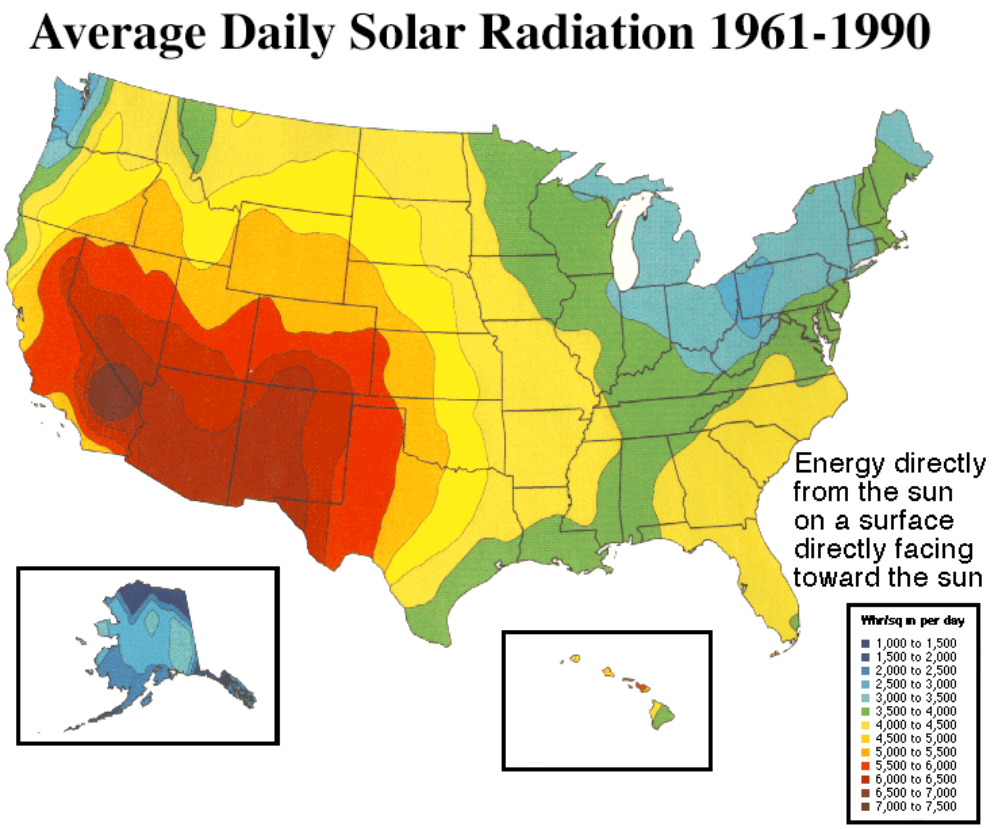


Figure 7-1
Distribution of Direct-Normal Insolation in the U.S. (Wh/m²/day)
(Source: U.S. DOE)

7.3 Technology Description

To date, the parabolic trough is the only solar thermal technology that has achieved commercial operation at significant scale. Some 354 MW of trough solar-electric systems, hybridized to use natural gas firing for up to 25% of the necessary heat input, have been operating in southern California since 1990.

The first large-scale test of the central receiver system was the 10-MWe Solar One project at Daggett, California, in the early 1980s, which used a steam-generating central receiver. Nine utilities, the U.S. Department of Energy (DOE), and EPRI conducted a second demonstration, Solar Two, at the same site, using molten-salt central-receiver technology. Startup operation began in April 1996, and the project was completed in April 1999. As of mid 2006, there are no currently operating MW-scale central-receiver plants, but there are several projects contemplated for installation in Spain, South Africa, and elsewhere. Also, the 11-MW “Planta Solar 10”, under construction in Spain since 2004, was scheduled to begin operation by late 2006.

The leading parabolic dish technology currently in the U.S. is by Stirling Energy Systems (SES), which is working with Sandia National Laboratory on a 6-dish 150-kW demonstration near Albuquerque NM preparatory to building a 40-dish 1-MW pilot facility in California. The pilot plant is to be the first phase of a program to build a 20,000-dish 500-MW plant to supply solar power to Southern California Edison under a power purchase agreement.

7.3.1 Parabolic Trough

Installed Capacity (est.)	360 MW worldwide 354 MW in U.S.
Technology Readiness	Early commercial Moderate confidence in cost estimates and technology projections
Environmental Impact	Minimal during manufacturing Minimal in operation
Economic Status	Competitive in some markets Currently the most economical solar electric technology No significant new systems built since 1980s; some manufacturing capability and experience has been lost, though new projects are underway
Policy Status	Along with other solar technologies, encouraged by RPS and energy policies in most jurisdictions
Trends to Watch	Hybrid operation and thermal storage New solar trough projects in Arizona, Nevada, Spain, Algeria, Italy, and elsewhere New materials and techniques to reduce manufacturing and O&M costs

Parabolic trough technology is currently the most proven solar thermal electric technology. This is primarily due to nine commercial-scale solar power plants, the oldest of which has been operating in the California Mojave Desert since 1984. These plants, which continue in daily operation, range from 14 to 80 MW nameplate capacity, for a total of 354 MW. At these facilities, large fields of parabolic trough collectors supply at least 75% of the annual thermal energy used to produce steam for a Rankine steam turbine/generator cycle.

A collector field consists of about 1,000 single-axis tracking parabolic-trough solar collectors, each with an area of 100 m^2 to 500 m^2 (see Figure 7-2). The solar field is highly modular, comprising many parallel rows of solar collectors aligned on a north-south axis. Each collector has a linear parabolic-shaped reflector that focuses the sun's direct-beam radiation onto a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the day to ensure that sunlight is continuously focused on the receiver.



Figure 7-2
Solar Trough Collector Field at Kramer Junction, California. Note the receiver tube at the reflectors' focal point that transports heat-transfer fluid.

The sun heats the HTF from about 560 F (290 C) to 735 F (390 C) as it circulates through the receiver tube. The HTF then returns to a series of heat exchangers in the power block, where it is used to generate high-pressure superheated steam at 1,450 psia (10 MPa) and 700 F (370 C). The superheated steam is then fed to a conventional reheat steam turbine/generator to produce electricity. Spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps to be transformed back into steam. Condenser cooling is provided by mechanical draft wet cooling towers. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field.

Historically, parabolic trough plants use solar energy as the primary energy source to produce electricity. Given sufficient solar input, such plants can operate at full rated power using solar energy alone. During summer months, the plants typically operate for 10 to 12 hours a day at full rated electric output. However, all plants built to date have been solar/fossil hybrids, meaning that they have a backup fossil-fired capability that can be used to supplement solar output during periods of low solar radiation. Thermal storage is another strategy that can provide dispatchability without a fossil-fuel backup system.

The solar collector field provides maximum solar output in June when the sun is highest. The gas-fired heater is typically used to extend operation to late afternoon and early evening hours during the summer peak period and to augment the solar collector field during cloudy periods. Although the gas-fired heater is physically capable of more extended use, power plants operated as qualifying facilities (QF) under PURPA are limited to generating 25% of total energy from gas. Utility-owned plants are not subject to the same limitation on gas use at the present time. The California plants' principals—formerly including Sunray Energy, the Kramer Junction Co., KJC Operating Co., and FPL Energy, but now principally FPL Energy—benefit from federal and state investment incentives, solar property tax exclusion, and accelerated depreciation intended to encourage solar projects.

7.3.2 Central Receiver

Installed Capacity (est.)	Currently <1 MW worldwide (PS-10, scheduled to operate by late 2006, will be 11 MW)
Technology Readiness	Early demonstration Moderate-low confidence in cost estimates and technology projections
Environmental Impact	Minimal during manufacturing and operation Most modern designs use steam, oil, or molten salt for heat transfer and storage; which are easily contained if spilled
Economic Status	Unlikely to be competitive in near future without substantial further development Long-term performance remains to be demonstrated, with significant uncertainty about component and O&M costs
Policy Status	Along with other solar technologies, encouraged by RPS and energy policies in most jurisdictions
Trends to Watch	Potentially large projects in Europe and South Africa Thermal storage to allow dispatchable solar power

Solar central receiver plants use hundreds to thousands of sun-tracking mirrors called heliostats to focus concentrated solar radiation on a tower-mounted heat exchanger (receiver). Because they perform better at larger sizes, these plants are best suited for utility-scale applications of many tens to a few hundreds of megawatts.

The heliostat field surrounding the tower is laid out to optimize the annual performance of the plant. In a typical installation, solar energy collection occurs at a rate that exceeds the maximum required to provide steam to the turbine. Consequently, a thermal storage system can be charged at the same time that the plant is producing power at full capacity. Without energy storage or fossil-fuel hybridization, solar technologies are limited to annual capacity factors of less than approximately 30%. However, with storage capability, a central receiver could potentially operate all of the time without a backup fuel source. The Solar Two project actually demonstrated such 24-hour operation.

Although central receivers are commercially less mature than parabolic trough systems, several component and experimental systems have been field tested around the world in the last 25 years to demonstrate the engineering feasibility and economic potential of the technology. Table 7-1 lists these experiments along with some of their more important characteristics. These experimental facilities were built to show that solar central receivers can produce electricity and to test and improve individual system components.

Table 7-1
Central Receiver Demonstration Projects

Project	Country	Power Output (MWe)	Heat Transfer Fluid	Storage Medium	Operation Began
SSPS	Spain	0.5	Liquid Sodium	Sodium	1981
EURELIOS	Italy	1	Steam	Nitrate Salt/Water	1981
SUNSHINE	Japan	1	Steam	Nitrate Salt/Water	1981
Solar One	USA	10	Steam	Oil/Rock	1982
CESA-1	Spain	1	Steam	Nitrate Salt	1983
MSEE/Cat B	USA	1	Molten Nitrate	Nitrate Salt	1984
THEMIS	France	2.5	Hi-Tec Salt	Hi-Tec Salt	1984
SPP-5	Russia	5	Steam	Water/Steam	1986
TSA	Spain	1	Air	Ceramic	1993
Solar Two	USA	10	Molten Nitrate Salt	Nitrate Salt	1996
Solar Tres	Spain	15	Molten Nitrate Salt	Nitrate Salt	uncertain

Solar One, which operated from 1982 to 1988, was then the world's largest central receiver plant. It proved that large-scale central-receiver power production was feasible. In that plant, water was converted to steam in the receiver and used directly to power a conventional Rankine-cycle steam turbine. The thermal storage system stored heat from solar-produced steam in a tank filled with rocks and sand, using oil as the heat-transfer fluid. The storage system extended the plant's power-generation capability into the night and provided heat for generating low-grade steam for keeping parts of the plant warm during off-hours and for morning startup. Unfortunately, the storage system was complex and thermodynamically inefficient. While Solar One successfully demonstrated central receiver technology, it also revealed the disadvantages of a water/steam system, such as intermittent turbine operation due to short-term cloud cover and lack of effective thermal storage.

During the operation of Solar One, research began on a more advanced molten-salt central receiver design that would store energy more efficiently. This led to the Solar Two project (Figure 7-3). In the Solar Two power tower, liquid salt at 550 F (290 C) was pumped from a "cold" storage tank through the receiver, where it was heated to 1,050 F (570 C), then on to a "hot" tank for storage. When power was needed from the plant, hot salt was pumped to a steam

generating system that produced superheated steam for a conventional Rankine-cycle turbine/generator system. From the steam generator, the salt was returned to the cold tank, where it was stored and eventually reheated in the receiver. Determining the optimum storage size to meet power-dispatch requirements was an important part of the system design process. The Solar Tres project, which was originally targeted to begin in 2003 but has been delayed by funding and project development difficulties, will attempt to demonstrate sufficient energy storage capacity to power a turbine at full output for an average of 13 hours per day



Figure 7-3
Solar Two Central Receiver in Operation. The two tanks to the left of the tower base are the storage tanks for the hot and cold molten salt solutions.

The Solar Two storage medium was a 60/40 mixture of sodium nitrate and potassium nitrate, which melts at 428 F (220 C). It was maintained in a molten state at 554 F (290 C) in the "cold" storage tank. Molten salt can be difficult to contain and transport because it has a low viscosity (similar to water) and it wets metal surfaces extremely well. An important consideration in successfully implementing this technology is identifying pumps, valves, valve packing, and gasket materials that will work with molten salt. Accordingly, Solar Two was designed with a minimum number of gasketed flanges, while most instrument transducers, valves, and fittings were welded in place. Designers specified stainless steel for all pipes, valves, and vessels because of its corrosion resistance in the molten-salt environment. In addition, the design must allow the receiver to rapidly change temperature—during cloud passage, for example—without being damaged. The Solar Two receiver could safely change from 554 F to 1058 F (290 C to 570 C) in less than one minute.

The developers of Solar Two envisioned the project primarily as a demonstration of a complete molten salt central receiver power plant, albeit at a less than commercial scale. In reality, the program was more a development effort than a demonstration effort. Operators used many of the program's resources to improve system components and devise solutions for problems that arose. The result is that Solar Two was quite successful as a development program. Much was learned and documented that should substantially reduce the technical risks associated with future molten salt central receiver plants.

Solar Two's major contributions toward resolving key issues included:

- It clearly demonstrated that a solar central receiver can operate as a dispatchable power plant as part of a utility generating mix. On several occasions the plant operated for many consecutive days, providing power to the grid during peak load periods even after sundown, and in some cases even through the night. During one such period, the plant operated continuously for 154 hours, although at reduced power because of limited thermal storage capacity.
- Although trace heating was a major unresolved concern at the conclusion of earlier central receiver projects, substantial progress toward resolving this issue was made at Solar Two. (Trace heating is needed to prevent the molten salt from solidifying while the plant is not operating.) After the total rework of the original trace heating system during 1996, the system operated with good reliability through the end of the project. Effective trace heating in the vicinity of bends and unusual shapes such as those present in the receiver piping is still an issue of some concern, but reasonable solutions have been proposed that can be employed in future plants.
- Except for the heliostat field, which had known deficiencies, Solar Two actually achieved design-point efficiencies for all its major subsystems. Of particular importance were the receiver and thermal storage performance parameters. The receiver demonstrated efficiencies in the range of 86% to 88%, and the effective efficiency of the storage subsystem was 99% after taking into account that some of the collected thermal energy is transported quickly to the steam generator. Even if all of the energy were to reside in thermal storage for a 24-hour period before transport to the steam generator, efficiency would have been about 97%.
- Storage performance is highly significant. That subsystem worked under normal operating conditions for essentially three years, and was particularly well characterized. It clearly demonstrated the ability to store energy for several days with minimal losses. In addition, post-experiment examination of the tanks (carbon-steel for the low-temperature tank and stainless steel for the high-temperature tank) showed little evidence of corrosion, which suggests not only excellent performance but also long service life for molten-salt storage systems. No other renewable energy generation option can offer storage with performance approaching this level. In addition, the incremental cost of this storage is relatively low, by some estimates, approximately 10% of the total plant cost assuming five hours of storage.

Project funding limitations, coupled with concerns about the condition of the heliostat field, prevented the operation of Solar Two for another year or two. This is unfortunate, because a number of equipment and operating strategy issues had been resolved during the project, and it may have been possible to obtain operating experience under conditions characteristic of commercial operation. Data on annual operating efficiencies obtained under such conditions

could have been adjusted to account for known deficiencies in the plant such as turbine generator limitations and heliostat field condition.

In addition to annual energy production potential, several other key technical issues remain unresolved and cause risk levels to remain high. These include:

- Long thermal time constants still result in limitations on useful energy collection. Morning warm-up periods for the thermal collection and electricity generation subsystems are still measured in hours. Warm-up periods might be reduced by improving warming strategies using stored thermal energy and by increasing plant capacity factors by increasing field size and storage capacity. The effectiveness of such measures remains to be demonstrated in future plants.
- Lifetime and maintenance requirements for molten-salt valves are still uncertain. The Solar Two evaluation team recommended redesigning the salt loop to minimize the use of valves. Another recommendation for future plants was to use pumps with long shafts so that they can be placed on top of the salt tanks.
- Acceptable parasitic power consumption needs to be demonstrated. Substantial related progress was made with Solar Two, but long-term power production is needed to resolve this concern.
- System startup in high winds is still an issue. As with earlier central receiver field tests, the inability to operate during high winds was a significant cause of lost energy at Solar Two.
- Heliostat field availability at Solar Two was less than expected. In contrast, availability for Solar One was very high. While inattention to the entire plant facility between the two projects was likely a major cause for the drop in availability, the issue of long-term heliostat life is still open. It also appears that earlier high hopes for potentially low-cost stretched membrane heliostats have diminished and that for the foreseeable future, plants will rely on glass-metal designs. This has implications for commercial plant costs because the glass-metal designs are more expensive. On the other hand, experience with trough systems demonstrates that glass reflectors perform very well under real-world operating conditions.

7.3.3 Dish/Engine

Installed Capacity (est.)	<1 MW worldwide
Technology Readiness	Early engineering and demonstration Low confidence in cost estimates and development projections
Environmental Impact	Minimal during manufacturing None in operation
Economic Status	May become competitive with success of SES-SCE/SDG&E projects, but risk is evidently high Long-term performance remains to be demonstrated, with great uncertainty about component and O&M costs
Policy Status	Along with other solar technologies, encouraged by RPS and energy policies in most jurisdictions
Trends to Watch	New demonstration projects, particularly under the SES-SCE and SES-SDG&E power purchase agreements announced in August and September 2005 Development of Stirling engines in related industries New materials and techniques to reduce manufacturing and O&M costs

Compared with the other two solar thermal technologies, dish/engine systems are capable of higher efficiency, greater modularity, and more autonomous operation. The high efficiency and modularity of dish/engine systems, if coupled with low-cost manufacturing and operation, would give this technology the potential to be among the least expensive and most versatile sources of renewable energy. The modularity of dish/engine systems allows them to be deployed for remote and distributed applications, as well as in larger arrays. As with the other solar thermal technologies, dish/engine systems can also be hybridized with a fossil fuel to provide dispatchable power. This technology is in the demonstration stage, with several engineering-development issues that need demonstrated solutions before commercial applications are possible.

A major demonstration, planned to lead ultimately to a 500- to 850-MW generating plant, was announced as part of a power-purchase agreement between Stirling Energy Systems and Southern California Edison in early August 2005. A month later, SES and San Diego Gas & Electric announced a similar agreement, this time for 300 to 900 MW. If these proceed as planned, they promise to significantly accelerate dish/engine technology development.

Dish/engine systems employ a parabolic reflector to focus concentrated sunlight onto a receiver located at the focal point of the dish (Figure 7-4). The sunlight heats a working fluid in the receiver tube, which transfers heat to a small engine used to generate electricity. Many thermodynamic cycles and working fluids have been considered for dish/engine systems, but the Stirling and open Brayton (gas turbine) cycles are generally favored. Conventional automotive Otto and Diesel engine cycles are not feasible in this application because of the difficulties in integrating them with concentrated solar energy.



Figure 7-4
25-kW SAIC Dish/Engine System at the DOE Mesa Top Thermal Test Facility. (Source: NREL)

The key components that affect the cost and performance of dish/engine systems are the concentrator, the receiver, and the engine itself. To achieve the high temperatures required to efficiently convert heat to work, the dish must precisely track the sun on two axes.

Concentrators

The size of a dish/engine system's solar concentrator is determined by the heat input requirements of the engine. At a nominal maximum direct-normal solar insolation of 1,000 W/m^2, a 25-kW dish/Stirling system has a concentrator diameter of approximately 10 meters. Concentrators use a reflective surface of aluminum or silver deposited on glass or plastic. The most durable reflective surfaces have been silver/glass mirrors. Because dish concentrators have short focal lengths, relatively thin glass mirrors of approximately 1 mm are required to accommodate the required curvatures. In addition, for rear-surface-reflector mirrors, glass with low iron content helps to reduce absorbance losses in the glass. Depending on the glass thickness and iron content, silvered mirrors have solar reflectance values in the range of 90% to 94%. Although glass mirrors achieve high performance and the technology is well-understood, they drive up the cost of the concentrator. For this reason, ongoing work has centered on developing low-cost reflective elements, such as those based on polymer films and stainless-steel membranes.

Typically, concentrators approximate a paraboloid of rotation by using an array made up of multiple mirrors supported by a truss structure. One innovative solar-concentrator design uses stretched membranes, in which a thin reflective membrane is stretched across a rim or hoop. A second membrane is used to close off the space behind. A partial vacuum is drawn in this space, bringing the reflective membrane into an approximately spherical shape.

A concentrator's optical design and accuracy determine the concentration ratio, defined as the average solar flux through the receiver aperture divided by the ambient direct-normal solar insolation. Typical concentration ratios are over 2,000. The intercept fraction, defined as the fraction of the reflected solar flux that passes through the receiver aperture, is usually greater than 95%.

The receiver absorbs energy reflected by the concentrator and transfers it to the engine's working fluid. The absorbing surface is usually placed behind the focus of the concentrator to reduce the flux intensity incident on it. Stirling and Brayton engines each have their own interface issues. Stirling engine receivers must efficiently transfer concentrated solar energy to a high-pressure oscillating gas, usually helium or hydrogen. In Brayton receivers, the flow must be steady and relatively low pressure.

There are two general types of Stirling receivers: direct-illumination receivers (DIRs) and indirect receivers, which use an intermediate heat-transfer fluid. DIRs adapt the heater tubes of the Stirling engine to absorb the concentrated solar flux. Because of the high heat-transfer capability of high-velocity, high-pressure helium or hydrogen, DIRs are capable of absorbing high levels of solar flux (approximately 75 W/cm^2). However, balancing the temperatures and heat addition between the cylinders of a multiple-cylinder Stirling engine remains an integration issue.

Liquid-metal heat-pipe solar receivers help solve this problem. In a heat-pipe receiver, liquid sodium metal is vaporized on the absorber surface of the receiver and condensed on the Stirling engine's heater tubes. This results in a uniform heater-tube temperature, thereby enabling a higher engine working temperature for a given material, and therefore higher engine efficiency. Longer-life receivers and engine heater heads are also theoretically possible through the use of a heat pipe. Stirling receivers are typically about 90% efficient in transferring energy delivered by the concentrator to the engine.

Solar receivers for dish/Brayton systems are less developed. In addition, the poor heat-transfer coefficients of relatively low-pressure air, combined with the need to minimize pressure drops in the receiver, make receiver design challenging.

Engines

The engine in a dish/engine system converts heat to mechanical power in a manner similar to conventional engines—by compressing a working fluid when it is cold, heating the compressed working fluid, and then expanding it through a turbine or with a piston to produce work. The mechanical power is converted to electrical power by an electric generator or alternator. Electrical output in current dish/engine prototypes using a Stirling engine is about 25 kWe.

The Stirling engine is a leading candidate for dish/engine systems because of its high efficiency and because its characteristic external heating makes it adaptable to concentrated solar flux. The Stirling engines used in solar dish/Stirling systems use hydrogen or helium working gas and operate at high temperatures and pressures, up to 700 C (1,300 F) and 20 MPa (2,900 psia), respectively. In the Stirling cycle, a working gas is alternately heated and cooled by constant-temperature and constant-volume processes. Stirling engines usually incorporate an efficiency-enhancing regenerator that captures heat during constant-volume cooling and replaces it when the gas is heated at constant volume. There are a number of mechanical configurations that implement these constant-temperature and constant-volume processes. Most involve the use of pistons and cylinders. Some use a displacer (a piston that displaces the working gas without changing its volume) to shuttle the working gas back and forth from the hot region to the cold region of the engine. For most engine designs, power is extracted by a rotating crankshaft. An exception is the free-piston configuration, where the pistons are not constrained by crankshafts or other mechanisms. They bounce back and forth on gas springs and the power is extracted from the power piston by a linear alternator or pump. The best Stirling engines today achieve thermal-to-electric conversion efficiencies of about 40%.

The Brayton engine—also called the jet engine, combustion turbine, or gas turbine—is an internal-combustion engine similar to an Otto- or Diesel-cycle engine in that air is compressed, fuel is added, and the mixture is burned. In the Brayton cycle, however, the hot exhaust gases expand through a turbine, rather than against a piston. In a dish/Brayton system, solar heat is used to replace (or supplement) the fuel. As in the Stirling engine, recuperation of waste heat is a key to achieving high efficiency. Therefore, waste heat exhausted from the turbine is used to preheat air from the compressor.

7.4 Technology Status

A critical limiting factor today for further development of solar thermal technologies is that its worldwide industrial base is very small. The progress of the 1980s—most evident with trough systems—was fueled in large part by public policies that encouraged deployment of solar thermal and other renewable technologies. Those policies also enticed new industrial participants into the solar thermal arena. There does appear to be growing legislative backing for such policies recently. Assuming that this trend continues, the extensive existing industrial infrastructure can quickly become engaged in solar thermal technology and business development, as most of the equipment in solar thermal plants consists of glass and metal formed by routine industrial processes.

Table 7-2 is a technology monitoring guide of the leading developers and technical issues in solar thermal power generation. Natural gas hybridization and backup capability as well as thermal storage capability create advantages relative to solar photovoltaic technology. Table 7-3 is a technology process development “map” for solar thermal power generation.

7.4.1 Parabolic Trough

In 1984, Luz International installed Solar Electric Generating System I (SEGS I) in Daggett, California. It originally had an electric capacity of 13.8 MW, incorporated six hours of thermal storage, and used natural-gas-fueled superheaters to supplement the solar energy. The storage system was taken out of service after a fire in 1999, but the rest of the plant is still operating. Luz also constructed additional plants, SEGS II through VII, each with 30-MW capacity. In 1990, Luz completed construction of SEGS VIII and IX in Harper Lake, each with 80 MW capacity. The total generating capacity of these plants is 354 MW; individually and combined, they are the largest solar power plants in the world. From the mid 1990s until about 2000, they had generated more solar-electric kWh than the total of all other worldwide sources.

As a result of regulatory and policy obstacles, as well as marginal economics without ongoing tax credits, Luz International and four subsidiaries filed for bankruptcy on November 25, 1991. Several companies now operate and maintain these facilities as independent power generators. As of February 2005, FPL Energy held a significant minority ownership in all but SEGS I and II, making it the largest holder of solar-electric generation facilities. In its later years, Luz had begun developing direct steam generating solar collectors and integrating the solar collector field into a gas-fired combined cycle plant. Firms that continue involvement in this technology, besides FPL Energy, include Solargenix Energy (formerly Duke Solar Energy, renamed in April 2003, and 55% owned by Acciona Solar as of early 2006), Solar Millennium AG, the Belgian company Belgo International, and, a German-based subsidiary of Pilkington Glass named FlabegSolar.

In December 2002, Sierra Pacific Resources of Las Vegas announced plans for its two Nevada utility subsidiaries, Nevada Power and Sierra Pacific Power, to buy the output of a 50-MW parabolic trough plant near Boulder City, Nevada. The project, to be built by Solargenix, is part of the utilities' strategy to comply with the state's renewable portfolio standard that requires them to increase their use of renewable energy by 2% per year until it accounts for 15% of their total energy sales. Groundbreaking for the plant's construction was in February 2006 and operation is scheduled to start in 2007.

Table 7-2
Technology Monitoring Guide Solar Thermal Power Plants

Leading Developers of the Science or Technology							
Technologies	**R&D Intensity**	**Government Organizations**	**Nonprofit Organizations**	**Developers and Vendors**	**Major Trends**	**Changes To Watch For**	**Unresolved Issues**
Parabolic Trough/Gas Hybrid	Moderate	Sandia, NREL, CIEMAT (Spain)	DLR (Germany)	FlabegSolar (Pilkington) Solargenix (formerly Duke Solar) Solel Solar Millenium	Lower-cost mirror support structures, thermal storage, improved-performance receiver tubes	Direct steam generation	Steam flow control
Central Receiver	Moderate	Sandia, NREL	DLR (Germany)	Nexant (Bechtel) Boeing Rocketdyne	Molten-salt receiver	Thermal storage, decoupling energy collection from electricity generation	Energy production, cost
Parabolic Dish/Stirling Engine	Low	Sandia		Stirling Energy Systems (SES) Schlaich-Bergermann and Partner (SBP) Arizona Public Service Solar Test & Research (STAR) Center	Lower-cost dish and mirror structures	Durable free-piston engine	Engine availability, O&M costs, cycling impacts

Table 7-3
Technology Process Development Map: Solar Thermal Power Plants

	Central Receiver Station	Solar Thermal Trough/Gas Hybrid	Central Receiver Molten Salt	Parabolic Dish Stirling Engine
Features and Advantages				
Technology Characterization	Heliostat field with direct steam cycle	Parabolic trough Heat transfer from oil to steam cycle	Heliostat field Heat transfer from molten salt to steam cycle	Parabolic dish Heated air powers Stirling engine
Efficiency	8%	9-12%	8-17%	16-28%
Resources	Flat terrain with high annual direct insolation and natural gas availability (for backup)	Flat terrain with high annual direct insolation and natural gas availability	Flat terrain with high annual direct insolation and natural gas availability	High annual direct insolation and natural gas availability
Challenges and Disadvantages				
Cost	Capital cost	Capital cost	O&M cost	O&M cost
Operation	Steam cycle control High parasitic losses		High freezing point of salt	Uncertain maintenance costs
Technology Needs	Steam control system, energy storage, parasitic loss reduction	Direct steam generation, inexpensive reflectors with resistance to soiling, energy storage	Reliable, cost-effective trace heating capability	Need for highly reliable reflectors, trackers, and engines
Costs				
Relative Capital	High	Medium	Medium	Medium
Relative O&M	High	Medium	Medium	Medium
Busbar	30-40¢/kWh	8-25¢/kWh	5-25¢/kWh	5-25¢/kWh
Development Timeframe				
Research	Late 1970s	late 1970s	1980s	1970s-1980s
Development	early 1980s	1980s	1980s	1980s-1990s
Demonstration	1984-1987	1986-1987	1993-1998	1983-1990s
Commercialization	N/A	1988	2005	2005
Markets				
Key Issues	This technology replaced by molten salt	Examples operating successfully High first cost hurts market prospects Limited competition for parabolic trough collectors; strong competition for other key components	High first cost hurts market prospects Limited competition for molten-salt equipment; strong competition for other key components	High first cost hurts market prospects Limited competition for air heater, Stirling engine and parabolic dish collectors
Impact on Technology Outlook	None	Recent interest, driven in part by RPS in CA, NV, AZ, and Spanish solar incentive may spur very large-scale development in next 5-10 years	Little or none short term due to high cost and need for relatively large system sizes (>100 MW). Increased interest in troughs and dishes may spur this technology as well	Surprising announcement of SES-SCE PPA shows promise to accelerate this technology to large-scale plants

The Spanish government's alternative energy program has been testing trough systems at its solar test facility in Almería. They have announced plans for a pair of 50-MWe trough power plants in Spain, which will include six hours of molten-salt thermal storage and will be constructed by Solar Millennium. Also, since the passage in March 2004 of the latest version of the Spanish solar feed-in tariff, which guarantees at least 22 Eurocents/kWh for plants up to 50-MW capacity, more than ten would-be solar-plant builders have applied for permits.

The World Bank's Global Environment Facility (GEF) has pursued government and commercial interests in building the next wave of solar thermal trough power plants. The builders envision these installations as fossil-hybrid combined-cycle plants, with the solar contribution limited to about 10%. Egypt is developing a hybrid solar fossil thermal power plant that will generate 100 to 160 MW, approximately 30 MW of which will be provided by solar power. In India, the German financial institution KfW is supporting a 135-MW naphtha-fired integrated solar combined-cycle system (ISCCS) generator with a 35-MW solar component. The Moroccan national utility, ONE, plans to build an ISCCS plant with a net output of 180 MW, 30 MW of which will be solar trough. Early feasibility studies for similar systems are also underway in Brazil, Iran, Mexico, and Spain.

Development efforts are underway to improve solar collector assembly technology. A consortium in Europe has developed and tested an advanced collector that is intended to contain the best features of the second and third generations of Luz collectors (LS-2 and LS-3). In addition, Solargenix in the U.S. is developing a collector based on the LS-2 design that is expected to offer advantages in manufacturing, installation, and resistance to high winds. Solel, the Israeli firm that owns the rights to the Luz technology, has developed an improved evacuated receiver element.

7.4.2 Central Receiver

After operating for three years and successfully demonstrating the feasibility of molten-salt central receiver technology, Solar Two shut down in 1999. Since the Solar Two project, the center of central receiver activity has moved to Europe, where interest in such concepts has continued for more than two decades. A consortium—including Boeing, Bechtel subsidiary Nexant, and their Spanish partner Ghersa—invested significantly to investigate design options, prepare cost estimates, and negotiate contract opportunities for a new central receiver plant in Spain, Solar Tres. It was to be a 15-MWe molten nitrate salt plant with about 16 hours of thermal storage to allow for around-the-clock operation. The aim was to achieve a capacity factor of about 60% and use the project as a springboard to near-term opportunities for numerous full-scale (greater than 50 MW) commercial central receiver plants in Spain, other worldwide markets, and eventually in the southwest U.S. . Table 7-4 compares Solar Two and Solar Tres.

Prospects for the construction of Solar Tres appeared good until early 2003, when reports began to surface of reduced interest due to cuts in government subsidies. Its status through 2003 appeared uncertain, but the Spanish government reversed its subsidy decrease in 2004 and established even more favorable incentives for solar thermal generation, so it now seems likely to be completed. Moreover, there appear to be near-term plans afoot for more than 10 multi-megawatt Spanish solar thermal plants (nearly all parabolic trough, except for PS-10 and Solar Tres).

Table 7-4
Comparison between Solar Two and Solar Tres Projects

	Solar Two	Solar Tres
Steam Turbine Net Power (MW)	10	15
Annual DNI (MWh/m^2)	2.7	2.0
Field Layout	Surround	North
Solar Multiple	1.1	2.6
Field Size (m^2)	82,000	150,566
Receiver Size (MWt)	40	96
Receiver Configuration	Cylindrical	Billboard
Storage (hrs)	3	16
Mature annual capacity factor	20%	50%
Mature annual efficiency	8%	14%
Mature year O&M cost ($/kWh)	0.14	0.011
Levelized energy cost ($/kWh)	NA	0.13

South Africa's major electric utility, Eskom, has also been actively evaluating solar thermal options for use in that country. Unlike the solar energy resources in Spain, where the best locations are still 10% to 20% below the best southwestern U.S. sites, some South African sites are among the best in the world. There have been reports that Eskom may build and evaluate a 100-MWe central receiver plant. This is good news for the solar thermal development community, as such a plant would represent an order-of-magnitude size increase over Solar Two and could demonstrate actual commercial-scale central-receiver operation. However, such a large one-step scale increase entails considerable risk, especially in view of the fact that the performance evaluation of Solar Two was so short-lived. To mitigate this risk, Eskom would conduct a series of component demonstrations prior to final plant construction.

7.4.3 Dish/Engine

Cummins Power Generation, a subsidiary of Cummins Engine Company, pursued dish-Stirling systems for remote and grid-connected applications from 1991 through 1996. Some innovative progress was made, but the program was terminated by the parent company as part of a decision to realign operations along their traditional diesel business line. Some of the Cummins work was continued by WGAssociates, in cooperation with Sandia National Laboratories in Albuquerque, New Mexico. This effort was augmented by incorporation of a German Stirling engine, the SOLO Kleinmotoren V 161, through a licensing arrangement between Kockums in Sweden and WGAssociates. Sandia has focused this work on demonstration of unattended operation for extended periods, and has made substantial progress with two nominally 10-kW units it is testing. Evidently the WGAssociates technology has been acquired by SES (see below).

Three major government-industry dish-Stirling programs emerged in the 1990s, two in the U.S. and one in Europe. Both U.S. programs enjoyed substantial support from DOE through Sandia National Laboratories.

One U.S. program is operated by Stirling Energy Systems, Inc. (SES), and stems from the McDonnell Douglas work of the 1980s. SES holds the rights to the McDonnell Douglas concentrator technology, and continues the relationship with Kockums to use its 4-95 25-kWe engine, which SES has the exclusive right to market in North America. The company's "SunCatcher" product is a 28-kW dish/engine unit with 89 rectangular mirror facets arranged in a paraboloid to focus sunlight onto a four-cylinder reciprocating Stirling engine. SES claims that the SunCatcher currently has a maximum solar-to-electricity conversion efficiency of 32% to 34%. SES has operated test units at the University of Nevada Las Vegas (UNLV) and at its engineering and technology demonstration site in Huntington Beach, California. The latter facility is owned by Boeing, which assumed ownership of McDonnell Douglas during the 1990s. In 2004, SES began working with Sandia on a 6-dish 150-kW demonstration program to clarify and mitigate scale-up issues for the SES design.

SES and Southern California Edison announced in August 2005 that they had signed a power purchase agreement calling for the construction of 500 to 850 MW of dish/Stirling generation. Details of this arrangement have not been released, but there is apparently to be a 1-MW (40-dish) demonstration phase followed by the full-scale plant, which will comprise at least 20,000 dishes, in the 2010 timeframe. In September 2005, SES announced another large power-purchase agreement, this time with San Diego Gas and Electric, for 300 to 900 MW of generation; however, no other details of the plan were available at the time of writing.

The second major U.S. program was operated by Science Applications International Corp. (SAIC) in conjunction with STM Power (formerly Stirling Thermal Motors). STM became involved with Stirling engines in the 1970-1980 timeframe in conjunction with an automotive Stirling engine program funded by the Ford Motor Co. STM is working on a commercial design for a 25-kW Stirling engine and feels that it has a solution to three major problems of past engine designs: complicated power control systems, seal design for the reciprocating piston rods, and a large heater head that is expensive to manufacture. STM's 4-120 engine addresses these problems by using a variable-angle swashplate drive to regulate output power, pressurizing the crankcase to reduce pressure drop across the rod seals, and designing a stacked heat-exchanger heater head. SAIC had been developing polymer stretched-membrane concentrators as a lower-cost alternative to glass, but is now using thin, flexible glass facets. Four of its 22-kWe units have been under test: two at utility test sites in Arizona and one each at UNLV and in Colorado. One of the Arizona units has been hybridized to run on landfill gas. This effort appears to have been dormant since about 2005.

The European program, called EuroDish, is a joint venture of several German and Spanish firms, with government support from the European Community and the German and Spanish governments. This program is headed by Schlaich-Bergermann and Partner (SBP), and uses the SOLO Kleinmotoren V-161 engine. Eleven units have been built and tested. SPB has focused attention on achieving fully automatic operation.

In addition, a number of small industrial firms have emerged to develop and/or commercialize Stirling systems of various sizes ranging from tens of watts to tens of kilowatts. Many of these have originated since 1995, apparently in response to growing interest in distributed generation. Owing to their use of external, continuous combustion, Stirling engines are expected to have environmental characteristics superior to those of internal combustion engines. In fact the SOLO unit mentioned above is being developed primarily for on-site cogeneration.

7.5 Cost and Economic Issues

The cost of electricity from solar thermal power plants depends on a multitude of factors, including capital and O&M cost and system performance. It is important to note that the technology cost and the eventual cost of electricity generated will be significantly influenced by factors independent of the technology itself. For example, for parabolic troughs and central receivers, small stand-alone projects would be very expensive. To reduce the technology costs to be competitive with those of conventional fossil technologies, solar projects must be scaled up to larger plant sizes. One strategy might be to create a solar power park, in which multiple projects could be built at a single site over time. In addition, because solar thermal technologies essentially replace conventional fuel with capital equipment, the cost of capital and taxation issues related to capital-intensive technologies will have a strong effect on their competitiveness.

Except for parabolic troughs, none of the solar thermal technologies described in this report have ever been commercially available. *Therefore, real cost data based on recent commercial production and (except for troughs) plant operation do not exist.* The data presented in Table 7-5 include cost estimates derived from 2006 research conducted by Black & Veatch for EPRI.

Due to the limited activity in building new parabolic trough plants until recently, and the pre commercial status of dish Stirling technologies, EPRI notes that they stand to benefit significantly from learning-by-doing cost reductions during commercial scale up, and this effect cannot be represented accurately in the cost projections. EPRI therefore recommends that use of these data be restricted to order-of-magnitude cost comparisons in far-future planning, because actual costs will depend greatly upon the cumulative deployments achieved by a given year for each of the technologies.

Table 7-5
Performance and Cost Estimates for Solar Thermal Technologies (Dec-06 $)

	Parabolic Trough-Gas Hybrid	Dish Stirling Goal Estimate[1]
Rated Capacity		
Plant Size (no/ of units x unit size, MW)	1 x 100 MW	4,000 x 25 kW = 100 MW
Physical Plant		
Unit Life, Years	30	30
Land Required, acres	575	600
Scheduling		
Available for Commercial Orders, Year	1990	Later
Hypothetical In-Service Year	2010	2010
Preconst., License & Design Time, Months	10	12
Idealized Plant Construction Time, Months	20	14
Capital Costs		
Month/Year Dollars	Dec 2006	Dec 2006
Structures & Improvements	110	50
Collectors, and Concentrators	1,710	1,080
Thermal Storage		--
Steam Generator plus Hybrid Fossil/Heater Head	390	100
Power Generation	330	690
Balance of Plant	240	260
General Facilities and Engineering Fee	560	400
Project and Process Contingency	500	390
Total Plant Cost	3,850	2,970
AFUDC (Interest during construction)	150	80
Total Plant Investment (includes AFUDC)	3,990	3,150
Owner Costs		
Due Diligence, Permitting, Legal, Development	400	320
Tax and Fees	0	0
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	4,390	3,470
O&M Costs		
Fixed, $/kW-yr	58	56
Variable, $/MWh		
Performance/Unit Availability		
Equivalent Planned Outage Rate, %		
Equivalent Unplanned Outage Rate, %		2
Equivalent Availability, %	96	98
Plant Annual Output MWh/yr	255,000	225,000
Assumed DNI, kWh/m2-day	7.65	765
Confidence and Accuracy Rating		
Technology Development Rating	Early Commercial	Developmental
Design & Cost Estimate Rating	Simplified	Simplified Goal

[1]Dish Stirling data provided by SES.

Parabolic Trough

Data presented in Table 7-6, which are derived from previous studies by EPRI and others [1, 7, 8, 9], will be used to estimate upper and lower bounds for cost and performance. The lower bound on annual solar efficiency can be inferred from the SEGS VI column of the table. The 10.7% efficiency value shown is somewhat higher than the 9.8% value calculated for the entire Kramer Junction park in 1998. This can be explained entirely by the SEGS VI collector aperture area, which, at 188,000 m^2, is less than one-fifth of the total collector area of the park by about 14%. Owing to higher steam-cycle efficiency, this plant outperformed the earlier plants and proved that parabolic trough installations could achieve higher efficiency. Contrary to earlier assumptions, it has been demonstrated that the later SEGS plants, including SEGS VI, use little if any gas for plant warming. Thus, for the current evaluation, a value of 11% will be used as the lower bound on this efficiency.

Table 7-6
Selected Data for Solar Trough Systems

	SEGS VI	SEGS 2000	SEGS 2010	Near Term	Advanced
Plant Size (MWe)	30	80	320	100	200
Solar Field Area (m^2)	188,000	510,120	3,531,600	800,000	2,000,000
Thermal Storage (hours)	None (fossil hybrid)	None (fossil hybrid)	10	4	12
Capacity Factor (total) (%)	34	34	50	33	53
Solar Capacity Factor (%)	*22.5*[1]	*25.5*[1]	50	33	53
Insolation (DNI) (kWh/m^2-yr)	2891	2725	2725	2840	2840
Annual Energy Production (total)	89.4	238.3	1402	289.1	928.6
Annual Solar Energy (GWh/yr)	59.0	178.7	1402	289.1	928.6
O&M Costs ($/kW-yr)	107	63	43	NA	NA
O&M Costs (¢/kWh)	*3.6*[1]	*2.1*[1]	*1.0*[1]	1.7	0.6
Collector Costs ($/kWe)	3048	1138	1327	NA	NA
Collector Cost ($/$m^2$)	*486*[1]	*178.5*[1]	*120.2*[1]	222	147
Storage Cost ($/kWe)	NA	NA	528	360	324
Total Capital Cost ($/kW)	3972	2693	2999	3150	2535
Annual Solar-Electric Efficiency	10.7	12.9	14.6	13	16
Plant Cost[1] *($/$m^2$)*	*633.8*	*422.3*	*271.8*	*393.8*	*253.5*

1. Data in italics are calculated values inferred from other entries or data discussed in references.

The columns labeled "SEGS 2010" and "Advanced" contain a good measure of optimism. In particular, the Advanced plant's costs include assumptions about cost reductions that are debatable and may prove unrealistic. In the SEGS 2010 plant, collector costs per unit area are assumed to be very low. This suggests that the collector costs assumed in both the SEGS 2010 and SEGS 2000 are too optimistic. For this evaluation, the data presented for the Near-Term plant appear reasonable as a lower bound on cost, and with experience and expanded production it seems reasonable to expect those costs to drop by 10%. Hence, $\$350/m^2$ will be used as the lower bound cost estimate.

The Near-Term plant also provides the basis for estimating the upper bound on efficiency, again because the apparent optimism of the SEGS 2010 and Advanced plants has been tempered. However, it seems reasonable to expect that at least half of the 20% receiver efficiency improvement assumed in the Advanced plant will actually occur, which would increase plant efficiency by about 10% over that of the Near-Term plant. Hence, 14% will be used for the current evaluation.

For the upper bound on cost, the value achieved with SEGS VI provides a firm basis. It is reasonable to assume that additional experience would reduce that cost somewhat—perhaps by 5%—to approximately $\$600/m^2$. Because that value is given in 1997 dollars, it is adjusted by the Producer Price Index (PPI) to December 2002 dollars—an increase of about 4%. This yields a value of approximately $\$625/m^2$.

A 90%-confidence levelized energy cost (LEC) range can now be calculated for trough systems. This analysis assumes a fixed charge rate—covering all annual charges related to the plant's capital investment—of 10.5%, and annual insolation of 2,500 kWh/m^2. This insolation is somewhat less than that reported above for Kramer Junction, but is felt to be more representative of typical locations for trough plants. For O&M costs, the upper bound assumes the value demonstrated at the Kramer Junction 150-MWe park: 2.5¢/kWh. For the lower bound, it seems reasonable to assume that mature plants would approach a value between those shown for the Advanced and Near-Term plants. For this evaluation, 1.0¢/kWh will be used. The resulting upper and lower values for LEC are as follows:

$$LEC_U = (100)(0.105)(625)/(2500)(0.11) + 2.5 = 26.4¢/kWh$$

$$LEC_L = (100)(0.105)(350)/(2500)(0.14) + 1.0 = 11.5¢/kWh$$

Hence the LEC for mature trough plants is estimated, with a 90% confidence level, to lie between about 12¢/kWh and 26¢/kWh. These values are based on the assumed fixed charge rate and insolation level, and can be easily adjusted—using the above relationships—to reflect different values for those parameters if desired.

Central Receiver

With respect to the cost of a central receiver project, there is little basis to make substantial changes from the projections EPRI developed in 1989 [7]. Solar Two, the only major central receiver hardware activity since 1989, provided no new cost information, although it did provide solid, positive experience with molten salt storage equipment and operation. It therefore provides a qualitative reduction in prudent contingency factors for some of the major plant components, and strengthens the basis for a portion of the lower-bound cost estimate from the 1989 evaluation. However, that lower bound also assumed significant cost reduction in heliostats, based on the use of stretched polymer membranes rather than glass reflectors. In 1989, the expectation was that the unit-area cost of heliostats would eventually drop to $\$75/m^2$ if polymer reflectance and lifetime were acceptable. However, experience with polymer membranes over the past decade—for heliostats, dish reflectors, and troughs—has not been encouraging. All current and foreseeable system development work is now based on glass reflectors. Hence the heliostat portion of the lower-bound cost is now somewhat suspect.

Additional perspective on cost projections can be obtained from EPRI's 1997 *Renewable Energy Technology Characterization* report [1]. That study offers projections for a 2010 central receiver plant with 13 hours of molten-salt thermal storage. Projections are also presented for 2020 and 2030, which include modest improvements in cost and operating efficiencies. The latter improvements are judged to be speculative, but the 2010 projection is felt to be realistic with one important exception: heliostat costs for 2010 and beyond are assumed to approach the $\$75/m^2$ level, which is probably optimistic, as discussed in the previous paragraph. It should also be noted that $\$75/m^2$, in current dollars, has been a long-term goal for heliostat costs for more than two decades. Hence the goal, in real-dollar terms, has actually been decreasing. This reduces the credibility of the goal, especially because experience suggests that the hoped-for reductions in materials costs are becoming less likely.

The 2010 central receiver plant cost, expressed in dollars per unit area of heliostats, was projected to be $\$210/m^2$ in 1997 dollars. Adjusting by the fabricated-structural-metal-products Producer Price Index (PPI) increase from 1997 to 2002 increases this amount by about 4%, to $\$218/m^2$ in 2002 dollars. In EPRI's 1989 evaluation, the corresponding cost was about $\$250/m^2$ in 2002 dollars,. In light of the above discussion of heliostat costs—in particular the speculative nature of the $\$75/m^2$ goal—this evaluation will retain the lower-bound cost estimate of $\$250/m^2$. Similarly, there is little basis for changing the upper-bound cost estimate from the value calculated for the 1989 evaluation: $\$535/m^2$.

Applying a rate of inflation based on the PPI yields an LEC range, expressed in 2002 dollars, of approximately 7.3¢/kWh to 29¢/kWh—essentially the same as it was in 1989.

Dish/Engine

Progress with dish/engine systems over the past decade has come primarily from testing individual units fielded by SES, SAIC/STM, SBP, and Sandia. In aggregate, including the earlier experience of the 1980s, these units logged nearly 80,000 operating hours through mid-2002. The units at Sandia in Albuquerque have run unattended without incident for periods of several

weeks, which bodes well for increased reliability of system operation. However, there is as yet no large body of operating experience on which to base projections for mature-system energy costs that have substantially more validity than those offered in EPRI's 1989 evaluation [7].

Similarly, because these programs are all heavily supported by government sources and commercial offerings do not yet have public visibility, there is little basis for developing new cost estimates with increased confidence. One factor is evident, however, that would tend to increase the lower bound cost estimate described in the 1989 evaluation: it now appears that all firms pursuing dish systems are employing glass reflectors. As with central receiver heliostats, experience with polymer membranes has been disappointing. This is expected to increase the cost of the dish concentrator component by as much as 100%, which in turn would increase the cost of the entire unit by about 30%. The impact on the lower-bound LEC would be an increase of about 30%, assuming no change in the upper-bound efficiency value.

Hence the LEC range for dish systems today is estimated to be 7.3¢/kWh to 30¢/kWh, in 2002 dollars.

7.6 Environmental Issues

Like solar PV technologies, solar thermal electric technologies are environmentally benign relative to other forms of electricity generation. Without energy storage, all large-scale solar plants have similar footprints, roughly 5 acres/MW (2 hectares/MW), but solar thermal plants also have water requirements and potentially damaging outcomes of operational mishaps that PV plants lack. Of course, if the plant is hybridized, operation of the fossil-fueled section will be accompanied by the usual emissions and hazards of fossil-fuel use.

7.6.1 Land Use

As mentioned, solar thermal plants without storage require about two hectares per megawatt of peak capacity in good solar-resource locales (greater than 2,200 kWh/m^2/yr). However, plants that incorporate some storage may require 3 to 10 times more land per peak megawatt, and their generating units will typically not be designed to use the entire peak thermal output of the collector field. Therefore, a more meaningful metric of land use would be the area required per annual megawatt-hour of output, which would range between about 0.2 and 1.6 x 10^{-3} hectare/MWh/yr. (Note that, although conceptually distinct, these two quantities actually have the same fundamental units of area/power)

7.6.2 Water Use

Water requirements of trough and tower solar thermal generating plants are similar to those of other steam plants of equal nameplate capacity using wet cooling towers. Dry cooling is a viable water-conserving alternative, but at a cost of up to 10% lower operating efficiency. Thus, for optimum efficiency, some 2 to 4 m^3 of cooling water is needed for every megawatt-hour generated. Dish/Stirling engines require no water. In all cases, a small amount of water may be needed for mirror cleaning.

7.6.3 Molten Salt for Central Receiver

No hazardous gaseous or liquid emissions are released during operation of a solar central receiver plant. If a molten salt spill occurs, the salt will freeze before significant soil contamination occurs. The salt may be picked up with a shovel and can be recycled if necessary.

7.6.4 Oil for Heat Transfer in Trough Applications

The current heat transfer fluid (Monsanto Therminol VP-1) is an aromatic hydrocarbon, biphenyl-diphenyl oxide. The oil is classified as non-hazardous by U.S. standards but is a hazardous material in California. When spills occur, contaminated soil is removed to an on-site bio-remediation facility that uses indigenous bacteria in the soil to decompose the oil until HTF concentrations have been reduced to acceptable levels. In addition to liquid spills, there is some level of HTF vapor emissions from valve packing and pump seals during normal operation, but such emissions are well within currently permissible levels.

7.6.5 Potential for Greenhouse Gas Reduction

Solar thermal power plants that are not hybridized with fossil fuel generate no direct emissions of CO_2, methane, or other greenhouse gases. Even when hybridized, the solar-generated portion of the plant's output is emissions-free. Consequently, all solar-thermal power plants provide greenhouse gas emissions reductions. In addition, should a CO_2 emissions-reduction mandate be enacted in the future, solar thermal power could become an important component of a CO_2 emissions-reduction strategy and could participate in CO_2 emissions trading.

As discussed in Chapter 11, the CO_2 emissions-reduction potential of a renewable energy power plant is a function of the generation mix of the existing generation system, while the effective CO_2 emissions-reduction cost is a function the CO_2 emission rate and the average generation costs of the base system and the renewable energy power plant.

7.7 Design, Deployment and O&M Issues

Issues associated with design, deployment, and O&M include the reliability and maintainability of sun-tracking drive systems and balance-of-plant systems, operation under extreme weather conditions (wind, precipitation, dust), and labor requirements. As noted in the "Cost and Economic Issues" discussion, there are currently few solar thermal systems in commercial operation (with the notable exception of the SEGS plants in California) and only a handful deployed as demonstration prototypes, yielding limited real-world O&M experience.

7.7.1 Parabolic Trough

Through much of the 1990s, the DOE-Sandia-NREL solar thermal program worked closely with the operators of the trough plants in southern California to reduce O&M costs for these systems. That work focused primarily on the five 30-MWe plants—SEGS III through VII—located at Kramer Junction, California. Through that effort, participants learned a great deal about

optimizing O&M procedures and about hardware improvements that would increase energy production and reduce O&M costs. As a result, these costs have been substantially reduced, and the O&M requirements for mature commercial plants based on similar hardware can be estimated with improved confidence.

The solar collector assembly (SCA) of a trough system rotates around the horizontal north/south axis to track the sun in its apparent motion through the sky during the day. The axis of rotation is located at the collector center of mass to minimize the tracking power required, and the drive system uses hydraulic rams to position the collectors. The SEGS plants were designed for a nominal lifetime of 30 years. SCAs on those systems were designed for normal operation in winds up to 25 mph (40 km/h) and with somewhat reduced accuracy in winds up to 35 mph (56 km/h). They are designed to withstand a maximum wind of 70 mph (113 km/h) in their stowed position, aimed 30 degrees below the eastern horizon.

Actual experience in California has resulted in many lessons learned. During the period 1992 through 1998, the Sandia-industry O&M improvement program provided a 31% increase in annual solar energy production from the 150-MWe solar park at Kramer Junction. In addition, annual O&M costs per megawatt were reduced by 19%. Together, these advances resulted in a reduction in O&M costs/kWh of 38%, from about 4¢/kWh in 1992 to about 2.5¢/kWh in 1998—not including costs for natural gas fuel. The advances in collector design and receiver elements described previously are also likely to increase annual energy performance through improvements in wind damage resistance, integrity and protection of metal-to-glass seals, stability of optical alignment of collector-reflectors and receiver elements, and increased efficiency of receivers.

The following are some specific advances at Kramer Junction:

- Although the mirrors have proven to be among the trough systems' most reliable components, differential thermal expansion caused some separation of the mirrors from their mounting pads. The problem was resolved through the use of new mounting materials and adhesives. In general, mirrors can be maintained without degradation through simple periodic washing. Front-surface mirrors have the potential to yield higher reflectivity, but must demonstrate long-term performance, durability, and washability.
- Mirror breakage at the edges of the collector fields in high winds was a major problem that often caused cascading breakage of heat collection elements (glass-encapsulated receivers) and other mirrors. A means of strengthening the edge-mounted mirrors with a backing made of fiberglass-resin successfully reduced breakage of these mirrors. Additional work developed operating strategies for high wind conditions, with the aim of allowing plant operation in high winds to avoid loss of solar energy while also ensuring that vulnerable collectors would be stowed in a safe position before wind damage could occur. Although some valuable insights were developed, results of this work were inconclusive.

- By 1992, approximately 15% of the 50,000 heat collection elements (HCE) in the Kramer Junction park were damaged, either through loss of vacuum in the space between the receiver and the concentric glass tube or through loss of the glass tube entirely. Because loss of the glass reduced performance to a much greater extent than loss of the vacuum, workers developed a temporary repair procedure in which a new glass tube could be affixed to the HCE. Then after several adjacent HCEs developed problems, all could be replaced at the same time. In addition, strategies to protect the glass-to-metal seal have reduced the incidence of vacuum loss in the HCEs. Finally, Solel has developed a new HCE design that uses an improved selective receiver-tube coating with reduced emissivity and greatly increased resistance to oxidation—and associated degradation of optical and thermal properties—in the event of vacuum loss. Protection of the vacuum seal is also enhanced in this new design. Although not yet fully evaluated, this HCE, called UVAC, would likely be used in subsequent trough plants. Future HCE designs should use new tube materials to minimize bowing problems, allow broken glass sleeves to be replaced *in situ*, and continue to improve coating materials that efficiently transmit solar energy to the working fluid.
- The Luz LS-3 collector initially showed higher performance than earlier Luz collectors, owing to higher concentration ratio and higher peak optical efficiency. Over time, however, these units would lose their alignment, causing significant performance degradation. Subsequent changes in the mechanical design of the LS-3 have corrected this problem, and LS-3 collectors used in SEGS VIII and IX showed substantial improvement in alignment maintainability. Operators also devised procedures for identifying collectors that were developing alignment problems.
- Because the solar collector assemblies track the sun, piping connections to the receiver tubes must tolerate motion. Originally, corrugated flex hoses served this purpose. Reliability of these was marginal, and occasionally a catastrophic failure would occur, resulting in a fire fed by the heat-collection oil. The corrugations also caused noticeable pressure losses in the heat-collection loop. Many of these hoses have been replaced with a ball-joint arrangement that has greatly improved the reliability of these connections. Ball joints are highly likely to be used in future trough plants. Better seals for pumps in the thermal collection loop represent another advance, which has greatly improved pump reliability.

Several key issues remain for trough systems, including the following:

- Despite substantial progress, O&M costs are still quite high. The trough community projects that these costs can be reduced to 1¢/kWh or less, but this remains to be demonstrated.
- Although incremental advances have been made, substantial reductions in capital costs have not been identified.
- Increasing plant size, including thermal storage, and further increasing total collector area to fill the thermal storage and increase plant capacity factor are likely to result in significant cost reductions. This is clearly the most promising direction if trough systems are to provide solar electricity without adding to fossil fuel combustion and associated emissions. However, unlike the situation with central receiver systems, cost-effective, reliable, and efficient thermal storage has not yet been demonstrated with trough systems.

- Molten salt storage appears to have good prospects for use in trough systems, particularly because of its success with the central receiver approach. However, the storage subsystem will contribute more cost to a trough system than to a central receiver system because salt cannot, as yet, be used as the heat collection fluid. The oil-to-salt heat exchangers such a storage system would require could add a larger cost component than salt storage tanks.
- Alternative heat collection fluids have been proposed for trough systems, such as molten salt and water-steam. These may offer higher peak performance, owing to higher operating temperatures, which could translate into lower costs. However, the technical difficulties of handling these fluids without leaks or freezing throughout large collector fields in a wide range of environmental conditions are difficult to overestimate. It is highly unlikely that either of these approaches will displace the current heat collection approach in the foreseeable future, so projected cost reductions based on advanced heat collection fluids are highly speculative. This indicates that credible cost projections for trough systems are limited to those based on close derivatives of the systems deployed in southern California.

Other O&M issues include tracking maintenance via computerized maintenance management software, performing periodic collector alignment, developing system design specifications and operating procedures to allow quick start-up, and developing an effective O&M organization to handle the unique demands of operating a solar trough plant.

7.7.2 Central Receiver

The Solar Two plant was assembled in the mid-1990s. Initial operation began in June 1996, and the plant was operated in various experimental modes through April 1999. The original intent was to complete system checkout during the first several months, then conduct a one-year experimental evaluation program during which the characteristics of the plant would be fully explored and documented without emphasis on power production. This was to be followed by a two-year period of simulated commercial operation in which optimum power production was the only goal.

In practice, initial operation uncovered serious problems with the system design. The trace heating subsystem had to be completely reworked, and the steam generator developed an early tube rupture. These repairs and others set back the schedule by about 18 months. Consequently, the experimental evaluation and the power production phases were conducted concurrently over about a 12-month period. During this period, the design-point (i.e., peak) performance of the system and major components was well characterized. However, operators did not collect longer-term operating performance information, so they could not determine actual annual system performance. Some performance projections were possible, based on a combination of modeling and actual data.

Peak component and system efficiencies for Solar One and Solar Two are shown in Table 7-7. In addition to measured values for the two plants, this table shows goals for both Solar Two and a commercial plant. The table shows that the net peak efficiency for Solar Two was projected to be essentially the same as that actually observed for Solar One. For Solar Two, analysts factored some acknowledged deficiencies in the heliostat field into the projected goal, but these were to be offset by a higher receiver efficiency (which arises from a reduction in physical size, owing to

improved fluid heat transfer, and thus reduced radiation losses). Parasitic losses would also be higher for Solar Two, primarily because of the need for trace heating.

Solar Two's actual peak performance was somewhat less than the goal. This resulted primarily because of deficiencies in the heliostat field, as discussed earlier. It is reasonable to assume that those deficiencies would be eliminated in a new power plant. It is remarkable that the inclusion of energy storage in the Solar Two plant produced an almost negligible impact on the overall plant efficiencies.

Of greater significance are annual system efficiencies. While these were not measured for Solar Two, an attempt to estimate these was made by the Sandia evaluation team. These are shown in Table 7-8, along with measured values for Solar One and goals for Solar Two and a Commercial Plant. Also shown are values adjusted for the known deficiencies of Solar Two.

Table 7-7
Peak Central-Receiver System Efficiency Components

Category	Solar One Actual (%)	Solar Two Goal (%)	Solar Two Actual (%)	Commercial Plant Goal (%)
Mirror Reflectivity	90.3	90.7	90.7	94
Field Efficiency	76	72	66	71
Field Availability	99	98	94	99
Mirror Corrosion	100	97	97	100
Mirror Cleanliness	95	95	90	95
Receiver Efficiency	78	87	88	88
Storage Efficiency	N/A	99	99	99
Steam/Turbine Generator	33	34	34	42
Gross Peak Efficiency	16.6	17.2	14.7	23.2
Parasitic Loss Factor	90	88	87	93
Net Peak Efficiency	15	15	13	22

Table 7-8
Annual Average Central Receiver System Efficiency Components

Category	Solar One Actual (%)	Solar Two Goal (%)	Solar Two Adjusted (%)	Commercial Plant Goal (%)
Plant Availability	90	90	90	91
Overall Field Performance	58	50	51.5	56
Receiver Efficiency	65	76	76	79
Piping Efficiency	99	99	99	99
Storage Efficiency	N/A	97	97	99
Steam/Turbine Generator	30	32	41	41
Gross Annual Efficiency	10.1	10.5	13.9	16.3
Parasitic Loss Factor	72	73	73	90
Net Annual Efficiency	7.3	7.7	10.1	14.7

The heliostat field represents the largest single capital investment in a central receiver power plant. Relatively few heliostats have been manufactured to date, and their cost remains high. In contrast to solar trough drive systems, which move on only one axis, heliostats must move in two axes and reflect the sun's rays onto the central tower with a high degree of accuracy. Thus, related O&M is more complex and costly.

While it is a suitable working fluid in many respects, molten salt, has proven problematic in others. It can be troublesome to maintain in a molten state, requiring a fairly complex heat trace system employing electric wires attached to the outer surface of pipes. Valves can also be a problem in a molten salt system, requiring special packing and extended bonnets. Design improvements and standardization in valve design would reduce risk and ultimately reduce O&M costs. Based on O&M experience at Solar Two, subsequent central receiver projects are likely to employ new materials or thermal management practices that ease some of the problems observed.

7.7.3 Dish/Engine

Like central receiver heliostats, dish/engine systems must track the sun in two axes and with extreme accuracy. This introduces increased complexity and potential for O&M problems. Dish/engine systems must be stowed when wind speeds are too high, typically about 35 mph (16 m/s). If intended for remote or autonomous operation, a dish/engine system must therefore be equipped with reliable sun and wind sensors to determine whether conditions warrant operation.

Dish/engine systems need a parabolic reflective surface to focus sunlight on a receiver; however, that does not necessarily require a mirror. Although a reflective surface of silver deposited on glass is the most durable option, low-cost and lightweight polymer films stretched over hoops and drawn into a spherical shape with a vacuum have also been used successfully on a small scale, with hope that their relatively lower cost will offset their greater fragility.

Other systems of concern include the receiver, the engine—most commonly a Stirling engine, although Brayton cycle engines are also being investigated—engine cooling systems, and the alternator. In particular, the Stirling engine must demonstrate acceptable efficiency and reliability before commercial deployment can be seriously considered. In general, dish/engine systems would benefit from the introduction of a commercial engine system produced in volume.

7.8 Equipment Markets and Key Participants

The high-concentration solar thermal electric technologies discussed in this chapter will prove most practical and economical in regions with abundant direct-normal sunlight. This requirement somewhat constrains suitable locations for solar thermal in comparison to other solar technologies such as flat-plate photovoltaics, which can make use of diffuse or indirect sunlight. In addition to the systems successfully operating in southern California, other nations pursuing solar thermal power development include Spain, Italy, Greece, Japan, Russia, France, Egypt, India, Morocco, Brazil, Iran, and Mexico.

The 1991 bankruptcy of Luz International and its subsidiaries had a large impact on the subsequent viability of solar thermal systems. While some remaining companies have the expertise and resources needed to deploy a large-scale solar thermal project, in point of fact very few significant commercial systems have been commissioned in a decade. The following list of developers, consultants, and manufacturers includes those currently engaged in developing and providing solar thermal technologies. This list is provided for informational purposes only; no endorsement is implied.

Acciona Energia, C/ Yanguas y Miranda, 1 - 5º, 31002 - Pamplona, Spain. Acciona's mission is to be leaders in the management of infrastructures, services and renewable energy, actively contributing to social well-being and sustainable development. Its annual revenue exceeds $5 billion and it operates on five continents.
www.acciona-energia.com

Advanced Thermal Systems, 5031 West Red Rock Dr., Larkspur, Colorado 80118.

Arizona Public Service Co., P.O. Box 53999, Phoenix, Arizona 85072. Through its Solar Test and Research (STAR) Center, APS is a utility leader in researching and implementing many types of solar energy systems.

www.aps.com

Boeing Rocketdyne, 100 North Riverside, Chicago, Illinois 60606.

www.boeing.com/space/rdyne/flash.html

CIEMAT (Research Centre for Energy, Environment and Technology), Carretera Senés s/n - 04200 Tabernes (Almería), Spain. CIEMAT is a Research Public Institution attached to the Spanish Ministry of Education and Science. The Solar Platform of Almería, jointly managed by CIEMAT and DLR, is one of the most important European Centers on Solar Thermal Energy.

www.ciemat.es/eng/

DLR (German Aerospace Center), Koln, Germany. This public non-government center focuses on aviation, space flight, and energy technology in close cooperation with partners from academia and industry. An experienced solar plant contractor and operating agent, DLR is involved in solar trough feasibility studies in Spain and elsewhere.

www.dlr.de

Duke Solar Energy, see Solargenix Energy.

FlabegSolar, Also known as Flabeg Solar International, this company is a subsidiary of the Pilkington Group, one of the world's leading glass manufacturers. FlabegSolar manufactures a highly-specialized glass called Optisol™ that is used for solar reflectors, flat-plate collectors, and PV applications. Pilkington supplied the parabolic trough reflectors for SEGS I through IX and is active in solar thermal feasibility studies and development activities.
www.flabeg.com

FPL Energy, 700 Universe Blvd., Juno Beach, Florida 33408.

www.fplenergy.com

Industrial Solar Technology Corp., 4420 McIntyre St., Golden, Colorado 80403. IST designs, manufactures, installs and operates large-scale parabolic trough collector systems for industrial and commercial water heating, steam generation, and absorption cooling.
www.industrialsolartech.com

KJC Operating Co. (Kramer Junction), 41100 Highway 395, Boron, California 93516.

www.kjcsolar.com

Nexant Corp., 44 Montgomery St., San Francisco, California, 94104. In addition to its California headquarters, Nexant has offices in Colorado, London, and Bangkok. Nexant was a key partner in early solar power tower projects including Solar Two and, with Ghersa, has formed a company in Spain to finance and build Solar Tres.

www.nexant.com

Paneltec Corp., Lafayette, Colorado 80026. Paneltec is involved in the development and manufacture of mirror facets using sandwich panel technology. The company custom-laminates honeycomb and foam core panels for a variety of scientific and industrial applications.

www.panelteccorp.com

R.W. Beck, 1125 17th St., Suite 1900, Denver, Colorado 80202.

www.rwbeck.com

Schott Solar, SCHOTT AG, Hattenbergstr. 10, 55122 Mainz, Germany

www.schott.com/solar/

Science Applications International Corp. (SAIC), 9455 Towne Center Dr., San Diego, California 92121. SAIC partnered with STM Corp. to develop an integrated dish-Stirling system under the DOE Utility-Scale Joint Venture Project but has been inactive in the field since 2005.

www.saic.com

Solar Millennium AG, Naegelsbachstr. 40, D-91052 Erlangen, Germany. Solar Millennium offers services for the construction and operation of large-scale solar-thermal power plants. They specialize in parabolic trough and solar chimney power plants.

www.solarmillennium.de

Solargenix Energy, 2101-115 Westinghouse Blvd., Raleigh, North Carolina, 27604. Formerly Duke Solar Energy and now 55% owned by Acciona Energia, Solargenix is developing a range of solar thermal systems using compound parabolic collectors for broad use in buildings and electricity generation. In addition to electricity generation, Solargenix's activities focus on industrial process heat, absorption cooling, desalination, space heating, domestic hot water, and biomass.

www.solargenix.com

Solel Solar Systems, Inc., Jerusalem, Israel. Financed by European investors and founded in Israel, Solel purchased most of the assets of Luz Industries. The company has a production line and test site, and has become the major supplier of replacement collectors to the California SEGS power plants.

www.solel.com

Stirling Energy Systems (SES), Biltmore Lakes Corporate Center, 2920 E. Camelback Road, Suite 150, Phoenix, Arizona 85016. SES has used McDonnell Douglas intellectual property and partnered with national laboratories to develop a dish/Stirling engine unit that it plans to use in 800 to 1750 MW of power plants for power-purchase agreements announced in 2005.

www.stirlingenergy.com

STM Corp., 275 Metty Dr., Ann Arbor, Michigan 48103

www.stmpower.com

Sunray Energy, Inc., 35100 Santa Fe St., Daggett, California 92327

7.8.1 Internet Resources

In addition to the vendors and organizations listed above and in the technology monitoring guide (Table 7-2), the reader can visit the following Internet websites. Note that while these sites contain information and contacts that may be of interest, EPRI cannot vouch for the accuracy or quality of all of their content.

U.S. DOE Energy Office of Efficiency and Renewable Energy

www.eere.energy.gov

U.S. DOE Concentrating Solar Power Program
The U.S. DOE administers the SunLab program through two of its national laboratories: Sandia National Laboratory in New Mexico, and the National Renewable Energy Laboratory in Colorado. SunLab operates the National Solar Thermal Test Facility.

www.energylan.sandia.gov/sunlab

U.S. DOE/USA Solar Trough Initiative
Funded by the U.S. DOE and operated by SunLab, TroughNet is a comprehensive source for government efforts in solar thermal technology, projects, research and development, and other related resources.

www.eere.energy.gov/troughnet

U.S. National Renewable Energy Laboratory (NREL)

www.nrel.gov

American Solar Energy Society
ASES is a national organization dedicated to advancing the use of solar energy for the benefit of U.S. citizens and the global environment. The society sponsors conferences and publishes a magazine and white papers on the subject. ASES is the U.S. section of the International Solar Energy Society.

www.ases.org

Center for Renewable Energy and Sustainable Technology
The Center for Renewable and Sustainable Technology provides excellent background information and extensive links to other websites.

www.crest.org

Solar Energy Industries Association
SEIA is a national trade association of solar energy manufacturers, dealers, distributors, contractors, and installers. Its membership includes more than 500 companies.

www.seia.org

7.9 References

1. *Renewable Energy Technology Characterizations,* EPRI and U.S. Department of Energy: December 1997. TR-109496.

2. A. Zavoico, W. Gould, B. Kelly, and I. Pastoril, "Solar Power Tower (SPT) Design Innovations to Improve Reliability and Performance—Reducing Technical Risk and Cost," presented at the ASME 2001 International Solar Energy Conference, Washington, D.C.: April 2001.

3. Kelly, B., Herrmann, Ulf, and Hale, Mary Jane, "Optimization Studies for Integrated Solar Combined Cycle Systems," presented at the ASME 2001 International Solar Energy Conference, Washington, D.C.: April 2001.

4. Stone, K., Liden, B., Ellis, E., Sattar, T., and Mancini, T., "SES/Boeing Dish Stirling System Operation," presented at the ASME 2001 International Solar Energy Conference, Washington, D.C.: April 2001.

5. Diver, R., Andraka, C., Rawlinson, K., Thomas, G., and Goldberg, V., "The Advanced Dish Development System Project," presented at the ASME 2001 International Solar Energy Conference, Washington, D.C.: April 2001.

6. Mayette, J., Davenport, R., and Forristall, R., "The Salt River Project SunDish-Stirling System," presented at the ASME 2001 International Solar Energy Conference, Washington, D.C.: April 2001.

7. Holl, R.J., Status of Solar-Thermal Electric Technology, EPRI, Palo Alto, CA: 1989. GS-6573.

8. DeMeo, E., *Solar-Thermal Electric Power: 2003 Status Update*, EPRI, Palo Alto, CA: March 2003. 1008463.

9. Price, H., Lupfert, E., Kearney, D., Zarza, E., Cohen, Gl, Gee, R., and Mahoney, R., "Advances in Parabolic Trough and Solar Power Technology," *Journal of Solar Energy Engineering*, Vol. 124: May 2002.

10. *Stirling Engine Assessment*, EPRI, Palo Alto, CA: October 2002. 1007317.

11. Leitner, A. "Fuel from the Sky: Solar Power's Potential for Western Energy Supply," NREL/SR-550-32160. Golden, CO: National Renewable Energy Laboratory, July 2002.

8
OCEAN TIDAL ENERGY

Installed Capacity (December 2006)	<1.0 MW Worldwide 0.07 MW in United States Estimated annual incremental U.S. capacity additions: 2007 - 0.2 MW 2008 - 0.0 MW 2009 - 4.8 MW 2010 - 110.0 MW 2011 - 117 MW
Technology Readiness	Marine Current Turbine (UK), Verdant (USA), and Clean Current (Canada) prototype Tidal In Stream Energy Conversion (TISEC) devices demonstrated at sea in 2006 More demonstrations expected in 2007
Environmental Impact	Proper siting, installation, operation, and decommissioning, potentially position TISEC devices as one of the more environmentally benign generation technologies Little or no visual impact Environmental studies of impacts on hydrology, geology, and aquatic plants, fish, marine life, underwater noise needed for each application
Economic Status	EPRI economic feasibility studies indicate TISEC technology is competitive today at a half dozen "good" sites (average annual power density of >2 kW/m2 and other required site attributes) in the U.S.
Regulatory Status	Some projects likely to be controversial due to uncertain environmental impacts The Federal Energy Regulatory Commission (FERC) has asserted jurisdiction over tidal energy under the Federal Power Act (FPA), making it the lead agency for any approvals of tidal power projects in the U.S Many U.S. regulatory barriers inhibit licensing of tidal energy pilots or commercial scale projects Strong public support required to overcome federal, state, and local regulatory inertia
Trends to Watch	Continued technology funding in the UK and other European countries, Australia U.S. Department of Energy (DOE) funding for FY 2007 tidal energy RD&D program Individual demonstration and early commercialization projects, including multi-megawatt “wave farms” over the next decade, in Europe, the U.S., and Australia

8.1 Introduction

The history of tidal power goes back to at least the Middle Ages. Primitive tidal mills were operated in England in the 11th century. Numerous tidal mills were built in Western Europe, Canada, and the U.S. during the 18th century. As a result of the industrial revolution and subsequent widespread use of electric power, tidal mills became obsolete. With the growing demand for electrical power, the U.S. Army Corps of Engineers was authorized in 1935 to construct a 65-MW tidal power project in Cobscook Bay, Maine. The program was suspended in 1937 due to lack of funding, with construction completed on Quoddy Village (for the workers) and several small auxiliary dams. Throughout the 1950s, 60s and 70s, the U.S. and Canadian Governments sponsored many major investigations of tidal power possibilities in the Bay of Fundy.

Actual construction of "first generation" modern tidal power plants (dam or barrage systems) has been limited to one large (200 MW) facility at LaRance, France, a small (20 MW) experimental plant at Annapolis, Nova Scotia that is still operating today, and a number of small experimental plants in Russia and China.

"Second generation" or in-stream tidal energy technology (i.e., using the kinetic energy from the moving stream of the tidal currents) is a new technology which has seen a heightened interest in the commercial development of tidal energy conversion technology in the UK, Ireland, Italy, Norway, Sweden, and the U.S. over the past five years. This section addresses second-generation tidal in stream energy conversion (TISEC) only.

8.1.1 What Is Ocean Tidal Energy?

The tides are the result of gravitation forces exerted by the moon and the sun on the oceans of the earth, with the moon having the predominant influence. The changing relative position of these bodies causes the surface on the oceans to be raised and lowered periodically, as illustrated in Figure 8-1, according to the following interacting major harmonic cycles:

- A half-day cycle – due to the rotation of the earth within the gravitational field of the moon, resulting in a period of 12 hours 25 minutes between successive high tides. The difference in sea level between high and low tides represents the tidal range. When the sea is rising, it is called flood tide and, when falling, it is called ebb tide.
- A 14-day cycle – resulting from superposition of the gravitational fields of the moon and sun. At new moon and full moon, the sun's gravitational field reinforces that of the moon, resulting in maximum or spring tides. At quarter phases of the moon, the sun's attraction partially cancels that of the moon, resulting in minimum or neap tides.
- A 29.54 day cycle – The moon revolves in an elliptical orbit around the earth every 29.54 days.

The gravitational forces of the sun and the moon create two "bulges" in the earth's oceans: one closest to the moon, and the other on the opposite side of the globe, as illustrated in Figure 8-2. These "bulges" result in two tides a day, called semi-diurnal tides—the dominant tidal pattern in most of the world's oceans. The tide generating forces are explained in more detail in Figure 8-3.

Except at the vernal (spring) and autumnal equinoxes (see Figure 8-1), the axis of the earth's rotation is not perpendicular to the plane of the sun's apparent orbit, and there is a continued variation in the angle of incidence of the suns attractive forces resulting in a daily variation in the tides. Similarly, the moon's attractive forces vary during a lunar day, causing a lunar-diurnal variation. Therefore, successive tides during the same day are not of equal magnitude. This is called mixed semi-diurnal tides, as shown in Figure 8-4.

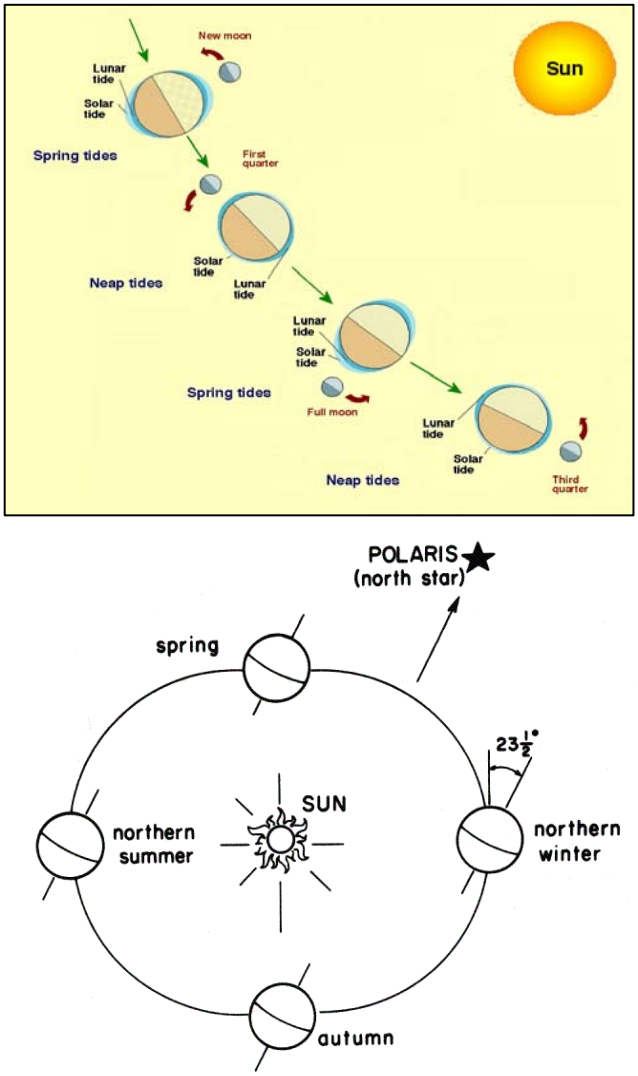


Figure 8-1
Earth, Moon and Sun's Influence on Tides

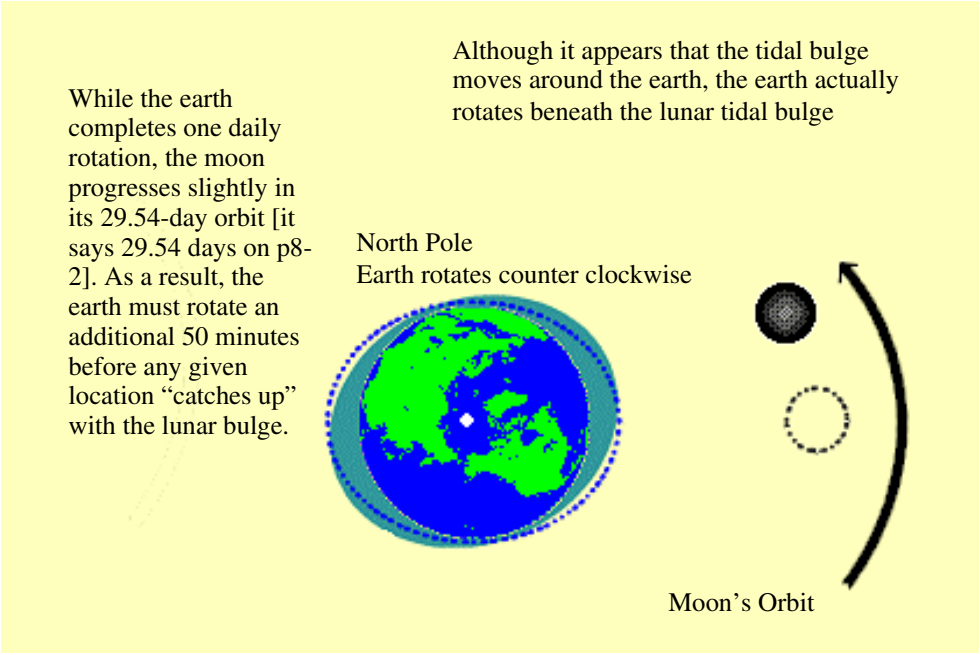


Figure 8-2
Schematic of the Tidal Bulge

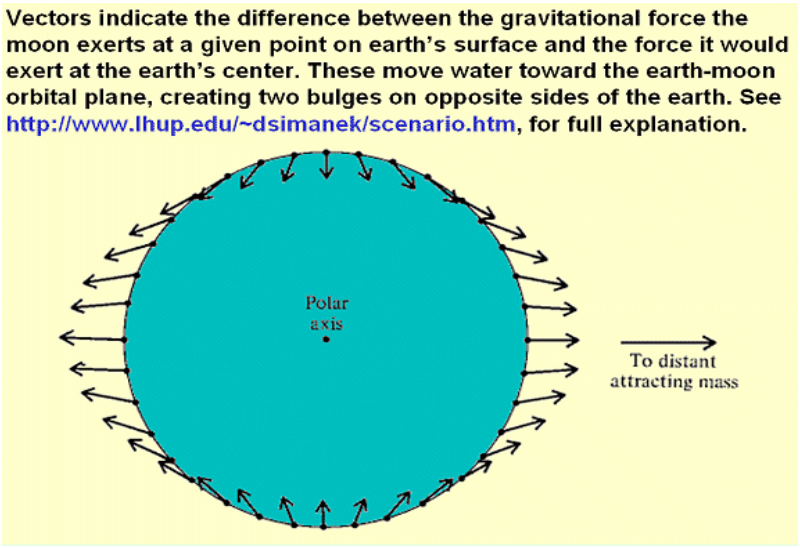


Figure 8-3
Tide Generating Forces based on Earth-Moon Interactions

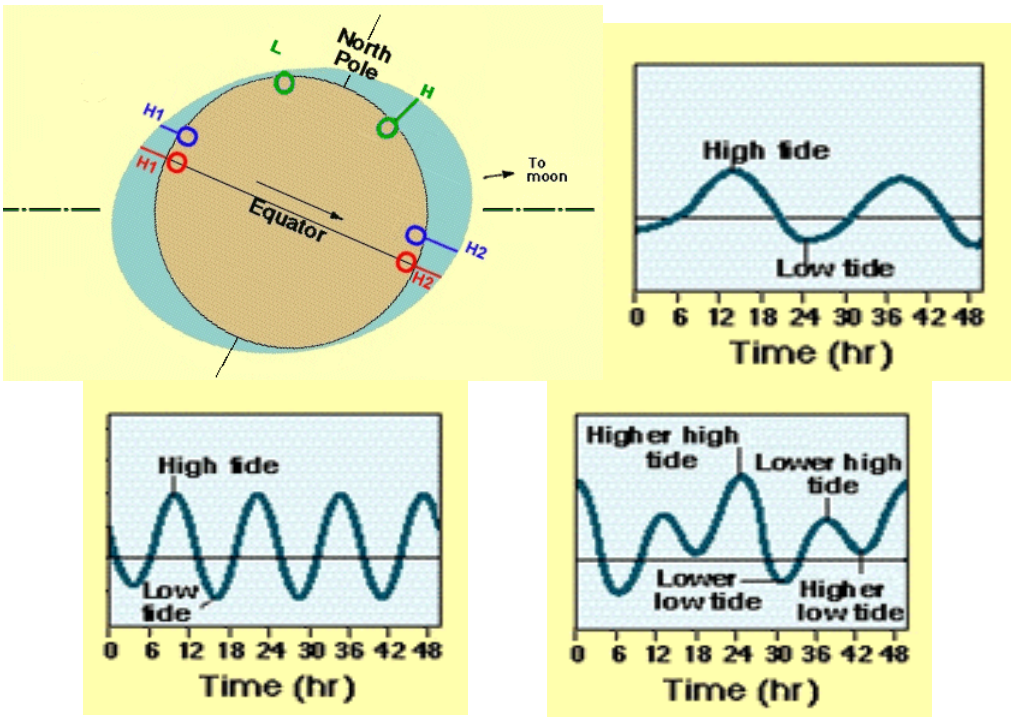


Figure 8-4
Diurnal, Semi-Diurnal and Mixed Semi-Diurnal Tides

Mid-ocean tidal ranges are about 0.6 meters (m). The largest tides occur along coasts and are influenced by the geography of the shoreline. Most of the large tidal ranges throughout the world occur in large estuaries which provide a funnelling effect. In estuaries where the total length of the estuary is twice the tidal wave length, it is possible for hydraulic resonance to occur (e.g., in the Bay of Fundy). This results in a significant increase in the tidal amplitude and may cause tidal bores (tidal waves) at river mouths.

As the axis of the earth is tilted at 23.5 degrees to the moon's orbit, the two bulges are not equal unless the moon is over the equator, as shown on the upper right hand side of Figure 8-4. This difference in tidal height between the two daily tides is called the declinational inequality. This repeats on a 14 day cycle as the moon rotates around the earth. One cycle of high water to low water takes an average of 12.4 hours, although there are occasional variations resulting in a lengthening or shortening of this time.

The solar tidal bulge is only 46% as high as the lunar tidal bulge. While the lunar bulge appears to migrate around the Earth once every twenty nine and a half days, the solar bulge appears to migrate around the Earth once every day. As the lunar bulge moves exactly into and then 90° out of phase with the solar bulge, this gives rise to spring and neap tides, as illustrated in Figure 8-5. Spring tide is the very highest and very lowest tide (i.e. the largest tidal range) which occurs twice a month (every 14/15 days) when the moon is either new or full (when the gravitational pull of the sun and moon is aligned). Neap tides are the opposite of the spring tide. The ratio of springs to neaps can be as much as 2 to 1.

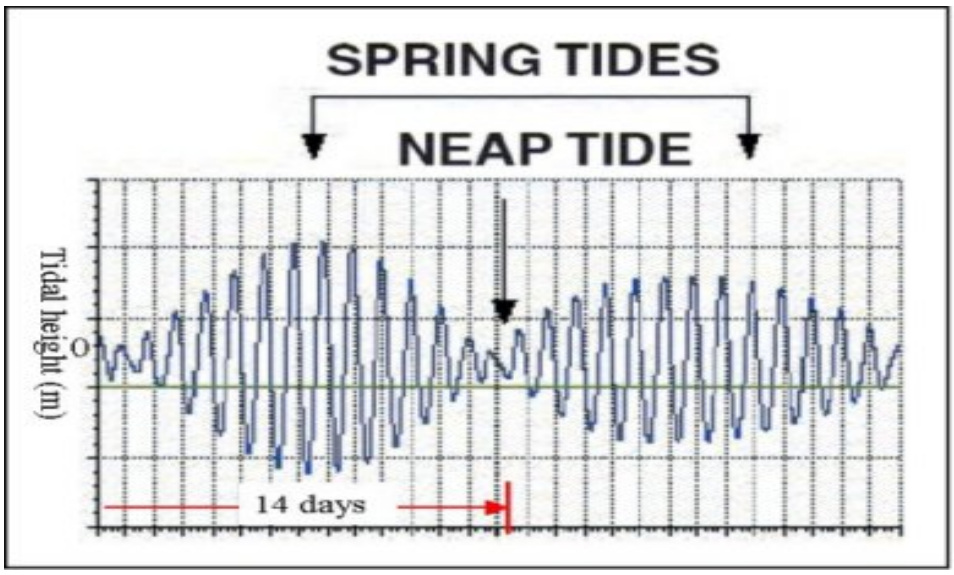


Figure 8-5
Spring and Neap Tides

There are more than a hundred harmonic constituents (cyclic components) of the tide, each with a different cycle time. These constituents combine so that tides only completely repeat themselves every 18.6 years. Only the first few constituents are important for our purposes.

The global distribution of the mean tidal range is shown in Figure 8-6.

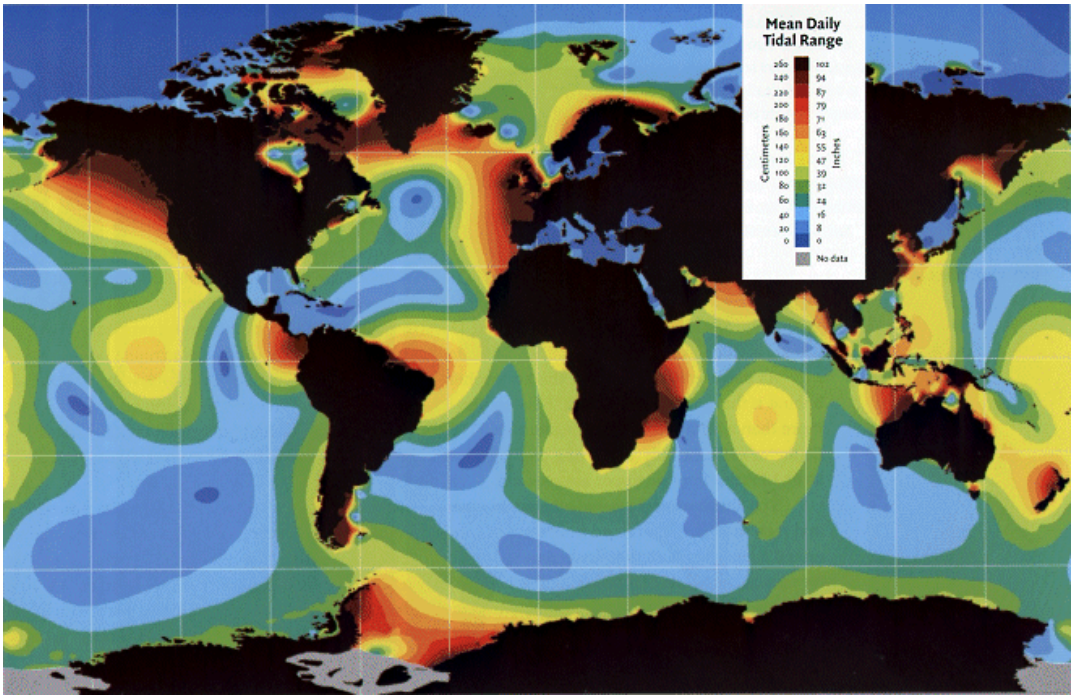


Figure 8-6
Global Distribution of Mean Tidal Range

The Moon's gravity imparts tremendous energy to the Earth, raising tides throughout the global oceans. Some of this energy dissipates with waves rolling across coastal shallows and shoals, but most of it dissipates due to friction between the water and the shallow floor beneath it. Richard Ray at NASA's Goddard Space Flight Center, Greenbelt, MD., and Gary Egbert of the College of Oceanic and Atmospheric Sciences, Oregon State University, Corvallis, OR, studied six years of satellite altimeter data. According to their report, which appeared in the June 15, 2000 issue of *Nature*, about 1 trillion watts, or 25 to 30 percent of the total tidal energy dissipation, occurs in the deep ocean; the remainder occurs in shallow seas. Historically, the principal sink of tidal energy has been thought to be bottom friction in shallow seas. There has long been suggestive evidence, however, that tidal dissipation also occurs in the open ocean through the scattering by ocean-bottom topography of surface tides into internal waves, but estimates of the magnitude of this possible sink have varied widely. Therefore, approximately 70 to 75 percent, or 3 trillion watts, are dissipated in shallow seas.

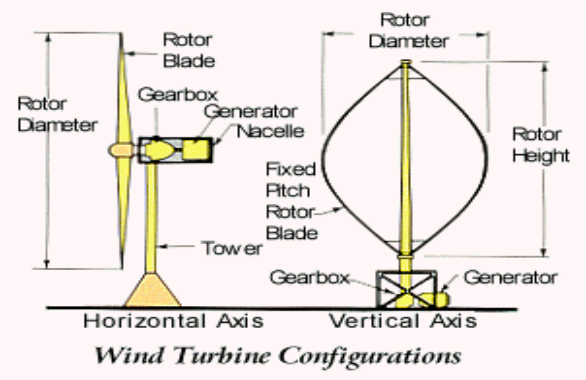
8.1.2 How Can Tidal Energy Be Harnessed?

Tidal energy extraction is complex and many device designs have been proposed. It is helpful to introduce these designs in terms of their physical arrangements and energy conversion mechanisms. Water turbines, like wind turbines, are generally grouped into two types:

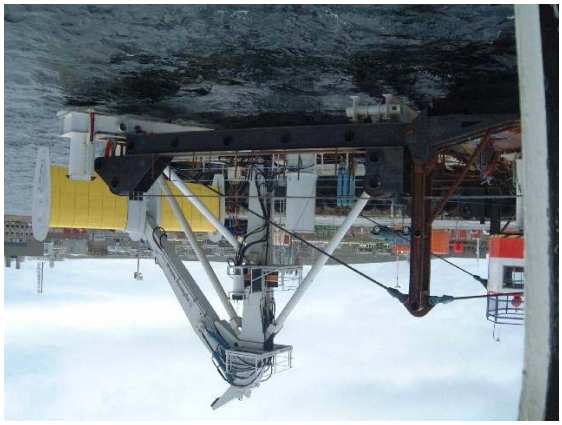
1. Vertical-axis turbines, in which the axis of rotation is vertical with respect to the ground (and roughly perpendicular to the water stream)
2. Horizontal-axis turbines, in which the axis of rotation is horizontal with respect to the ground (and roughly parallel to the water stream.)
3. Venturi system that converts pressure drop of water passing through the ventori to drive a generator
4. Oscillatory systems that convert tidal flow to drive a water pump and generator

Figure 8-7 illustrates the four types of turbines and other devices for electricity generation application.

Horizontal- and Vertical-Axis Turbines



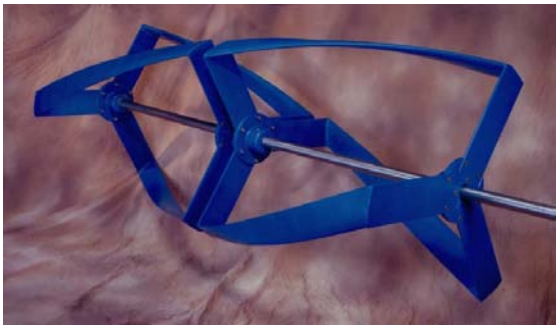
Marine Current Turbines Horizontal Axis Turbine



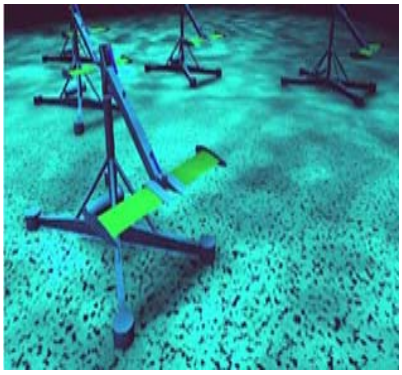
Venturi Tidal Flow Conversion Device



Gorlav Vertical-Axis Water Turbine Rotor



Oscillatory Tidal Current Device Schematic



Stingray Oscillatory Tidal Current Device



Figure 8-7
Tidal Energy Conversion System Configurations

The subsystems typically include a blade or rotor, which converts the energy in the water to rotational shaft energy; a drive train, which usually comprises a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, and interconnection equipment. Additional ways of grouping these devices include:

- Fixing – Devices may be either gravity base, bottom-mounted, attached to a mono pile foundation, anchored, moored and allowed to "fly" in the stream as a result of buoyancy and/or dynamic pressure forces. They may also be hung from a floating platform (with the platform moored to maintain its location).
- Open vs. ducted – Turbine rotors may be either open, much like wind turbines, or have ducting. Since the energy is a function of the cross-sectional area of the influenced water, using a duct of a given cross sectional area is the equivalent of using an open rotor whose cross-sectional area is the same. The wind energy industry has found that adding length to a rotor blade is more economical then adding a duct to increase the area and power of a wind machine. A duct, however, may be useful in a situation where a given turbine does not have yaw control and the direction of the tidal stream may vary by up to 20 degrees.
- Fixed vs. variable pitch blades – Pitch control is used to limit power, maximize the efficiency of the turbine and enable bi-directional operation. There are other ways to accomplish these three functions with fixed blade turbines and many different design concepts for implementing them.
- Closed center (hub-type) vs. open center – Instead of a fixed hub and rotating blades, a design variation uses an outer fixed rim and an inner rotating bladed disc. The potential benefit in an open center design is the elimination of the need for a gearbox by encapsulating the stator of a generator on the rim of the machine.
- Savonius vs. Darrieus Vertical Axis Turbines – First invented in Finland, the Savonius turbine is S-shaped if viewed from above. This drag-type vertical axis turbine turns relatively slowly, but yields a high torque. The Darrieus turbine was invented in France in the 1920s. Often described as looking like an eggbeater, this vertical axis turbine has vertical blades that rotate into and out of the wind. Using aerodynamic lift, these turbines can capture more energy than drag devices. The Giromill and cycloturbine are variants on the Darrieus turbine.
- Helical vs. cycloidal aerodynamic lift type vertical axis turbine blade configuration – A helix is a three-dimensional curve that lies on a cylinder or cone, so that its angle to a plane perpendicular to the axis is constant. A cycloid is the curve traced by a point on the circumference of a circle that rolls on a straight line.

There are a couple of other types being investigated (e.g., hydro venturi and oscillating), however, they are not of sufficient practical importance at this time to be described in this report.

8.1.3 Will These Systems Survive Storms and Hostile Marine Environments?

Yes. Being totally submerged means that tidal energy conversion systems will not need to bear the full brunt of a storm. Relative to long-term survival in the environment, oil and gas platforms using anti-corrosion and biofouling technology are surviving 50 years, including equipment in more hostile splash and tidal zones. The MCT 300-kW first-of-a-kind experimental prototype has been continuously operating for over three years (since May 2003) off the UK coast.

8.1.4 Will These Tidal Power Plants Affect the Environment?

Given proper care in site planning, tidal in stream power promises to be one of the most environmentally benign electrical generation technologies and should not cause any permanent damage to the environment. Early demonstration and commercial tidal in stream power plants should include rigorous monitoring to record both environmental impacts as well as natural impacts at nearby undeveloped sites.

While no definitive “in-situ” monitoring studies have been conducted to date, due to the newness of the technology and lack of deployed systems, anecdotal information from numerous temporary testing activities in the U.S., UK, and abroad have not observed any harm to aquatic life. Further, theoretical evaluations based on technology specifications (such as rotation speed and other physical parameters) and extensive fish studies based on traditional hydro turbine systems suggest these new technologies are environmentally friendly.

The blades of TISEC devices rotate very slowly (around 10 rpm for a 18 meter diameter rotor) and the speed at the tip of the blade is about 10-12 m/s (22-27 mph). The devices are self limiting in that any faster speeds result in cavitation.

Two TISEC test programs with thorough environmental assessments of sea life and environmental effects will start in 2007: the Verdant RITE project in New York's East River and the MCT SeaGen project in Strangford UK.

Tidal energy environmental issues include:

- No noticeable environmental effects have been recorded from three years of testing of the 300-kW MCT Seaflow tidal machine in the UK.
- Concerns have been documented in the environmental impact statement prepared by the European Marine Energy Center (EMEC) – Tidal.
- No noticeable effects have been identified from short term U.S. testing in the East River, NY; Merrimack River, MA; and Long Island, NY.
- The most thorough environmental monitoring program ever conducted is set to proceed for the Verdant project’s 16-foot diameter open rotor horizontal axis TISEC device in the East River, New York, NY in 2007. The first two of six turbines were installed in December 2006.

8.1.5 Will Regulatory Agencies Grant Permits for Offshore Tidal Power Plants?

Even though tidal energy technologists may assume that there are no known environment concerns, the novelty of the technology at the federal, state and local level will likely trigger conservative evaluations and extensive approval processes. Permitting a tidal power plant presents a significant barrier to the development of tidal energy technology and to commercial use of the technology. The primary reasons are:

- There are a wide variety of regulations and agencies involved; the process is complex and each state and project is unique.
- There is no precedence upon which regulators can base approval decisions.

- The only licensing process available is the FERC hydropower process which was created to manage the impacts of conventional hydropower facilities with impoundments and with 30 to 50 year cycles. That process is both lengthy (5 to 8 years) and costly (considerably beyond what the fledgling TISEC device industry can afford).
- No specific "fast-track" or "conditional" (i.e., if negative impacts are seen, the license is revoked and devices must be taken out) regulations exist for short-term non-commercial ocean energy demonstration projects.
- There is no accountability for acts of omission, creating a bias for delay. Stakeholders can be and are generally held accountable for acts of commission (taking action) and not for acts of omission (doing nothing). Without an accountability for action, the default is "more study" and "no action."
- Opponents of a particular ocean energy project can use regulatory uncertainty to their advantage to contest a project
- The first preliminary permits issued by FERC resulted in the granting of development rights to project developers who appear to be more interested in developing new TISEC device concepts than developing projects.
- Lack of regulatory standards is making it impossible to predict whether or not, on what terms and at what costs a permit will be issued. This situation is deterring private investment.

As of January 2007, 32 applications for TISEC power plant permits, listed in Table 8-1, have been filed with the Federal Energy Regulatory Commission, of which only four have received preliminary permits. To address the permitting logjam, FERC hosted a conference in Washington, D.C. in December 2006 to discuss the status of ocean-based hydroelectric technologies and explore the environmental, financial, and regulatory issues pertaining to their development.

Three new FERC applications for preliminary permits were filed in October (all in NY):

- Natural Current Services - 136-square-mile tidal energy project off Orient Point
- Verdant Power - Plum Gut.
- Verdant Power - off Fishers Island.

Table 8-1
List of Tidal In Stream Energy Conversion (TISEC) Projects in the FERC Database

	Developer	Project	State	Docket Number	Submit Date	Issue Date	Expire Date
1	Verdant Power	East River	NY	12178			Expired
2	Verdant Power	East River	NY	12611	9/6/2005	12/13/2005	1/30/2008
3	Golden Gate Energy	San Francisco Bay	CA	12585	4/27/2005	10/11/2005	9/30/2008
4	Tacoma Power	Tacoma Narrows	WA	12612	9/15/2005	2/22/2006	1/31/2009
5	Oceana	Deception Pass	WA	12663	3/31/2006		
6	Oceana	Portsmouth Area	NH	12664	3/29/2006		
7	Oceana	Astoria	NY	12665	3/27/2006		
8	Oceana	Kennebec	ME	12666	4/3/2006		
9	Oceana	Penobscot	ME	12668	4/3/2006		
10	Oceana	Cape and islands	MA	12670	4/17/2006		
11	Oceana	Columbia	OR	12672	4/28/2006		
12	Oceana	Katchemank Bay	AK	12694	6/19/2006		
13	Oceana	Ice Passage	AK	12695	6/19/2006		
14	Oceana	Gastineau Channel	AK	12696	6/19/2006		
15	Oceana	Wrangell Narrows	AK	12697	6/19/2006		
16	Oceana	Central Cook Inlet	AK	12705	6/28/2006		
16	SNOPUD	Deception Pass	WA	12687	6/15/2006		
17	SNOPUD	Rich Passage	WA	12688	6/15/2006		
18	SNOPUD	Spiden Channel	WA	12689	6/15/2006		
19	SNOPUD	Admiralty Inlet	WA	12690	6/15/2006		
20	SNOPUD	Agate Passage	WA	12691	6/15/2006		
21	SNOPUD	San Clemente Channel	WA	12692	6/15/2006		
22	SNOPUD	Guemes Channel	WA	12698	6/15/2006		
23	ORPC	Resurrection Bay	AK	12678	5/30/2006		
24	ORPC	Cook Inlet	AK	12679	5/30/2006		
25	ORPC	Western Passage	ME	12680	5/30/2006		
26	ORPC	Cobscook Bay	ME	12711	7/10/2006		
27	UEK	Hydrokinetic energy	NH	12722			
28	Natural Currents	Wards Island	NY	12718			
29	Port Townsend	Admiralty Inlet	WA				

8.1.6 Will Offshore Tidal Power Be Reliable and Cost-effective?

Yes. TISEC technology in a good tidal site can provide a cost of electricity in the same range as existing commercial on-land wind technology, natural gas (at $5/MMBTU), and ultra supercritical coal.

8.1.7 What Is the Installed and Planned Capacity?

The installed capacity in the U.S. as of December 31, 2006 is 0.07 MW (two 34kW Verdant water turbines in the East River in NY). Table 8-2 presents the EPRI estimate of tidal in stream capacity (in MW) that will come on line (i.e., commissioned and selling electricity into the grid) in the U.S. from 2007 though 2011.

Table 8-2
Installed and Planned U.S. Tidal Energy Capacity

Developer	Project Name-Site	2007	2008	2009	2010	2011
Verdant (1)	East River, NY	0.2		4.8	10	15
ORPC (2)	Western Passage, ME				50	
Oceana or Some One Else (3)	Golden Gate, CA				50	50
SNOPUD (4)	Admiralty Strait, WA					50
TBD (5)	Cook Inlet, AK					2
TOTAL NEW	YEARLY CAPACITY	0.2	0.0	4.8	110	117
	CUMULATIVE	0.2	0.2	5	115	232

*Estimate based on what is known as of 2006; assumes that FERC changes its policies to enable tidal in stream plants to be permitted at about the same cost as on-land wind plants and that Congress provides the same incentives to tidal in stream energy as for wind energy.

(1) Assumes extractable rated capacity of the East River is 30MW; however, EPRI has not studied this site.
(2) Assumes that ORPC will be able to leverage off the system, and will be able to get a license without a pilot plant.
(3) EPRI is not confident that Oceana has the skills required to develop this project. Nevertheless, we are making an optimistic assumption that someone will develop the Golden Gate site since it is the most economically attractive site in the lower 48 states of the U.S.
(4) Assumes that Tacoma Power will not implement the Tacoma Narrows project for which they have a FERC preliminary permit, and that SNOPUD will instead develop a tidal project in the upper Puget Sound.
(5) Assumes that a developer in Alaska will initiate a project, as the state has the best tidal resources of any state in the U.S.

If these early demonstration projects prove successful, medium-size tidal farms up to 50 MW in capacity could be deployed within the next five to eight years. In general, the industry expects that tidal energy will experience a growth rate similar to that of wind during the last decade, although these predictions depend largely on government support and incentives for the emerging tidal energy industry.

8.1.8 What Other Introductory Information Is Important to Know?

Before discussing TISEC devices, it is necessary to define a few terms:

- ***TISEC Area (A) –*** the cross sectional area of the current flow intercepted by the device (i.e., shroud inlet area for a shrouded turbine, swept area of the turbine blades for an unshrouded turbine, plan form area for a vertical axis turbine).
- ***Rated Power (P_r)*** – that power level which can be sustained without overheating the generator or the design power level corresponding to the mean maximum spring current speeds for a particular deployment site, whichever is less.
- ***Free flow power available to TISEC Device (P_a)*** – a function of the TISEC area A and the instantaneous current speed (U) = ½ * density of the water (typically taken as 1,024 kg/m^3 for seawater) * A * U^3 (watts).
- ***Mean Maximum Spring Speed (MMSS***) – The average of the maximum or peak spring current speeds over a one year period.
- ***Mean Maximum Neap Speed (MMNS)*** – The average of the maximum or peak neap current speeds over a one year period.
- ***Water to wire efficiency for standard lunar month cycle*** = E_{in} / E_{out}

  where

  – E_{in} is the free flow energy available for a given time period (usually a year)
  – E_{out} is the TISEC energy output for a given time period (usually a year)

8.2 Tidal Power and Energy Resource Characterization in United States and Canada

The last half dozen years has seen a heightened interest in the commercial development of tidal energy conversion technology in the UK, Ireland, Italy, Norway, Sweden and the U.S.

8.2.1 United States

The National Ocean Service (NOS) Center for Operational Oceanographic Products and Services (CO-OPS) collects and distributes observations and predictions of water levels and currents to ensure safe, efficient and environmentally sound maritime commerce. The center manages the National Water Level Observation Network (NWLON) and a national network of Physical Oceanographic Real-Time Systems (PORTS) in major U.S. harbors. The NOS Tidal Current program is described in Reference 8-1.

Tidal Current Prediction Source - NOS

Professional mariners and ship operators of all propelled vessels of 1,600 gross tons or more are required by the Code of Federal Regulation (33 CFR Chapter I, 7/1/91 Edition, U.S. Coast Guard, DOT '164.01 and '164.33) to carry the current edition of the Tide Tables and the Tidal Current Tables published by the National Ocean Service (or its equivalent) when operating their vessel in navigable waters of the United States (except in the St. Lawrence Seaway). The tables predict the daily magnitude and timing of high and low water, maximum flood, maximum ebb, and slack for a limited number of representative stations known as reference stations. Predictions at these locations are the basis for predictions at thousands of subordinate, secondary stations through the use of scaling factors and time differences.

The CO-OPS NOS predictions page (http://co-ops.nos.noaa.gov/tide_pred.html) is separated into two sections. The first, Tidal Predictions, provides tidal predictions at a few thousand stations around the U.S., Caribbean and Pacific Islands. The second, Tidal Current Predictions, provides tidal current prediction for a few hundred U.S. and Canadian tidal current reference stations; as well as time and speed adjustment to allow the calculations to predict tidal currents at a few thousand secondary stations. Both tide and tidal current predictions are provided for the present calendar year. The predictions are updated in late October or early November to include the following calendar year.

Current velocity tables are at http://co-ops.nos.noaa.gov/curents04/currpred.html. Both tide and tidal current predictions are based upon analyses of observations at reference stations. Since extremes of meteorological conditions have been excluded from the analyses, the predicted values should be considered as those expected under average weather conditions. Generally, prolonged onshore winds or a low atmospheric pressure can produce higher-than-predicted levels, while the opposite can result in lower levels than those predicted. The tidal water levels are given in feet above Mean Low Water, which is the nautical chart datum of soundings for the U.S. Tidal current speeds are, meanwhile, provided in knots.

Unlike tide stations, which are normally located along the shoreline, most tidal current stations are located offshore in channels, rivers and bays. Tidal current stations are often named for the channel, river or bay in which they are located or for a nearby navigational reference point.

Current Reference Stations

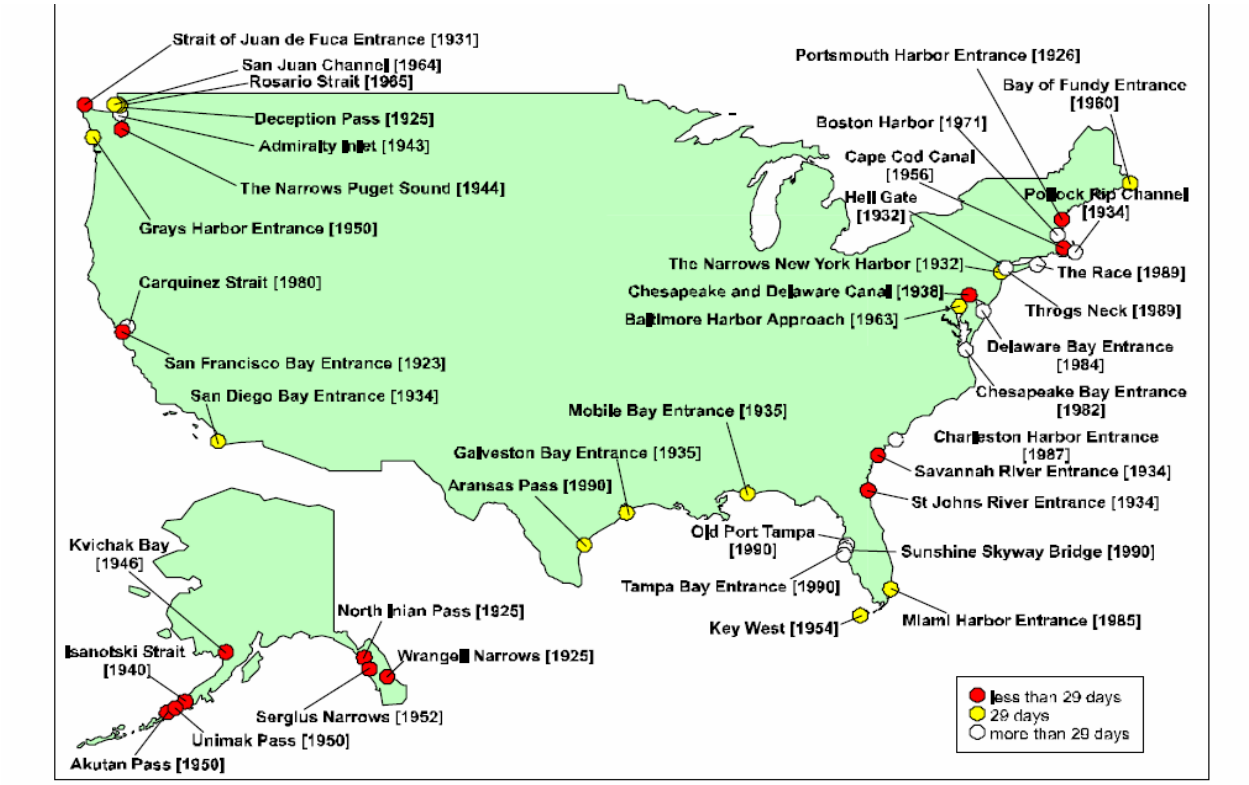
The published CO-OPS NOS Tidal Current Tables are presented in the same format as the NOS Tide Tables. A limited number of reference stations have daily predicted times of floods, ebbs, and slacks and maximum current at floods and ebbs printed in a section known as “Table 1.” Most tidal current predictions are based on data sets that would be considered inadequate for making tidal water level predictions. Historically, due to technological, logistical and resource limitations, current measurements are of a shorter duration than water level measurements. The long term continuous operation of the National Water Level Observation Network (NWLON) stations, results in tidal water level constituents that are better resolved and more up to date than the tidal current constituents.

For a larger group of tidal current stations called subordinate stations, predicted floods, ebbs and slacks are calculated by the user from the “Table 1" predictions with time differences and speed ratios. These constants are listed in a section of the Tidal Current Tables known as “Table 2.” Table 2 also indicates which tidal current reference station to apply the constants. The constants are obtained by a non-harmonic analysis that compares a short period of data at the subordinate station with observations or predictions for the same period at the reference station. The amount of subordinate station data used is usually less than 15 days and in some cases as little as one day. Deciding which reference station to use for a subordinate station is a subjective decision usually based on proximity and similarity in the shapes of the tidal current curves.

Data from tidal current reference stations are the source for computing accepted values of harmonic and non harmonic constants essential to daily tidal current predictions. Existing tidal current predictions are presently based on limited data sets from reference stations that date as early as 1901. The data from these stations serve as the control for the reduction of short time series from subordinate current stations through comparison of simultaneous observations. Historically, reference stations require a minimum of 15 days of continuous velocity observations for harmonic analysis from which subordinate stations predictions can be computed with time differences and speed ratios. Longer time series improve predictions at reference stations by separating similar harmonic constituent frequencies.

U.S. Geographical Coverage

Figure 8-8 shows CO-OPS NOS reference stations for tidal current prediction in the five U.S. regions of interest—Cook Inlet Alaska, Puget Sound Washington, San Francisco Bay California, Bay of Fundy Maine and Massachusetts.



Tidal current reference stations of the United States categorized by duration of observations with the year of data acquisition in brackets.

Figure 8-8
United States Tidal Current Reference Stations

Characteristics of the Tidal Current Data

Table 8-3 presents a list of characteristics for each of the tidal current reference stations. It can be used to compare and contrast the predicted tidal currents. The number of harmonic constituents used to make tidal current predictions varies between eight (8) for the Canadian station, Bay of Fundy Entrance, and twenty nine (29) for Carquinez Straits in California. Predictions for the Bay of Fundy Entrance are provided by the Canadian Hydrographic Service and are included in this study because 135 U.S. subordinate stations are referenced to it.

Table 8-3
U.S. Tidal Current Site Characteristics

Reference Station Name	Number of Subordinate Stations	Number of Constituents	MFC Speed (knots)	MEC Speed (knots)	Permanent Current (knots)	Tidal Ratio	Tidal Class-ification
Bay of Fundy Entrance (Canada)	135	8	2.3	2.4	-0.041	0.09	S
Boston Harbor, MA	153	13	1.1	1.2	-0.280	0.15	S
Cape Cod Canal, MA	16	17	4.0	4.5	0.000	0.10	S
Pollock Rip Channel, MA	115	16	2.0	1.8	0.150	0.08	S
San Diego Bay Entrance, CA	27	16	1.2	1.5	-0.090	0.36	M M S
San Francisco Bay Entrance, CA	136	20	2.9	3.4	-0.200	0.38	M M S
Carquinez Strait, CA	57	29	2.1	2.2	-0.138	0.51	M M S
Grays Harbor Entrance, WA	44	20	1.9	2.8	-0.300	0.30	M M S
Strait of Juan de Fuca Entrance, WA	1	14	0.6	1.5	-0.500	0.53	M M S
Admiralty Inlet, WA	75	17	1.6	2.6	-0.500	0.53	M M S
The Narrows Puget Sound, WA	31	20	3.2	2.8	0.000	0.44	M M S
Deception Pass, WA	4	17	5.2	6.6	-0.650	0.29	M M S
Rosario Strait, WA	46	20	1.1	1.9	-0.400	0.70	M M S
San Juan Channel, WA	13	21	2.6	2.6	-0.050	0.50	M M S
Wrangell Narrows, AK	345	21	3.7	3.4	0.000	0.16	S
Sergius Narrows, AK	62	18	5.9	5.5	0.200	0.06	S
North Inian Pass, AK	28	21	2.9	5.1	-1.400	0.17	S
Isanotski Strait, AK	11	18	3.6	2.8	0.400	0.36	M M S
Unimak Pass, AK	35	20	3.4	3.0	0.500	0.72	M M S
Akutan Pass, AK	7	21	5.8	5.3	0.200	0.56	M M S
Kvichak Bay, AK	39	17	2.5	2.5	-0.300	0.29	M M S

S = Semidiurnal, M M S = Mixed Mainly Semidiurnal, M M D = Mixed Mainly Diurnal, D = Diurnal

The maximum flood currents (MFC) and maximum ebb currents (MEC) shown in Table 8-3 are the average of the greatest speeds during a flood or an ebb period. They provide an estimate of the strength of current at the reference stations which were usually chosen to be located where the strongest currents in a bay or estuary could be measured. The volume of water that must pass a given point in a bay or estuary is equal to the tidal prism above that location. The tidal prism is approximately the surface area of the bay multiplied by the mean tidal range of the bay. Tidal currents will be proportional to the tidal prism and inversely proportional to the cross sectional area through which the volume of water must pass. The strongest currents (> 5 knots) occur in narrow channels or channels through which large volumes of water must pass (Deception Pass, Sergius Narrows, and Akutan Pass). The weakest currents (< 1 knot) occur in wide or deep channels (Strait of Juan de Fuca Entrance) or at some distance from the ocean.

Example Tidal Current Data

The availability of tidal current predictions and observed current data is limited relative to the availability of tidal data. Continuous measurements of currents were not possible until recently. Short deployments of current meters at various estuaries have been carried out for over 100 years. Archived data sets are available but data quality can vary considerably based on the age of the data and location of the measurements. Inquiries about specific locations to ascertain if data exists, its quality and availability can be answered by the National Oceanographic Service (NOS) office at (301) 713-2815 between 7AM-3PM Eastern Time or via e-mail at: Tide.Predictions@noaa.gov

NOS tidal current predictions are available in various bays, harbors, estuaries, and within rivers and channels. Inquiries and requests for tidal current predictions can also be sent to the NOS.

Currents are spatially variable, thus predictions should NOT be extrapolated even to near-by locations. Interpolation between two nearby locations should NOT be attempted.

Short term tidal current predictions for a single calendar month at any of the primary or secondary stations listed in the Tidal Current Predictions section of the NOS web site can be obtained via e-mail from: Tide.Predictions@noaa.gov. Subsequent requests for additional months are subject to a fee for custom predictions described below.

Long term tidal current predictions (more than one month) are not available for secondary tidal current stations through the internet or e-mail from the NOS office. Long term tidal current predictions on a calendar year basis can be obtained by calling the NOS office at (301) 713-2815 between 7:00 am-3:00 pm Eastern Time or via e-mail at: Tide.Predictions@noaa.gov

Tidal current predictions are available in several different formats.

- International Format - An electronic ASCII file which provides time and speed of current for a single location in a column delimited format. It is most suitable for importing into a database, plotting, or other computer program.
- Standard Format - Available in hardcopy and as an electronic ASCII file which provides time and speed of current for a single location in a page readable format.

- Manuscript Format - Available in hardcopy and as an electronic PostScript file, which provides time and speed of current for a single location in a format that presents three-months of data on each page.

8.2.2 Canada

The Tides, Currents and Water Levels Web Site (http://www.waterlevels-niveauxdeau.gc.ca/) provides predicted times and heights of high and low waters, and the hourly water levels for over seven hundred stations in Canada. The printed version is published yearly and is available through authorized chart dealers **(http://www.charts.gc.ca/chs/en/dealers/)** [Reference 8-2]. Presently, there are no actual current predictions available on the website. The Canadian Tide and Current Tables come in seven different volumes covering the regions shown in Figure 8-9.

The Tide Tables provide predicted times and heights of the high and low waters associated with the vertical movement of the tide. The Current Tables provide predicted times for slack water and the times and velocities of maximum current, all of which are associated with the horizontal movement of the tide.

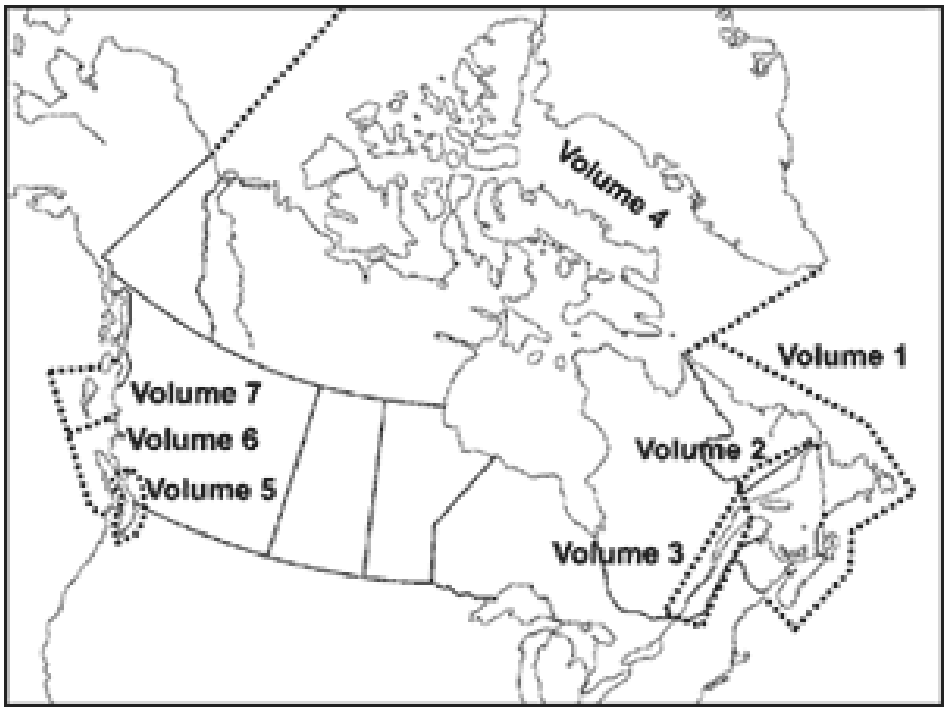


Figure 8-9
Canadian Tide and Current Tables and Regions Covered by the Canadian Data

The Tidal Current Atlases present a comprehensive view of the hourly rate and direction of major tidal currents within specific coastal regions of Canada. The Atlases use arrows to indicate the direction and the velocity of surface currents. They are used in conjunction with the Tide and Current Tables, provided annually by the Canadian Hydrographic Service. Tidal Current Atlases are available for Bay of Fundy and Gulf of Main, St. Lawrence Estuary from Cap de Bon-Désir to Trois-Rivières and Juan de Fuca Strait to Strait of Georgia in the Pacific Coast.

Department of Fisheries and Oceans (DFO) Software – *WebTide*

Because CHS current tables exist for only three sites in Atlantic Canada, EPRI used the freely available *WebTide* software package to develop tidal current time histories at the sites selected for conceptual design by the NB and NS Advisory Groups. *WebTide* is a graphical user interface to a tidal prediction program covering the ocean regions shown in Figure 8-10, developed by the Bedford Institute of Oceanography and maintained by the Department of Fisheries and Oceans (http://www.mar.dfo-mpo.gc.ca/science/ocean/coastal_hydrodynamics/WebTide/webtide.html). Predictions can be obtained for any geographic coordinates inside a selected region and are based upon analyses of the output from a variety of ocean models.

WebTide is based on a relatively coarse numerical grid. Several Canadian experts have told EPRI that *WebTide* was never intended to yield accurate tidal current velocities in nearshore, constricted passages. Even so, it was the only tool available to develop velocity time histories at the selected NB and NS sites.

The EPRI approach was to use *WebTide* to "hindcast" tidal current velocities at a location and time period of nearby short-term measurements, and then use those data to develop regression relationships for adjusting *WebTide* velocities at that location, applying those adjustments to a year-long hindcast at the nearby TISEC transect selected by our NB and NS stakeholders.

8.2.3 Tidal Power Flux and Average Annual Energy

This section describes the methodology used by EPRI to calculate the total average annual tidal stream energy resource available and extractable at selected sites in Alaska, Washington State, California, Massachusetts, Maine, New Brunswick, and Nova Scotia.

Site Screening

Potential TISEC sites typically are found where there is a narrow channel or passage between two landmasses, or an inlet into a bay, through which substantial volumes of tidal water must flow. Among the many attributes of a potential TISEC project site is the size of the tidal stream resource, which is a function of both the speed of the tidal currents (incident power density) and the channel cross-sectional area (width and depth). As detailed in Site Survey Reports, sites also should have suitable seabed geology for proper anchoring of the TISEC devices, and should be situated reasonably close to existing grid interconnection points and shoreside support centers with suitable harbors for inspection, maintenance, and repair.

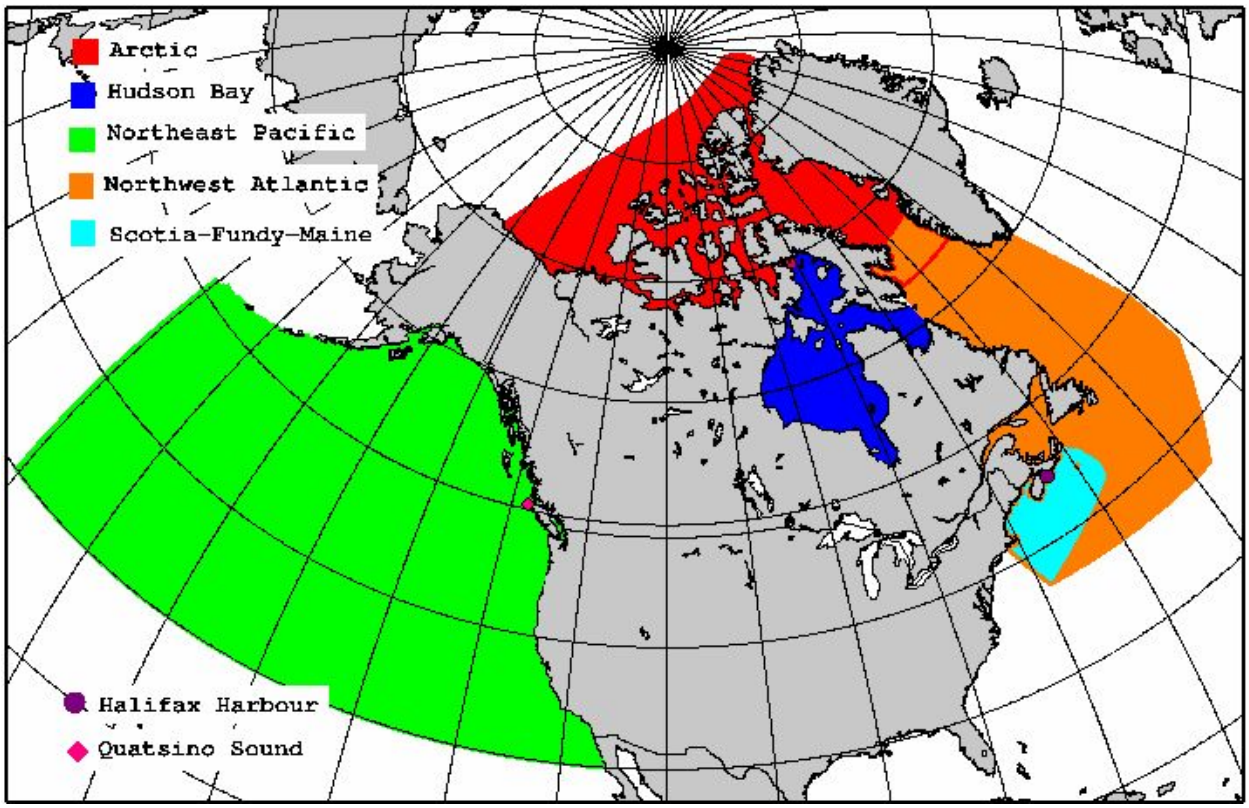


Figure 8-10
WebTide Ocean Model Regions

Initial screening of sites for inclusion in Site Survey reports was based on peak ebb and flow velocities reported in tidal current tables or shown as vectors on hydrographic charts. Any site that had either flood or ebb peak currents averaging at least three knots (1.5 m/sec) was included in the Survey Report. Sites also were included if there was anecdotal evidence for high tidal flow speeds, even when the three-knot peak speed criterion was not met.

Mean Annual Power Density

To estimate mean annual power density, it is first necessary to know the speed of the surface currents as a function of time, which is available from a variety of data sources, as previously discussed in Sections 8.2.1 and 8.2.2. The power density for a flow with a known current velocity may be readily calculated. The calculation must then account for the vertical variability of current speed with depth, and its horizontal variability across the channel. This yields an estimate for the mean annual, depth-averaged, width-averaged tidal stream power density.

Surface Current Velocities

Surface current velocities for the east coast sites surveyed were obtained from the best available data. For most U.S. locations, these were predictions from the NOS Tidal Current Tables, where they were available. NOS predictions were available for all six sites surveyed in Massachusetts, but only for five out of the ten sites surveyed in Maine.

For the eleven U.S. sites where NOS predictions were available, the commercial software program *Tides & Currents* was used to predict the surface velocity time history for the entire calendar year of 2005, at 30-minute intervals. A probability distribution analysis was then performed on this time history to create a histogram showing how frequently particular speed categories occurred throughout that year. For sites in Washington and Alaska, calculations were made independent of *Tides & Currents* using a fitted sinusoid approach.

Frequency distributions for two west coast and east coast sites are given below. The much larger diurnal inequality on the west coast results in a modal velocity (most commonly occurring) closer to the lower end of the velocity distribution. Peak velocities are more similar from tide to tide in the semi-diurnal tidal regimes on the east coast, yielding a narrower distribution with the modal velocity shifted towards the upper end.

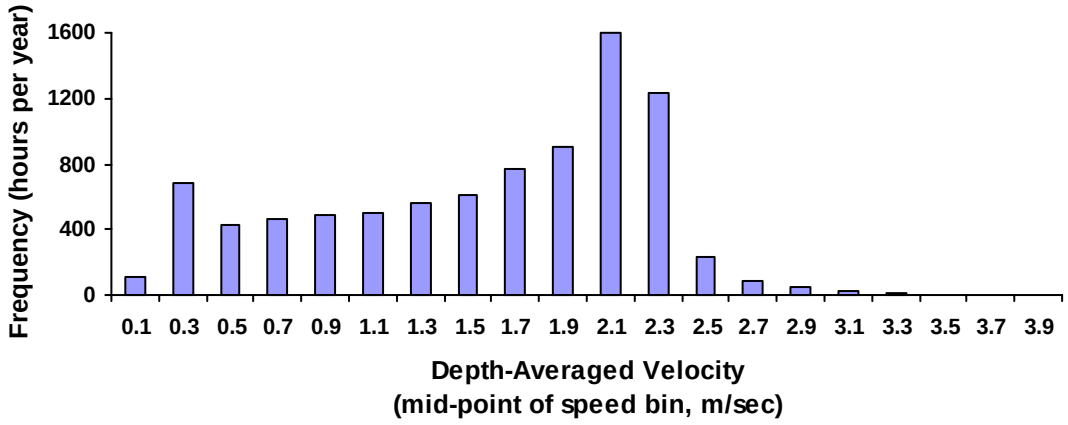


Figure 8-11
Annual Average Tidal Current Speed Probability Distributions for Cape Blomidon transect, Minas Passage, NS (East Coast)

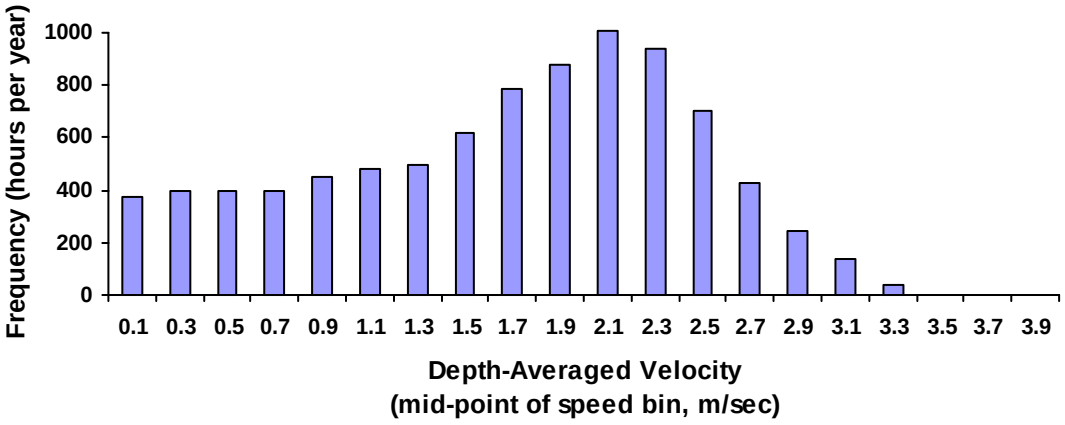


Figure 8-12
Annual Average Tidal Current Speed Probability Distributions for Dog Island transect, Western Passage, ME (East Coast)

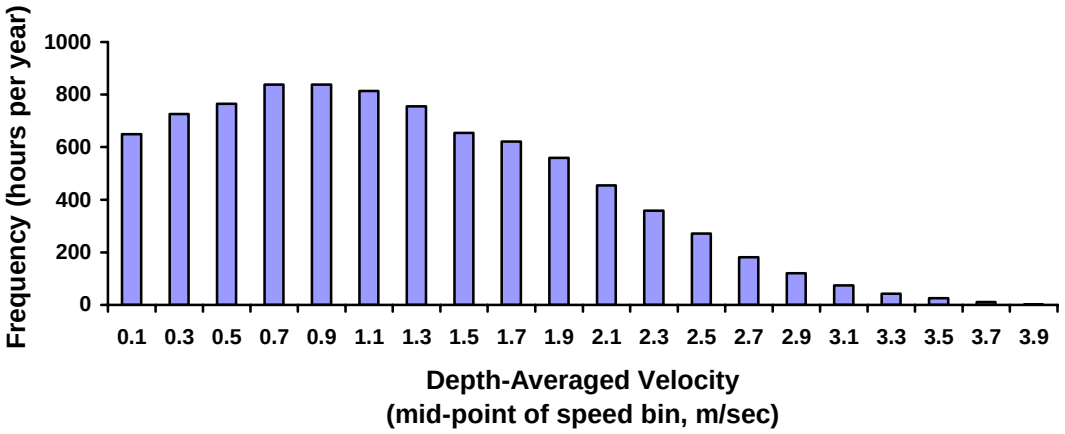


Figure 8-13
Annual Average Tidal Current Speed Probability Distributions for Point Evans Transect, Tacoma Narrows, WA (West Coast)

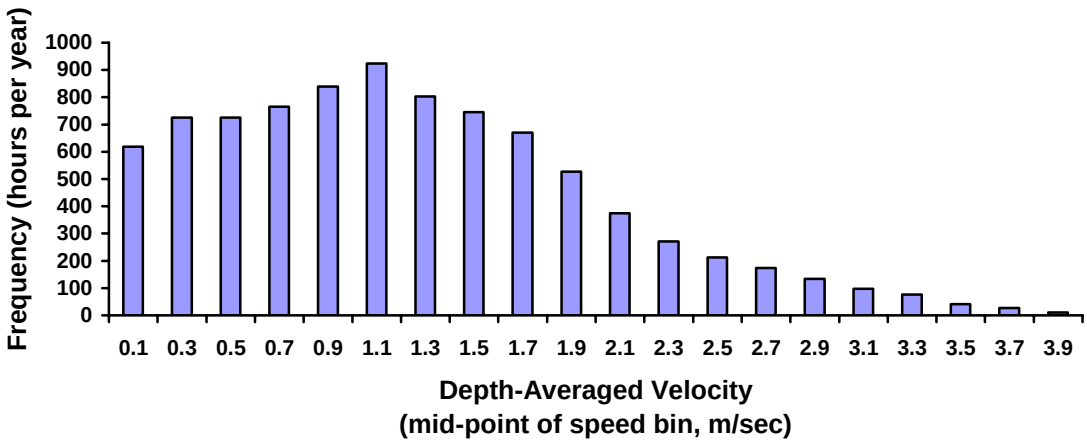


Figure 8-14
Annual-Average Tidal Current Speed Probability Distributions for Cairn Point Transect, Knik Arm, AK (West Coast)

Once the velocity distribution has been determined for a site, the power density for each bin of the distribution is calculated. The weighted average of these power densities is the annual average power density. Note that this is for the surface velocities at the current reference station and must be modified to take into account depth and cross-channel variations in velocity.

Extrapolation of Velocity Time History to a Different Channel Section

In some cases, current data or predictions may be available in a region outside of a constricted channel where a TISEC plant might be sited. This is the case for sites in California (San Francisco) and Maine, where the potential TISEC project sites are at narrow transects where the channel flow is most constricted and the tidal currents are fastest, but the NOS prediction stations are at wider transects where the currents are slower. For these two designs, open-channel flow theory was used to extrapolate predicted current speeds from the wider transect to the narrower transect where the project is located. Note that this assumes the flow decelerates rapidly and uniformly beyond the constricted area. However, strong tidal flows may continue into a section of channel that is wider, manifesting as something akin to a "jet" of strong flow confined to the deeper, central channel, and not uniformly spreading out across its full width.

Assuming the flow does decelerate uniformly and is subcritical (Froude number <1), two open-channel fundamental equations can be applied to make this extrapolation. The first invokes continuity (conservation of mass), and the second invokes conservation of energy.

Continuity implies that mass is neither created nor destroyed. The governing relation states that in the absence of fluid inputs or outputs between two channel transects (e.g., no fresh water inputs from rivers or no drainage to other tributaries), then there is no change of fluid mass in the channel reach between the two transects, and the volumetric flow rate (Q, in cubic meters per second) remains constant.

This equals the depth-averaged velocity (U, in meters per second) at a transect times the flow cross-sectional area (A, in square meters, which is equal to the depth of the flow, h, times the width of the transect, W):

$$Q = UA, \text{ where } A = hW$$

Conservation of energy in open-channel flow is expressed by the Bernoulli equation, which is best understood by referring to the accompanying definition sketch, below.

$$\left(z_1 + h_1 + \frac{U_1^2}{2g}\right) = \left(z_2 + h_2 + \frac{U_2^2}{2g}\right) + h_f$$

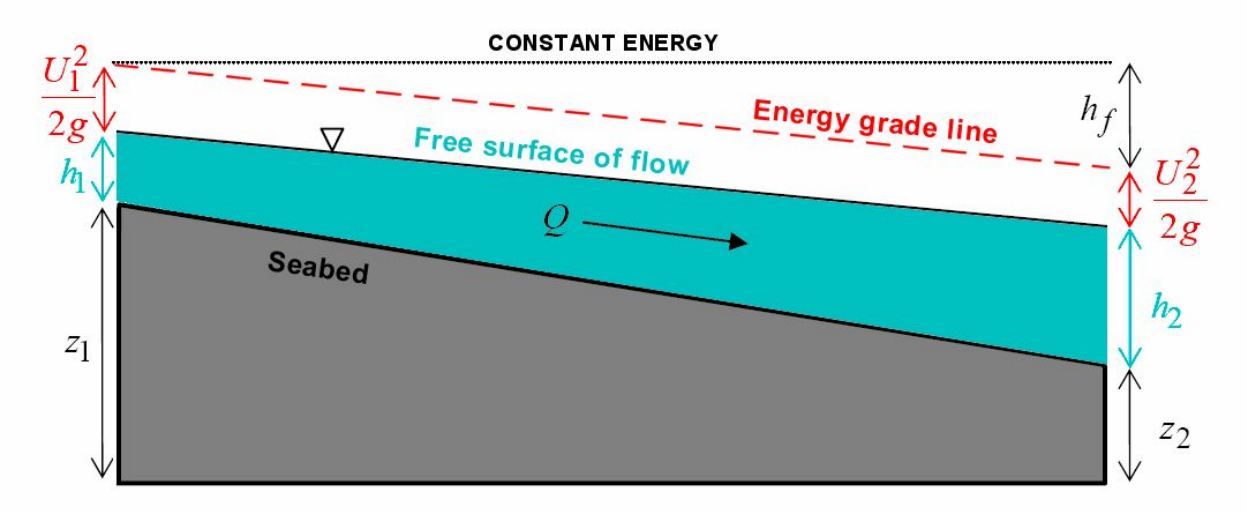


Figure 8-15
Open-Channel Flow Theory: Energy Equation and Definition Sketch

Assuming negligible friction loss (h_f) between the two transects and, if the seabed elevation and channel width are known at both locations and if the flow depth and depth-averaged velocity are known at one transect (h_1 and U_1), then the unknown flow depth and depth-averaged velocity at the second transect (h_2 and U_2) can be found because there are two equations (continuity of mass and conservation of energy) and two unknowns.

Writing the open-channel energy equation, neglecting the friction loss term:

$$z_1 + h_1 + \frac{U_1^2}{2g} = z_2 + h_2 + \frac{U_2^2}{2g}$$

Writing the continuity of mass equation in terms of channel width and depth:

$$W_1 h_1 U_1 = W_2 h_2 U_2$$

and re-arranging to state h_2 in terms of U_2:

$$h_2 = W_1 h_1 U_1 / W_2 U_2$$

and then substituting this expression for h_2 in the energy equation above yields an equation with two real roots, only one of which matches the known flow conditions at Transect 1.

Consider the following example: A tidal change constricts from 3000m to 1500m in width, while the seafloor rises by 10m. If the velocity in the wider, deeper section is 2 m/s and the water depth is 60m, then application of the equations above predicts a velocity of 4.9m/s and depth of 49m in the narrower, shallower section. Since the kinetic power density varies with the cube of the velocity, the power density is *fifteen times greater* in the constriction than in the wide channel.

Accounting for Depth Variations in Velocity

The depth-averaged tidal stream power density was estimated from the surface value by annually assuming a $1/10^{th}$ power law approximates the decrease in current velocity from the sea surface to the bottom of the channel (see Figure 8-16 for comparison with other possibilities).

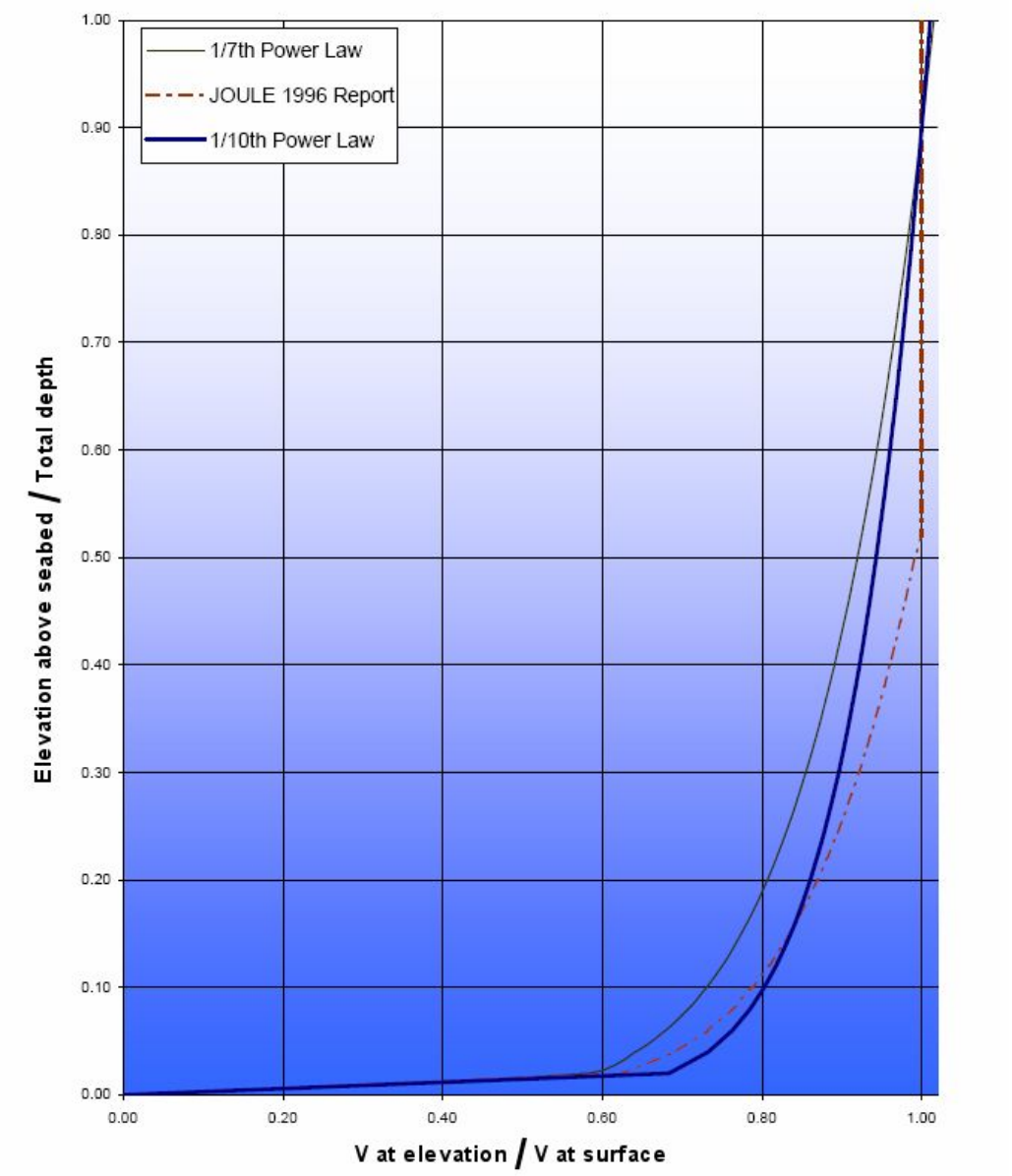


Figure 8-16
Alternative Profile Formulations of Velocity Variability with Depth
(1/10th-Power Law used)

The general power law relationship for vertical profiles of horizontal fluid flow velocity near a solid boundary (the seabed, for example) is as follows:

$$u(z) = u_o \left(\frac{z}{z_o} \right)^{1/10}$$

where *u(z)* is the horizontal velocity at some depth *z*, and u_o is the reference velocity at reference depth (z_o). Depths are measured relative to the bottom, and the seabed is at *z*=0. Based on the 1/10-power law velocity profile, the depth-averaged value of velocity is 90.9% of its surface value - the derivation of which is given below.

For any reference velocity and depth, the depth-averaged velocity is given by:

$$\bar{u} = \frac{\int_{h_1}^{h_2} u\,dz}{\int_{h_1}^{h_2} dz} = \frac{\int_{h_1}^{h_2} u_o\left(\frac{z}{z_o}\right)^{1/10} dz}{\int_{h_1}^{h_2} dz} = \frac{u_o\left(\frac{1}{z_o}\right)^{1/10}}{h_2 - h_1}\left(\frac{10}{11}\right)\left(h_2^{11/10} - h_1^{11/10}\right)$$

When the reference velocity is the surface velocity, then h_2 is the channel depth (D), h_1 is zero 0, z_o is the reference elevation (also the surface elevation), and the depth averaged velocity is given by:

$$\bar{u} = \frac{u_o\left(\frac{1}{D}\right)^{1/10}}{D}\left(\frac{10}{11}\right)\left(D^{11/10} - 0^{11/10}\right) = u_o\left(\frac{10}{11}\right) = 0.909u_o$$

Since flow power density is proportional to the cube of flow velocity, an expression for the depth-averaged power density may be derived in a similar fashion:

$$\overline{u^3} = \frac{\int_{h_1}^{h_2} u^3\,dz}{\int_{h_1}^{h_2} dz} = \frac{\int_{h_1}^{h_2} u_o^3\left(\frac{z}{z_o}\right)^{3/10} dz}{\int_{h_1}^{h_2} dz} = \frac{u_o^3\left(\frac{1}{z_o}\right)^{3/10}}{h_2 - h_1}\left(\frac{10}{13}\right)\left(h_2^{13/10} - h_1^{13/10}\right) = u_o^3\left(\frac{10}{13}\right) = 0.769u_o^3$$

Therefore, the depth-averaged tidal current power density at each site surveyed was estimated as 76.9% of the mean annual surface power density.

Accounting for Across-Channel Variations in Velocity

It is assumed that the velocity is constant across the width of a channel. This overestimates the available resource, since currents close to shore will be slower than those in mid-channel. This is a necessary approximation in the absence of other data, however, and should not affect the relative resource ranking of sites surveyed.

Channel Cross-Sectional Area

To estimate the channel cross-sectional area, a transect can be drawn across the channel on a bathymetric chart or hydrographic chart of soundings. This transect can then be divided into sections, where the section width can be chosen to capture the complexity of cross-channel bathymetry: many narrow sections to capture rapidly changing bathymetry, but only a few wide sections to capture flat or gradually changing bathymetry. For each section, the area of the trapezoid between section boundaries is calculated, and the results summed for all sections.

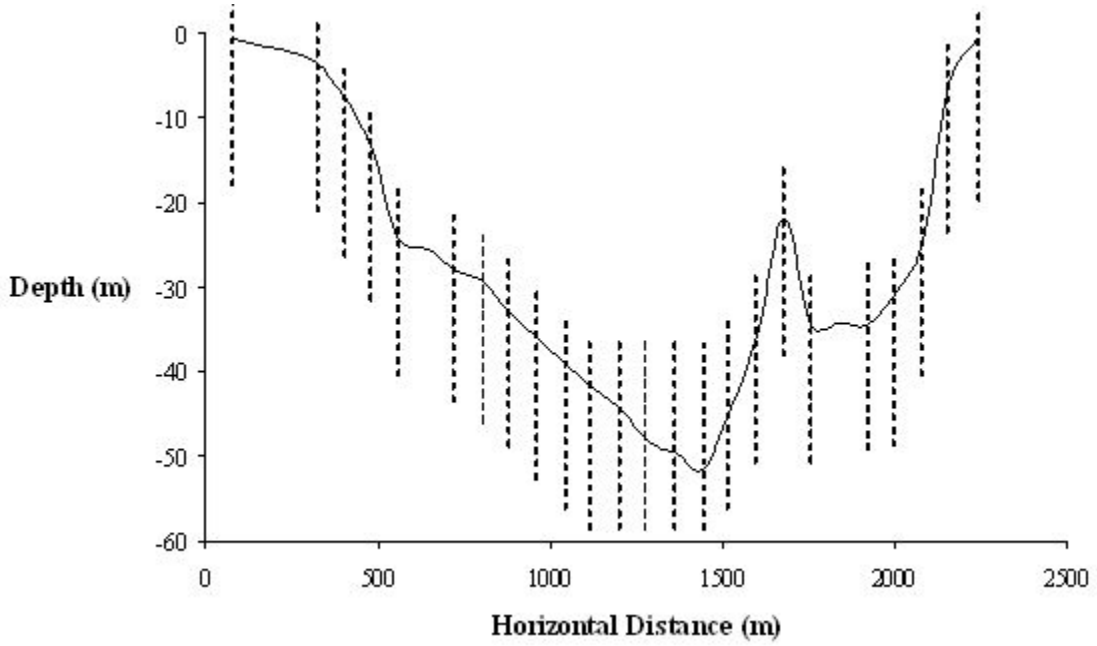


Figure 8-17
Cross-Section of Tidal Channel (dotted lines show section boundaries)

The chart datum (shoreline elevation) for depth contours or soundings as reported from NOAA or USGS is typically Mean Lower Low Water (MLLW). MLLW is defined as the annual average of the daily lower low tides. To this subtidal channel area was added a rectangular area, whose width was the channel width (shoreline to shoreline) at MLLW, and whose height was half of the mean tidal range (Figure 8-18). This combination approximates the average cross-sectional flow area and also the flow area at mid-tide, when current speeds usually are greatest.

For sites in Alaska and Washington, a considerably more sophisticated procedure was used, which takes into account the co-variant nature of tidal stream power density and channel cross-sectional area. Using digital bathymetry, the cross-sectional area of the channel referenced to mean low water can be readily calculated by breaking the channel surface up into grids of known dimensions. This is analogous to the calculation of trapezoidal areas for other sites. Figure 8-19 shows a representative digital bathymetric map.

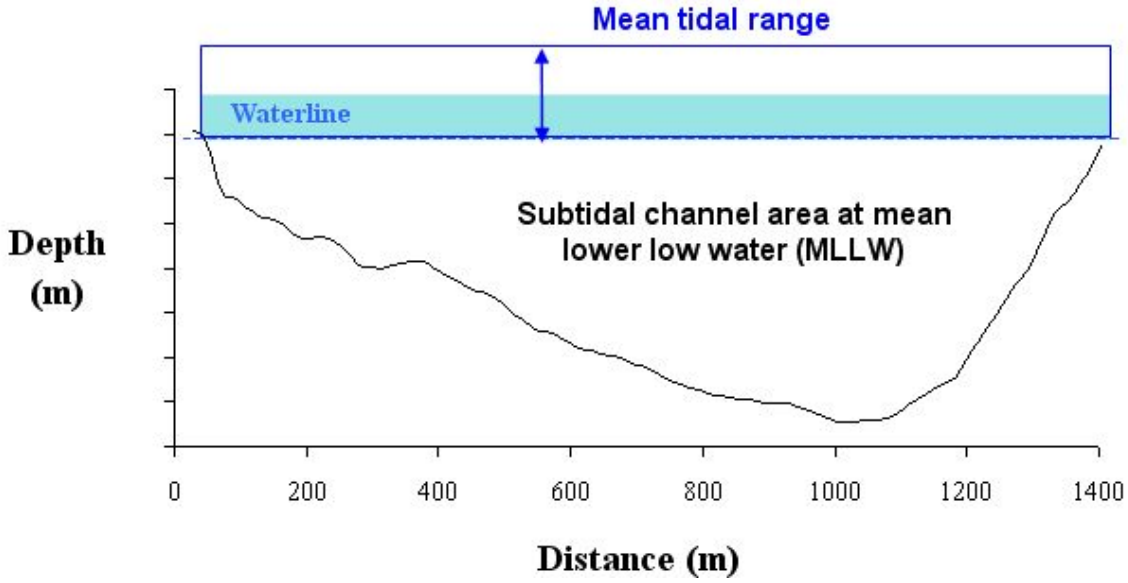


Figure 8-18
Accounting for Tidal Range in Cross-Sectional Area Calculation

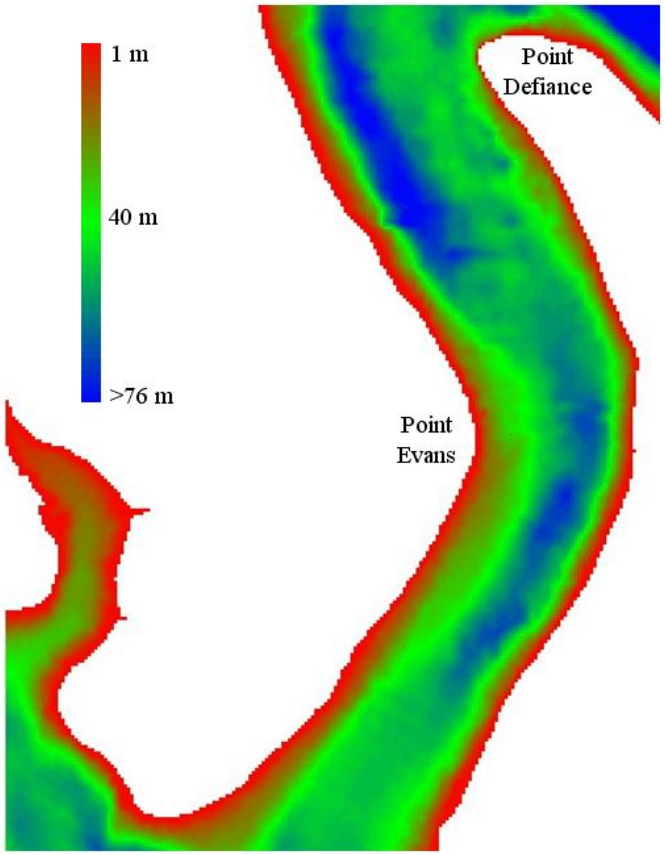


Figure 8-19
Digital Bathymetry for Tacoma Narrows, WA

Once a baseline cross-sectional area has been established for a particular transect, the time variation of the cross-sectional area is determined using NOAA tide predictions. Provided a tide station is relatively close to the current station used to make the power density predictions, a coincident time-history for the height of water level above or below MLLW is produced. As with the other sites, assuming that the channel width does not change appreciably with the tidal range, the relative change in area may be obtained by multiplying the departure from MLLW by the channel width. Adding this quantity to the baseline cross-sectional area calculated from the digital bathymetry of the transect yields a time-history of channel cross-sectional area.

By synchronizing the two time histories (one of depth-averaged power density and one of channel cross-sectional area), a time history of total tidal stream power is produced. As before, averaging the time history over a year yields the mean annual power.

Results are comparable to the simplified approach described previously.

It is worth noting that either approach is less valid in the case of extensive shoals or flats that are dry at MLLW. Since the reference tidal prism is based on MLLW depths, as the water level rises and these areas become covered by water, their contribution to the channel flow is neglected. This is not an issue for any of the design sites.

Available Resource

The total available tidal stream resource is the product of the mean annual, depth-averaged power density times the mean channel cross-sectional area. This yields the mean annual kinetic tidal power.

Extractable Resource

As mentioned earlier, environmental concerns have been assumed to limit the mean annual extractable power to 15% of the mean annual kinetic power. Given the similarities between wind turbines and tidal stream turbines, it is tempting to believe that, with sufficient downstream spacing to avoid wake effects, an unlimited number of turbine rows can be placed along the length of a tidal channel. The basic nature of the tidal stream and wind energy resources is quite different, however.

Wind turbines extract energy from the lower turbulent boundary layer of the atmosphere and, as energy is extracted, this reduces the wind speed immediately behind the turbine and increases the rate of downward turbulent momentum transfer until the wind speed essentially re-establishes itself a relatively short distance downwind of the turbine. Wind energy is thus replenished from above, drawing from airflows extending the full height of the troposphere, which is 16- to 18-km thick over the equator and about 10-km thick over the poles.

In contrast to atmospheric flows, tidal stream flows are constrained between the seabed and sea surface, in depths that are usually less than 100 m. Tidal stream energy is therefore more spatially constrained, and withdrawal of excessive amounts could reduce natural circulation to the point that significant environmental effects occur. Based on limited modeling done to date, a blanket average kinetic energy extraction of 15% was been selected as the level of extraction which will not result in significant alteration to the estuary circulation.

Only a few studies have been published that address this subject. In a review of tidal stream resource assessments for the Carbon Trust, Black & Veatch Consulting, Ltd., has adopted a 20% "Significant Impact Factor" as the percentage of the total available resource that can be extracted without significant environmental effect (Reference 4). The justification for this selection is not given.

Early numerical modeling by Ian Bryden and his colleagues led them to suggest 10% as a "rule of thumb" conservative estimate of the extractable resource in a simple channel (References 3 and 28). This was based on the application of open-channel flow theory to simulate a tidal channel connecting two unconstrained bodies of water (as between two islands, for example). The modeled tidal channel had a width of 1 km, a length of 4 km, and a natural tide level difference of 0.8 m between each end of the channel. Results are shown below in Figure 8-20.

Note the localized steepening of the water surface gradient in the immediate vicinity of the turbine array, which creates a localized jump in flow speed. This locally increases the kinetic energy flux such that the 10% notional extraction level actually corresponds to a 9.2% drop in kinetic energy flux compared to the natural channel. The overall reduction in flow speed along the entire channel length averages 2.6%.

A subsequent paper (References 29) extends this analysis to a sea loch inlet, where an enclosed basin area of 50 km^2 communicates to an unconstrained ocean by a channel that is 500 m long, 200 m wide, and 30 m deep. It was noted that, as with the straight channel, flow blockage and energy extraction by the turbine array creates a locally-steep sea surface gradient, as the rate of tidal loch filling or emptying decreases when the channel is blocked by a row of turbines. In this particular case, the authors suggest that up to 30% of the natural flux may be extractable.

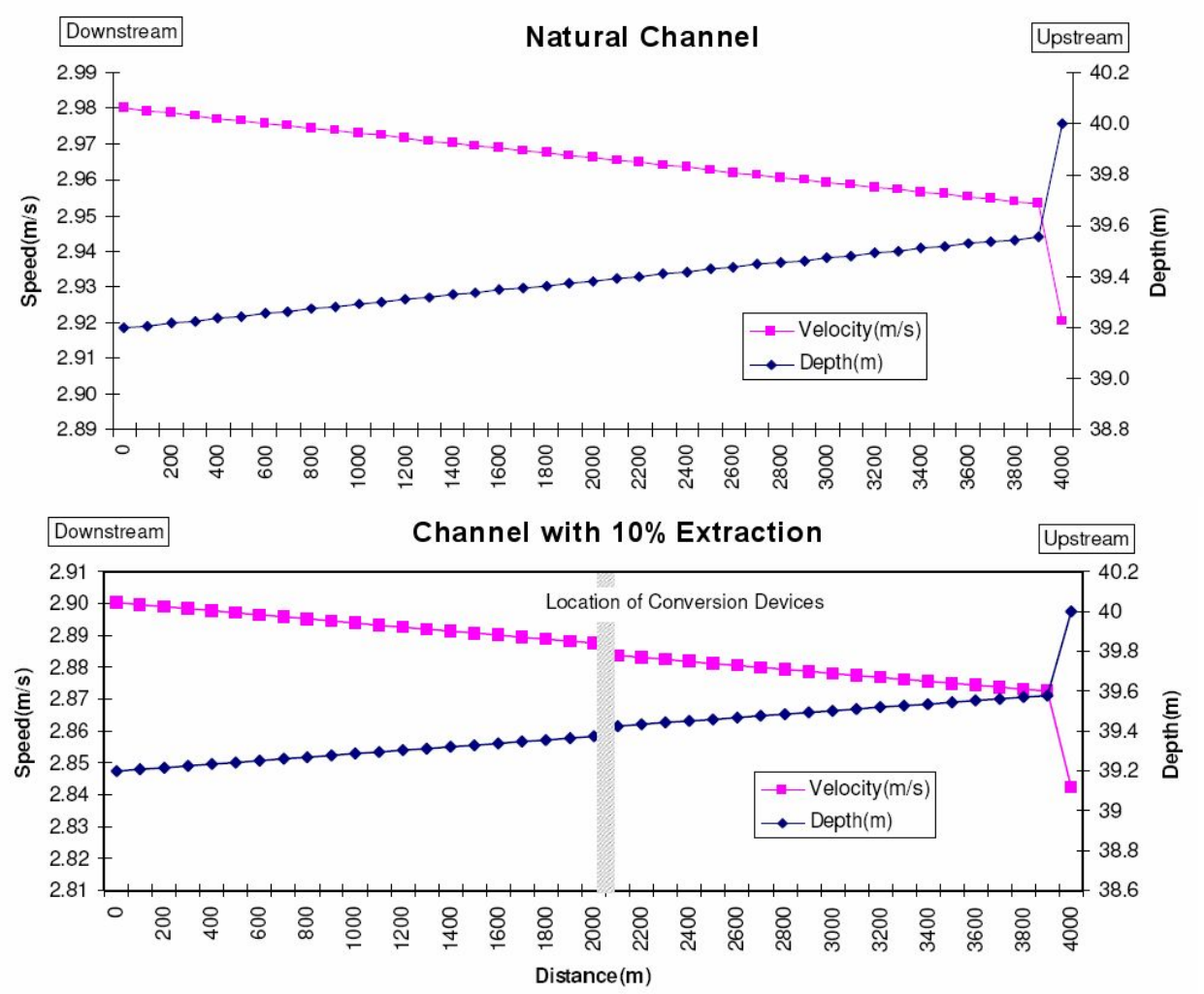


Figure 8-20
Influence of Energy Extraction on Flow in a Tidal Channel

In reviewing these results, EPRI has used 15% as the environmental extraction limit. According to the open-ended channel model results reported in Reference 29, this would result in a tidal current speed reduction averaging 4% along the entire channel length. It is unknown whether or not such a change in flow speed would result in significant environmental consequences, such as slower transport of nutrients and oxygen or less turbulent mixing. However, it is worth noting that the above studies assume steady state conditions – and tidal flows are inherently unsteady. Extraction of energy and subsequent reduction in downstream flow rates will result in an increased head at the mouth of the estuary (since the tidal basin will be filling slower), giving rise to a partially restorative forcing. Extraction rates are likely to be a function of channel geometry and tidal regime and, therefore, specific to particular channels. Better understanding of these effects would require the development of ecosystem-level models, driven by site-specific hydrodynamic numerical models, reflecting actual site bathymetry and tidal changes in sea level, as well as turbine-specific interactions with the flow. Numerical modeling should be validated with appropriately-scaled physical models in laboratory current flumes.

Number of Homes Powered

In order that one may easily relate the average annual extractable power number for a tidal plant to something that most people understand, we use the number of U.S. homes that can be powered by that plant. From the International Energy Agency, we know that in 2003 the average power used by a U.S. residence was 1.3 kW. Therefore, the number of homes powered is equal to the average annual extractable power of the tidal current stream (15% of the total mean annual resource) times the efficiency of generating electricity from the extracted energy divided by 1.3 kW per average U.S. home.

The assumed drive train, generator, and power conditioning component efficiencies values (i.e., the total efficiency of generation electrical energy from extracted energy) used are:

- $\eta_{\text{drive train}} = 96\%$
- $\eta_{\text{generator}} = 95\%$
- $\eta_{\text{power conditioning}} = 98\%$

Multiplication of these component efficiencies yields 90% conversion efficiency of the energy extracted from the tidal stream to electricity. The energy extracted from the tidal stream is limited by and always less than the Betz limit, 59%.

8.3 Tidal Energy Conversion (TISEC) Technology Description

Tidal power research programs in industry, government and at universities in the UK, Norway, Ireland, Italy, Sweden, Canada and the U.S. over the last half a dozen years have established an important foundation for the emerging tidal power industry.

8.3.1 Tidal Energy Conversion (TISEC) System Developers

Today, a number of small companies backed by government organizations, private industry, and venture capital are leading the commercialization of technologies to generate electricity from ocean tidal streams. In early 2005, EPRI requested information from 23 known TISEC device developers. Fourteen (14) of the 23 provided a response. All contacted manufacturers are listed below.

Tables 8-5 represents the screening results of the 14 companies that provided information in response to the RFI package.

Table 8-4
Offshore Tidal Energy Conversion Device Developers Contacted

Manufacturer / Website	Address	Device Name	Response
Aquantis www.aquantis.com www.clipperwind.com	6305 Carpinteria Ave., Suite 300, Carpinteria, CA 93013	Unknown	None. Information is proprietary and patent pending
Blue Energy Canada Inc www.bluenergy.com	Box 29068 1950 West Broadway, Vancouver, BC V6J 1Z0	Unknown	No response due to resource limitation
Clean Current	405 - 750 Pender Street West Vancouver, B.C., Canada V6C 2T7	Unknown	No interest
Engineering Business www.engb.com	Riding Mill, Nothumberland, NE44 6EG UK	Stingray	None. EB is no longer in the business
GCK (Gorlov) www.gcktechnology.com	607 Bluff Drive San Antonio, TX 78216,	Gorlov Helical Turbine (GHT)	Yes
Florida Hydro www.floridahydro.com	171 Comfort Road, Palatka, FL 32177	Open Center Turbine	None. Sold to Open Hydro. See below
Hammerfest STROM AS www.e-tidevannsenergi.com	Strandt.1 9613 Hammerfest, Norway	Unknown	No response. Many unsuccessful attempts to contact
HydroVenturi www.hydroventuri.com	13 Princes Gardens Kensington, London, SW7 1NA England	Unknown	Yes
Lunar Energy Ltd www.lunarenergy.co.uk	Parkgate House Office Park, Ferriby Road, Hessle, East Yorkshire, HU13 0QF, UK	RTT	Yes
Marine Current Turbines Ltd, www.marineturbines.com	The Court, The Green, Stoke Gifford, Bristol BS34 8PD, UK	SeaGen	Yes
Ocean Renewable Power www.oceanrenewablepower.com	2723 West Jetton Ave Tampa, FL 33629	OCGen™	No. EPRI did not identify them in time
Open Hydro www.openhydro.com	171 Comfort Road, Palatka, FL 32177	Open Centre Turbine™	Yes
Ponte di Archimeda	Italy	Enermar (Kobold)	Yes
Qiniteq	Bincleaves UK	QinetiQ cycloidal	Yes
Renewable Devices Ltd http://www.renewabledevices.com/swift/	Bush Estate, Edinburgh EH 26 0PH UK	Unknown	No. EPRI did not identify them in time
RM Davis	UK	Tide / Waterflow Generator.	Yes
Seapower Int'l AB www.seapower.se	Essingeringen 72C, S-11264 Stockholm Sweden	EXIM™	Yes

Table 8-4 (continued)
Offshore Tidal Energy Conversion Device Developers Contacted

Manufacturer / Website	Address	Device Name	Response
SMD Hydrovision www.smdhydrovision.com	Wincomblee Road, Newcastle upon Tyne NE6 3QS England	TidEl	Yes
Tidal Electric www.tidalelectric.com	14 Edith Road, London SW19 8UYUK	Tidal Lagoon	No. Technology involves water impoundment
UEK www.uekus.com	PO Box 3124, Annapolis, Maryland 21403	Underwater Electric Kite (UEK)	Yes
Univ of Naples www.dpa.unina.it/adag/	Italy	Mythos	Yes
Verdant Power www.verdantpower.com	4640 13th St North, Arlington, VA 22207	Kinetic Hydro Power System (KHPS)	Yes
Woodshed Technologies www.woodshedtechnologies.com.au	Level 50 101 Collins St, Melbourne 3000 Australia	Tidal Delay™	Yes

Table 8-5
Initial Screening of Responses

Company	Device Name	Respons-iveness to RFI	Development Stage	Technology Readiness Circa 2007
GCK	Gorlov Helical Turbine	Yes	Prototype testing	Yes
Hydro Venturi	RV	No	Low Head RV testing in run-of-river application	No
Lunar Power	RTT 2000	Yes	Subscale Tank Testing – prototyping build in progress	Yes
Marine Current Turbines	SeaGen	Yes	Prototype testing	Yes
Open Hydro	Open Centre Turbine™	Yes	Prototype testing	Yes
Ponte di Archimeda	Enemar	No	Prototype testing	Yes
QuinteQ	Cycloidal	Yes	Conceptual	No
RM Davis	RoDa	No	Conceptual	No
Seapower	EXIM™	Yes	Prototype testing	Yes
SMD Hydrovision.	TidEl	Yes	Prototype testing	Yes
UEK	UEK	Yes	Prototype testing	Yes
Univ of Naples, Italy	Mythos	No	Prototype testing	No
Verdant Power	KHPS	Yes	Prototype testing	Yes
Woodshed Technologies	TimeDelay™	Yes	Conceptual, however, relying only on existing technology	Yes

Of the 14 companies above that responded to the EPRI RFI, 10 devices satisfied the initial screening criteria. One of the 10, Woodshed Technologies, was found to have no critical technology issues, but, was not directly comparable to the other eight devices.

Woodshed Technologies has proposed a unique concept that relies upon specific siting conditions. The basic concept is to use the head difference that arises between the water levels in a bay and the nearby ocean due to the time taken for tidal flows into and out of the bay to run a hydroelectric turbine installed in a pipe across a peninsula, isthmus or other natural barrier dividing the two bodies of water under tidal influence. This is an innovative concept that awaits the right geographical and tidal phasing situation. However, because this concept is the only TISEC device concept which requires a difference in tidal range times in an ocean and a nearby bay, we could not directly compare it to the other concepts identified and characterized in this report.

Five companies provided some information; however the information was either not fully responsive to the EPRI Request for Information or did not meet the technology readiness by circa 2007 criteria.

- HydroVenturi – Key information needed, such as the power output as a function of input water velocity, was stated to be proprietary.
- Ponte di Archimeda – Provided a previous technical paper and not a response to the specific information requested.
- The Quinteq Cycloidal Device is at the conceptual stage of development with many design, performance, deployment, operation and maintenance issues yet to be addressed. Fundamental research to investigate the technical and economic viability of the cycloidal tidal stream electricity generator was performed (Reference 5).
- RM Davis provides some conceptual level information and stated that they did not have the resources to be fully responsive to the RFI. The “RoDa” concept uses a venturi to empty a chamber holding a floating weight. The venturi opening is designed with a butterfly valve to reverse water flow from exiting to entering the chamber. The floating weight rises and falls as required by the flooding and emptying action of the valve-controlled venturi. The floating weight generates electric power during both the down and up strokes.
- The University of Naples, Italy - Provided a previous technical paper and not a response to the specific information requested

The remaining eight devices were then characterized in more detail with the objective of determining any critical issues relating to technological readiness for a pilot plant at sea demonstration in the 2007 time period. Table 8-6 summarizes the technology characterization.

Table 8-6
TISEC Device Characterization Summary

	GCK	Lunar	MCT	Open Hydro	Seapower	SMD Hydro	UEK	Verdant
Device Name	GHT	RTT 2000	SeaGen	OCT	Exim TTPP	TidEL	Underwater Electric Kite	RITE
Type	V-axis Helical Turbine	H-axis Ducted Turbine	H-axis Twin Turbine	H-axis 0pen center	V-axis Savonius turbine	H-axis Twin Turbine	H-axis Augmented Turbine	H-axis Unducted Turbine
Develop-ment Status	1m dia X 2.5m high test in Merrimack River in Sept. 2004.For others see Appendix B	1 to 1.5 m dia (1/20th) scale test in water tank	11m dia 300kW tested at sea (note 1) since May 2003 15kW tested in 1994-5	3m (1/5th) scale testing at sea	Full-scale test in Sep 2003	1/10th scale tested	7 prototypes up to 10m in dia – see Appendix H (note 2)	Tested Pakistan 1989, Md and NY in 2002-2003
Next Develop-ment Step	Develop shaft mounted gen unit optimized for GHT	Deploy 1 MW unit in 2006 at EMEC – plan 2MW com'l unit	Deploy 16 m dia. com'l. design unit in 2006	Deploy 1.5 MW unit in 2006	Full-scale pilot plant to be commis-sioned in 2005	Full-scale prototype to be deployed at EMEC in 2006	10 MW – 25 unit project in DE - in permitting	Pilot 6-Unit Integrated System in the East River NY
Power Train Type	Direct drive permanent magnet gen connect to GHT shaft	Hydraulic based on modified COTS pump	Planetary COTS Gearbox	Direct rim drive generator	Gearbox	Gearbox	Planetary drive - proprietary	Speed Increaser COTS
Founda-tion/	Suspension or attached to sea floor	Gravity Base	Monopile embedded in sea bed	Gravity base or monopile	Anchors & Chains4-fold	Anchors and chains	Via cable (note 3)	Monopile
Rotor Size	1m dia x 2.5m length	19.5m (3.9 m hub diameter)	2 rotors 16m dia	15m	1m dia X 3 m high	8m blades on 2.5m dia hubs.	Twin 10ft	5m
Rated Power (kW)	7	2,000	1,200	1,520	14	1,000	400	34
Rated Speed	2.58 m/s	3.1 m/s	2.3 m/s with MMSS of 3.5	2.57 m/s	3 m/s	2.3 m/s	3 m/s	2.1 m/s
Area (m^2) in $P=0.5 \cdot AV^3$ equation	2.5	490.8 (cross section of 25tm dia duct	402	313.8	6	537	14.59	19.6
Com'l Price	Yes, turbine only.	Not Com'l yet	Not Com'l yet	Not Com'l yet	Yes, but excluding site specific costs, grid.	Not Com'l yet	Yes	Yes

Please refer to the Report TP-004-NA on the EPRI website [http://www.epri.com/oceanenergy/streamenergy.html] for an in-depth description of each of the eight TISEC devices listed above.

8.3.2 Offshore Tidal Energy DT&E Projects

As summarized below, there are many worldwide in-stream tidal energy development, test and engineering (DT&E) projects.

Table 8-7
Selected Tidal Energy Development, Test and Engineering Projects

Device/Project Name	**Enermar**	**SeaFlow**	**GHT**	**GHT**	**Race Rocks, BC Canada**	**RITE**	**Open-Centre Turbine**
Device Developer/Country	**Ponte di Acrhimede**	**MCT**	**GCK**	**Verdant/GCK**	**Clean Curent**	**Verdant**	**Open Hydro**
Test Site	**Straits of Messina**	**Devon UK**	**Long Island Sound NY**	**Amesbury MA**	**Race Rocks, BC Canada**	**East River NY NY**	**EMEC Tidal UK**
Date Initial Op Cap (IOC)	**Jun-05**	**May-03**	**May-04**	**Aug-04**	**Nov-06**	**Dec-06**	**Jun-05**
Duration of Testing	**Ongoing**	**Ongoing**	**July 19-24, 2004**	**Sep-Oct, 2004**	**Ongoing**	**Planned for 18 months**	**12 Months Miniumium**
Device Type	Vertical Axis	Single Rotor Horizontal Axis	Vertical Axis	Vertical Axis	Ducted Horizontal Axis	Single Rotor Horizontal Axis	Horizontal Axis Rim Bearing/Gen
Device Size	6 m dia by 5 m high	11 m diameter	1 m dia by 2.5 m high	1 m dia by 2.5 m high	Unknown	6 turbines 5 m diameter	6m Diameter
Cross sectional area (m^2)	30	94.9	2.5	2.5	Unknown	19.6	87
Device Rated Power	160 kW at 3.5 m/s	300 kW at 1.84 m/s	7 kW at 2.6 m/s	7 kW at 2.6 m/s	Unknown	35.9kW at 2.2 m/s	220 kW at 4.1 m/s
Power Train Type	Gearbox	Gearbox	Direct drive PM Gen connected to shaft	Direct drive PM Gen connected to shaft	Unknown	Gearbox	Direct drive PM rim generator
Structure	Anchoring blocks	Mono pile	Hung from Barge	Hung from Barge	Monopile	Mono pile	Mono piles
Permitting	Ubiv of Messina. No impact	UK Consents	NYSDEC, USACE & Others	MA Dept of Env Pro (MDEP)	Unknown	NYSDEC, USACE & Others	EMEC Tidal UK
Status/Lessons Learned	Connected to ENEL grid in Jul 2005	Over 3 years of operation. Lessons learned used in SeaGen		See report at Mass Tech Collaborative website	Drilling sockets for monopile can be more difficult than planned	Drilling sockets for monopile can be more difficult than planned	Installation August 2006

Table 8-7 (continued)
Selected Tidal Energy Development, Test and Engineering Projects

Device/Project Name	TidEl	SeaGen	RTT1000	Canoe Pass BC Canada	Tacoma Narrows, WA	Admiralty Straits WA	San Francisco CA	Minas Passage NS
Device/Project Developer/Country	SMD Hydrovision	MCT	Lunar	New Energy	Tacoma Power	Snohomish PUD	Oceana or City of SF	Nova Scotia Power
Test Site	EMEC Tidal UK	Strangford UK	EMEC Tidal UK	Canoe Pass BC Canada	Tacoma Narrows, WA	TBD	Golden Gate	TBD
Date Initial Op Cap (IOC)	2007	2007	2007	2006-2008	2009	2010	2009	2009
Duration of Testing								
Device Type	Twin Rotor Horizontal Axis	Twin Rotor Horizontal Axis	Horizontal Axis Ducted	Vertical axis	TBD	TBD	TBD	TBD
Device Size	Twin 18.5m dia rotors and 22m crossbeam	Twin 16 m diameter rotors	8.1 m diameter and inlet to duct	250-500 kW				
Cross sectional area (m^2)	537	402	65					
Device Rated Power	1 MW at 2.3 m/s	1.2 MW at 2.3 m/s and 2.5 MW at MMSS of 3 m/s	1 MW at 3.1 m/s					
Power Train Type	COTS gearbox	COTS planetary gearbox	Hydaulic based on modified COTS pump					
Structure	Two anchors and five cables	Mono pile	Gravity Base					
Permitting	EMEC Tidal UK	UK Consents	EMEC Tidal UK	In permitting in Canada	FERC Prel permit granted in Feb 2006	Application for FERC Prel permit filed in July 2006	FERC Prel permit granted in Oct 2005 to Oceana	In permitting in Canada
Status/Lessons Learned								

8.3.3 EMEC Tidal

When the European Marine Energy Centre (EMEC) was established by Highlands and Islands Enterprise (HIE) and its funding partners in 2003, it was with the intention of stimulating and accelerating the development of both wave and tidal prototype energy generating devices. EMEC Wave became operational in June 2004. In June 2006, a tidal test site ready for deployment by developers was established.

HIE engaged Tulloch Prime Contracting Limited (Tulloch) to undertake the design and construction of the tidal test facility located in the Fall of Warness, Eday, Orkney. The project was managed under HIE's property framework contract by Synergie Scotland Ltd .

The test facility comprises a new control building in a plot adjacent to Cauldale on Eday, and there are four export cables between 3,000 m and 4,000 m in length connected to the four offshore test berths where prototype devices will be attached in the future.

EMEC Tidal is sited at the Fall of Warness, off the outlying island of Eday. There will be four test berths for tidal devices, each with a dedicated cable connecting back to the local grid. As with the wave test center, there will be a building to house the necessary switchgear and control equipment. The test facility will be connected to the local electricity grid at Cauldale on Eday

and a separate communications link will carry information on device performance back to the data center in Stromness.

A number of tidal energy devices are being developed worldwide. Of these, RTVL—a joint venture between Scottish and Southern Energy and the Weir Group, Lunar Energy and SMD Hydrovision have already committed to testing their devices at the Fall of Warness facility. Negotiations continue with a number of others.

EMEC -Tidal cost approximately £6 million.

8.4 Performance Prediction

Published data on Tidal Energy Conversion (TISEC) devices seldom provide sufficient detail to assess the accuracy of power production claims. The offshore wind energy industry routinely publishes turbine performance data in the form of curves and/or tables depicting generated power as a function of wind speed (see General Electric 3.6 MW turbine at http://www.gepower.com/prod_serv/products/wind_turbines/en/index.htm, or Vestas 2.0 MW turbine at http://www.natwindpower.co.uk/northhoyle/gsv80.pdf for examples), yet tidal energy developers rarely provide similar data on generated power as a function of sea state.

This lack of documentation also makes it difficult to compare the likely performance of different TISEC devices in a given tidal climate, particularly when different underlying assumptions and simulation or model test methods have been used to generate their power production estimates. Without such documentation, it is impossible to establish a baseline performance against which industry improvements can be benchmarked.

In order to overcome these hurdles, EPRI developed the *Guidelines of Preliminary Estimation of Power Production by Offshore Tidal Energy Conversion Devices*. Please refer to Report TP-001-NA, available for public download at the EPRI website [www.epri.com/oceanenergy], for further information.

8.5 Cost and Economic Issues

EPRI independently estimated plant system costs based on the MCT SeaGen dual 18-m diameter rotor device design for seven good tidal sites in North America. A good in-stream tidal site is one that has a large volume of fast moving water, has bathymetry and seabed characteristics that allow a TISEC device to be sited, has minimum or no conflicts with other uses of the sea space, and is close to a load and grid interconnection. EPRI surveyed potential sites in Massachusetts, Maine, New Brunswick, and Nova Scotia and documented the results in four EPRI TP 003 reports (References 12 - 15). In Alaska, Washington, and California, the sites and devices were pre-selected. Table 8-8 describes the seven feasibility evaluation sites.

Table 8-8
Summary of Feasibility Evaluation Sites

	AK Knik Arm Cook Inlet	WA Tacoma Narrows	CA Golden Gate	MA Muskeget Channel	ME Western Passage	NB Neah Harbor Passage	NS Minas Passage
Cross Section Area (m^2)	72,500	62,600	74,700	17,500	36,000	60,000	225,000
Power Density (kW/m^2)	1.6	1.7	3.2	0.95	2.9	0.7-2	4.5
Available Power (MW)	116	106	237	13.3	104	43-100	1,013
Extract Power (MW)	17.4	16	35.5	2.0	15.6	6.5-15	152
# Homes Powered	12,000	11,100	27,300	1,500	12,000	5,000-11,500	117,000

Power is average annual; extractable power is limited to 15% of available power; assumes 90% power take off efficiency
Number of homes powered assumes 1.3 kW per average home
NB and NS power estimates have a higher degree of uncertainty than U.S. sites due to lack of measurement stations in Canada

Using the economic methodology, financial assumptions, and incentives described in Reference 12, EPRI calculated the cost of electricity (COE) for a taxable utility generator, a municipal non taxable generator, and the internal rate of return for a taxable non utility generator. The results are shown below in Table 8-9.

Table 8-9
Cost Estimates for Feasibility Evaluation Sites

	AK Knik Arm Cook Inlet	WA Tacoma Narrows	CA Golden Gate	MA Muskeget Channel	ME Western Passage	NB Neah Harbor Passage	NS Minas Passage
Number of Turbines	66	68	40	9	12	66	250
Total Plant Cost ($M)	110	103	90	17	24	68	486
Yearly Level O&M Costs	4.1	3.8	3.6	0.6	1.0	2.3	18
Annual Energy (GWh)	128	121	129	1.5	40	64	1,140
Utility Gen COE	9.2 – 10.8	9.0 – 10.6	6.6 - 7.6	8.6 - 9.9	5.6 - 6.5	10.0 -11.7	3.9 -4.6
Muni Gen COE	7.1 - 8.4	7.2 - 8.4	4.9 - 5.6	6.0 - 6.7	4.2 - 4.8	9.2 -11.2	3.9 -4.6
Non Utility Gen IRR	None	None	21%	None	34%	None	31%

Cost of electricity (COE) in U.S. cents/kWh

The cost of electricity (COE) is the total plant cost multiplied by the fixed charge rate, plus the annual operation and maintenance cost (O&M), all divided by the annual energy produced. The fixed charge rate is the percentage of the total plant cost that is required over the project life to cover the annual revenue requirements, and as such, accommodates the individual state and provincial tax rate and incentives structure. The COE for a utility and municipal generator is in the range of 4 – 12 cents/kWh (2005 US$).

The internal rate of return (IRR) is the discount rate at which the present value of the net cash flows over the project life is equal to the equity investment at the commercial operating date. Neither Alaska, Washington, Massachusetts, nor New Brunswick designs produced a rate of return for a non-utility generator. California, Maine, and Nova Scotia designs do offer a rate of return for a non-utility generator, in the range of an estimated 21% - 34%.

TISEC device technology is similar to wind technology and has benefited from the learning curve of wind machine production experience, both on shore and off shore. As a result, the entry point for a TISEC plant is less than that of a wind plant back in the late 1970s and early 1980s (i.e., over 20 cents/kWh). Additional TISEC cost reductions will be realized through value engineering and economies of scale.

8.6 Deployment, Operation, and Maintenance

Due to the lack of experience with actual tidal farms, deployment, operation and maintenance (O&M) is an area of considerable uncertainty. The offshore oil, gas and wind industries, however, are coping with similar issues, and there is a reasonable understanding of both deployment and O&M issues and their economic implications.

Deployment and O&M of offshore installations such as oil and gas platforms, wind farms, or tidal farms is more difficult and expensive than equivalent onshore installations. Erection and commissioning operations are more difficult, and accessibility for routine servicing and maintenance is a major concern. The vessels to be used for deployment and O&M are expensive and contribute a significant fraction of the O&M cost. During harsh winter storm conditions, a tidal farm may be inaccessible for a number of days due to sea, wind, and visibility conditions.

8.6.1 Placement

The dimensions of an adequate tidal velocity cross section segment and the requirement to extract only 10-to-20 percent of the energy in the tidal stream determine the size and number of units that can be deployed in a tidal turbine farm. The minimum depth needed to accommodate a TISEC unit is the turbine diameter plus a bottom buffer distance (to reduce the friction effect of the bottom) and a surface buffer distance (to meet the navigable vessel draft requirements and wind affects—which could be positive or negative).

Minimum width is determined by the unit width plus a side buffer distance. The side buffer distance is determined by the fore and aft flow disturbance patterns created by the TISEC unit. Though each design is different, in general TISEC units should be placed so that their interference patterns do not overlap. However, computational fluid dynamics (CFD) field

modeling for each type of unit should be performed to verify ideal spacing. In addition, other values may come into play in determining the minimum width, such as accommodating navigational channels and space to bring in TISEC service vessels.

8.6.2 Anchoring Systems

Anchoring systems hold a TISEC unit in place and resist the loads created by the water flowing through the unit. They include pilings, cables, weights, anchored boats or floats, wall-like structures, and existing dams or tailraces. Pilings are either drilled or driven (pounded) into the sub-terrain to provide a stable structure for mounting the turbine system. Cables use a chain or wire cable anchoring system that is either attached to a permanent land structure or an underwater anchor. Weights are used in anti-buoyancy devices to hold the structure to the floor of the stream by gravity. Anchored boats/pontoons are held in place with cable anchors on the bottom or tied to structures on the shore. Wall-like structures are installed, or cast-in-place structures, mounted on the floor of the body of water or stream; these resemble a traditional dam structure but may or may not include an impoundment. TISEC devices can be supported by other existing support structures, such as piers, bridges, and offshore oil and gas platforms and wind turbines.

8.6.3 Multi-Directional Current Capability

TISEC devices are capable of uni-directional, bi-directional, or multi-directional water flow direction. Uni-directional systems allow flow in one direction only and are used for river applications. Bi-directional systems allow the water to pass through from two opposite directions to drive the rotor and generator. Multi-directional systems operate under all flow directions and either do not change orientation as direction varies or change orientation to face the prevailing current by pivoting around a pole or cable anchor point.

8.6.4 Monitoring and Maintenance

Like wind energy generators, larger TISEC systems typically operate unattended and are monitored and controlled via a supervisory control and data acquisition (SCADA) system. SCADA communicates real-time data on water conditions (e.g., water velocity), power production, power quality, and other unit operations via a telecommunication link. Via SCADA, a remote observer can determine if and when a specific unit might require maintenance.

Access to the units by O&M personnel is a major design problem acknowledged by developers. Designers thus generally strive to maximize the between-service lives of the components, as well as provide the capability to service equipment without having to go off-line. Maintenance typically involves cleaning and replacement of certain components due to wear and tear. Each developer has different maintenance strategies: some use divers for some part of servicing (although underwater work is recognized as expensive and impractical for some environments and local communities); some use retractable TISEC systems that can be fully serviced above water on their pilings or via moored service ship; and some periodically swap in and out full units to perform all maintenance onshore in a more controlled environment.

8.6.5 Transmission/Distribution Lines

If a TISEC plant is to supply grid power, the distance to grid will have a major influence on the project cost. The construction cost of transmission/distribution lines is roughly proportional to their length. Submarine (underwater) transmission cable is more expensive than overland transmission cable. As the power size of projects increases, the maximum economically-viable distance to transmission lines or local users will increase (this is similar to the situation with wind farms).

Initial TISEC plants will be a few MW to a few tens of MW in size and will connect to distribution lines at distribution voltage levels.

8.7 Environmental Issues

EPRI has evaluated tidal energy environmental issues and their possible impacts. The conclusions are:

1. All energy producing technologies, including ocean energy conversion, have the potential to produce unacceptable environmental impacts.
2. Given proper care in siting, installation, operation, and decommissioning, tidal in stream energy technology promises to be one of the most environmentally-benign electricity generation technologies. Any negative environmental effects can be minimized and, in some cases, eliminated by diligent attention to the environmental effects.
3. The discussion of environmental impacts in the U.S. has not been fair and balanced, and has instead focused on conjuring up potential negative consequences.
4. In many cases, analytical models of the complex environmental interactions do not exist and therefore pilot plant demonstrations are required. Unlike large hydroelectric projects, modern ocean energy technologies are modular and can be removed if serious environmental impacts occur. Ocean energy projects, including environmental monitoring and Before-After-Impact and Test and Control Site (to separate natural versus human-induced changes) Studies carried out at specific sites represent the only possible way to achieve an improved understanding of the environmental impacts from tidal energy conversion.

This section summarizes the tidal in stream energy projects that have been permitted for construction and operation worldwide, describes the key environmental issues, and suggests a research program for addressing those issues.

8.7.1 International Projects

- MCT SeaFlow – Devon UK
  - 300-kW demo unit deployed, 3 years experience at sea (Devon UK)
- MCT SeaGen – Strangford Lough, UK
  - 1.2-MW device in construction
  - Permit granted to deploy at environmentally-sensitive site

- British Columbia Canada Race rocks project
  - Initial operation began in November 2006
- European Marine Energy Center, UK
  - Three devices scheduled to be installed in 2007

8.7.2 United States Projects

- Verdant – East River, New York
  - FERC allowing deployment of six turbines to support license application
  - Sockets being drilled; first two units installed in December 2006
  - Four more units to be installed in 2007

Table 8-10 lists five environmental issues that must be addressed.

8.7.1 Withdrawal of Tidal Energy

Since tidal energy technology is modular, the energy extraction can be limited to avoid significant ecological impact. Two references define the percentage of environmentally benign tidal energy extraction:

- Reference 8-3; Ian Bryden Robert Gordon University = 10%
- Reference 8-4; Black &Veatch = 20%

Recent research by Dr. Ian Bryden, now at the University of Edinburgh, Scotland, indicates that the extractable resource may be significantly greater than earlier reported, depending on specifics of the site.

Table 8-10
Major Environmental Issues Facing Tidal In Stream Energy Projects

Tidal Issue	Impact(s)	Mitigation
Withdrawal of Tidal Energy	Retardation of tidal discharge rates and lowering of tidal range levels may affect natural ecosystem process in fragile estuaries	Limit the withdrawal of tidal energy to that level which does not result in any noticeable ecological effects
Interactions with Marine Life, Seabirds and Benthic Ecosystems	Fish mortality seems to be the most significant issue. Effects on the benthic ecosystems primarily during installation and effects on sediment transport processes are also of concern	Limit the rotation speed of the blades to that level which precludes fish mortality
Atmospheric and Oceanic Emissions	Applies to devices with closed-circuit hydraulic systems where working fluid (which may be biodegradeable) may leak or spill during transfers and use of fluids for installation (ie., drilling sockets in hard rock seabed)	Use only biodegradable fluids
Visual Appearance and Noise	The aesthetic effect of visually impacting the pristine coast is unacceptable. Significant underwater noise levels could have adverse effects on marine mammals	Fully submerge the energy conversion devices, land the cable under the shore and muffle underwater noise as required
Conflicts with Other Uses of Sea Space	Potential conflicts with recreational uses, commercial shipping, commercial fishing, crabbing and kelp farming, dredge solid disposal, and other activities	Hold siting, design and installation, operation, and procedure discussions with all local stakeholders prior to making final plant detail design decisions

EPRI is sponsoring a PhD thesis on the *Effect of Kinetic Power Extraction* at the University of Washington. Extraction of kinetic power from tidal streams alters the tidal regime in an estuary by reducing flow volumes, constricting the tidal range, and altering the timing of tidal events. However, the magnitude of these impacts depends strongly on the level of power extraction, estuary geometry, and the natural tidal regime. An understanding of the various fluidic effects of large-scale kinetic power extraction is an essential first step in a more detailed investigation of ecosystem impacts. The ongoing research addresses these issues using a combination of analytical methods, data from device demonstrations, and computational fluid dynamic (CFD) models.

Preliminary results from the University of Washington work are validating the work in the UK.

The modular nature of tidal energy technology also has a minor effect on natural processes. It would be counterproductive for the user to over-develop any particular tidal current resource because, at a certain point, adding more and more turbines ceases to generate additional kinetic energy. The tidal stream is in effect a self-regulating energy supply and any significant reduction in water transfer reduces the energy capture and its commercial viability.

8.7.2 Interactions with Marine Life Including Underwater Noise

The rotational speed of underwater turbine rotors is very slow because of the need to avoid cavitation. For this reason, tidal turbine motors are unlikely to be a serious threat to marine life. Underwater noise is also likely to be low due to the low speed operation.

8.7.3 Atmospheric and Oceanic Emissions

For devices using close-circuit hydraulics, working fluid spills or leakage may be a concern. These concerns can be mitigated through system design features including the use of biodegradable lubricating oils and other fluids. Only relatively small amounts of anti-fouling paints (relative to ships) of the most environmentally-acceptable kind (copper based) need to be used. Appropriate environmental monitoring of these effects also must be performed.

8.7.4 Visual Impacts

Tidal power plants are not likely to be visually intrusive since they are completely submerged. At a cost, the cable landing could be completely buried from the shore to the grid interconnection point.

8.7.5 Conflicts with Other Uses of Sea Space

The potential for conflict with other users of sea space must be addressed early in the siting of tidal power plants. Potential conflicts may exist with marine-protected areas, shipping, fishing, lobstering, scientific research areas, military warning areas, telecommunication cable routes and dredge spoil disposal sites. Most of the conflicts can be avoided via appropriate research during site selection and early dialogue with groups that might be affected.

8.7.6 Environmental Benefits

Tidal energy can provide a number of other benefits in both the environmental and social areas. First, global carbon and pollutant emissions are reduced by displacing fossil-fuel electricity generation. In remote coastal areas, including small islands, it can help reduce the reliance on auxiliary (diesel) power stations. Currently, many remote coastal areas receive their electricity via overhead transmission and distribution lines, which are often perceived to have adverse visual impacts. Again, such impacts would be reduced by having separate tidal power installations serving individual coastal communities.

8.7.7 European Marine Energy Center (EMEC) Tidal Environmental Assessment

AURORA Environmental was contracted to undertake an environmental impact assessment for the EMEC tidal test facility, including a number of baseline and supporting studies, and to prepare an environmental statement. Copies of the environmental statement (in eight sections) and all supporting studies are available for download at http://www.hie.co.uk/emec-tidal.html

8.8 U.S. Regulatory Framework

Due to the absence or minimal nature of any civil works such as dams and powerhouses, TISEC site permitting and licensing should be less complicated and is expected to be less time consuming than that for traditional hydropower dams. Variables affecting the ease of permitting and thus site value include site ownership, social factors, environmental factors and energy needs.

The approval process for deploying TISEC devices is not well defined and the process will vary with location. However, in stream tidal power projects will likely be under FERC jurisdiction and will require an Environmental Impact Assessment (EIA) and involvement of multiple agencies. In the last four years, the federal commission has approved three permits to study tidal sites. Applications for 29 others, all filed in 2006, are under review. No developer has yet applied for a tidal in stream build and operate license.

8.8.1 Regulatory Agencies

The primary Federal agencies with tidal jurisdiction include:

- Federal Energy Regulatory Commission (FERC—an independent agency)
- U.S. Army Corps of Engineers (U.S. Department of Defense)
- National Oceanic and Atmospheric Administration (U.S. Department of Commerce)

Other federal agencies that are likely to be involved include the U.S. Coast Guard, the National Marine Fisheries Service, the U.S. Environmental Protection Agency, the Minerals Management Service (U.S. Department of Interior) and the U.S. Fish and Wildlife Service. Various state and local agencies also participate in the permitting process.

The federal agencies, NOAA, USACOE, and FERC, are described below.

The ***NOAA*** mission, under the U.S. Department of Commerce, focuses on conservation and management of the nation's coastal and marine resources. NOAA is the only agency that has licensing authority and regulations specifically designed for a marine renewable project—the law administering the licensing and regulation of ocean thermal energy conversion (OTEC) projects. To date, no plants have ever been licensed and there is little interest in OTEC demonstrations.[i] At this point in time, NOAA is only involved in a tidal project if there are ocean uses associated with their regulatory authority, e.g., a tidal project located within a protected area such as a Marine Sanctuary.

The ***Marine Management Service (MMS)*** was designated by the 2005 Energy Policy Act as the lead agency with jurisdiction for permitting offshore structures beyond three nautical miles of the coast line. This applies to oil and gas platforms, wind turbines and other offshore structures that alter or obstruct navigable waters outside of state limits (three nautical miles (nm)) and extends activities into the OCS out to the 200 nm of the exclusive economic zone (EEZ).

The US Army Corps of Engineers issues permits under Section 10 of the for underwater submarine cables and transmission lines. But the permit does not confer any property rights or leases within the OCS.

Pursuant to the Federal Powers Act, ***FERC*** is an independent agency regulating interstate transmission of natural gas, oil, and electricity and hydropower projects. FERC also has regulatory authority over the terms and rates for power supply contracts from a wave power project to a local utility. FERC issues licenses for private hydropower development on navigable waterways, federal lands and commerce clause waterways. Hydropower licensing processes is a time consuming and expensive process. It includes consulting with a wide range of stakeholders, identifying environmental issues through a scoping process and preparing environmental documents such as an environmental assessment (EA) or an environmental impact statement (EIS). Licenses are issued by Commission Order. This traditional licensing process takes several years to complete and the license is issued for 30 to 50 years. Clearly, the FERC regulations were not designed for temporary pilot wave power projects.

Tidal electric power sold onto the grid is another jurisdictional area for FERC. A FERC license can be applied for using an alternative licensing process (ALP) that permits scoping of environmental issues to occur prior to the application being filed with the Commission. This is an attempt to streamline the pre-filing and licensing application process. The applicant files a preliminary draft environmental review document along with the application for license. The ALP is more flexible overall, but more cumbersome at the beginning, as it attempts to combine four processes into one collaborative process:

- The pre-filing consultation process. It involves three steps: holding a public hearing to solicit comments, distributing the preliminary application and comments to the involved agencies and developing a scoping document.

- Evaluation of project impacts, pursuant to the National Environmental Policy Act (NEPA). The applicant drafts the document in collaboration with FERC and the other cooperating agencies. Under FERC leadership, the agencies identify which issues need to be addressed, what type of field research is needed, and what other regulations might be applicable.
- Preparing other Federal and state regulatory review materials, such as the Section 7 of the Endangered Species Act (ESA) or the Marine Sanctuaries Act.
- Implementing a negotiation process (if appropriate).

There is a plethora of statutes and regulations relevant to oceans, coasts and the management of marine resources. While there are over 40 principle statutes on the federal level, only a handful is directly relevant to wave power jurisdictions.

Under most federal licensing/permitting regimes (e.g., FERC hydropower licensing, Section 404 permits), federal agencies must consult with the affected states and comply with their laws and regulations. For the foreseeable future, each permitting process will differ slightly, depending on the role of the state agencies that will have either parallel review authority, additional requirements relating to the CZMA, and a range of state environmental statutes protecting public resources. The general approvals on the state level include the following:

- Environmental Quality Review Boards
- Clean Water Act Certifications
- Coastal Zone Management Programs
- Siting Boards for Energy Facilities and Transmission Lines
- State Parks, Forests, and Cultural & Historic Resources
- Tidal Wetlands and Coastal Erosion Hazard

Local government agencies will most likely get involved with the cable landfall connection. The local land use groups include Town Planning and Zoning Boards that regulate by-laws (e.g., setbacks) and construction on local tracts of land.

Some states will have a more cooperative attitude than others depending on the experience and willingness of the state to promote tidal power projects. In some cases, a state may take a very conservative approach to regulatory compliance for a demonstration project by requesting extensive field surveys and/or separate state approval processes. In effect, this will discourage other developers from proposing demonstrations because the cost and schedules are not tenable for a pilot project.

In summary, the extensive level of coordination and possible field studies required for the approval process are barriers to demonstrating tidal power in a timely and cost-effective manner. The private developer is responsible for funding the preparation of the NEPA document which may take several years to prepare. Complying with this licensing process, cooperating with dozens of federal and state regulators, and executing field surveys and monitoring studies will add significantly to the developer's pre- and post-construction costs as well as scheduling issues.

Significant interagency coordination is required between the federal and state agencies where the wave power project will be sited. Parallel review and approval processes will occur at the state level and each state may have its own approach to regulatory compliance as well as it own permits. Early public and agency involvement is critical to identify the interested groups and agencies involved in the approval process.

State and local permitting must also be considered for tidal energy projects. Applicants for a FERC license must consult with the affected states and comply with their laws and regulations. Each permitting process will differ depending on the role of the state agencies that will have either incorporated federal requirements or additional requirements related to resource management.

Also, it bears noting that the Federal Power Act does not have size or duration exceptions to the license requirement. In other words, if a 100-kW project is built on navigable water, it's going to need a license. Section 10 of the Federal Power Act allows FERC to exempt a project of under two MW from some licensing requirements, but it is uncertain whether FERC can wholly exempt projects from acquiring a license. The agency can, however, dispense with studies or other procedures to be followed for getting a license or for other administrative requirements.

In December 2006, FERC hosted the Hydroelectric Infrastructure Technical Conference to, among other things, discuss the regulatory issues pertaining to the development of wave and tidal generation technologies. While no definitive regulatory actions were immediately adopted, EPRI did advocate a permitting process that facilitates demonstration projects and, in turn, generates information that can then be used to evaluate a permitting process over the longer term.

8.8.2 Recent Tidal Energy Permitting History

Five U.S. in stream tidal power projects have been completed or are in the licensing process:

- Long Island, NY: Short-term testing (a few days) of a barge-mounted Gorlov Helical Turbine (GHT) rotor, not grid connected
- Amesbury, MA: Short-term testing (two months) of a barge-mounted GHT rotor integrated with Hardware/Software Platform, not grid connected.
- East River Project, NY: 18-month test of six 39-kW horizontal-axis, open rotor turbines, grid connected. FERC waived the need for a license for the project's installation and operation, based upon three conditions: (1) its experimental nature with plans to collect data to be used to obtain a larger plant license; (2) short duration of test; and (3) no impact on interstate commerce (Verdant had to agree not to sell the electricity generated). Licenses were obtained from the USACOE and the NY Dept of Environmental Conservation.
- Golden Gate (San Francisco, CA) tidal project: The FERC permit holder is Oceana Golden Gate Tidal Company.
- Tacoma Narrows , WA Tidal project: The FERC permit holder is Tacoma power, the local municipal utility. Tacoma Power issued a solicitation for consulting and engineering services to support this project. Proposals were due in November 2006. As of January 2006, there has been no news on the evaluation of the proposals and the selected contractor.

The Long Island Project

A FERC license was not required as the project did not generate electricity into the electrical grid. Permits were issued by the following ten agencies

- New York State Department of Environmental Conservation (NYSDEC)
- New York State Department of State (NYSDOS)
- New York Office of General Services (NYSOGS)
- U.S. Army Corps of Engineers (USACOE)
- U.S. Coast Guard, Long Island Sector (USCG-LIS)
- U.S. Department of Commerce, National Oceanographic and Atmospheric Administration, National Marine Fisheries Service (USDOC, NOAA, NMFS)
- Suffolk County, Long Island
- Town of Shelter Island
- Town of Southampton
- Village of North Haven

Amesbury Project

Unknown. Please address questions to Trey Taylor, President, Verdant Power LLC at 703-528-6445 or ttaylor@verdantpower.com

Verdant East River Roosevelt Island Tidal Energy (RITE) Project

Believing that the RITE Project required a FERC Hydropower license to generate and deliver electricity from the tidal flows of the East River, on May 31, 2002, Verdant Power submitted an application to FERC for a preliminary permit for a FERC license. In August, at the request of the FERC Chairman, Verdant Power briefed the FERC Chairman and staff on its plans for the project. In that briefing, Verdant Power described the need for a customized licensing approach for these types of technologies. At the Chairman's direction, the RITE Project provided the platform for recommending such an approach. On September 9, 2002, Verdant Power received the FERC Preliminary Permit for the project (FERC Docket P-12178).

In the fall of 2003, Verdant Power engaged the Syracuse, New York office of Devine, Tarbell and Associates (DTA) to provide FERC licensing support. Using the Traditional Licensing Process, in October 2003, Verdant Power and DTA distributed the RITE Project Initial Consultation Document (ICD) and scheduled and conducted the initial agency and public meetings on Roosevelt Island on December 15th. Participants and interested parties at the agency meeting included seven federal agencies, four state agencies, and a number of interested New York City government representatives. Since a kinetic hydropower project has no precedent, a fundamental issue identified by agency representatives following the agency meeting was a need to clarify jurisdiction and project requirements among the federal and state agencies.

A meeting to address this issue was scheduled among the agency representatives at the New York Army Corps of Engineers office on January 27, 2003. At this meeting, FERC stated that they had no site jurisdiction other than issuing the preliminary permit and they had no requirements on Verdant Power prior to receiving the project license application. In the absence of a FERC lead, permitting for the six-turbine study array was jointly assumed by the Army Corps of Engineers, Section 10 of the River and Harbors Act and Section 404 Clean Water Act permits, and New York State Department of Environmental Conservation (NYSDEC) Protection of Waters permit which initiates the New York State Environmental Quality Review (SEQR) process.

Following the agencies decisions on the permits required for the six-turbine study array, Verdant Power submitted permit applications to the Army Corps and to the NYSDEC on February 10, 2004.

On February 2, 2005, Verdant filed a petition requesting "relief from the requirements of hydropower licensing under the Federal Power Act." Verdant stated that it wanted to test, for an 18-month period, six of the underwater turbine units referenced in its preliminary permit application, to evaluate the potential impacts of the technology on fish, navigation, and other non-developmental resources, as well as to gain operational performance data. Power generated by the turbines would be delivered to two customers on Roosevelt Island.

On April 14, 2005, FERC issued an order concluding that the installation and testing of the six turbines discussed by Verdant in its petition did not require licensing by the Commission, based on the following conclusions and conditions: (1) the technology in question is experimental; (2) the proposed facilities are to be utilized for a short period for the purpose of conducting studies necessary to prepare a license application; and (3) power generated from the test project will not be transmitted o, or displace power from, the national electric energy grid. We noted that Verdant failed the third provision, because it proposed to provide power to two customers, thus displacing power from the grid.

On May 16, 2005, Verdant filed a request for clarification or rehearing of the Commission's April 14, 2005 order.

On July 27, 2005, FERC granted the requested clarification. In the April 14 Order, FERC discussed the precedent regarding the manner in which hydropower projects connected to the interstate electric power grid can, through displacement, affect interstate commerce. It further stated that a project affecting interstate commerce should require a license. Under Verdant's proposal, as modified in its request for clarification, although electricity from the grid would physically be displaced by power produced from the test project, Verdant would make the entities that otherwise would have provided that power whole. Given those circumstances, Verdant's activities would effectively have no net impact on the grid or on interstate commerce. Therefore, Verdant may test its facilities, under the conditions set forth in the April 14 Order, as clarified in this order, without a license under Part I of the Federal Power Act.

Verdant interfaced with fifteen (15) different federal and state agencies to establish its permitting requirement. The Army Corps coordinated the federal agencies in the permitting process to assess potential environmental, navigational, security and other impacts. The seven (7) federal agencies included the U.S. Coast Guard, U.S. Fish and Wildlife Service, National Oceanographic

& Atmospheric Administration (NOAA) Fisheries, U.S. National Park Service, the Environmental Protection Agency, FERC and the USACE. NYSDEC coordinated the state agencies in addressing water quality, fisheries and other issues. Participants included eight internal NYSDEC permitting, legal, water quality, and fisheries organizations.

8.9 Conclusions

In-stream tidal energy technology is an emerging technology. Several small-scale and surface-piercing devices now ready for pilot demonstration testing in the U.S. and Canada. Large-scale non-surface piercing devices will be ready for pilot scale demonstration testing in the U.S. and Canada within a year or two. Most sites require non surface piercing devices.

The MCT 300-kW experimental prototype has been operating in the UK for over three years and much has been learned. The 18-month Verdant Roosevelt Island Tidal Energy (RITE), East River NY demonstration project (six turbines at 34 kW each) is now licensed and will commence testing in late 2006. The MCT SeaGen 1-MW commercial prototype is being fabricated and will commence testing in 2007 at Strangford UK, an environmentally-sensitive site. Both the Verdant and MCT test programs include extensive environmental and marine life monitoring. Additional tidal systems including an Open Hydro Turbine, a Lunar Energy RTT1000, and a SMD Hydrovision 1 MW prototype are scheduled for installation and testing at the European Marine Energy Center in the Orkneys in 2007.

Although technologically ready for demonstration, many important questions about the application of in- stream tidal energy to electricity generation remain to be answered, such as:

- What type/size will yield optimal economics?
- Will the installed cost of tidal energy conversion devices realize its potential of being less expensive than solar or wind?
- Will the predictability of tidal earn a capacity credit for its dispatch ability?
- Will the performance, cost, and reliability projections be realized in practice once tidal energy devices are deployed and operated?

Tidal energy technology R&D at universities can help to answer many of the technology outstanding questions. Areas of needed research include:

- 3D computational fluid dynamics coupled with accurate velocity measurements for micro-siting tidal plants, including pilot plants
- Understanding how turbulence, ice and suspended sediment affect the choice of technology and its performance and lifetime
- Understanding the energy extraction limit for precluding significant ecological effects
- Turbine interaction within an array to minimize spacing in limited seabed situations.

8.9.1 Internet Resources

EPRI: www.epri.com/oceanenergy/

European Wave Energy Thematic Network: http://www.wave-energy.com

Department of Transportation and Industry (UK): http://www.dti.gov.uk/renewable

Australian Renewables including Wave Energy:
http://www.greenhouse.gov.au/renewable/index.html

Danish Wave Energy: http://www.waveenergy.dk/

European Commission 'Thermie' wave energy site:
http://europa.eu.int/comm/energy_transport/atlas/htmlu/wave.html

European Wave Energy Research Network (EWERN):
http://www.ucc.ie/ucc/research/hmrc/ewern.htm

European Wave Energy Thematic Network: http://www.wave-energy.net/

Japan Marine Science & Technology Center, JAMSTEC:
http://www.jamstec.go.jp/jamstec/MTD/Whale/

Norwegian Wave Energy Site: http://www.phys.ntnu.no/instdef/prosjekter/bolgeenergi/index-e.html

Open University, UK: http://www.openuniversity.edu/StudentWeb/t265/update/wave.htm

World Wave Atlas: http://www.oceanor.no/projects/wave_energy/

8.10 References

EPRI Tidal Power (TP) Reports are available at www.epri.com/oceanenergy/.

1. Assessment of the National Ocean Service's Tidal Current Program". NOAA Technical Report NOS CO-OPS 022, April 1999.
2. Tides in Canadian Waters, G.C. Dohler, Canadian Hydrographic Service, Department of Fisheries and Oceans © Government of Canada Publications, Cat. No. Fs 23-89/1986 E, ISBN 0-662-14829-0.
3. Bryden. Ian, "Tidal Current Power" Slide Presentation, Centre for Environmental Engineering and Sustainable Energy, Robert Gordon University, 2002.
4. Black & Veatch Group, 2004. "UK, Europe, and Global Tidal Energy Resource Assessment." Marine Energy Challenge Report No. 107799/D/2100/05/1. London: Carbon Trust.

5. "Marine Current Turbines: Solving Engineering Challenges to Capture Energy from the Sea" Peter Fraenkel, Technical Director, MCT, presented at OceanEnergy 2005, April 26-28, 2005.

6. "Tidal Power Using the Gorlov Helical Turbine Demonstration Project – Long Island Sound, GCK Technology Inc, December, 2004.

7. "Amesbury Tidal Energy Project – Integration of the Gorlov Helical Turbine into an Optimized Hardware/Software System Platform" Verdant Technology and GCK Technology Inc, April 30, 2005.

8. "Regulating Innovation: Permitting and Licensing New York City's East River Kinetic Hydropower Project" Ron Smith, CEO Verdant Power LLC, presented at Powergen RE, March 2004.

9. TP-001-NA - Guidelines of Preliminary Estimation of Power Production by Tidal In Stream (Current) Energy Conversion Devices.

10. Boon, J., 2004. SECRETS OF THE TIDE: Tide and Tidal Current Analysis and Predictions, Storm Surges and Sea Level Trends. West Sussex, UK: Horwood Publishing, Ltd. 300 pp.

11. TP-002-NA- Economic Assessment Methodology for In Stream Tidal Energy Devices.

12. TP-003-MA - Results of Survey and Characterization of Potential Tidal Energy Site Locations in Massachusetts.

13. TP-003-NB Results of Survey and Characterization of Potential Tidal Energy Site Locations in New Brunswick.

14. TP-003-NS Results of Survey and Characterization of Potential Tidal Energy Site Locations in Nova Scotia.

15. TP-003-ME Results of Survey and Characterization of Potential Tidal Energy Site Locations in Maine.

16. TP-004-NA Survey and Characterization of In Stream Tidal Energy Conversion Devices.

17. TP-005-NA Methodology for the Conceptual Level Design of Tidal In Stream Energy Conversion Power Plants.

18. TP-006-AK, Alaska Pilot and Commercial System Level Design Study.

19. TP-006-WA, Washington Pilot and Commercial System Level Design Study.

20. TP-006-CA, California Pilot and Commercial System Level Design Study.

21. TP-006-MA, Massachusetts Pilot and Commercial System Level Design Study.

22. TP-006-ME, Maine Pilot and Commercial System Level Design Study.

23. TP-006-NB, New Brunswick Pilot and Commercial System Level Design Study.

24. TP-006-NS, Nova Scotia Pilot and Commercial System Level Design Study.

25. TP-007-NA, North America Environmental and Regulatory Issues Report.

26. TP-008 NA, Final TISEC Summary Report.

27. EPRI Summer Seminar, 2005.

28. Bryden, I.G., T. Grinsted, and G.T. Melville, 2004. Assessing the potential of a simple tidal channel to deliver useful energy. *Applied Ocean Research 26*: 198–204.

29. Bryden, I.G., and G.T. Melville, 2004. Choosing and evaluating sites for tidal current development. *Proc. Instn. Mech. Engrs., Part A: Journal of Power and Energy*, *Vol. 218,* pp. 567-577.

9
OCEAN WAVE ENERGY

Installed Capacity (as of December 31, 2006)	<4 MW worldwide 0.04 MW in United States
Wave Energy Conversion (WEC) Technology Readiness	Ocean Power Delivery (UK), Ocean Power Technology (USA), WaveDragon (Denmark), WaveSwing (Netherlands), Fred Olsen (Norway), WaveBob (Ireland), ORECon (UK), Renewable Energy (Australia), and Energetech (Australia) prototype WEC devices were demonstrated at sea in 2006
Economic Status	First commercial sale announced in Portugal 2005, made possible by significant feed-in tariffs First U.S. commercial plant in Oregon announced in 2006, made possible through public support and other state incentives
Environmental Impact	Proper care in siting, installation, operation, and decommissioning, potentially makes ocean wave energy technology one of the more environmentally benign electricity generation technologies More study, including pilot demonstration testing, needed
Regulatory Status	Some projects likely to prove controversial due to uncertain environmental impacts The Federal Energy Regulatory Commission (FERC) has asserted jurisdiction over ocean energy under the Federal Power Act (FPA) Many regulatory barriers in the U.S. exist for licensing an ocean wave energy pilot or commercial scale project The 2005 Energy Bill gives the Mineral Management Service (MMS) of the Department of Interior (DOI) the power to lease lands on the outer continental shelf (OCS), that is, 3 to 200 nm offshore, but does not eliminate other federal jurisdiction Strong public support is required to overcome the inertia that many federal, state, and local regulatory agencies will bring to the permitting process
Trends to Watch	Continued technology funding in the UK and other European countries and Australia A U.S. Department of Energy (DOE) funded ocean energy RD&D program by FY 2007 Individual demonstration projects and early commercialization projects, including multi-megawatt “wave farms” over the next decade, in Europe, the U.S., and Australia

9.1 Introduction

Ocean waves are generated by the influence of wind on the ocean surface as depicted in Figure 9.1. Ripples on the surface create a steep slope against which the wind can push and cause waves to grow. In deep water, waves can travel for thousands of miles until their energy is dissipated on distant shores. Thus wave energy produced anywhere in an ocean basin ultimately arrives at its continental shelf margins virtually undiminished until it reaches ~200 m depths.

Individual waves represent an integration of all winds encountered as they travel over the ocean surface. Ocean waves are consistent, and sea states can be accurately predicted more than 48 hours in advance. This predictability allows time for other generation resources to be brought on-line to compensate for low-energy sea states. However, the characteristic of wave energy that makes it especially attractive for electricity generation is its high power density compared to the power density of solar and wind energy.

Ocean waves are composed of orbiting particles of water. Near the surface, the orbits are the same size as the wave height. Orbit amplitude decreases exponentially with depth, such that 95% of the wave energy is stored between the surface and a depth equal to a quarter of the wavelength. Figure 9-2 shows particle orbits for different water depths.

9.1.1 Harnessing Wave Energy

Wave energy extraction is complex and many device designs have been proposed. For understanding the device technology, it is helpful to introduce these in terms of their physical arrangements and energy conversion mechanisms, such as:

- Distance from shore—Wave energy devices may convert wave power at the shoreline, near to the shore (defined as shallow water where the depth is less than one half of the wavelength), or offshore.
- Bottom mounted or floating—Wave energy devices may be either bottom-mounted or floating.

Wave energy devices can be classified by means of the type of displacement and reaction system employed. Various hydraulic or pneumatic power take-off systems are used and in some cases the mechanical motion of the displacer is converted directly to electrical power (direct-drive).

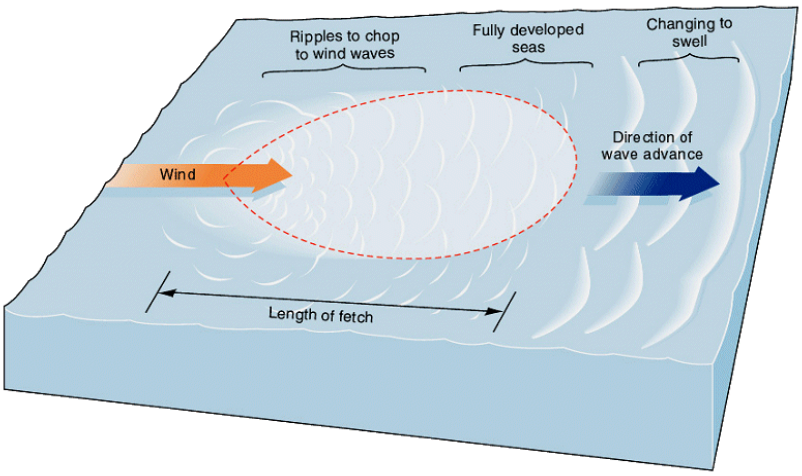


Figure 9-1
Wind Blowing Over Fetch of Water Produces Waves

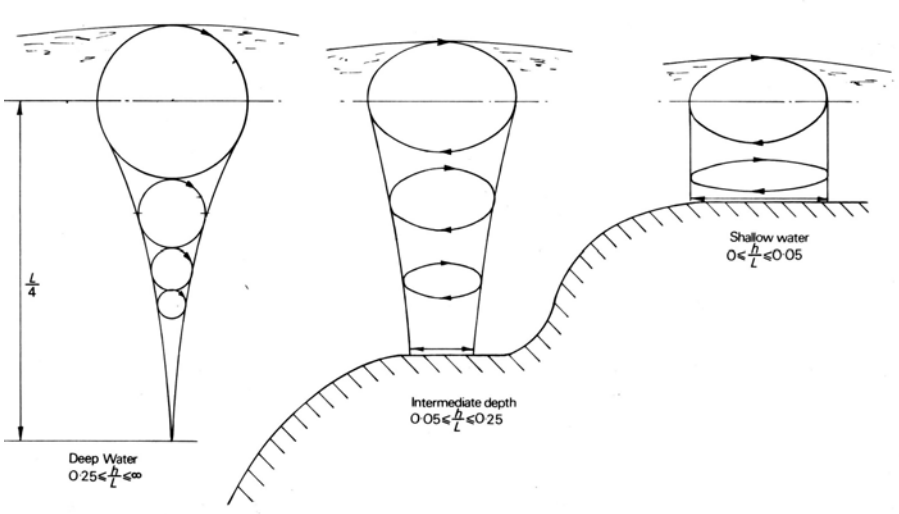


Figure 9-2
Particle Motion in Different Water Depths

Four of the best known device concepts are introduced below and the principle of operation is illustrated in Figures 9-3a – 9-3d.

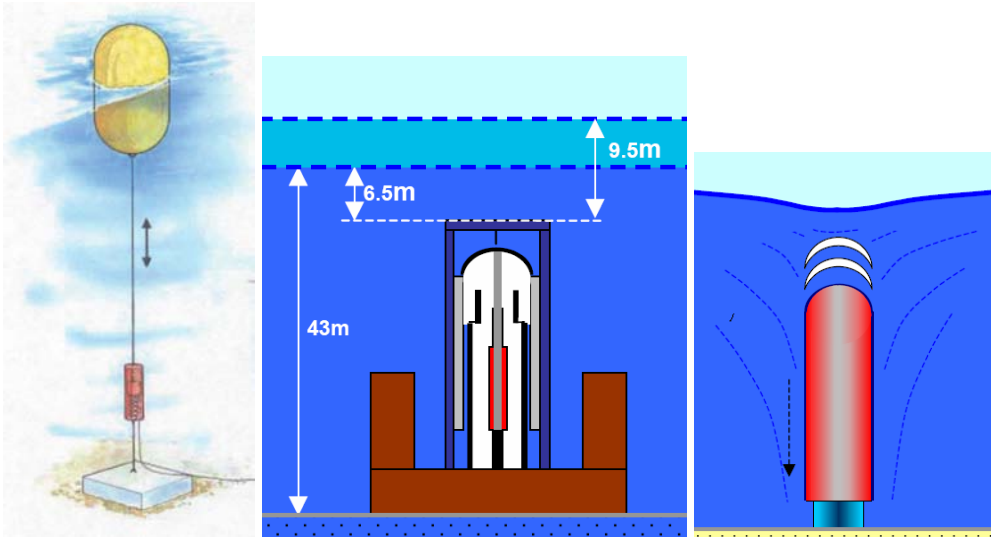
- **Point absorber** (Figure 9-3a)—A bottom-mounted or floating structure that absorbs energy in all directions. The power take-off system may take a number of forms, depending on the configuration of displacers/reactors. The illustration on the left in Figure 9-3a shows a floating buoy and the illustration on the right shows a bottom-standing device; a completely submersed point absorber, with a linear direct generator to convert the oscillatory motion into electricity. The upper floater traps air inside, forming an effective spring element. Pressure differences on the top of the float (created by surface wave action), will set the top floater into motion and the system starts to oscillate

- **Oscillating Water Column** (OWC) (Figure 9-3b)—At the shoreline, this could be a cave with a blow-hole and an air turbine/generator in the blow hole. Near or offshore, this is a partially-submerged chamber with air trapped above a column of water. As waves enter and exit the chamber, the water column moves up and down and acts like a piston on the air, pushing it back and forth. A column of air, contained above the water level, is compressed and decompressed by this movement to generate an alternating stream of high-velocity air in an exit blowhole. The air is channeled through a turbine/generator to produce electricity.
- **Overtopping terminator** (Figure 9-3c)—A floating reservoir structure with a ramp over which the waves topple and hydro turbines/generators through which the water returns to the sea. As shown in Figure 9-3c, a floating structure moves at or near the water surface, typically with reflecting arms to focus the wave energy. It has both a ramp and a reservoir, so that as waves arrive, they overtop the ramp and are restrained in the reservoir. The head of collected water turns the turbines as it flows back out to sea and the turbines are coupled to generators to produce electricity.
- **Attenuator** (Figure 9-3d)—One incarnation of the attenuator principle is a long floating structure that is orientated parallel to the direction of the waves. The structure is composed of multiple sections that rotate in pitch and yaw relative to each other. The motion is used to pressurize a hydraulic piston arrangement and then turn a hydraulic turbine/generator to produce electricity. Figure 9-3d illustrates a freely-floating hinged contour attenuator device. The four sections move relative to each other and this motion is converted at each hinge point to electricity by a hydraulic power converter system.

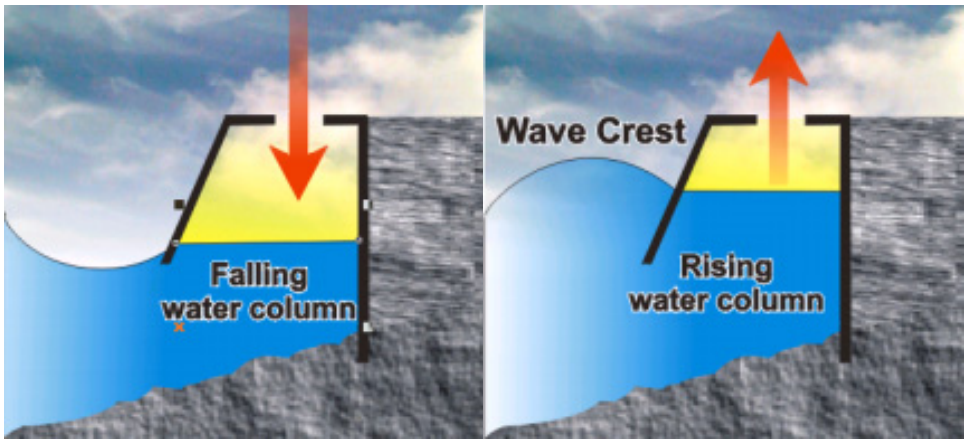
There are many other design concepts, but they are beyond the scope of this report.

9.1.2 Survival in Storms and Hostile Marine Environments

Today's wave energy conversion technology is the result of many years of testing, modeling, and development by many developer organizations. Full-scale prototypes have been continuously operating and providing electricity into an electric grid in the UK since the summer of 2004. The core theme of the current design concepts is survivability.



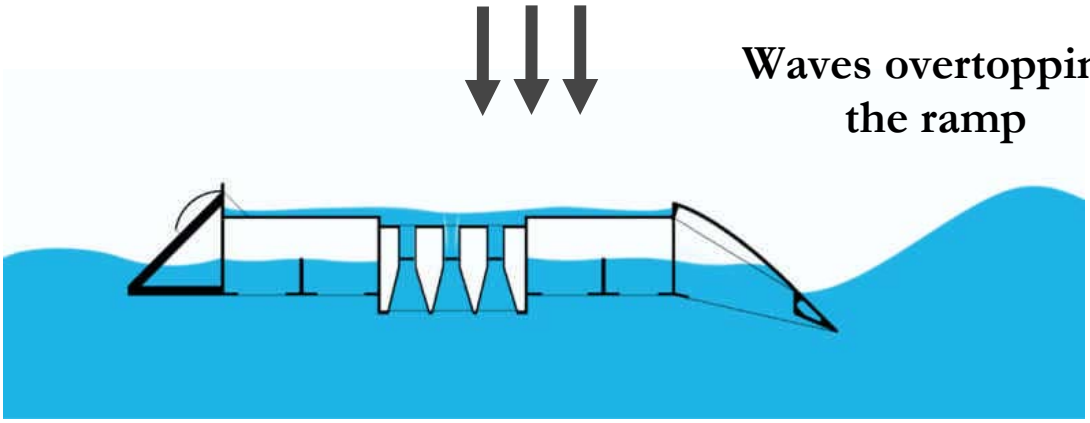
(a)



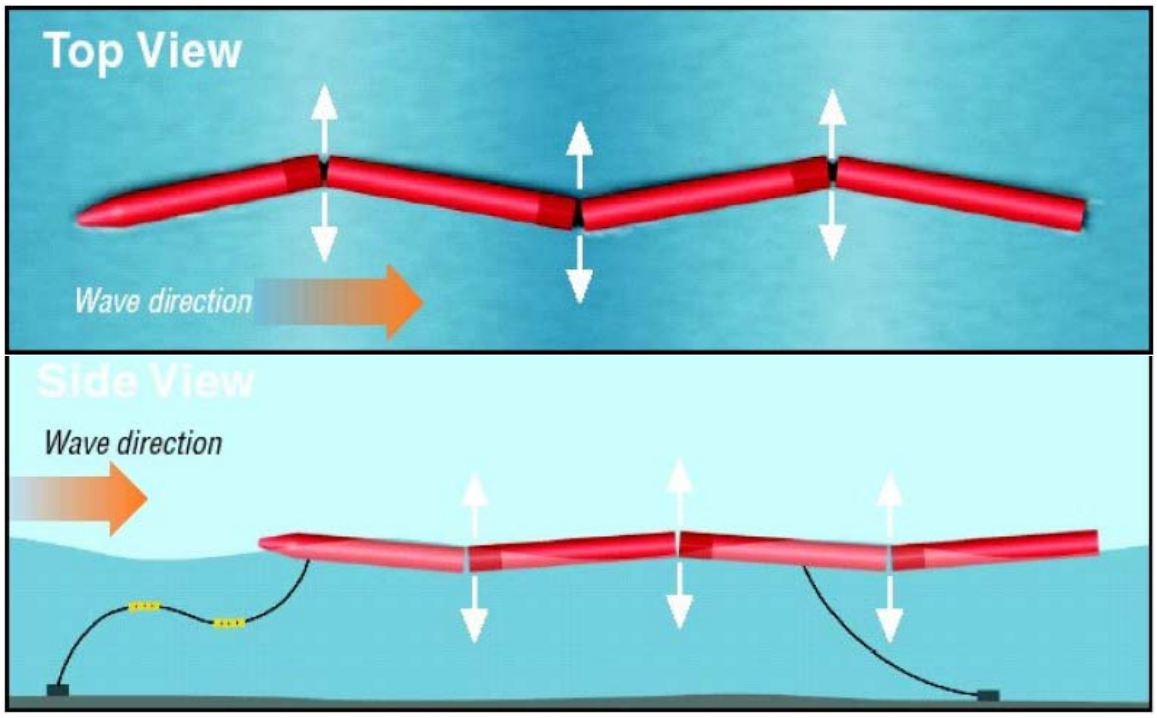
(b)

Figure 9-3
(a) Wave Energy Device Concepts and Principles of Operation, Point Absorber Wave Energy; (b) Device Concepts and Principles of Operation, Oscillating Water Column

(continued on next page)



(c)



(d)

Figure 9-3 (continued)
(c) Wave Energy Device Concepts and Principles of Operation, Overtopping Terminator;
(d) Wave Energy Device Concepts and Principles of Operation, Hinged Contour Attenuator

9.1.3 Effect of Wave Power Plants on the Environment

All electricity generation systems affect the environment. Given proper care in site planning, however, offshore wave power promises to be one of the most environmentally benign electricity generation technologies. We recommend that early demonstration and commercial offshore wave power plants include rigorous monitoring of the environmental effects of the plant and similar rigorous monitoring of a nearby undeveloped site in its natural state (so that natural effects can be separated from induced effects in long-term trends). With proper siting and installation, operation and maintenance care, offshore wave energy power plants should not cause any permanent damage to the environment.

9.1.4 Permits for Offshore Wave Power Plants

The novelty of the technology at the federal, state, and local level will likely trigger conservative evaluations and extensive approval processes. The 2005 Energy Bill signed by President Bush assigned primary responsibility for leasing lands for ocean energy projects in federal waters (3 to 200 miles) to the Mineral Management Service (MMS) of the U.S. Department of the Interior (DOI).

Permitting a wave power plant presents a significant barrier to the development of wave energy technology and to commercial use of the technology. The primary reasons are:

- A wide variety of regulations and agencies are involved, which makes the process complex. Moreover, each state and project is unique.
- There is no precedent upon which regulators can base an approval decision.
- The only FERC processes available were created to manage the impacts of conventional hydropower facilities with impoundments and with 30- to 50-year cycles. Those processes are both lengthy (5 to 8 years) and costly (way beyond what the fledgling wave energy industry device industry can afford).
- No specific “fast-track” or “conditional” (i.e., if negative impacts are seen, the license is revoked and devices must be taken out) regulations exist for short-term non-commercial ocean energy demonstration projects.
- No accountability for acts of omission and a built-in bias for delay. People in the system can be and are generally held accountable for acts of commission (taking action) and not for acts of omission (doing nothing). Without accountability for omissions, the default is “more study” and “no actions.”
- Opponents of a particular ocean energy project can use regulatory uncertainty to their advantage to oppose a project.
- Lack of regulatory standards makes it impossible to predict whether or not and on what terms a permit will be issued and at what costs, thus deterring private investors from funding projects.

Nevertheless, it is likely that strong public support and the positive experiences in the UK and other countries will influence the federal, state, and local agencies to allow this emerging technology to go forward. Furthermore, the November 2006 filing by AquaEnergy Group Ltd is the nation's first application for a license to construct a wave plant in the U.S. (exclusive of the wave plant in Navy waters in Hawaii). This filing for the Makah Bay Offshore Wave Energy Pilot Project in Washington State may help to clarify the evolving permitting process.

To help address permitting uncertainty, FERC hosted a conference in Washington, D.C. in December 2006 to discuss the status of ocean-based hydroelectric technologies and explore the environmental, financial, and regulatory issues pertaining to their development. Notes and analysis from the conference will be published on the EPRI Ocean Energy public website (www.epri.com/oceanenergy/).

9.1.5 Installed Capacity and Expected Growth

Table 9-1 presents the EPRI estimate of offshore wave capacity (in MW) that could come online (i.e., commissioned and selling electricity into the grid) in the U.S. between 2006 and 2010.

Installed offshore capacity to date is <4 MW worldwide; Less than 1 MW is currently grid-connected and the devices are prototypes. The first shore-based grid-connected wave power unit was deployed in Scotland in July 2000 and has since operated successfully. The first offshore grid-connected wave power unit was deployed at the European Marine Energy Center in the Orkneys in July 2004 and testing is still ongoing. Based on the successful testing, however, the first commercial sale of an offshore wave power plant was announced in May 2005. In addition, a number of demonstration projects are planned in Portugal, China, Japan, Australia, and the U.S.

9.1.6 Other Important Considerations

The energy content of waves is a function of wave height and wave period.

- Sea state–In real sea conditions, many wave heights and periods occur simultaneously and it is necessary to resort to a statistical description. Data for a particular site can be summarized on a scatter diagram, which is a record of the wave motions, showing the number of occurrences of particular combinations of H_s (significant wave height equal to the average of the third highest waves) and Tp (peak wave time period). Each combination of H_s and Tp is referred to as a sea state.

It is also a function of the wave energy generation devices used.

- Efficiency–This can be defined in several ways. A simple view is to consider “resource-to-wire” efficiency: the ratio of the energy a device actually captures to the energy that is available to be captured.

- Availability–The proportion of time a device is ready to generate, irrespective of whether the resource is suitable for generation.
- Capacity factor–The energy produced during a certain period divided by the energy that would have been produced had the device been running continually and at maximum output.

Table 9-1
Installed and Planned Wave Energy Capacity (as of December 1, 2006)

<4 MW worldwide:

- 0.04 MW in United States
- 0.75 MW – OPD Pelamis at EMEC, Orkney, Ireland
- 1.0 MW – WaveSwing at Lexious, Portugal
- 0.5 MW – Energetech at Port Kembla, Australia
- 0.04 MW – Ocean Power Technology at Oahu, Hawaii
- 0.1 MW – WaveBob (R.Bedard/EPRI estimate)
- 0.3 MW – Fred Olson (R Bedard/EPRI estimate)
- 0.1 MW – Renewables Holding CETO (R. Bedard/EPRI estimate)
- 1.0 MW – ORECon (assuming their test is full scale)

Developer	Project Name-Site	2007	2008	2009	2010	2011
Finavera (1)	Makah Bay, WA		1			
Energetech (2)	Point Judith, RI		2			
Ocean Power Technology (3)	Reedsport, OR				50	
TBD (4)	Lincoln County OR					30
OSU (5)	Lincoln County OR RD&D Facility			1		
TBD	Northern California				30	
TBD	Hawaii					100
TOTAL NEW	YEARLY CAPACITY		3	1	80	130
	CUMULATIVE		3	4	84	214

Assumes that FERC changes its policies to enable wave plants to be permitted at about the same cost as on-land wind plants and that Congress provides the same incentives to wave energy as for wind energy.

(1) Assumes pilot plant funding. However, a commercial plant is not expected to be built because local demand and transmission infrastructure do not exist.
(2) Assumes that FERC allows Energetech to sell electricity from the pilot plant and does not make them reimburse Narragansett Electric for electricity that they do not generate. Also assumes that the plant does not reach commercial status due to the economics of the poor wave climate.
(3) Assumes that OPT will be able to leverage off the system, take advantage of environmental work done by Finavera, and be able to get a license without a pilot plant.
(4) Lincoln County has filed an application with FERC for a half dozen offshore wave plants in their coastal state waters.

(5) Assumes that OSU is successful at getting the funding for a wave energy RD&D plant at Newport, OR and that the plant typically has about 1 MW of devices operating at any one time

Ocean wave energy is one of the most concentrated and widely available forms of renewable energy in coastal areas. The World Energy Council estimates that about 10% of worldwide electric energy demand could be met by ocean wave energy. The current installed electric capacity is about 3.5 TW (1 TW = 10^6 MW). The fact that 37% of the world's population lives within 60 miles of a coastline establishes a good match between resource and demand and could facilitate widespread adoption of emerging technologies that generate electricity from ocean waves.

In general, the industry expects that wave energy will experience a growth rate similar to that of wind during the last decade, although these predictions depend largely on government support and incentives for the emerging wave energy industry.

9.2 Wave Power and Energy Resource

A number of sources provide wave data for assessing potential sites, including *in situ* measurements, satellite measurements, wind-wave models, and visual observations. When assessing a specific site, analysts typically choose a suitable primary data source and then verify the data sets by other methodologies to confirm their accuracy. In order to properly identify inter-annual variations and long-term trends, data sets should cover 5 to 10 years.

In situ measurements for ocean waves have been conducted in many locations worldwide. Industrialized nations often have extensive historical data sets, which can be used to derive useful statistics for site assessments. These measurements are normally performed by small floating measurement buoys, which derive statistical parameters such as significant wave height, wave period, and wave direction from the buoys' accelerations.

In addition, satellites deployed by NASA and the ESA perform altimetry measurements and wave height can be analyzed by interpreting radar response signals from these satellites. Because these measurements cannot detect wave direction and period, they are typically used as a secondary source of information.

Wind-wave models calculate wave data from a wind-field input. This methodology has been well refined over the last decade and modern third-generation models yield very accurate long-term statistics (up to 50 years). Model predictions are especially useful when *in situ* measurements are not available for sufficiently long periods of time.

Visual observations are performed from merchant and other ships, and programs to collect such data have been in place for over 50 years. The observations are considered to be good long-term indicators of wave patterns. However, because ships tend to avoid stormy seas, the data sets miss extreme events.

In shallow waters (<100 m), the influence of the ocean floor generally reduces wave power levels. Submerged features such as canyons can also focus energy, leading to hot spots in close

proximity to shore. A number of shallow-water wave transformation models take into account the bathymetry to calculate near-shore wave data. Experience with shore-based oscillating water column devices shows a need for extensive modeling in such locations. The accuracy of such models depends largely on the accuracy and resolution of the local bathymetry data.

9.2.1 Data Sources

The two largest inventories of long-term measured wave data in the U.S. are maintained by the National Data Buoy Center (NDBC) of the National Oceanic and Atmospheric Administration (http://www.ndbc.noaa.gov), and by the Coastal Data Information Program (CDIP) of Scripps Institution of Oceanography (http://cdip.ucsd.edu/).

NDBC data buoys are equipped with strapped-down accelerometers for measuring wave conditions derived from buoy heave response. Wave spectra are computed from 20-minute time-series measurements of sea surface elevation changes, and these records are archived at one-hour intervals. CDIP offshore wave measurements are made almost exclusively made by Datawell Waverider® buoys, but offshore oil and gas production platforms also are used when available, to mount submerged pressure gauges. Wave spectra are computed from 17-minute time-series measurements of sea surface elevation changes, and these records are archived at six-hour intervals.

The six reference stations, one each for the states of Maine, Massachusetts, California, Oregon, Washington, and Hawaii are listed in Table 9-2 and mapped in Figures 9-4 through 9-6.

Table 9-2
Offshore Wave Energy Reference Measurement Stations

State	Station Number	Station Name	Latitude (deg N)	Longitude (deg W)	Depth (m)	Measurement Period (years)
ME	NDBC 44005	Gulf of Maine	43.18	69.18	22	1983 – 2002
MA	NDBC 44008	Nantucket Shoals	40.5	69.43	63	1983 – 2002
CA	NDBC 46012	Half Moon Bay	37.4	122.7	80	1983 – 2002
OR	CDIP 0037	Coquille River	43.11	124.51	64	1985 – 1996
WA	CDIP 0036	Grays Harbor	46.86	124.07	38	1987 – 2002
HI	CDIP 0098	Makapuu Point	21.32	157.59	91	1982 – 1996

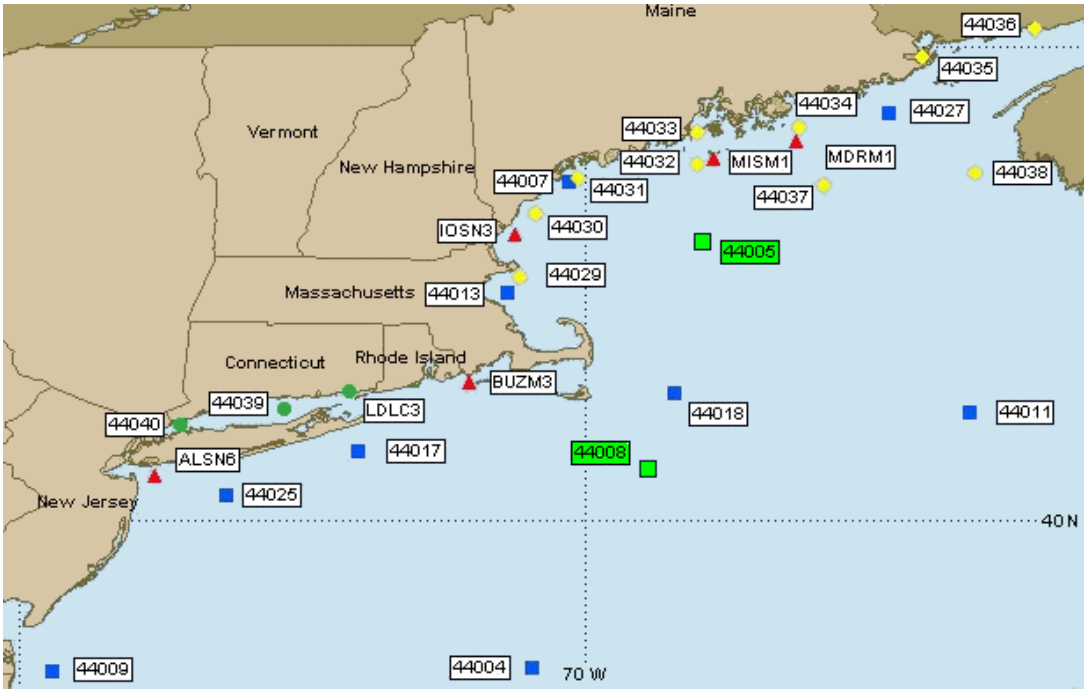


Figure 9-4
New England Reference Stations (NDBC 44005 and 44008 are bright green squares)

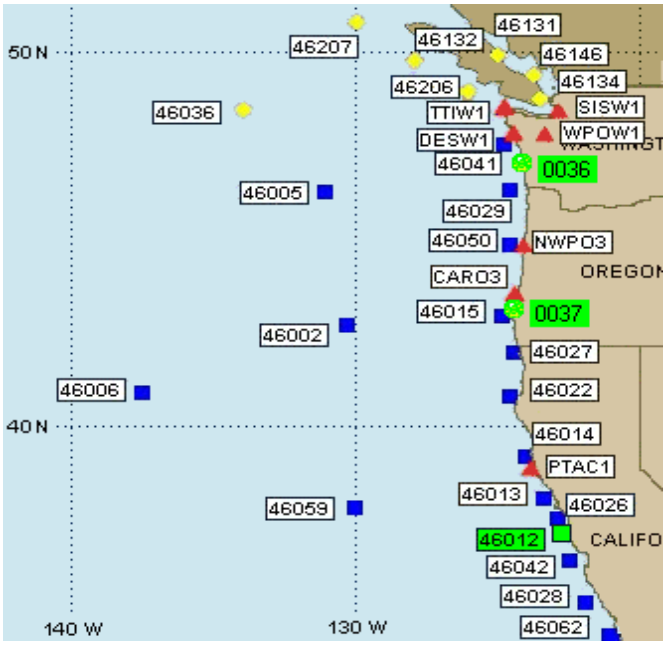


Figure 9-5
West Coast Reference Stations
(NDBC 46012 is green square; CDIP 0036 and 0037 are green circles)

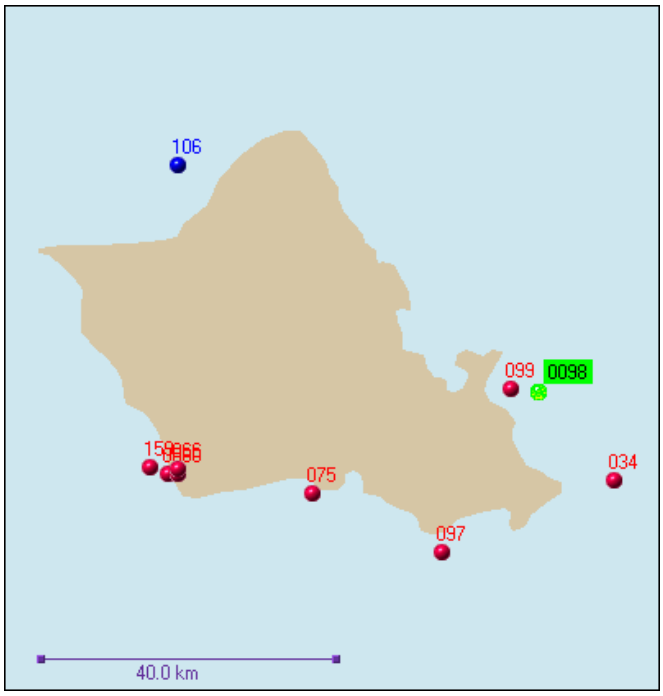


Figure 9-6
Oahu HI Reference Station, (CDIP 0098 is green circle)

Ocean waves are a complex, strongly variable phenomenon. Real seas contain waves that are random in height, period, and direction. Real seas remain constant over the period of a few hours, resulting in a sea state that can be described by a directional spectrum. The directional spectrum shows the distribution of energy in frequency f and direction .

Statistical parameters derived from the wave energy spectrum are used to describe sea states and determine their characteristics relevant to wave energy use. Sea states are often characterized by wave height, period, and direction parameters. The spectral parameters for characterization of wave energy resources are the significant wave height H_s, spectral peak period T_p, mean direction ($\bar{\theta}$), and wave power level P (i.e., the flux of energy per unit length of wave crest). The variation in sea states during a period of time (e.g., month, season, year) can be represented by a scatter diagram, which indicates how often a sea state with a particular combination of H_s and T_p occurs.

9.2.2 Wave Energy Scatter Diagrams

To develop the wave energy scatter diagrams for this initial resource specification, sea state parameter records were read to extract the significant wave height (H_s in m), and the peak wave period (T_p in sec), which is the inverse of the frequency at which the wave spectrum has its maximum value for the measured sea state record. Based on these two parameters, the incident wave power (J in kilowatts per meter of wave energy device width, or kW/m) associated with each sea state record was estimated by the following equation:

$$J = 0.42 \times (H_s)^2 \times T_p \qquad \textbf{Eq. 9-1}$$

The 0.42 multiplier in the above equation is exact for any sea state that is well represented by a two-parameter Bretschneider spectrum, but it could range from 0.3 to 0.5, depending on the relative amounts of energy in sea and swell components and the exact shape of the wave spectrum. Although such an estimate, based solely on the parameters H_s and T_p, is not exact, it was deemed adequate for this initial specification.

Once the sea state parameters are read, and Equation 9-1 is used to estimate the incident wave power for a given measurement record, the record is sorted into the appropriate sea state bin according to the values of H_s and T_p for that record. Once all records are sorted, the number of records in each bin is divided by the total number of records in the entire measurement period. This yields the percentage of time that a given sea state bin occurs. When multiplied by 8766 hours in an average year (accounting for 29 days in February every fourth year), this gives the number of hours that each sea state occurs.

Multiplying the number of hours that each sea state occurs by the incident wave power density (in kW/m) for that bin yields the wave energy contribution (in kWh/m) of that bin. Summing the wave energy contribution across all bins and dividing by the number of hours in a year yields the annual average incident wave power at the reference location.

Figure 9-7 shows scatter diagram tables and figures for five stations; one in Hawaii, two in the Pacific Northwest, and two in the Atlantic Northeast. The full data set also contains the raw scatter diagram, a joint probability distribution table, the number of hours that each sea state occurs during an average year, the wave energy scatter diagram, and the estimated incident wave power in each sea state, as calculated by Equation 9-1, assuming a Bretschneider two-parameter wave spectrum.

CDIP 0098 Makapuu Point	Upper Tp:	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	18.5	20.5	
	Lower Tp:	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	19.5	Total annual hours
Hs and Tp bin boundaries		Tp (sec)													
Lower Hs	Upper Hs	Hs (m)	5	6	7	8	9	10	11	12	13	14	15	17	20	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
5.75	6.25	**6**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
5.25	5.75	**5.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
4.75	5.25	**5**	0	0	0	0	1	2	1	1	1	1	1	1	0	*8*
4.25	4.75	**4.5**	0	0	0	0	4	4	3	2	3	1	1	1	0	*19*
3.75	4.25	**4**	0	0	0	2	12	8	5	5	6	5	0	2	0	*45*
3.25	3.75	**3.5**	0	0	3	10	32	19	13	16	17	8	0	3	0	*122*
2.75	3.25	**3**	0	1	20	51	100	45	34	40	44	21	1	4	0	*360*
2.25	2.75	**2.5**	0	40	124	244	272	89	83	103	100	49	3	11	0	*1,119*
1.75	2.25	**2**	18	299	348	590	550	175	210	270	240	103	10	31	0	*2,843*
1.25	1.75	**1.5**	146	393	365	624	524	215	283	329	309	156	10	41	1	*3,396*
0.75	1.25	**1**	27	44	65	174	164	69	79	95	82	35	2	13	0	*849*
0.25	0.75	**0.5**	0	0	1	1	2	0	1	0	0	0	0	0	0	*5*
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
			191	*777*	*925*	*1,696*	*1,660*	*627*	*712*	*860*	*802*	*379*	*28*	*106*	*1*	***8,766***

(a)

Figure 9-7
(a) Scatter Diagram for Point Makapuu, Oahu, Hawaii.

CDIP 0036 Grays Harbor	Upper Tp:	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	18.5	20.5	
	Lower Tp:	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	19.5	Total annual hours
Hs and Tp bin boundaries		Tp (sec)													
Lower Hs	Upper Hs	Hs (m)	5	6	7	8	9	10	11	12	13	14	15	17	20	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	1	1	0	1	0	*3*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	1	1	1	1	2	1	*5*
6.75	7.25	**7**	0	0	0	0	0	0	0	1	1	1	1	3	0	*7*
6.25	6.75	**6.5**	0	0	0	0	0	0	1	3	2	2	2	4	0	*15*
5.75	6.25	**6**	0	0	0	0	1	2	2	6	3	5	4	8	0	*31*
5.25	5.75	**5.5**	0	0	0	1	5	3	4	11	8	11	9	11	1	*63*
4.75	5.25	**5**	0	0	0	3	9	8	9	25	17	17	17	19	1	*124*
4.25	4.75	**4.5**	0	0	0	8	16	18	16	33	26	29	22	24	2	*195*
3.75	4.25	**4**	0	0	3	13	31	31	27	58	41	38	29	34	6	*311*
3.25	3.75	**3.5**	0	1	8	30	54	48	48	89	59	47	34	41	5	*465*
2.75	3.25	**3**	0	4	15	50	93	76	67	127	83	56	43	43	5	*662*
2.25	2.75	**2.5**	1	12	25	91	177	132	109	174	96	72	55	57	10	*1,013*
1.75	2.25	**2**	7	22	59	218	331	199	143	191	88	64	49	66	11	*1,450*
1.25	1.75	**1.5**	40	88	188	557	513	264	144	160	79	48	37	54	6	*2,178*
0.75	1.25	**1**	68	166	325	557	344	121	65	90	53	44	46	66	9	*1,954*
0.25	0.75	**0.5**	7	31	47	52	33	14	12	16	12	21	20	22	1	*289*
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
			123	*324*	*672*	*1,580*	*1,606*	*917*	*647*	*985*	*570*	*457*	*370*	*456*	*59*	***8,766***

(b)

Figure 9-7 (continued)
(b) Scatter Diagram for Gray's Harbor, Washington

NDBC 46012 Half Moon Bay	Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	14.5	17.5	20.5	
	Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	13.5	16.5	19.5	Total annual hours
Hs and Tp bin boundaries		Tp (sec)													
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	14	17	20	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0	0	1	1	1	*3*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	0	0	1	2	1	*5*
5.75	6.25	**6**	0	0	0	0	0	0	1	0	1	1	2	3	1	*9*
5.25	5.75	**5.5**	0	0	0	0	0	1	1	1	2	2	5	7	1	*21*
4.75	5.25	**5**	0	0	0	0	0	2	2	3	5	6	13	15	1	*47*
4.25	4.75	**4.5**	0	0	0	0	1	5	6	10	8	17	33	25	2	*106*
3.75	4.25	**4**	0	0	0	0	2	13	15	19	24	46	80	37	3	*239*
3.25	3.75	**3.5**	0	0	0	1	8	40	34	39	47	92	128	50	8	*448*
2.75	3.25	**3**	0	0	0	4	20	75	63	67	89	172	192	67	17	*768*
2.25	2.75	**2.5**	0	0	1	15	50	161	115	112	167	283	241	98	26	*1,270*
1.75	2.25	**2**	0	0	6	43	126	277	201	209	270	357	262	124	41	*1,915*
1.25	1.75	**1.5**	0	5	25	110	175	335	257	284	299	327	271	197	38	*2,324*
0.75	1.25	**1**	0	13	29	59	64	185	164	160	157	192	307	179	19	*1,529*
0.25	0.75	**0.5**	0	1	1	2	3	9	7	8	6	17	22	6	0	*82*
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
			1	*19*	*62*	*233*	*449*	*1,102*	*865*	*913*	*1,077*	*1,514*	*1,559*	*813*	*159*	***8,766***

(c)

Figure 9-7 (continued)
(c) Scatter Diagram for Half Moon Bay, California; (continued on next page)

NDBC 44005 Gulf of Maine	Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	14.5	17.5	20.5	
	Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	13.5	16.5	19.5	Total annual hours
Hs and Tp bin boundaries		Tp (sec)													
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	14	17	20	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	1	0	0	0	*1*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	1	0	0	0	0	*2*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	1	1	0	0	0	*3*
6.75	7.25	**7**	0	0	0	0	0	0	0	1	3	1	0	0	0	*5*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	3	4	2	0	0	0	*9*
5.75	6.25	**6**	0	0	0	0	0	0	1	6	5	1	1	0	0	*15*
5.25	5.75	**5.5**	0	0	0	0	0	1	8	10	7	3	1	0	0	*30*
4.75	5.25	**5**	0	0	0	0	0	6	20	14	8	4	1	0	0	*54*
4.25	4.75	**4.5**	0	0	0	0	0	24	32	15	11	6	1	1	0	*90*
3.75	4.25	**4**	0	0	0	0	3	68	32	17	15	10	2	1	0	*149*
3.25	3.75	**3.5**	0	0	0	1	29	128	30	24	24	15	4	2	0	*256*
2.75	3.25	**3**	0	0	0	13	134	134	27	34	35	23	4	2	0	*407*
2.25	2.75	**2.5**	0	0	3	122	270	107	46	55	45	27	6	3	0	*684*
1.75	2.25	**2**	0	2	75	443	222	122	87	98	74	39	15	3	0	*1,179*
1.25	1.75	**1.5**	0	85	410	478	148	249	165	137	98	46	14	2	0	*1,832*
0.75	1.25	**1**	48	477	477	279	299	498	248	172	110	58	20	5	1	*2,692*
0.25	0.75	**0.5**	83	178	76	119	183	334	147	98	58	42	27	9	1	*1,355*
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
			132	*742*	*1,041*	*1,455*	*1,288*	*1,669*	*843*	*687*	*501*	*280*	*97*	*28*	*2*	***8,766***

(d)

Figure 9-7 (continued)
(d) Scatter Diagram for Gulf of Maine

NDBC 44008 Nantucket Shoals		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	14.5	17.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	13.5	16.5	19.5	*Total annual hours*
Hs and Tp bin boundaries			Tp (sec)													
Lower Hs	Upper Hs	**Hs (m)**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**14**	**17**	**20**	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	1	0	0	*1*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	1	1	0	0	0	*2*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	1	1	1	0	0	*4*
6.75	7.25	**7**	0	0	0	0	0	0	0	1	3	3	1	0	0	*7*
6.25	6.75	**6.5**	0	0	0	0	0	0	1	2	4	4	1	0	0	*12*
5.75	6.25	**6**	0	0	0	0	0	0	2	4	9	6	1	0	0	*23*
5.25	5.75	**5.5**	0	0	0	0	0	1	4	10	13	9	1	0	0	*38*
4.75	5.25	**5**	0	0	0	0	0	3	11	22	18	11	1	0	0	*66*
4.25	4.75	**4.5**	0	0	0	0	0	12	24	33	28	13	2	1	0	*113*
3.75	4.25	**4**	0	0	0	1	4	37	41	47	42	15	2	2	0	*193*
3.25	3.75	**3.5**	0	0	1	3	17	89	65	60	44	14	5	2	0	*298*
2.75	3.25	**3**	0	0	1	8	52	160	89	76	44	17	8	2	0	*459*
2.25	2.75	**2.5**	0	2	3	38	135	235	118	87	51	27	11	3	0	*710*
1.75	2.25	**2**	0	3	19	147	272	341	150	117	71	35	11	2	0	*1,167*
1.25	1.75	**1.5**	0	21	116	380	451	450	210	143	83	35	11	2	0	*1,902*
0.75	1.25	**1**	7	123	292	536	480	598	273	159	95	54	22	5	0	*2,643*
0.25	0.75	**0.5**	10	62	90	123	174	318	164	77	50	31	20	6	2	*1,127*
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
			17	*213*	*522*	*1,234*	*1,585*	*2,246*	*1,153*	*839*	*555*	*275*	*100*	*25*	*3*	***8,766***

(e)

Figure 9-7 (continued)
(e)Scatter Diagram for Nantucket Shoals, Massachusetts

Figure 9-8 presents graphical scatter diagrams for Hawaii, Gray's Harbor, Washington, Half Moon Bay, California, and Gulf of Maine wave energy reference measurements stations. The wave climate of Hawaii is distinguished by two peaks, one representing the trade winds out of the northeast and the second representing Kona winds from the south. The Gulf of Maine wave climate is much lower than the Pacific Northwest and is characterized by shorter wavelength waves.

9.2.3 Wave Power Flux and Average Annual Energy

The power of ocean waves is expressed in kW per meter wave crest front as shown in Figure 9-9. Annual averages range from 10 kW to 100 kW/m wave front depending on the site location around the globe. For example, northern California averages 40 kW/meter wave crest peaks to over 1 MW/m wave crest during storms.

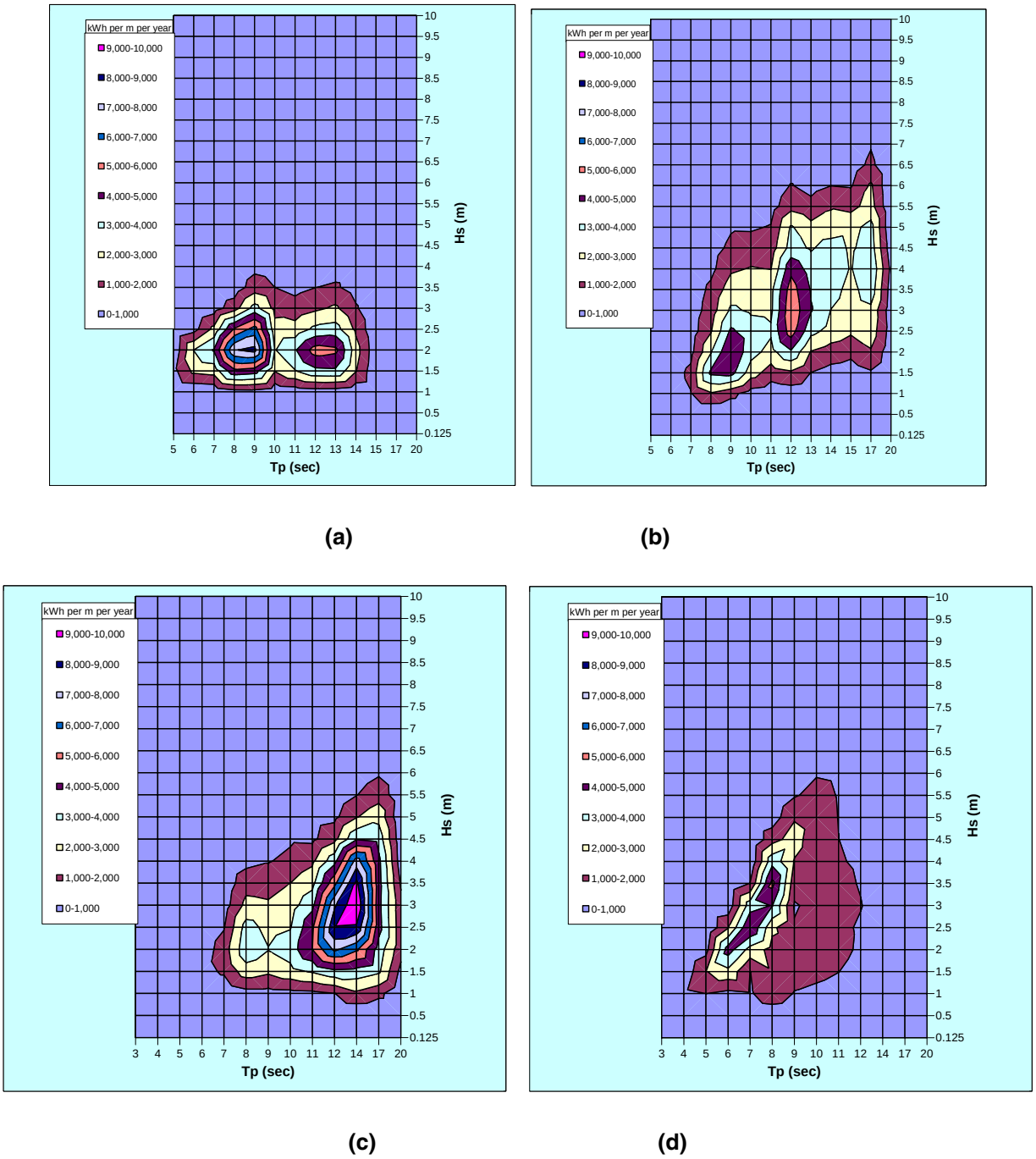


Figure 9-8
Scatter Diagrams for (a) Point Makapuu, Oahu, (b) Hawaii; Gray's Harbor, WA; (c) Half Moon Bay CA; and (d) Gulf of Maine

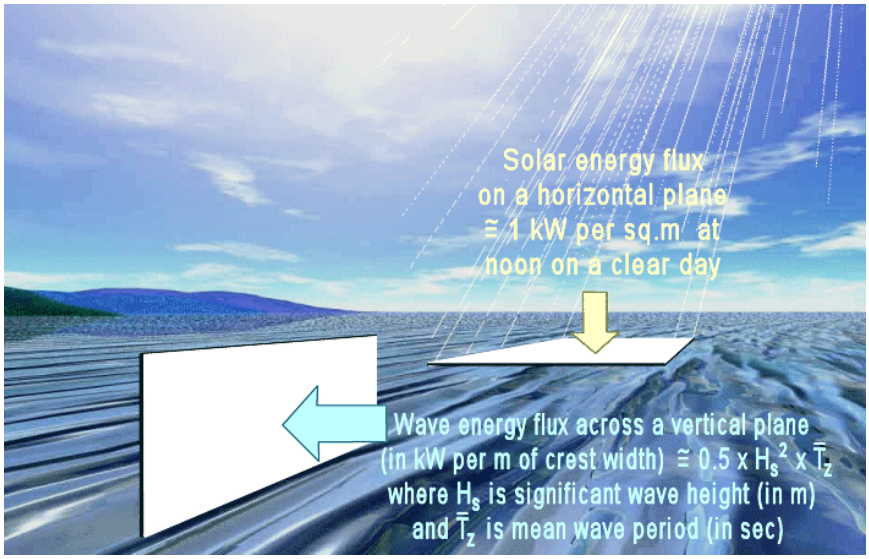


Figure 9-9
Wave Power Flux

Figure 9-10 shows the graphical relations between lines of constant wave power density, P, and gradient or slope, H/L, as functions of the significant wave height, H_s, and zero crossing energy period, T_e. In addition, a statistical wave distribution matrix is superimposed over the graph.

The U.S. regional wave regimes and the total annual incident wave energy for each of these regimes are shown in Figure 9-11. The total U.S. available incident wave energy flux is about 2,100 TWh/yr. The DOE Energy Information Energy (EIA) estimates 2003 hydroelectric generation to be about 270 TWh which is a little more than a tenth of the yearly offshore wave energy flux into the U.S. Therefore, U.S. wave energy is a significant resource.

Figure 9-12 shows annual average wave energy densities worldwide. It is a useful high-level indicator of the potentially attractive deployment sites for wave energy systems. For detailed economic assessments, additional statistical parameters such as directionality and variability should be considered.

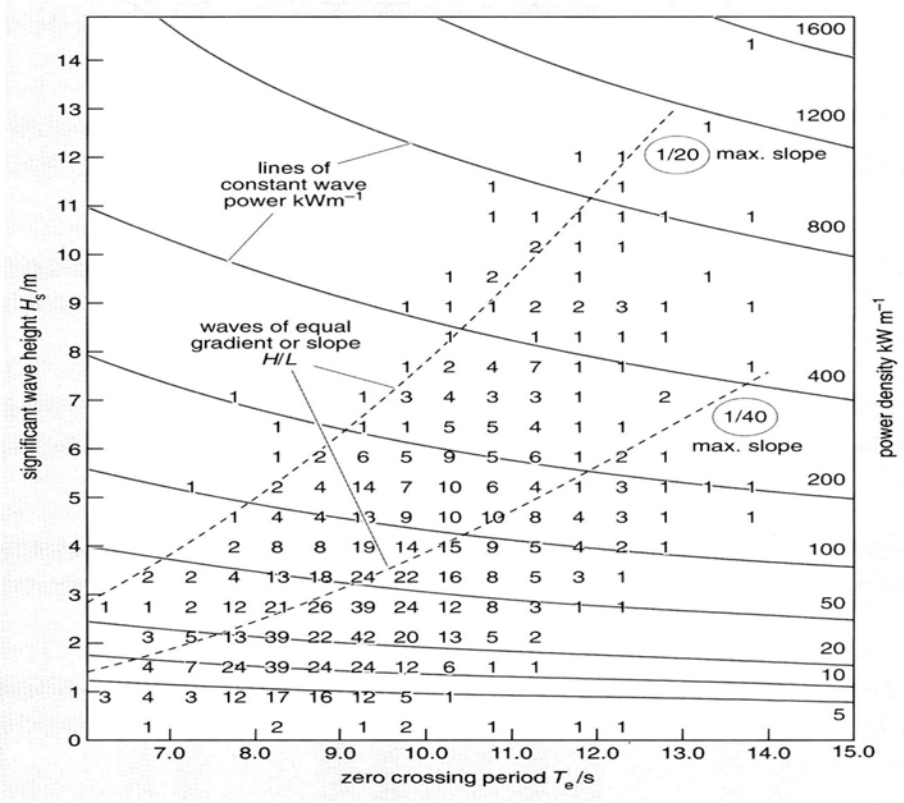


Figure 9-10
Statistical Wave Distribution Matrix and Lines of Constant Wave Power and Gradient

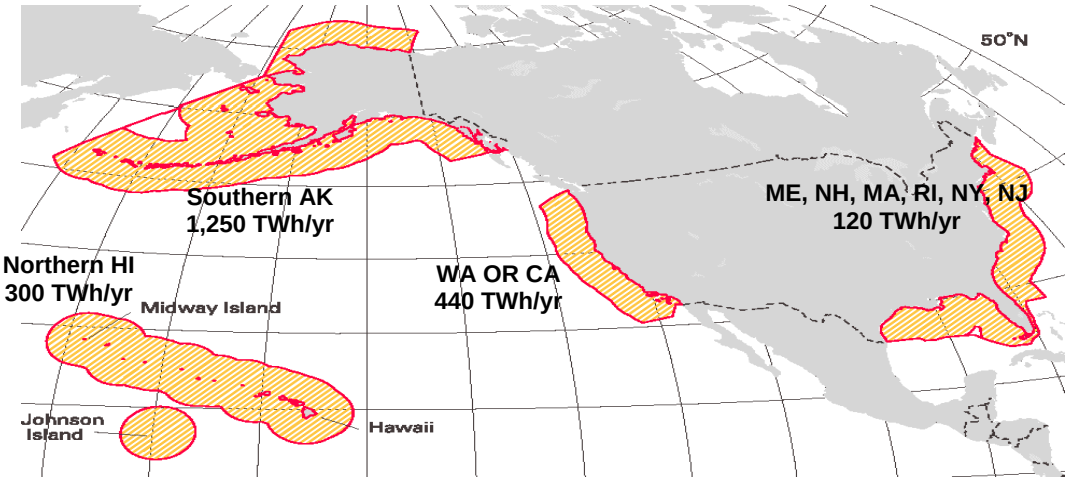


Figure 9-11
U.S. Wave Energy Resources

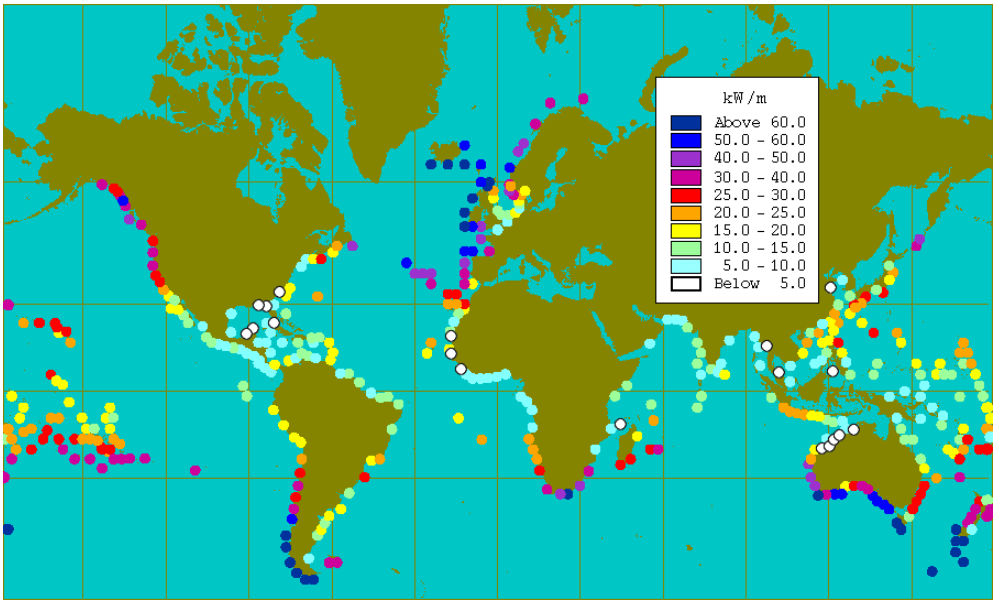


Figure 9-12
Annual Wave Power Averages Worldwide in kW/m Wave Front

9.3 WEC Technology Description

Wave power research programs in industry, government, and at universities in the UK, Denmark, Netherlands, Portugal, and Australia have established an important foundation for the emerging wave power industry over the last half a dozen or so years. In the 1970s, the UK regarded wave power as an alternative to nuclear generation and had the most aggressive R&D program in the world. Although the program contributed to important basic research on optimal control and tuning of wave power conversion devices, it ultimately stalled as oil prices dropped and, as a result, government funding stopped. In the past five years, continuing research in wave-powered generation, advances in remote control capabilities, and advances in the offshore industry led to economically-viable designs, some of which have been tested as single prototypes in the last three years.

9.3.1 WEC System Developers

Today, a number of small companies backed by government organizations, private industry, utilities, and venture capital are leading the commercialization of technologies to generate electricity from ocean waves. In early 2004, EPRI requested information from all known WEC device developers. Table 9-3 summarizes the resulting information.

Table 9-3
Offshore Wave Energy Conversion Device Manufacturers

Device Developer (1) Website	Street Address	Development Status (2)	Device Name	Contact
Able Technologies www.abletechnologiesLLC.com	330 Audubon Road Englewood, NJ 07631, USA	Experimental	Wave Pipe	Stan Rutta srutta@yahoo.com 201-569-7292
AquaEnergy www.aquaenergygroup.com	P.O. Box 1276 Mercer Island WA 98040, USA	Technology Demonstration	AquaBuOY	Alla Weinstein alla@aeg-ltd.com 425-430-7924
AW Energy www.aw-energy.com	16 (Terra Building) FI-02600 Espoo Finland		WaveRoller	Lars Sonckin kaari Tel/Fax +358 9 7262404 info@aw-energy.com
AWS Energy www.waveswing.com	Reashank House Alness Pt Business Park, Alness Ross-shire IV17OUP UK	Commercial Demonstration	Archimedes Wave Swing	Fred Gardiner fred@awsocean.com 44 (0) 1349 884422
BioPower	Suite 145 National Innovation Centre, Eveleigh, NSW 1430 Australia		bioWave™	Tom Finnegan tfinnegan@biopowersystems.com 61 (0) 438 201 160
Bourne	Los Angeles, CA		OceanStar	
C-Wave Limited www.cwavepower.com	Bldg 27, Univ of Southampton, SO017 1 BJ UK		C-Wave	Giles Edward Giles.Edward@cwavepower.com 023 8059 8565
College of the North Atlantic	Box 370 Burin Bay Arm NL A0E 1G0		Wave Pump	Michael Graham Mike.Graham@cna.nl.ca 709-891-5600
Ecofys www.ecofys.co.uk	3503 RK Utrecht Kanaalweg 16-G Netherlands	Experimental	Waverotor	Peter Scheijgrond p.scheijgrond@ecofys.nl 31 (0) 30-2808 447
Energetech www.energetech.com.au	7/12 Lord St Botany 2019 New South Wales Australia	Commercial Demonstration	Uiscebeatha	Tom Engelsman 61 2 6549 6300 Tom.Engelsman@Energetech.com.au
Energiesysteme GmbH	Bitburger Str 42-44, Berlin 13051 Germany		ECOWAS III	Paul Link MAMOEnergy@aol.com 49 30 9252270
Fred Olsen Ltd	NO-0156 Oslo, Norway	Technology Demonstration	Buldra	Tore Gulli +47 22 34 11 30 Tore.Gulli@fredolsen.no
Independent Natural Resources www.inri.us	Minnesota, USA	Experimental	SEADOG – water pump	Mark Thomas 612-817-0497 mthomas10@uswest.net

Table 9-3 (continued)
Offshore Wave Energy Conversion Device Manufacturers

Device Developer (1) Website	Street Address	Development Status (2)	Device Name	Contact
Manchester Univ of www.umip.com	The Fairbairn Building PO Box 88 Manchester M60 1QD		Bobber	Margaret M Lewis Tel: 0161 306 3067 margaret.lewis@umip.com
Ocean Energy Ltd	3 Casement Square Cobh, Cork Ireland		Ocean Energy Buoy (OEBuoy)	John McCarthy oceanenergy@dol.le
Ocean Power Delivery www.oceanpd.com	104 Commercial St. Edinburgh,EH6 6NF, UK	Early Commercial	Pelamis	Max Carcass 44 131 554 8444 max@oceanpd.com
Ocean Power Technologies www.oceanpowertechnologies.com	1590 Reed Road Pennington, NJ 08534, USA	Early Commercial	PowerBuoy	George Taylor 609-730-0400 gtaylor@oceanpowertech.com
Ocean Wave Energy Company www.owec.com	Bristol, Rhode Island, USA		Ocean Wave Energy Converter	Foerd Ames 401-253-4488
Ocenergy www.owec.com	54 Beach Rd, Norwalk, CT, USA		Wave Pump	Peter Grueterich 203-550-0271 peter@ocenegy.com
OreCON Ltd www.orecon.com	Tamar Science Park, Derriford Plymouth, PL6 8BX UK	Technology Demonstration	MRC1000	Frasier Draper 44 1752 762 105 contact@orecon.com
Oregon State Univ www.eecs.orst.edu/msrf	Corvallis, OR 97331-3211		Various direct drive buoys	Dr. Annette von Jouanne 541-737-0831 avj@ece.orst.edu
Renewable Energy Holdings www.reh-plc.com	Ioma House Hope St, Douglas Im1-1AP, Isle of Man UK	Technology Demonstration	CETO	Mike Proffitt 01 624 641 199
Renewable Energy Wave Pump	8037 Trevor Place Vienna VA 22182 USA		REWP	Shamil Ayntrazi sayntrazi@hotmail.com
SeaPower Group www.seapower.com	Essingeringen 72C 11264 Stockholm Sweden		Floating Wave Power Vessel	Inge Pettersson 33 493 285 567 pettersson.inge@euromail.se
Sieber Energy SyncWave Energy www.sieberenergy.com			SyncWaveTM	Nigel Protter nprotter@gmail.com 604-894-0116
Vortex Hydro Energy www.vortexhydroenergy.com	4870 West Clark Rd, Suite 108 Ypsilanti, MI 48197, USA		VIVACE	Tad Dritz 734-223-4223 tadcaspian@columbus.rr.com

Table 9-3 (continued)
Offshore Wave Energy Conversion Device Manufacturers

Device Developer (1) Website	Street Address	Development Status (2)	Device Name	Contact
Waveberg No known website	3920 Goldfinch Street, San Diego, CA 92103 USA		Water Pump	Paul Wegnerer 619-298-4279 pwegnerer@epitomepharm.com
Wavebob Ltd	NI Science Park Queens Island Belfast, BT9 3DT Ireland	Technology Demonstration	Wavebob	William Dick 353 5991 61822 william.dick@wavebob.com
Wave Dragon ApS www.wavedragon.net	Blegdamsvej 4 1st Floor, DK-2200 Copenhagen, Denmark	Commercial Demonstration	Wave Dragon	Lars Christiansen 45 3536 0219 info@wavedragon.net
Wave Energy AS www.waveenergy.no	Opstadveien AS 4330 Aalgaard, Norway	Technology Demonstration	Seawave Slot Cone Generator	Monika Bakke Monika.bakke@waveenergy.no 47 51 61 09 30
Wave Gen www.wavegen.co.uk	50 Seafield Road, Longman Industrial Estate, Inverness IV1 1Lz, UK		Offshore OWC	David Langston 44 1463 238094
Wave Power Plant	2563 Granite park Dr, Lincoln, CA 95648 USA		Sea Gate-1	Ghazi Khan ghazikhan4@yahoo.com 916-434-7076
Wave Star Energy www.wavestarenergy.com	Maglemosevej 61 DK-2920 Charlottenlund Denmark	Technology Demonstration	Wave Star	Resen Steenstrup prs@wavestarenergy.com 45 3940 4696

(1) This list excludes individual inventors who have contacted EPRI over the past year because of the large number of such inventions

(2) The following definition of development stage was used

- Empty cell – concept or laboratory testing stage
- Experimental – Subscale at sea testing
- Technology Demonstration – Large size engineering prototype at sea testing whose purpose is to test for function and performance
- Commercial Demonstration – Large size manufacturing prototype at sea testing whose purpose is to test for commercial viability
- Early Commercial – Offering many units of large size for purposes of generating and selling the electricity produced

Table 9-4 presents high level specifications for those devices that have been prototyped.

Table 9-4
Major WEC Device Manufacturers

Company	Device Length (m)	Device Width (m)	Avg Power (kW)[2]	Device Weight (tons)	Principle of Operation	Power Train
AquaEnergy	6	6	17	22	Floating Point Absorber	Water Pump
AWS Energy	9.5	9.5	351	NA	Bottom-Mounted Point Absorber	Linear Generator
Ecofys	25-35	25	500	200	Monopile mounted hydrodynamic rotors	Rotary Generator
Energetech	25	35	259	450	Bottom-Mounted Terminator – OWC	Air Turbine
Fred Olsen	Unknown	Unknown	Unknown	Unknown	Multi-point absorber	Unknown
Independent Natural Resources Inc.	5.4	5.4	16	112	Bottom-Mounted Point Absorber	Water Pump
Ocean Power Delivery	120	4.6	153	380	Floating Attenuator	Hydraulic
Ocean Power Technology (40 kW unit)			40		Point absorber	Hydraulic
ORECon	32	32	532	1250	Floating OWC	Air/Hydraulic
Renewable Holdings	Unknown	Unknown	Unknown	Unknown	Bottom mounted OWC	Air
WaveBob	15	15	131	440	Floating Point Absorber	Hydraulic
Wave Dragon	150	260	1369	22,000	Floating Overtopping Ramp	Low Head Hydro
Wave Energy	NA	6	150	Unknown	overtopping device with multiple inflow layers	Water turbine
Wave Star	Unknown	Unknown	3,000	Unknown	Multi point absorbers on bottom mounted structure	Unknown

9.3.2 European Marine Energy Center

EMEC (see Figure 9-13), established by Highlands and Islands Enterprise and its funding partners in the UK, aims to stimulate and accelerate the development of marine power devices, initially through the operation of a testing center in Orkney, UK. The center's facilities include four test berths situated along the 50 m water depth contour off Billia Croo on the Orkney mainland (approximately 2 km offshore). Armored cables link each berth to a substation onshore. These cables link to an 11 kV transmission cable connecting to the national grid and to a data/communications center located in nearby Stromness.

The main elements of the facility include:

- Four Test Berths: Four individual armored cables (electrical conductor rated at 11 kV/2.5 MW, two fiber-optic cables, and two control wires) connected to the onshore substation
- Substation: Containing switchgear, metering equipment, power factor correction equipment, communications equipment, emergency generator, and the grid isolator
- Observation Point: Containing two video cameras and a wireless communication link to the test site, linked back to the Value Center
- Weather Station: Stand-alone solar-powered meteorological station linked to the Data Center.

The center became operational at the end of 2003. Additional information is available at http://www.emec.org.uk/index.html.



Figure 9-13
European Marine Energy Center (EMEC)

9.3.3 American Marine Energy Center Pacific Northwest

Oregon State University announced in August 2005 that they will seek to develop a national offshore research development and demonstration (RD&D) wave energy test facility off the Coast of Lincoln County in central Oregon. The site is close to the OSU Hatfield Marine Science Center in Newport, Oregon. OSU expects to fund commitments for this project in 2007. In July 2006, Lincoln County filed an application for a preliminary permit with FERC to build and operate a number of wave power plants including the OSU RD&D test facility.

OSU has a track record of successful wave energy technology research and has developed three direct drive prototype buoys. These buoys are designed to be anchored one to two miles offshore in typical water depths greater than 100 feet, where the buoys will experience gradual, repetitive waves. OSU's research team continues to pursue optimum wave energy topologies and has also developed a Permanent Magnet Rack and Pinion Generator Buoy and a Contact-less Force Transmission Generator Buoy.

Figure 9-14 shows an array or park of direct-drive buoy modules that represent the long-term vision of OSU wave energy effort.

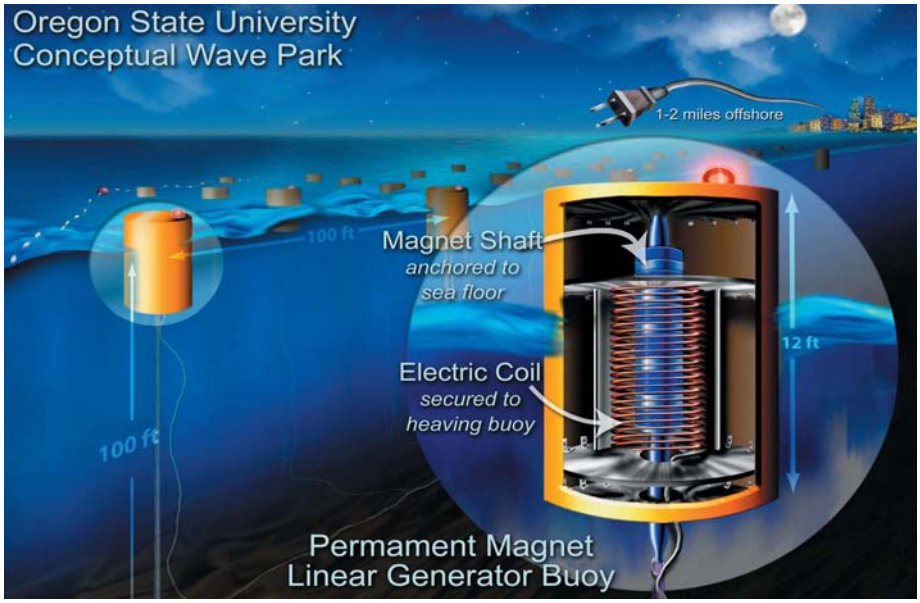


Figure 9-14
Permanent Magnet Linear Generator in a Conceptual Wave Park Vision

9.4 Performance Prediction

Published data on WEC devices seldom provide sufficient detail to assess the accuracy of power production claims. The offshore wind energy industry routinely publishes turbine performance data in the form of curves and/or tables showing generated power as a function of wind speed (see General Electric 3.6 MW turbine at http://www.gepower.com/prodserv/products/wind_turbines/en/index.htm, or Vestas 2.0 MW turbine at http://www.natwindpower.co.uk/northhoyle/gsv80.pdf for examples), yet wave energy developers rarely provide similar data on generated power as a function of sea state.

This lack of documentation makes it difficult to compare the likely performance of different WEC devices in a given wave climate, particularly when different underlying assumptions and simulation or model test methods have been used to generate the power production estimates. Finally, without such documentation, it is impossible to establish a "baseline" performance against which industry improvements can be benchmarked.

In order to overcome these hurdles and enable a performance comparison of technologies, EPRI developed Guidelines of Preliminary Estimation of Power Production by Offshore Wave Energy Conversion Devices (Reference 1, EPRI WP-001-U.S. is available for public download at our website www.epri.com/oceanenergy/).

The capture width ratio of a device for a particular sea state is calculated as the absorbed power (before losses in conversion to electric power) resulting from a particular sea state numerical simulation (or random wave model test), divided by the product of the incident wave power and the width of the simulated device (or model). Thus if capture width ratio (CWR) is represented by the equation:

$$CWR = P_{abs} / (J \times D_y) \qquad \textbf{Eq. 9-2}$$

where CWR is the capture width ratio (dimensionless, no units),

P_{abs} is the absorbed power in simulated or modelled sea state (e.g. in kW/),

J is the incident power in simulated or modelled sea state (e.g. in kW/m), and

D_y is the cross-wave dimension of the simulated device or test model (e.g. in m),which would be the diameter of a cylindrical buoy or beam of a rectangular raft.

For example, consider the numerical simulation results published by the wave energy research group at the Norwegian Institute of Technology (NTH), University of Trondheim, for a slack-moored, heaving-cylinder device with phase control (Reference 2, which can be downloaded at http://www.phys.ntnu.no/instdef/prosjekter/bolgeenergi/simwec.pdf). The wave energy absorber is a cylindrical spar buoy, 3.3 m in diameter, with a molded depth of 5.1 m. A reaction plate, 8 m in diameter, is suspended from the buoy, in line with a double-acting hydraulic cylinder. The reaction plate is submerged 10 m below the sea surface, and relative motion between the buoy

and plate strokes the cylinder, absorbing wave energy by converting work done on the buoy and plate by waves into fluid work.

This is a useful example because it illustrates how to handle the mismatch that occurs when device performance data are based on simulated or test sea states characterized by mean zero-crossing period (T_z) rather than the peak period characterization (T_p) that is used in this specification. It also illustrates how to extrapolate a limited set of simulation or test results to H-T_p sea state bins that have not been simulated or tested.

On page 17 of the above NTH paper, Table 9 lists the following results for numerical simulations of Pierson-Moskowitz (P-M) spectra, based on a 100-second steady-state simulation. The P-M spectrum is a special case of the Bretschneider spectrum, in which

$$T_p = T_z / 0.710 \qquad \textbf{Eq. 9-3}$$

This equation should be used to convert T_z-based simulation or test results from P-M spectra to T_p for calculating the incident wave power during the simulations or test runs.

The P-M spectrum simulation results are tabulated below. The top row indicates the mean-zero crossing period (T_z), and the second row indicates the associated peak period (T_p) calculated by Equation 3. The third row indicates the significant wave height (H_s), the fourth row indicates the absorbed power result (P_{abs}), and the fifth row indicates the incident wave power (J) calculated by Equation 9-1. Based on the buoy's diameter of 3.3 m, the last row of the table indicates the capture width ratio (C) in each sea state, as calculated by Equation 9-2.

NTH Simulation Results for Slack-Moored Heaving Buoy in P-M Spectra									
T_z (sec)	3.8	4.3	4.9	5.3	5.9	6.4	6.9	7.4	7.9
T_p (sec)	5.4	6.1	6.9	7.5	8.3	9.0	9.7	10.4	11.1
H_s (m)	0.9	1.3	1.6	2.0	2.4	2.9	3.4	4.0	4.6
P_{abs} (kW)	2.5	3.8	5.3	6.6	7.7	9.2	11.2	12.7	14.9
J (kW/m)	1.8	4.3	7.4	12.5	20.1	31.8	47.2	70.0	98.9
C	0.42	0.27	0.22	0.16	0.12	.088	.072	.055	.046

The next step is to map these capture width ratio results into the appropriate H_s-T_p bins of the "85% rectangular section" of the wave energy scatter diagram, which is done for the Hawaii station in the table below.

Capture Width Ratios for Hawaii Wave Energy Scatter Diagram									
Hs	**Tp (sec)**								
(m)	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
3	*.134*	*.108*	*.097*	.088	***.077***	***.070***	***.064***	***.059***	***.055***
2.5	*.161*	*.130*	.116	*.105*	***.093***	***.084***	***.077***	***.071***	***.065***
2	*.201*	.162	*.145*	*.131*	***.116***	***.105***	***.096***	***.088***	***.082***
1.5	.268	.216	*.193*	*.175*	***.154***	***.140***	***.128***	***.118***	***.109***

Note that only five of the NTH results (shaded in black and white print and yellow-shaded bins, red font in color print) map into the H_s-T_p distribution where 85% of the incident wave energy occurs in Hawaii. In a case such as this, the developer must either conduct new simulations targeted at the remaining 31 bins in the above table, which is the preferred approach, or the developer can fit a capture width ratio function to existing results that fall outside the "85% rectangular section," yielding CWR as a function of H_s and T_p and applying this function to the empty bins. For example, Reference 2 shows that P_{abs} is linearly proportional to H_s. Because J is proportional to $(H_s)^2$, it follows that CWR can be extrapolated according to the ratio 1/(Hs). This factor has been used to fill in the missing CWR values in the first four columns of the above table (*italicized blue font*). CWR as a 2nd-order polynomial function of T_p for a given H_s can then be fitted to the first four elements in each row, enabling extrapolation of CWR values into the last five columns (***bold italicized green font***). Multiplying the CWR in each bin by the incident wave energy (kWh/m/yr) in that same bin yields the annual amount of energy absorbed from sea states in that bin per meter of buoy diameter. Summing these products across all 36 bins shows that this device would absorb 12.3% of the wave energy in the entire section.

For each state in which developers want to predict the performance of their WEC device, they should enter their performance data into a table with the same number of columns and rows as the highlighted "85% rectangular section" in the wave energy scatter diagram for the sea state of their choice. Each cell in this table should contain a developer's best estimates of the CWR of the device when operating in a random seaway having the same H_s and T_p as the midpoints of the sea state bin associated with that cell.

Developers also should document how they obtained the absorbed power results (P_{abs}) used to calculate CWR, as well as providing the cross-wave dimension (D_y) of their full-scale device. The documentation supplied depends on whether the absorbed power results are from numerical model simulations or physical wave tank testing of scale models.

(a) For numerical simulation results, the following information is required:

i. Time domain or frequency domain?

ii. Spectrum formula used (P-M, Bretschneider, JONSWAP, etc.)

iii. Duration of simulations (steady-state portion from which results derived)

iv. Model or prototype scale used to validate numerical simulation

v. Validation results showing how well the numerical simulation predicts measured physical model or prototype output

(b) For physical model test results, the following information is required:

i. Dimensions of model or prototype

ii. Dimensions (length, width, depth) of model test tank (or water depth and distance from shore for prototypes)

iii. Spectrum formula used (P-M, Bretschneider, JONSWAP, etc.)

iv. Duration of measurements (steady-state portion from which results derived)

9.5 Pilot and Commercial Scale Design, Cost, and Economic Issues

In 2004, EPRI performed an Offshore Wave Power Feasibility Definition Study examining five locations and two WEC technologies. Offshore Wave Power Plant Design, Performance, and Cost Technical Reports have been published for sites in Hawaii, Oregon, San Francisco, Massachusetts, and Maine (References 9 through 13). Designs have been developed for both demonstration-scale and commercial-scale power plants. Plants are based on the Ocean Power Delivery (OPD) Pelamis WEC device. A second study was performed for the San Francisco, California site with an Energetech oscillating water column (OWC) device.

9.5.1 Sites

Table 9-5 provides key parameters of the five sites. A pilot and a commercial scale plant at each site were designed and the performance and cost predicted based on the Pelamis WEC device. For the San Francisco site, a second study with the Energetech device was also performed.

Table 9-5
Key Site Parameters

	Hawaii Pelamis	Oregon Pelamis	California Pelamis Demo / Comm'l[(1)]	California Energetech Demo / Comm'l[(1)]	Mass. Pelamis	Maine Pelamis
Distance from shore to plant	2 km	3.5 km	13/28.5 km	14/22.5 km	9.1 km	9.2 km
Water depth at site	50-60 m	50-60 m	30/50-60 m	15/40 m	50-60 m	50-60 m
Average Annual Wave Energy Power Flux at site	15.2 kW/m CDIP 034	21.2 kW/m CDIP 0037	11.2 kW/m CDIP0062 / 20 kW/m NDBC 44026	11.2 kW/m CDIP0062 / 20 kW/m NDBC 44026	13.8 kW/M NDBC 44018	4.9 kW/m NDBC 44007
Power Cable Landing	Makai Pier	Int'l Paper Outflow Pipe	Wastewater Outflow Pipe	Wastewater Outflow Pipe	Directional Drilling	Direction al Drilling

Grid Interconnect (I/C) Point	Waimanalo Beach S/S	Gardiner S/S	Ocean Beach Water Treatment Plant	Ocean Beach Water Treatment Plant	Wellfleet distribution line	Old Orchard Beach S/S
I/C Distance from shore	0.5 km	4 km [2]	0.5 km	0.5 km	0.5 km	0.5 km
Ocean floor sediments	Bedrock & Limestone	Sand & Mud	Soft Sediments	Soft Sediments	Sand	Gravel, Rock, Sand
Distance from harbor	40 km	25 km	31/40 km	26/42 km	72 km	30 km

1. The demonstration plant is sited within the exclusionary zone in 35 m deep water whereas the commercial plant is sited outside the zone in 60 m deep water
2. The Gardiner substation is adjacent to the International Paper Plant and the shore end of the effluent pipe

9.5.2 WEC Devices Studied

Feasibility studies using two WEC device designs, the Pelamis device and the Energetech devices, were performed at a San Francisco site. The Pelamis WEC device consists of four cylindrical steel sections connected by three hydraulic power conversion modules (PCM). Total length of the device is 120 m and device diameter is 4.6 m. Figure 9-15 shows the device being tested at EMEC.

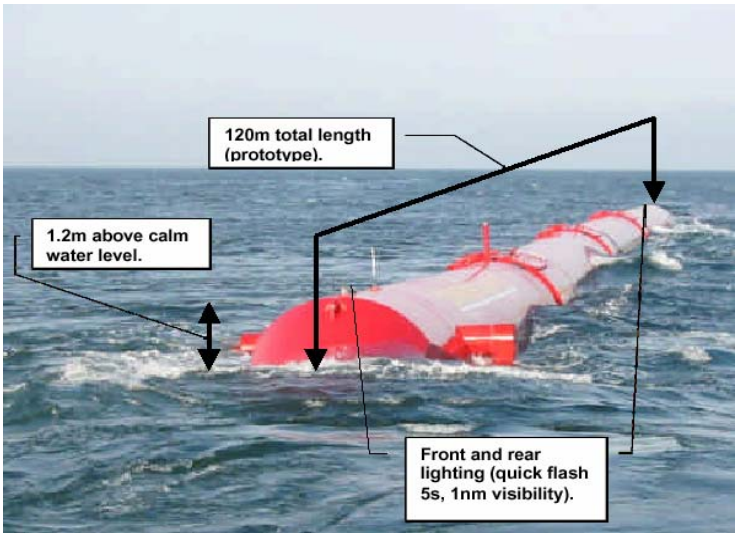


Figure 9-15
Preproduction Prototype Pelamis

The prototype Pelamis mooring system (Figure 9-16) is a caternary type mooring using a combination of steel wire rope, chain, dead weights, and embedment anchors.

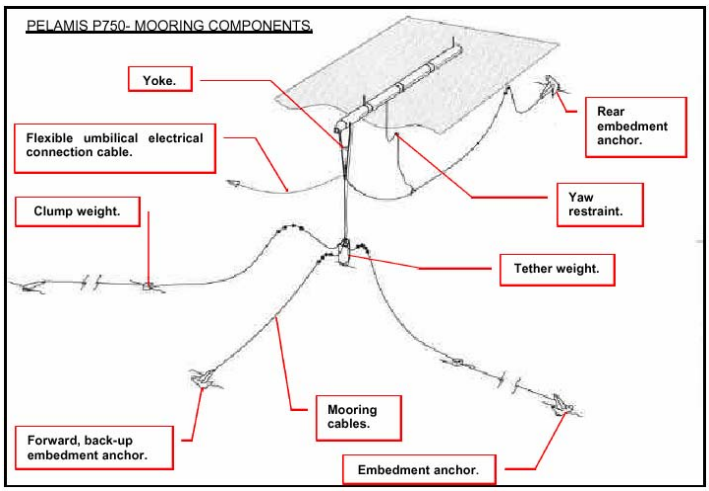


Figure 9-16
Mooring Arrangement of the Prototype Pelamis Design

Figure 9-17 illustrates the Energetech device, which uses the oscillating water column (OWEC) principle, standing on four support legs. The length of these legs depends on the water depth at the deployment site. Mooring chains hold the structure in place and are attached to steel piles on the other side, providing good anchoring capabilities.



Figure 9-17
Energetech Preproduction Prototype OWC Device Showing Mooring Design

9.5.3 Pilot or Demonstration Plant Design (Oregon Example)

The drawing below (Figure 9-18) shows the electrical interconnection of the demonstration plant for the Oregon site. A single floating Pelamis device is moored in a water depth of 50 to 60 m. An umbilical riser cable connects the Pelamis to a junction box on the ocean floor. From this junction box, a double-armored three-phase cable is buried in soft sediments along a 3-km route leading to the outfall of an existing effluent pipe, which is 1 km offshore. The cable is then routed through the 5-km effluent pipe to the International Paper (IP) Facility, which is about 4 km inland. An additional cable section connects to the Gardiner substation located next to the IP property.

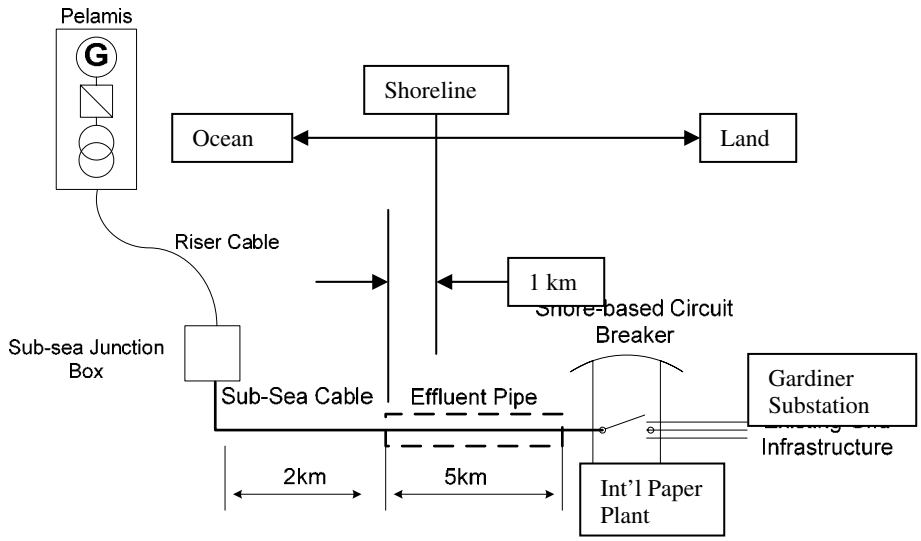


Figure 9-18
Electrical Interconnection of a Single Unit Pelamis Plant–Oregon Example

The estimated performance of the single device demonstration plant at each of the five sites is shown in Table 9-6.

Table 9-6
Estimated Performance of Pilot Demonstration Plants (Oregon Example)

	Hawaii Pelamis	Oregon Pelamis	California Pelamis	California Energetech	Mass Pelamis	Maine Pelamis
Rated Capacity (kW)	750	750	750	1,000 kW	750	750
Annual Energy Absorbed (MWh/yr)	1,989	1,472	1,229	1,643	1,268	426
Annual Energy Produced (MWh/yr)	1,663	1,001	835	1,264	964	290
Average Electric Power at Busbar (kW)	180	114	95	144	98	33
Number of Homes Powered by Plant	180	114	95	144	98	33

Availability=assumes 85% for demonstration plant

Power Conversion Efficiency=assumes 80% for Pelamis demonstration plant

Power conversion efficiency and directionality factor are each 90% for Energetech

According to the DOE's Energy Information Administration, annual average power per home is 1 kW

9.5.4 Commercial Scale Plant Design (Oregon Example)

As shown in Figure 9-19, the commercial system is sized to generate 300,000 MWh/yr (90 MW at a 40% capacity factor). It uses a total of four clusters, each containing 45 Pelamis units (i.e., 180 total Pelamis WEC devices), connected to sub-sea cables. Each cluster consists of three rows with fifteen devices per row. The four sub-sea cables connect the four clusters to shore as shown in Figure 9-19. The electrical interconnection of the devices is accomplished with flexible jumper cables, connecting the units in mid-water. The introduction of four independent sub-sea cables and the interconnection on the surface provides some redundancy in the wave farm arrangement.

The four clusters are each 2.25 km long and 1.8 km wide, covering an ocean stretch of roughly 9 km. The four arrays and their safety area occupy roughly 16 km^2. Further device stacking of up to four rows might be possible to reduce the array length, but is not considered in this design because subsequent rows of devices would likely be subject to a diminished wave energy resource and therefore yield a lower output. Such effects and their impacts on performance are not well understood at present.

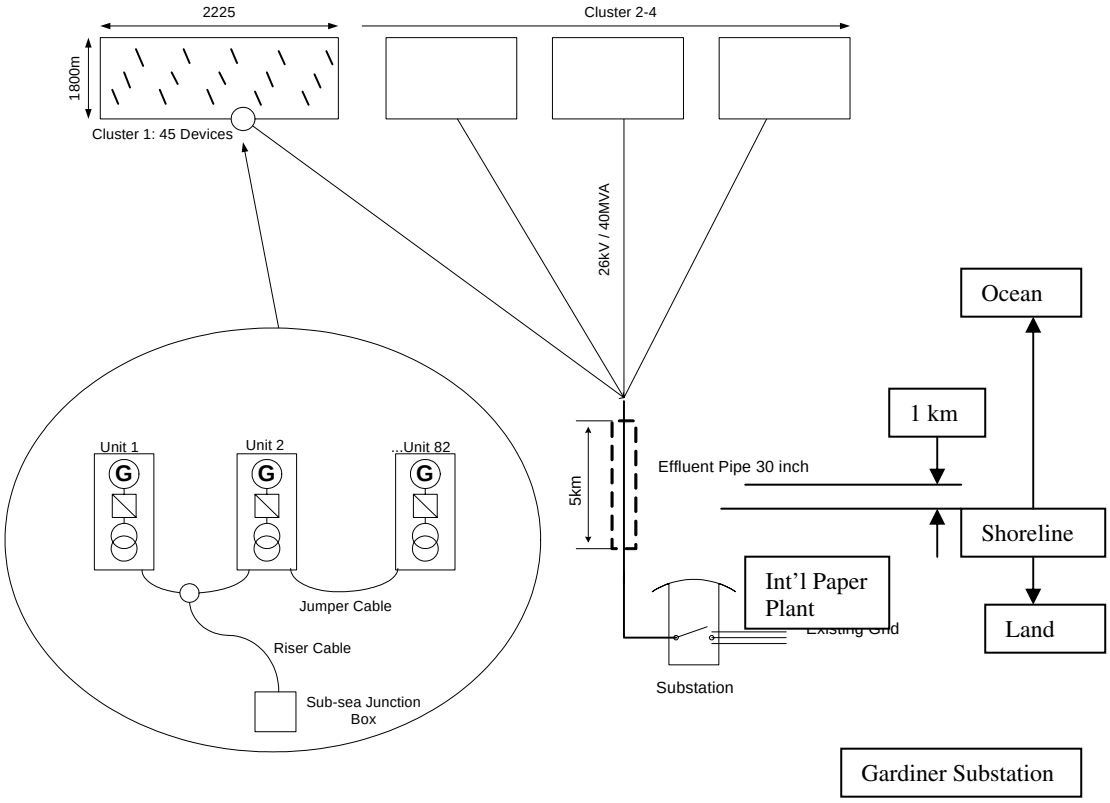


Figure 9-19
Electrical Interconnection of a Commercial-Scale Pelamis Plant–Oregon Example

Table 9-7 shows the estimated performance of the commercial-scale plant at each of the five sites. The rated capacity is derated from 750 kW per device for the demonstration plant to 500

kW for the commercial plant. The performance assessment of the demonstration plants shows that the PCMs are overrated and reducing the rated power to 500 kW per device would yield a significant cost reduction and only a relatively small decrease in annual output (attributed to the fact that the U.S. sites have a lower energy level then UK sites for which the device was originally developed).

For each state, point designs for both a single-unit demonstration and a commercial wave power plant were used to estimate cost and performance. Performance estimates were developed using local wave data obtained from measurement buoys and performance data supplied by the manufacturer. Cost estimates were developed by creating a detailed breakdown of the various cost centers and outlines of installation and operation procedures, and by cross checking them with a variety of sources, including local operators, the design team, local manufacturers, and similar offshore projects in the oil and gas and offshore wind industries.

Table 9-7
Estimated Performance of Commercial Plants

	Hawaii Pelamis	Oregon Pelamis	California Pelamis	California Energetech	Mass Pelamis	Maine Pelamis
Rated Capacity (kW)	500	500	500	1,000	500	500
Annual Energy Absorbed (MWh/yr)	1,989	1,997	1,683	2,714	1,738	584
Annual Energy Produced (MWh/yr)	1,663	1,669	1,407	1,973	1,453	488
Average Electrical Power at Busbar (kW)	191	191	161	225	166	56
Number of Homes Powered by Plant	191	191	161	225	166	56

Availability=assumes 95% for demonstration plant

Power conversion efficiency=assumes 88% for Pelamis

Power conversion efficiency=90% and Directionality factor=85% for Energetech

Annual average power per home=1 kW per EIA data

9.5.5 Demonstration and Commercial Scale Plant Cost Estimates

Cost assessments for the demonstration plant were carried out using a rigorous assessment of each cost center. Installation activities were outlined in detail and hourly breakdowns of offshore operational activity were created to properly understand the processes and associated cost implications. Wherever possible, manufacturing estimates were obtained from local manufacturers. An uncertainty range was associated with each cost element and a Monte Carlo Simulation was run to determine the uncertainty of capital cost. Cost centers were validated by Ocean Power Delivery (the selected WEC device manufacturer) based on its production experience of its first full-scale prototype machine, which was deployed in 2004. Table 9-8 presents the cost estimate ranges, both before and after incentives are applied, including the 10% federal investment tax credit, the 25% Oregon investment tax credit (limit of $10 million), the California 6% investment tax credit, and the Massachusetts installation cost tax deductibility.

Cost assessments for the commercial wave power plant were performed using the same rigorous assessment processes as the demonstration plant estimates. Instead of simply applying learning curves to the demonstration unit, a point design for the commercial plant was established and its cost estimated. For cost centers that lend themselves well to cost reduction, outlines were created of how such cost reduction will be achieved. Again, cost centers were validated by Ocean Power Delivery based on their production experience of their first full-scale prototype machine which was deployed in 2004. Plant inspection, maintenance, and repair tasks and outlines were validated by local marine operators. The utility generator (UG) cost of electricity (COE) estimates for six commercial scale plants is shown in Table 9-9.

Table 9-8
Pilot Demonstration Plant Installed Capital Cost–Before and After Incentives

Installed Capital Cost ($M)[1]	Hawaii Pelamis	Oregon Pelamis	Calif Pelamis	Calif Energetech	Mass Pelamis	Maine Pelamis
Before Incentives: Cost Estimate Range	3.6-5.5	3.7-5.7	4.4 – 7.3	3.9 – 7.2	4.4-6.9	4.8-7.7
After Incentives: Cost Estimate Range	3.3-5.0	2.5-3.8	3.7 – 6.1	3.3 – 6.0	3.9-6.0	4.4-6.9

Table 9-9
Utility Generator Commercial Plant COE after Tax Incentives

Commercial Plant	Hawaii Pelamis	Oregon Pelamis	Calif Pelamis	Calif Energetech	Mass Pelamis	Maine Pelamis
Number of Units Needed for 300,000 MWh/yr	180	180	213	152	206	615
Total Plant Investment ($M)	270	235	279	238	273	735
Annual O&M Cost ($M)	11	11	13	11	12	33
10-Year Refit Cost ($M)	24	23	23	15	26	74
COE (cents/kWh) nominal	12.4	11.6	13.4	11.1	13.4	39.1
COE (cents/kWh) real	10.4	9.7	11.2	9.2	11.1	32.2

The cost of electricity estimates were generated using the economic methodology in Reference 2 (EPRI-WP-002 U.S.). The methodology provides key financial assumptions such as the book life and the cost of money.

Figure 9-20 presents the breakdown of the commercial plant COE for each of the major cost elements. Significant findings include:

- Large impact of O&M cost (one of the main reasons for feasibility demonstration testing)
- The three critical cost centers are 1) absorber structure (steel cost), 2) power take-ff, and 3) moorings
- The sub-sea transmission and infrastructure costs, which contribute a high fraction of the cost for the pilot-scale plant are less significant for the commercial-scale plant.

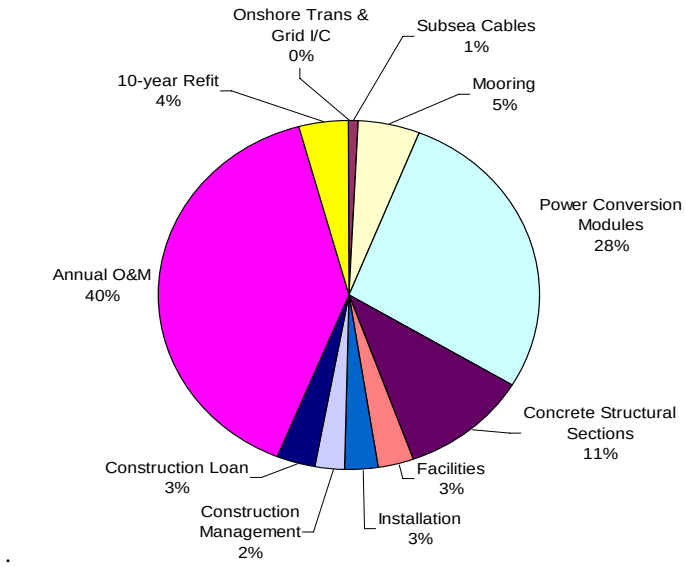
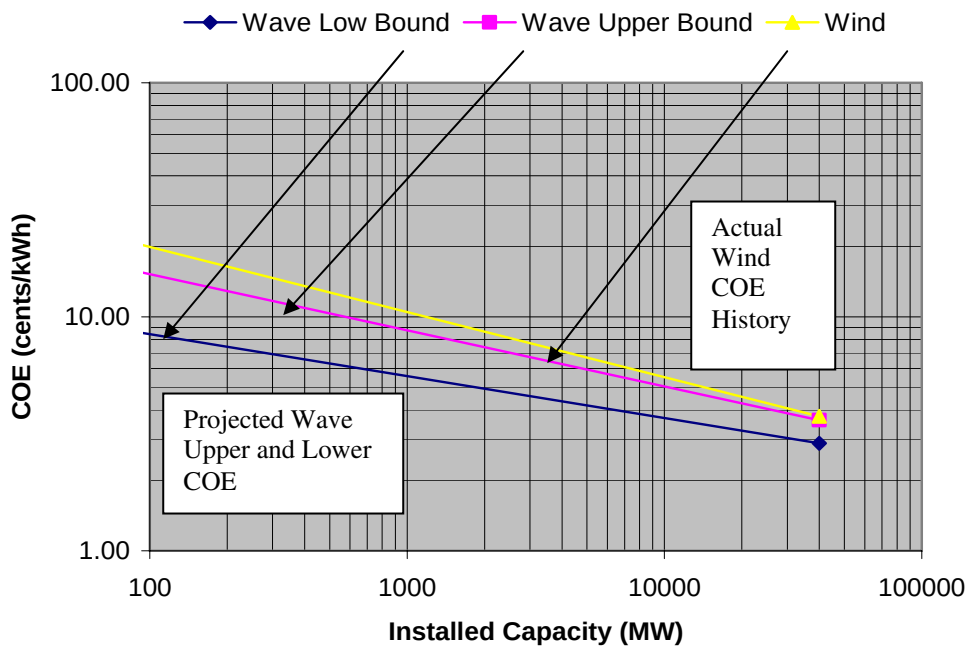


Figure 9-20
Commercial Scale COE Breakdown–Oregon Example

9.5.6 Commercial Scale Plant Economic Assessment

The costs and cost of electricity shown in the previous section are for the *first* commercial-scale wave plant. It is an established fact that learning through production experience reduces costs—a phenomenon that follows a logarithmic relationship such that for every doubling of the cumulative production volume, there is a specific percentage reduction in production costs. The specific percentage used in this study was 82%, which is consistent with documented experience in the wind energy, photovoltaic, shipbuilding, and offshore oil and gas industries.

The industry-documented wind energy learning curve is shown as the top line in Figure 9-21. This curve was developed by EPRI based on data from a multitude of sources. The lower and higher bound cost estimates of wave energy are also shown in Figure 9-21. The 82% learning curve is applied to the wave power plant installed cost but not to the O&M component of the cost of electricity (which is why the three lines are not parallel).



.

Figure 9-21
Levelized COE Comparison to Wind–Oregon Example

9.6 Operation and Maintenance

Due to the limited operating experience with actual wave farms, the largest unknown element of wave power conversion is O&M. The offshore oil and gas and offshore wind industries are coping with very similar issues, however, and there is a reasonable understanding of some the O&M issues and resulting economic implications.

Operation of offshore installations such as oil and gas platforms, wind farms, or wave farms is more difficult and expensive than equivalent onshore installations. Erection and commissioning operations are more difficult, and accessibility for routine servicing and maintenance is a major concern. The vessels to be used for installation, operation, and maintenance are a large cost item. Figure 9-22 shows a very expensive anchor handling vessel and a less expensive Multi-cat vessel. Use of current North Sea Anchor Handling Vessels may be prohibitively expensive.



Figure 9-22
Anchor Handling and Multi-Cat Vessels

Even given favorable weather conditions, offshore O&M tasks are more difficult and expensive than those on shore due to the distance of the wave farms from shore and the exposure of the site. Many wave power units currently under development are free-floating and small in scale, which may keep O&M costs in check. Freely floating devices are easier to access, because the device will move at a similar phase and velocity as a vessel docking. In addition, free-floating devices can be detached and towed into a nearby harbor without any specialized equipment requirements.

The severe weather conditions experienced by an offshore wave farm dictate the requirement for high-reliability components coupled with adequate environmental protection for virtually all components exposed to sea conditions. Consequently, remote monitoring and visual inspection are important to maintain appropriate unit availability.

9.7 Avoidance and Mitigation of Environmental Impact Concerns

EPRI has identified wave energy environmental issues, their possible impacts, and mitigation studies. The conclusions are:

1. All energy producing technologies, including ocean energy conversion, have the potential to produce unacceptable environmental impacts.
2. Given proper care in siting, installation, operation and decommissioning, ocean energy technology holds the promise of becoming one of the most environmentally-benign electricity generation technologies. Negative environmental effects can be minimized and in some cases eliminated by diligent attention to the environmental effects.
3. The discussion of environmental impacts in the U.S. has not been fair and balanced, and has instead focused on conjuring up potential negative consequences.
4. In many cases, analytical models of the complex environmental interactions do not exist and therefore pilot plant demonstrations are required. Unlike large hydroelectric projects, modern ocean energy technologies are modular and can be removed if serious environmental impacts occur. Ocean energy projects, including environmental monitoring and Before-After-Impact and Test and Control Site (to separate natural versus human-induced changes) Studies carried out at specific sites represent the only possible way to achieve an improved understanding of the environmental impacts from wave and tidal energy conversion.

This section summarizes the wave energy projects that have been permitted for construction and operation worldwide, summarizes and gives links to major environmental issues and impact assessments reports published, and lastly describes the key environmental issues and a suggested research program for addressing those issues.

9.7.1 Wave Projects Permitted and in Licensing Process (including pending)

Worldwide wave energy projects permitted, with initial operation dates:

- LIMPET, WaveGen, UK - 2000
- OWC, Portugal - 2002
- Wave Dragon, Norway - June 2003
- OPT PowerBuoy in Navy waters, Hawaii – March 2004
- Pelamis, Ocean Power Delivery, EMEC UK - August 2004
- AWS Energy, Wave Swing, Portugal - October 2004
- Energetech, Port Kemble, Australia - March 2005
- Wavebob, Ireland - 2005
- Renewable Holdings, CETO, Australia - 2005
- Ocean Power Delivery, Portugal - 2007
- Wave Hub, UK, OPD, OPT and Fred Olsen - 2007

Wave projects in licensing process

- Five applications for preliminary permits have been submitted to FERC:
  - Reedsport, Douglas County, Oregon – OPT
  - Douglas Country, Oregon (excluding above area) – Douglas County
  - Lincoln County, Oregon – Lincoln County
  - Mendocino, California – PG&E
  - Eureka, California – PG&E
  - Point Judith, RI – Energetech
- Numerous in countries including the UK, Ireland, Portugal, Spain, France, and South Africa.

A summary of U.S. wave projects with completed licensing processes:

- Hawaii – Ocean Power Technology (PowerBuoyTM)
  - Wave project licensed (by US Navy) and installed
  - EIS – Finding of No Significant Impact (FONSI)
  - Installed in June 2005 - Only environmental impact noticed to date is fish habitat creation

- Makah Bay, Washington - AquaEnergy
  - Wave project with full license application submitted to FERC
  - Environmental assessment stated FONSI

9.7.2 Existing Environmental Studies

Table 9-10 summarizes the key environmental issues and possible impacts.

Table 9-10
Key Environmental Issues and Mitigation Recommendations

Wave Issue	Impact(s)	Mitigation
Withdrawal of Wave Energy – changes to sediment transport patterns	Lowering of wave energy levels reaching the coast may reduce longshore sediment transport, possibly reduce erosion in the vicinity of the site, and increase erosion "down coast"	If down coast erosion takes place, either wave farm dispersion and/or groins may be required
Interactions with Marine Life, Seabirds and Benthic Ecosystems	May provide artificial "haul-out" space for pinnepeds, enabling larger populations to exist than would otherwise be possible. Submerged components such as anchors and cables may provide substrates for colonization by algae and invertebrates creating "artificial reefs."	Design the devices to minimize haul out space for pinnepeds and birds (for example, a conical "hat" on point absorbing buoys.
Atmospheric and Oceanic Emissions	Applies to devices with closed circuit hydraulic systems where working fluid (which may be biodegradable) may leak or spill during transfers	Do not employ seawater based systems. Use only bio degradable fluids
Visual Appearance and Underwater Noise	The aesthetic effect of visually impacting the pristine coast, although this only applies to coastal and near shore systems as offshore systems will not be visible from the coast. Significant underwater noise levels could have adverse effects on marine mammals	Do not employ coastal or near shore wave power plants.
Conflicts with other uses of Sea Space	Potential conflicts with recreational uses (i.e., surfing), commercial shipping, commercial fishing, crabbing and kelp farming, dredge solid disposal and other activities. Any underwater cables can lead to fishing gear snags and gear loss.	Hold siting, design and installation, operation and procedure with all local stakeholders prior to making final plant detail design decisions
Interfering with the migration marine mammals such as gray whales	Large offshore wave energy conversion device arrays have the potential to interfere with the migratory patterns of marine mammals. For example in California, grey whales use the sea space off the California coast for their annual migration from Alaska to the Baja. A web of cables could pose a hazard to migrating marine mammals.	Installation activities should be planned for the summer months when the seas are the calmest and when the whales are not migrating. Cables should be minimized and buried or rock bolted to the seabed

For more information on wave energy conversion environmental issues please refer to EPRI Report WP-007-US located on the EPRI website [www.epri.com/oceanenergy/]. Meanwhile, Hydrokinetic & Wave Workshop proceedings from the DOE's Environmental Effects Workshop can be found at :

http://hydropower.inl.gov/hydrokinetic_wave/

UK Wave Hub

The British government has announced it will provide roughly $8.5 million toward installation of a first-of-its kind “electricity socket” on the sea floor off the coast of southwest England to feed power from wave energy devices to the nation’s grid.

Up to four wave energy machines could plug into the so called “Wave Hub,” which would transmit electricity via a 10-mile-long undersea cable to a grid interconnection on the mainland at Hayle in Cornwall. The Wave Hub, which has a total estimated installation cost of about $38 million, is Britain’s most ambitious project to boost innovative marine energy technology designed to produce electricity from wave action and tidal currents.

If approved, the project is expected to be operational in 2008. Officials at the regional development agency say that, so far, no show-stopping environmental issues have been found for Wave Hub. “We have looked at environmental issues from almost every angle, ranging from potential impacts on marine life, the fishing industry and seabirds right through to wave height, protected wrecks and even the potential effects of electromagnetic fields on basking sharks,” said Nick Harrington, Wave Hub project manager at the development agency, in a June 2006 press release. “What the studies have shown us is that Wave Hub would have very little impact on the environment during its construction and operation, which gives us confidence in applying to the government for planning permission.”

The regional development agency has contributed $4.7 million toward the project and earlier this year picked three companies as development partners for Wave Hub. They are UK-based Ocean Prospect Ltd. and Ocean Power Technologies and Fred. Olsen Ltd. of Norway.

The UK Wave Hub Environmental Assessment report is available at the Wave Hub website.

9.7.3 Environmental Benefits of Ocean Energy

Ocean wave energy is “clean” energy with no emission of any kind. Potential environmental benefits fall into two classes: 1) those benefits derived from displacing other energy supplies that do produce emissions and 2) direct benefits such as wave energy absorption in breakwater structures for providing calm harbors

Avoided emissions

As an example, for a San Francisco Golden Gate Commercial Scale Tidal Plant or an offshore California Wave Power Plant with:

- 35 MW Annual Average – 106 MW Rated Power
- 300,000 MWh/yr electrical energy produced

If CO2 Cost is 0.8 cents/MWh for natural gas or 1.6 cents/MWh for coal ($25/ton and 0.4 tons/MWh for gas and 0.8 tons/MWh for coal), then the carbon cost of not implementing the Golden Gate Passage Tidal Plant over a 30 year life is:

- $7 Million (natural gas)
- $14 Million (coal)

9.7.4 Recommended Next Steps

Research areas

1. Assess and minimize the environmental impacts on
    a. Fish and mammals
    b. Estuary ecology
    c. Shore dynamics and ecology

2. Minimize the cost of operating ocean energy power plants
    a. Increase performance
    b. Reduce the costs of operations and maintenance

3. Support ocean energy technology development
    a. Tuning devices for wave environments

4. Develop standards, common language
    a. Performance measurement and reporting
    b. Test protocols

The most pressing need is pilot demonstration testing with full environmental monitoring to determine environmental effects and issues related to ocean wave and tidal energy systems.

9.8 Regulatory Issues

9.8.1 Chronology of Licensing Offshore Wave Energy Plants in the U.S.

- 1970s – Oil embargos and inflationary conditions leads Congress to enact the Ocean Thermal Energy Conversion (OREC) Act. NOAA develops a one-stop-shopping licensing regime. OTEC projects do not materialize.
- 2002 - AquaEnergy files a declaration of intent (DOI) with FERC concerning a proposed 1-MW Makah Bay Wave project.
- 2003 - FERC asserts jurisdiction over the proposed AquaEnergy Project
- 2003 Navy Offshore Wave Project in Hawaii
  - Funding from the Office of Naval Research (through an earmark)
  - 300-page EIS prepared by Belt Collins using public monies
  - Receives a FONSI (finding of no significant impact)
  - ONR streamlines licensing process through USACOE
  - Neither MMS nor FERC is involved
- 2004 - Energetech files a DOI with FERC concerning a proposed 500-kW Oscillating Water Column project called GreenWave in waters less than 3 miles from shore
- 2005 – FERC asserts jurisdiction over the proposed Energetech project and does not credit over two years work with the CMRC
- 2005 - The Mineral Management Service (MMS), part of the Department of Interior, is empowered by the Energy Policy Act of 2005 to assume authority for renewable projects, such as wave, wind, or solar power on offshore lands (>3 miles to OCS except National Park System, National Wildlife Refuge System, National Marine Sanctuary System or National Monument). The Makah Bay project, located in a National Marine Sanctuary, does not fall under MMS jurisdiction and remains under FERC
- 2006 - MMS decides to develop a programmatic Environmental Impact Assessment – funds Argonne National Laboratory
- 2006 - Public scoping meetings are the first step in the preparation of a Programmatic Environmental Impact Statement (EIS) for the nation's Outer Continental Shelf (OCS) Renewable Energy and Alternate Use Program
- July, 2006 - OPT generates power for 8 of 24 months with mechanical problems being fixed in the interim months. Performance models are verified. Modified design are deployed in Hawaii in late summer 2006

9.8.2 MMS Rulemaking

- MMS is presently in rulemaking according to the following schedule:
  - Scoping – May 5 to July 5, 2006
  - Publish Draft EIS – February 2007
  - Publish Proposed Rule – February 2007
  - Public Hearings – March, April 2007
  - Comment Period Closes – April 2007
  - Publish Final EIS – August 2007
  - Record of Decision – September 2007
  - Final Rule – September 2007
- At the time of this writing, MMS is preparing a programmatic environmental impact statement that will focus on generic impacts from each industry sector based on global knowledge, and identify key issues that subsequent, site-specific assessments will consider. The programmatic EIS will focus on the environmental, cultural, and socioeconomic impacts associated with establishing a national alternative energy program and rules.
- As part of this EIS, three study areas for the State of California were defined. Maps of these areas, showing jurisdictional boundaries can be downloaded from http://ocsenergy.anl.gov. A draft EIS and draft rules are scheduled to be published February 2007 and final rules in the late summer of 2007. MMS will coordinate with other agencies in the permitting of offshore renewable energy projects. At the time of this writing, it is not certain how this new program for ocean energy developments will affect the licensing and permitting process for offshore wave power plants. For further information on the EIS and rulemaking process please visit http://ocsenergy.anl.gov/.
- EPRI has asked MMS to use the Eureka California site as a test case for the programmatic Environmental Impact Statement which they are developing. MMS has agreed.

9.8.3 Ocean Zones

The zones establishing national sovereignty over sea, airspace and economic resources is complex, with overlapping legal authorities and agency responsibilities.1 The United Nations Convention on the Law of the Sea2 establishes the sovereignty of a coastal nation over its territorial seas (out to 12 nautical miles3) and defines exploitation rights in the Exclusive Economic Zone (out to 200 nm). As shown in Figure 9-23, in the United States, the boundary between State and federal jurisdiction is located three nautical miles from the coastline. States have jurisdictional authority over and title to submerged lands out to three nautical miles offshore. Beyond the three-mile limit, the federal government has primary jurisdictional authority, with the right to manage and develop resources in the seabed, including oil, gas, and all other minerals.

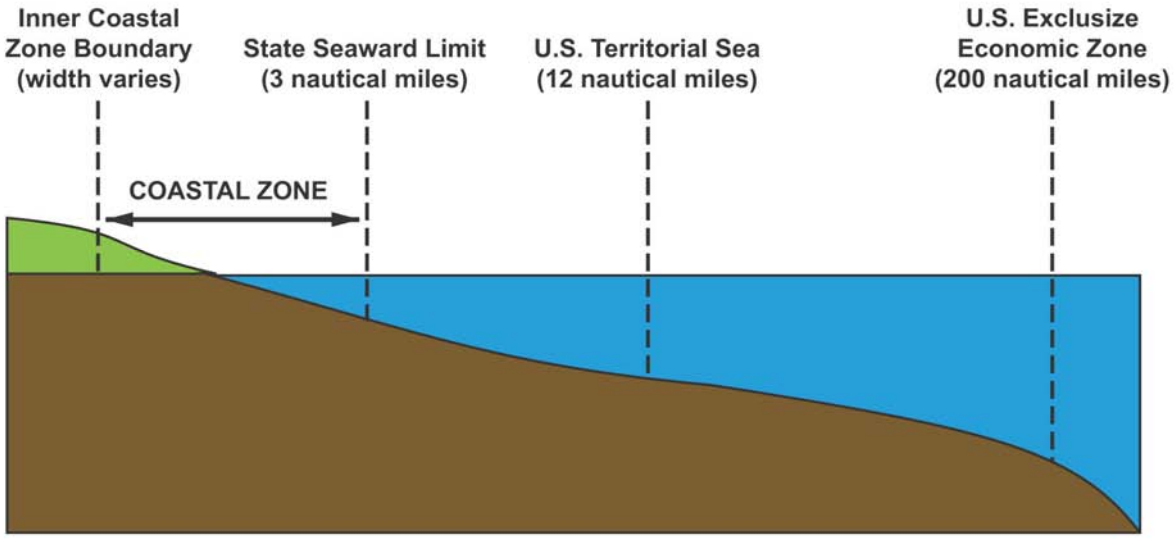


Figure 9-23
Primary Maritime Boundaries Relevant to Coastal Development Permitting for WEC Project

[1] See http://www.oceancommission.gov/documents/prepub_report/primer.pdf

[2] UNCLOS contains a legal framework covering navigation, maritime boundaries, fisheries, the marine environmental, etc. Since 1994, 138 nations have joined this Convention.

[3] A nautical mile is approximately 6076 feet.

9.8.4 Federal Permits, Licenses and Respective Agencies

Permit Authorization	Agency	Intent or Requirement	Time (est.)
EPACT 2005	MMS	Authorized to manage leasing of federal seabed (> 3 miles state limit) for ocean energy	?
FERC Preliminary Permit	FERC	Secures priority of application for a license for a water power project while the permittee obtains data and performs acts required to determine the feasibility of the project and to support a license application.	Approximatel y four months
FERC License	FERC	Authorizes operation of hydroelectric projects that are located on a navigable waterway of the U.S. for license terms between 30 and 50 years. Temporary, experimental projects that are isolated from national grid may be relieved of licensing requirements.	5 to 7 years
Section 10 Rivers & Harbors Act	USCE	Regulates structures and/or work in or affecting navigable waters of the U.S., including the construction of permanent structures; review is concurrent with Section 404 review. Section 10 review includes ESA Section 7 consultation.	3 to 36 months
Section 404 Dredge/Fill permit	USCE	Regulates discharge of dredged or fill material into the navigable waters at specified sites; review is concurrent with Section 10 review.	3 to 36 months
Section 401 Water Quality Certificate	USCE and/or FERC	Sets guidelines for activities affecting the water quality in order to maintain minimum water quality standards.	12 months
Endangered Species Act Incidental Take Permits	USFWS, NOAA	Provides for the protection of threatened and endangered species of fish, wildlife, and plants and the ecosystems upon which they depend. Incidental take permits, which allow a landowner to conduct activities on their land that might incidentally harm or “take” a listed species, may be granted upon submittal of a habitat conservation	n/a
Marine Mammal Protection Act	USFWS, NOAA	Prohibits the taking of marine mammals in the U.S. and its territorial waters; incidental take or harassment permits may be granted. 6 to 8 months for incidental take; 120 days for incidental harassment.	See left cell
Migratory Bird Treaty Act	USFWS	Prohibits the harming of migratory birds, listed at 50 CFR 10.13. No permit program is in place to authorize the incidental taking of a listed migratory bird.	n/a

Permit Authorization	Agency	Intent or Requirement	Time (est.)
Magnuson - Stevens Fishery Conservation and Management Act	NOAA	A TISEC facility must not be constructed in conflict with fishery management plans.	n/a
NPDES	USEPA	Protects water quality by regulating point source discharges into a public body of water. Permit requirement is applied to commercial and industrial entities.	3 to 12 months
Section 106 National Historic Preservation Act	USCE	Requires federal agencies to “take into account” the effects of project siting on properties listed or eligible for listing on the National Register of Historic Places. Lead federal agency must document how options that avoid, minimize, and mitigate adverse impacts to historical properties were considered in approving the project.	n/a
Coast Guard Regulations - hazards to navigation	USCG	Aids to navigation placed on structures in the waters of the U.S. must be approved by the USCG and must follow established marking standards.	n/a
National Park Service	NPS	In accordance with the National Park Service Organic Act of 1916 (16 U.S.C. 1 et seq.) the National Park Service (NPS) preserves unimpaired the natural and cultural resources and values of the National Park System for the enjoyment, education and inspiration of this and future generations.	

9.8.5 California State and Local Government Agencies with Permitting and/or Review Authority

In addition to Federal level regulatory agencies, a number of state and local level regulatory agencies have review and approval authority. As an example, the California agencies are listed below.

	Agency	**Type of activity**	**Regulatory requirement**
STATE	California Coastal Commission	Development within Coastal Zone (submerged/tidal lands or other public trust lands; lands not covered by registered LCP) Development outside Coastal Zone	Coastal development permit Federal consistency review
	California State Lands Commission	Use of tide and submerged lands	General lease
	California State Water Resource Control Board Regional Water Quality Control Boards	Any activity which may result in discharge into state waters	Section 401 certification Waste discharge requirements
	California Department of Fish and Game	Any activity	Consultation under California Endangered Species Act
	All state and local agencies	Any activity	CEQA assessment
LOCAL	County/city governments	Development within Coastal Zone (lands covered by registered LCP)	Coastal development permit

Coastal Zone Management Act/California Coastal Act

The federal Coastal Zone Management Act of 1972 (CZMA) authorizes the Coastal Zone Management Program (CZMP), which is administered at the federal level by the Coastal Programs Division within the National Oceanic and Atmospheric Administration (NOAA). In conjunction with the federally approved California Coastal Management Program authorized by the CZMA, the California Coastal Act of 1976 established the California Coastal Zone and placed it under the jurisdiction of the California Coastal Commission. The California Coastal Commission is one of California's two coastal management agencies vested with federal consistency review authority for the purpose of administering the federal CZMA in California (the other agency is the San Francisco Bay Conservation and Development Commission, whose jurisdiction covers the waters of San Francisco Bay and contiguous areas).

The Coastal Commission transfers coastal permitting authority over most new development to local city and county governments that have registered an approved Local Coastal Program (LCP) with the Coastal Commission. The Coastal Commission retains permanent coastal permit jurisdiction over development proposed on tidelands, submerged lands, and other public trust lands within the Coastal Zone. All new development proposed development within the Coastal Zone must receive a coastal development permit from the Coastal Commission or the appropriate local government agency.

In addition, the CZMA gives the Coastal Commission regulatory control (federal consistency review authority) over all federal activities and federally licensed, permitted or assisted activities, wherever they may occur (i.e., landward or seaward of the respective coastal zone boundaries fixed under state law) if the activity affects coastal resources.

WEC projects situated within the Coastal Zone will require a coastal development permit from the Coastal Commission or the appropriate local government agency. WEC projects situated outside the Coastal Zone will still need to obtain a consistency certification from the California Coastal Commission before any of the necessary federal coastal development permits can be issued by the appropriate agencies.

Submerged Lands Act/California State Lands Act

The Submerged Lands Act grants coastal states title to offshore lands within their historic boundaries, as well as the rights to the natural resources on or within those lands. The federal government relinquishes its claims to the lands and resources, but maintains the right to regulate offshore activities for national defense, international affairs, navigation, and commerce.

The California State Lands Act established the State Lands Commission and assigned to it exclusive jurisdiction over all state-owned tide and submerged lands. These lands include the tidal and submerged lands adjacent to the entire coast and offshore islands of the state from the mean high tide line to three nautical miles offshore.

Any WEC project involving floating devices, seabed structures, and/or power transmission cables on state-owned tide and submerged lands will require a General Lease from the State Lands Commission.

California Environmental Quality Act (CEQA)

CEQA requires that project proponents study and disclose a project's anticipated environmental impacts and specify means to avoid or minimize those impacts. Environmental review is characterized by an Environmental Impact Report (EIR), which records the scope of the applicant's proposal and analyzes all its known environmental effects. Project information is used by state and local permitting agencies in their evaluation of the proposed project.

A proponent for any project needing state or local agency approval must comply with CEQA or indicate that its project is exempt from CEQA, pursuant to the exemptions described in CEQA regulations. The California Coastal Commission would most likely be the lead CEQA agency for any WEC projects.

The California Endangered Species Act (CESA)

CESA generally parallels the main provisions of the Federal Endangered Species Act and is administered by the California Department of Fish and Game (DFG). CESA establishes a petitioning process for the listing of threatened or endangered species. The California Fish and Game Commission is required to adopt regulations for this process and establish criteria for determining whether a species is endangered or threatened. CESA prohibits the "taking" of listed species except as otherwise provided in State law. During the CESA process, state lead agencies are required to consult with DFG to ensure that any action it undertakes is not likely to jeopardize the continued existence of any endangered or threatened species or result in destruction or adverse modification of essential habitat.

In fulfillment of CESA obligations, approval must be obtained from DFG before any state or local permits for a WEC project can be issued.

9.8.6 Internet Resources

EPRI: www.epri.com/oceanenergy/

European Wave Energy Thematic Network: http://www.wave-energy.com

Department of Transportation and Industry (UK): http://www.dti.gov.uk/renewable

Australian Renewables including Wave Energy:
http://www.greenhouse.gov.au/renewable/index.html

Danish Wave Energy: http://www.waveenergy.dk/

European Commission 'Thermie' wave energy site:
http://europa.eu.int/comm/energy_transport/atlas/htmlu/wave.html

European Wave Energy Research Network (EWERN):
http://www.ucc.ie/ucc/research/hmrc/ewern.htm

European Wave Energy Thematic Network: http://www.wave-energy.net/

Japan Marine Science & Technology Center, JAMSTEC:
http://www.jamstec.go.jp/jamstec/MTD/Whale/

Norwegian Wave Energy Site: http://www.phys.ntnu.no/instdef/prosjekter/bolgeenergi/index-e.html

Open University, UK: http://www.openuniversity.edu/StudentWeb/t265/update/wave.htm

World Wave Atlas: http://www.oceanor.no/projects/wave_energy/

Resource: http://www.worldenergy.org/wec-geis/publications/reports/ser/wave/wave.asp

9.9 References

EPRI Wave Power (WP) Reports are available on our website www.epri.com/oceanenergy/

1. WP-001-U.S. Guidelines of Preliminary Estimation of Power Production by Offshore Wave Energy Conversion Devices.
2. WP-002-U.S. Rev 4 Cost of Electricity (COE) Assessment Methodology for Offshore Wave Energy Devices.
3. WP-003-HI Results of Survey and Assessment of Potential Offshore Wave Energy Site Locations in Hawaii.
4. WP-003-WA Results of Survey and Assessment of Potential Offshore Wave Energy Site Locations in Washington.
5. WP-003-OR Results of Survey and Assessment of Potential Offshore Wave Energy Site Locations in Oregon.
6. WP-003-ME Results of Survey and Assessment of Potential Offshore Wave Energy Site Locations in Maine.
7. WP-004-U.S. Rev 1 Assessment of Offshore Wave Energy Conversion Devices.
8. WP-005-U.S. Methodology, Guidelines, and Assumptions for the Conceptual Design of Offshore Wave Energy Power Plants (Farms).
9. WP-006-HI System Level Design, Preliminary Performance and Cost Estimate–Hawaii.
10. WP-006-OR System Level Design, Preliminary Performance and Cost Estimate–Oregon.
11. WP-006-ME System Level Design, Preliminary Performance and Cost Estimate–Maine.

12. WP-006-MA System Level Design, Preliminary Performance and Cost Estimate–Massachusetts.

13. WP-006-SFa System Level Design, Preliminary Performance, and Cost Estimate–San Francisco, California, Pelamis Offshore Wave Power Plant.

14. WP-006-SFb System Level Design, Preliminary Performance, and Cost Estimate–San Francisco Energetech Offshore Wave Power Plant.

15. WP-007-U.S. Identification of Environmental Issues.

16. WP-008-U.S. Identification of Permitting Issues.

17. "Wind Energy Costs" NWCC Wind Energy Series, Jan 1997, No 11.

18. "Regulating Innovation: Permitting and Licensing New York City's East River Kinetic Hydropower Project," Ron Smith, CEO Verdant Power LLC, presented at Powergen RE, March 2004.

19. WP-009 – OR "Phase 1.5 Oregon Wave Energy Report" December, 2005

10
RENEWABLE ENERGY GRID INTEGRATION TECHNOLOGIES

Integrating large blocks of renewable energy generation into the electricity grid has become an important issue in several regions of the United States and throughout the world, especially in the case of wind generation. The principal issue is how intermittent and nondispatchable generation such as wind and solar energy affect the reliability, operation, and operating cost of the electricity system.

For example, in Germany, more than 20,000 MW of installed wind capacity is already affecting the operation of the German electricity grid [1]. Impacts include large swings in wind generation as weather fronts pass through the country, increased cycling of baseload units, increased spinning reserve requirements, and the creation of transmission bottleneck centers during peak demand and high renewable generation periods. In the United States, large concentrations of wind generation in the windy regions of west Texas and the upper Midwest create situations in which wind generation exceeds the load carrying capability of the transmission system during windy periods. Until transmission upgrades increased the load carrying capability in Texas, it was necessary to curtail wind plant operation at times [2]. In Hawaii, the amount of wind generation that can be added to the individual island grids is limited by their ability to absorb the wind energy, especially at night when the load demand is low [3].

These issues are being addressed via a number of measures, including:

- Limited transmission upgrades to eliminate bottlenecks and increase load carrying capability
- Addition of capacitors and power electronic devices to control power factor and quality
- Integration with hydro and pumped storage facility operations
- Addition of batteries, compressed air energy storage, and other storage facilities
- Addition of combustion turbines and other peaking generation
- Development of generation forecasting systems to forecast next-hour and next-day generation of wind and solar energy
- Curtailment of renewable generation when the energy is not needed or transmission is not available.

This chapter addresses the energy storage and other integration technologies addressed above, which can be used to mitigate the impacts of adding large amounts or wind, solar, and other intermittent generation to the electricity grid. Topics addressed include: renewable generation integration issues, renewable generation integration technology, and energy storage technology.

Recent EPRI reports on integration impacts and technologies include: *Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning: Utility Wind Interest Group - Xcel Energy-North Case Study* (EPRI 1004807, December 2003); *Wind Power Integration Assessment and Case Studies* (EPRI 1004806, March 2004), *Wind Power Integration: Smoothing Short-Term Power Fluctuations* (EPRI 1008389,) March 2005, *Wind Power Integration: Energy Storage for Firming and Shaping* (EPRI 1008388, March 2005). Survey of Wind Integration Study Results (EPRI 1011883, March 2006); and EPRI-DOE *Handbook of Energy Storage for Transmission and Distribution Applications* (EPRI 1001834, December 2003).

10.1 Renewable Generation Integration Issues

Wind has proven to be a very economical and clean source of energy. However, the nature of wind resources and the equipment employed to produce electricity from wind have lead to power system integration issues. The simple explanation for these issues is that most wind-driven generators cannot perform all the functions that are expected from traditional generation. And, because wind power is relatively new, the planners and operators of bulk-power systems have limited experience to make changes that may be needed to integrate large-scale wind power into the existing power grid. This section addresses renewable generation integration issues and costs with regard to power system planning and operation. It is based on information presented in the EPRI reports, *Wind Power Integration Assessment and Case Studies* (EPRI 1004806, March 2004), *Wind Power Integration: Smoothing Short-Term Power Fluctuations* (EPRI 1008389,) March 2005, *Wind Power Integration: Energy Storage for Firming and Shaping* (EPRI 1008388, March 2005) and *Survey of Wind Integration Study Result*s (EPRI 1011883, March 2006).

10.1.1 Power System Planning and Operation

System Generation Fundamentals

The main function of generation in an electric power system is to produce electric energy to serve the power system load. This function of generation may include regeneration from stored energy. The Authoritative Dictionary of IEEE Standards Terms, Seventh Edition, ANSI/IEEE Std. 100, defines generation as producing or storing electric energy with the intent of enabling practical use or commercial sale of the available energy. A generating station is also defined as “a plant wherein electric energy is produced from some other form of energy (for example, chemical, mechanical or hydraulic) by means of suitable apparatus.”

The operation of electric power systems is fundamentally different from services provided by other types of utilities. Electric systems have two unique physical characteristics:

- Electric energy is not commercially stored[4] like natural gas and water. Production and consumption (generation and load) must be balanced in near real-time. This requires continuous monitoring of loads, generation, and the voltages and flows throughout the power system, as well as adjusting generation output to match consumption.
- The transmission and distribution network is primarily passive, with few "control valves" or "booster pumps" to regulate electrical flows on individual lines. Flow-control actions are limited primarily to adjusting generation output and to opening and closing switches to add, remove, or reroute transmission and distribution lines and equipment from service.

These two operating constraints lead to four reliability consequences with practical implications that dominate power system design and operations:

- Every action can potentially affect all other activities on the power system. Therefore, the operations of all bulk-power participants must be coordinated.
- Cascading problems that quickly escalate in severity are a real threat. Failure of a single element can, if not managed properly, cause the subsequent rapid failure of many additional elements, potentially disrupting the entire power system.
- The need to be ready for the next contingency may limit current operations (for example, likely power flows that occur if another element fails could limit the allowable power transfers).
- Because electricity flows at nearly the speed of light, maintaining system stability and reliability often requires that actions be taken instantaneously (within fractions of a second), requiring automatic computations, communications, and controls.

These concepts have important consequences for what constitutes congestion and how wind power interacts with the power system.

[4] Electricity is not "stored" directly. When electricity is "stored," it is converted to another form of energy and re-converted later. Pumped storage hydro converts electricity to mechanical potential energy by lifting water. Batteries convert electric energy to chemical potential energy. The re-conversion to electricity uses conventional generators or inverters.

Expectations Based on Traditional Generators

Reliable and low-cost operation of the interconnected electric utility is not a "natural" state but relies on operational scheduling, planning, and coordination of a multitude of electric utility control systems. Therefore, a traditional electric utility generator is not just a source of energy. Operators have relied on an array of performance capabilities and specific services from traditional generators. Some of these services are simply provided by the generators as part of participation in the energy market. Others are obtained from bidding in separate ancillary services markets that have evolved, particularly in light of deregulation. The exact definition of these services varies in different markets, but in general, they fall into the categories described in Table 10-1.

Response time is one of the critical factors in defining these generation capabilities and services. Time is critical because of the nature of the electric utility as described above. Furthermore, wind power integration issues—as well as the value attributed to wind power—are to a large degree measured by how well the traditional generation functions are fulfilled.

Table 10-1
Functions and Services Provided by Generation

Functions and Services	Short Description	Time Frame
Base load units (non-regulating)	**Energy** (firm) scheduled well in advance, based on availability, price, and long-term contracts.	**Long-term** commitments
Committed units (usually with regulation capacity)	**Energy** (firm) scheduled based on availability and price to meet block load, with LOLE[1] and load forecasts considered.	Day before plan, **hourly** resolution
Load-following or energy-balancing units	**Energy** ramping to follow the load, met by adjusting generation schedules and the imbalance energy market.	Hourly plan with **5- to 10-minute** resolution
Frequency regulation (regulating reserves)	**Service** provides capacity based on a signal from dispatcher, with AGC[2] to meet CPS 1 and CPS2[3] and no net energy[4].	Every few minutes, **minute-to-minute** resolution
Reactive supply and voltage control	**Service** of injecting or absorbing of reactive power to control local transmission voltages (usually provided with energy).	Continuous with response in **seconds**
Spinning operating reserves	**Service** to provide energy in response to contingencies and frequency deviations.	Begin within **10 sec** full power in **10 min**
Non-spinning operating reserves	**Service** to provide load/generation balance in response to contingencies, not frequency response.	Respond within **10 minutes**

Table 10-1 (continued)
Functions and Services Provided by Generation

Functions and Services	Short Description	Time Frame
Replacement reserves	**Service** to restore contingency capacity to prepare for the next generation or transmission contingency.	Respond within **60 minutes**, run up to 2 hours
System black start	**Service** to restore all or a major portion of the power system without outside energy after a total collapse.	**As required**

1. Loss of load expectation (LOLE) is the probably measure that a load cannot be served with available generation.
2. Automatic generation control (AGC) is a method for adjusting generation to minimize frequency deviations and regulate tie-line flows.
3. Control performance standards (CPS1 and CPS2) are minute-to-minute and 10-minute average criteria for load frequency control in each control area. These criteria require the control areas to maintain their area control errors (ACE) within tight limits. ACE is measured in MW and is defined as the instantaneous difference between the actual and scheduled interchanges plus frequency bias (imbalances that bias the system toward maintaining 60 Hz).
4. Frequency regulation service is usually provided from generation that is on-line and delivering some level of base energy power on a full-time basis or scheduled. The service is to increase and decrease power output where the average output over the scheduled period does not change—that is, there is no net change in delivered energy attributed to the frequency regulation service. Consequently, energy-storage devices could provide this service.

Typical System-Operating Strategy

A system-operating strategy, with or without wind generation, will likely include energy balancing (from both committed and reserve units), unit commitment block scheduling, and an economic dispatch procedure. This strategy starts with a forecast of system load with time-varying characteristics and expected minimums and maximums. Inventories of available generation and the estimated cost of energy, as well as other services, are maintained. Desired reserve margins are set. Baseload units and firm energy blocks can be scheduled so that, in the short term, the operator is only dealing with the differences between the predicted and actual load and/or available generation.

Thus, the system operator is effectively managing supply and demand over three time scales: (1) days- and hours-ahead scheduling, (2) intra-hour load following and balancing, and (3) fast regulation to maintain system frequency and voltage. The impact that wind generation may have on this strategy is discussed later. All three time frames are also important to effective integration of any generation resource, including wind.

Energy Balancing

System operators run load-following and regulation markets to ensure that there is adequate on-line generation capacity for ramping up or down to follow the load and to regulate the faster and more random changes in load.

- For frequency regulation: Load-following units must be on-line and provide fast response to meet the minute-by-minute fluctuation in the system energy balance. The North American Electric Reliability Council (NERC) has set guidelines on control performance in frequency regulation.
- For intra-hour load following: These resources are being dispatched to follow the within-the-hour load change in the frequency consistent with the economic dispatch cycle (5 to 10 minutes per cycle).
- For reliability: This is the primarily contingency reserves (use of spinning and fast-start generators) that can be deployed within 10 minutes in order to replace any MW loss following line or generator outage. Typically, one-half of system operating reserves is spinning, so that a sudden loss of generation will not result in a loss of load, with the balance available to serve the load within 10 minutes. This includes replacement reserves.

Both regulation and load following are dealt with on a control area basis. It is not necessary to compensate for each and every load variation directly, but the aggregate change in the area must be balanced. The fast, random fluctuations associated with regulation are typically uncorrelated. Consequently, the total regulation requirement is not the sum of all the regulation requirements of the individual loads and uncontrolled generators, but is instead the sum of the correlated components.

Load-following requirements tend to be more highly correlated; most area profiles rise in the morning and drop off in the evening. Still, because load-following requirements are not perfectly correlated, the total system load-following requirement is less than the sum of the load-following requirements of individual end users. This aggregation of loads has a powerful effect on system planning and operation because the system must respond to total variations, not the sum of individual variations.

Unit Commitment

Unit commitment (UC) is part of a set of programs for scheduling generation on an hourly to weekly basis. Vertically integrated utilities typically run their UC optimization computer programs the day before operations. These complicated computer programs accept as inputs detailed information on the characteristics of the individual generating units that are available to produce electricity on the following day. These characteristics include current unit status, minimum and maximum output levels, ramp-rate limits, startup and shutdown costs and times, minimum runtimes, and unit fuel costs at various output levels.

Economic Dispatch

Once generators are committed (turned on and synchronized to the grid), they are available to deliver power to meet customer loads and reliability requirements. Utilities typically run their least-cost dispatch model every five minutes or so. This model forecasts load for the next five-minute interval and decides how much more or less generation is needed during the next interval for regulation to meet the system load. The model then selects the least-cost combination of units that meet the need during the next intra-hour interval.

Role of Ancillary Services

In addition to committing and dispatching units, system operators may contract for ancillary services to support operation of the grid. FERC has defined ancillary services as those necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. This statement recognizes the importance of ancillary services for bulk-power reliability and to support commercial transactions. Though the resources necessary to create these services are generators, the services themselves must be deployed and controlled by the same system operator that controls the transmission system.

Ancillary services are conceptually well defined. They have existed throughout the history of the power system. However, the details of obtaining them from markets are still evolving. Ancillary services normally provided by generation include regulation, contingency reserves, voltage control, and black start capability.

Regulation

Power system operators need rapid, automatic control over some generation resources (AGC) to compensate for normal short-term fluctuations in the aggregated load and generation in order to meet NERC control performance criteria. This is related to maintaining the real power balance and stable frequency in the power system. Time scales are minute to minute.

The power system operator could eliminate the need for regulation by insisting that all end-use consumption conforms precisely (minute-by-minute) to its power purchase schedule. Alternatively, each end-use consumer could be required to contract with a generator to precisely match its individual minute-to-minute load fluctuations. These alternatives are both impractical and wasteful from a viewpoint of minimizing needed resources.

Contingency reserves are also planned in case of sudden loss of generation, off-system purchases, unexpected load fluctuations, and/or unexpected transmission line outages. These contingency reserves may be spinning or non-spinning reserve, or simply serve as replacement. Reserve generation units may be categorized as follows:

- **Contingency reserves**. The power system must always be prepared to survive the unexpected loss of a generator or a transmission line. To accomplish this, the power system operator is required to maintain contingency reserves consisting of spinning reserve and non-spinning reserve sufficient to meet the largest credible contingency.

- **Spinning operating reserve.** At least half the contingency reserve is typically spinning reserve. Spinning reserve comes from generation that is on-line, not fully loaded, capable of responding fully within 10 minutes, and able to maintain that output for at least two hours. Spinning reserve units are also required to be responsive to frequency deviations.
- **Non-spinning reserve.** The definition of non-spinning reserve is similar to that of spinning reserve except that the reserve is not required to be on-line or frequency responsive. In addition, non-spinning reserve does not have to be provided by generation; it can be provided by dispatchable demand, interruptible exports, certified off-line generation, or external imports.
- **Replacement reserve.** Contingency reserves must be restored so that the system is prepared for a subsequent unexpected outage. Some regions specifically identify replacement reserves, which are capable of responding within one hour and sustaining that response for an additional two hours. They can be generators, loads, or resources from outside the independent system operator's (ISO) control area.

Together, spinning reserve, non-spinning reserve, and replacement reserve provide resources that begin responding immediately to an unexpected event, are fully deployed within 10 minutes, are capable of responding to a second event within one hour, and can sustain the total response for three hours. This coordinated set of resources is designed to provide sufficient time for markets to begin functioning again and return the system to normal operations. All of these services and regulation are typically procured through day-ahead and hour-ahead markets run by the ISO.

Figure 10-1 provides a summary of deployment times for various ancillary services. Reserves are deployed only during contingency operations, while regulation and voltage control are required during both normal and contingency operations.

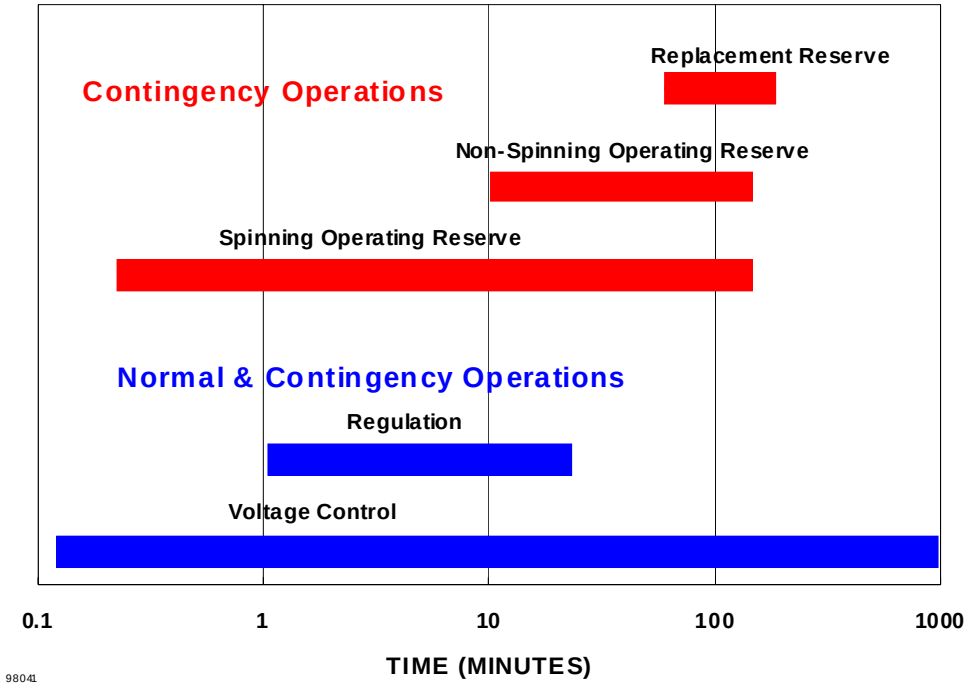


Figure 10-1
Ancillary Services Are Distinguished by Their Deployment Times and Durations

Voltage Control

Because of relatively strict geographic requirements for voltage control, it is not normally procured through markets. Instead, all generators are required to provide limited reactive support and voltage control without compensation. Reactive support—the generation or absorption of reactive power (MVAR)—is the resource that is used to control the voltage in the vicinity of the generator. All generators are required to be capable of following a system-operator-supplied voltage schedule under automatic voltage control within a power factor of typically 0.90 lagging and 0.95 leading. The system operator will typically compensate generators if it requires them to provide additional reactive support and voltage control.

Black Start

Because of relatively strict geographic requirements for black-start capability, it is also not normally procured through markets. System operators determine the system's black-start requirements to ensure that the system could be restored to service expeditiously if it should ever fail completely. Long-term contracts are established with selected black-start units. Each black-start unit must be capable of starting, without external assistance, within 10 minutes. It must be capable of supplying the reactive power requirements and controlling the voltage of the energized transmission system, and must be capable of operating for a minimum of 12 hours.

10.1.2 Technical Integration Issues of Intermittent Generation

When wind, solar, and other intermittent generation resources are part of the generation mix, operators must consider the unique characteristics of the generator when planning and operating the power system. The following six characteristics of intermittent generation are likely to require changes in unit commitment, economic dispatch, and operating reserves:

- Intermittency
- Ramping burdens
- Fluctuating power output
- Limited reactive power control
- Distributed generation
- Remote location of some renewable resources.

Intermittency

The output of most traditional generators can be planned as well as controlled, even minute-to-minute, to meet the expected daily load and to balance or regulate variations in that load. Wind power output depends on the weather and is determined by time-varying wind speeds; its output varies day to day as well as from hour to hour and even minute to minute. Two wind facilities may have the same capacity rating and annual energy production. However, the different wind regimes may result in very different hourly, daily, and seasonal operating schedules.

Ramping Burdens

Maintaining grid stability usually refers to moment-to-moment balancing of the load and generation by holding a constant frequency. Rapid changes in system loads are matched by quickly ramping generation up or down to balance load and generation in a five-to-10-minute timeframe. Also, some units are required to ramp more quickly, following an AGC signal to maintain system balance. Operators refer to this process as regulation, and the time frame is in minutes. A substantial load change may cause sudden changes in frequency, to which speed governors on individual generator units must respond. The number of plants and their capacity to provide load balancing and regulation is limited in any power system. The challenge is to have sufficient energy balancing and regulating generation with ramp rates to meet the worst-case load fluctuations.

Fluctuating Power Output

Rapid changes in power system loading or in generation can also cause small voltage fluctuations that manifest themselves as light flicker. Voltage changes of 1% to 2% can cause visible flicker. Wind turbines can cause voltage fluctuations due to a number of natural weather and machine conditions. These include fluctuations in wind speed, cut-in or cut-out transients, tower shadow effects, wind shear, and pitching and yaw errors of blades. Another factor in flicker production is the type of generator: induction with fixed or variable poles, variable-speed

through electronic power conversion with or without pitch control, directly connected synchronous generators, or synchronous generators connected through a converter.

Limited Reactive Power Control

Reactive power supplied or absorbed by a renewable generation facility may vary along with the real power generation, depending on the type of generator. For example, most wind turbines use induction rather than synchronous generators and therefore require external capacitors to provide reactive power, usually switched in discrete steps. Even with switched capacitors, reactive control to match wind power generation may still be an issue. For example, externally switched capacitors will probably satisfy the steady-state reactive power balance requirement for the system but will not address any dynamic VAR control needs. Dispatching reactive power to maintain transmission network voltage could place new requirements on controlled generating facilities or necessitate capital investment for reactive compensation equipment. The addition of power electronics into the wind system can provide both dynamic and static reactive power control.

Distributed Generation

Wind, solar, and other renewable generation are deployed both as large projects interconnected to the transmission system and as small distributed facilities connected to the distribution system. Even though wind is considered primarily as a bulk-generation resource, a growing number of installations are being deployed on distribution systems at or near smaller load centers. Because distributed systems are designed for one-way power flow, distributed generators require special arrangements for connection and protection.

Two types of distributed wind and solar applications are common. Some facilities use local distribution to collect energy from individual units and deliver it to the distribution system. Other facilities are more dispersed and are individually connected to the system. Integration issues that may surface in these distribution scenarios are voltage regulation, coordination of protection, and interferences or harmonic flows along rights of way. In general, these are the same integration concerns that occur when generation is added into the distribution system.

Remote Location of Some Renewable Resources

Although good quality renewable energy sites exist throughout the United States, the best wind and solar resources are located relatively far from large load centers. In addition, sites selected for building large wind farms are likely to be away from population centers. This is not unique to wind. For example, other generation types such as hydro and coal-fired stations may also be located at significant distances from load centers. However, wind developments have tended to not consider the available transmission capacity to these sites nor include transmission-related costs of taking the wind to market.

10.1.3 Renewable Generation Technical and Associated Cost Impacts

The technical issues for integrating renewable generation ultimately lead to cost issues related to the impacts of intermittency, ramping, fluctuating output, lack of control, and remote location on transmission scheduling, system dispatch, network stability, load following, and load balancing. With traditional generation, operators assume that most of the available energy resources are "dispatchable" and therefore expect to be able to schedule generator output with a high probability of delivery of the specified output. For wind, solar and other intermittent generation, this assumption is not valid.

The impacts of intermittent wind generation on both technical and ancillary costs are summarized in the EPRI Report, S*urvey of Wind Integration Study Results* (EPRI 1011883, March 2006). This report reviews the wind integration studies conducted for nine North American mainland systems. These studies include the following:

- NYSERDA-NYISO
- Xcel North-280 MW
- Xcel North-1500 MW
- Alberta Electric System Operator (AESO)
- Bonneville Power Administration (BPA)
- Southwest Public Service Company
- WE Energies
- Great River Energy
- PacifiCorp

The wind generation penetration levels considered in these studies range from 0.3% to 20% of system peak load. Table 10-2 presents the wind integration technical impacts determined in each of these studies, and Table 10-3 presents the wind integration cost impacts. These summary tables provide a high-level view of the individual study results and allow for comparisons among the system studies.

Table 10-2
Summary of Integration Technical Impacts

Study	Penetration	Operating Reserve			Load Following		Scheduling	Reliability
	%	Regulating	ACE	Contingency	Intra-hour	Inter-hour	Uncertainty	Cap. Credit
NYSERDA-NYISO	10	+17%	Minimal	No impact	+3%	+6%	+19% to +44%	15%
Xcel-280	0.3	+4%	Minimal	n/a	n/a	+0%	n/a	n/a
Xcel-1500	15	+12.9%	Minimal	n/a	+15.6%	+5%	n/a	27%
AESO	13	+49%	n/a	+134%	+49%	+134%	n/a	n/a
BPA	11	n/a	n/a	n/a	0 to +3.5%	n/a	+17.2%	n/a
SPS	20	n/a	n/a	n/a	n/a	n/a	+49.6%	n/a
WE	14	+9%	n/a	n/a	+9%	n/a	+38%	n/a
GRE	16.6	+28%	n/a	n/a	n/a	n/a	n/a	n/a
Pacificorp	20	n/a	n/a	n/a	n/a	+17% to +22%	n/a	n/a

Table 10-3
Summary of Integration Cost Impacts ($/MWh)

Study	Penetration Level (%)	Regulation	Intra-Hour Load Following	Inter-Hour Load Following	Scheduling/Unit Commitment	Total
NYSERDA-NYISO	10	-	-	-	-	
Xcel-280	0.3	-	0.41	1.44		1.85
Xcel-1500	15	0.23	0.00	4.37		4.60
AESO	13	7.37	-	3.64	-	11.01
BPA	11	0.19	0.28	-	1.00	1.47
SPS	20	1.00 - 2.25	0.01	-	-	1.01 - 2.26
WE	14	1.08	0.14	-	1.61	2.83
GRE	16.6	1.28	0.18	-	3.08	4.54
Pacificorp	20	-	-	2.50	3.00	5.50

Table 10-2 shows that most of these studies have not assessed the impacts of wind generation on contingency reserves. For the two studies that did make this assessment, the results are completely different with the NYSERDA study finding no impact and the AESO study showing an approximately 134% increase in contingency reserves. There is certainly not sufficient data to suggest any trends in this particular area. This is not the case for regulating reserve impacts, however. Table 10 2 shows that many of the studies assessed the impact on regulating reserve requirements. The majority of study results show that wind penetrations up to 20% lead to regulating reserve requirements of 30% or less. Table 10 3 shows that the associated cost impacts of the increased regulating reserve burdens vary from twenty cents to a couple of dollars per MWh of wind. Much of the variation in these is associated with the assumed cost of providing (or obtaining) regulating reserves.

Table 10-2 shows that the increase in intra-hour and inter-hour variability is relatively low for most of the studies. The potential increase in intra-hour load following burdens range from 3-15% with the exception of the one 49% study result. Likewise, the potential increase in inter-hour load following burden was found to range from approximately 5% to 22%. Table 10 3 shows that the associated intra-hour load following cost impacts are also relatively low, ranging from zero to forty cents per MWh of wind. The inter-hour load following costs are generally more significant. For the studies where the inter-hour load following cost were determined in isolation, the cost impacts were $2.50 - $3.50 per MWh of wind generation. In other studies the inter-hour load following cost is embedded with the uncertainty costs determined from scheduling/unit commitment assessments, but the costs appear to be in the same general magnitude range.

Table 10-2 shows that the increase in the standard deviation for scheduling uncertainty ranges from 20-50%, again with the AESO study yielding the highest increase. The associated costs shown in Table 10 3 are in the $1.00 to $4.50 per MWh range. Again, it should be noted that some of the Scheduling costs shown in Table 10 3 (Xcel and Xcel 1500 MW) are a combination of both uncertainty and inter-hour load following costs (additional dispatch and start-up costs associated with inter-hour wind variability). Furthermore, the Scheduling cost shown for the PacifiCorp study is solely associated with inter-hour load following and does not include any component of uncertainty cost. Table 10 2 also shows that the capacity credit allocated to wind generation is only addressed in two of the nine studies presented here, with the credit ranging from 15% to 27%.

Table 10-3 shows that the total operating cost impacts for most of the studies summarized in this technical update ranged from $1.00 to $5.50 per MWh of wind generation, with only one study yielding the costs in excess of $10/MWh. It should be noted that not all cost components were calculated for all studies. Nonetheless, the studies that did evaluate cost impacts for most time frames yielded costs in this same range.

10.1.4 Standards and Regulatory Actions

Connection Standards for Distributed Generation

Because most distribution systems in the United States have been designed to operate as radial (one-way) systems, the installation of DER in significant amounts can result in conflicts with distribution operations. These possible conflicts, coupled with the recent renewed interested in distributed generation sources, has prompted a great deal of interest in DER interconnection practices within the industry. IEEE 1547 is the recently approved interconnection standard developed through the combined efforts and support of the U.S. Department of Energy, NREL, electric utilities, hardware technology manufacturers, and consultants.

This standard establishes criteria and requirements for interconnection of DER to the electric grid. The guidelines in IEEE 1547 apply to all distributed generation sources, including distributed wind generation. Distributed wind power typically receives more scrutiny than more conventional distributed generation technologies because of its intermittent nature. In addition to the typical DER interconnection issues, wind generation results in an increased potential for power-quality-related problems such as voltage flicker and voltage regulation disturbances. More experience with small wind generation in distribution systems will increase understanding of these issues and is vital to minimizing the costs of interconnection.

Regulatory Treatment of Wind Power

Several regulatory actions are affecting wind-power integration related to markets and costs. Generally these have been favorable to wind power because of special provisions and exceptions enacted by control area and by states. These are briefly discussed here. It should be noted that such regulatory actions are expected to impact wind integration in the future.

FERC Order 888

In 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888, which required transmission-owning utilities under FERC jurisdiction to provide open access transmission service to eligible wholesale power customers. However, FERC's implementation of Order 888 resulted in some inadvertent market outcomes, at least for wind energy. Of special interest are the energy imbalance provisions of Order 888. The energy imbalance service corrects for hourly mismatches between the scheduled delivery and the actual delivery of energy to a load located within a control area. FERC also allowed transmission providers to apply a penalty if energy deliveries vary 1.5% or more (either higher or lower) from advance energy schedules.

Because wind is an intermittent energy resource primarily dependant on the weather, it is basically impossible for wind generators to deliver wind energy within the 1.5% band included in the Order 888 tariffs. Further, even in the unlikely event that a wind generator can absorb the energy imbalance costs, the wind plant investor would have difficulty obtaining project financing because the risk of incurring energy imbalances is known to be high. The best that a wind generator can be expected to do is sell into a larger diversified portfolio and hence minimize the risk of incurring any energy imbalance costs.

This situation led policy makers to create special provisions or exemptions from these energy imbalance penalties for renewable generation sources such as wind and photovoltaics. Some of these provisions are summarized in Table 10 4. Despite these exceptions, more than half of the states in the United States still impose FERC Order 888 tariffs on wind generation.

FERC Order 2000 and Other Pending Rulings

In issuing Order 2000 in 1999, FERC moved away from individual utility open-access transmission tariffs to focus more on creating regional transmission services and tariffs via Regional Transmission Organizations (RTOs). In a move that will be more beneficial to wind energy, FERC required RTOs to implement a real-time balancing market to allow transmission customers to balance their energy schedules. Note, however, that formation of RTOs under Order 2000 is voluntary, and there are still sectors in the electric power industry and regions in the country where RTO participation is relatively meager. Moreover, RTOs are evolving institutions. It may be several years before RTOs are fully functional with robust real-time balancing markets.

In an effort to standardize wholesale bulk power market and transmission services across the country, FERC recently refocused its RTO initiative, authorizing a standard market design (SMD) that would apply to all RTOs and transmission owners under FERC jurisdiction. Accordingly, FERC issued a Notice of Proposed Rulemaking (NOPR) in July 2002 on certain requirements and services. FERC believed that standardizing transmission provisions should lower transaction costs and reduce interface issues between RTOs and transmission providers.

Since this NOPR, FERC has terminated the controversial SMD, and decided to pursue a slightly different policy goal than the SMD proposed rule. FERC is now focused on reforming transmission policy with the goal of preventing undue discrimination in transmission service. Some RTOs, however, such as ISO-New England, have proposed to incorporate elements of SMD.

10.2 Renewable Generation Integration Technologies

Renewable generation integration technologies include generator interface and output controls, fault ride-through technology, auxiliary reactive power compensation equipment, integration with hydro and pumped storage, other energy-storage technologies, and renewable generation forecasting tools. Table 10-5 maps the wind issues with wind solutions based on descriptions provided in this report.

Table 10-4
Scheduling Provisions Beneficial to Wind

ISO	Provision	Comments
CA ISO	CA ISO conducts day-ahead, hourly, and near-real-time forecasts of potential wind generation. Wind generators schedule based on the CA ISO forecasts and pay a forecast fee of up to $0.10/MWh. Penalties associated with energy imbalances are based on the monthly cumulative total of positive and negative variances between scheduled and actual deliveries of next-hour wind energy.	These provisions were in a proposed tariff that CA ISO filed with FERC by early 2002. FERC has already approved it, making CA ISO or RTO the first to rely on wind forecasting to incorporate wind energy into energy and transmission scheduling protocols.
ERCOT ISO	Wind generation is allowed a 50 percent deviation from schedules. Load-serving entities absorb any energy imbalance costs.	Texas has a mandatory target of 10,000 MW of new renewable energy by 2025. The provision works because load-serving entities are buying wind energy to meet the energy requirement.
New York ISO	Currently operating intermittent renewable energy generators, and up to 500 MW more of such generating capacity, are exempt from regulation penalties.	If bidding into the day-ahead market, then any deviations in energy deliveries are settled at the real-time prices without penalties, with wind generators being paid the real-time price for energy deliveries over schedule and conversely paying the real-time price if energy deliveries are below schedule. These provisions are available to all generators. For the hour-ahead, the NY ISO resets the wind schedule to actual metered delivery before real-time settlement.
PJM ISO	Any deviations in energy deliveries are settled at the real-time prices without penalties, with wind generators being paid the real-time price for energy deliveries over schedule, and conversely, paying the real-time price if energy deliveries are below schedule. These provisions are available to all generators. Thus, PJM reflects an early example of the Order 2000 vision of real-time balancing markets.	Wind generators must submit a daily schedule but can change those schedules up to 20 minutes before the hour.

Table 10-5
Mapping Solution Categories with Wind Power Problems

Generation Characteristics and Solution Categories	Generator Controls	Fault Ride Through	Reactive Compensation	Forecasting Tools	Energy Storage
Intermittency	N/A	Helps	N/A	Helps	Solves
Ramping burdens	Helps	N/A	N/A	Helps	Solves
Fluctuating output	Helps	Helps	Solves [1]	N/A	Solves [1]
Limited reactive power	Solves [1]	N/A	Solves	N/A	Solves [1]
Distributed collection	N/A	Helps	Helps	n/a	N/A
Remote locations	Helps	Helps	N/A	N/A	Helps

1. Depends on the specific technology.

Some of these solutions are already being applied in wind farm applications, while others are only in the design and development stage. The role of various solutions stems from the basic planning and operating objectives of utility power systems that were addressed in the previous section. The solutions are intended to complement wind power capabilities and to fill in some of the gaps of wind power relative to traditional generation.

10.2.1 Generator Interface and Output Control

The generator type, interface, and output controls vary between renewable generation technologies. The generator system for biomass, geothermal, and other renewable technologies that generate steam to drive a steam turbine generator are similar to those for conventional fossil and nuclear power plants. Those that use biogas to drive a gas turbine generator are similar to conventional combustion turbines. Solar photovoltaic generators use inverters to convert dc electricity to 50- or 60-Hz ac electricity. Wind turbines use various generator and interface types, including asynchronous induction generators that are either connected directly to the grid or through power electronics that convert ac to dc and back to 50- or 60 Hz-ac electricity. Each generator type affects the electricity system and can impact *ramping* burden, *fluctuating* output power, and *reactive* power control performance in different ways. An understanding of the differences in the renewable generator output control is essential for effective integration into the electricity grid.

Except for solar photovoltaic power generation, which uses inverters to convert dc to ac electricity, virtually all renewable generators are based on one of three generator-connection types: (1) constant-speed induction generators with direct grid connection; (2) variable-speed induction or asynchronous generators with power electronic interface to grid; and (3) variable-speed generator with HVDC link to grid. Each is described further below.

Apart from these mainstream systems, many other designs and technologies have been developed and tried over time. Some have survived, others have come and gone, and still others are yet to be installed and proven in the field.

Constant-Speed Induction Generator with Direct Grid Connection

A constant-speed, or fixed-speed wind turbine consists of a rotor and a squirrel-cage induction generator connected via a gearbox, as shown in Figure 10-2. The generator stator winding is connected to the grid. The generator slip varies with the generated power, so the speed is not in fact constant. However, because the speed variations are very small (just 1% to 2%), it is commonly referred to as a "constant-speed" turbine. A squirrel-cage generator always draws reactive power from the grid, which is undesirable, especially in weak networks. The reactive power consumption of squirrel-cage generators is therefore nearly always compensated by capacitors. The capacitor may be fixed or switched in stages depending on voltage conditions.

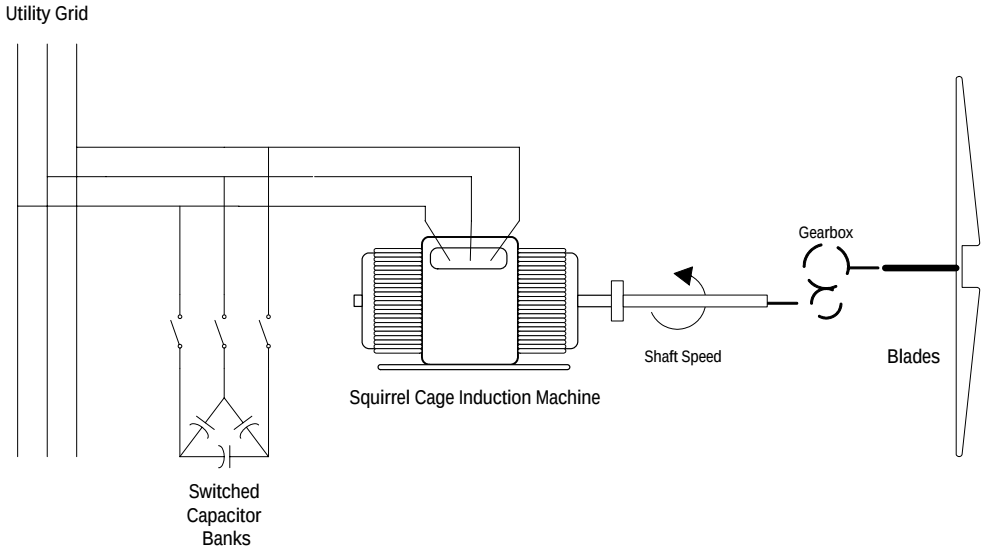


Figure 10-2
Constant-Speed Induction Machine-Connected Wind Turbine Generator with Gear Box

The 30-MW Peetz Table wind power plant in Northeast Colorado is a good example of a large constant-speed wind turbine installation. This plant consists of 33 NEG Micon turbines rated at 900 kW, and uses capacitive-compensated induction generators. The plant is connected to the grid via a 34.5-kV to 115-kV substation (see Figure 10-3). The entire field is collected via underground direct burial 35-kV primary cable. A switched capacitor bank is installed at 35 kV in the 50-MW substation and controlled by the Western Area Power Administration (WAPA) SCADA system.



Figure 10-3
Grid Interface for Peetz Table 30-MW Wind Farm

Variable-Speed Induction or Asynchronous Generator with Power Electronic Interface to Grid

Variable-speed wind turbines have progressed dramatically in recent years. Variable-speed operation can only be achieved by decoupling electrical grid frequency and mechanical rotor frequency. To this end, power electronic converters are used, such as an ad-dc-ac converter combined with advanced control systems.

Doubly Fed Induction Generator

In a variable-speed turbine with a doubly fed induction generator, the converter feeds the rotor winding, while the stator winding is connected directly to the grid (Figure 10-4). The electrical rotor frequency can be varied by this converter, thus decoupling mechanical and electrical frequency and making variable-speed operation possible.

The power electronics are typically rated at 30% of the generator rating, thus leveraging the investment in electronics. Control advantages include better wind power tracking, smoother output power, more constant torque, and reduction in torque surges.

This type of wind turbine generator (WTG) offers the simplicity of the induction generator with advantages of electronic control. They can benefit wind integration in rural and more isolated grids by maintaining system stability, reducing the risk of voltage collapse, and minimizing the impact of grid disruptions. The design is currently very popular and machines are available in sizes up to 4.5 MW from a half dozen manufacturers. Competition is steep in Europe, where all six manufactures are engaged. However, in North America GE Wind (formerly U.S. Windpower, Zond, and Enron) has dominated sales by threat of U.S. patent infringement. At least four patents were issued on this variable-speed wind turbine design from January 1991 through July 2003. The original patent, by Richardson and Erdman [10], was assigned to U.S. Windpower, Inc.

Recently, however, other manufacturers such as Enercon and Gamesa have made either cross-licensing agreements or patent agreements with GE Wind. Gamesa is currently offering this technology in the US.

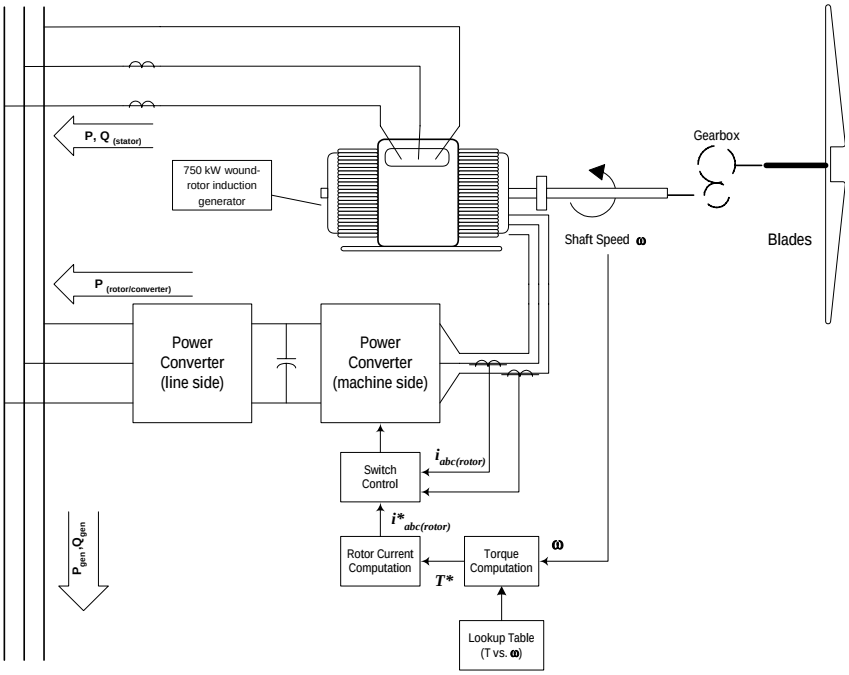


Figure 10-4
Variable-Speed Doubly-Fed Induction Machine Connected WTG with Gear Box

Full-Converter Asynchronous or Induction Generator

Advances in power electronic technology have made the full converter—processing 100% of the wind power current—a practical reality. This completely decouples the turbine by means of a power electronic converter and allows a wide range of variable-speed operation. In some cases, a direct-drive approach is taken and the gearbox is completely eliminated (see Figure 10-5). The direct-drive approach results in obvious maintenance and cost savings. However, generator speed is also reduced, requiring additional electrical poles in the generator that leads to a relatively large machine resembling a water wheel in a hydroelectric plant. Alternatively, another U.S. manufacturer, Clipper Windpower, offers a slightly different approach. The Clipper WTG is based on a distributed drivetrain approach, consisting of four permanent magnet synchronous generators connected to the grid via a four-quadrant IGBT switched inverter.

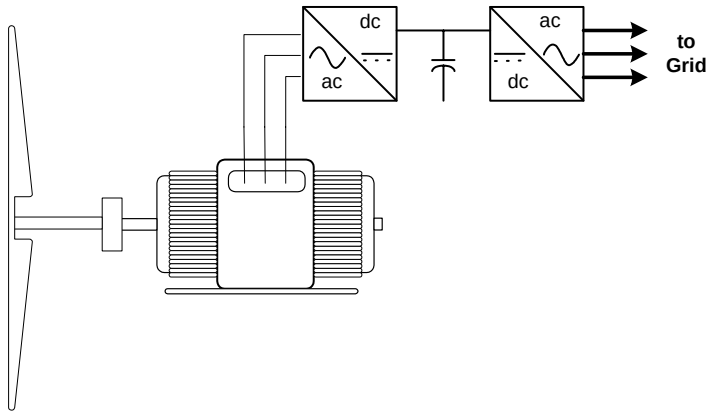


Figure 10-5
Variable-Speed, Direct-Drive Asynchronous Machine Converter-Connected WTG (no gear box)

In a full-converter machine, power electronics are sized for the full and transient overload rating. The topology usually includes two stages: first to rectify the variable-speed output of the generator, and second to produce ac power for interfacing with the electric grid, as shown in Figure 10-6. These turbines are available in sizes up to 4.5 MW from three manufacturers and provide a full range of output control, including both the real and reactive power. In a variable-speed turbine with direct-drive, the generator and the grid are dynamically isolated.

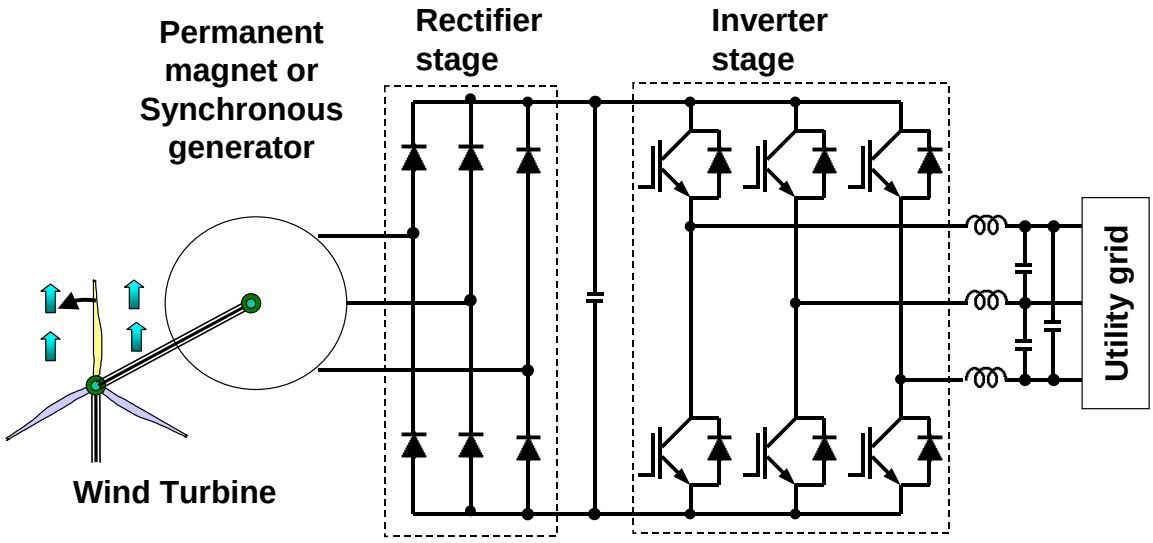


Figure 10-6
Direct-Drive Synchronous Generator with Simple Rectifier at the WTG and Voltage-Source Converter Interface With the Utility Grid

Overall, variable-speed WTGs experience less mechanical stress. In addition, rapid power fluctuations occur only rarely because the rotor acts as a flywheel (storing energy temporarily as a buffer). In general, no flicker problems occur with variable-speed turbines. The type of electronic interface allows for fast reactive power control and compensation for grid voltage variations. With VAR control, it is possible to decouple wind changes and other system events from the prime mover, thus improving overall performance. Although power electronics make the generator more expensive, variable-speed operation can lead to major savings elsewhere, such as lighter-weight mechanical components and lighter foundations in offshore applications.

Variable-Speed HVDC-Link to Grid

With the advent of offshore and potentially large-scale wind farms, the high-voltage dc (HVDC) link is being considered as a feasible grid interface. Advances in power electronics technology have led to the development of HVDC systems at lower power ratings than were previously cost-effective. For instance, one manufacturer has a system in the range of two to 200 MW based on IGBT voltage source converters such as shown in Figure 10-7. One advantage of voltage-source self-commutated converters over traditional HVDC current-source converters, which are thyristor-based, is that synchronous rotating machines are not required at each end of the link. The ac connection voltages at both ends do not have to be the same, possibly saving a site transformer at the shore [11].

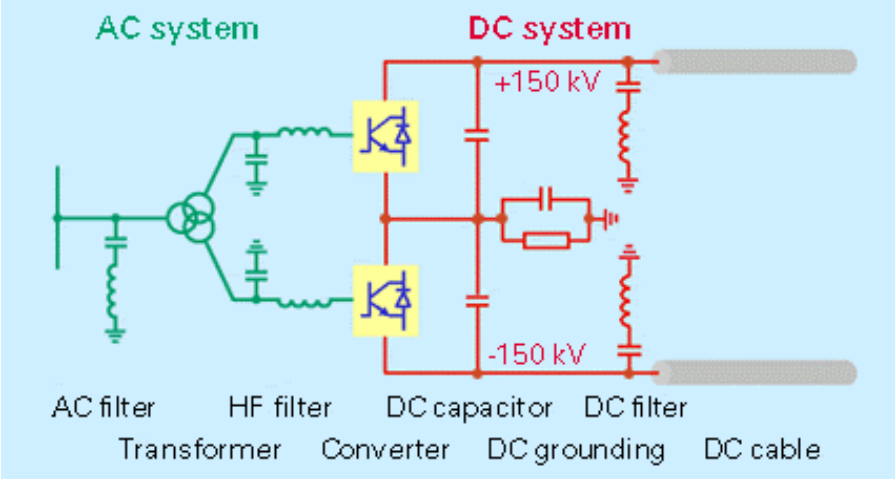


Figure 10-7
One Leg, Single-Line Diagram of 12-Pulse HVDC System (Source: Siemens)

Although HVDC systems are available from at least three manufacturers, to date only a demonstration system has been installed, and there has yet to be an offshore installation. The technology is in its infancy and further advances are likely. In the longer term, there is the possibility that offshore turbines will be directly connected to high-voltage dc without conversion to ac. In this scheme, a platform is required to house the offshore converter and switchgear, and the whole wind farm would be lost if the cable fails. So far, studies [12] indicate that the HVDC connection is currently too expensive for distances closer to shore than 25 km and for power levels less than 200 MW. There is also a risk associated with applying new HVDC technology offshore before it has been proven in onshore applications.

10.2.2 Ride-Through During Faults and Other Grid Disturbances

Weather events and accidents that result in switching events, lightning strikes, equipment failures, and downed power lines are a fact of life on utility grids around the world. Protective devices at the grid interface of wind turbines are intended to protect both the turbine from grid disturbances and the grid from either poor quality generation or from unwanted islanding fed by the wind generator. A practical problem has emerged where turbine protection trips the unit off-line during momentary system faults, where the operating utility prefers that the generation remain on-line and ride through the brief disturbance. Better coordination of the protection settings and more immunity in some power electronic-connected turbines are needed.

Several techniques have been developed to ride through momentary voltage dips caused by faults and/or switching events. These techniques can reduce wind power *intermittency* and the potential rapid loss of generation (*ramping burdens*) due to tripping as well as help with *remote* location exposure to power system disturbances and issues related to protection and tripping of the wind generators.

Adaptive Protective Relaying

Adaptive relaying is an application of the concept that protection timing and trip limits for generators and feeders should vary depending on power system conditions. In this way, the cutoff of a distributed generator may be advanced or delayed in order to minimize circuit and generator disruption. Because of the very short decision time, relays are either preprogrammed to sense conditions and act accordingly or there will need to be some local intelligent agent that supervises and controls the response.

Low-Voltage Ride-Through Circuits

One drawback of the variable-speed wind systems is that the built-in power electronics are relatively sensitive to grid disturbances compared to an induction or synchronous generator interface without electronics. On the other hand, the power electronic interface offers a faster and more controllable connection than the conventional machines. The result is that a perceived weakness has been turned into an advantage by the addition of low-voltage ride-through capability in electronically-interfaced wind machines. The ride through is feasible in both the full converter and double-fed machines for momentary low voltages that last less than 15 cycles. This can be a very practical solution because 80% to 90% of low voltage events are momentary.

The key to the solution is to limit the high current in the rotor in order to protect the converter and to provide a bypass for this current via a set of resistors that are connected to the rotor windings. With these resistors, it is possible to ride through neighboring faults or faults cleared downstream without disconnecting the turbine from the grid. Because the generator and converter stay connected, synchronization is maintained during and after the fault, and normal operation can be continued immediately after the fault has been cleared. As an additional feature, reactive power can be supplied to the grid during long dips in order to facilitate voltage restoration. A control strategy has been developed that takes care of the transition back to normal operation. Without this control strategy, large transients would occur.

GE Wind was the first to offer low-voltage ride-through capability on its 1.5-MW double-fed induction generator. This low-voltage ride-through (LVRT) option allows the machine to stay connected to the grid during grid faults, thus keeping wind farms on-line by feeding reactive power during system events. It can be programmed to align with the operational/control parameters of the host transmission system. The ride-through option can be effective even below 30% voltage at the point of common coupling, as shown in Figure 10-8. The system remains engaged until after the fault is cleared, providing support to bring the system back to normal operating conditions.

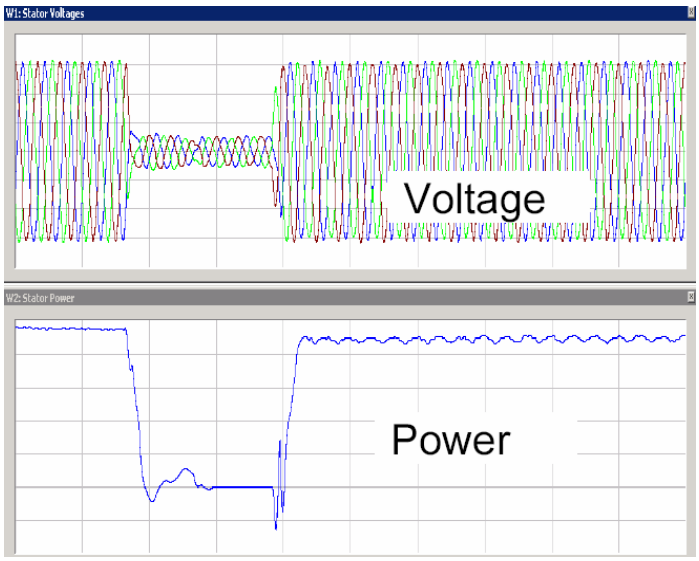


Figure 10-8
A Severe Voltage Sag to Less Than 30% Voltage Remaining Voltage for 100 ms (Upper Trace) and Wind Turbine with LVRT Recovering After the Event (Lower Trace)

The reported performance of the GE system is in line with laboratory and simulation results reported by Torbjörn Thiringer [13] at Chalmers University of Technology, Göteborg, Sweden. Thiringer found that a full-power electronic converter can be set up to ride through a voltage disturbance with virtually no dynamic interaction and a preprogrammed response. In his results, a doubly-fed induction machine responded like a fully electronic interface for small voltage sags and like an induction machine for large sags. Figure 10-9 shows the typical machine response to a large voltage sag for four commercially available wind turbine generators, where the response each turbine has to the voltage sag differs considerably. The oscillations damp out within seconds after the event.

Over the years, utilities have begun requiring wind plants to remain online during transmission system events. As a result, wind turbine manufacturers have begun integrating low voltage ride-through technologies. With the recent FERC Order 661a, wind plants larger than 20 MW are required to remain online during voltages down to 0% voltage for up to 9 cycles. The variable speed wind turbines are capable of meeting such requirements without necessitating additional equipment. Other technologies, such as the constant speed induction generator require additional compensation to sustain voltages within the wind plant to acceptable levels.

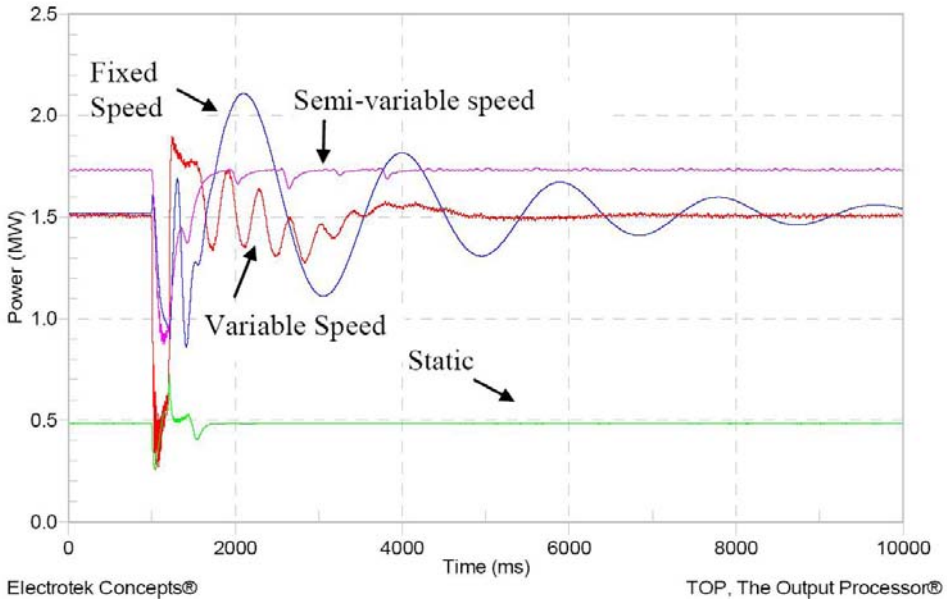


Figure 10-9
Response of Four Commercially Available Wind Turbine Generators to a Large Voltage Sag

10.2.3 Reactive Compensation Equipment

As with any other generation technology, wind-driven generators need reactive power to excite the generator field and to control the voltage at the output terminals. The induction-type machines, which have been most popular for wind generation to date, require an external reactive power source. This source of reactive compensation is usually provided by lumped capacitor banks that are connected when the generator operates. Compensating capacitor banks can also be switched in stages relative to the power and system voltage levels. Electronic compensation provides the added benefit of being infinitely variable and usually more responsive than permanent and switched capacitor banks.

Solutions that can be expected from auxiliary compensation equipment include providing needed levels of *reactive* power control, supporting local voltage regulation, and helping with control of *distributed* collection. In addition, fast-acting electronic-controlled compensators may be responsive enough to mitigate *fluctuating* wind power output and related flicker.

There are four basic types of reactive compensation/voltage control options that can be utilized to meet specific power factor/voltage regulation requirements, including:

- Distributed Constant Power Factor
- Distributed Variable Power Factor
- Centralized Switched Capacitor Banks
- Static var (STATCOM, DSVC, etc.)

Figure 10-10 provides an illustration of each of the four approaches.

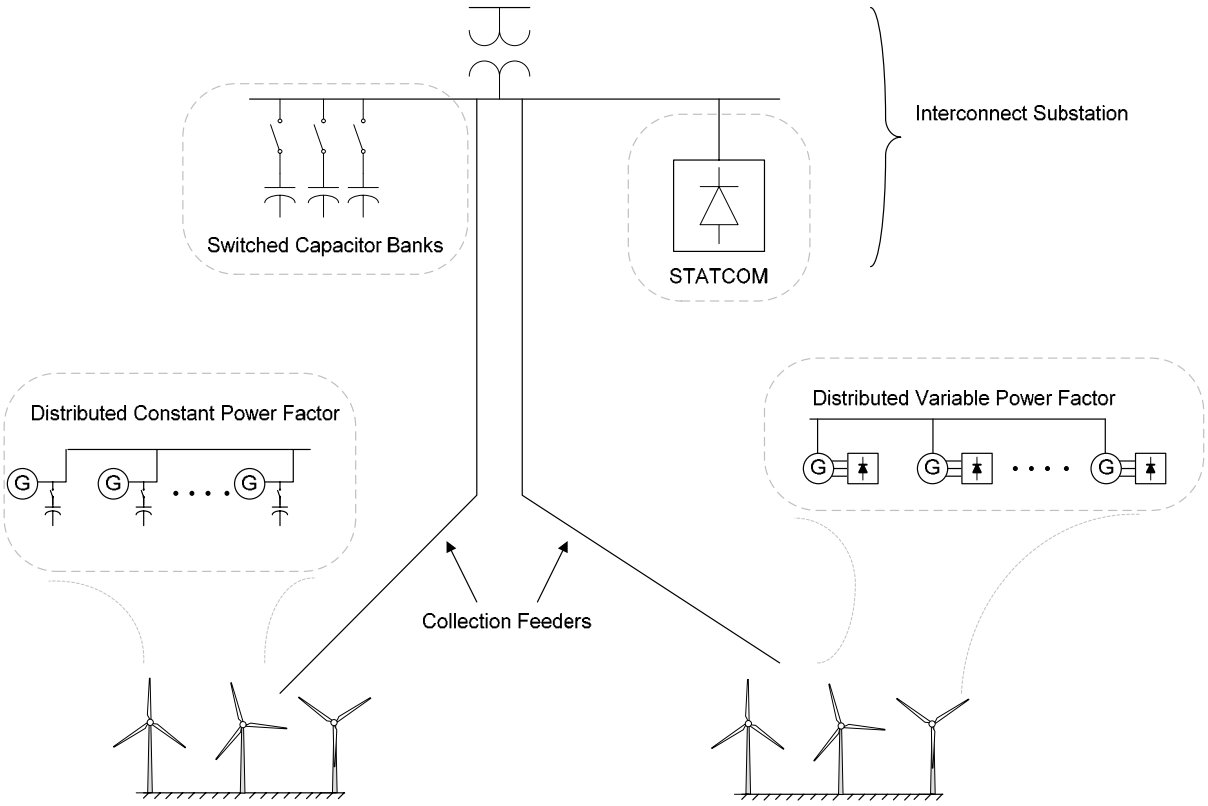


Figure 10-10
Illustration of Various Reactive Compensation and Voltage Control Mechanisms for Wind Farm Applications

Distributed Constant Power Factor

This type of compensation refers to the mechanically switched capacitor banks utilized at each WTG, set to operate at a pre-defined constant power factor over the full range of generator output. It is worth noting that the effectiveness of this approach is dependent upon the collection system (lines, cables, and transformers). A WTG power factor set point of 0.99 leading (generator convention) does not constitute a 0.99 leading power factor at the point of common coupling (PCC). The reactive power drawn by the substation and WTG transformers and collection lines must be taken into account as well, and depending upon the X/R ratio of these components, this could be significantly different.

If necessary, switched capacitor banks located at the substation are commonly utilized to provide unity power factor at the PCC.

Distributed Variable Power Factor

Distributed Variable Power Factor offered by some turbine vendors provides plant-wide control of each WTG's reactive power production/consumption. This approach takes advantage of the reactive power capabilities of each turbine to control plant-wide voltages and/or power factor.

The advantages to this approach include:

- Voltage regulation throughout the wind plant and the PCC
- Controllable power factor at the PCC

The effectiveness of this approach to regulate the power factor and/or voltage at the point of common coupling (PCC) is plant-specific. The collection system determines how many vars can be injected into the PCC. The maximum amount of reactive power injection at the PCC is equal to the total reactive compensation minus all collection system reactive power losses. This is illustrated inFigure 10-11, which shows the effective impact of the collection system on the aggregate power factor at the substation for a sample wind farm.

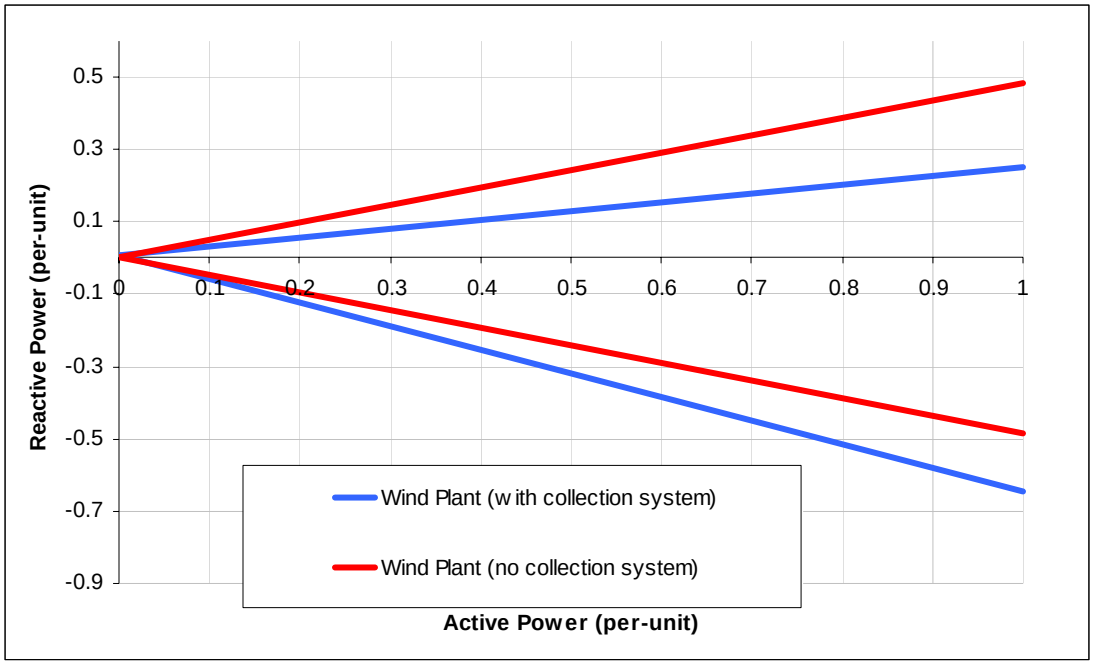


Figure 10-11
Power Factor Curves for Example Wind Plant

This limit may be further reduced due to the voltage profile seen along the collection system feeders. The turbines will inject reactive power into the system, up to the normal operating range of the terminal voltage. The same applies for absorbing reactive power under low-voltage conditions. Therefore, the amount of reactive power injection, or support, at the PCC is determined by both the reactive power losses as well as the WTG voltage profiles. Transformer tap settings also play a significant role in the reactive power curve for a particular plant. Detailed analysis is necessary to determine a plant's full reactive power capability.

Substation Switched Capacitor Banks

Large, switched capacitor banks installed at the interconnect substation are typically utilized in conjunction with switched banks at the WTG terminals. The advantage of this approach is the

relative cost-effectiveness and ability to regulate the voltage and power factor at the point of common coupling (PCC). These capacitor banks are usually sized to hold unity power factor on the primary side of the substation transformer. Optionally, the capacitor banks can be controlled by the utility system operator to switch in or out based upon local system voltages as well.

Note that switched capacitor banks are less effective in extremely low voltage conditions due to the much lower reactive power injection resulting from the lower voltage (reactive power is decreased by the square of the voltage: $Q=V^2/X$).

Switching can be either mechanical, using contactors or circuit breakers, or electronic using thyristors. Figure 10-12 shows an example application in India. This reactive power compensation system includes 600 kVAR of low-voltage thyristor-switched capacitors and 300 kVAR of medium-voltage fixed capacitors for a 2.8-MW (7 x 400 kW WTGs) wind farm. In this case, the thyristor switching provides for a smoother transition of the low-voltage units.



Figure 10-12
Fixed and Switched Capacitor Bank Supporting a 2.8-MW Wind Farm in India
(Source: Crompton Greaves Ltd.)

Switched capacitor banks can have some practical drawbacks. One is that their discrete size, with limited steps and lumped into one location, make compensation less than optimal. Frequent mechanical switching of the bank may create transient disturbances on the system. The control and response of the switching cannot effectively respond to rapid demands for reactive power during system transients.

Switched reactive compensation has become a standard component of wind power plants that employ induction generators. In conventional generation plants (fossil, hydro, and nuclear), the reactive compensation problem is solved by using a synchronous machine, which has built-in reactive power control provided via the generator field current control. The synchronous generator is more difficult to apply in wind power due to the variability of wind turbine output power and speed.

Power Electronic Custom Power Devices

When power electronics are a part of the wind turbine generator, the issue of local reactive compensation is usually solved. This is the case with both the doubly- fed and full-converter wind generators. Both of these converter systems have fast-acting VAR control capability because they employ power electronic conversion to interface the variable-speed turbine with the constant-frequency grid. And reactive compensation is one of the key advantages of these variable-speed conversion systems. However, in most existing wind-farm applications, the WTGs are not variable speed, and this built-in reactive compensation may not be present.

Auxiliary equipment that combines power electronics with capacitors is another solution to reactive compensation and VAR control in these plants. This technology involves devices and circuit configurations of power electronic equipment used in distribution systems rated 1 kV through 38 kV. The IEEE has identified this technology area as *custom power* and recently published a standard to define the different configuration and applications [14].

Custom power devices include static switches, inverters, converters, injection transformers, master control modules, and/or energy-storage modules that have the ability to perform current-interruption and voltage-regulation functions in a distribution system to improve power quality. As shown in Table 10-6, these individual devices may have more than one function, including sag/swell, interruption, reactive power, and harmonic compensation. Voltage regulation is also a direct result of reactive or harmonic compensation.

For wind applications, sag/swell and reactive compensation devices may be used for plant-level reactive compensation. Improved voltage regulation can be obtained from several of these custom power technologies, and a fast response capability may also enhance system stability. The most likely devices for wind plant application are the static shunt compensator (DSTATCOM) and the distribution static VAR compensator (DSVC). Devices that provide fast voltage regulation and voltage-sag compensation such as the static voltage regulator (SVR, also called dynamic voltage restorer or DVR) and the static series compensator (SSC) are also possible solutions.

Table 10-6
Types and Functions of Custom Power Devices per Draft IEEE Standard 1409

Mitigation Device	Sag/Swell Compensation	Interruption Compensation	Reactive (Flicker) Compensation	Harmonic Compensation
Static Series Compensator (SSC)	X			
Static Voltage Regulator (SVR)	X			
Static Transfer Switch (STS)	X	X		
Backup Stored Energy System Devices (BSES)	X	X		X
Static Circuit Breaker (SSB)	X	X		
Static Shunt Compensator (DSTATCOM)	X		X	X
Distributed Static Var Compensator			X	
Distributed Series Capacitor			X	
Series/Shunt Capacitor	X		X	X

Static Shunt Compensator (DSTATCOM)

DSTATCOM is a distribution-class static VAR compensator that can address the reactive power management requirements of both wind systems and nearby dynamic loads. This microprocessor-controlled device utilizes power electronic switches to instantaneously insert the appropriate number of multi-stage power capacitors, providing reactive compensation on a cycle-by-cycle basis. The device is often applied to weak systems to compensate for (relatively) large loads (or wind generators) that cycle on and off and may create irritating flicker. A DSTATCOM can control only voltage or a combination of voltage and power factor. In some cases, the theoretical inrush of an induction motor started on the system can be greater than the available fault current at the point of common coupling. In this case, it is difficult to distinguish between a turbine start and actual fault. Therefore, fault duty and coordination of downstream breakers must be considered in this application.

Figure 10-13 shows a DSTATCOM device that was utilized for a wind farm at Foote Creek, Wyoming. The manufacturer calls it dynamic VAR (or D-VAR), and the technology is based on a superconducting magnet. This system continuously monitors the collector bus voltage of a wind farm to ensure that the voltage remains within the utility's predetermined range. Continuous voltage regulation is accomplished by a combination of VAR injection or absorption from the dynamic VAR system and controlled switching of distribution capacitor banks. In addition, the system mitigates voltage transients at the collector bus that typically originate on the transmission grid and may otherwise cause the wind turbine generators to trip off-line.

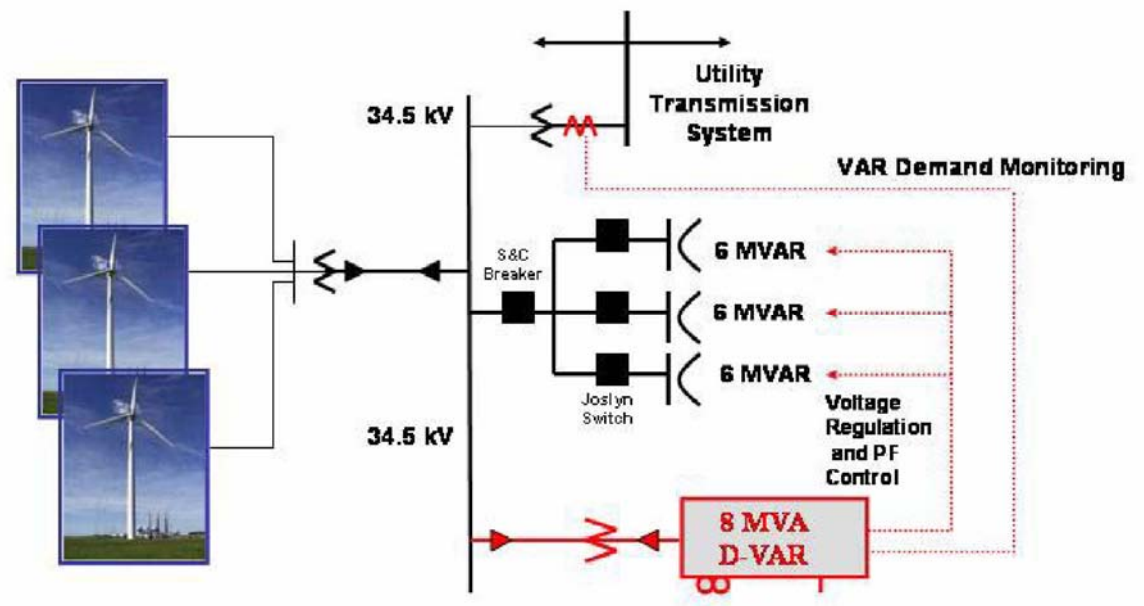


Figure 10-13
Conceptual Layout of a Dynamic VAR Device and Switched Capacitors Supporting a Wind Farm (Source: American Superconductor)

Another type of DSTATCOM uses a voltage-source converter with dc-link capacitor and protects the distribution system from voltage flicker caused by the rapidly varying reactive current draw of nonlinear dynamic loads. It thus enables such problem loads (or generators) to co-exist on the same feeder with more sensitive loads. In effect, this device instantaneously exchanges real and reactive power with the distribution system without the use of bulky capacitors or reactors. ABB, Mitsubishi Electric, S & C Electric, Siemens, and others offer DSTATCOM products.

Distribution Static VAR Compensator (DSVC)

A DSVC is a shunt-connected device with thyristor switching of passive-reactive components (capacitors and reactors) in continuous and/or discrete steps. The device exchanges a continuously-controlled reactive current with the power system to control electrical parameters of the line at the point of common coupling. Typically, the DSVC equipment for distribution applications is used for voltage control, reactive power compensation, and power factor correction.

The DSVC provides ac voltage control by generating and absorbing reactive power using passive elements. It can also be applied in balancing or unbalanced conditions. As shown in Figure 10-14, it is normally constituted by one thyristor-controllable reactor (TCR) and a number of thyristor-switched capacitor (TSC) branches. The value of the reactance of the inductor is changed continuously by controlling the firing angle of the thyristors, while each capacitor is switched on and off at the instants corresponding to the current zero crossings, thus avoiding inrush currents as well as undesirable switching transients. With this arrangement, the SVC can generate continuously variable reactive power in a specified range, and the size of the TCR is

limited to the rating of one TSC branch. Obviously, the size of the reactor limits the power that can be absorbed in the inductive range [15]. There are various versions of this configuration that may be classified as a DSVC.

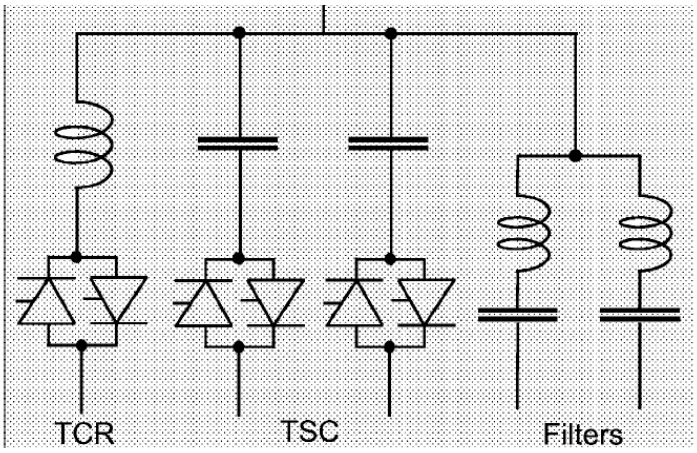


Figure 10-14
Simplified Schematic of a Static VAR (SVC) or Distribution Static Var Compensator (DSVC)

Figure 10-15 shows one example of such a device is the PureWave AVC, a DSVC made by S&C Electric. Although typically applied for heavy commercial and industrial processes with varying electric loads, it may also be effective for a small wind installation with rapidly varying reactive power demand. This DSVA provides real-time voltage support for voltage sags and dips, flicker mitigation, and power-factor correction. By reducing voltage fluctuations and managing reactive power flow, the electric power system stability, reliability, and capacity are increased. The DSVC can enable problem loads to coexist on the same feeder with varying generation and more sensitive loads, obviating the need for separate feeders. Manufacturers such as ABB, Mitsubishi Electric, S&C Electric, Siemens, and Square D offer DSVC products.

A field installation of a small DSVC at a wind site is shown in Figure 10-16. This static VAR compensator was installed in 1997 for a 1.2-MW wind farm in India, comprising 3 x 400 kW WTG. The SVC rating is 180 kVAR of high-voltage fixed capacitors, a 275-kVAR thyristor-switched capacitor, and a 30-kVAR fixed capacitor with 30 kVAR of thyristor-controlled reactor.

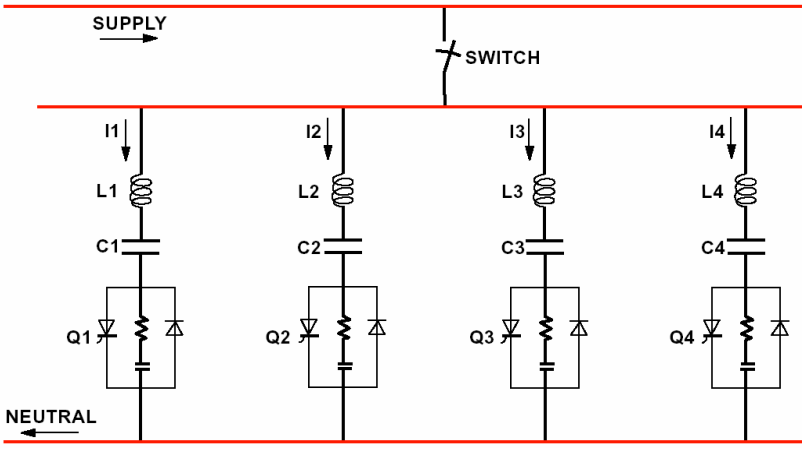


Figure 10-15
Configuration of Commercially Available DSVC Source: S&C Electric



Figure 10-16
Distribution Static VAR Compensator (DSVC) at Wind Site in India
(Source: Crompton Greaves Ltd.)

10.2.4 Wind Energy Forecasting Tools

Today's wind energy market assumes that generation will be intermittent. Various contractual provisions have been devised to handle deviations between forecasted and actual power delivered. Better forecasting tools will directly help with both the *intermittency* and *ramping* characteristics of wind power with positive financial consequences. It is clear that a more accurate wind forecast helps both the buyer and seller of wind energy. From the point of view of the seller, better forecasts will minimize contractual penalties, and higher confidence will maximize the value of the wind power. From the buyer's perspective, accurate wind power forecasts reduce risk and increase power system reliability.

One of the main costs of wind-power intermittency is reserve requirements. This additional reserve is required in order to 1) maintain the same level of control performance in minute-by-minute regulation and 2) minimize any additional operating cost due to the balancing of intra-hour slow variation. Expected limits in control and variability for wind power increase reserve requirements. In the worst case, every unscheduled megawatt must be offset by some other resource, generally at high cost.

Experience with wind energy is evolving better forecasting tools. Better forecasts can reduce the need for reserves and increase the value of wind energy. There are many different components that go into developing an accurate wind power forecast. Prediction of weather, use of statistics, and probabilistic methods are all needed. Even research on new methods involving artificial neural networks [16] has been evaluated. Physical and statistical models are applied to predict the wind with integration of numerical wind prediction information to include local effects and the specific power-producing characteristics of the wind turbines. These required elements are then developed into a system with an accurate wind-power forecast.

Due to the growth in wind generation and the potential value of more accurate power forecasts, this area is expected to significantly evolve in the next few years. Today, there are many wind-power forecasting systems. EPRI has been monitoring and evaluating the latest forecasting technologies for many years. Five wind energy forecasting systems have been of particular interest in the United States: the *Prediktor* Wind Energy Forecasting system developed by Risoe National Laboratory; the *eWind* system developed by AWS Truewind,, LLC, the 3TIER Environmental Forecast Group forecast system; the *WEFS* forecasting system developed by Applied Modeling, Inc.; and the ISET Wind Forecast system from Germany.

These five forecasting systems are similar in some respects, but they use different techniques to forecast the wind speed and direction and corresponding wind-energy generation. Most of the forecast systems share common features. For example generating a 48-hour forecast typically includes the following including some or all of the following:

1. Download numerical weather forecast data from NCEP web site.

2. Calculate wind flow around wind plant using Meso-scale or wind-flow model.

3. Apply model operating statistics (MOS) to estimate adjusted wind speed and direction at wind plant.

4. Estimate hourly power generation at 100% availability using wind plant model.

5. Apply model operating statistics (MOS) to estimate adjusted wind speed and energy generation.

6. Issue 48-hour forecast of hourly wind speed and energy generation.

However, the forecast systems differ with respect how they use physical models and statistical adjustments to predict wind flow patterns and wind energy generation. The blending of physical and statistical models depends on the forecast window, e.g. the forecast interval into the future. Short forecast time intervals up to about six hours typically rely on simple persistence, artificial neural network (ANN), linear regression, and other statistical techniques to forecast weather conditions and wind energy generation. Longer forecast time intervals above four to six hours typically use numerical weather prediction, physical wind flow models, and statistical techniques to predict weather conditions, wind flow patterns near the wind turbines, and wind energy generation.

The five forecasting systems are described in this section as examples of wind-energy forecasting tools that are currently available. Forecasting performance has varied from site to site, and it is therefore difficult to compare forecasting tools used at different sites.

During 2001 to 2003, EPRI collaborated with the U.S. Department of Energy and the California Energy Commission to test and evaluate the forecast performance of three of the forecasting tools at a 75-MW wind project in Texas and at 90-MW and 67-MW wind projects in California. The evaluations measured the monthly and annual mean and mean absolute errors of the 48-hour forecasts of hourly wind speed and wind energy generation to evaluate forecast performance [17][18][19][20][21]. These evaluations showed that meteorology-based forecast systems generate more accurate forecasts than simple climatology models, but that there is room for improvement to reduce forecast errors by using improved numerical weather prediction, wind flow modeling, and statistical tools.

During 2004, EPRI, the California Energy Commission, and the California Independent System (CAISO) Operator initiated a wind energy forecasting project to develop and test a short-term five-minute/three-hour regional forecasting algorithm for integration into the CAISO energy management system to support dispatching of generation resources on the California grid. A second objective was to test advanced numerical weather prediction and wind flow models to improve the accuracy of 48-hour wind energy forecasts. The 18-month project was completed in 2005 [22][23][24][25].

10.2.5 Energy-Storage Technology

Of all the solutions discussed thus far, energy storage has the greatest potential to solve many wind integration issues. The addition of storage can put wind energy more on par with the value of energy from traditional generation. Properly sized, energy storage can address wind energy *intermittency* and *ramping* concerns. Energy storage with fast output power control can also meet the power system's *reactive power* needs and reduce concerns about *fluctuating* wind output.

Even *remote* wind locations, with constrained transmission lines, can be better utilized when energy storage allows scheduling of power flows when transmission capacity is available.

The main issue with energy storage is its cost. Also, there are application challenges for optimizing the power and energy requirements for each specific situation. Of the 10 or 12 viable storage technology options, all have advantages and disadvantages to consider. For example, the larger scale solutions such as pumped storage hydro and compressed air energy storage (CAES) have shown the best economics but may be very difficult to site. More modular technologies, such as batteries and ultracapacitors, are much easier to site but may not store sufficient energy at an affordable price. Higher energy capacity technologies, such as flow batteries, may not provide sufficient power response to meet system ramping requirements. The following sections cover energy-storage value, performance attributes, and comparative costs related to wind-power applications.

Detailed information on the status, commercial and demonstration experience, performance and cost of energy storage technology is presented in the 2003 EPRI report, *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications* (EPRI 1001834, December 2003). A 2004 Wind Application supplement to the *EPRI-DOE Energy Storage Handbook* presented a uniform approach to defining applications and estimating the benefits of energy storage to wind energy.

Energy Storage Applications and Benefits

The intermittent nature of wind power generation creates unique economic challenges for developers when plants are operating in a deregulated environment. One of the basic principles of deregulation is that buyers and sellers of electricity will be able to enter into freely negotiated contracts, months or even years ahead of time. This puts wind generators at a significant disadvantage, due to the high risk associated with guaranteeing “firm” power at the contracted delivery time. From an economic point of view, the intermittency of wind power has become the number one issue for wind integration.

One way to minimize risk and increase wind value is to operate an energy-storage device in parallel with the wind turbine. Appropriate operation of the resulting hybrid system will potentially decrease the trading risk by allowing firm power levels to be achieved. In addition, storage enables optimizations and will help maximize the possible revenue. Such operational capability potentially allows the wind generator to take advantage of price fluctuations and to avoid penalties for missing scheduled deliveries.

This potential for energy storage to directly augment the value of wind energy has been recognized [26][27]. Even so, it is likely that more than one benefit will be needed to make an energy-storage investment cost-effective. Wind energy arbitrage, ancillary service, firming and shaping, spillage or curtailment reduction, and T&D investment deferral are all potential value adders of energy storage. Benefits and opportunities are very site- and market-specific and may also change over time. The full spectrum of potential benefits should be considered when assessing the merits of combining energy storage with wind power. The choice to participate in one market may preclude others. Economic dispatch of the stored energy can be a critical and rather complex problem, requiring both speculation and real-time decision making.

Arbitrage Benefits

Wind energy sold into bulk electricity markets often receives lower-than-average energy value. One reason is that errors in forecasting wind can lead to substantial energy imbalance penalties. Because energy storage allows for shifting wind output over time, it mitigates wind forecasting errors or delivers energy at a time when electricity prices are higher. The latter provides an energy arbitrage value to the wind storage system. As reported by TVA [28], arbitrage benefits increase when there is daily volatility in energy market prices. Higher peak energy prices increase storage benefits, but higher off-peak energy prices decrease storage benefits. TVA also found that if storage is used for only arbitrage, there is no optimal ratio of storage capacity to wind-production capacity. The desired sizes of wind power and storage capacity can be chosen based on individual merits, separately determined.

Ancillary Services Benefits

In these early days of power system deregulation, markets and prices for ancillary services have varied significantly. Spot market prices for regulation and reserves have often exceeded the coincident prices for energy. These potentially lucrative service markets have not been available to wind generators because of the intermittency of wind resources. However, energy storage will enable wind energy to participate in the ancillary services market. A storage sub-system, which can change output immediately and has very low operating cost when idle, is especially well suited to supply reserves and regulation in addition to providing energy arbitrage.

One requirement for using a wind and storage system for ancillary services is that the system is on-line fulltime and available to respond quickly and reliably to orders for these services. Several different types of storage batteries can charge and discharge fast enough to provide frequency regulation. On-line storage can also provide spinning reserve and black start services. Inverter-connected energy-storage systems may be capable of providing voltage regulation services by making use of the kVAR rating of the inverter. The potential exists for a wind and storage system to provide useful fulltime ancillary support service during charging and during discharging, providing regulation, contingency reserve, or simply for providing green energy to the grid.

In another TVA study [25], the potential for using energy storage in different ancillary service markets was evaluated. Figure 10-17 shows the annual total operating benefits for three ISOs. Results reflect the prevailing and varying prices in each market.

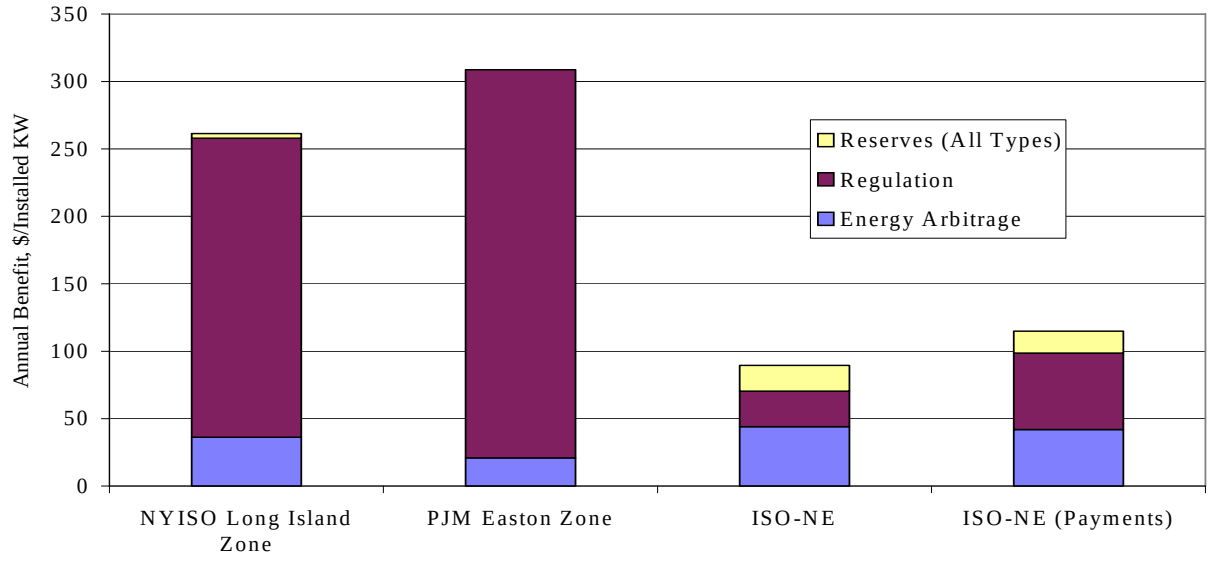


Figure 10-17
Storage Operating Benefits in Different Ancillary Services Markets

In this case, prices in ISO-NE were significantly different from the other two markets. Regulation provides the dominant benefit in PJM and NY-ISO. For ISO-NE, the regulation benefit is much smaller than in the other markets, but it is still substantial. The benefit available by providing reserves was noticeable only in the ISO-NE case. The need for reserves varies significantly in different areas of the country.

TVA found that if other benefits in addition to clearing price for ancillary services were taken into account, then the value can be significantly affected. ISO-NE was investigated because necessary data were available and because other benefits in ISO-NE were much lower than in the other two ISOs. The results for this case are labeled in the figure as "ISO-NE (Payments)." In this case, accounting for the other payments increased the overall benefits by 30%. A test case was run to estimate the impact of the decline in regulation prices in the NYISO during the period of analysis. As might be expected, the sensitivity of ancillary values to changing market prices was found to be high. Overall, ancillary service markets for energy storage offer excellent value-added potential. However, financing based on ancillary services alone is unlikely due to potential price volatility.

Other Energy Storage Benefits

Energy storage used for firming and shaping will allow more of the wind-generated energy to be sold as firm energy by better matching wind output with daily load variations. The value of this application of energy storage is the difference in market price between firm and non-firm energy.

Curtailment of wind generation and related spillage of wind resources in constrained power systems can be avoided when energy storage is applied. The condition that causes wind generation to be curtailed during certain periods may be related to time of day or contingency limits on the transmission or related to the required margins for load following and regulating

generation. The value provided by energy storage in these cases is the capture of wind energy that would otherwise be lost, as well as any related green power and production tax credits.

Closely related to curtailment avoidance is the value associated with substation or transmission investment deferral. Here, energy storage allows scheduling of the power to periods when assets are not heavily loaded, thus improving asset utilization and deferring the need for upgrades or expansions.

Finally, in some cases energy storage has been considered as a way to help stabilize real and reactive power flow variations related to wind power. Energy storage must have fast response, using a power electronic interconnection, combined with relatively high power capacity storage, can mitigate voltage fluctuations that may be associated with fluctuating wind power output. Such energy storage applications may have high value in solving localized stability and light flicker problems.

Energy Storage Attributes and Costs

Despite the various possibilities for added value from energy storage in wind power, application experience has been very limited. There are two main reasons for this current situation. One is that electric energy storage in a convenient form, such as batteries, is relatively expensive, typically tens to hundreds of dollars per unit kWh storage capacity, or even thousands of dollars in short duration power quality applications [30]. The second is that the electric utility grid has served as a large-scale energy balancing and redistribution system for intermittent wind energy. The grid also provides some level of damping for fluctuating wind power. Although it is effective, balancing, redistribution, and damping capacity of the grid, are limited, and it incurs a cost in operating the power system. As the penetration of wind generation grows, or in cases where the grid is relatively weak, energy storage will find new applications. Both the longer-term high energy capacity storage for daily energy shaping, and the short term, high-power capacity storage for system stabilization, may be applicable.

A growing number of energy storage technologies are becoming available for these applications. In particular new types of enclosed batteries, being developed for the electric vehicle and portable electronics industries, may be applicable to wind power. Also, because wind plants are considered stationary applications and do not restrict size and weight, several larger-scale energy storage technologies including pumped storage, compressed air, and large flow batteries are good candidates. These larger systems may provide a needed economy of scale and better serve large wind farm. In cases requiring both long-term energy and short-term stabilization, hybrids may be considered.

Table 10-7 lists the candidate energy storage technologies, including advantages, disadvantages and examples of manufacturers.

Table 10-8 compares the key performance and cost factors of these candidate technologies. The comparison includes both long-term and short-term wind power applications. Long term is an eight-hour capacity, with daily cycling to follow the system load, and short-term is two-second charging and discharging to meet wind power stabilization requirement. The initial cost per kWh of each technology is based on existing plant costs and ratings or is projected for new technologies based on the expected relative cost and performance. Several conclusions can be drawn from this table.

- Currently for the enclosed batteries, only NAS looks like a possible cost-effective solution for firming and shaping wind energy. The key issues for other battery types are limited DOD and short life expectancy or high initial cost.
- From the flow battery technologies, VRB looks promising because of relatively high-cycle life and scalability.
- CAES and pumped hydro provide and excellent match with wind energy by providing lower initial cost and higher storage capacities to account for the 30 to 40% wind plant capacity factor. Also their larger scale and long life are a good match for today's large scale wind farms.

Short-term energy storage technologies that fit wind stabilizing applications show relatively low initial cost. However, for this application, energy storage must compete with other solutions such as improved turbine output controls, fast response of turbines employing power electronics, and a natural mitigation of fluctuations that comes from the diversity of large numbers of wind turbines operating simultaneously.

In addition to the initial and life cycle costs, key factors for applying these energy storage technologies to wind applications are power and energy performance, usable charge and discharge cycles, and reliability. Figure 10-18 is a simple model that shows the separation of the charge and discharge equipment. In this model the charge and the discharge durations can also be designed independently. Since wind power typically has a capacity factor of 30 to 40%, it is not unusual that the charging system may be rated higher than the discharging system. This allows capturing the wind energy during a short period. Also, large storage capacity will allow effective operation during periods of low wind production.

This model addresses the main performance considerations of separately designing power and energy requirements. For example, as shown in the figure, the system performance may benefit from the power rating being independent of energy capacity. Also charging may involve different converter equipment, and a longer period, than discharging. Available ancillary services, such as frequency regulation or spinning reserve, may require that the discharge converter be on line and independent of the charging converter.

Table 10-7
Advantages and Disadvantages of Candidate Energy Storage Technologies to Support Wind Power Energy Intermittency and Output Fluctuations

	Technology	Advantages	Disadvantages	Manufacturers
Independent Operating Electric Storage Technology	Vented Lead-Acid (PbA Default)	Mature and well-known Low initial cost Long life	Coup de fouet Relatively intolerant of temperature extremes	Enersys GNB (Exide)
	Valve-Regulated Lead-Acid	Low maintenance Low initial cost	Coup de fouet Intolerant of temperature extremes, Short life	C&D Technologies Hawker Energy (Enersys)
	Vented Nickel-Cadmium (Ni-Ca)	Mature and well-known Long life, Relatively tolerant to temperature extremes	Low cell voltage Float effect makes, capacity testing difficult	Saft Alcad
	Lithium ion batteries	High energy density Long life	Relatively untested, High initial cost (at present), Requires balancing and charge control electronics	Valence Johnson Controls (formerly Varta)
	Lithium metal polymer batteries	High energy density Tolerant to temperature extremes	Relatively untested, High initial cost (at present), Requires balancing and charge control electronics, one source	Avestor
	Nickel-Metal Hydride (Ni-MH)	High energy density, possible cycle life advantage over PbA	Low cell voltage Intolerant of temperature extremes, Float effect makes capacity testing difficult	Johnson Controls (formerly Varta) Electro Energy
	Vanadium Redox (VRB)	Relatively high energy for large system Power and energy rating is independent	Single manufacture and limited sources for Vanadium, Not yet proven for cycle life or maintenance costs	VRB Power Systems
	Compressed Air (CAES)	Mature technology, long life, Low cost for large scale Power and energy independent	Requires suitable site geology, may have ramp rate limit Large scale requires large capital investment and collaborations	For main Turbo-expander, Alstom, Dresser-Rand, Sulzer
	Pumped Hydro	Mature technology, long life, Low cost for large scale Power and energy independent	Requires suitable site geology, difficult environmental, large scale requires large capital investment and collaborations	For systems, Gugler GmbH, Sulzer, North Am. Hydro, Water Alchemy, Harris
	Sodium sulfur batteries (NAS)	High energy density	Relatively new and untested, High initial cost (at present), Single manufacture	NGK Insulator

Table 10-7 (continued)
Advantages and Disadvantages of Candidate Energy Storage Technologies to Support Wind Power Energy Intermittency and Output Fluctuations

	Technology	Advantages	Disadvantages	Manufacturers
Hybrid Pairs	Zinc-bromine batteries, (needs Power partner)	High energy density Flat voltage profile	Relatively unknown and untested, Mechanical parts require maintenance May require occasional stripping cycles, Single manufacture	ZBB Energy
	Regenerative zinc-air, (needs power partner)	High energy density	Relatively unknown and untested, Voltage drop at start of discharge, Limited shelf and cycle life, Single manufacture	Metallic Power
Short Term Stabilizer	Ultracapacitors	High current density, for short-term power, high cycle life	High initial cost (at present), Relatively low energy density, stacking limitation TBD	Maxwell, NESS Capacitor, EPCOS, ESMA, NEC, etc
	Flywheels	High current density, for short-term power, High cycle life	Relatively high initial cost per kWH, Low energy density	Active Power, Beacon, Hitec, Piller, Pentadyne, Teledyne, Urenco

Table 10-8
Performance and Cost Comparison of Energy Storage Technologies to Support Wind Energy Intermittency and Output Power Fluctuations

Energy Storage Options for Wind Plant Applications	Plant Energy MWh	Plant Power MW	Energy W-H/kg† @ ~8 Hr	Power W/kg† @~2sec	Energy Used DOD††	Cycle Life†† # at DOD	Cost $††† /kWh	Cost $††† /kW	Cycle eff. RT
- Daily Cycles/Shaping (8-Hours) -									
Batteries (enclosed)									
Lead-Acid (PbA)	16-80	2-10	30-40	400-600	80%	1000	402	1800	70%
Nickel-Cadmium (Ni-Cd)	16-80	2-10	30-55	400-600	80%	3500	865	3600	65%
Lithium Ion (Li ion)	16-80	2-10	100-200	200-500	80%	3000	1417	6800	75%
Sodium-Sulfur (NAS)	16-80	2-10	125-200	n/a	90%	4500	370	2000	75%
Nickel Metal Hydride (Ni-MH)	16-80	2-10	60-80	150-200	80%	3000	1250	5200	65%
Batteries (flow)									
Vanadium Redox (VRB)	16-80	2-10	n/a	n/a	100%	3000	411	2300	70%
Zinc-Bromine (Zn-Br)	16-80	2-10	n/a	n/a	100%	2000	467	2800	75%
Compressed Air (CAES)	1600	50-200	n/a	n/a	100%	25 years	75	450	75%
Pumped Hydro (small)	1600	50-200	n/a	n/a	varies	25 years	221	1500	85%
Pumped Hydro (large)	8000	1000	n/a	n/a	varies	50 years	125	900	90%
- Short-Term Stabilization (2-seconds) -									
Lead-Acid (PbA)	0.01	2-10	30-40	400-600	3%	2000	1000's	250	70%
Flywheels	0.01	2-10	2-3	400-800	75%	>10000	1000's	250	85%
Ultra Capacitors (EC)	0.01	2-10	5-10	1500	75%	>10000	1000's	500	90%

Notes:

† Many factors affect specific energy and power for enclosed ES systems such as batteries or capacitors. There are always tradeoffs of energy or power, and other factors such as electrod design, depth of discharge (DOD), operating temperature, age, and abuse affect performance of both.

†† For this application it is assumed that the number of cycles should not be less than 1000 (~3 years life) and 6600 cycles (~20 years life) is desirable. With most batteries and some capacitors life depends on DOD, therefore, in these cases DOD is selected to correspond to the technology life expectancy. Also, limiting DOD reduces available plant energy and, in this analysis, the reduction has been compensated by specifying more storage capacity in the system.

††† The costs are based primarily on initial investment or $/kW and some technology experience and economy of large scale production is assumed. The cost/kWh is calculated by the largest plant MW rating, and both DOD and RT efficiency are included. Life cycle costs, including battery replacements, and O&M costs are not considered.

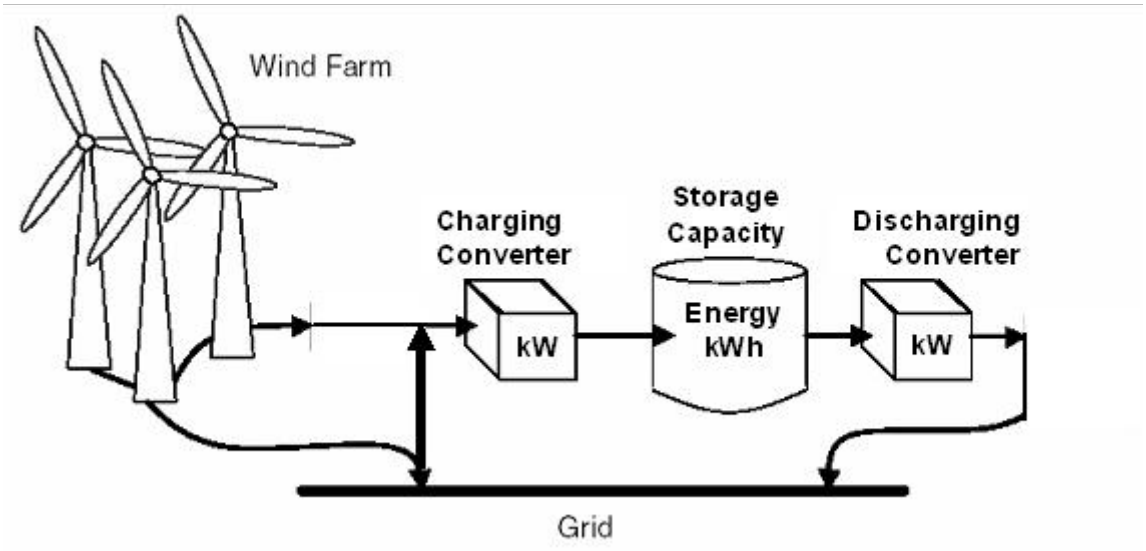


Figure 10-18
Model for Evaluation of Energy Storage with Wind Power

In the future, energy storage will be an increasingly important component of wind plant applications as wind penetration increases, costs of wind intermittency are recognized, and as the costs of available energy storage technologies are reduced. Wind-storage applications are expected to be most needed when wind power is installed in relatively weak power systems, such as remote or island sites, and when the cost of electric energy is relatively high. Because of the relatively large scale of wind plants and the need to meet daily load cycles, long-term and scalable energy storage technologies are most likely for wind applications. These technologies need to be scalable and to clearly benefit from economies of scale. Examples are CAES, Pumped Hydro, VRB, and low-cost batteries such as lead acid.

Short-term energy storage technologies for stabilization of wind fluctuations are not likely to find practical applications in wind plants anytime soon. The current costs of these technologies, typically thousands of dollars per kW, are not likely justified by the wind power fluctuation issue. Short-term energy storage for stabilization competes directly with other solutions including, the grid's ability to absorb fluctuation energy, improvement in wind turbine output controls for mitigating fluctuations, the diversity and smoothing effects of many wind turbines in the same general vicinity, and other power electronic equipment such as the DSVC.

10.3 References

10.3.1 Endnotes

1. *Wind Report 2004*: E.ON Netz GmbH, Bayreuth, Germany. 2004, updated by "German Renewable Energy Sector Shows Impressive Growth," *Greenprices*, January 24, 2007.

2. *Study of Electric Transmission in Conjunction with Energy Storage Technologu*: Lower Colorado River Authority, Austin, TX, Ridge Energy Storage & Grid Services, Austin, TX, RnR Engineering, Austin, TX, and Walter J. Reid Consulting, Ausitn, TX. August 2003.

3. Giovanni, Dan, *Wind Energy in the Big Island*: Hawaii Electric Light Company, Hilo, HI. Presented at USDOE/DBEDT Forum. April 2002.

4. Brooks EDL, Smith J, Pease J, McGree M. "Assessing the Impact of Wind Generation on System Operations at Xcel Energy-North and Bonneville Power Administration." *Windpower 2002*. AWEA Washington, D.C.

5. Brooks, D., Lo, E., Zavadil, R., Santoso, S., Smith, J. "Characterizing the Impact of Significant Wind Generation Facilities on Bulk Power System Operations Planning." UWIG, May 2003.

6. Dragoon, K., Milligan, M. "Assessing Wind Integration Costs with Dispatch Models: A Case Study." *Windpower* 2003, Austin, TX.

7. Hirst, E. "Integrating Wind Energy with the BPA Power System: Preliminary Study." Prepared for BPA Power Business Line, September 2002.

8. Hirst, E. "Integrating Wind Output with Bulk Power Operations and Wholesale Electricity Markets." *Wind Energy* 5(1) 2002. pp. 19–36.

9. Electrotek Concepts, Inc. "Systems Operations Impacts of Wind Generation Integration Study." Prepared for We Energies, June 2003.

10. United States Patent #5,083,039, Variable Speed Wind Turbine, Richardson et al. issued January 21, 1992.

11. Asplund G. et al. "DC Transmission Based on Voltage Source Converters." CIGRE Session 1998 paper No 14-302.

12. Grainger, W. and Jenkins, N. "Offshore Wind Farm Electrical Connection Options." British Wind Energy Association, 2002

13. Torbjörn Thiringer et al. "Grid Disturbance Response of Wind Turbines Equipped With Induction Generator and Doubly-Fed Induction Generator." Chalmers University of Technology, IEEE T&D Dallas, September 2003.

14. IEEE Draft Trial-Use Guide for Application of Power Electronics for Power Quality Improvement on Distribution Systems Rated 1 kV through 38 kV, P1[409], D10, September 5, 2003.

15. Ambra Sannino, Jan Sversson, Tomas Larsson, "Power-Electronic Solutions to Power Quality Problems." *Electric Power Systems Research* 66 (2003) 71-82, Department of Electric Power Engineering, Chalmers Univ. of Technology, Gothenburg, Sweden.

16. *Short-Term Wind Generation Forecasting Using Artificial Neural Networks*, Report 1009219, EPRI Palo Alto, CA: October 2003.

17. *California Wind Energy Forecasting System Development and Testing Phase 1: Initial Testing,* California Energy Commission, Sacramento CA, EPRI Palo Alto, CA: 2002. 1003778.

18. *California Wind Energy Forecasting System Development and Testing Phase 2: 12-Month Testing,* California Energy Commission, Sacramento CA, EPRI Palo Alto, CA: 2003. 1003779

19. *Texas Wind Energy Forecasting System Development and Testing Phase 1: Initial Testing,* EPRI Palo Alto, CA, U.S. Department of Energy, Washington D.C.: 2003. 1008032.

20. *Texas Wind Energy Forecasting System Development and Testing Phase 2: 12-Month Testing,* EPRI Palo Alto, CA, U.S. Department of Energy, Washington D.C.: 2004. 1008033.

21. *Wind Energy Forecasting Applications in Texas and California*. EPRI Palo Alto, CA: 2003. 1004038.

22. *California Regional Wind Energy Forecasting System Development, Volume 1: Executive Summary,* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013262.

23. *California Regional Wind Energy Forecasting System Development, Volume 2: Wind Energy Forecasting System Development and Testing and Numerical Modeling of Wind Flow over Complex Terrain,* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013263.

24. *California Regional Wind Energy Forecasting System Development, Volume 3: Wind Tunnel Modeling of Wind Flow over Complex Terrain,* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013264.

25. *California Regional Wind Energy Forecasting System Development, Volume 4: California Wind Generation Research Dataset (CARD),* EPRI Palo Alto, CA, California Energy Commission, Sacramento, CA: 2006. 1013265.

26. Andrew Cruden and Graham J. W. Dudgeon. *Opportunities for Energy Storage Devices Operating with Renewable Energy Systems.* EESAT 2000, September 18–20, Orlando Florida.

27. Goren Strbac, Graeme N.Bathurst, and Nick Jenkins. *Integration of Renewable Generation into the UK Market—Opportunities for Energy Storage*. EESAT 2000, September 18–20, Orlando Florida.

28. Robert E. Taylor and Joseph J. Hoagland, *Using Energy Storage With Wind Energy for Arbitrage*, EESAT 2002, April 15–17, 2002 San Francisco California.

29. R. Taylor, J. Hoagland, D. Bradshaw. *Energy Storage for Ancillary Services*, EESAT 2002, April 15–17, 2002 San Francisco California.

30. T. Key, H. Kamath, Electric Energy Storage: Will it Help Enable DE, Primen Perspective on Distributed Energy, Primen, DE-PP-23, August 2003.

10.3.2 General

Wind Power Integration Assessment and Case Studies. EPRI, Palo Alto, CA: March 2004. 1004806

EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications), EPRI, Palo Alto, CA, U.S. Department of Energy, Washington, D.C.: December 2003. 1001834.

Norris, B., *EPRI Energy Storage Handbook: Wind Energy Storage Applications*, Gridwise Engineering Co., Danville, CA: February 2003.

Technical Assessment Guide–Storage, EPRI, Palo Alto, CA: December 2000. 1001203.

10.3.3 Renewable Generation Grid Impacts and Integration

Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning: Utility Wind Interest Group - Xcel Energy-North Case Study, Utility Wind Interest Group, Reston, VA, EPRI, Palo Alto, CA. December 2003. 1004807

Wind Report 2004: E.ON Netz GmbH, Bayreuth, Germany. 2004.

10.3.4 Battery Energy Storage

Assessment of Advanced Batteries For Energy Storage Applications in Deregulated Electric Utilities, EPRI, Palo Alto, CA: 1998. TR-111162.

Lessons Learned from the Puerto Rico Battery Energy Storage System, Sandia National Laboratories, Albuquerque, NM: 1999. SAND99-2232.

Benjamin L. Norris, Greg J. Ball, *Utility Test Results of a 2-Megawatt, 10-Second Reserve-Power System*, Sandia National Laboratories, Albuquerque, NM: 1999. SAND99-2570.

TD. Berndt, *Maintenance Free Batteries*, 2nd ed., Research studies Press Ltd., Taunton, Somerset, England: 1997.

William E. Jones and David I. Feder, “Float Behavior of VRLA Cells: Theory vs. Reality,” paper 7-4, Proceedings 17th Int. Telecom Energy Conference, The Hague, Netherlands: 1995.

Battery Energy Storage for Utility Applications: Phase I—Opportunities Analysis, Sandia National Laboratories, Albuquerque, NM: 1994. SAND94-2605.

Chino Battery Energy Storage Plant, Vol. 1 EPRI, Palo Alto, CA: 1993. TR-101787.

Chino Battery Energy Storage Plant: First Year of Operation, EPRI, Palo Alto, CA: 1993. TR-101786.

Development of Zinc-Bromine Batteries for Utility Applications: Commercialization Task, EPRI, Palo Alto, CA: 1991. GS-7093.

Design and Costs for a Generic 10-MW Utility Lead-Acid Battery Energy Storage Plant, EPRI, Palo Alto, CA: 1988. AP-5845.

10.3.5 Compressed Air Energy Storage

Hybrid Plants for Power Generation in the Uninterruptible Power Substation, Phase I, EPRI Report, to be published.

Transient Analysis of Hybrid Plants—Hybrid Plants for Power Generation in the Uninterruptible Power Substation, Phase II, EPRI Report, to be published.

Hybrid Plants for Power Generation in the Uninterruptible Power Substation, Phase III, EPRI Report, to be published.

Compressed Air Storage with Humidification: An Economic Evaluation, EPRI, Palo Alto, CA: 1998. TR-111691.

Standard Compressed Air Energy Storage Plant: Design and Cost, EPRI, Palo Alto, CA: 1994. TR-103209.

History of First U.S. Compressed Air Energy Storage (CAES) Plant, EPRI, Palo Alto, CA: 1993. TR-101751, Vols. 1 & 2.

Proceedings: Second International Conference on Compressed Air Energy Storage, EPRI, Palo Alto, CA: 1993. TR-101770.

Compressed Air Storage with Humidification (CASH) Coal Gasification Power Plant Investigation, EPRI, Palo Alto, CA: 1991. GS-7453.

Recuperators for Compressed Air Energy Storage Plants, EPRI, Palo Alto, CA: 1989. GS-6571.

10.3.6 Pumped Hydro Energy Storage

"Existing Capacity and Planned Capacity Additions at U.S. Electric Utilities by Energy Source and State—1999," U.S. DOE, http://www.eia.doe.gov/cneaf/electricity/ipp/html1/t17p01.html.

"The Comprehensive Electricity Competition Act: A Comparison of Model Results—Appendix B: CECA Competitive Case: Deta Forecasting Products," U.S. DOE, http://www.eia.doe.gov/oiaf/servicerpt/ceca/apb.html.

Annual Energy Outlook 2001, Reference Case Tables Forecasting Products, U.S. DOE, http://www.eia.doe.gov/oiaf/aeo/earlyrelease/aeotab_9.htm.

Pumped Storage Planning and Evaluation Guide, EPRI, Palo Alto, CA: January 1990. GS-6669.

Compendium of Pumped Storage Plants in the United States, American Society of Civil Engineers: 1993. ISBN: 0-87262-991-0.

Hydroelectric Pumped Storage Technology: International Experience, American Society of Civil Engineers: 1996. ISBN: 0-7844-0144-6.

10.3.7 Flywheel Energy Storage

A Summary of the State of the Art of Superconducting Magnetic Energy Storage Systems, Flywheel Energy Storage Systems, and Compressed Air Energy Storage Systems, Sandia National Laboratories, Albuquerque, NM: 1999. SAND94-1854.

Abacus Technology Co., An Assessment of Flywheel Energy Storage Technology for Hybrid and Electric Vehicles, for the U.S. Department of Energy, Office of Transportation Technologies, Electric and Hybrid Propulsion Division: July 1996.

Utility-Size Flywheel Energy Recovery and Storage System (FERS) Feasibility Study, EPRI, Palo Alto, CA: 1989. RP 1084-20.

Draft Report on Current Status of Flywheel Energy Storage, EPRI Internal Draft Report, EPRI, Palo Alto, CA: November 1995.

Flywheels for Electric Utility Energy Storage, EPRI, Palo Alto, CA: 1999. TR-108889.

10.3.8 SMES

W. Buckles and W. V. Hassenzahl, "Superconducting Magnetic Energy Storage," *IEEE Power Engineering Review*, Vol. 20, No. 5, pp. 16-20: May 2000.

An Assessment of High Temperature Superconductors for High Field SMES Systems, EPRI, Palo Alto, CA: 1999. TR 110719.

A Summary of the State of the Art of Superconducting Magnetic Energy Storage Systems, Flywheel Energy Storage Systems, and Compressed Air Energy Storage Systems, Sandia National Laboratories, Albuquerque, NM: 1999. SAND94-1854.

J. T. Steiger, G. Fuchs, P. Verges, K. Fischer, L. Schultz, and A. Gladun, "Critical Current in Silver Sheathed Bi-2223 Tapes," IEEE Trans. Appl. Supercon. 7, 1347: 1997.

M. A. Green, R. A. Byrns, and S. J. St. Lorant, "Estimating the Cost of Superconducting Magnets and the Refrigerators Needed to Keep Them Cold," *Advances In Cryogenic Engineering*, Vol. 37, Plenum Press, New York: February 1992.

J .E. Dagle, J. G. De Steese, M. K. Donnelly, and D. J. Trudnowski, *Evaluation of Superconducting Magnetic Energy Storage at Blythe*, prepared for San Diego Gas and Electric, Battelle, Pacific Northwest Labs, Richland, Washington: July 1995.

John H. Doudna, *Analysis of Benefits from Superconducting Magnetic Energy Storage on the ML&P System*, Interim Report No. 3: April 1995. PTI Report No. R4-95.

11
GREENHOUSE GAS EMISSIONS CONTROL

11.1 Greenhouse Gases

Several greenhouse gases are known to contribute to humanity's effect on the radiation balance in the atmosphere and, hence, on global temperature and potential climate change. The greenhouse gases of concern include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and certain chlorofluorocarbons (CFC) that react with and deplete the ozone layer. The estimated lifetimes of these gases in the atmosphere before they oxidize to carbon dioxide and their infrared absorbing strengths vary. Table 11-1 compares the lifetimes in the atmosphere and the infrared absorbing strengths of greenhouse gases relative to carbon dioxide as a function of time.

Table 11-1
Lifetimes in the Atmosphere and Relative Infrared Absorption Strengths of the Greenhouse Gases

Gas	Lifetime in the Atmosphere	Infrared Absorbing Strength per Unit Mass vs. CO_2		
		20-year	50-year	100-year
Carbon Dioxide (CO_2)	Variable	1	1	1
Methane (CH_4)	12 (±3) Years	56	21	7
Nitrous Oxide (N_2O)	120 Years	280	310	170
Chlorofluorocarbons (CFCs)	Not Given	4,900	3,800	Not Given

Source: U.S. DOE EIA, "Emissions of Greenhouse Gases in the U.S. 1996" October 1997.

Over a 50-year timeframe, methane absorbs 21 times as much infrared radiation as an equal mass of carbon dioxide. Thus, we say that the *infrared absorbing equivalent* of a ton of methane released by a landfill is 21 tons of carbon dioxide. Similarly, the infrared absorbing equivalents of a ton of nitrous oxide and a ton of chlorofluorocarbons are 310 tons and 3,800 tons of carbon dioxide, respectively.

11.2 Role of Renewable Energy Technology

Renewable generation technologies typically produce no direct emissions of fossil fuel carbon dioxide, methane, or other greenhouse gases, and can be used to offset greenhouse gas emissions by the fossil-fuel-fired component of the system generation mix. Consequently, renewable energy can be considered to be a greenhouse gas emissions reduction technology as well as a renewable energy power technology. In addition, should greenhouse gas emission reduction mandates be enacted in the future, renewables would become an important component of a greenhouse gas emissions reduction strategy and would likely play a key role in carbon dioxide emissions trading.

The carbon dioxide emissions reduction potential of a renewable energy power plant is a function of the fuel mix of the existing generation system. The effective carbon dioxide emissions reduction cost is a function the CO_2 emission rate and the difference between the average generation costs of the base system and those of the renewable energy power plant.

11.3 Fossil Carbon Intensity of Fuels

The carbon intensity of generation technologies is measured by the carbon emissions released by burning a fuel to generate a megawatt hour of electricity. It depends on the carbon and heat contents of the fuel as well as the net thermal efficiency of the power generation technology.

Table 11-2 compares the fuel heat and carbon contents with the fossil carbon intensity of coal, oil and natural gas. Dry wood is included in the table to highlight the zero carbon intensity of sustainably-grown biomass fuel. The data are presented in units of mass of carbon released per unit of fuel in both mass and higher heating value (HHV) heat content units. Sub-bituminous coal has the highest carbon intensity per unit energy content (27.77 kg carbon/GJ) and natural gas has the lowest fossil carbon intensity (13.8 kg carbon/GJ).

Table 11-2
Fossil Carbon Intensity of Coal, Oil, Natural Gas and Wood Fuels

Fuel Type	Heat Content—HHV		Carbon Content		Fossil Carbon Intensity	
	(Btu/lb)	(MJ/kg)	(lb-C/lb)	(kg-C/kg)	(lb-C/MBtu)	(kg-C/GJ)
Coal: Bituminous	13,700	31.798	0.782	0.782	57.08	24.59
Coal: Sub-bituminous	9,000	20.889	0.580	0.580	64.44	27.77
Oil	20,000	46.420	0.92	0.92	46.0	19.8
Natural Gas	23,400	54.311	0.75	0.75	32.1	13.8
Wood (dry)	8,000	18.568	0.45	0.45	0*	0*

*Note: Fossil carbon intensity is the measure relevant to greenhouse gas. By this measure, wood from renewable growth of trees has zero carbon intensity. If the carbon content of the fuel were put into the same formula used for fossil fuels, the carbon intensity of wood is 54.2 lb-C/Mbtu (23.4 kg-C/GJ).

Table 11-3 compares the impacts of fuel carbon content and technology net heat rate to the fossil carbon intensity of selected coal- and natural-gas-fired generation technologies. The data are presented in units of mass of CO_2 and carbon (C) released per megawatt-hour of electricity generated. Existing coal-fired power plants operating at 34.1% thermal efficiency (HHV) exhibit the highest generation carbon intensity per megawatt-hour generated (0.26 metric ton C/MWh) while advanced, natural gas fuel cell plants operating at 63.7% net thermal efficiency exhibit the lowest generation carbon intensity (0.08 metric ton C/MWh) (Note that one metric ton = one tonne).

Table 11-3
Carbon Intensity of Generation Technologies

Fuel— Technology (Net HHV Efficiency) English Units:	Carbon Content (lb/MBtu)	Net Heat Rate (Btu/kWh)	Fossil Carbon Emission	
			CO_2 (ton/MWh)	C (ton/MWh)
Coal				
Typical existing (0.341)	56.7	10,000	1.04	0.28
Pulverized, 95% scrubbed (0.376)	56.7	9,087	0.94	0.26
Advanced, IGCC (0.467)	56.7	7,308	0.76	0.21
Natural Gas				
Existing Steam Plant (0.331)	32.1	10,300	0.61	0.17
Advanced, CC (0.538)	32.1	6,350	0.37	0.10
Advanced, CT (0.427)	32.1	8,000	0.47	0.13
Advanced, fuel cell (0.637)	32.1	5,361	0.32	0.09
SI Units:	**Carbon Content (kg/GJ)**	**Net Heat Rate (kJ/kWh)**	**CO_2 (tonne/MWh)**	**C (tonne/MWh)**
Coal				
Typical existing (0.341)	24.43	10,550	0.95	0.26
Pulverized, 95% scrubbed (0.376)	24.43	9,587	0.86	0.23
Advanced, IGCC (0.467)	24.43	7,710	0.69	0.19
Natural Gas				
Existing Steam Plant (0.331)	13.83	10,867	0.55	0.15
Advanced, CC (0.538)	13.83	6,699	0.34	0.09
Advanced, CT (0.427)	13.83	8,440	0.43	0.12
Advanced, fuel cell (0.637)	13.83	5,656	0.29	0.08

Source: Ref. 5 (“EIA Kyoto”), Tables 16, 17 (pages 73-75), U.S. DOE, October 1998.

11.4 CO_2 Emissions Offsets

11.4.1 Factors Affecting CO_2 Emissions Offset

Calculation of the CO_2 emissions offset resulting from adding wind, solar, and other renewable generation to a utility system at first appears to be straightforward and uncomplicated. However, several indirect factors complicate the calculation and typically result in actual net CO_2 emissions offsets that are lower than those estimated using the straightforward levelized method presented below. These factors include:

- Renewable generation penetration into the generation mix
- Renewable generation duty cycle characteristics
- Hydro, pumped storage, and peaking capacity in existing generation mix
- Impacts on the dispatch and annual capacity factor of each component of the generating mix
- Possible increased cycling of baseload coal and gas units
- Increased spinning reserves for load following and regulation.

The impacts of these factors vary with the renewable generation type and grid characteristics and tend to be greatest for wind, which is an intermittent resource and not dispatchable, and lowest for biomass, geothermal, and hydro, which are typically dispatchable. The impacts for solar photovoltaic and thermal generation are intermediate between those of wind and the other renewables as discussed further below.

Wind

In most cases, the daily operating cycle of wind generation does not follow the daily load demand cycle. For example, peak wind generation may occur at night during the winter and in the afternoon during the summer. In addition, wind generation can ramp up or down quickly as weather fronts move by, creating the need to rapidly increase or decrease other generation connected to the grid in order to follow load. When the penetration of wind generation in the mix is a few percent, the impacts are usually minimal and the electricity grid can easily absorb the wind generation. However, if wind penetration rises above 10% to 15%, especially during low load periods at night, then the impacts become more significant. In the latter case, addition of wind generation usually requires an increase in spinning reserves for load following and regulation, increased cycling of base load coal units, and possible curtailment of wind generation at night. Each of these factors decreases the net CO_2 emissions offset resulting from adding wind to the generating mix. In fact, the net emissions offset can even be negative, e.g. the CO_2 emissions can actually increase. For more information, consult recent references that address wind integration impacts (UWIG-EPRI [3], White [4], and E.ON Netz GMBH [5]).

Solar PV and Thermal

Solar PV and thermal generation are also intermittent resources, but their operating cycles are predictable and more synchronized with the daily load demand cycle. In addition, solar thermal generation is usually configured to include backup gas-firing heating to allow the plant to operate during off-peak hours. Thus their actual net CO_2 emissions offsets would be somewhat lower than the levelized emissions offsets presented below.

Biomass, Geothermal, and Hydro

Biomass, geothermal, and hydro units are typically dispatchable and their CO_2 emissions offsets should be close to the levelized offsets presented below.

Planting Trees and Other Fast-Growing Crops

In addition to the CO_2 emissions offsets of renewable generation technologies, plantations of fast-growing trees and other biomass crops such as eucalyptus, hybrid poplar, and switch grass act as carbon sinks that absorb CO_2 from the atmosphere via photosynthesis.

For example, as discussed in Reference 6, the annual growth of a hybrid poplar plantation in the Pacific Northwest absorbs five to eight tons of carbon per acre or 18.3 to 29.3 ton CO_2/acre per year (11.2 to 18.0 metric tons C/hectare per year, where one hectare = 10,000 square meters).

As shown in Table 11-3, a coal-fired power plant generates up to 1.04 tons of CO_2/MWh (0.95 metric ton carbon/MWh). Therefore, an acre of hybrid poplar would absorb the CO_2 produced by generation of 17.6 to 28.2 MWh from coal.

A 500-MW coal-fired power plant operating at 85% capacity factor generates 3,723,000 MWh/year and 3,872,000 tons CO_2/year. In order to absorb the entire CO_2 volume generated by the plant each year, the required hybrid poplar plantation would cover 132,000 to 211,000 acres or 206 to 330 square miles.

11.4.2 Levelized CO_2 Emissions Offsets

This section presents charts and other information to estimate the CO_2 emissions offsets resulting from adding renewable generation to an electricity system. The estimates assume that (1) each MWh of electricity generated by renewable resources replaces one MWh of electricity that would otherwise be generated by the existing generation mix; and (2) the relative contribution of each component of the mix to generation and CO_2 emissions does not change.

As discussed above, the actual net CO_2 emissions offset is likely to be lower than the emissions offset presented here. That is, depending on renewable generation and system characteristics, the actual net offset will be negative or zero to 100% of the offset for wind, 50% to 100% for solar PV and thermal, and 90% to 100% for biomass, geothermal, and hydro.

Figure 11-1 plots the fossil CO_2 emission offset (tonne CO_2/MWh) for coal, oil, and natural gas generation as a function of the percentage of total kilowatt-hours of generation contributed by the respective fossil fuel sources. The chart shows separate curves for 100% fossil fuel generation by coal, oil, and natural gas. These curves provide representative data for illustration only and can vary greatly depending on the specific generation technology involved (see Table 11-3). The levelized CO_2 emission offset for a specific blend of coal, oil, and natural gas generation is estimated by either interpolating a value between the three curves or by calculating a weighted average of the values determined by the coal, oil, and gas curves on the chart.

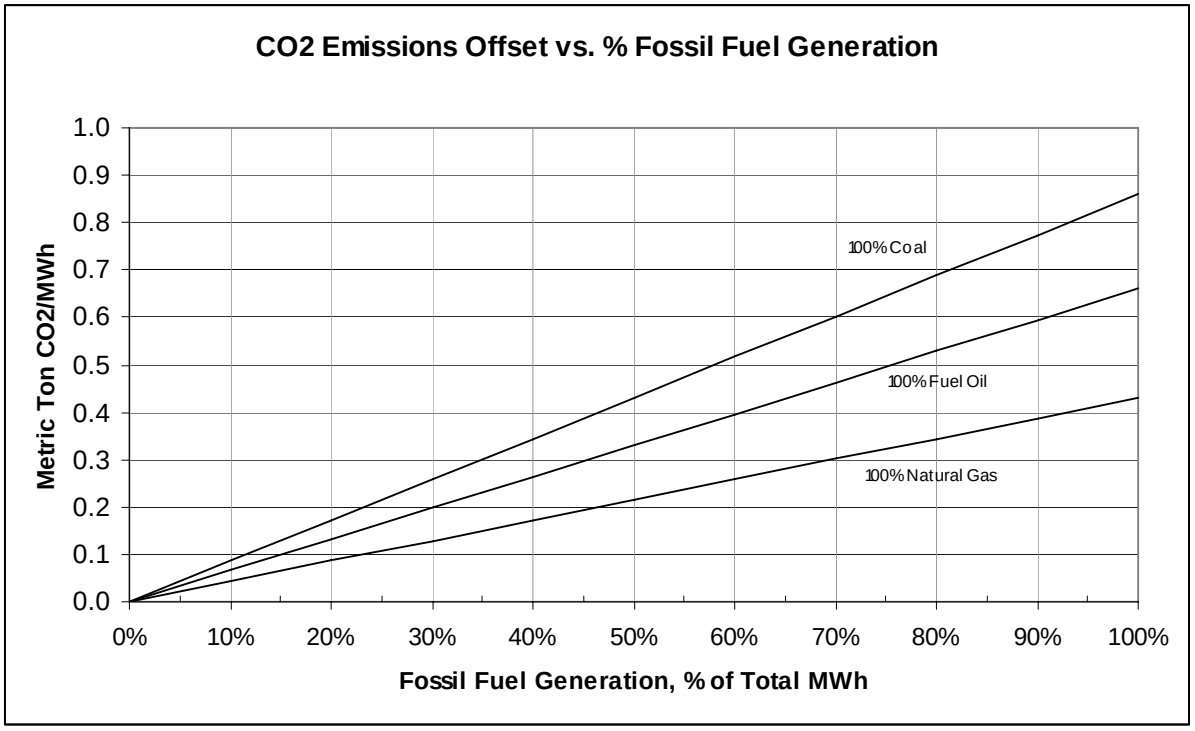


Figure 11-1
Levelized CO_2 Emissions Offset vs. % Fossil Fuel Generation

Figure 11-2 shows the levelized CO_2 emissions control cost ($/tonne CO_2) as a function of the cost premium of renewable power relative to the existing system generation cost and the CO_2 emissions offset. Figure 11-3 is similar except that it shows the CO_2 emission control cost as a function of the fossil fuel mix and assumes that 50% of the generation is contributed by coal, oil, and natural-gas-fired technologies.

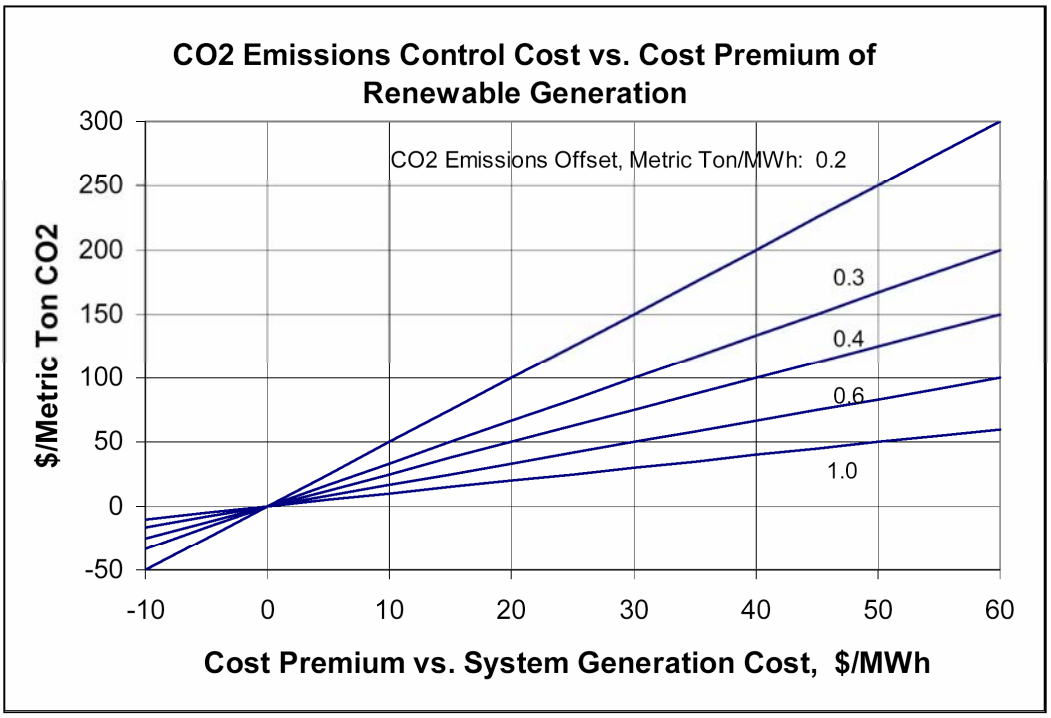


Figure 11-2
Levelized CO_2 Emissions Control Cost vs. Cost Premium and CO_2 Emissions Offset

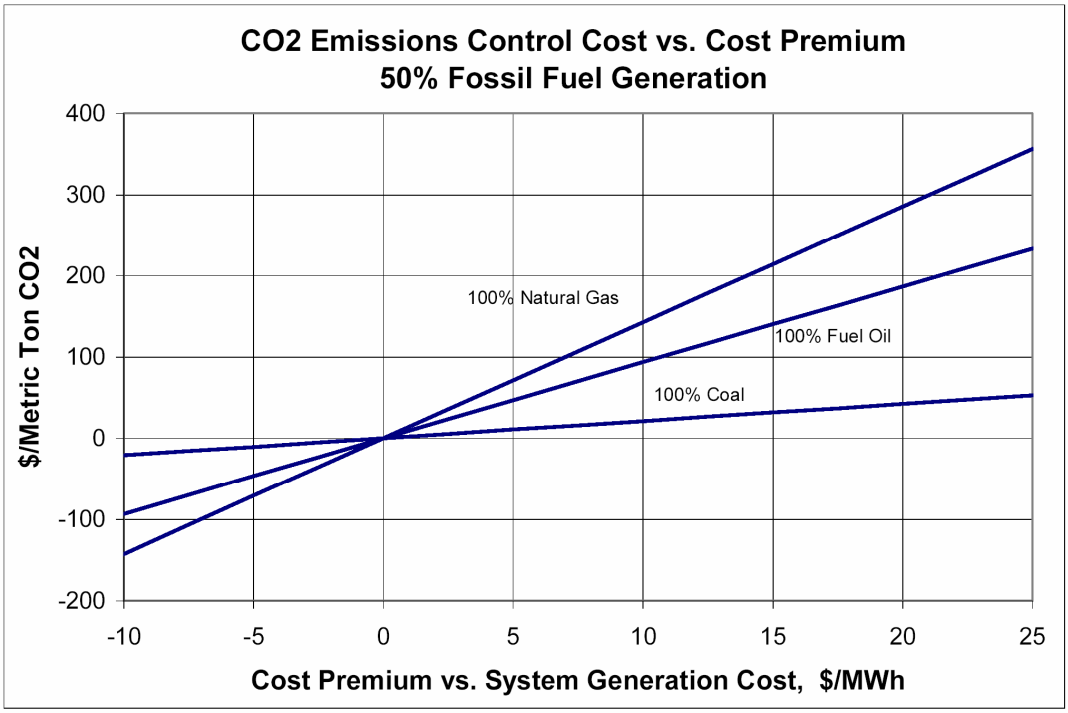


Figure 11-3
Levelized CO_2 Emissions Control Cost vs. Cost Premium and Fossil Fuel Mix at 50% Generation from Fossil Fuels

To illustrate application of the charts, if a fossil generation mix is 70% coal and 30% natural gas, and fossil fuels supply 90% of the kilowatt-hours generated, Figure 11-1 indicates the CO_2 emissions factors for coal and natural gas (at 90%) are about 0.77 and 0.39 tonne CO_2/MWh, respectively. Thus the weighted CO_2 emissions offset factor is (0.77 x 70%) + (0.39 x 30%) = 0.66 tonne CO_2/MWh. If the cost premium is $10/MWh, then the CO_2 Emissions Control Cost is [$10/MWh / 0.66 tonne/MWh = $15.15/tonne CO_2].

11.5 Factors Affecting Generation Cost of Renewable Technologies

Renewable energy generation costs are sensitive to various factors. The following section discusses the factors that affect the generation cost and, in turn, the levelized carbon dioxide reduction cost of using a given renewable energy technology. All cost figures are in end-of-year 2006 U.S. dollars.

11.5.1 Wind

Wind generation cost is most sensitive to the annual average wind speed at the site. As wind speed increases, wind energy generation increases, and thus the unit cost of energy ($/MWh) decreases. Table 11-4 presents wind plant performance and levelized cost vs. PNL wind speed class for a 100-MW wind plant. The data are excerpted from Table 3-6 in Section 3,

Table 11-4
Wind Plant Performance and Levelized Energy Cost vs. Wind Speed Class for a 100-MW Wind Plant ($/MWh, Dec-2006 $)

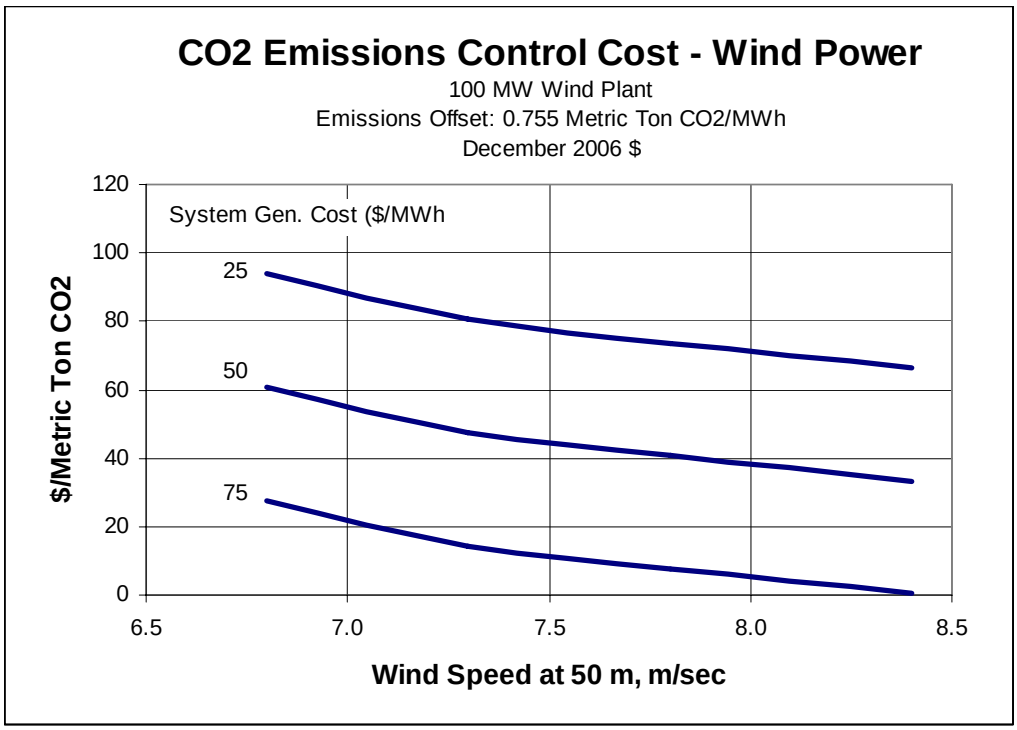
PNL Wind Class	**3**	**4**	**5**	**6**
Average Wind Speed (m/s @ 50 meter measurement height)	6.8	7.3	7.8	8.4
Average Wind Speed (m/s @ 80 meter hub height)	7.2	7.8	8.4	9.0
Wind Shear Factor	0.14	0.14	0.14	0.14
Air density, kg/m3	1.09	1.09	1.09	1.09
Array and Energy Losses, %	8.0	8.5	9.0	9.0
Gross Capacity Factor, %	36.4	41.1	44.2	47.6
Net Capacity Factor, %	32.5	36.5	39.0	42.0
100 MW Project				
Net Energy Output (MWh/yr)	**285,000**	**320,000**	**342,000**	**368,000**
Levelized Energy Cost ($/MWh)				
Fixed Charge @12.5%/yr	77.0	68.5	64.1	59.6
O&M	14.0	12.5	11.7	10.9
Land Lease	1.8	1.8	1.8	1.8
Grid Integration	3.0	3.0	3.0	3.0
TOTAL	95.8	85.8	80.6	75.2

Figures 11-4 and 11-5 respectively show the sensitivities of wind generation costs to the annual average wind speed and the base system generation cost. The Federal Production Tax Credit is not considered in this analysis.

The levelized wind energy cost ranges between $75 and $96/MWh for average 50-m wind speeds of 8.4 and 6.8 m/sec, respectively.

Figure 11-4 presents the resulting levelized CO_2 emissions control cost for three system generation costs, $25, $50, and $75/MWh. The analysis assumes the CO_2 emissions offset factor is 0.755 metric ton CO_2/MWh, which is consistent with the advanced IGCC coal plant example in Table 11-3 and a representative mix of coal and cleaner natural gas combustion.

As the wind speed or system generation cost increase, the levelized CO_2 emissions control cost declines and can become negative. The negative CO_2 control costs correspond to wind generation costs that are lower than the base system cost. For example, at a system generation cost of $75/MWh, the CO_2 emission cost is negative for wind speeds above about 8.4 m/sec.



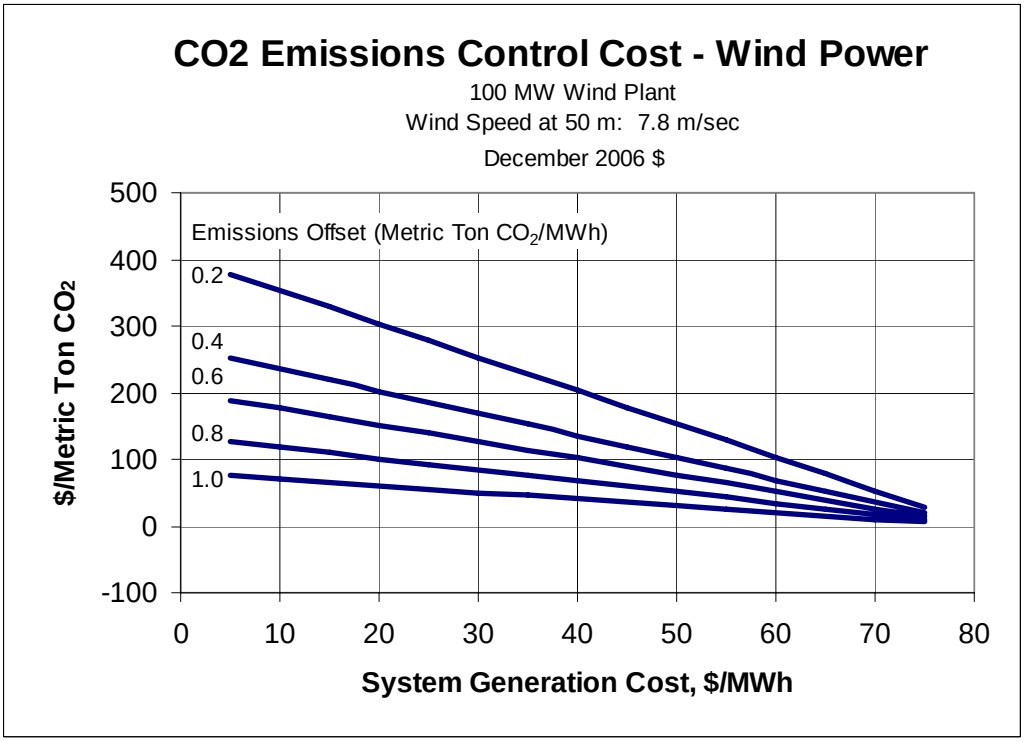


Figure 11-4
Levelized CO_2 Emissions Control Cost vs. Average Wind Speed at 50 m (top) and System Generation Cost (Bottom) for a 100-MW Wind Plant (Dec 2006 $)

11.5.2 Biomass

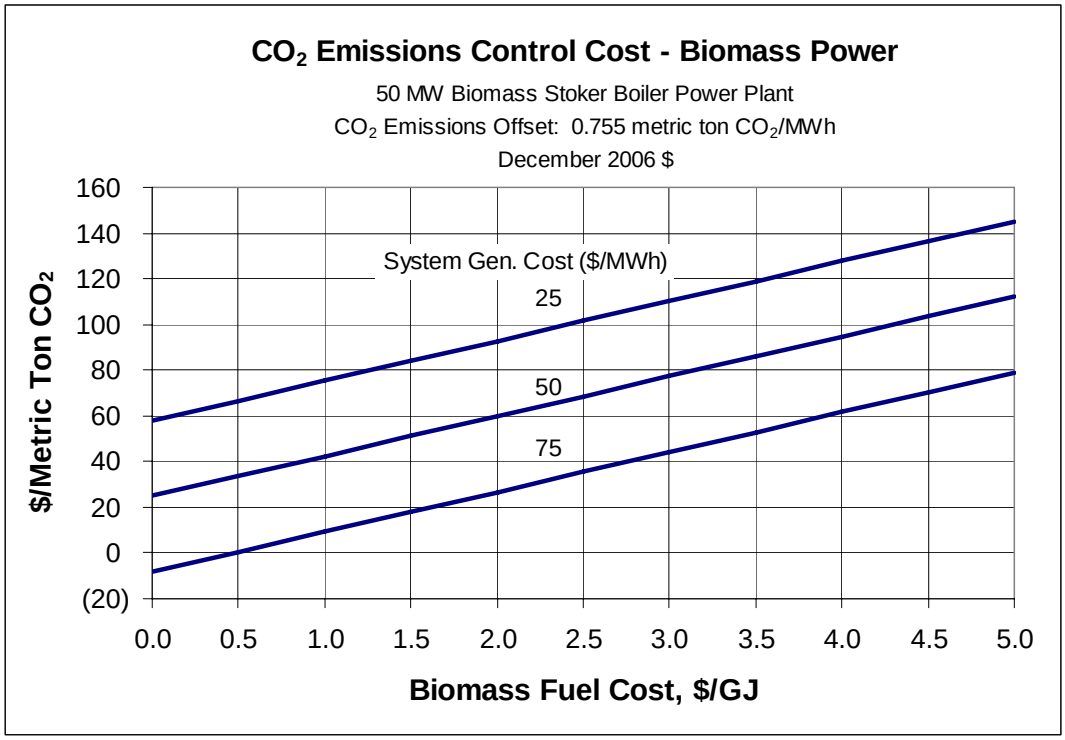
Biomass generation cost is most sensitive to the delivered biomass fuel cost, the installed cost of the biomass power system, and the net thermal efficiency of the power cycle. The installed cost is expected to remain relatively stable over time, but the delivered biomass fuel cost may decline as new crop planting, cultivation, harvesting, and handling technologies improve. The net thermal efficiency of the power cycle has the potential to improve as well.

Table 11-5 summarizes the total capital requirement, fixed and variable O&M, plant performance, and levelized cost of electricity for 50-MW biomass-fired stoker and fluidized bed boiler power plants. The performance and cost parameters are based on Table 4-26 and do not include the Federal Production Tax Credit.

Figure 11-5 shows the levelized CO_2 emissions control cost as a function of the biomass fuel and system generation costs. Assuming the system generation cost is $50/MWh, the levelized CO_2 cost ranges between $25 and $112 /MWh as the fuel cost varies between zero and $5.00/GJ at $2.50/GJ, the levelized CO2 cost varies between minus $51and plus $140/MWh as the system generation cost varies between $140 and zero $/GWh.

Table 11-5
Levelized Cost of Electricity for 50-MW Biomass-Fired Stoker and Fluidized Bed Boiler Power Plants ($/MWh, Dec-2006 $)

	Stoker Boiler	FBC Boiler
Total Capital Requirement, $/kW	3,390	3,495
Fixed O&M Cost, $/kW-yr	88.4	91.0
Variable O&M Cost, $/MWh	3.6	4.1
Net Heat Rate, Btu/kWh	12,500	12,300
GJ/kWh	13,179	12,969
Fuel Cost, $/GJ	2.50	2.50
Capacity Factor	85%	85%
Levelized Cost of Electricity, $/MWh		
Capital @12.5%/yr	56.9	58. 7
Fuel @ $2.50/GJ	32.9	32.4
Fixed and Variable O&M	15.5	16.3
TOTAL	105.3	107.4



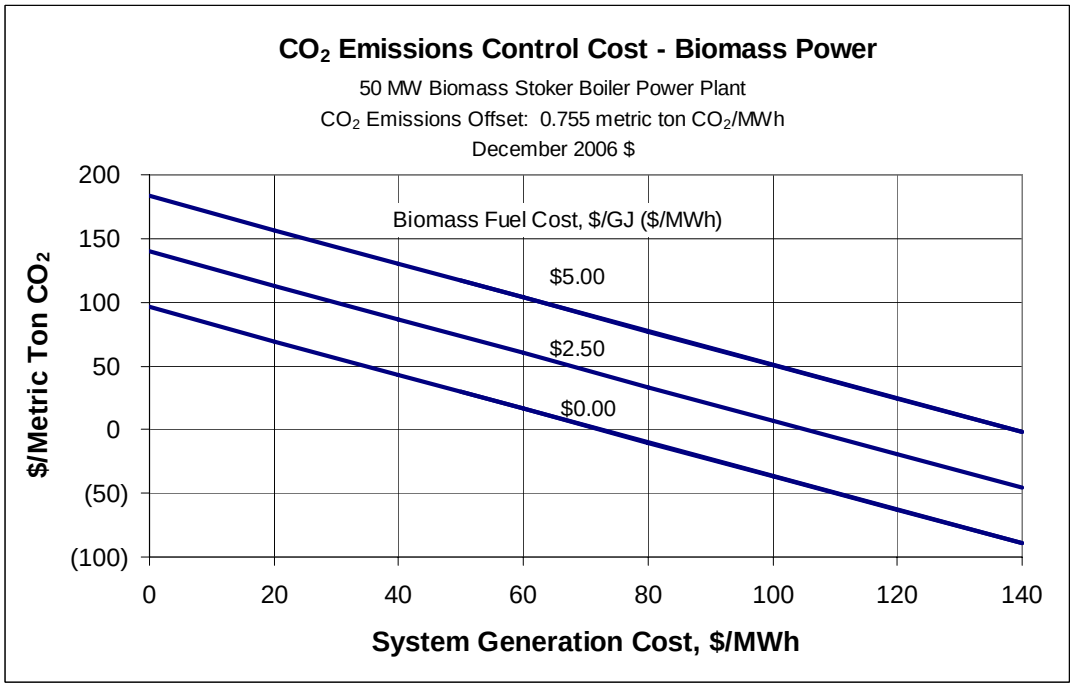


Figure 11-5
Levelized CO_2 Emissions Control Cost vs. Delivered Fuel Cost (Top) and System Generation Cost (Bottom) for a 50-MW Stoker Boiler Biomass Power Plant (Dec-2006 $)

11.5.3 Solar Photovoltaics

Photovoltaic (PV) generation cost is most sensitive to the annual insolation rate at the site and the installed cost of the PV system. The installed cost is expected to continue to decline over time as new technology is developed and commercialized. Table 11-6 presents 20-year levelized cost of electricity for 5- and 50-MW solar photovoltaic power plants. The plants use fixed flat plate modules that face toward the equator at a horizontal angle equal to the latitude of the site. The estimated levelized cost of electricity is 526 and 481 for the 5- and 50-MW PV plants, respectively.

Figure 11-6 shows the expected sensitivities of the levelized CO_2 emissions control costs to the annual insolation rate (top), and the base system generation cost (bottom). In the United States, the annual total insolation rate varies between about 2,400 kWh/m^2/yr at the best sites in West Texas and about 1,300 kWh/m^2/yr in the Pacific Northwest and New England.

Table 11-6
Levelized Cost of Electricity for 5- and 50-MW Solar Photovoltaic Plants with Fixed Flat Plate Modules ($/MWh, Dec-06 $)

Rated Capacity	1 X 5 MW	10 x 5 MW
Capital Cost, $/kW	9205	8445
O&M , $/kW year	20.2	14.5
Fuel GJ/kWh	0.0	0.0
Capacity Factor	25.40%	25.40%
Levelized COE ($/MWh)		
Capital @ 12.5%/yr	517.1	474.4
O&M	9.1	6.5
Fuel	0.0	0.0
TOTAL	526.2	481.0

Figure 11-6 presents the resulting levelized CO_2 emissions vs. annual insolation and system generation cost. The analysis assumes the CO_2 emissions offset factor is 0.755 tonne CO_2/MWh.

At a base system generation cost of $50/MWh, the levelized CO_2 emissions control cost ranges between $465 and $1,181/tonne CO_2 as the annual insolation rate varies between 2,600 and 1,200 kWh/m^2/yr, respectively.

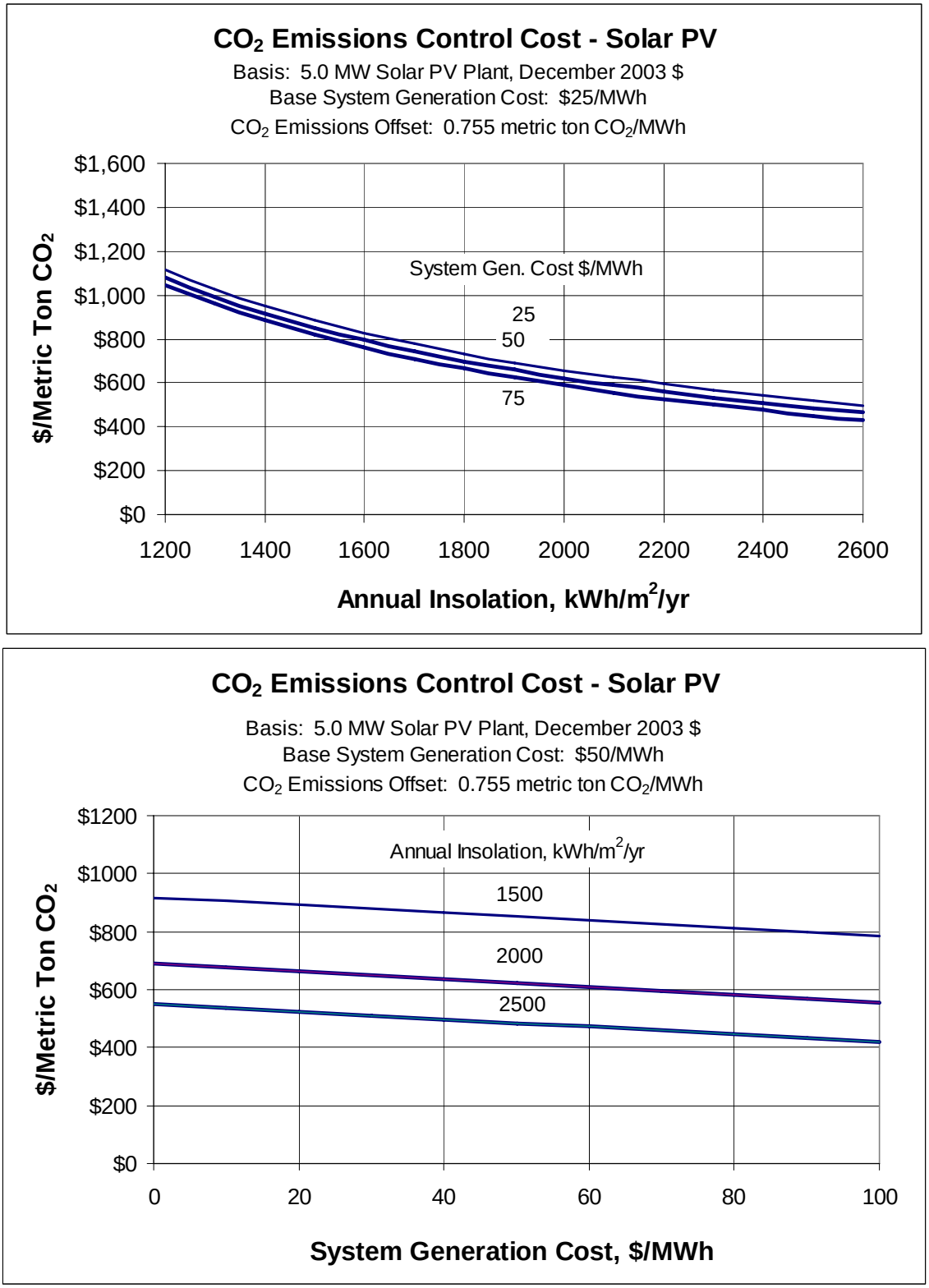


Figure 11-6
Levelized CO_2 Emissions Control Cost vs. Annual Insolation for a 5.0-MW fixed Flat-Plate Solar PV Plant vs. Annual Insolation (Top) and System Generation Cost (Bottom, Dec-06 $)

11.5.4 Geothermal

Geothermal generation cost is most sensitive to the geothermal energy production and the installed cost of the geothermal wells and power system.

Table 11-7 presents the 20-year levelized cost of electricity for 50-MW flash-steam and 20-MW binary-cycle geothermal plants. The data are based on Table 6-10 in Chapter 6. The levelized COE is $55 and $87/MWh for the flash-steam and binary cycle geothermal plants.

Figure 11-7 shows the resulting CO_2 emission control costs vs. the base system generation cost for the 50-MW flash-steam and 20-MW binary-cycle geothermal plants. The analysis assumes the CO_2 emissions offset factor is 0.717 tonne CO_2/MWh, including the adjustment for fossil fuel CO_2 emissions released during the production of geothermal power.

Table 11-7
Geothermal Power Energy Cost vs. Year of Commercial Order for 50-MW Flash-Steam and and 20-MW Binary-Cycle Geothermal Power Plants ($/MWh, Dec-06 $)

Geothermal Technology	Flash Steam	Binary Cycle
Rated Capacity, MW	50	20
Capital Cost, $/kW	2,470	4,028
O&M, $/kW-yr	125.1	142.0
Net Heat Rate, GJ/kWh	30,000	30,000
Fuel Cost $/GJ	0	0
Capacity Factor	90%	85%
Levelized COE, $/MWh		
Capital & 12.5%/yr	39.2	67.6
O&M	15.9	19.1
Fuel	0	0
TOTAL	55.0	86.7

Figure 11-6 shows that, as the base system generation cost increases, the CO2emmisions control cost decreases and becomes negative for generation cost greater than $59/MWh for flash-steam and $89/MWh for binary-cycle geothermal plants.

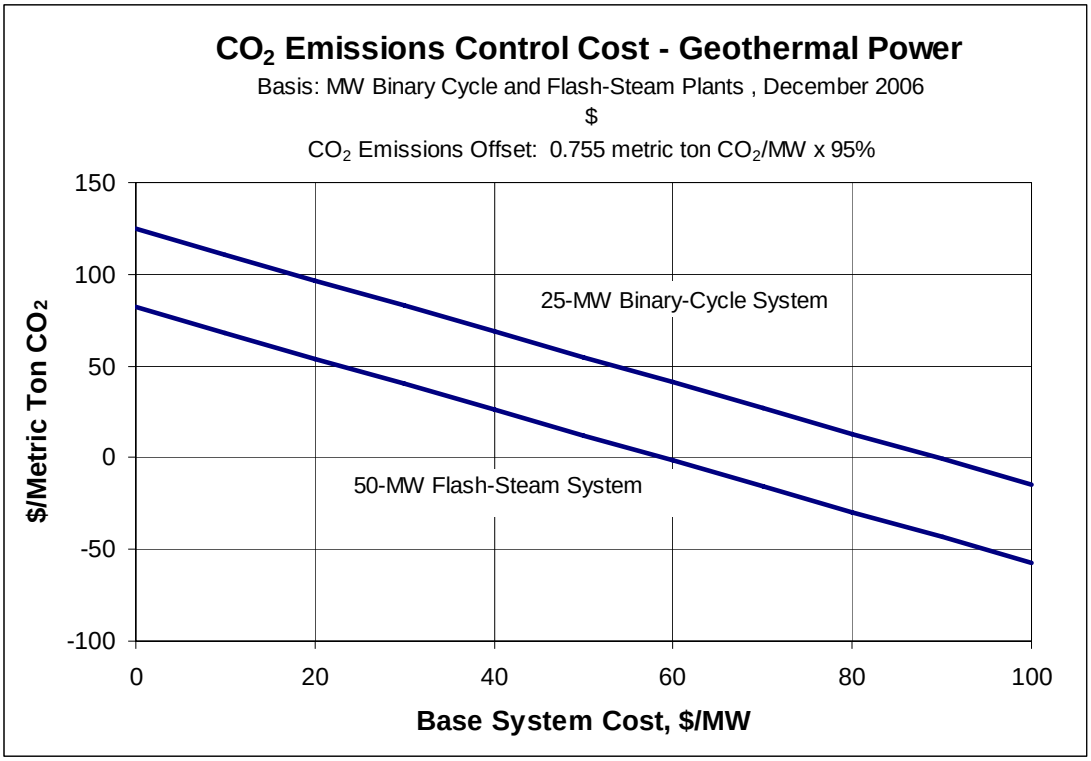


Figure 11-7
Levelized CO_2 Emissions Control Cost for 50-MW Flash-Steam and 20-MW Binary-Cycle Power Plants vs. Base System Generation Cost (Dec-06 $)

11.5.5 Solar Thermal

The solar thermal generation cost is highly sensitive to the annual insolation rate at the site and the installed cost of the solar thermal system. The installed cost is expected to continue to decline over time as new technology is developed and commercialized.

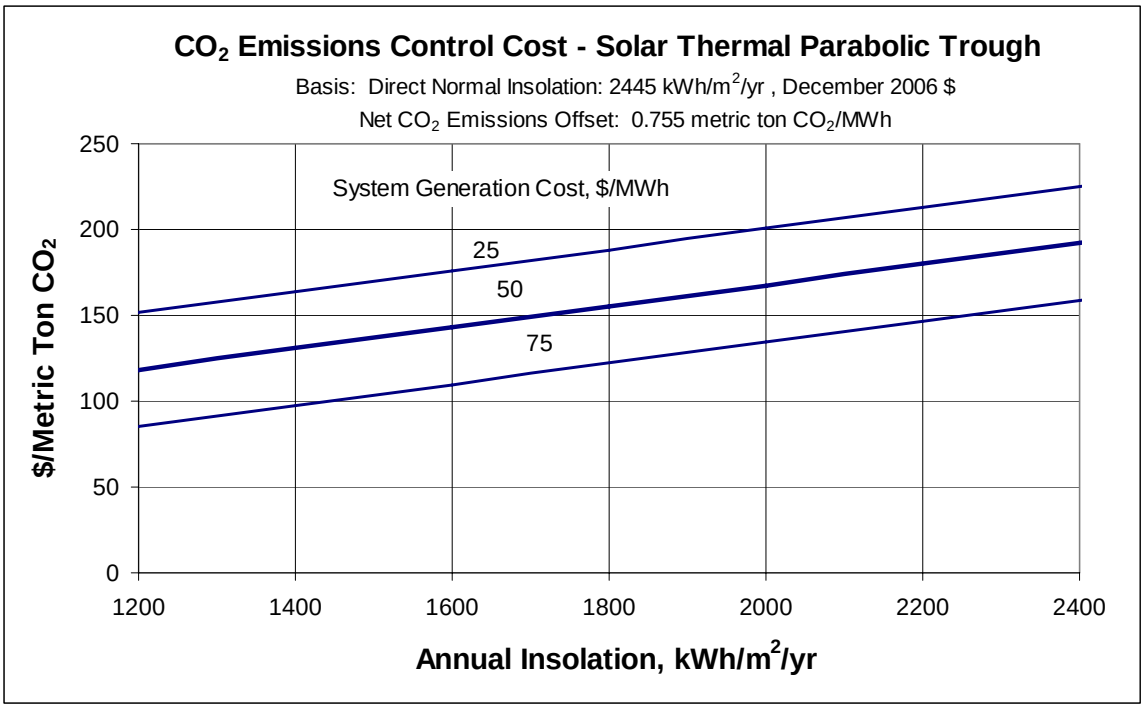
Table 11-7 presents the 20-year levelized cost of electricity for 80-MW parabolic trough and dish-Stirling power plants. The data are based on Table 5-10 in Chapter 5. The levelized COEs are respectively $238 and $218/MWh for the solar thermal parabolic trough and dish-Stirling power plants.

Table 11-8
Levelized Cost of Electricity for 80-MW Parabolic-Trough and Dish-Stirling Solar Thermal Power Plants (Dec-06 $)

	Parabolic Trough	Dish Stirling
Rated Capacity, MW	80	80
Capital Cost, $/kW	4,390	3,470
Fixed O&M $/kW-yr	58	56.0
Var. O&M, $/MW-hr	0	0
Net Heat Rate, GJ/kWh	0	0
Fuel, $/GJ	0	0
Capacity Factor	29.1%	25.7%
Levelized COE $/MWh		
Capital @12.5%	215.3	192.7
O&M	22.8	24.9
Fuel	0.0	0.0
TOTAL	238.0	217.5

Figures 11-8 and 11-9 present the resulting levelized CO_2 emissions control costs for 80-MW for solar thermal parabolic trough and dish Stirling power plants. The analysis assumes the CO_2 emissions offset factor is 0.755 tonne CO_2/MWh.

The figures show that the CO_2 emissions control cost decreases with both annual insolation and system generation cost.



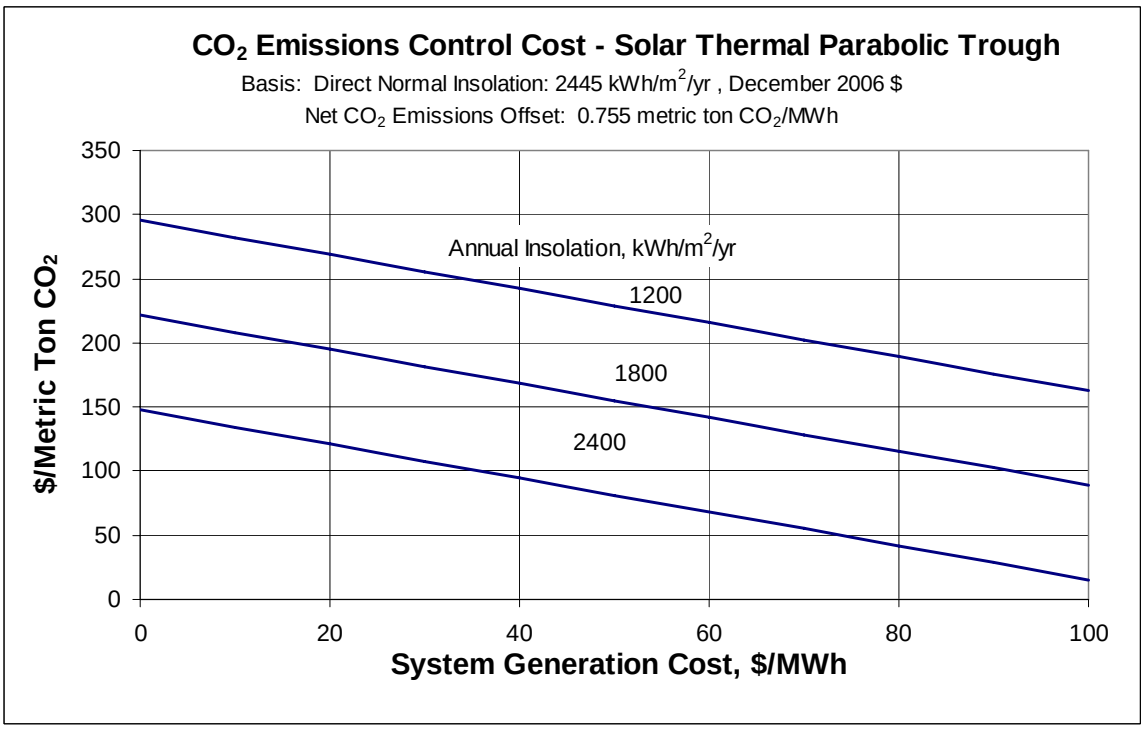


Figure 11-8
Levelized CO_2 Emissions Control Cost vs. Annual Insolation (Top) and System Generation Cost (Bottom) for an 80-MW Solar Thermal Parabolic Trough Power Plant (Dec-06 $)

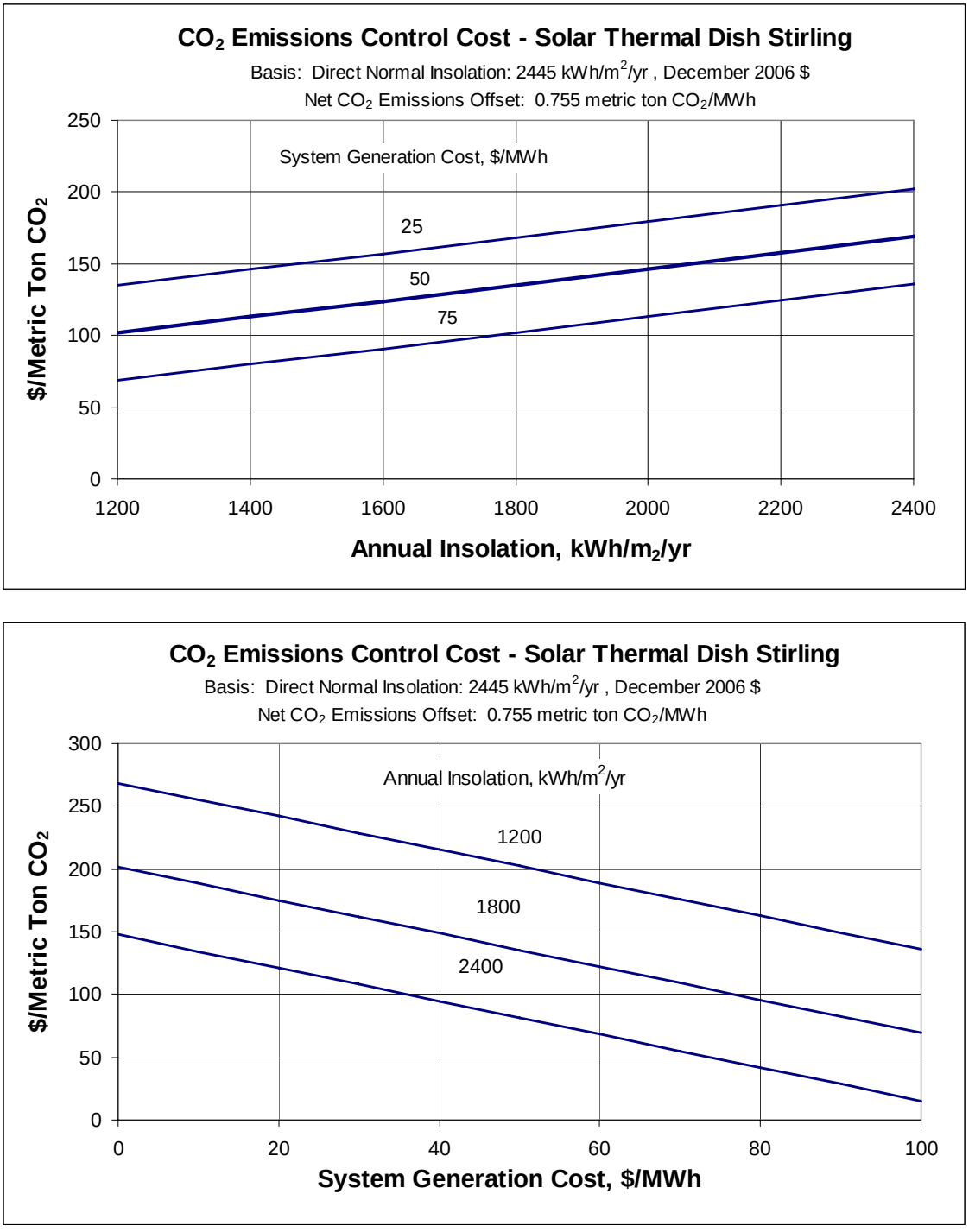


Figure 11-9
Levelized CO_2 Emissions Control Cost vs. Annual Insolation (Top) and System Generation Cost (Bottom) for an 80-MW Solar Thermal Dish Stirling Engine Power Plant (Dec-06 $)

11.6 References

1. *Greenhouse Gas Reduction with Renewables*, EPRI, Palo Alto, CA, 2000: TR-113785.

2. *Renewable Energy Technology Characterizations*, EPRI, 1997: TR-109496.

3. *Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning: Utility Wind Interest Group - Xcel Energy-North Case Study* EPRI, Palo Alto, CA, 2003: 1004807.

4. White, David J., "Danish Wind: Too Good to be True?", *The Utilities Journal*, pp 37-39, July 2004.

5. *Wind Report 2004,* E.ON Netz Gmbh, Bayreuth, Germany 2003.

6. Stanton, Brian, Jake Eaton, Jon Johnson, Don Rice, Bill Schutte, and Brian Moser, "Hybrid Poplar in the Pacific Northwest, the Effects of Market-Driven Management," *Journal of Forestry*, June 2002.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California, and Charlotte, North Carolina, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

Together...Shaping the Future of Electricity

Program:

Renewable Energy Technology and Strategy

© 2007 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Printed on recycled paper in the United States of America

1012722

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com