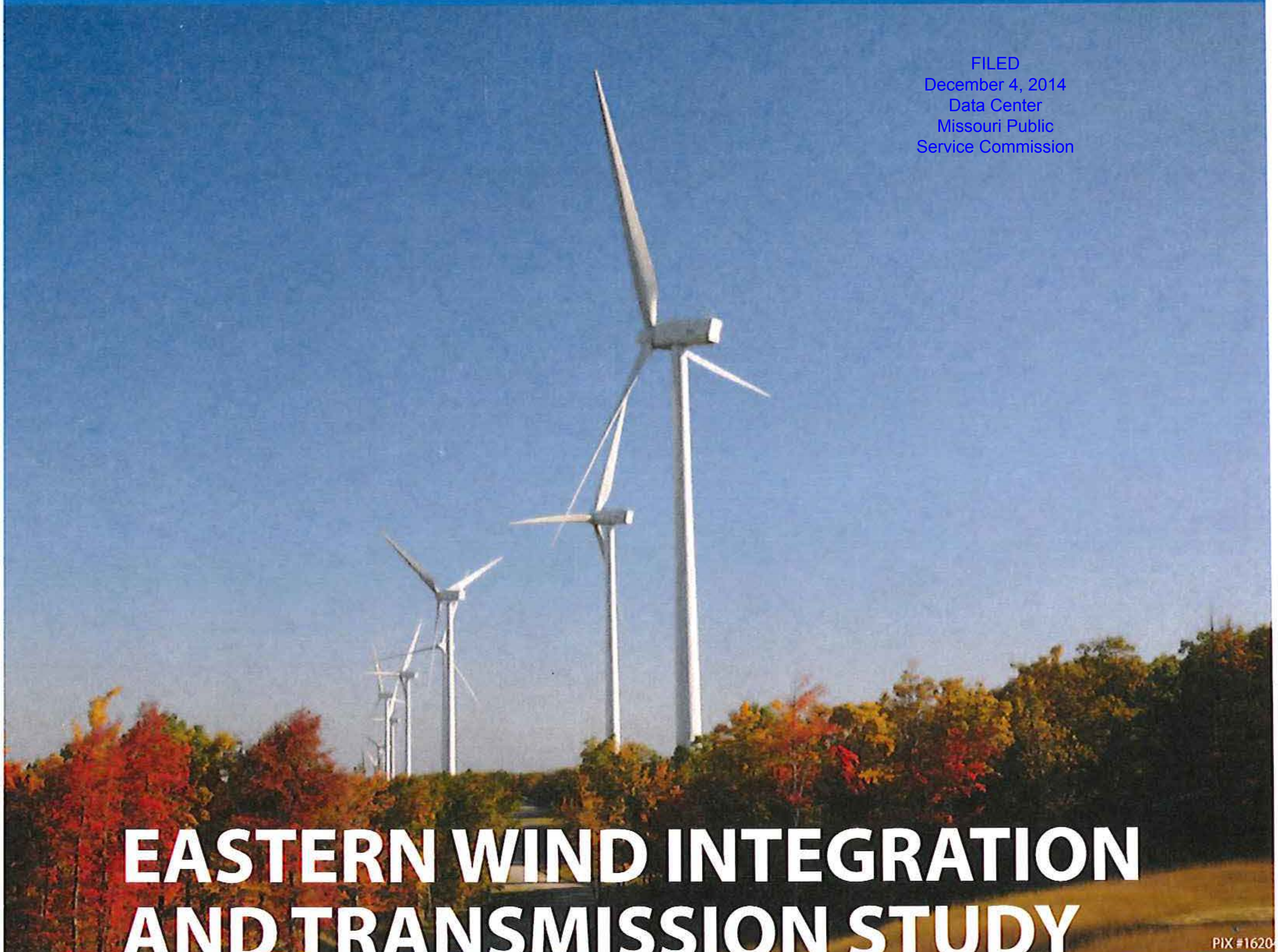


EASTERN WIND INTEGRATION AND TRANSMISSION STUDY

PREPARED FOR:
The National Renewable Energy Laboratory
A national laboratory of the U.S. Department of Energy

PREPARED BY:
EnerNex Corporation

REVISED FEBRUARY 2011

EASTERN WIND INTEGRATION AND TRANSMISSION STUDY

Revised February 2011
Prepared for NREL by: EnerNex Corporation
Knoxville, Tennessee
NREL Technical Monitor: David Corbus
Prepared under Subcontract No. AAM-8-88513-01

Subcontract Report
NREL/SR-5500-47078

National Renewable Energy Laboratory
1617 Cole Boulevard, Golden, Colorado 80401
303-275-3000 • www.nrel.gov

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

Contract No. DE-AC36-08GO28308

NOTICE

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mailto:reports@adonis.osti.gov

Available for sale to the public, in paper, from:
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/ordering.htm

Printed on paper containing at least 50% wastepaper, including 10% post consumer waste.

TABLE OF CONTENTS

PREFACE 15
ACKNOWLEDGEMENTS 16
ABBREVIATIONS AND ACRONYMS 18
EXECUTIVE SUMMARY 22
- About the Study 22
- Scenario Development and Analysis 24
- Key Study Findings 27
- Scenario Costs 29
- Study Methodology 31

PROJECT OVERVIEW 35
- Transmission Requirements 35
- Wind Operational Impacts 40
- Reserve Requirements 41
- Production-Cost Modeling Results 44
- Wind Integration Costs 45
- Carbon Sensitivity Analysis 47
- Contributions to Resource Adequacy 51

SUMMARY AND FUTURE WORK 55
SECTION 1: Introduction 61
- Project Objectives 62
- Key Issues and Questions 62
- Overview of Project Tasks 63
- Organization of this Report 64

SECTION 2: Wind Scenario Development 66
- Introduction 66
- Description of Mesoscale Database 66
- Scenario Development Process 70
- Scenario Descriptions 70
- Regional wind Capacity and Energy 71
- Scenario Details 73

SECTION 3: Analytical Methodology: Data, Models, and Tools 81
- Model Development 83
- Tools 87
- Assumptions 90

SECTION 4: Developing Economic Transmission Overlays 98
- Background 98
- Application of Expansion Methodology 100
- Analysis 117
- Design of HVDC Overlay Transmission 120

SECTION 5: Power System Regulation and Balancing with Significant Wind Generation 124

Power System Operation and Control 124
Effects of Wind Generation on Power System Control 134
Modeling and Analysis for Assessing Wiind Integration Impacts 137
Summary 153
SECTION 6: Assessing Impacts on Power System Operation 156
Wind Integration Impacts and Costs 156
Analytical Approach 157
Results 159
Scenario Analysis 164
Sensitivity Analysis 180
SECTION 7: Wind Generation Contributions to Resource Adequacy and Planning Margin 194
Background 194
Analytical Approach 194
Results 202
Analysis 205
SECTION 8: Synthesis and Implications 207
Notes on the Analytical Methodology 207
Total Costs 209
Implications of This Study 211
SECTION 9: Findings, Conclusions, and Recommendations 214
Key Findings and Conclusions 214
Summary 225
Recommendations for Future Study 226
GLOSSARY 231
BIBLIOGRAPHY 238

LIST OF FIGURES

Figure 1. NERC synchronous interconnections 23
Figure 2. Summary of installed wind generation capacity by operating region for each scenario 26
Figure 3. Comparison of scenario costs 30
Figure 4. Study process 32
Figure 5. Assumed operational structure for the Eastern Interconnection in 2004 34
Figure 6. Scenario2, annual generation differences between unconstrained case and constrained case 36
Figure 7. Scenario 2, annual generation weighted locational marginal price (LMP) for constrained case 37
Figure 8. Conceptual EHV transmission overlays for each study scenario 38
Figure 9. Regulating reserve requirements by region and scenario 42
Figure 10. Annual production-cost comparison 45

Figure 11. Integration cost by scenario and year 46
Figure 12. Generation expansion for the Scenario 2 carbon sensitivity case 48
Figure13. Generation expansion by scenario, including the carbon sensitivity case 49
Figure 14. Carbon emissions for different scenarios 49
Figure 15. Generation utilization by unit and fuel type for Scenario 2 and carbon sensitivity case 50
Figure 16. Comparison of generation-weighted LMP by region for Scenario 2 and carbon sensitivity case 50
Figure 17. Present value of accumulated costs for base scenarios and carbon sensitivity 51
Figure 18. LOLE/ELCC results for high penetration scenarios, with and without transmission overlays 54
Figure 2-1. LCOE for all wind facilities in database 68
Figure 2-2. Capacity factor for all wind in database 69
Figure 2-3. Aggregate capacity factor for all wind in database 69
Figure 2-4.Study regional definitions 71
Figure 2-5. Annual energy production by region 72
Figure 2-6. Nameplate capacity by region 73
Figure 2-7. Wind plant size and location for Reference Case 74
Figure 2-8. Installed capacity—Scenario 1 75
Figure 2-9. State map of nameplate capacity—Scenario 1 75
Figure 2-10. Installed capacity—Scenario 2 76
Figure 2-11. State map of nameplate capacity—Scenario 2 77
Figure 2-12. Installed capacity—Scenario 3 78
Figure 2-13. State map of nameplate capacity—Scenario 3 78
Figure 2-14. Installed capacity —Scenario 4 79
Figure 2-15. State map of nameplate capacity—Scenario 4 80
Figure 3-1. Overview of the study process 82
Figure 3-2. Study area 93
Figure 4-1. Capacity expansion by scenario 101
Figure 4-2. Scenario 1 installed capacity sites 103
Figure 4-3. Scenario 2 installed capacity sites 103
Figure 4-4. Scenario 3 installed capacity sites 104
Figure 4-5. Scenario 4 installed capacity sites 104
Figure 4-6. Scenario 2 annual generation-weighted LMP for Scenario 2 105
Figure 4-7. Scenario 2 generation difference between unconstrained case and constrained case 106
Figure 4-8. Scenario 2 interface annual energy difference between unconstrained case and constrained case 107
Figure 4-9. Transmission and substation costs per megawatt-mile 109
Figure 4-10. SPP EHV conceptual transmission plan 110

Figure 4-11. Midwest ISO RGOS, Phase I, Preliminary 111
Scenario T, 765-kV
Figure 4-12. EWITS Scenario 1 conceptual transmission plan.......... 112
Figure 4-13. EWITS Scenario 2 conceptual transmission plan.......... 112
Figure 4-14. EWITS Scenario 3 conceptual transmission plan.......... 113
Figure 4-15. EWITS Scenario 4 conceptual transmission plan.......... 113
Figure 4-16. Scenario 1 annual generation-weighted.......... 118
LMP comparison118
Figure 4-17. Scenario 2 annual generation-weighted.......... 118
LMP comparison
Figure 4-18. Scenario 3 annual generation-weighted.......... 119
LMP comparison
Figure 4-19. Scenario 3 annual generation-weighted.......... 119
LMP comparison
Figure 4-20. An example showing 800-kV HVDC lines 121
tied by 765-kV lines and underlying 345-kV lines
Figure 4-21. A postcontingency example showing five 800-kV.......... 122
HVDC lines example tied by 765-kV lines and underlying 345-kV lines
Figure 4-22. An example of the assumed distribution of 123
the flows on the underlying AC system
Figure 5-1. NERC reliability regions and balancing authorities 127
as of January 2005 and August 2007
Figure 5-2. U.S. RTOs.......... 128
Figure 5-3. Depiction of regulation and load-following.......... 130
characteristics of demand
Figure 5-4. Normalized 10-minute variability for five different 135
groups of wind generation. The 500MW scenario is part
of the 5,000-MW scenario, which is part of the 15,000-MW
scenario, and so on
Figure 5-5. Ten-minute variability of load and net load for.......... 136
MISO and PJM
Figure 5-6. Eastern Interconnection balancing authorities.......... 138
Figure 5-7. Illustration of short-term (next 10-minute interval).......... 144
forecasts of load and wind generation
Figure 5-8. Errors in short-term forecasts of load and wind.......... 144
generation; load error is assumed to be zero in the
mathematical procedure
Figure 5-9. Illustration of short-term (10-minute ahead) wind 145
generation forecast errors as a function of average
hourly production
Figure 5-10. Standard deviation of 1-hour persistence forecast 147
error for PJM in Reference Case
Figure 5-11. Distributions of hourly regulating reserve requirements.......... 152
for PJM Scenario 3, for load only (ideal wind generation)
and load net of wind generation

Figure 6-1. Wind energy penetration levels by region using 2004 hourly profiles ... 160
Figure 6-2. Annual average variable spinning reserve using 2004 hourly profiles ... 161
Figure 6-3. Annual APCs using 2004 hourly profiles ... 162
Figure 6-4. Annual steam turbine coal generation summary with 2004 hourly profiles ... 163
Figure 6-5. Annual combined cycle and combustion turbine gas generation with 2004 hourly profiles ... 164
Figure 6-6. Annual APC comparison for actual cases ... 165
Figure 6-7. Wind integration costs ... 166
Figure 6-8. Wind integration costs ($/MWh of annual wind energy in 2024) ... 167
Figure 6-9. Annual wind energy input summary for Scenario 1 ... 168
Figure 6-10. Annual wind curtailment summary using 2004 hourly load and wind profiles ... 169
Figure 6-11. Annual wind curtailment summary using 2005 hourly load and wind profiles ... 169
Figure 6-12. Annual wind curtailment summary using 2006 hourly load and wind profiles ... 170
Figure 6-13. Annual generation energy by fuel type using 2004 hourly load and wind profiles ... 171
Figure 6-14. Annual generation energy by fuel type using 2005 hourly load and wind profiles ... 171
Figure 6-15. Annual generation energy by fuel type using 2006 hourly load and wind profiles ... 172
Figure 6-16. Annual generation energy by fuel type using 2004 hourly profiles ... 172
Figure 6-17. Annual generation energy by fuel type using 2005 hourly profiles ... 173
Figure 6-18. Annual generation energy by fuel type using 2006 hourly profiles ... 173
Figure 6-19. Change in annual generation from ideal to actual cases using 2004 hourly profiles ... 174
Figure 6-20. Change in annual generation from ideal to actual cases using 2005 hourly profiles ... 175
Figure 6-21. Change in annual generation from ideal to actual cases using 2006 hourly profiles ... 175
Figure 6-22. Annual generation-weighted LMPs using 2004 hourly profiles ... 176
Figure 6-23. Annual generation-weighted LMPs using 2005 hourly profiles ... 177
Figure 6-24. Annual generation-weighted LMPs using 2006 hourly profiles ... 177

Figure 6-25. Annual regional transaction energy using 2004 hourly profiles ... 178
Figure 6-26. Annual regional transaction energy using 2005 hourly profiles ... 179
Figure 6-27. Annual regional transaction energy using 2006 hourly profiles ... 179
Figure 6-28. Interface flow duration curve sample ... 181
Figure 6-29. APCs with 2005 hourly wind and load patterns ... 184
Figure 6-30. Integration cost summary with 2005 hourly wind and load patterns ... 185
Figure 6-31. Annual generation-weighted LMPs with 2005 hourly wind and load patterns ... 185
Figure 6-32. Annual generation-weighted LMP comparison ... 187
Figure 6-33. Capacity expansion by scenario including carbon sensitivity, 2008–2024 ... 188
Figure 6-34. Carbon impact of modeled scenarios ... 189
Figure 6-35. Cost impact of modeled scenarios ... 189
Figure 6-36. Forecast generation locations for sensitivity to scenario 2 ... 190
Figure 6-37. Annual generation production by fuel type with 2005 hourly wind and load patterns ... 191
Figure 6-38. Annual generation energy changes from ideal case to actual case ... 192
Figure 6-39. Annual generation-weighted LMP comparison ... 192
Figure 7-1. ELCC example system with and without resource ... 195
Figure 7-2. ELCC example system at the same LOLE ... 195
Figure 7-3. Scenario 1, existing transmission system August interface limits (MW) ... 198
Figure 7-4. Scenario 2, existing transmission system August interface limits (MW) ... 198
Figure 7-5. Scenario 3, existing transmission system August interface limits (MW) ... 199
Figure 7-6. Scenario 4, existing transmission system August interface limits (MW) ... 199
Figure 7-7. Scenario 1, conceptual transmission overlay August interface limits (MW) ... 200
Figure 7-8. Scenario 2, conceptual transmission overlay August interface limits (MW) ... 200
Figure 7-9. Scenario 3, conceptual transmission overlay August interface limits (MW) ... 201
Figure 7-10. Scenario 4, conceptual transmission overlay August interface limits (MW) ... 201
Figure 7-11. ELCC results for existing and overlay transmission ... 203
Figure 7-12. Tie benefit results for existing and overlay transmission ... 204

Figure 8-1. Flow diagram for study analytical methodology ... 208
Figure 8-2. Costs by scenario ... 211
Figure 9-1. Comparison of production simulation results ... 219
(integration cost) for base unit-commitment algorithm
and more sophisticated "bid-logic" approach
Figure 9-2. Comparison of LMPs for hurdle rate sensitivity ... 220
Figure 9-3. Scenario 2, carbon case generation expansion ... 221
Figure 9-4. Generation expansion by scenario, 2008–2024 ... 221
Figure 9-5. Carbon emission comparison ... 222
Figure 9-6. Change in generation for carbon sensitivity ... 223
Figure 9-7. Change in LMP for carbon sensitivity ... 223
Figure 9-8. Scenario cost comparisons ... 224

LIST OF TABLES

Table 1. Total and Offshore Wind in the Scenarios ... 26
Table 2. Transmission Cost Assumptions ... 39
Table 3. Estimated Line Mileage by Scenario ... 39
Table 4. Estimated Costs by Scenario (US $2009, millions) ... 39
Table 5. Reliability Zones for LOLE Analysis with Installed Wind ... 53
Generation Capacity (Nameplate Wind in Megawatts)
Table 2-1. LCOE Economic Assumptions (US $2009) ... 67
Table 2-2. Summary of Energy by Region for Scenarios ... 72
Table 2-3. Reference Case, 6% of 2024 Load Requirements ... 73
Table 2-4. Scenario 1—20% High Capacity Factor, Onshore ... 74
Table 2-5. Scenario 2—20% Hybrid with Offshore ... 76
Table 2-6. Scenario 3—20% Local, with Aggressive Offshore ... 77
Table 2-7. Scenario 4—30% Aggressive Onshore and Offshore ... 79
Table 3-1. Summary of Demand and Energy Assumptions Used ... 84
within the Scenario Definitions
Table 3-2. Status Categories Applied to all Units Within the Database ... 85
Table 3-3. Summary of Active Generation Capacity by Region ... 86
(Nameplate Capacities in Megawatts)
Table 3-4. Summary of Planned Generation Capacity by Region ... 86
through 2024 (Nameplate Capacities in Megawatts
Table 3-5. Summary of Generator Retirement Capacity by ... 87
Region through 2024 (Nameplate Capacities in Megawatts)
Table 3-6. Average Fuel Costs Modeled by System ... 94
Table 3-7. Target Reserve Margins by Region ... 96
Table 3-8. Modeled Generator Prototype Data Values in US $2008 ... 97
Table 3-9. Modeled Penetration of Demand Response by Region ... 97
(as percent age of peak)
Table 4-1. Top 24 Interfaces with the Largest Annual ... 108
Energy Difference
Table 4-2. Annual APC Savings for Each Scenario (US $2024, millions) ... 109

Table 4-3. Cost per Mile Assumption (US $2024, millions) 114
Table 4-4. Estimated Line Mileage Summary (Miles) 115
Table 4-5. Estimated Cost Summary (US $2024, millions) 115
Table 4-6. Benefit and Cost Comparison (US $2024, millions)............................... 115
Table 4-7. Estimated Additional Transmission Investments.................................. 116
for Scenario 1
Table 4-8. Estimated Additional Transmission Investments.................................. 116
for Scenario 2
Table 4-9. Estimated Additional Transmission Investments.................................. 117
for Scenario 3
Table 4-10. Estimated Additional Transmission Investments................................ 117
for Scenario 4
Table 4-11. Wind Curtailment Summary 120
Table 5-1. Excerpts from NERC Glossary of Terms Related to 129
Operating Reserves
Table 5-2. 2009 CPS2 bounds for Selected Eastern 132
Interconnection BAAs
Table 5-3. Mapping of Reserve Components in Categories for 140
Production Simulations
Table 5-4. Contingency Reserve Requirements by Operation 141
Region for 2024
Table 5-5. Summary of Reserve Methodology for Study Scenarios...................... 147
Table 5-6. Example Application of Reserve Methodology 149
to Hourly Data
Table 5-7. Adjustment of Spinning Reserve for Reduction 151
in Wind Generation
Table 5-8. Spinning Reserve Requirements by for the 152
Reference Case
Table 5-9. Spinning Reserve Requirements for Scenario 1 152
Table 5-10. Spinning Reserve Requirements for Scenario 2 153
Table 5-11. Spinning Reserve Requirements for Scenario 3 153
Table 5-12. Spinning Reserve Requirements for Scenario 4 153
Table 6-1. Integration Costs ($/MWh of Wind Energy in US$ 2024).................... 162
Table 6-2. Integration Costs US$ 2024 163
Table 6-3. Wind Curtailment Comparison for Sensitivity 182
Case 1, Non Must-Run
Table 6-4. Wind Curtailment Comparison for Sensitivity 182
Case 2, Copper Sheet
Table 6-5. Wind Curtailment Comparison for Sensitivity 183
Case 3, Wind Energy Credit
Table 6-6. Annual Generation Energy Summary by Fuel Type 183
Table 6-7. Scenario 1, Hurdle Rate Sensitivity Results... 186
Table 6-8. Scenario 3, Hurdle Rate Sensitivity Results... 186
Table 6-9. Scenario 2, Carbon Sensitivity Operational Impact Results................. 193

Table 7-1. Reliability zones for LOLE analysis with installed wind Generation Capacity (Nameplate wind in megawatts) 197
Table 7-2. ELCC Results for Isolated System (no ties) 202
Table 7-3. ELCC Results for Existing Transmission System 202
Table 7-4. ELCC Results for Overlay Transmission System 203
Table 7-5. Benefits from Overlay 205
Table 8-1. Assumptions used in Scenario Cost Calculations 209

PREFACE

The Eastern Wind Integration and Transmission Study (EWITS) is the culmination of an effort that spanned two and one-half years. The study team began by modeling wind resources in a large part of the Eastern Interconnection and finished by conducting a detailed wind integration study and top-down transmission analysis. The study resulted in information that can be used to guide future work. A number of other studies have already examined similar wind integration issues, but the breadth and depth of the analysis in EWITS is unique. EWITS builds on the work of previous integration studies, which looked at considerably smaller geographic footprints, focused almost exclusively on wind integration, and did not include transmission. EWITS took the next step by expanding the study area and including conceptual transmission overlays.

Just a few years ago, 5% wind energy penetration was a lofty goal, and to some the idea of integrating 20% wind by 2024 might seem a bit optimistic. And yet, we know from the European experience—where some countries have already reached wind energy penetrations of 10% or higher in a short period of time—that change can occur rapidly and that planning for that change is critically important. Because building transmission capacity takes much longer than installing wind plants, there is a sense of urgency to studying transmission. It is already starting to limit wind growth in certain areas.

The goal of the EWITS team was not to further any specific agenda or regional vision of the future, but to be as objective as possible while conducting a technical study of future high-penetration wind scenarios. To help guide the EWITS work, the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) convened a Technical Review Committee (TRC) composed of regional electric reliability council representatives, expert reviewers, transmission planners, utility administrators, and wind industry representatives. Over a period of 14 months while the study was in progress, the TRC held 6 full-day meetings along with numerous Webinars and conference calls to review study progress; comment on study inputs, methods, and assumptions; assist with collecting data; and review drafts of the study report.

Planning for the expansion of the electrical grid is a process that requires an immense amount of study, dialogue among regional organizations, development of technical methodologies, and communication and coordination among a multitude of important stakeholders. Keeping abreast of the changes is challenging because there are so many different developments, ideas, and viewpoints. It is my hope that the EWITS results will be helpful to all those involved in the planning of the future electrical grid and form a foundation for future studies.

David Corbus
Senior Engineer, NREL

ACKNOWLEDGMENTS

The National Renewable Energy Laboratory (NREL) thanks the U.S. Department of Energy (DOE) for sponsoring EWITS; the Technical Review Committee (TRC) for such great participation and input; and the study team of EnerNex Corporation, the Midwest Independent System Operator (Midwest ISO), and Ventyx for carrying out the work. Thanks also go to Study Lead Robert Zavadil, along with Michael Brower of AWS Truewind, who conducted the wind modeling study.

PROJECT MANAGER

David Corbus	NREL

STUDY TEAM

EnerNex Corporation:	Jack King, Tom Mousseau, and Robert Zavadil
Midwest ISO:	Brandon Heath, Liangying (Lynn) Hecker, John Lawhorn, Dale Osborn, and JT Smith
Ventyx:	Rick Hunt and Gary Moland

TECHNICAL REVIEW COMMITTEE

John Adams	New York Independent System Operator (NYISO)
Mark Ahlstrom	WindLogics
Jared Alholinna	CapX 2020 (Great River Energy)
Steve Beuning	Xcel Energy
Clifton Black	Southern Company
Jay Caspary	Southwest Power Pool (SPP)
Charlton Clark	DOE
Cathy Cole	Michigan Public Service Commission
David Corbus (co-chair)	NREL
Dan Fredrickson	Mid-Continent Area Power Pool (MAPP)
Michael Goggin	American Wind Energy Association (AWEA)
Sasan Jalai (observer)	Federal Energy Regulatory Commission (FERC)
Brendan Kirby	NREL
Chuck Liebold	PJM Interconnection
Michael Milligan	NREL
Jeff Mitchell	North American Electric Reliability Corporation (NERC; ReliabilityFirst)
Nathan Mitchell	American Public Power Association (APPA)
Don Neumeyer	Organization of MISO States (Wisconsin Public Service Commission)

Mark O'Malley	University College Dublin
Dale Osborn	Midwest ISO
Dick Piwko	GE Energy
Matt Schuerger (co-chair)	NREL
Ken Schuyler	PJM Interconnection
Richard Sedano	Regulatory Assistance Project
J. Charles Smith	Utility Wind Integration Group (UWIG)
Jason Smith	SPP
Dave Souder	PJM Interconnection

Finally, we thank René Howard (WordProse, Inc.), Kathy O'Dell (NREL), and Christina Thomas (Sage TechEdit Inc.) for their help in editing and production and Mark Schroder (Purple Sage Design) for designing this *Executive Summary and Project Overview* and the full report.

ABBREVIATIONS AND ACRONYMS

ACE	area control error
AECI	Associated Electric Cooperative, Inc.
AGC	automatic generation control
AMRN	Ameren
APC	adjusted production cost
ATC	American Transmission Company
BAA	balancing authority area
BAAL	balancing authority ACE limit
B/C	benefit cost (analysis)
CAPX 2020 (GRE)	Capital Expansion Plan for 2020 (Great River Energy)
CC	combined cycle
CC/Seq	combined cycle with sequestration
CO2	carbon dioxide
CPM	control performance measure
CPS1	Control Performance Standard 1
CPS2	Control Performance Standard 2
CT	combustion turbine
DCS	Disturbance Control Standard
DOE	U.S. Department of Energy
DR	demand response
ECAR	East Central Area Reliability Coordinating Agreement (a former NERC reliability region)
EERE	Office of Energy Efficiency and Renewable Energy
EGEAS	Electric Generation Expansion Analysis System
EHV	extra-high voltage
EHV AC	extra-high voltage AC
EHV DC	extra-high voltage DC
ELCC	effective load-carrying capability
EMS	energy management system
EPJM	East PJM
EPRI	Electric Power Research Institute

ERAG MMWG	Eastern Interconnection Reliability Assessment Group Multi-Regional Modeling Working Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ES&D	electricity supply and demand
EWIS	European Wind Integration Study
EWITS	Eastern Wind Integration and Transmission Study
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GE-MARS	GE Energy's Multi-Area Reliability Simulation program
GW	gigawatt
GWh	gigawatt-hour
HSIL	high-surge impedance loading
HVDC	high-voltage DC
Hz	hertz
IGCC	integrated gasification combined cycle
IGCC/Seq	integrated gasification combined cycle with sequestration
IESO	Independent Electricity System Operator
ISO	independent system operator
ISO-NE	New England ISO
JCSP	Joint Coordinated System Plan (2008)
km	kilometer
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
LMP	locational marginal price
LOLE	loss of load expectation
LOLP	loss of load probability
m	meter

MACC	Mid-Atlantic Area Council (a former NERC reliability region)
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
MHEB	Manitoba Hydro Electric Board
MISO	Midwest ISO
MBtu	million British thermal units
MRO	Midwest Reliability Organization
MW	megawatt
MWh	megawatt-hour
NBSO	New Brunswick Security Operator
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NWP	numerical weather prediction
NYISO	New York ISO
O&M	operations and maintenance
OMS	Organization of MISO States
PHEV	plug-in hybrid electric vehicle
PJM	PJM Interconnection
PTC	production tax credit
REC	renewable energy credit
RET Coal	coal plant retirement
RFC	ReliabilityFirst Corporation
RGOS	Regional Generation Outlet Study
RPS	renewable portfolio standard
RTO	regional transmission organization or regional transmission operator
SCUC	security-constrained unit commitment
SERC	Southeastern Electric Reliability Council
SLH	single largest hazard
SPP	Southwest Power Pool
SPS	Southwestern Public Service
ST	steam turbine
TRC	Technical Review Committee
TRE	Texas Regional Entity

TVA	Tennessee Valley Authority
TWh	terawatt-hours
UCTE	Union for the Co-ordination of Transmission of Electricity
UWIG	Utility Wind Integration Group
V	volt
W	watt
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WI PSC	Public Service Commission of Wisconsin
WWSIS	Western Wind and Solar Integration Study

EXECUTIVE SUMMARY

The total installed capacity of wind generation in the United States surpassed 25 gigawatts (GW) at the end of 2008. Despite the global financial crisis, another 4.5 GW was installed in the first half of 2009. Because many states already have mandates in place for renewable energy penetration, significant growth is projected for the foreseeable future.

In July 2008, the U.S. Department of Energy (DOE) published the findings of a year-long assessment of the costs, challenges, impacts and benefits of wind generation providing 20% of the electrical energy consumed in the United States by 2030 (EERE 2008). Developed through the collaborative efforts of a wide-ranging cross section of key stakeholders, that final report (referred to here as the 20% Report) takes a broad view of the electric power and wind energy industries. The 20% Report evaluates the requirements and outcomes in the areas of technology, manufacturing, transmission and integration, environmental impacts, and markets that would be necessary for reaching the 20% by 2030 target.

The 20% Report states that although significant costs, challenges, and impacts are associated with a 20% wind scenario, substantial benefits can be shown to overcome the costs. In other key findings, the report concludes that such a scenario is unlikely to be realized with a business-as-usual approach, and that a major national commitment to clean, domestic energy sources with desirable environmental attributes would be required.

The growth of domestic wind generation over the past decade has sharpened the focus on two questions: Can the electrical grid accommodate very high amounts of wind energy without jeopardizing security or degrading reliability? And, given that the nation's current transmission infrastructure is already constraining further development of wind generation in some regions, how could significantly larger amounts of wind energy be developed? The answers to these questions could hold the keys to determining how much of a role wind generation can play in the U.S. electrical energy supply mix.

ABOUT THE STUDY

DOE commissioned the Eastern Wind Integration and Transmission Study (EWITS) through its National Renewable Energy Laboratory (NREL). The investigation, which began in 2007, was the first of its kind in terms of scope, scale, and process. The study was designed to answer questions posed by a variety of stakeholders about a range of important and contemporary technical issues related to a 20% wind scenario for the large portion of the electric load (demand for energy) that resides in the Eastern Interconnection (Figure 1). The Eastern Interconnection is one of the three synchronous grids covering the lower

48 U.S. states. It extends roughly from the western borders of the Plains states through to the Atlantic coast, excluding most of the state of Texas.

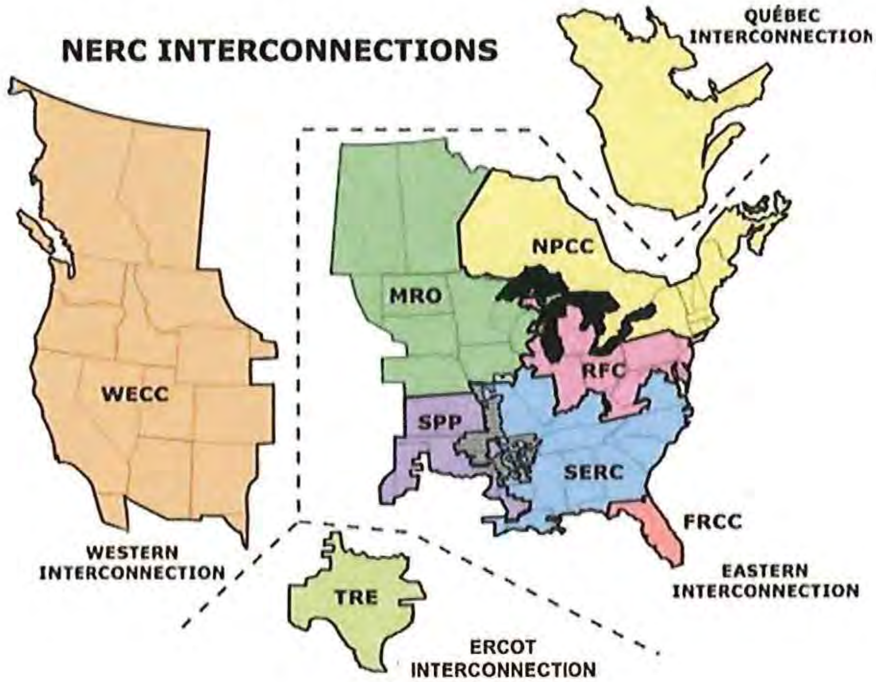


Figure 1. NERC synchronous interconnections

Notes: NERC = North American Electric Reliability Corporation; WECC = Western Electricity Coordinating Council; TRE = Texas Regional Entity; ERCOT = Electric Reliability Council of Texas; MRO = Midwest Reliability Organization; SPP = Southwest Power Pool; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; FRCC = Florida Reliability Coordinating Council

EWITS is one of three current studies designed to model and analyze wind penetrations on a large scale. The Western Wind and Solar Integration Study (WWSIS), also sponsored by DOE/NREL, is examining the planning and operational implications of adding up to 35% wind and solar energy penetration to the WestConnect footprint in the WECC. The European Wind Integration Study (EWIS) is an initiative established by the European associations of transmission system operators in collaboration with the European Commission. EWIS is aimed at developing common solutions to wind integration challenges in Europe and at identifying arrangements that will make best use of the pan-European transmission network, allowing the benefits of wind generation to be delivered across Europe.

EWITS was the first of its kind in terms of scope, scale, and process. Initiated in 2007, the study was designed to examine the operational impact of up to 20% to 30% wind energy penetration on the bulk power system in the Eastern Interconnection of the United States.

SCENARIO DEVELOPMENT AND ANALYSIS

To set an appropriate backdrop for addressing the key study questions, the EWITS project team—with input from a wide range of project stakeholders including the Technical Review Committee (TRC)—carefully constructed four high-penetration scenarios to represent different wind generation development possibilities in the Eastern Interconnection. Three of these scenarios delivered wind energy equivalent to 20% of the projected annual electrical energy requirements in 2024; the fourth scenario increased the amount of wind energy to 30%.

In each scenario, individual wind plants from the Eastern Wind Data Study database (see sidebar) were selected to reach the target energy level. The wind data consisted of hourly and 10-minute wind plant data for each of three years: 2004, 2005, and 2006. Wind plants were available in all geographic locations within the Eastern Interconnection except off the shore of the southeastern United States and Canada (because of limitations on the scope of work for the wind modeling). Approximately 4 GW of new Canadian renewable generation was modeled to cover imports of new Canadian wind and hydro to the northeast.

The Eastern Wind Data Study

A precursor to EWITS known as the Eastern Wind Data Study (AWS Truewind 2009) identified more than 700 GW of potential future wind plant sites for the eastern United States. All the major analytical elements of EWITS relied on the time series wind generation production data synthesized in this earlier effort. The data cover three historical years—2004, 2005, and 2006—at high spatial (2-kilometer [km]) and temporal (10-minute) resolution. On- and offshore resources are included, along with wind resources for all states.

A brief description of each scenario follows:

- **Scenario 1, 20% penetration –** High Capacity Factor, Onshore: Utilizes high-quality wind resources in the Great Plains, with other development in the eastern United States where good wind resources exist.
- **Scenario 2, 20% penetration –** Hybrid with Offshore: Some wind generation in the Great Plains is moved east. Some East Coast offshore development is included.
- **Scenario 3, 20% penetration –** Local with Aggressive Offshore: More wind generation is moved east toward load centers, necessitating broader use of offshore resources. The offshore wind assumptions represent an uppermost limit of what could be developed by 2024 under an aggressive technology-push scenario.

- **Scenario 4, 30% penetration** – Aggressive On- and Offshore: Meeting the 30% energy penetration level uses a substantial amount of the higher quality wind resource in the NREL database. A large amount of offshore generation is needed to reach the target energy level.

The study team also developed a **Reference Scenario** to approximate the current state of wind development plus some expected level of near-term development guided by interconnection queues and state renewable portfolio standards (RPS). This scenario totaled about 6% of the total 2024 projected load requirements for the U.S. portion of the Eastern Interconnection.

What Are ISOs and RTOs?

In the mid-1990s, independent system operators (ISOs) and regional transmission operators (RTOs) began forming to support the introduction of competition in wholesale power markets. Today, two-thirds of the population of the United States and more than one-half of the population of Canada obtain their electricity from transmission systems and organized wholesale electricity markets run by ISOs or RTOs. These entities ensure that the wholesale power markets in their regions operate efficiently, treat all market participants fairly, give all transmission customers open access to the regional electric transmission system, and support the reliability of the bulk power system.

Source: Adapted from IRC (2009).

Figure 2 depicts the installed capacity by regional entity (either independent system operators [ISOs] or regional transmission operators [RTOs]; see sidebar) for each of the wind generation scenarios in EWITS. Table 1 shows the contribution of total and offshore wind to the scenarios.

Supplying 20% of the electric energy requirements of the U.S. portion of the Eastern Interconnection would call for approximately 225,000 megawatts (MW) of wind generation capacity, which is about a tenfold increase above today's levels. To reach 30% energy from wind, the installed capacity would have to rise to 330,000 MW.

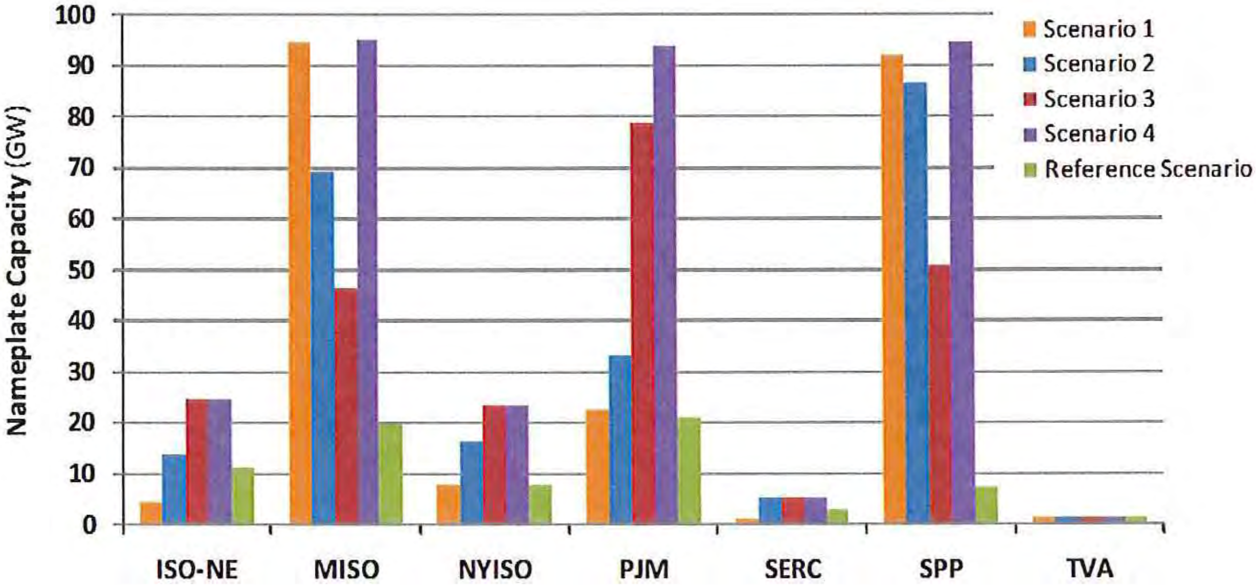


Figure 2. Summary of installed wind generation capacity by operating region for each scenario *(Notes: ISO-NE = New England Independent System Operator, MISO = Midwest ISO, NYISO = New York ISO, PJM = PJM Interconnection, SERC = Southeastern Electric Reliability Council, SPP = Southwest Power Pool, TVA – Tennessee Valley Authority)*

TABLE 1. TOTAL AND OFFSHORE WIND IN THE SCENARIOS

Region	Scenario 1 20% High Capacity Factor, Onshore		Scenario 2 20% Hybrid with Offshore		Scenario 3 20% Local, Aggressive Offshore		Scenario 4 30% Aggressive On- and Offshore	
	TOTAL (MW)	Offshore (MW)	Total (MW)	Offshore (MW)	Total (MW)	Offshore (MW)	Total (MW)	Offshore (MW)
MISO/ MAPP[a]	94,808		69,444		46,255		95,046	
SPP	91,843		86,666		50,958		94,576	
TVA	1,247		1,247		1,247		1,247	
SERC	1,009		5,009	4,000	5,009	4,000	5,009	4,000
PJM	22,669		33,192	5,000	78,736	39,780	93,736	54,780
NYISO	7,742		16,507	2,620	23,167	9,280	23,167	9.280
ISO-NE	4,291		13,837	5,000	24,927	11,040	24,927	11,040
TOTAL	223,609	0	225,902	16,620	230,299	64,100	337,708	79,100

[a] MAPP stands for Mid-Continent Area Power Pool.

KEY STUDY FINDINGS

The EWITS technical work yielded detailed quantitative information on

- Wind generation required to produce 20% of the projected electrical energy demand over the U.S. portion of the Eastern Interconnection in 2024
- Transmission concepts for delivering energy economically for each scenario (new transmission for each scenario is based on economic performance for the conditions outlined in that scenario)
- Economic sensitivity simulations of the hourly operation of the power system defined by a wind generation forecast scenario and the associated transmission overlay
- The contribution made by wind generation to resource adequacy and planning capacity margin.

The specific numeric results of the analysis are sensitive to the many assumptions that were required to define the 2024 study year. The study assumptions were developed in close coordination with the TRC. Changes in the assumptions, such as the cost of various fuels, the impact of regulation and policy, or the costs associated with new construction, would have a major influence. Other assumptions, such as the electrical energy demand and its characteristics—penetration and capabilities of demand response, influence of smart grid technologies, or the very nature of the load itself (as in an aggressive plug-in hybrid electric vehicle [PHEV] scenario)—would be likely to have a measurable impact on the results.

In general, though, the study shows the following:

- High penetrations of wind generation—20% to 30% of the electrical energy requirements of the Eastern Interconnection—are technically feasible with significant expansion of the transmission infrastructure.
- New transmission will be required for all the future wind scenarios in the Eastern Interconnection, including the Reference Case. Planning for this transmission, then, is imperative because it takes longer to build new transmission capacity than it does to build new wind plants.
- Without transmission enhancements, substantial curtailment (shutting down) of wind generation would be required for all the 20% scenarios.
- Interconnection-wide costs for integrating large amounts of wind generation are manageable with large regional operating pools and significant market, tariff, and operational changes.
- Transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of the available generation resources. Although costs for aggressive expansions of the existing grid are significant, they make up a relatively small portion of the total annualized costs in any of the scenarios studied.

- Carbon emission reductions in the three 20% wind scenarios do not vary by much, indicating that wind displaces coal in all scenarios and that coal generation is not significantly exported from the Midwest to the eastern United States; carbon emissions are reduced at an increased rate in the 30% wind scenario as more gas generation is used to accommodate wind variability. Wind generation displaces carbon-based fuels, directly reducing carbon dioxide (CO_2) emissions. Emissions continue to decline as more wind is added to the supply picture. Increasing the cost of carbon in the analysis results in higher total production costs.

The scenarios developed for EWITS do not in any way constitute a plan; instead, they should be seen as an initial perspective on a top-down, high-level view of four different 2024 futures. The transition over time from the current state of the bulk power system to any one of the scenarios would require additional technical and economic evaluation, including detailed modeling of power flows and a study of the effects on the underlying transmission systems. A more thorough evaluation of the sensitivity of the EWITS results to the range of assumptions made would also be required to guide the development of any specific bottom-up plans.

The significant amount of analytical work performed in EWITS, though, answers the questions posed at the outset of the project:

1. What impacts and costs do wind generation variability and uncertainty impose on system operations? **With large balancing areas and fully developed regional markets, the cost of integration for all scenarios is about $5 (US$ 2009) per megawatt-hour (MWh) of wind, or about $0.005 per kilowatt-hour (kWh) of electricity used by customers.**

2. What benefits accrue from long-distance transmission that accesses multiple and geographically diverse wind resources? **The study results show that long-distance (and high-capacity) transmission can assist smaller balancing areas with wind integration, allowing penetration levels that would not otherwise be feasible. Furthermore, all scenarios, including the Reference Case, made use of major transmission upgrades to better interlock Eastern Interconnection markets for assisting with wind integration.**

Why Regional Markets?

Because they span large geographic areas, regional markets optimize the power grid by promoting efficiency through resource sharing. These organized markets are designed so that an area with surplus electricity can benefit by sharing megawatts with another region in the open market. This allows participants and operators to see the big picture when it comes to dispatching electricity in the most efficient manner.

Source: Adapted from www.isorto.org. Accessed November 2009.

3. What benefits are realized from long-distance transmission that moves large quantities of remote wind energy to urban markets? **Long-distance transmission, along with assumed modifications to market and system operations, contributes substantially to integrating large amounts of wind that local systems would have difficulty managing. In addition, long-distance transmission has other value in terms of system robustness that was not completely evaluated in EWITS.**

4. How do remote wind resources compare to local wind resources? **In the Eastern Interconnection, the Eastern Wind Data Study database (AWS Truewind 2009) shows that the higher quality winds in the Great Plains have capacity factors that are about 7%–9% higher than onshore wind resources near the high-load urban centers in the East. Offshore plants have capacity factors on par with Great Plains resources but the cost of energy is higher because capital costs are higher.**

5. How much does geographical diversity, or spreading the wind out across a large area, help reduce system variability and uncertainty? **Quite substantially.**

6. What is the role and value of wind forecasting? **With significant wind generation, forecasting will play a key role in keeping energy markets efficient and reducing the amount of reserves carried while maintaining system security.**

7. What benefit does balancing area cooperation or consolidation bring to wind variability and uncertainty management? **This and other recent studies (see Bibliography) reinforce the concept that large operating areas—in terms of load, generating units, and geography—combined with adequate transmission, are the most effective measures for managing wind generation.**

8. How does wind generation capacity value affect reliability (i.e., supply resource adequacy)? **Wind generation can contribute to system adequacy, and additional transmission can enhance that contribution.**

SCENARIO COSTS

EWITS looks at a "snapshot" in time for a single year in the future. A transformation of the bulk power system in the Eastern Interconnection to the degree suggested by the study scenarios would result if many capital investments were made from the present through 2024. Consequently, economic analysis of the scenarios brings to light complicated questions that cannot be answered precisely without a detailed timeline of capital expenditures.

Because the study scenarios need to be compared on an economic basis, total costs for each scenario are approximated by identifying the fixed (investment) and variable (production) cost components. These costs are then summed, allowing the study team to view some measure of economic performance for each scenario side by side.

Study analysts calculated costs for each scenario as the sum of production-related costs (e.g., fuel costs) plus annualized amounts for capital investments in new conventional generation, wind plants, and transmission. The results for the Reference Case and the four high-penetration scenarios (Figure 3, in millions of US$2009) show that Scenario 1 is the least costly of the 20% scenarios, and that the increased cost of offshore wind adds to the costs in Scenarios 3 and 4.

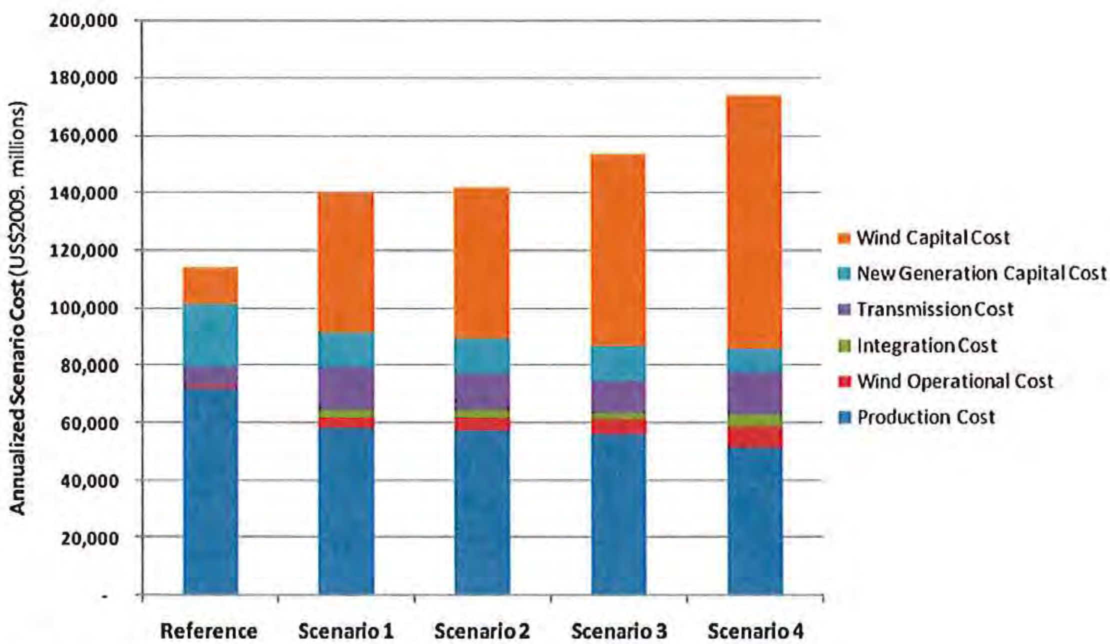


Figure 3. Comparison of scenario costs

Although production-related costs constitute a large fraction of the total costs for all scenarios, these decline as the amount of wind generation increases. In scenarios 3 and 4, capital costs for wind generation increase because of slightly lower capacity factors and the much higher capital cost of offshore construction.

Transmission costs are a relatively small fraction for all scenarios, with only a small absolute difference seen across the 20% cases. Wind integration costs are measurable but very small relative to the other factors.

None of the initial scenarios include any costs associated with carbon, which increases production costs significantly. The carbon price was addressed in a sensitivity analysis for Scenario 2, as described later in this *Executive Summary and Project Overview.*

STUDY METHODOLOGY

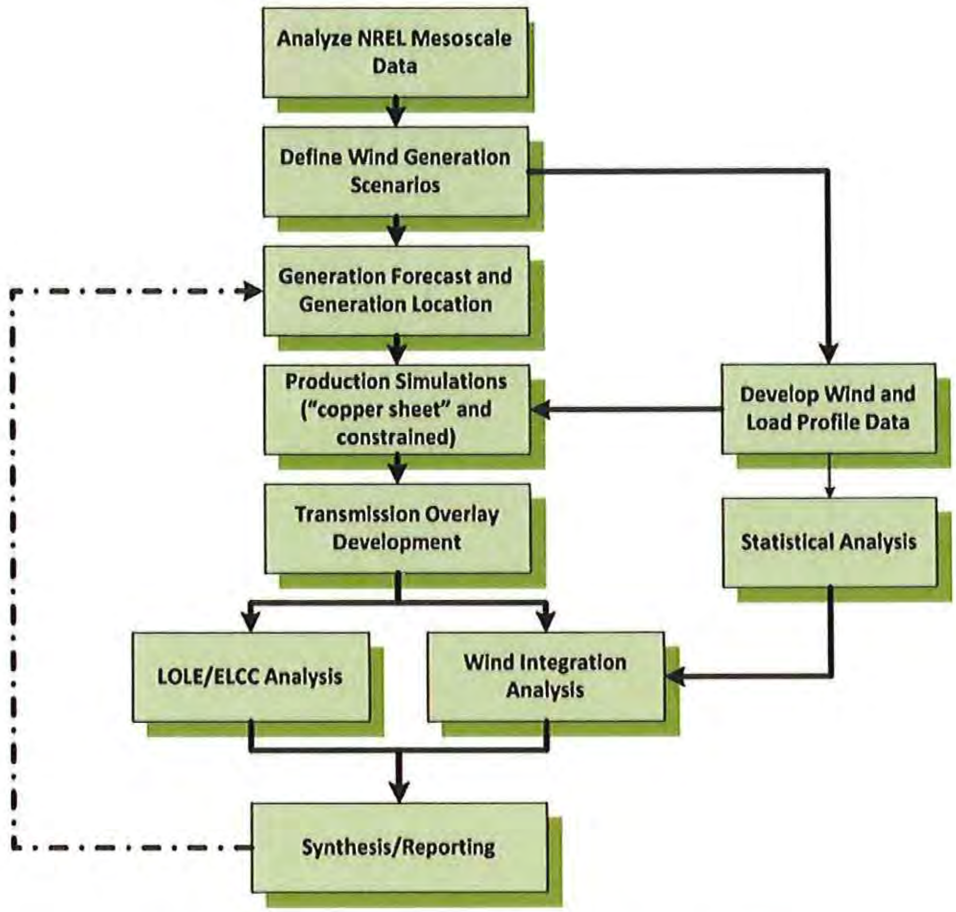
The EWITS project consisted of three major tasks: (1) wind plant output data development, (2) transmission requirements analysis, and (3) wind integration analysis. In wind integration studies, it is important to use concurrent load and wind data to capture the correlations between load and wind (i.e., weather; see sidebar).

The project team developed the quantitative information through a multistage analytical process, shown graphically in Figure 4. Methods developed and refined in previous integration studies formed the basis for the technical analysis, but were necessarily extended because the scope and size of this effort surpassed that of earlier studies. Focus on transmission requirements for the substantial amount of wind generation required to meet the 20% and 30% energy targets was a new and significant part of the study scope.

The Role of Weather and Wind Forecasting

Using numerical weather prediction models, also known as mesoscale models, is an accepted method for producing a time series of wind plant output data. Essentially, physics-based, numerical simulations on supercomputers, integrated with observational data sets, re-create the weather of historical years and generate a four-dimensional gridded wind-speed data set. A wind speed time series data set can be extracted and converted to wind power output. This approach produces a temporally, spatially, and physically consistent wind data set. For EWITS, this was done for hundreds of wind plants and the study team used these data sets in the modeling of the different scenarios.

Wind forecast data modeling is an increasingly common tool used by utilities and ISOs to schedule generation units. Wind integration studies typically include the effect of wind forecast errors on integration costs.



Notes: A copper sheet simulation assumes no transmission constraints or congestion.
LOLE = loss of load expectation and ELCC = effective load-carrying capability

Figure 4. Study process

Current transmission expansion planning is based on a decision-making process that starts with the present and looks forward through time. The existing bulk power grid in the United States is the result of such a bottom-up approach. In EWITS, the project team used top-down economic methods to develop the conceptual transmission capacity needed to deliver energy to load. These top-down methods tend to create designs with more transmission than bottom-up methods. The primary reason is that the total economic potential of increasing the economic efficiency of the generation fleet—including wind generation in the Eastern Interconnection—is used to justify transmission expansion. The combination of capturing the economic potential of both nonwind and wind generation loads the transmission lines more efficiently (i.e., the lines are not just being used for wind). The transmission requirements are mainly off peak for the wind generation and on peak for the nonwind generation.

Although the study assumptions were touched on previously, a more detailed look is helpful at this point. Peak demand and energy for all study regions was based on 2004–2006 Federal Energy Regulatory Commission (FERC) data combined with 2006 power flow data. These data had been compiled for a previous study, and were reviewed by all stakeholders at that time. To preserve correlation with the wind generation profile data, load data for EWITS were mapped to conform to actual wind profiles representing calendar years 2004, 2005, and 2006.

Because of the very large amount of wind generation studied, it was important to establish a framework for the day-to-day operations of the Eastern Interconnection in 2024. Results from past integration studies have shown that operational structure plays a major role in determining the difficulty or ease with which wind generation is integrated. Small balancing areas, which were the original building blocks of today's major interconnections, can be significantly challenged by large amounts of wind generation. Large effective balancing areas (see sidebar) have more supply resources to deploy and benefit substantially from diversity in both load and wind generation.

Extrapolating from trends that have been seen for the past decade, the study team—with input from the TRC—assumed that by 2024 operations in the Eastern Interconnection (at least the significant fraction modeled explicitly in EWITS) would be conducted under the auspices of seven large balancing areas, which are shown in Figure 5. The structure as it existed in August 2007 was used for comparison. Five of the seven correspond to existing RTOs in the Eastern Interconnection.

The project team also assumed that operations in each area would conform to the same structure. For example, on the day before the operating day, all generating units bid competitively to serve load, and after market clearing, operators perform a security-constrained unit commitment to ensure that adequate capacity will be available to meet forecast load. During the operating day, generators are dispatched frequently to follow short-term demand trends under a fast, subhourly market structure. A competitive ancillary services market

Operating the Grid

Balancing Authority

A balancing authority is the responsible entity that maintains load resource balance within a given, predefined area (the balancing authority area). The authority develops integrated resource plans, matches generation with load, maintains scheduled interchanges with other balancing authority areas, and supports interconnection frequency of the electric power systems in real time.

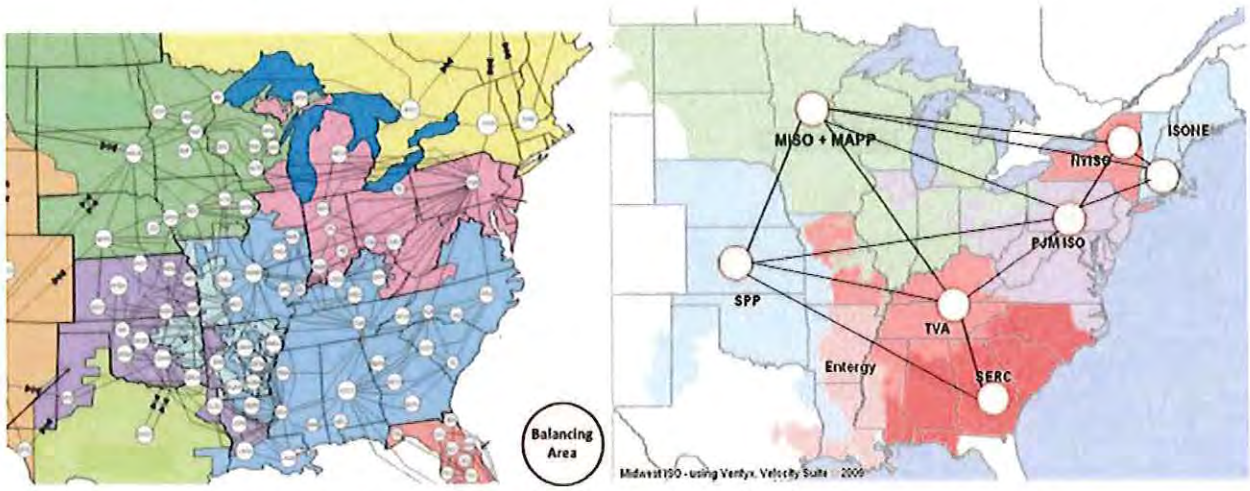
Reliability-Related Services

In the NERC Functional Model, which defines the set of functions that must be performed to ensure the reliability of the bulk electric system, these include the range of services, other than the supply of energy for load, that are physically provided by generators, transmitters, and loads in order to maintain reliability. In wholesale energy markets, they are commonly described as "ancillary services."

Source: Adapted from http://www.nerc.com/files/opman_12-13Mar08.pdf. Accessed November 2009.

supplies regulation, balancing, and unused generation capacity to cover large events such as the loss of major generating facilities.

The assumptions made about operating structure are very significant given the current operations in the Eastern Interconnection. The assumed market mechanisms, however, are actually in use today, albeit not uniformly, and have been shown in previous studies to be of substantial value for wind integration. There is some probability that developments in market operation over the next decade could further enhance the ability to integrate wind energy.



As of August 1, 2007 | Assumption for 2024

Figure 5. Assumed operational structure for the Eastern Interconnection in 2024 (white circles represent balancing authorities; Entergy is operated as part of SERC)

PROJECT OVERVIEW

This section describes the transmission requirements, wind operational impacts, production-cost modeling results, wind integration costs, carbon sensitivity analysis, and the wind contribution to resource adequacy for EWITS.

TRANSMISSION REQUIREMENTS

EWITS uses a deterministic, chronological production-cost model (PROMOD IV®)[1] for evaluating transmission requirements. The study process began with locating wind generation across the interconnection, and then determining what additional nonwind capacity would be required in each region to maintain reliability for the projected energy demand in the study year. No new transmission was considered at this stage. This step allowed the study analysts to identify the locations of electrical energy supply and locate the loads or demand for the energy. To develop the transmission overlays, then, the project team used economic signals to connect the "sources" (supply) to the "sinks" (loads).

The study team used an economics-based expansion planning methodology to develop transmission requirements for each scenario based on the output of the different production simulations. Before each set of simulations, the additional nonwind capacity required to reliably serve the projected load was determined using traditional generation expansion methodologies. Wind generation was assigned a firm capacity value of 20%. Next, wind generation and the indicated conventional expansion were added to the production-cost model that contained the existing transmission network.

After simulating system operation over an entire year of hourly data, study analysts then compared the results of this modeling simulation to those from a similar simulation in which constraints on the transmission system were removed. The comparison indicates how regional or interconnection-wide production costs increase because of transmission congestion, or put another way, what value could be achieved by eliminating or reducing transmission constraints. Differences between the "constrained" case and the "unconstrained" case yield the following information:

- The areas of economic energy sources and sinks
- The interface flow changes to determine the incremental transfer capacity needs
- The total benefit savings, which in turn gives a rough estimate of a potential budget for building transmission to relieve constraints and reduce congestion costs

[1] PROMOD IV (developed by Ventyx) is an integrated electric generation and transmission market simulation system that incorporates extensive details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. PROMOD IV performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar level. (Bus-bar refers to the point at which power is available for transmission.)

Transmission flows between regions in EWITS are determined in part by the differences between production simulations using a "copper sheet" (i.e., no transmission constraints, no congestion) versus the existing transmission system. Transmission capacity is designed to deliver 80% of the desired energy flow. Figure 6 shows the annual generation differences between the unconstrained and constrained cases for Scenario 2. This helps to define the energy source and sink areas and gives insight into the optimal locations for potential transmission lines and substations. Red represents the energy source areas; blue signifies the energy sink areas. As Figure 7 illustrates, the price signal drives energy from low-cost source areas to high-cost sink areas if the transmission system is not constrained across the study footprint.

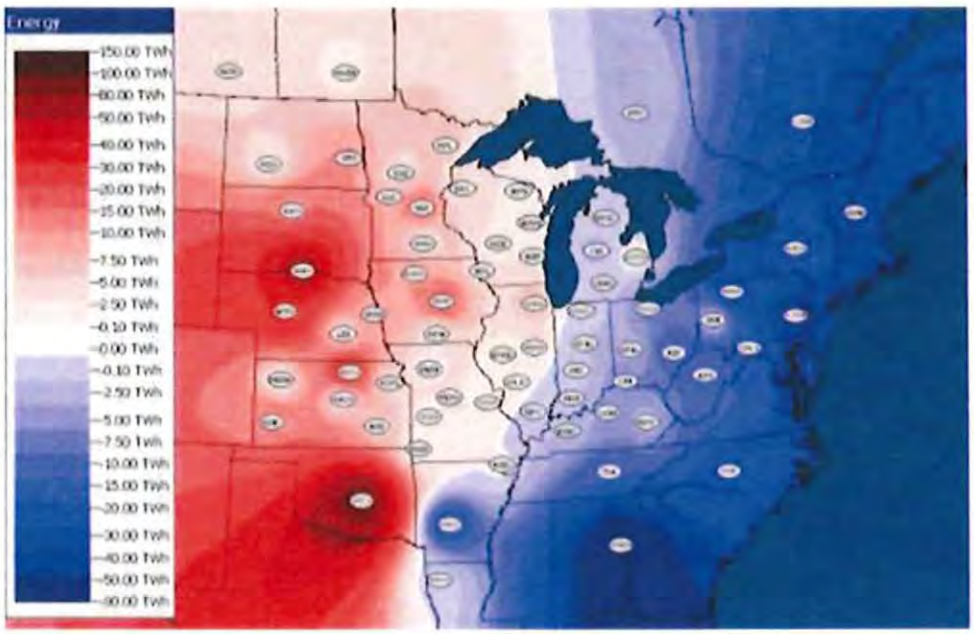


Figure 6. Scenario 2, annual generation differences between unconstrained case and constrained case *(Note: Because price contours developed from defined pricing hubs, they do not correspond exactly to geography.)*

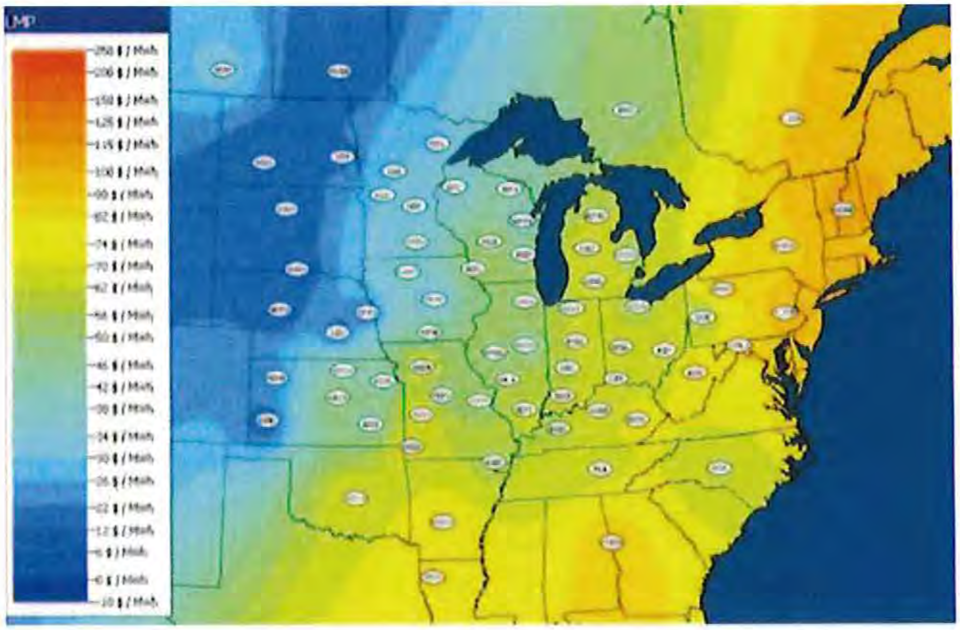


Figure 7. Scenario 2, annual generation weighted locational marginal price (LMP) for constrained case

Using these comparative results as a guide, and with input from the TRC, the study team developed transmission overlays for each scenario.

The conceptual transmission overlays, shown in Figure 8, consist of multiple 800-kilovolt (kV) high-voltage direct current (HVDC) and extra-high voltage (EHV) AC lines with similar levels of new transmission and common elements for all four scenarios. Tapping the most high-quality wind resources for all three 20% scenarios, the project team arrived at a transmission overlay for Scenario 1 that consists of nine 800-kV HVDC lines and one 400-kV HVDC line. For Scenario 2, analysts moved some wind generation eastward, resulting in a reduced transmission overlay with seven 800-kV HVDC lines and one 400-kV HVDC line. As more wind generation is moved toward the east and more offshore resources are used in Scenario 3, the resulting transmission overlay has the fewest number of HVDC lines, with a total number of five 800-kV HVDC lines and one 400-kV HVDC line. To accommodate the aggressive 30% wind target and deliver a significant amount of offshore wind along the East Coast in Scenario 4, the overlay must be expanded to include ten 800-kV HVDC lines and one 400-kV HVDC line.

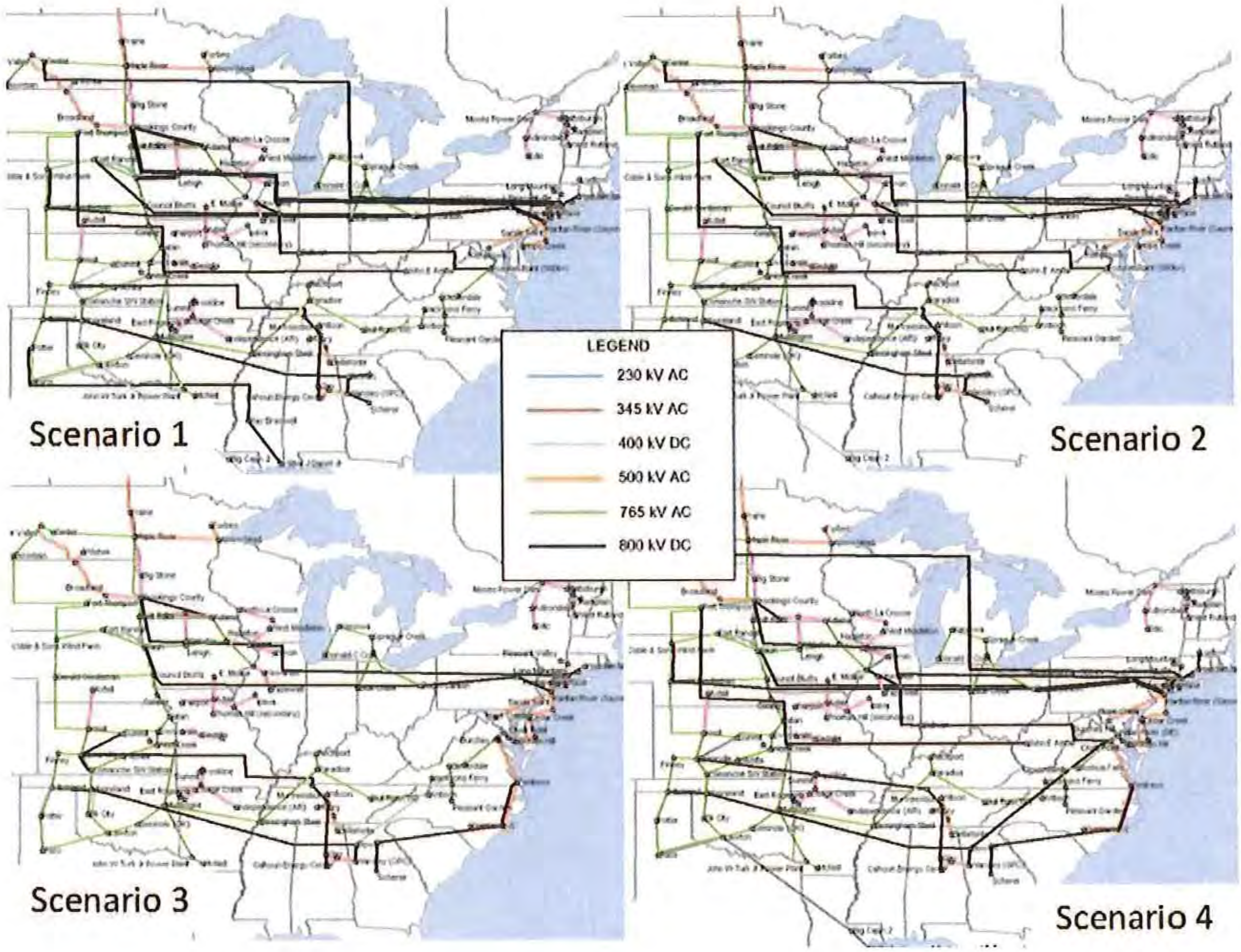


Figure 8. Conceptual EHV transmission overlays for each study scenario

Tables 2 through 4 summarize the transmission and construction cost-per-mile assumptions by voltage level, the estimated total line miles by voltage level, and the estimated cost in US$2024 for the four wind scenario conceptual overlays, respectively. In Table 4, the total AC line costs include a 25% margin to approximate the costs of substations and transformers. In addition, the total HVDC line costs include those for terminals, communications, and DC lines. Costs associated with an offshore wind collector system and those for some necessary regional transmission upgrades are not included in the total estimated cost and would increase total transmission costs. With approximately 22,697 miles of new EHV transmission lines, the transmission overlay for Scenario 1 has the highest estimated total cost at $93 billion (US$2009).

TABLE 2. TRANSMISSION COST ASSUMPTIONS							
COST-PER-MILE ASSUMPTION							
VOLTAGE LEVEL	345 KV	345 KV AC (DOUBLE UNIT)	500 KV	500 KV AC (DOUBLE CIRCUIT)	765 KV	400 KV DC	800 KV DC
US$2024 (MILLIONS)	2,250,000	3,750,000	2,875,00	4,792,00	5,125,000	3,800,000	6,000,000
US$2009 (MILLIONS)	1,440,000	2,410,000	1,850,00	3,080,00	3,290,000	2,440,000	3,850,000

TABLE 3. ESTIMATED LINE MILEAGE BY SCENARIO								
ESTIMATED LINE MILEAGE SUMMARY								
VOLTAGE LEVEL	345 KV	345 KV AC (DOUBLE CIRCUIT)	500 KV	500 KV AC (DOUBLE CIRCUIT)	765 KV	400 KV DC	800 KV DC	TOTAL
REFERENCE	3,106	292	593	494	2,624	470	2,400	9,979
SCENARIO 1	1,977	247	1,264	243	7,304	560	11,102	22,697
SCENARIO 2	1,977	247	1,264	243	7,304	560	8,352	19,947
SCENARIO 3	1,977	247	1,264	742	7,304	769	4,747	17,050
SCENARIO 4	1,977	247	1,264	742	7,304	560	10,573	22,667

TABLE 4. ESTIMATED COSTS BY SCENARIO (US$2009, MILLIONS)								
Estimated Cost Summary (US $2024, millions)								
VOLTAGE LEVEL	345 KV	345 KV AC (DOUBLE CIRCUIT)	500 KV	500 KV AC (DOUBLE CIRCUIT)	765 KV	400 KV DC	800 KV DC	TOTAL
Reference	5,607	880	1,367	1,900	10,790	1,383	9,243	31,170
Scenario 1	3,569	743	2,916	935	30,033	1,539	53,445	93,179
Scenario 2	3,569	743	2,916	935	30,033	1,539	40,206	79,941
Scenario 3	3,569	743	2,916	935	30,033	1,898	22,852	64,865
Scenario 4	3,569	743	2,916	935	30,033	1,539	50,898	92,551

Specific findings and conclusions from development of the transmission overlays for each scenario include the following:

- The 800-kV HVDC and EHV AC lines are preferred if not required because of the volumes of energy that must be transported across and around the interconnection, as well as the distances involved.
- Similar levels of new transmission are needed across the four scenarios, and certain major facilities appear in all the scenarios. This commonality is influenced by the top-down method used and the location of the wind generation in each scenario. The study focuses on four possible 2024 "futures." Determining a path for realizing one or more of those futures was outside the study scope. Large amounts of transmission are also required in the Reference Case.
- The modeling indicates that significant wind generation can be accommodated as long as adequate transmission capacity is available and market/operational rules facilitate close cooperation among the operating regions.

- Transmission offers capacity benefits in its own right, and enhances wind generation's contribution to reliability by a measurable and significant amount.
- The EHV DC transmission that constitutes a major portion of the overlays designed for the scenarios in EWITS has benefits beyond those evaluated here. For example, it would be possible to schedule reserves from one area to another, effectively transporting variability resulting from wind and load to areas that might be better equipped to handle it. And the transfer capability of the underlying AC network could be enhanced by using the DC terminals to mitigate limitations caused by transient stability issues.

WIND OPERATIONAL IMPACTS

Reliable delivery of electrical energy to load centers entails a continuous process of scheduling and adjusting electric generation in response to constantly changing demand. Sufficient amounts of wind generation increase the variability and uncertainty in demand that power system operators face from day to day or even from minute to minute. Quantifying how the amounts of wind generation in each of the study scenarios would affect daily operations of the bulk system and estimating the costs of those effects were major components of EWITS.

Using detailed chronological production simulations for each scenario, the study team assessed impacts on power system operation. The objective of these simulations was to mimic how day-to-day operations of the Eastern Interconnection would be conducted in 2024 with the prescribed amounts of wind generation in each scenario, new conventional generation per the expansion study, and the transmission overlays the study team developed. Ways to manage the increased variability and uncertainty attributable to wind generation, along with the resulting effect on operational costs, were of primary interest.

EWITS uses a deterministic production-cost model to run hourly power system operational simulations using the transmission overlays for each scenario and the wind plant outputs and actual load data for 2004, 2005, and 2006. The model takes the wind generation at each "injection bus" (i.e., the closest transmission connection to the wind plant) and dispatches nonwind generation units accordingly for each market region while solving at the model node for the LMP. The tool simulates actual power system operations by first solving the unit-commitment problem (i.e., what conventional generators will be dispatched to meet load), then using the wind power and load forecasts, and finally dispatching the units based on the actual modeled wind and load data. Obtaining realistic results is necessary because unit-commitment decisions must actually be made well in advance, allowing generators sufficient time to start up and synchronize to the grid. A hurdle rate accounts for hourly transactions among eight different market regions. The simulation is done over the entire study region and the wind plant and load time series data capture geographic diversity.

RESERVE REQUIREMENTS

With large amounts of wind generation, additional operating reserves (see sidebar) are needed to support interconnection frequency and maintain balance between generation and load. Because the amounts of wind generation in any of the operating areas, for any of the scenarios, dramatically exceed the levels for which appreciable operating experience exists, the study team conducted statistical and mathematical analyses of the wind generation and load profile data to estimate the additional requirements. These were used as inputs to the production-cost modeling. The analysis focused on the major categories of operating reserves, which included needs for regulation, load following, and contingencies.

In the production simulations for each scenario, study analysts took into account the additional uncertainty and variability resulting from wind generation by

- Incorporating the increased operating reserves as constraints on the commitment and dispatch of generating resources in each operating area
- Committing generating units for operation based on forecasts of load and wind generation, then dispatching the available units against actual quantities.

The levels of wind generation considered in EWITS increase the amount of operating reserves required to support interconnection frequency and balance the system in real time. Contingency reserves are not directly affected, but the amount of spinning reserves assigned to regulation duty must increase because of the additional variability and short-term uncertainty of the balancing area demand.

Types of Reserves

In bulk electric system operations, different types of generation reserves are maintained to support the delivery of capacity and energy from resources to loads in accordance with good utility practice.

Contingency Reserves

Reserves to mitigate a "contingency," which is defined as the unexpected failure or outage of a system component, such as a generator, a transmission line, a circuit breaker, a switch, or another electrical element. In the formal NERC definition, this term refers to the provision of capacity deployed by the balancing authority to meet the disturbance control standard (DCS) and other NERC and regional reliability organization contingency requirements.

Operating Reserves

That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. This type of reserve consists of both generation synchronized to the grid and generation that can be synchronized and made capable of serving load within a specified period of time.

Regulating Reserves

An amount of reserve that is responsive to automatic generation control (AGC) and is sufficient to provide normal regulating margin. Regulating reserves are the primary tool for maintaining the frequency of the bulk electric system at 60 Hz.

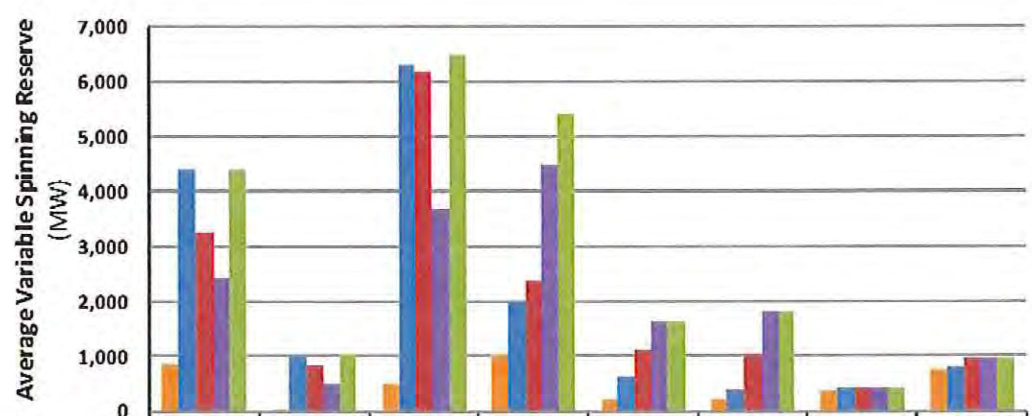
Spinning Reserves

The portion of operating reserve consisting of (1) generation synchronized to the system and fully available to serve load within the disturbance recovery period that follows a contingency event; or (2) load fully removable from the system within the disturbance recovery period after a contingency event.

The assumption of large balancing areas does reduce the requirement, however. Under the current operational structure in the Eastern Interconnection, the total amount of regulation that would need to be carried would be dramatically higher.

Using the methodology developed for EWITS, the study team calculated regulating reserve requirements for each region and each scenario from hourly load data and 10-minute wind production data. The result is an hourly profile that varies with both the amount of load and the level of wind generation. The calculations account for important characteristics of the wind generation scenario, such as the amount of geographic diversity and its influence on the aggregate short-term variability.

Figure 9 summarizes the regulating reserve requirements for each region and each scenario. The value indicated by the bar is the average of the annual hourly profile. The load-only case is a reference for calculating the incremental requirement resulting from wind generation.



	MISO	MAPP	SPP	PJM	NYISO	ISO-NE	TVA	SERC
Load Only	885	43	514	1055	217	202	365	741
Actual Wind S1	4,424	1,020	6,308	1,994	618	399	420	816
Actual Wind S2	3,245	835	6,176	2,359	1,118	1,046	418	955
Actual Wind S3	2,419	503	3,695	4,463	1,614	1,789	418	955
Actual Wind S4	4,423	1,038	6,487	5,410	1,614	1,789	418	955

Figure 9. Regulating reserve requirements by region and scenario. *The incremental amount resulting from wind generation is the difference between the scenario number and the load-only value.*

Current operating experience offers little guidance on managing the incremental variability and uncertainty associated with large amounts of wind generation in the operating footprints defined for EWITS. The statistical analysis conducted on the time series data from the scenarios, however, forms a highly reasonable analytical foundation for the assumptions and reserve requirement results that the study team carried forward to the production simulations.

The team's analysis of reserve requirements with substantial amounts of wind generation resulted in the following findings and conclusions:

- The assumptions made about how the Eastern Interconnection will be operated in 2024 played an important role in minimizing the additional amounts of spinning reserve that would be required to manage the variability of large amounts of wind generation.
- The large size of the market areas assumed in the study allows substantial benefits of geographic diversity to be realized.
- The pooling of larger amounts of load and discrete generating resources via regional markets also realizes diversity benefits. The per-unit variability of load declines as the amount of load increases; larger markets also have more discrete generating units of diverse fuel types and capabilities for meeting load and managing variability.
- With real-time energy markets, changes in load and wind that can be forecast over a short interval—10 minutes in EWITS, 15 to 20 minutes in current practice—are compensated for through economic movements of participating generating units. Because load changes over 10-minute intervals can be accurately forecast, they can be cleared in a subhourly market.
- The fastest changes in balancing area demand—on time scales from a few to tens of seconds—are dominated by load, even with very large amounts of wind generation.
- Incremental regulating reserve requirements are driven by errors in short-term (e.g., 10 to 20 minutes ahead) wind generation forecasts.
- Data from the Eastern Wind Data Study can be used to characterize both variability and uncertainty for a defined scenario. With more wind generated over a larger geographic area, percentages of aggregate wind variability and uncertainty decrease. These quantitative characterizations are useful for estimating incremental reserve requirements.
- Current energy market performance shows that, on average, subhourly market prices do not command a premium over prices in the day-ahead market. Consequently, the hourly production simulation will capture most of the costs associated with units moving in subhourly markets, and the spinning reserve requirements for regulation and contingency will appropriately constrain the unit commitment and dispatch.

The EWITS analysis addresses these requirements only; as wind displaces marginal conventional generation, those nonwind resources deliver less energy and thus realize less revenue. With large amounts of wind generation such as those considered in EWITS, additional costs could be associated with those displaced marginal units that are not captured in the production modeling.

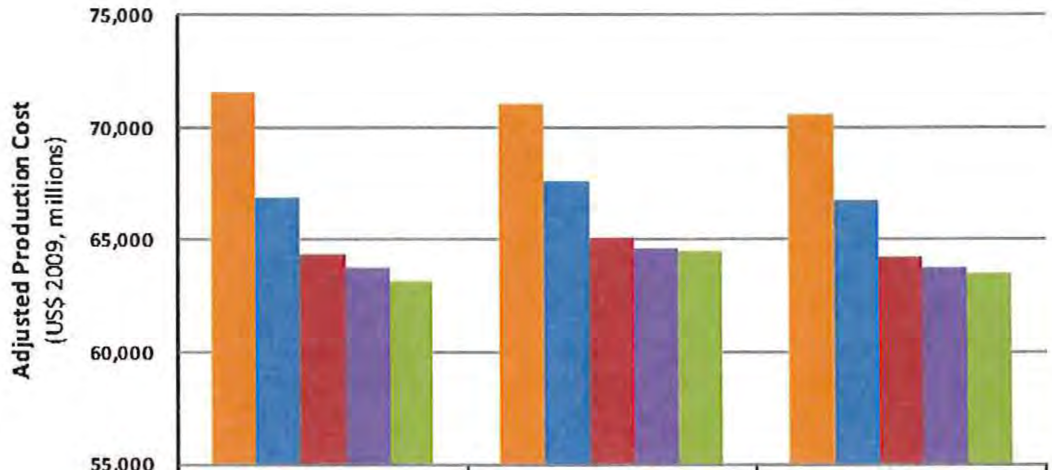
PRODUCTION-COST MODELING RESULTS

The project team ran annual production simulations for all three wind and load years and all scenarios. The raw results included hourly operations and costs for each generator and flows on each transmission element in the model, but because of the sheer volume of data generated, the project team had to analyze summary information.

The detailed production modeling of a system of such size and scope reduces the number of assumptions and approximations required. Although the large volume of results is a disadvantage, the results do contain information from which conclusions can be drawn—with relatively high confidence—about wind generation impacts on other system resources. Specifically,

- Generation displacement depends on the location and amount of wind generation.
- Because of its low dispatch price, wind generation will reduce LMPs. The effect in a particular region is greater with local wind resources.
- The addition of overlay transmission works to equalize LMPs across the footprint. Because of transfer limits, there are still price differences across the footprint, but the magnitude of the difference is reduced with the overlays.
- Offshore wind has more effect on LMPs in eastern load centers because of its proximity to large load centers otherwise served by generation with higher costs.

Figure 10 shows total production costs for each of the high-penetration wind scenarios and for the Reference Case. The primary effect of wind generation is to displace production from conventional sources; as the amount of wind generation increases, so does the magnitude of the displacement. The location of wind generation, however, also has an influence. Under the baseline assumptions used for the study, energy prices are higher in the East and lower in the western portion of the interconnection. Consequently, production costs are reduced more by wind in areas with higher costs; the production costs shown in Figure 10 do not account for the capital costs of the wind or infrastructure required to deliver wind energy to load.



	2004	2005	2006
Reference	71,642	71,042	70,623
Scenario 1	66,834	67,571	66,700
Scenario 2	64,380	65,059	64,226
Scenario 3	63,769	64,653	63,754
Scenario 4	63,219	64,509	63,474

Year

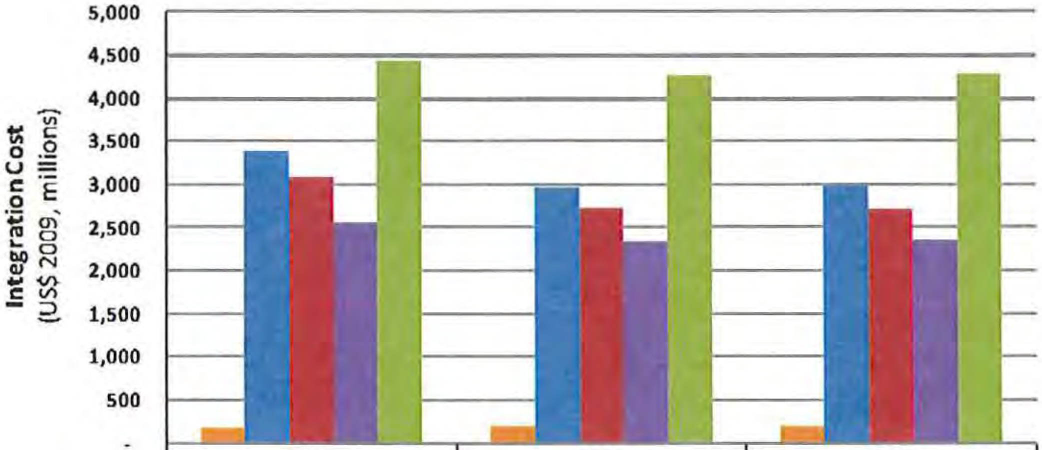
***Figure 10. Annual production-cost comparison** (US$2009, millions)*

WIND INTEGRATION COSTS

Assessing the costs for integrating large amounts of wind generation was another key aspect of EWITS. Team members used methods and analytical approaches employed in earlier integration studies as their starting point. As interim results became available, nuances in and challenges to applying that methodology to a large, multiarea production model became apparent. This project significantly bolstered the knowledge base and perspective on the components of the total cost associated with managing wind energy delivery.

The study team computed the cost of managing the delivery of wind energy (i.e., the integration cost) by running a set of comparative production simulations. In these cases, analysts assumed that wind energy did not require carrying additional regulating reserves for managing variability and short-term uncertainty. They also assumed that the hourly wind energy delivery was known perfectly in the unit-commitment step of the simulation. The differences in production costs among these cases and the corresponding cases where wind generation is not ideal can be attributed to the incremental variability and uncertainty introduced by the wind resource.

Figure 11 shows the calculated integration cost for each scenario. Costs vary by scenario and by year, but all are less than 10% of the bus-bar cost of the wind energy itself.



	2004	2005	2006
Reference	174	189	199
Scenario 1	3,396	2,967	2,989
Scenario 2	3,078	2,728	2,720
Scenario 3	2,560	2,337	2,359
Scenario 4	4,439	4,269	4,285

Year

Figure 11. Integration cost by scenario and year (US$2009)

Salient points from the integration impacts and costs analysis include the following:

- Because the production simulation model contains multiple operating areas, and because transactions between and among these areas are determined on an economic basis, variability from wind in a given area is carried through economic transactions to other areas. In earlier integration studies, wind impacts were isolated in the subject area by restricting transactions to predefined shapes based on historical contracts.
- Costs for integrating wind across the interconnection vary by scenario. For the 20% cases, Scenario 1 shows the highest cost at $5.13/MWh (US$2009) of wind energy; Scenario 3 shows the lowest integration cost at $3.10/MWh (US$2009).
- Integration costs average $4.54/MWh (US$2009) for the 30% scenario, which is roughly a combination of scenarios 1 and 3.
- Results for the 20% scenarios show that spreading the wind more evenly over the footprint reduces integration costs. This is particularly noticeable in the East, where there is more load and a larger number of resources to manage variability.

The project team also analyzed production simulation results to assess curtailment of wind generation resulting from transmission congestion or other binding constraints. Such constraints include excess electricity supply relative to demand and must-run generation ("minimum generation" limits), limitations in ramping capability, or availability of adequate operating reserves.

Varying amounts of wind generation curtailment were observed in the production simulation results. Findings include the following:

- Wind generation was assigned a very low dispatch price in the production simulations, allowing other sources to be redispatched first to relieve congestion. Even so, study analysts observed a modest amount of curtailment in some operating areas. This is likely the result of local or subregional transmission congestion.
- After conducting a sensitivity analysis consisting of additional production simulation runs, the study team determined that transmission congestion caused most of the curtailment. In these results, minimum generation levels, reserve constraints, and ramp limitations accounted for less than 1% of the curtailed energy.
- In developing the conceptual transmission overlays, facilities were sized to accommodate a large fraction—though not 100%—of the transaction energy from the unconstrained production simulation case. Consequently, a certain amount of wind generation curtailment was a likely outcome.

Ramp Rates

For a generator, the ramp rate (typically expressed in megawatts per minute) is the rate at which a generator changes its output. For an interchange, the ramp rate or ramp schedule is the rate, also expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period.

Because wind is variable and results in ramping, it is important to understand these ramp rates and maintain reserves to cover them as needed.

CARBON SENSITIVITY ANALYSIS

The entire analytical methodology, except for the loss of load expectation (LOLE) analysis (see the next section for more information on LOLE), was run for a scenario that considered a carbon price of $100/metric ton. The study team determined that the high price was necessary to bring about a significant change in the type of new generation built during the expansion modeling process. In addition, because it was a sensitivity analysis, choosing a high price helped to illustrate sensitivities. Figure 12 shows the results of the expansion, and Figure 13 compares the expansion for the carbon sensitivity case to the base scenarios and the existing Eastern Interconnection queue.

Results from the production simulations show that the impact on carbon emissions is substantial. Even though the carbon sensitivity case was based on Scenario 2, in which wind generation provides 20% of the energy in the Eastern Interconnection, carbon emissions are lower than those from Scenario 4, in which wind generation delivers 30% of that energy (Figure 14).

Little impact was observed on wind generation curtailment or integration cost. Relative to the original Scenario 2 (Figure 15), fossil-fuel generation is reduced; nuclear generation increases because the nuclear share of the new generation expansion is larger. Energy from combined-cycle plants also increases because it became the preferred resource for managing variability.

With the high cost of carbon, energy prices increase across the footprint (Figure 16). The present value of the accumulated costs more than doubles from the base scenarios (Figure 17).

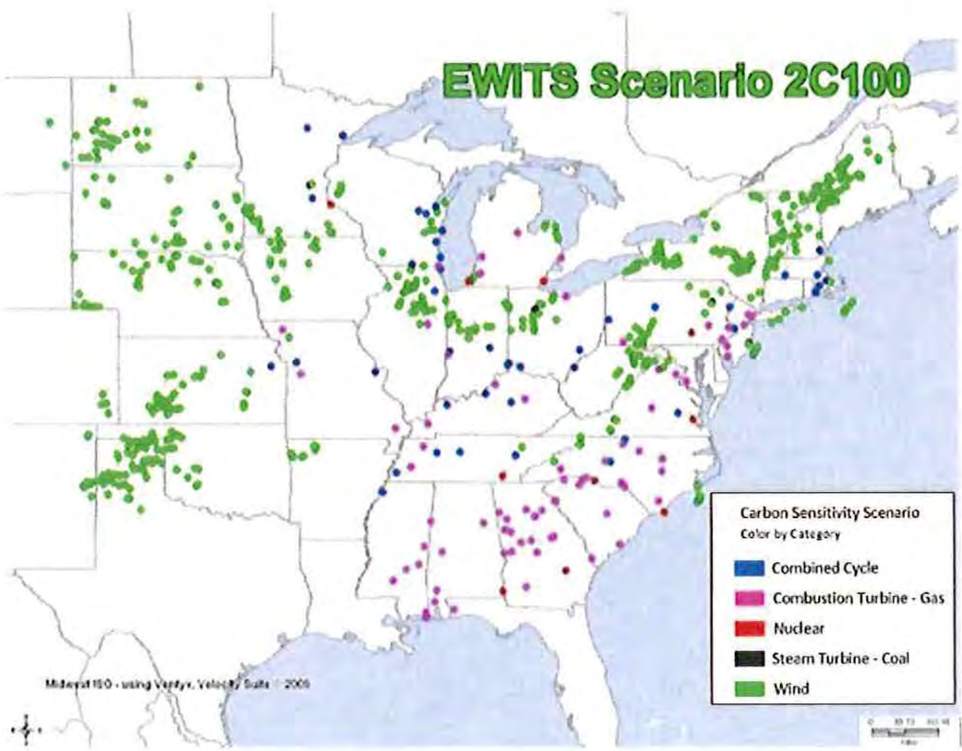
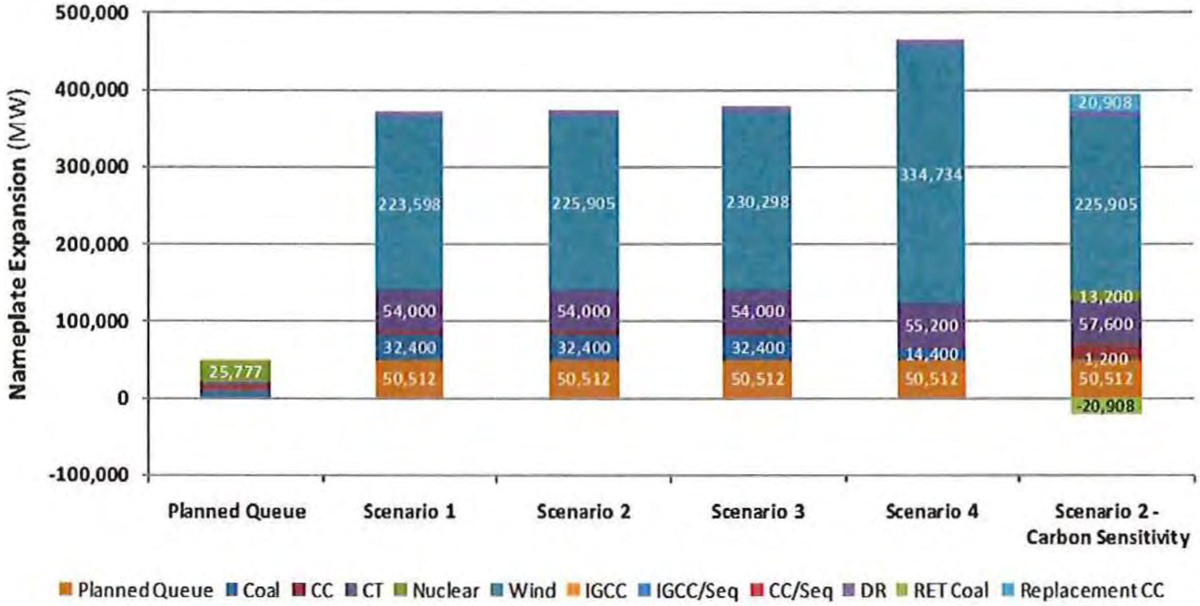


Figure 12. Generation expansion for the Scenario 2 carbon sensitivity case



CC = combined cycle; CT = combustion turbine; DR = demand response; IGCC = integrated gas combined cycle; IGCC/Seq = integrated gas combined cycle with sequestration; CC/Seq = combined cycle with sequestration; RET Coal = coal plant retirements; Replacement CC = replacement combined cycle

Figure13. Generation expansion by scenario, including the carbon sensitivity case

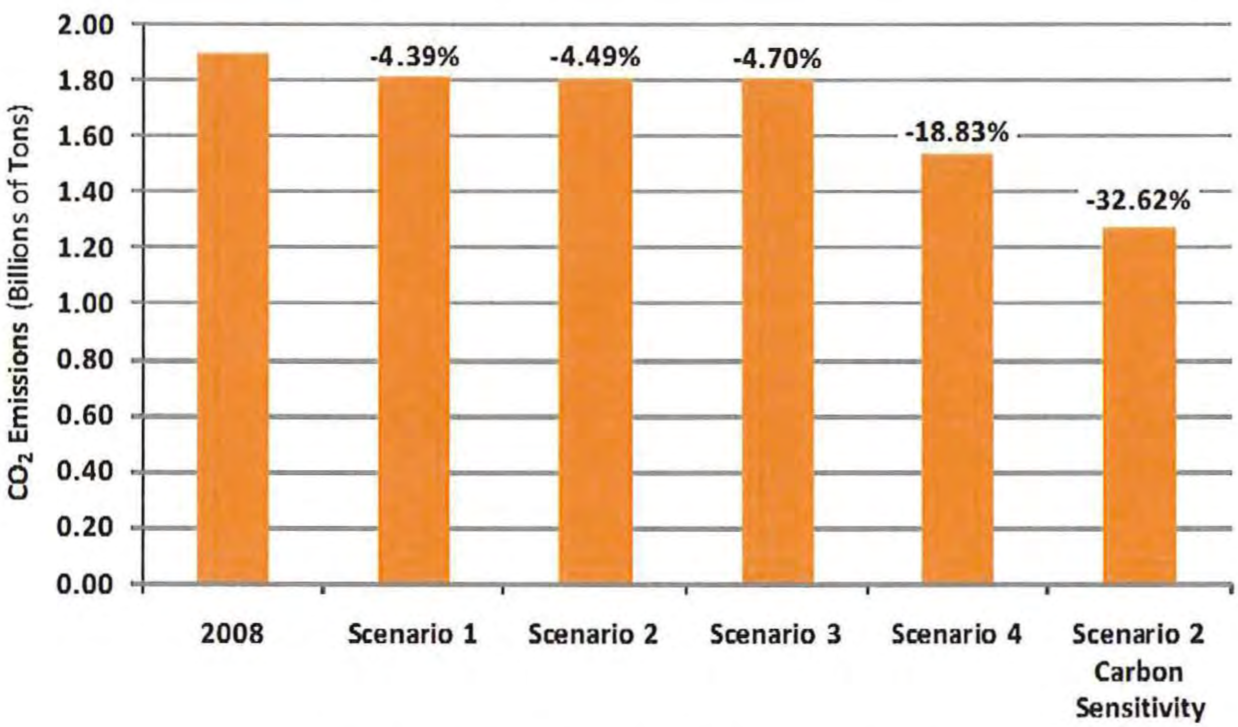
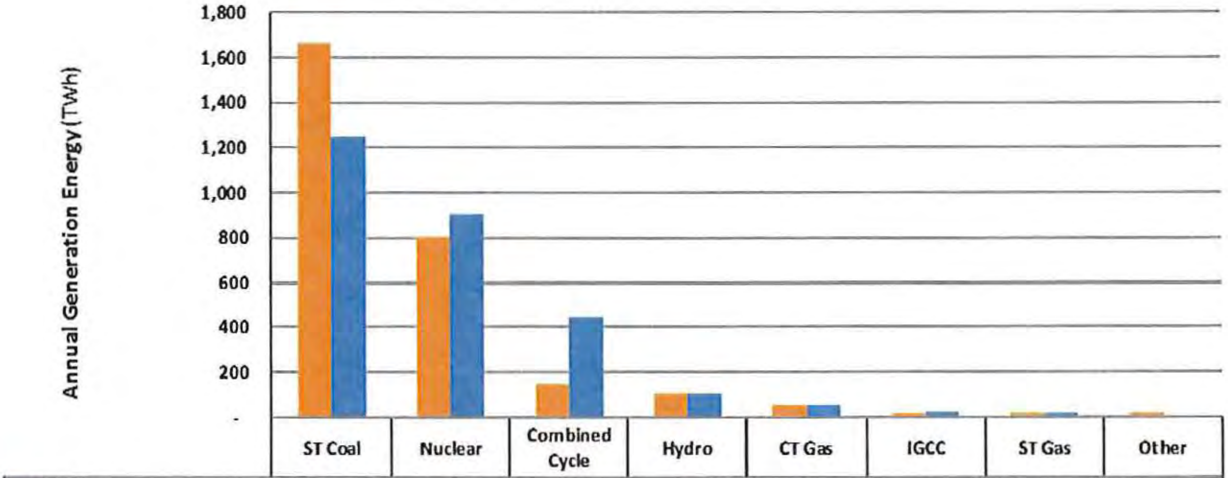
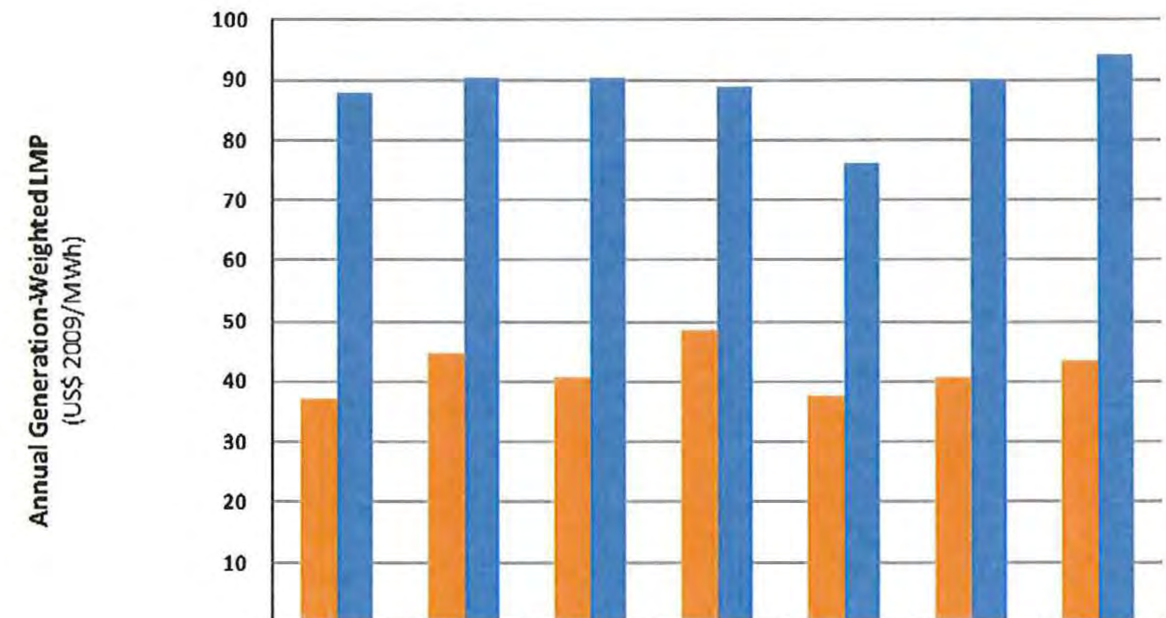


***Figure 14. Carbon emissions for different scenarios** (carbon price applies only to carbon scenario)*



	ST Coal	Nuclear	Combined Cycle	Hydro	CT Gas	IGCC	ST Gas	Other
Scenario 2	1,667	801	146	106	55	16	13	16
Scenario 2, Carbon 100$/Ton	1,249	906	444	106	53	18	14	5

Figure 15. Generation utilization by unit and fuel type for Scenario 2 and carbon sensitivity case



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
Scenario 2	37.11	44.57	40.78	48.49	37.68	40.75	43.53
Scenario 2, Carbon 100 US$/Ton	87.85	90.16	90.20	88.91	76.22	89.94	94.40

Figure 16. Comparison of generation-weighted LMP by region for Scenario 2 and carbon sensitivity case

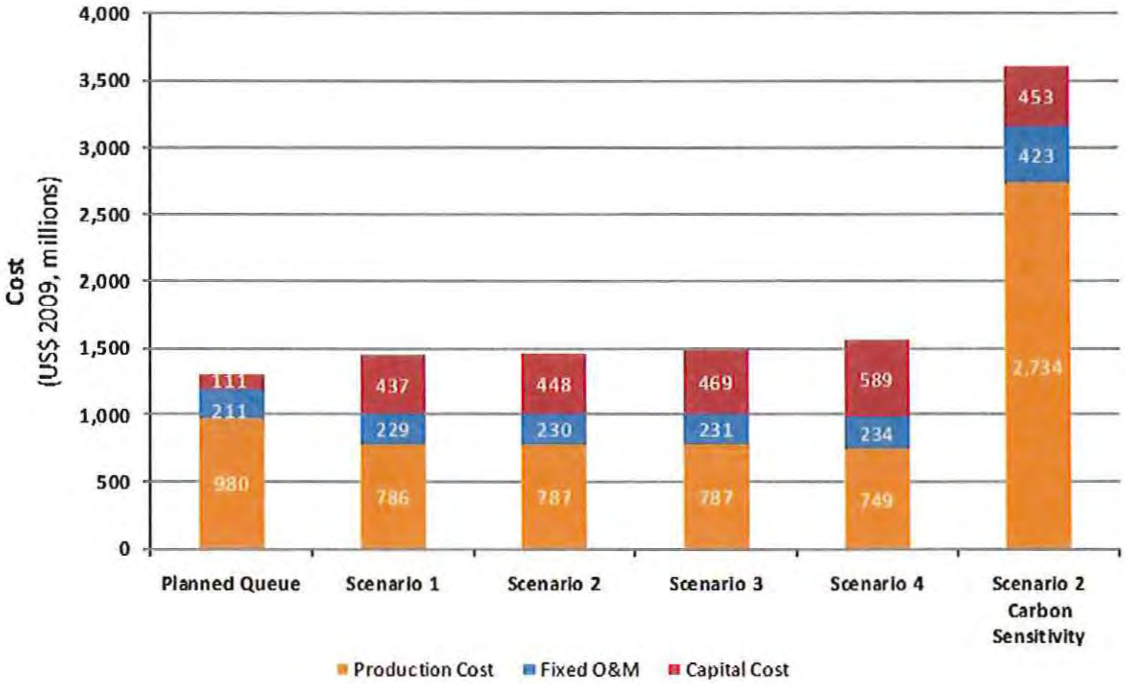


Figure 17. Present value of accumulated costs for base scenarios and carbon sensitivity (US$2009)

CONTRIBUTIONS TO RESOURCE ADEQUACY

Having sufficient generation capacity to meet forecast load is an important aspect of bulk power system reliability. Although wind generation cannot be dispatched to meet peak loads, EWITS shows some probability that wind generation would be available during periods of system stress (i.e., it needs additional energy to meet demand). Unlike conventional generating units, only a small fraction of the nameplate capacity rating of a wind plant can be counted on to be available for serving peak loads. With the amounts of wind generation considered in EWITS, though—more than 200,000 MW—understanding the small fraction in quantitative detail is important because it equates to billions of dollars of capital investment.

Reliability of the Grid

EWITS: The EWITS results represent a first detailed look at several "snapshots" of the Eastern Interconnection as it could exist in 2024 and is therefore not intended to provide a complete analysis of the reliability impacts to the present bulk power system. EWITS is aimed at characterizing the operational impacts for future scenarios, primarily through economics-based transmission expansion planning, resource adequacy studies, and hourly modeling simulations. Important technical aspects in the study related to Bulk-Power System reliability were not studied or were represented approximately or by means of best engineering judgments. A variety of comprehensive power system engineering analyses and studies still need to be conducted (see Summary and Future Work Section) to determine what additional situations should be addressed to maintain system reliability from the present to the 2024 study year when integrating large quantities of renewable generation.

The fraction of the nameplate rating of a wind plant that can be counted as dependable or firm capacity, expressed as a percentage, is known as the capacity value.

To estimate a 2024 capacity value for wind, the study analysts used the 2004, 2005, and 2006 effective load-carrying capability (ELCC) of wind at the future penetration level. The team analyzed each of the high-penetration wind scenarios that were explored in the operational analysis.

The EWITS team examined three different levels of transmission sensitivities. The level of transmission being modeled varied from no ties between areas to the different transmission levels of each existing and conceptual overlay scenario. These transmission sensitivities were

- Isolated system, stand-alone zone (no zone-to-zone interfaces modeled)
- Existing transmission system (constrained case and interface limits)
- Conceptual transmission overlay (increased zone-to-zone interface limits and new ties).

Data from the operational simulations were conditioned into the correct format for implementation into the LOLE model. Because that model uses a transportation representation for the transmission network, the study team ran a large number of additional production simulations to estimate the import capacity for each reliability zone. Predefined regional and planning areas were used as the modeling zones. Table 5 lists these zones along with the total nameplate amount of wind generation for each EWITS scenario.

Reliability of the Grid (continued)

Federal Energy Regulatory Commission (FERC) Study: FERC is conducting a new study with Lawrence Berkeley National Laboratory that is intended to validate whether frequency response is an appropriate metric for gauging the impacts on reliability of integrating increasing amounts of variable-output generation capacity into the three electrical interconnections. The study will do this by using today's transmission networks and generating facilities—including facilities under construction—as the basis for the models and studies in contrast to the alternative scenarios for 2024 used in EWITS. The new study is intended to investigate the frequency metric as an approach to identifying critical factors when integrating large amounts of variable generation into the bulk power system.

TABLE 5. RELIABILITY ZONES FOR LOLE ANALYSIS WITH INSTALLED WIND GENERATION CAPACITY (NAMEPLATE WIND IN MEGAWATTS)				
Zone	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
MISO West	59,260	39,953	23,656	59,260
MISO Central	12,193	11,380	11,380	12,193
MISO East	9.091	6,456	4,284	9,091
MAPP USA	13,809	11,655	6,935	14,047
SPP North	48,243	40,394	24,961	50,326
SPP Central	44,055	46,272	25,997	44,705
PJM	22,669	33,192	78,736	93,736
TVA	1,247	1,247	1,247	1,247
SERC	1,009	5,009	5,009	5,009
NYISO	7,742	16,507	23,167	23,167
ISO-NE	4,291	13,837	24,927	24,927
Entergy	0	0	0	0
IESO[a]	0	0	0	0
MAPP Canada	0	0	0	0
FULL STUDY SYSTEM	**223,609**	**225,902**	**230,299**	**337,708**

a Independent Electricity System Operator

Results of the ELCC analysis, shown graphically in Figure 18 for the cases with existing and overlay transmission, indicate that the transmission network has a significant positive impact on the capacity value of wind generation. For the calendar year with the smallest contribution, the aggregate capacity value of wind generation by scenario ranges from 53 GW to almost 65 GW.

Although the influence of transmission on wind generation capacity value is intuitive, the magnitude of the contribution is striking. Considering both the existing and the overlay transmission concepts developed for EWITS, the aggregate wind generation capacity value is increased by more than 20 GW in the 20% cases, and by nearly 30 GW at 30% wind penetration.

The capacity value results vary depending on the year, which is consistent with observations in previous studies (see Bibliography). The magnitude of the interannual variation is actually smaller than that seen in some of the earlier results. This could be a consequence of both the scale of the model and the large volume of wind generation.

Assessing the capacity value of wind generation has been a staple of most of the integration studies conducted over the past several years. The approach taken in the EWITS project likely represents the most thorough and detailed investigation to date because of the size and scope of the model, the process by which area transfer limits were determined, and the sensitivities evaluated. The wind capacity values calculated in EWITS are significantly higher than those found in previous studies. The study team recognizes that the results represent a macro view, in which some important intraregional transmission constraints are not considered. Because the project focuses on transmission, though, the results represent a target resource adequacy contribution that could be achieved for the wind generation scenarios studied.

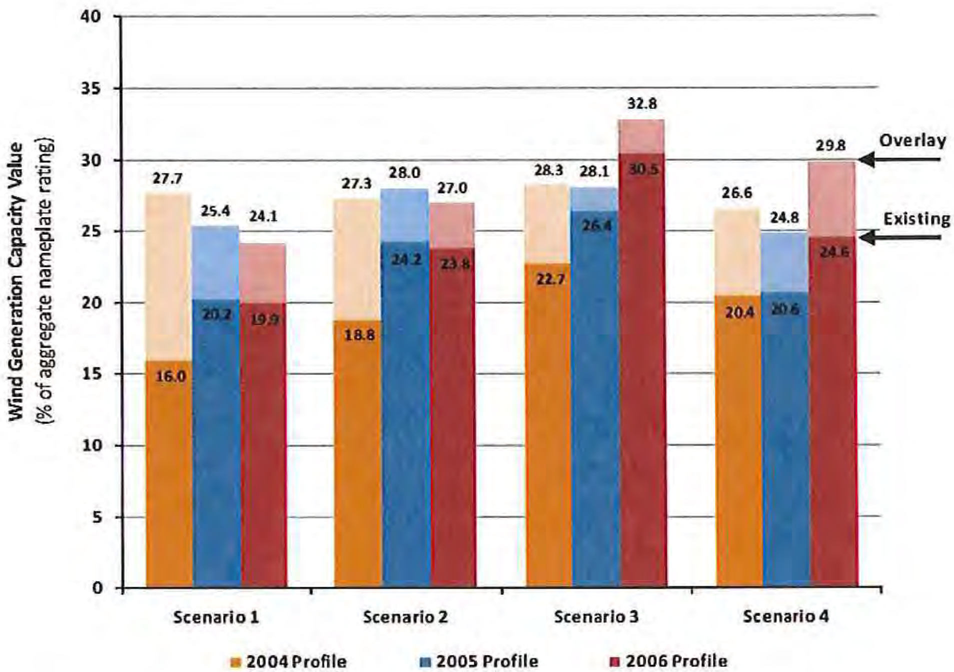


Figure 18. LOLE/ELCC results for high penetration scenarios, with and without transmission overlays

Specific findings and conclusions include the following:

- The LOLE analysis performed for EWITS shows that the existing transmission network in the Eastern Interconnection contributes roughly 50,000 MW of capacity benefits. With the transmission overlays developed for the EWITS wind scenarios, the benefit is increased by up to 8,500 MW.
- The LOLE analysis of the Eastern Interconnection with wind generation and the transmission overlays shows that the ELCC of the wind generation ranges from 24.1% to 32.8% of the rated installed capacity.
- The transmission overlays increase the ELCC of wind generation anywhere from a few to almost 10 percentage points (e.g., 18% to 28%).
- The ELCC of wind generation can vary greatly by geographic region depending on which historical load and wind profiles are being studied. Although interannual variations were observed, they are much smaller than those seen in previous studies (see, for example, EnerNex Corporation [2006]).
- Characteristics of the zonal ELCC differences among profiles tended to be the same across all four scenarios.

SUMMARY AND FUTURE WORK

The EWITS results represent a first detailed look at a handful of future snapshots of the Eastern Interconnection as it could exist in 2024. The analysis was driven primarily by economic considerations, with important technical aspects related to bulk power system reliability represented approximately or through engineering judgments.

EWITS is an important step in the uncertain world of long-range planning because it addresses questions such as feasibility and total ultimate costs, and begins to uncover important additional questions that will require answers. Although the TRC's representation from the Eastern Interconnection is extensive, the study team also recognizes that additional key stakeholders must be involved to further develop an interconnection-wide view of transmission system plans.

A complete evaluation of any of the scenarios would require a significant amount of additional technical analysis. The framework established by the scenario definitions and transmission overlay concepts, however, forms a foundation for conducting conventional power system planning to further evaluate the feasibility of these high-penetration scenarios and to improve the cost estimates.

Production simulation results from EWITS could be used to identify times of binding constraints or other periods of interest, such as large changes in wind production, minimum load periods, and conditions where loss of significant generation would raise questions about the security of the system. The state of the system during these periods—loads, committed generation and dispatch levels, and wind generation levels, among others—would be transferred to an appropriate AC power system model. A variety of power system engineering analyses could then be conducted to determine what additional equipment or operating limitations would be necessary to maintain system reliability. These analyses would include the following.

- An AC analysis that examines in more detail the power transfer limitations assumed in the production modeling. For EWITS, the team conducted production simulations using a DC power flow that does not consider the wide range of issues associated with voltage control and reactive power dispatch. An AC analysis would involve power flows that look at voltage and reactive compensation issues, dynamic and transient stability, and HVDC terminal control. Local and regional transmission needs could then be analyzed in much greater detail.
- Longer term dynamic analysis, where the actions of AGC, load tap changing on transformers, and capacitor or reactor switching for voltage control can be simulated and analyzed in much greater detail. Such dynamic analysis could examine subhourly market operation and

the response of generation to either AGC or market dispatch instructions while considering the limitations caused by prime mover or governor response, HVDC control actions, or special protective schemes. This analysis could be used to zoom in on system operation in real time, resulting in a higher confidence estimate of the operating reserve requirements and policies needed to maintain performance and reliability.

The analysis suggested for the large footprint considered in EWITS would require that many entities across the interconnection participate and collaborate. Personnel engaged in running similar studies with a regional focus would need to be involved, at a minimum, in a review capacity and for interpreting results. National entities such as NERC would also need to be engaged to oversee the development of the data sets and models. And because the size and scope of the system models might also require computational power beyond what is used today in the power industry, these suggested analyses could involve universities or national laboratories with appropriate resources.

The top-down views of the interconnection that EWITS yields constitute, in essence, the starting point for a substantially significant amount of subsequent engineering analysis. The analysis would paint a more accurate picture of the total transmission investment necessary, and illuminate measures necessary to preserve the security of the bulk power system. As with EWITS, such an effort would be beyond the scope of previous attempts, and would require cooperation and coordination at many levels to succeed.

Although EWITS is a technical study that examines future wind scenarios, the results pose some interesting policy and technology development questions:

- Could the levels of transmission, including the Reference Case, ever be permitted and built, and if so, what is a realistic time frame?
- Could the level of offshore wind energy infrastructure be ramped up fast enough to meet the aggressive offshore wind assumption in the EWITS scenarios?
- Would a different renewable profile or transmission overlay arise from a bottom-up process with more stakeholders involved?
- How can states and the federal government best work together on regional transmission expansion and the massive development of onshore and offshore wind infrastructure?
- What is the best way for regional entities to collaborate to make sure wind is optimally and reliably integrated into the bulk electrical grid?
- What is the difference between applying a carbon price instead of mandating and giving incentives for additional wind?

As is expected in a study of this type, especially when a wide variety of technical experts and stakeholders are giving ongoing input, a number of important variations on the 2024 future scenario can be envisioned. In addition, several technical areas in the study present opportunities for further technical investigation that could deepen understanding or reveal new insights:

- **Further analysis of production-cost simulation results:** The output from the many annual production simulations performed in EWITS contains detail on every generator and monitored transmission interface in the Eastern Interconnection. Because of scope and schedule constraints, the EWITS analysis was necessarily limited to summary results. Further analysis of these output data would likely generate additional valuable insights on impacts of wind generation on nonwind generation, and help define more detailed analyses that could be conducted in the future.
- **Smart grid implications and demand response sensitivities:** The Eastern Interconnection load considered in EWITS was based on regional projections out to the study year (2024). For the most part, load was considered "static." Major industry initiatives are currently exploring means by which at least a portion of the load might respond like a supply resource, thereby relaxing the constraints on scheduling and dispatch of conventional generating units. The implications for wind generation are potentially very significant, which is why alternative 2024 scenarios that consider the range of smart grid implications for the bulk electric system merit further consideration (scope limitations prevented these from inclusion in this phase of EWITS).
- **Nighttime charging of PHEVs:** Widespread adoption of electric vehicles has the potential to alter the familiar diurnal shape of electric demand. Because the wind resource is abundant at night and during the low-load seasons, increases in electric demand during these times could ease some of the issues associated with integration.
- **Commitment/optimization with high amounts of wind:** The approach for scheduling and dispatching generating resources used in the production simulations is based on current practice. In the future, new operating practices and energy market structures might be implemented that take advantage of the fact that uncertainty declines as the forecast horizon is shortened (for both load and wind generation). Intraday energy markets that allow reoptimization of the supply resources more frequently could offer some advantage for accommodating large amounts of variable and uncertain wind energy.
- **Fuel sensitivity:** In this phase of EWITS, the study team considered a single future for prices of other fuels used for electric generation. As history attests, there is much uncertainty and volatility inherent in some fuel markets, especially for natural gas. Alternate scenarios that explore the impacts of other fuel price scenarios on integration impacts and overall costs would be valuable.

- **The role and value of electrical energy storage:** With the substantial transmission overlays and the assumption of large regional markets, the EWITS results show that large amounts of wind generation can be accommodated without deploying additional energy storage resources. The ability to store large amounts of electrical energy, though, could potentially obviate the need for some of the transmission and reduce wind integration impacts. Analysis of bulk energy storage scenarios with generic storage technologies of varying capabilities would quantify the costs and benefits of an alternate means for achieving high penetrations of renewable energy.
- **Transmission overlay enhancement:** As described earlier, the analytical methodology was based on a single pass through what is considered to be an iterative process. Further analysis of the existing results could be used to refine the transmission overlays, which would then be tested in additional production simulations and LOLE analyses, along with AC power flow and stability analyses. This could reduce the estimated costs of the overlay and bolster the view of the required regional transmission expansion that would be needed to deliver the large amounts of wind energy to load.
- **Sequencing of overlay development:** EWITS focused on a snapshot of a 2024 scenario using a top-down perspective. The resulting transmission overlays and substantial amounts of wind generation would be developed over many years. An analysis over time—beginning now and extending to 2024—would yield important insights into the overall feasibility and costs of an aggressive transmission development future.
- **Wind generation curtailment:** Using wind generation curtailment selectively and appropriately could have high operational value. Although wind plants cannot increase their output at will without first spilling wind generation, downward movement is easily accomplished with today's wind generation technology. This could have very high economic value under certain circumstances. Wind generation is very capable of "regulating down"; for example, in an ancillary services market where the regulation service is bifurcated (i.e., regulation up and regulation down are separate services). Additional analysis of the scenarios studied in EWITS could help quantify what such a service would be worth to wind plant operators.

The current installed capacity of wind generation in many areas of the United States, coupled with prospective development over the next several years, requires that assessments of the bulk electric power system take a much broader view than has been typically employed. In addition, the unique characteristics of wind generation as an electrical energy supply resource are leading the power industry to new approaches for planning and analyzing the bulk electric power system.

Several of these techniques were demonstrated in EWITS, and are also being used in other large-scale wind integration analyses. The data sets compiled for the study represent the most detailed view to date of high-penetration wind energy futures and potential transmission. Given the significant changes coursing through the electric power industry, many alternative scenarios for the Eastern Interconnection in 2024 can be postulated. In that sense, EWITS is a solid first step in evaluating possibilities for the twenty-first century grid in the United States, with many more to follow.

SECTION 1: INTRODUCTION

As the penetration of bulk wind energy continues to grow, evaluating its effect on the operation of regional electrical systems becomes increasingly important. Evaluating wind energy's interaction with the utility grid allows for a better understanding of how to manage the wind resource during both planning and day-to-day operations. Quantifying the actual effect of wind energy on specific regional electrical systems will produce information critical to transmission planning.

Many states are adopting regional mandates on renewable energy penetration into the electrical grid, and these mandates could be adopted for the nation as a whole. Meeting the growing need for wind power in the United States will require careful analysis and modeling of how large amounts of wind power will be integrated into the electrical grid. Analyzing future scenarios of wind power penetration using state-of-the-art production-cost models, transmission power flow and power simulation models, and related methodologies is an important step in the energy and transmission planning process. Because new transmission will most likely be necessary for much of the future wind power that will be installed in the United States, it is imperative to plan for this transmission. The lead times for building transmission are significantly longer than those for building wind plants.

The U.S. Department of Energy (DOE) commissioned the work described in this report through its National Renewable Energy Laboratory (NREL). Known as the Eastern Wind Integration and Transmission Study (EWITS), the project was designed to consider a range of important and contemporary questions about integrating high-penetration wind energy into the grid. The technical work conducted for this study produced detailed quantitative information on the following:

- Wind scenarios that reach wind energy penetrations equivalent to 20% of the electrical energy delivered in the Eastern Interconnection in 2024
- Transmission concepts for delivering energy economically for each scenario (new transmission for each scenario is based on economic performance for the conditions of the generation scenario)
- Economic sensitivity simulations of the hourly operation of the power system defined by a wind generation forecast scenario and the associated transmission overlay
- The contribution made by wind generation to resource adequacy and planning capacity margin.

As part of this study, NREL convened a Technical Review Committee (TRC) with representation from regional electric reliability councils, expert reviewers, the study subcontractor, transmission planners, utilities, and wind industry representatives. The TRC met 6 times over 14 months during the project to review study progress; comment on study inputs, methods, and assumptions; assist with collecting data; and review drafts of the study report.

The Eastern Wind Data Study (AWS Truewind 2009), a precursor to this study, identified more than 700 gigawatts (GW) of potential future wind plant sites for the eastern United States. The hourly time series data produced in that study were used as primary inputs to this study's analytical methods. EWITS focuses on the integration of wind power into the majority of the Eastern Interconnection, a region covering much of the eastern half of the United States.

PROJECT OBJECTIVES

For this project, the study team evaluated the power system impacts, costs, and conceptual transmission overlays attendant with increasing wind generation capacity to 20% and 30% of retail electric energy sales in 2024 for the study area, which encompasses portions of the Eastern Interconnection under the auspices of the following entities:

- New England Independent System Operator (ISO-NE)
- New York ISO (NYISO)
- PJM Interconnection
- Tennessee Valley Authority (TVA)
- Portions of the Southeastern Electric Reliability Council (SERC)
- Southwest Power Pool (SPP)
- Midwest ISO
- Mid-Continent Area Power Pool (MAPP)

EWITS builds on the methods developed in previous wind integration studies and related technical work (see Bibliography), and coordinates with ongoing interregional power system investigations. Ultimately, the EWITS team's objective was to produce meaningful, broadly supported results through a technically rigorous and inclusive study process.

KEY ISSUES AND QUESTIONS

In the years preceding this study, numerous wind integration studies had been conducted for individual or regional entities (see Bibliography). When many of those studies were performed, the "outside world" (i.e., the operation of the grid outside the study confines) could be ignored or easily approximated from operating history. Now that the installed capacity of wind generation is approaching 30 GW in the United States (and concentrated in certain areas), and many states have passed legislation mandating that an appreciable fraction of electrical energy be produced by certain renewable resources, interest has grown past the confines of a single operating area.

Many of the key questions to be answered in this study are similar to those posed in previous wind integration studies, but the scope and scale are entirely different. The existing transmission infrastructure in the Eastern Interconnection has a limited capacity for accommodating additional wind generation; transmission congestion is already an issue in some areas, including those with the potential for tenfold or greater development in wind capacity. Consequently, evaluating transmission needs was also a major aspect of this study.

Key questions posed at the outset of the project include the following:

1. What impacts and costs do wind generation variability and uncertainty impose on system operations?

2. What benefits accrue from long-distance transmission that accesses multiple and geographically diverse wind resources?

3. What benefits are realized from long-distance transmission that moves large quantities of remote wind energy to urban markets?

4. How do remote wind resources compare to local wind resources?

5. How much does geographical diversity, or spreading the wind out across a large area, help reduce system variability and uncertainty?

6. What is the role and value of wind forecasting?

7. What benefit does balancing area cooperation or consolidation bring to wind variability and uncertainty management?

8. How does wind generation capacity value affect supply resource adequacy?

OVERVIEW OF PROJECT TASKS

Evaluating the impacts of large-scale wind generation development across the Eastern Interconnection in the United States required three major tasks: developing wind plant power outputs, conducting transmission analysis, and studying the implications of high-penetration wind integration. The last two tasks are formally part of the study documented in this report.

A reasonably accurate, physically consistent depiction of what wind generation would look like to power system operators has been the critical input to all previous integration studies. Expanding the area of interest to include nearly half of the land area of the lower continental United States posed a significant challenge in this respect. The precursor effort (AWS Truewind 2009), though, resulted in an extensive database of synthesized, high-resolution, correlated wind energy profiles for a significant portion of the Eastern Interconnection. A quality control process was applied to the raw data, followed by construction of more than 700 GW of wind power plant temporal data, down to a resolution of 10 minutes for a consecutive 3-year period (2004, 2005, and 2006).

From that starting point, the EWITS team began this project by defining four wind generation scenarios for 2024, three with 20% of the projected electrical energy demand across the Eastern Interconnection and one that stretched the wind generation penetration to 30%.

The wind generation profile data set the stage for some analytical work that represents the leading edge of engineering and economic methods combined with computational horsepower. With the tools and analytical methods described in this report, the study team designed extensive top-down transmission overlays that span the interconnection, and then rigorously analyzed the operating and planning reserve impacts.

EWITS is one of three to conduct this type of analysis on such a large scale. The Western Wind and Solar Integration Study (WWSIS) is examining the planning and operational implications of adding up to 30% penetration by energy of wind generation and solar energy to the WestConnect footprint in the Western Electricity Coordinating Council (WECC). The European Wind Integration Study (EWIS) is an initiative established by the European associations of transmission system operators in collaboration with the European Commission. EWIS is aimed at developing, where possible and appropriate, common solutions to wind integration challenges in Europe. The study also seeks to identify arrangements that will make the best use of the pan-European transmission network, allowing the benefits of wind generation to be delivered across Europe.

And as the amount of wind generation continues to increase, these studies are unlikely to be the last.

ORGANIZATION OF THIS REPORT

Section 2 describes the data the team used and the process employed to create the four wind generation scenarios. Characteristics of the wind resource on a regional basis are also described.

Section 3 discusses the data and analysis methods used to develop the scenarios for the 2024 study year. The section also describes the tools used for the detailed assessments of wind generation operational impacts and resource adequacy contributions.

Section 4 explains how the transmission overlays were developed for each scenario. The large amounts of wind generation considered here will increase the variability of the net demand and introduce some heightened uncertainty into operational considerations.

Section 5 discusses the approach for assessing how operating reserves would be affected by these large amounts of wind generation, and presents results by scenario and operating region.

Section 6 presents the range of operational impacts as determined from chronological hourly production simulations of the entire Eastern Interconnection.

Section 7 summarizes the analytical effort to determine how wind generation contributes to resource adequacy, an important element of power system reliability.

Section 8 explores the broader implications of the EWITS results.

Section 9 presents findings and conclusions drawn from the study's quantitative results. It also gives recommendations for future work should this effort be continued. These recommendations are drawn from comments and discussions among members of the project team and the TRC, along with project sponsors.

SECTION 2: WIND SCENARIO DEVELOPMENT

INTRODUCTION

Through a collaborative process, the Eastern Wind Integration and Transmission (EWITS) researchers developed four wind scenarios for analysis. The idea behind multiple scenarios was to examine the effect of different geographic positioning of the wind resources at 20% of the expected load for 2024 and to understand the effect of increasing the wind penetration to 30%.

This section briefly explains the process of developing the scenarios, and then describes the resulting four wind scenarios. Because of the large volume of data, both for the entire database and for the scenarios used in this study, the documentation in this report is necessarily in the form of summary charts, graphs, and tables that depict relevant characteristics of the time series data.

DESCRIPTION OF MESOSCALE DATABASE

The mesoscale database, which now resides at the National Renewable Energy Laboratory (NREL), contains 1,325 separate wind production plants, most hypothetical and others corresponding to the locations of existing operating wind plants. These plants are aggregations of the 2-kilometer (km) wind simulation grid data from meteorological simulations done by AWS Truewind (2009). The nameplate capacity of these plants varies from 100 megawatts (MW) to greater than 1,400 MW. The total installed nameplate capacity is approximately 700 gigawatts (GW).

The project that produced these data modeled the atmosphere over the study area using mesoscale modeling tools. Mesoscale refers to atmospheric phenomena (temperature, pressure, precipitation, and wind, for example) on scales of several kilometers to several hundred kilometers. By using known meteorological measurement data for historical years, the model can be guided to reproduce what the wind speeds and air density would have been at many points, both on the ground and at wind turbine hub height. Those wind speeds are used, along with local geographic information (e.g., mountains, lakes, and ridgelines), to estimate an area's wind power production over the time frame of the numerical weather simulation.

The simulation modeled wind in the Eastern Interconnection for 2004, 2005, and 2006. For each plant, the data span 3 years of 10-minute power production data. For each site, several hourly resolution forecast vectors were calculated, including a day-ahead horizon (18 to 42 hours), a 6-hour-ahead forecast, and a 4-hour-ahead forecast.

The wind data calculated for this study are roughly distributed according to the geographic quality of the wind resources across the eastern United States. Some heavier weighting was given to eastern states because high-capacity wind resources are concentrated in the western states. States like Nebraska and Minnesota have large amounts of high-quality wind; states like New Jersey, Maryland, and Ohio have relatively small amounts. The EWITS team made an effort to represent wind resources from all states with any reasonable wind resources in the data set.

One important measure of wind-resource quality is the levelized cost of energy (LCOE) for each facility in the database and for the wind database as a whole. The LCOE allows for direct comparisons among the lifetime costs—on an energy-delivered basis—of facilities with different capital and maintenance costs. Table 2-1 gives the economic parameters used for the calculations, and Figure 2-1 shows the LCOE for all the wind plants in the database (plotted by increasing cost against the accumulating nameplate capacity of the plants).

TABLE 2-1. LCOE ECONOMIC ASSUMPTIONS (US $2009)

ASSUMPTION	ONSHORE	OFFSHORE
Fixed Charge Rate (%)	11.92	11.92
Capital Cost ($/kW)	1,875	3,700
Fixed O&M ($/kW/yr)	11.50	15.00
Variable O&M ($/MWh)	4.79	14.50

Notes: kW = kilowatt; O&M = operations and maintenance; MWh = megawatt-hour.
Source: 2008 data from NREL and Lawrence Berkeley National Laboratory. See also Wiser and Bolinger (2009). Note that these costs are not the same as those used for the resource expansion planning documented later in this report. The values here reflect updated information that was not available when the study team explored expansion planning.

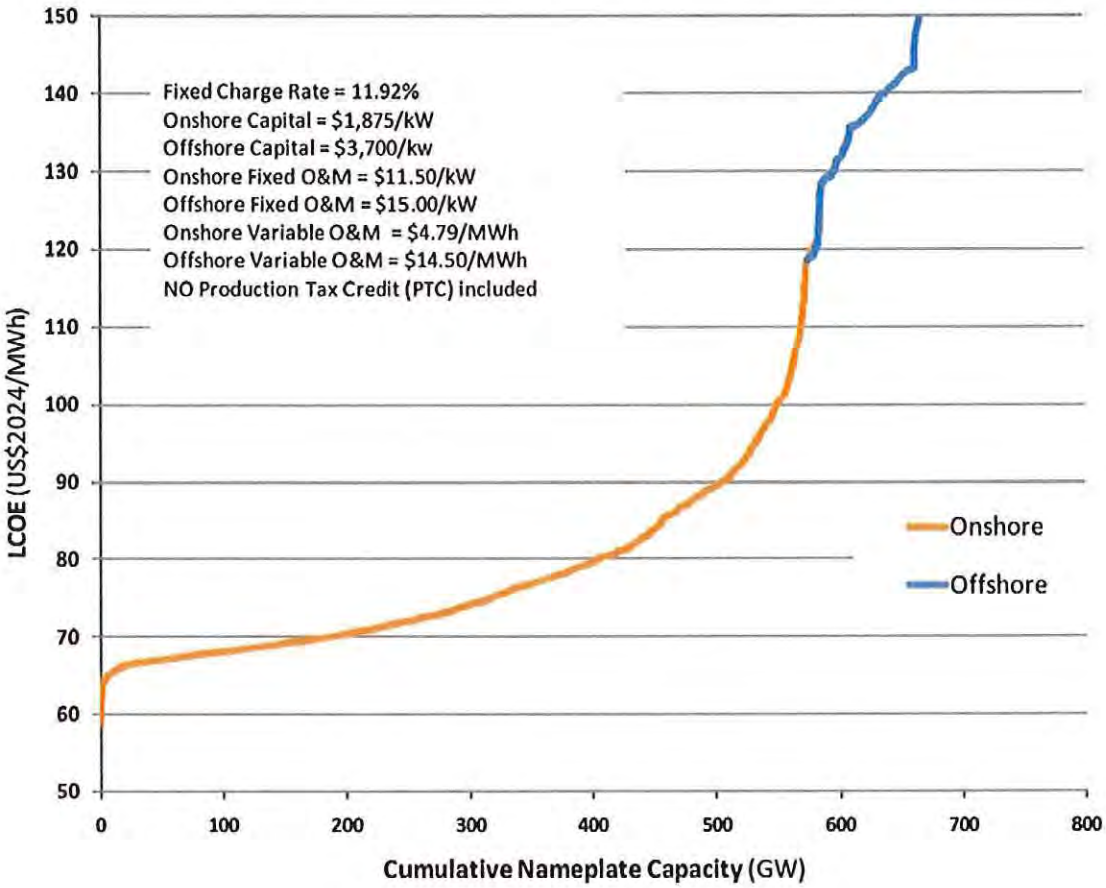


Figure 2-1. LCOE for all wind facilities in database

The plants with the lowest costs typically have the highest capacity factor. Offshore wind plants tend to have the highest LCOE because of their high capital and maintenance costs—even though their capacity factors are generally quite high. The data in Figure 2-1 reflect approximately 580 GW of onshore wind nameplate capacity and about 100 GW of offshore wind nameplate capacity in the Great Lakes and off the eastern seaboard. Offshore wind is located in waters up to 30 meters (m) deep.

Another useful way to look at the overall data is in terms of capacity factor versus cumulative nameplate capacity. Capacity factor can be seen as a reasonable proxy for return on construction, carrying, and operations costs. Figure 2-2 shows the incremental capacity factor for all plants in the database with and without considering offshore plants. The horizontal axis shows the total capacity in the database having a capacity factor equal to or greater than the capacity factor indicated on each curve. Capacity factors shown on this graph (and on Figure 2-3) are net, but curtailment (shutting down wind) is not taken into account.

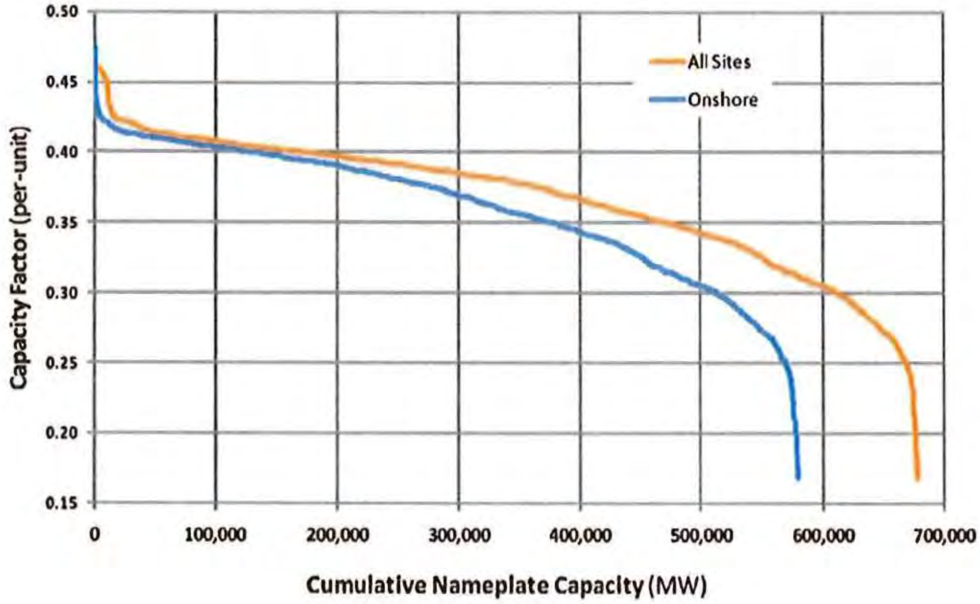


Figure 2-2. Capacity factor for all wind in database

Figure 2-3 shows the same data as Figure 2-2 except that the capacity factor is an aggregate of all units less than a selected capacity value. Figure 2-3 shows the total effective capacity factor for the total capacity selected on the capacity axis.

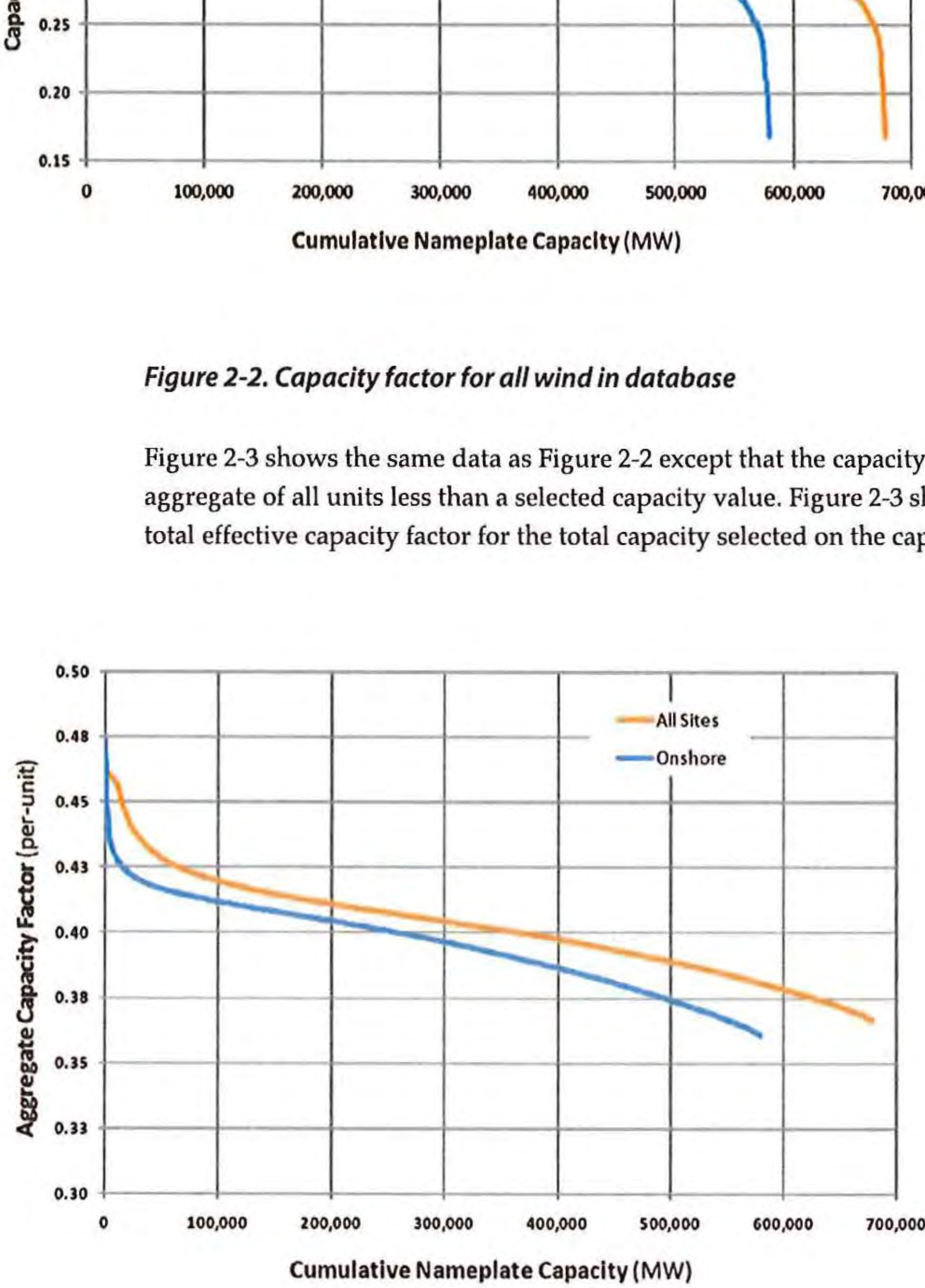


Figure 2-3. Aggregate capacity factor for all wind in database

SCENARIO DEVELOPMENT PROCESS

Once the project team defined the scenario goals, attention turned to developing the wind scenarios from the database described earlier. Four scenarios were constructed—three with 20% wind energy penetration and one with 30%.

For each of the scenarios, the study team took state renewable portfolio standard (RPS) goals and existing interconnection wind queues into account, and gave some consideration to distributing wind to all states with usable resources.

To yield data required for selection among all the resources calculated and stored in the database, some calculations were required. The study team analyzed the production time series data to determine annual and average capacity factor and energy production for 2004, 2005, and 2006 for each of the 1,325 sites.

Once the regional allocations were decided, the project team worked with NREL to segregate wind resources from the database by geographic region. Next, the team analyzed these data, and made the appropriate selections. Because this study is based on energy penetration criteria, these allocations are specified in the annual wind production target.

For regionally focused scenarios (all except Scenario 1), selections were based first on the regional allocations. Within the regions, the plants with the highest capacity factors were selected first. Plants were added to the scenarios by decreasing capacity factor until the target annual energy penetration was reached. The study team used 3-year average capacity factor and energy production values for this process.

After the quantitative process was complete, the allocations were manually checked to ensure that diversity and local siting goals were met. For instance, some adjustments were made to the scenarios to site some wind generation in all states with RPS in place or pending.

SCENARIO DESCRIPTIONS

Once the scenarios had been defined, the project team conducted various analyses on the scenario data. This section gives an overview of these analyses.

The five scenarios are as follows:

- Reference Scenario (also called Reference Case)—Existing RPS
- Scenario 1, 20% penetration—High Capacity Factor, Onshore
- Scenario 2, 20% penetration—Hybrid with Offshore
- Scenario 3, 20% penetration—Local with Aggressive Offshore
- Scenario 4, 30% penetration—Aggressive On- and Offshore.

REGIONAL WIND CAPACITY AND ENERGY

The scenario data were tabulated based on the independent system operator (ISO)/market region footprints for ease of aggregation and comparison. The regions were defined in 2009 (Figure 2-4) and the roughly described footprints follow:

ISO-NE: New England ISO

MISO + MAPP: Midwest ISO[1] and Mid-Continent Area Power Pool

NYISO: New York ISO

PJM: PJM Interconnection

SPP: Southwest Power Pool (includes Nebraska Power Association and Entergy[2] loads)

TVA: Tennessee Valley Authority

SERC: SERC Reliability Corporation without TVA and Entergy

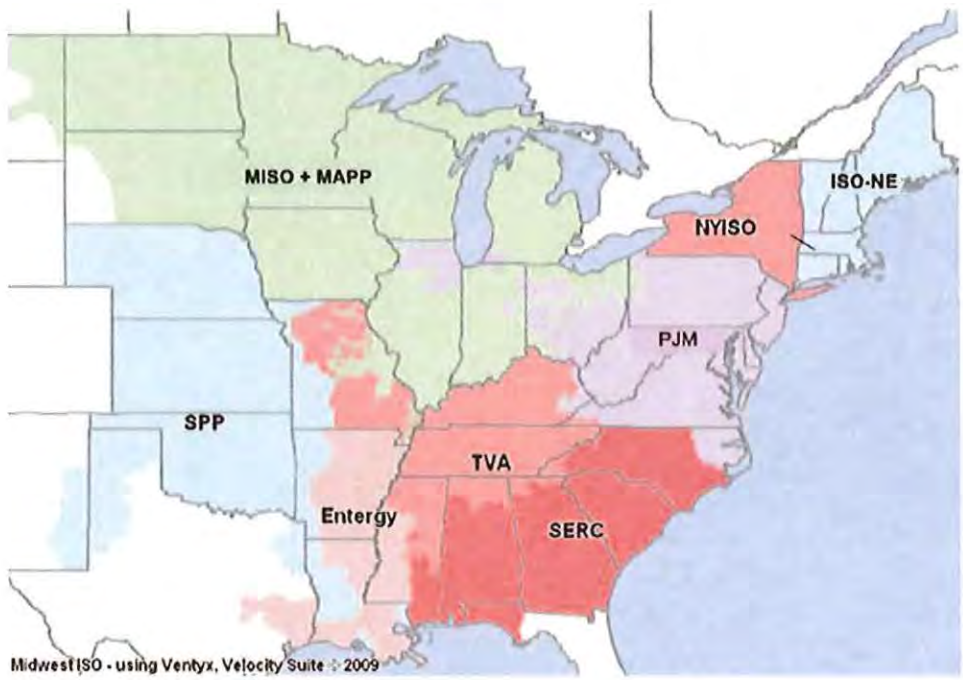


Figure 2-4.Study regional definitions

The scenarios were developed for the different energy targets. Table 2-2 and Figure 2-5 show the energy production allocation (in terawatt-hours [TWh]) by region for each of the four energy scenarios and for the Reference Scenario. The 20% energy scenarios (1 through 3) vary slightly because of the different resources used to achieve the targets.

[1] *Because of space considerations, Midwest ISO is shortened to MISO in tables and figures. Similarly, PJM Interconnection is shortened to PJM.*
[2] *Entergy is operated as part of SERC.*

TABLE 2-2. SUMMARY OF ENERGY BY REGION FOR SCENARIOS					
REGION	ANNUAL ENERGY (TWH)				
	REFERENCE SCENARIO	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
ISO-NE	33	13	46	82	82
MISO + MAPP	63	404	288	189	405
NYISO	20	22	48	71	71
PJM	65	64	97	244	295
SERC	13	3	16	16	16
SPP	26	234	245	139	243
TVA	4	4	4	4	4
TOTAL	**224**	**744**	**745**	**746**	**1116**

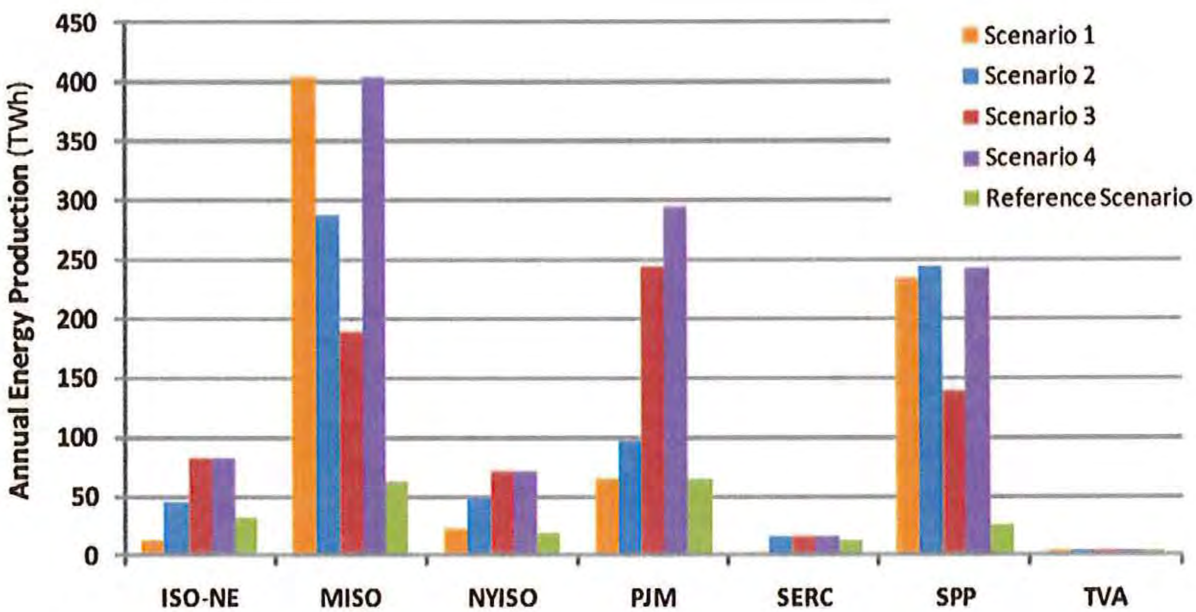


Figure 2-5. Annual energy production by region

Figure 2-6 shows the allocation of nameplate capacity for each region by scenario.

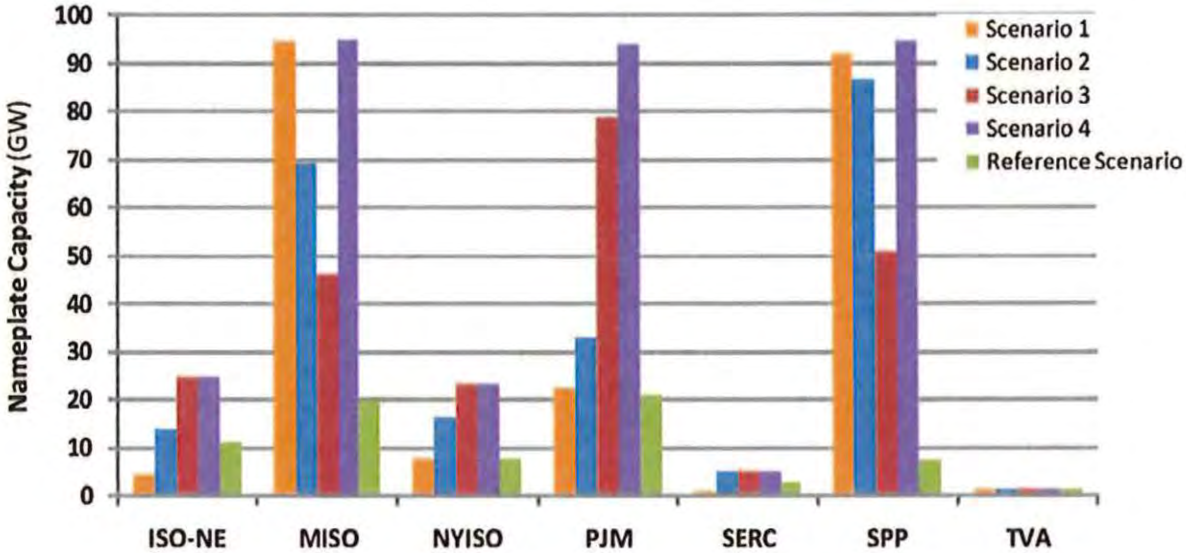


Figure 2-6. Nameplate capacity by region

SCENARIO DETAILS

The following sections give additional details for the five scenarios, including installed capacity by operating region, sizes and locations of plants, and state-by-state capacity.

REFERENCE CASE

This scenario is designed to approximate the current state of wind development plus some expected near-term development guided by interconnection queues and state RPS. This scenario totaled about 6% of the total 2024 projected load requirements for the Eastern Interconnection.

Table 2-3 lists capacity by operating region. Locations and sizes of individual plants are shown in Figure 2-7.

TABLE 2-3. REFERENCE CASE, 6% OF 2024 LOAD REQUIREMENTS				
REGION	ONSHORE (MW)	OFFSHORE (MW)	TOTAL (MW)	ANNUAL ENERGY (TWH)
ISO-NE	8,310	3,000	11,310	33
MISO + SAPP	19,732		19,732	63
NYISO	4,932	3,000	7,932	20
PJM	19,402	1,620	21,022	65
SERC	1,009	2,000	3,009	13
SPP	7,419		7,419	26
TVA	1,247		1,247	4
TOTAL	**62,051**	**9,620**	**71,671**	**224**

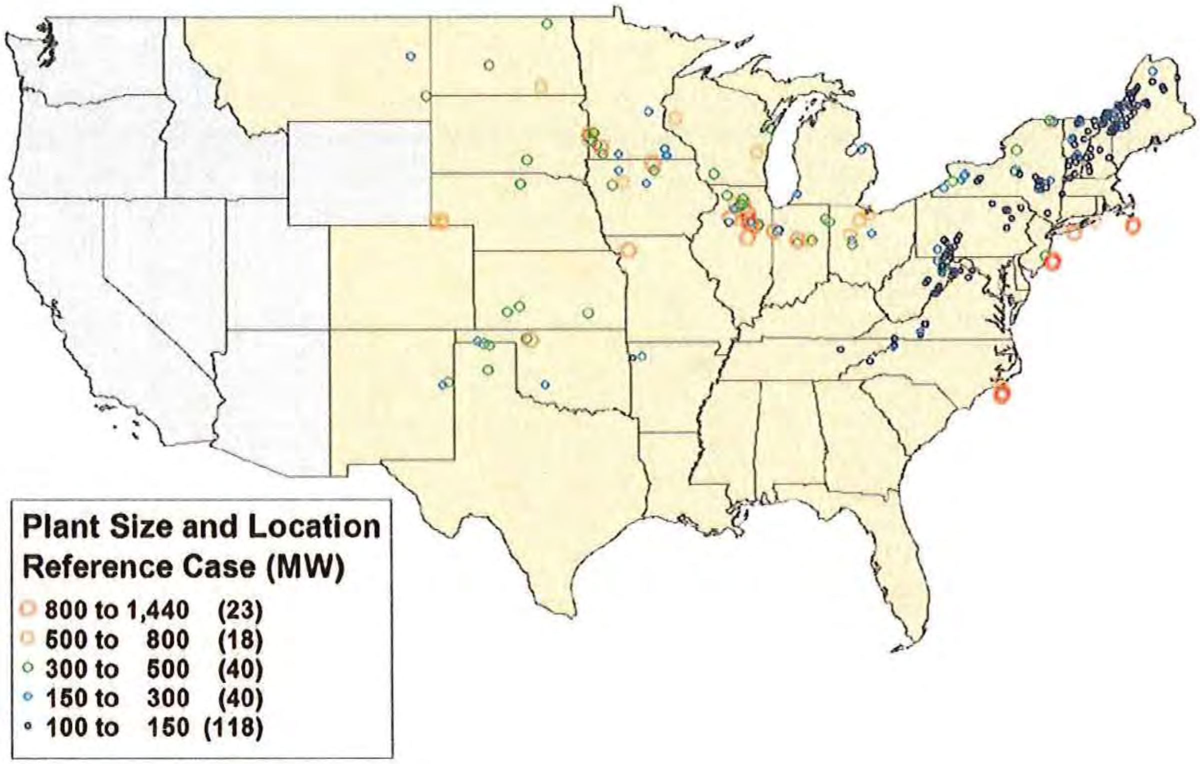


Figure 2-7. Wind plant size and location for Reference Case

SCENARIO 1

In general, this scenario exploits the onshore wind resources with high capacity factors across the interconnection. Consequently, it has the largest Great Plains wind capacity of the three 20% scenarios and takes advantage of the best onshore resources in the East.

Table 2-4 shows capacity by operating region. Locations and sizes of individual plants are shown in Figure 2-8. Figure 2-9 is a better visual illustration of state-by-state installed capacity.

TABLE 2-4. SCENARIO 1—20% HIGH CAPACITY FACTOR, ONSHORE

REGION	ONSHORE (MW)	OFFSHORE (MW)	TOTAL (MW)	ANNUAL ENERGY (TWH)
ISO-NE	4,291	0	4,291	13
MISO + SAPP	94,808	0	94,808	404
NYISO	7,742	0	7,742	22
PJM	22,669	0	22,669	64
SERC	1,009	0	1,009	3
SPP	91,843	0	91,843	234
TVA	1,247	0	1,247	4
TOTAL	**223,609**	**0**	**223,609**	**744**

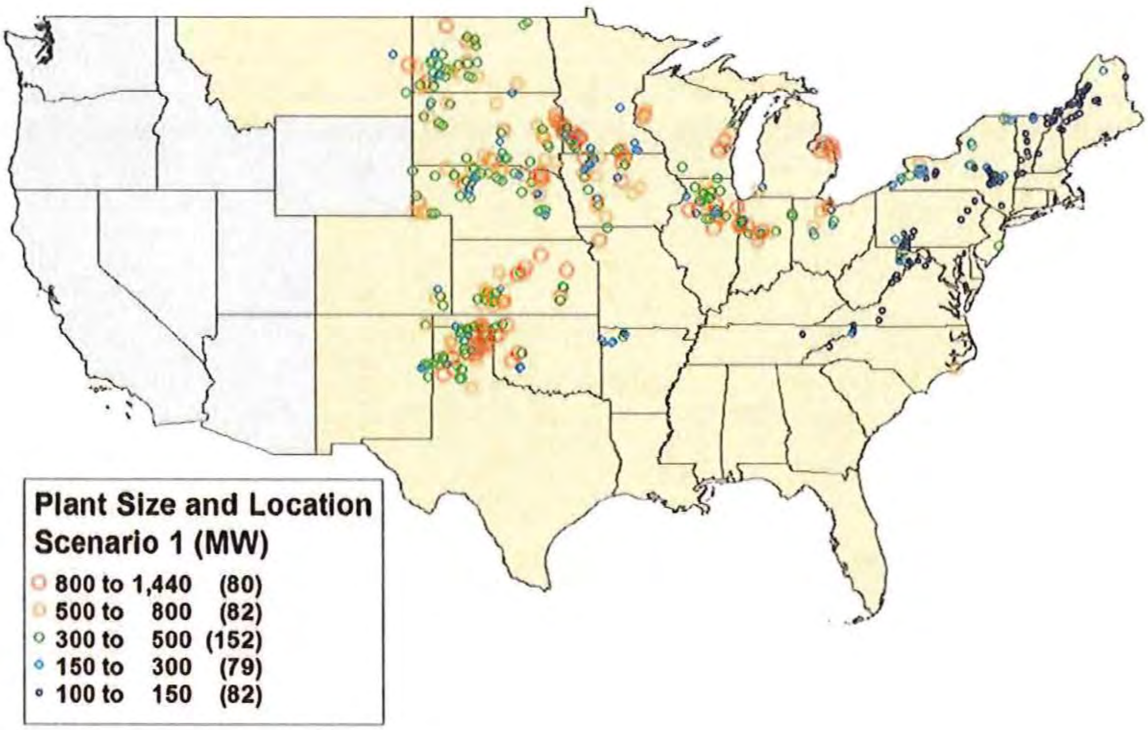


Figure 2-8. Installed capacity—Scenario 1

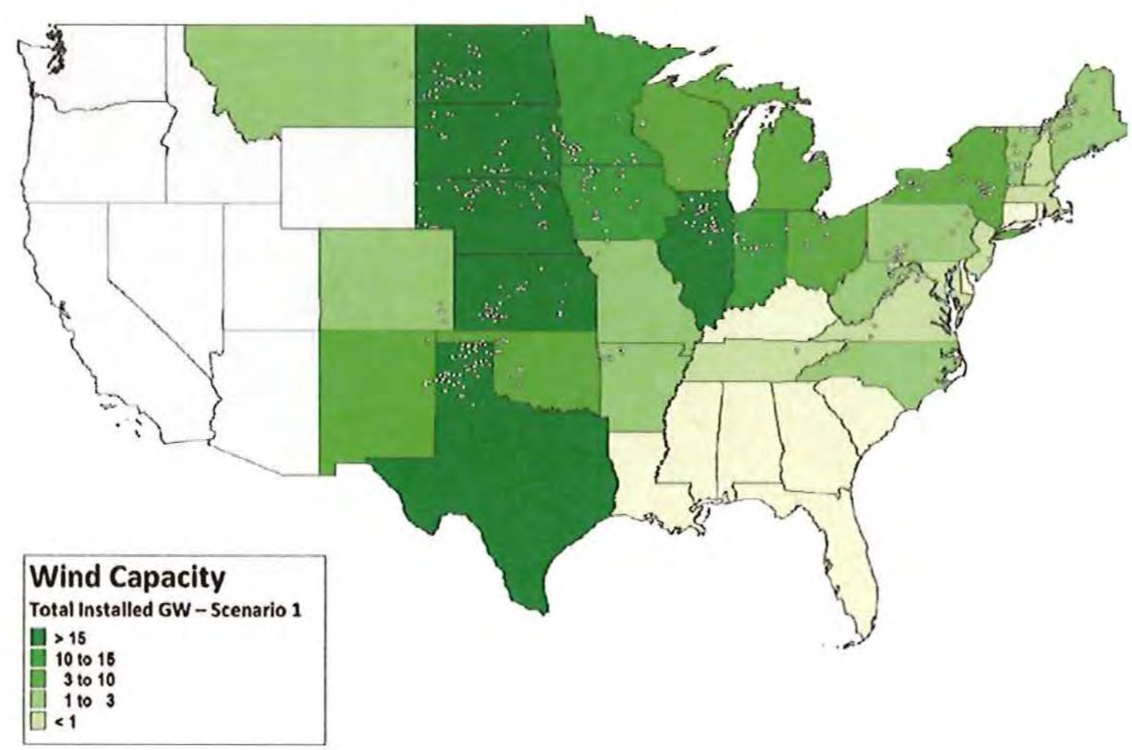


Figure 2-9. State map of nameplate capacity—Scenario 1

SCENARIO 2

In Scenario 2, some of the wind generation from the Great Plains is moved eastward. In addition, a modest amount of offshore development is assumed off the East Coast.

This scenario corresponds most closely to a 20% scenario studied in a recent collaborative planning effort (JCSP 2008).

Table 2-5 shows capacity by operating region. Figure 2-10 shows locations and sizes of individual plants, and Figure 2-11 shows state-by-state installed capacity.

TABLE 2-5. SCENARIO 2—20% HYBRID WITH OFFSHORE

REGION	ONSHORE (MW)	OFFSHORE (MW)	TOTAL (MW)	ANNUAL ENERGY (TWH)
ISO-NE	8,837	5,000	13,837	46
MISO + SAPP	69,444	0	69,444	288
NYISO	13,887	2,620	16,507	48
PJM	28,192	5,000	33,192	97
SERC	1,009	4,000	5,009	16
SPP	86,666	0	86,666	245
TVA	1,247	0	1,247	4
TOTAL	**209,282**	**16,620**	**225,902**	**745**

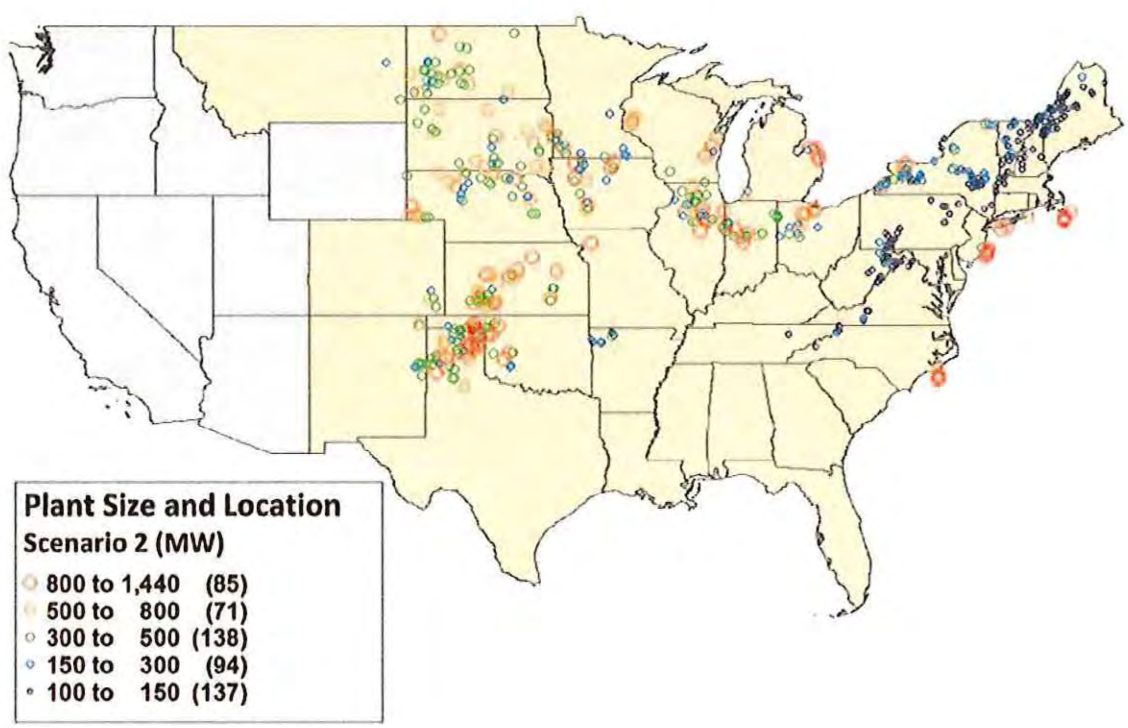


Figure 2-10. Installed capacity—Scenario 2

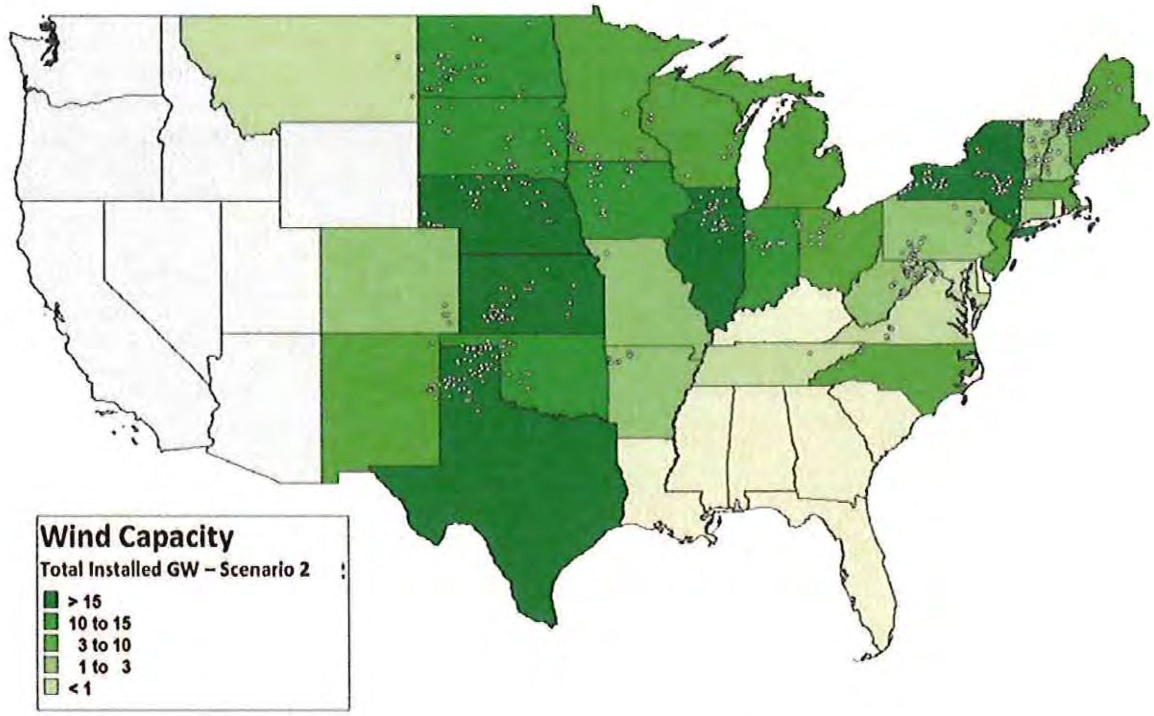


Figure 2-11. State map of nameplate capacity—Scenario 2

SCENARIO 3

To create a contrast with Scenario 1, a large amount of wind generation is moved from the Great Plains nearer to the East Coast load centers. To bring about this shift, a large amount of offshore wind generation is required.

Table 2-6 shows capacity by operating region. Locations and sizes of individual plants are shown in Figure 2-12, with the state-by-state illustration in Figure 2-13.

TABLE 2-6. SCENARIO 3—20% LOCAL, WITH AGGRESSIVE OFFSHORE

REGION	ONSHORE (MW)	OFFSHORE (MW)	TOTAL (MW)	ANNUAL ENERGY (TWH)
ISO-NE	13,887	11,040	24,927	82
MISO + SAPP	46,255	0	46,255	189
NYISO	13,887	9,280	23,167	71
PJM	38,956	39,780	78,736	244
SERC	1,009	4,000	5,009	16
SPP	50,958	0	50,958	139
TVA	1,247	0	1,247	4
TOTAL	**166,199**	**64,100**	**230,299**	**746**

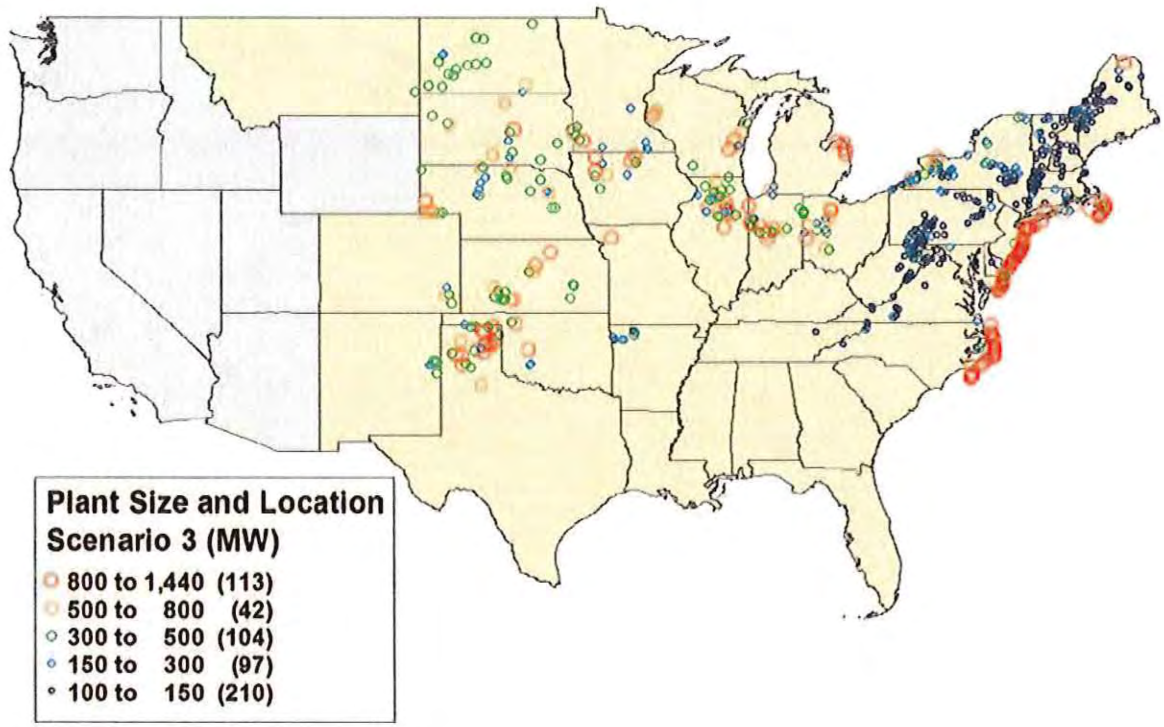


Figure 2-12. Installed capacity—Scenario 3

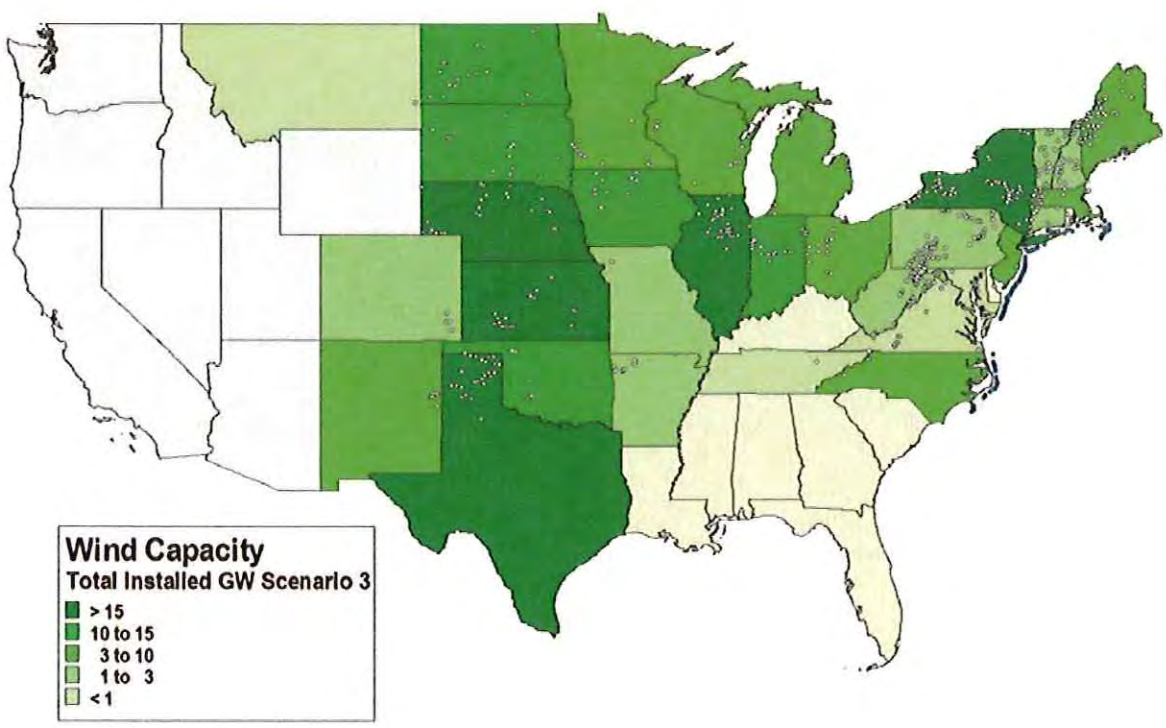


Figure 2-13. State map of nameplate capacity—Scenario 3

SCENARIO 4

Reaching 30% energy penetration requires more than 300 GW of wind generation, and therefore uses a significant portion of the higher quality wind resources in the NREL database. A large amount of offshore wind is required, and the amounts in the Great Plains are comparable to Scenario 1.

Table 2-7 shows capacity by operating region. Locations and sizes of individual plants are shown in Figure 2-14, with the state-by-state illustration in Figure 2-15.

TABLE 2-7. SCENARIO 4—30% AGGRESSIVE ONSHORE AND OFFSHORE

REGION	ONSHORE (MW)	OFFSHORE (MW)	TOTAL (MW)	ANNUAL ENERGY (TWH)
ISO-NE	13,887	11,040	24,927	82
MISO + SAPP	95,046	0	95,046	405
NYISO	13,887	9,280	23,167	71
PJM	38,956	54,780	93,736	295
SERC	1,009	4,000	5,009	16
SPP	94,576	0	94,576	243
TVA	1,247	0	1,247	4
TOTAL	**258,608**	**79,100**	**337,708**	**1,116**

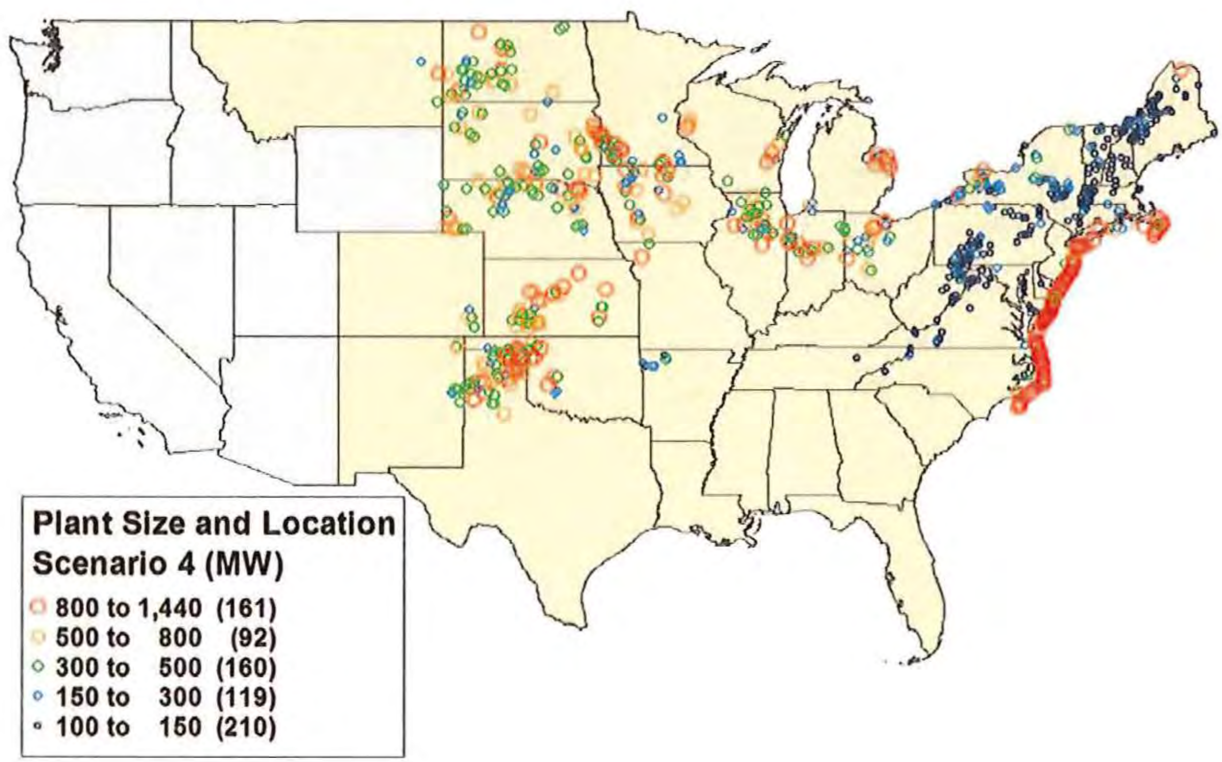


Figure 2-14. Installed capacity —Scenario 4

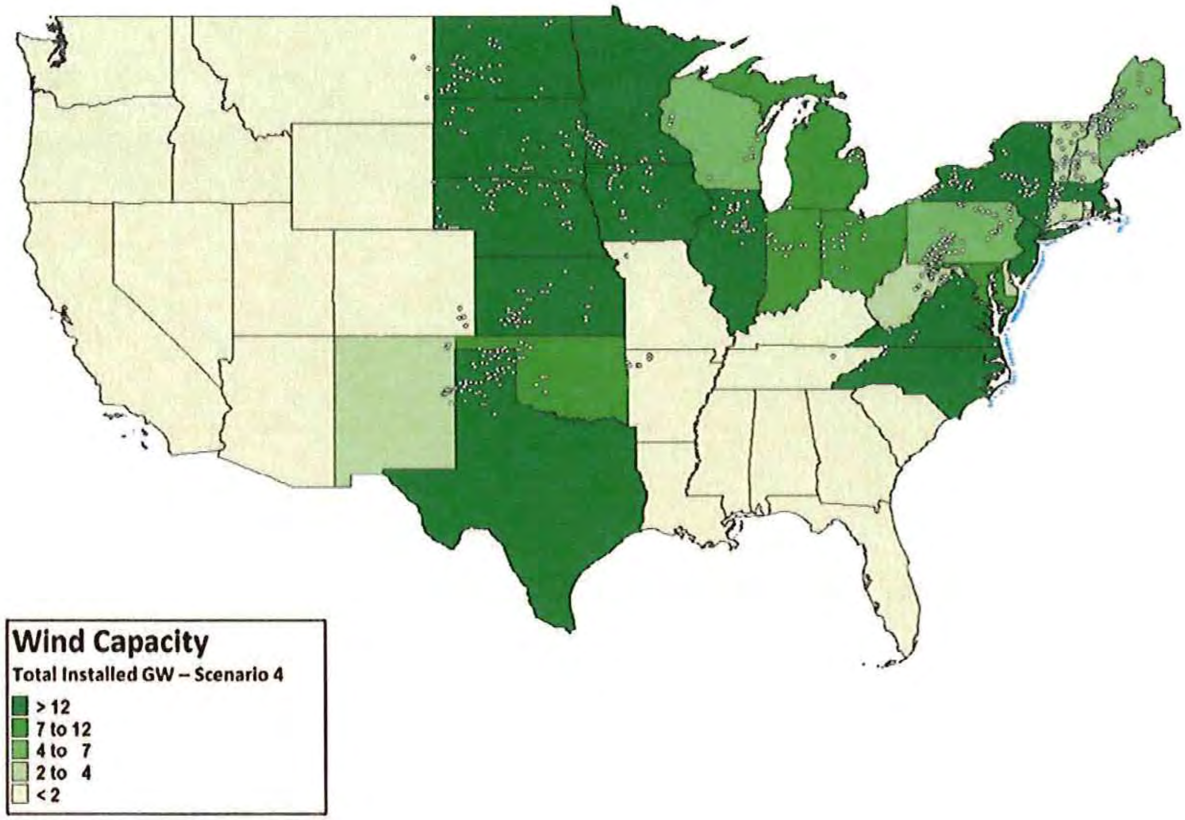


Figure 2-15. State map of nameplate capacity—Scenario 4

SECTION 3: ANALYTICAL METHODOLOGY: DATA, MODELS, AND TOOLS

The study analysis focused on three major areas:

1. Developing conceptual transmission to accommodate the levels of wind generation as defined in the four scenarios described in Section 2.

2. Assessing the impacts of the wind generation in each scenario on grid operations in the Eastern Interconnection.

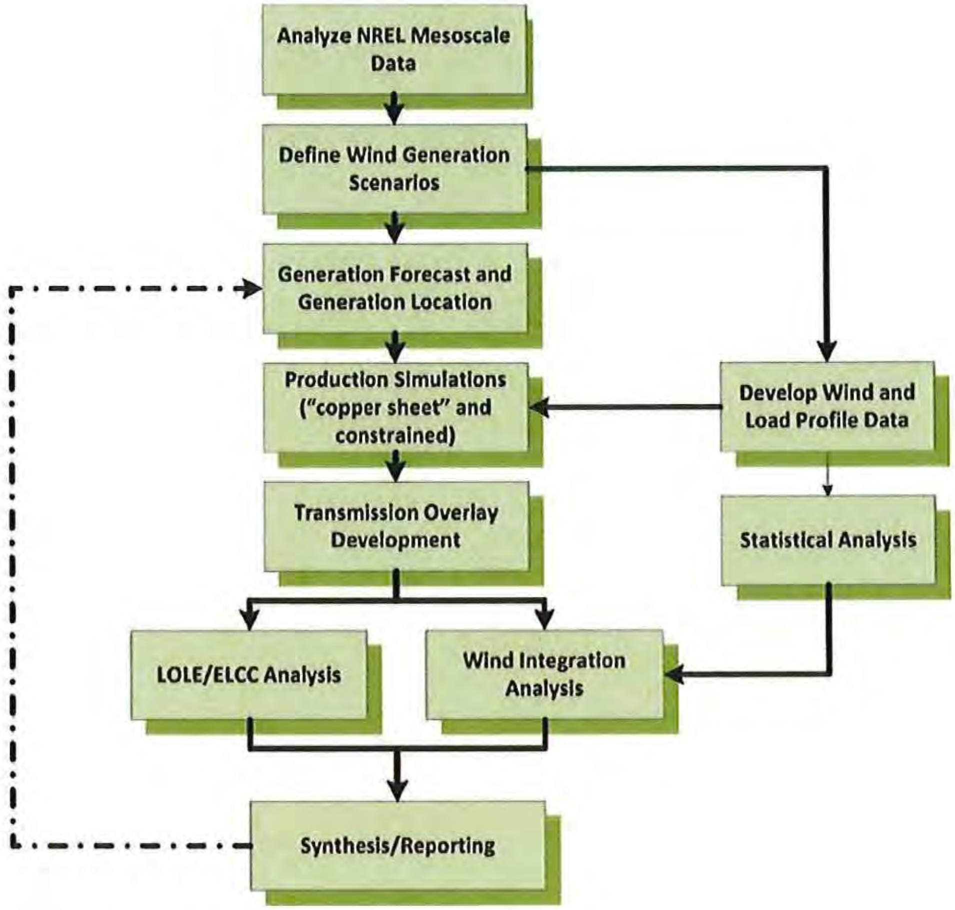
3. Determining the level to which wind generation in each scenario contributes to resource adequacy (i.e., its capacity value).

The analytical methods used in this study build on those established in previous integration studies conducted over the past 10 years (see, for example, EnerNex Corporation and Wind Logics 2004; Bai et al. 2007; GE Energy 2008).

A chronological data set of wind generation and load data is the critical input for EWITS. Load and wind data must be physically correlated because meteorology influences load patterns and is a critical factor for wind energy production. Hourly load data from across the interconnection for years corresponding to the National Renewable Energy Laboratory's (NREL) mesoscale data were obtained as the starting point for developing a representation of Eastern Interconnection loads in 2024. The basic resolution for both load and wind data is 1 hour, although higher resolution (10-minute average) data are available from the mesoscale data for wind generation, and samples of higher resolution data were collected from operating entities in the Eastern Interconnection.

Figure 3-1 is an overview of the process and methodology used in EWITS. All the analytical methods use the chronological wind generation and load data over a 3-year period as inputs. Brief descriptions of the methods follow:

- Statistical analysis of wind generation and load data, separately and in combination, to assess impacts on operating reserves
- Chronological production simulations, which, if correctly structured, are used to simulate scheduling and operation of the power system
- Monte Carlo-based chronological resource adequacy assessment, which uses annual or multiannual hourly data for load and wind generation to determine the probability that available supply resources would not be able to meet demand.



Notes: LOLE = loss of load expectation; ELCC = effective load-carrying capability.
Figure 3-1. Overview of the study process

The consensus approach for assessing wind integration impacts is to simulate the scheduling and operation of the power system with wind generation over an extended period of time. If the hourly load and wind data that drive the simulation extend over a sufficient time frame, the range of conditions evaluated can be considered statistically valid. In other words, all combinations of wind and load and their respective variability and uncertainty characteristics are represented in the input data. This prevents focusing only on severe events, like major wind ramps, that would be expected infrequently.

The EWITS team used chronological production simulations in several aspects of the analysis:

- Development of the transmission overlays, where production simulations for the current system determine both the locations and the economic value of new transmission

- Evaluation of operational impacts (where scheduling and real-time system operations are mimicked as closely as possible and details such as incremental operating reserves required to manage wind generation and increased uncertainty caused by wind generation forecast errors are considered directly)
- Determination of new area import limits with expanded transmission for evaluation of wind generation and new transmission contributions to resource adequacy.

The chronological wind and load data also support the preferred approach for assessing wind generation contributions to resource adequacy. With a chronological, Monte Carlo-based, probilistic resource adequacy assessment tool, the effects of wind generation on planning capacity margin can be calculated directly. Comparing these results to one without wind generation determines the specific contribution of the defined wind generation.

MODEL DEVELOPMENT

EWITS focuses on calendar year 2024. All the analytical elements are based on a model of what the Eastern Interconnection would look like in that year.

ELECTRICAL REPRESENTATION OF THE EASTERN INTERCONNECTION

The EWITS analysis depended on three sets of data that represent the electrical infrastructure of the Eastern Interconnection: load, transmission network, and generation. The Joint Coordinated System Plan (JCSP 2008) was an earlier effort to produce analytics of the electrical infrastructure that ignored regional transmission organization (RTO) and balancing authority seams while working under a common set of assumptions. The JCSP process included open stakeholder involvement in developing assumptions and verifying the base data. This open process gave all stakeholders the opportunity to review the information and make appropriate changes to the data to better reflect the system. This reviewed data set consists of forecast loads, along with planned and existing generation, and incorporates existing transmission development plans (or concepts) to supplement the existing transmission infrastructure.

Because a large amount of effort went into compiling and reviewing these data, the data were an appropriate starting point for this study.

LOAD

Demand for all study regions was originally based on the information within the PowerBase™ (a Ventyx product) database, which is based on the 2006 Federal Energy Regulatory Commission (FERC) Form 714, 2006 North American Electric Reliability Corporation (NERC) electricity supply and demand (ES&D) information, and 2006 power flow data. The load data for all regions were benchmarked against various reporting entities within each region and were also given to all stakeholders during the JCSP participant review process. Through this process, some areas specifically adjusted demand and energy projections. Most areas, however, deemed the PowerBase data to be suitable for the study.

The PowerBase database contains annual peak demand for each company within an area or region. This demand value is applied to an hourly load profile for each company, developed from filed historical load data. The EWITS study team used hourly profiles representing 2004, 2005, and 2006. In the PowerBase database, each company has its own unique hourly profile, with each company experiencing its peak demand at different times of the year. The PROMOD IV® economic energy model uses company-specific detail for demand and energy; however, because the Electric Generation Expansion Analysis System (EGEAS; from the Electric Power Research Institute [EPRI]) expansions are performed on a regional basis (see Section 3.3), the EWITS team had to aggregate each individual company's peak demand and determine a peak coincident factor for each study region. This was accomplished by summing the individual hourly peaks for each company for all 8,760 hours in the year, using the 2004 annual profiles. The maximum sum of the individual hourly peaks is the coincident peak for the year. Dividing the coincident peak by the sum of the individual company peaks gives a regional coincident factor, as seen in Table 3-1.

Just like the demand assumptions, annual energy values are also available from the PowerBase database. The EWITS team reviewed and checked the values to determine whether they needed update or verification.

TABLE 3-1. SUMMARY OF DEMAND AND ENERGY ASSUMPTIONS USED WITHIN THE SCENARIO DEFINITIONS

REGION	STUDY REGION COINCIDENCE FACTOR	2008 NONCOINCIDENT PEAK DEMAND (MW)	2008 COINCIDENT PEAK DEMAND (MW)	2008 ANNUAL ENERGY (GWH)	REFERENCE ANNUAL DEMAND ESCALATION (%)	REFERENCE ANNUAL ENERGY ESCALATION (%)
ENTERGY	0.9947	27,712	27,565	142,362	1.80	1.66
ISO-NE	0.9892	28,227	27,923	1335,776	2.27	1.69
MISO	0.9343	115,862	108,254	590,662	1.28	1.50
MAPP	0.9608	9,915	9,526	49,941	1.20	1.61
NYISO	0.9428	35,064	33,057	171,054	0.92	0.77
PJM	0.9497	142,826	135,637	717,468	1.90	1.65
SERC	0.9828	96,071	94,421	472,752	2.37	2.04
SPP	0.9798	47,478	46,519	220,543	1.34	1.77
TVA	0.9858	47,633	46,955	257,337	2.27	0.89

Notes: MW = megawatts; GWh = gigawatt-hours; ISO-NE = New England ISO; NYISO = New York ISO; MISO = Midwest ISO (shortened to MISO in figures and tables because of space considerations); MAPP = Mid-Continent Area Power Pool; PJM = PJM Interconnection (shortened to PJM because of space considerations); SERC = Southeastern Electric Reliability Council; SPP = Southwest Power Pool; TVA = Tennessee Valley Authority.

NETWORK

The EWITS study relies on the 2018 power flow model that was developed during the participant review process for a previous study of the Eastern Interconnection (JCSP 2008). The Eastern Interconnection Reliability Assessment Group Multi-Regional Modeling Working Group (ERAG MMWG) 2007 Series 2018 summer peak power flow model was used as the starting point for the development. To better represent the latest and most accurate transmission system for the study, the power flow model was reviewed and updated by study stakeholders to incorporate planned or proposed transmission projects.

GENERATION

The EWITS study used the PowerBase software as its platform for existing unit generator information. In addition to benchmarking its generator data, some asset owners supplied additional information, and the study team added the information to the database before model population. Stakeholders gave comments on adjusted capacities, ownership, in-service dates, and unit operational status. Building on the generators in the default PowerBase database, change cases were created to reflect the existing and future generation fleet. Each generator in the database or in a queue was assigned a status of active, planned, future, or canceled, as described in Table 3-2.

TABLE 3-2. STATUS CATEGORIES APPLIED TO ALL UNITS WITHIN THE DATABASE

STATUS	GENERATOR STATUS DESCRIPTION
ACTIVE	Existing online generation, including committed and uncommitted units. Does not include generation that has been mothballed or decommissioned.
PLANNED	A generator that is not online, has a future in-service date, is not suspended or postponed, and has proceeded to a point where construction is almost certain. Examples would include generators for which an Interconnection Agreement has been signed, all permits have been approved, all study work has been completed, state or administrative law approval has been obtained, and so on. One exception to this rule is the inclusion of recently proposed nuclear expansions throughout the Eastern Interconnection. Although the units do not qualify as "planned" units, JCSP participants felt strongly that the units be considered as part of the planned generation fleet. These units are used in the model to meet future demand requirements before the economic expansions. All units coming online between August 2007 and July 2008 show up as newly installed in 2008.
FUTURE	Generators with a future online date that do not meet the criteria of the planned status. Generators with a future status typically fall under one of the following categories: proposed, feasibility studies in progress, applications for permits submitted, and so on. These generators are not used in the models but are considered in the siting of future generation.
CANCELED	Generators that have been suspended, canceled, retired, or mothballed.

Table 3-3 summarizes active generation with the nameplate capacity described by region and generator unit type. Table 3-4 gives a summary of capacity additions planned between 2010 and 2024. Finally, Table 3-5 summarizes the generation that is planned to retire before 2024.

TABLE 3-3. SUMMARY OF ACTIVE GENERATION CAPACITY BY REGION (NAMEPLATE CAPACITIES IN MEGAWATTS)											
FUEL TYPE	COMBINED CYCLE (CC)	STEAMT URBINE (ST; COAL)	COMBUSTION TURBINE (CT)	HYDRO	IGCC[a]	NUCLEAR	BIOMASS	STEAM TURBINE (ST; GAS)	STORAGE	WIND	TOTAL
ENTERGY	13,422	5,919	3,446	691		5,182	95	15,760	28		44,543
ISO-NE	12,610	3,195	2,614	1,734		4,389	935	6,932	1,675	70	34,154
MISO	10,709	69,843	27,398	1,408	282	10,282	286	3,918	2,475	2,862	129,462
MAPP	1,077	7,319	2,142	2,449		891		24		498	14,400
NYISO	8,699	3,092	5,994	4,356		5,069	289	11,898	1,280	42	40,716
PJM	24,484	70,656	30,974	2,647		30,769	669	9,253	3,625	514	173,590
SERC	17,501	44,948	23,638	6,261		17,151	147	1,169	3,844		114,659
SPP	11,059	23,426	8,932	2,570		2,056	56	12,943	296	2,001	63,338
TVA	7,761	27,189	11,641	5,074		7,117			1,712	79	60,574
TOTAL	**197,322**	**255,587**	**116,779**	**27,191**	**282**	**82,906**	**2,473**	**61,896**	**14,935**	**6,065**	**675,435**

[a]IGCC = integrated gasification combined cycle

TABLE 3-4. SUMMARY OF PLANNED GENERATION CAPACITY BY REGION THROUGH 2024 (NAMEPLATE CAPACITIES IN MEGAWATTS)											
FUEL TYPE	CC	ST (COAL)	CT	HYDRO	IGCC	NUCLEAR	BIOMASS	ST (GAS)	STORAGE	WIND	TOTAL
ENTERGY	18,00	1,585				3,000					6,385
ISO-NE	110		70				50			607	837
MISO	2,235	3,972	374			4,163				597	11,340
MAPP										90	90
NYISO	640		1,100			1,600				460	3,800
PJM	1,127	92			2,071	4,706				862	8,858
SERC	1,652	500	280			8,848					11,280
SPP	500	2,995	1,407							2,748	7,380
TVA	660	549	340		677	3,460				50	5,736
TOTAL	**8,724**	**9,692**	**3,571**		**2,748**	**25,777**	**50**			**5,144**	**55,705**

TABLE 3-5. SUMMARY OF GENERATOR RETIREMENT CAPACITY BY REGION THROUGH 2024 (NAMEPLATE CAPACITIES IN MEGAWATTS)											
FUEL TYPE	CC	ST (COAL)	CT	HYDRO	IGCC	NUCLEAR	BIOMASS	ST (GAS)	STORAGE	WIND	TOTAL
ENTERGY											0
ISO-NE											0
MISO		561									561
MAPP											0
NYISO		177	825								1,002
PJM		615	868								1,483
SERC			62								62
SPP											0
TVA											0
TOTAL	0	1,353	1,755	0	0	0	0	0	0	0	3,108

TOOLS

The project team used three software tools to support the various analytical elements of the study. All are established tools in the electrical energy industry; their basic purpose and functions are described next.

PROMOD IV OVERVIEW

PROMOD IV is an integrated electric generation and transmission market simulation system that incorporates extensive details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. It performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV forecasts hourly energy prices, unit generation, fuel consumption, bus-bar energy market prices, regional energy interchange, transmission flows, and congestion prices. It uses an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, spinning reserve requirements, and customer demand.

TRANSMISSION SYSTEM REPRESENTATION

PROMOD IV captures the constraints and limitations inherent in electrical power transmission using a DC load flow algorithm. All major transmission equipment is modeled—voltage transformers, phase-angle regulators, DC ties, generation and load buses, and transmission lines with reactance and resistance inputs. The transmission topology data are fully integrated with the commitment and dispatch algorithm so that generators are scheduled, started, and cycled while transmission constraints are enforced. PROMOD IV simultaneously optimizes the transmission, generation commitment, and unit dispatch for all 8,760 hours under security-constrained unit commitment (SCUC) and economic-dispatch rules. PROMOD IV also models transmission interfaces, enforcing bidirectional limits on groups of lines.

The PROMOD IV tool includes both summer and winter normal-state ratings on power flow branches and interfaces to enforce normal flow limits on the transmission system. In addition, PROMOD IV recognizes contingency constraints, so that the dispatch will still be feasible if the system experiences any of a set of contingency events or combination of events. A single defined contingency can represent multiple transmission lines or generator outages (e.g., N-1, N-2, and more contingencies). Emergency ratings (summer and winter) on power flow branches and interfaces can be used to define additional energy that can flow on lines during contingency events. There are no program-imposed limitations on the number of contingencies or monitored lines.

An iterative approach is used to include the effects of marginal transmission losses in markets that have loss components in their locational marginal price (LMP) calculations. In each hour, actual dynamic losses are calculated line by line using a nonlinear solution, generators are penalized based on their incremental contribution to losses, and the simulation is repeated until the convergence tolerance is satisfied. PROMOD IV calculates the incremental loss at each bus and incorporates that marginal loss component into the bus LMP.

UNIT DISPATCH

PROMOD IV calculates dispatch lambdas for each unit capacity segment based on its variable costs, which include fuel (commodity, handling, and transportation); emissions; and operations and maintenance (O&M). Based on the reactance of the connected transmission lines, shift factors are calculated for each bus, so that injected generation will flow into the system while adhering to the physical characteristics of the grid. PROMOD IV incorporates each generator's costs, shift factors, and ramp rate limits into a linear program to optimize the dispatch across the entire system for each hour, honoring transmission constraints within a full security-constrained economic dispatch.

UNIT COMMITMENT

A multipass process is employed to establish day-ahead unit commitment for each generator based on forecast energy prices at the generator injection bus. Unit characteristics captured in the commitment and dispatch include multisegment operation, minimum capacity, ramp-up and ramp-down limits, start-up costs, minimum runtime and downtime constraints, and operating reserve contribution. The unit-commitment process also captures system operational effects, including transmission congestion, marginal losses, phase angle regulators, DC line operation, regional interchange, and tariffs. PROMOD IV also co-optimizes spinning reserve decisions within hourly dispatch. The following paragraphs describe the steps in the unit-commitment and dispatch solution.

First, a preliminary unit dispatch is performed without enforcing unit runtime and downtime constraints, ramp rates, and start-up cost effects. This preliminary solution is designed to create a starting point for the price of energy in each hour that is not subject to multihour commitment constraints. This dispatch incorporates a full view of transmission congestion and other detailed operations. Wind units can be set up to be dispatched in the preliminary solution by designating them as "Firm" resources, or they can be excluded in the preliminary price formation by designating them as "Non-Firm." The preliminary dispatch is performed for a 7-day period, starting Monday at 1:00 a.m. and ending Sunday at 12:00 p.m. (midnight). This gives each generation injection site (bus) a unique 168-hour forecast for energy prices. The 168-hour look-ahead from Monday to Sunday is designed to be long enough to account for unit-commitment decisions based on multiday constraints (e.g., 48-hour minimum downtime).

The second step in the unit-commitment process is to optimize the operation of each generator given the price forecast at its bus, subject to unit-specific operating constraints and unit bid (or cost) inputs. A mixed-integer program is used to optimize unit profit. If energy prices are higher than the unit bid in a given hour, it is assumed the unit must be committed in that hour for load or reliability, and the program optimizes the run schedule for the surrounding hours to meet runtime constraints and maximize profits or minimize losses. If a unit runs at a loss for any day (including start-up cost), a new unit bid is calculated by determining the price increase needed to allow the unit to break even over the given run period. This new bid is added to the unit cost from the preliminary unit dispatch for the next dispatch pass. Each unit is processed individually based on the forecast prices at its injection bus. The unit commitment is done for the entire week without knowing if any forced outages will occur. If a forced outage does transpire during the week, the rest of the week is re-optimized from the hour in which the unit returns to service.

When all units have been processed, a second complete dispatch pass is done with all unit constraints in place and all commitment bid adders applied. The second dispatch results in a new forecast of bus prices and the commitment is re-optimized for each unit within the mixed-integer program to reflect the effect of unit operating constraints and bids on bus prices. This final commitment is then "locked in" for the final dispatch pass.

During the final dispatch, the commitment schedule from the final mixed-integer solution for each unit is honored. The final dispatch also includes any Non-Firm resources that were not included in the preliminary passes. The dispatch process itself is a linear program optimization that includes a DC load flow solution to monitor flows on transmission lines, calculates and applies marginal loss factors at each generation node, recognizes market import-export tariffs, and co-optimizes for spinning reserve requirements.

In the EWITS Reference Scenario, the day-ahead wind forecast profiles are input as Firm resources, thus affecting the nodal prices used for unit commitment. The wind error profiles are input as Non-Firm, causing them to be used only in the final dispatch, changing the wind profiles to match the actual wind vectors. This modeling creates the disconnect between day-ahead unit commitment and final hourly dispatch based on the uncertainty of the wind forecast. A similar approach is used to model the effects of load uncertainty.

GE-MARS

The study team used GE Energy's Multi-Area Reliability Simulation (GE-MARS) program to calculate reliability indices. GE-MARS is a transportation-style model based on a sequential Monte Carlo simulation that steps through time chronologically and produces a detailed representation of the hourly loads and hourly wind profiles in comparison with the available generation, in addition to interfacing between the interconnected areas.

GE-MARS calculates, by area or area group, the standard reliability indices of daily or hourly loss of load expectation (LOLE, in days per year or hours per year) and expected unserved energy (EUE, in megawatt-hours per year). For EWITS, the study team used the daily LOLE index to determine the effective load-carrying capability (ELCC) of wind generation.

The basic calculations are done at the area level, which is how much of the data are specified and aggregated. Loads, wind profiles, and generation are assigned to areas, and transfer limits are specified between areas. All the core data assumptions for the GE-MARS model come from PROMOD IV but are aggregated into the LOLE study areas.

EGEAS

The EGEAS software is used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. Optimizations can be performed on a variety of constraints such as resource adequacy (loss-of-load hours), reserve margins, or emissions constraints. The EWITS study optimization is based on minimizing the 20-year capital and production costs, with a reserve margin requirement indicating when new capacity is required.

ASSUMPTIONS

To fully define the scenarios for the study year, the EWITS study team had to make a number of assumptions. And because any assumptions about a scenario 15 years in the future would be subject to differences of opinion and debate, many of the EWITS assumptions were drawn from the previous stakeholder-driven assessment of the Eastern Interconnection (JSCP 2008), which looked at the same year. Doing this allows EWITS to benefit from the significant amount of discussion and interaction that took place in that earlier effort to reach some agreement on what the Eastern Interconnection might look like in 2024.

OPERATIONS IN THE EASTERN INTERCONNECTION

Because the wind generation in the scenarios is not distributed evenly across the interconnection, either geographically or in a load-weighted sense, portions of the interconnection in the study scenarios have very high penetrations. These penetrations are well beyond the boundaries of actual experience with wind generation, resulting in effects on power system operation and control.

Previous wind integration studies (see Bibliography) offer some important conclusions relevant to defining the framework for operating the interconnection with these large penetrations of wind generation. One finding is that larger operating footprints allow the significant effects of geographic diversity on wind generation variability and uncertainty to be exploited. A second relevant finding is that the rules and processes that govern power system operations are an important factor in wind integration; structures that aggregate large amounts of load and generating resources into a single operational framework and encourage flexibility allow wind generation to be more easily integrated.

Currently, operations in a large portion of the Eastern Interconnection are under the auspices of five wholesale energy markets. For the 2024 study year, the study team assumed that these market footprints would remain, and that the other portions of the Eastern Interconnection explicitly represented in the model—TVA and portions of SERC—would operate in a manner similar to the market footprints.

A further assumption was made about the details of scheduling and operations processes in each of the operating areas. For purposes of production modeling, the team assumed that operations in each area had three major elements:

- A day-ahead unit-commitment process, where forecasts of load and wind generation for the next operating day are assessed through a SCUC evaluation. Currently, this step is performed some time following the day-ahead energy market clearing.
- A real-time or subhourly energy market, where participating units are economically dispatched on a frequent basis (5- to 10-minute intervals) based on short-term forecasts of net load (i.e., load minus wind generation).
- An ancillary services market that draws on many resources for the spinning and nonspinning reserves required for frequency support, balancing, and system security.

At present, not all of the operating areas in the study footprint operate in this manner. With the study horizon of 2024 and the strong trends in the industry in these directions, however, the assumption is appropriate for this type of study.

CAPACITY EXPANSION MODEL ASSUMPTIONS

Performing energy flow analysis in an out-year model requires that the load and generation balance meet generation fleet resource adequacy requirements. Existing area generation queues do not typically have planned capacity beyond a 5- to 10-year window. This results in gaps for resource adequacy for modeling years further into the future. Therefore, these gaps need to be filled in with proxy capacity that supplements and supports the existing fleet and generation queues. This ensures not only a reliable generation fleet but also enough capacity to be dispatched within the economic energy model.

A regional resource forecast model estimates, on a consistent least-cost basis, the type and timing of new generation and energy efficiency resources that need to be incorporated into the planning models to maintain adequate reserves. For this purpose, the study team used EPRI's EGEAS model to develop regional resource forecasts for the 11 regions in the Eastern Interconnection.[3] The Canadian provinces do participate in the PROMOD IV economic models, but do not require capacity expansion analysis because they have adequate resource availability. Appropriate resource adequacy is needed for all of these areas to avoid generation biases from one region to another, which would skew economic energy movement.

The study analyzed nine designated regions within the Eastern Interconnection, shown in Figure 3-2. All regions were studied as a whole with the exception of the Midwest ISO, which was divided into three study regions because the EGEAS software has a limitation of 1,000 thermal generating units and the Midwest ISO's footprint exceeds this limitation. The study adhered to the three existing Midwest ISO transmission expansion planning regions (Central, East, and West). The planning regions are the same as the existing regions. Each area is planned to have sufficient generation with the exception of specified interchange schedules and wind interchanges. From a capacity viewpoint, each area can supply its own needs.

[3] *The regions are MISO (which is divided into three regions), MAPP, SPP, TVA, PJM, SERC, Entergy, NYISO, and ISO-NE.*

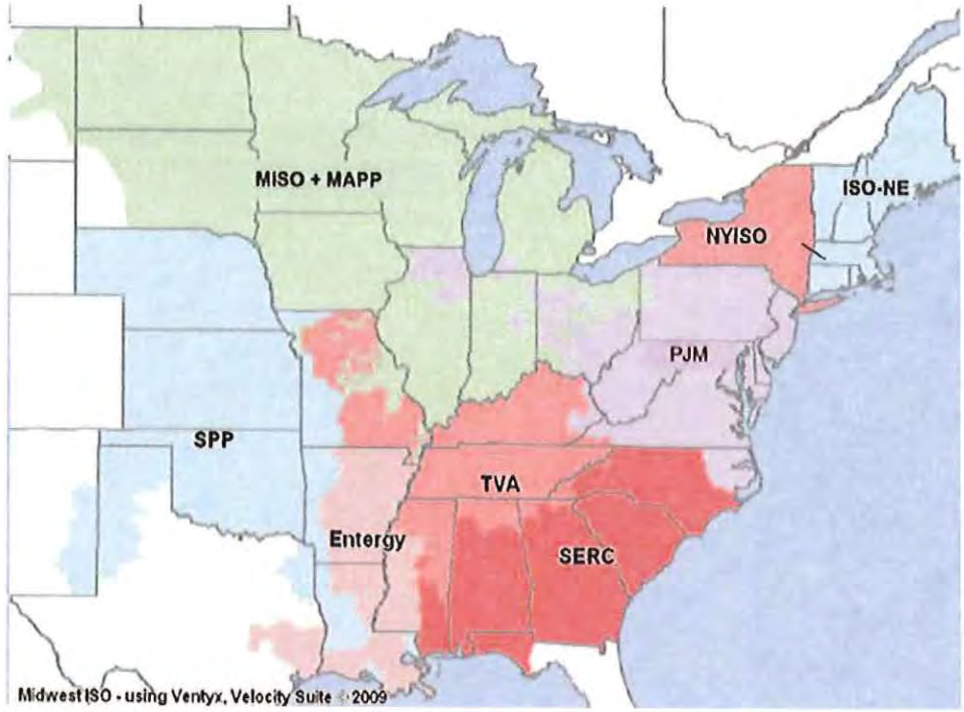


Figure 3-2. Study area

FUTURE FUEL COSTS

The economic models used with the EWITS study represent the generation fleet—unit by unit—for all regions. This modeling requires fuel cost projections for the entire fleet. Table 3-6 shows the 2008 average fuel costs modeled by region as well as the 2024 average cost. The fuel costs are a primary driver in the dispatch of generation within the energy models. The fuel cost assumptions were vetted through an earlier participant process.

TABLE 3-6. AVERAGE FUEL COSTS MODELED BY SYSTEM						
SYSTEM	YEAR (UNIT)	COAL	NATURAL GAS	URANIUM	OIL HEAVY	OIL LIGHT
ISO-NE	2008 (\$/MBTU)[a]	2.51	9.21	0.6	12.61	17.94
	2024 (\$/MBTU)	3.45	16.53	0.82	23.61	33.61
	ANNUAL GROWTH RATE (%)	2.01	3.72	1.97	4.00	4.00
MISO	2008 (\$/MBTU)	1.61	8.35	0.66	12.61	17.94
	2024 (\$/MBTU)	2.2	15.67	0.91	23.61	33.61
	ANNUAL GROWTH RATE (%)	1.97	4.01	2.03	4.00	4.00
MAPP	2008 (\$/MBTU)	1.13	8.06	0	12.61	17.94
	2024 (\$/MBTU)	1.55	15.38	0	23.61	33.61
	ANNUAL GROWTH RATE (%)	1.99	4.12	0	4.00	4.00
NYISO	2008 (\$/MBTU)	2.19	8.98	0.52	12.61	17.94
	2024 (\$/MBTU)	3.01	16.3	0.71	23.61	33.61
	ANNUAL GROWTH RATE (%)	2.01	3.80	1.97	4.00	4.00
TVA	2008 (\$/MBTU)	1.78	8.65	0.53	12.61	17.94
	2024 (\$/MBTU)	2.44	15.96	0.73	23.61	33.61
	ANNUAL GROWTH RATE (%)	1.99	3.90	2.02	4.00	4.00
SERC	2008 (\$/MBTU)	2.14	8.5	0.5	12.61	17.94
	2024 (\$/MBTU)	2.94	15.81	0.68	23.61	33.61
	ANNUAL GROWTH RATE (%)	2.00	3.95	1.94	4.00	4.00
SPP	2008 (\$/MBTU)	1.24	8.01	0	12.61	17.94
	2024 (\$/MBTU)	1.71	15.33	0	23.61	33.61
	ANNUAL GROWTH RATE (%)	2.03	4.14	0	4.00	4.00
PJM	2008 (\$/MBTU)	2	8.81	0.54	12.61	17.94
	2024 (\$/MBTU)	2.74	16.12	0.74	23.61	33.61
	ANNUAL GROWTH RATE (%)	1.99	3.85	1.99	4.00	4.00
ENTERGY	2008 (\$/MBTU)	1.47	8.29	0.55	12.61	17.94
	2024 (\$/MBTU)	2.02	15.54	0.76	23.61	33.61
	ANNUAL GROWTH RATE (%)	2.01	4.01	2.04	4.00	4.00

[a] *Millions of British thermal units*

PRODUCTION COST AND OTHER ECONOMIC ASSUMPTIONS

The variable cost associated with supply of the energy to load is an important metric in EWITS. Production-related costs encompass fuel and O&M, among others. With a large model consisting of multiple operating areas, the balance of energy transfers (imports and exports) in a given region may not sum to zero over the year. Consequently, the net "position" for the area is a function of more than just the raw cost of production.

Adjustments must be made to account for this transaction balance. Adjusted production cost (APC) for an annual period is defined as

Annual APC =

$$\sum_{i=1}^{8760}\sum_{j=1}^{M} C_{ij} + \sum_{i=1}^{8760} Load\_Weighted\_LMP_i * Purchase_i - \sum_{i=1}^{8760} Generator\_Weighted\_LMP_i * Sale_i$$

where

- i represents each hour in a year of the study.
- C_{ij} is the production cost of generator j during hour i.
- M is the number of total generators in the region.
- $Load\_Weighted\_LMP_i$ is load-weighted LMP during hour i.
- $Generator\_Weighted\_LMP_i$ is generator weighted LMP during hour i.
- $Purchase_i$ is a company's purchase of megawatts during hour i.
- $Sale_i$ is a company's sale of megawatts during hour i.

EWITS was performed using US$2024. Where possible, the assumed escalation rate of 3% was used to translate results into US$2009. Care must be taken with some of the results, however, because prices for individual fuels were escalated at different rates for different regions. For this reason, only some of the results in later sections are shown in US$2009.

A 15% annualized revenue requirement is used to determine the annual cost of the conceptual transmission plan. This is obviously subject to change in actual construction, depending on the cost structure of the constructing transmission owners.

RESOURCE ADEQUACY ASSESSMENT

Capacity additions in the model are based on reserve margin requirements. Reserve margin is calculated as the difference in available capacity and peak coincident demand divided by the peak coincident demand.

$$\text{Reserve Margin} = \frac{\text{Available Capacity} - \text{Peak Coincident Demand}}{\text{Peak Coincident Demand}}$$

Peak demand is determined using the noncoincident annual peaks applied to hourly load profile curves. The coincident peak occurs at the time the hourly load demand reaches its peak for the system (refer to Table 3-1 for demand assumptions). The available capacity is the maximum capacity available during the peak coincident demand from net transactions, interruptible load, and firm generation. Firm generation is the percentage of a generator's maximum capacity that is counted toward calculation of the reserve margin. For example, wind units contribute 20% of their maximum capacity toward reserve margin calculations. Table 3-7 shows the modeled reserve targets.

TABLE 3-7. TARGET RESERVE MARGINS BY REGION	
REGION	RESERVE TARGET (%)
ENTERGY	15.0
ISO-NE	15.0
MAPP	15.0
MISO	15.0
NYISO	15.0
PJM	15.5
SERC	15.0
SPP	15.0
TVA	15.0

GENERATION EXPANSION ALTERNATIVES

EGEAS has five primary alternatives for region expansion: coal-fired steam turbines, natural-gas-fired combined cycles, natural-gas-fired combustion turbines, nuclear facilities, and wind facilities. Before using the capacity expansion model, the project team eliminated other alternatives such as integrated gasification and combined cycle (IGCC) units with sequestration, biomass, and hydro facilities as options because they were not economically competitive with the conventional resources under the assumptions applied to the analysis.

Table 3-8 shows the attributes for the generation alternatives. It should be noted that the capital costs for wind generation in this table are lower than what is assumed later in the report when total costs are tabulated. These lower values were artifacts of an earlier planning study. Because of the approach used here, however—the amount of wind generation is predetermined by the scenario definitions—the lower numbers have no influence on the expansion results.

Wind is given a 20% capacity credit against the required planning margin; all other units produce 100% of available capacity at peak system hours. Because of the wind modeling technique, resource adequacy calculations take into account existing fleet, planned fleet, and modeled wind expansions before estimating the need for additional capacity.

TABLE 3-8. MODELED GENERATOR PROTOTYPE DATA VALUES IN US $2008[a]					
ALTERNATIVE	2008 OVERNIGHT CONSTRUCTION COST ($/KW)	2008 VARIABLE O&M ($/MWH)	2008 FIXED O&M ($/KW)	BOOK LIFE	OPERATING LIFE
COAL	1,833	4.60	28.22	40	60
CC	857	5.17	34.01	30	30
CT	597	4.62	17.72	30	30
WIND (ONSHORE)	1,750	5.70	11.93	25	25
WIND (OFFSHORE)	2,440	18.67	15.55	25	25
NUCLEAR	2,928	4.63	69.57	40	60

[a] All costs escalated at 3% annually during study period.
Notes: kW = kilowatt; MWh = megawatt-hour

Energy efficiency is not modeled beyond what is embedded in the modeled energy projections available through the PowerBase database. Demand response, however, is added to the individual areas to maintain existing penetration percentages through the study period, as shown in Table 3-9. The demand response units are modeled much like high-cost combustion turbines to limit capacity factors to values less than 1%.

TABLE 3-9. MODELED PENETRATION OF DEMAND RESPONSE BY REGION (AS PERCENTAGE OF PEAK)			
STUDY REGION	NONCOINCIDENT PEAK DEMAND (MW)	MODELED DEMAND RESPONSE (MW)	RATIO OF DEMAND RESPONSE TO PEAK DEMAND (%)
ENTERGY	22,712	50	0.18
ISO-NE	28,227	2,400	8.50
MISO + MAPP	125,777	4,362	3.47
NYISO	35,064	2,014	5.74
PJM	142,826	3,239	2.27
SERC	96,071	1,745	1.82
SPP	47,478	736	1.55
TVA	47,633	2,309	4.85

SECTION 4: DEVELOPING ECONOMIC TRANSMISSION OVERLAYS

The amounts of wind generation defined for study in this project exceed the current installed capacity by nearly an order of magnitude. Transmission issues are already limiting wind energy development in some regions, so it is a near certainty that significant new transmission would be necessary to accommodate the much higher amounts of wind generation represented in the Eastern Wind Integration and Transmission Study (EWITS) scenarios.

This section describes the methodology and results of the transmission assessment for the four scenarios examined in EWITS.

BACKGROUND

The transmission facilities that make up today's Eastern Interconnection were developed through a planning process that had two basic objectives: (1) to connect specific new generating units to load, and (2) to maintain or enhance the reliability of the bulk power system in the face of growing demand. By building transmission facilities to interconnect with neighbors, capacity resources could be shared in emergencies, reducing the amount of excess capacity an individual utility must maintain to serve load reliably. Opportunities for economic exchanges of energy under nonemergency conditions were a side benefit—though not usually the driver—of the process.

Because it is primarily a source of energy, not capacity, wind generation does not fit well into conventional resource adequacy-based transmission planning processes. In conventional planning, the focus will typically be concentrated on certain system conditions—peak or minimum load hours, or operation of the system with a major facility out of service. The status of conventional generating units during these periods is usually a given. With large amounts of wind generation, the disposition of other conventional generating units may not be so easily ascertained; in addition, high amounts of wind generation are likely in off-peak hours or seasons that might not be of special interest for reliability issues.

A transmission planning method based on economics has been developed, demonstrated, and even adopted by one Eastern Interconnection regional transmission organization (RTO) for insight into transmission needs for significant wind generation development, which conventional methods have more difficulty addressing. It was first used in the Joint Coordinated System Plan (JCSP), a collaborative planning process among the Midwest ISO, the Southwest

Power Pool (SPP), the PJM Interconnection (PJM), the Tennessee Valley Authority (TVA), the Mid-Continent Area Power Pool (MAPP), and other interested parties to develop conceptual interregional transmission plans required for a 5% wind energy scenario and a 20% wind energy scenario.

The method takes a top-down view by defining what transmission would be needed and possibly justified by benefits exceeding cost for a future year, given the locations of both loads and the sources of energy. In EWITS, the objective is to evaluate the transmission that would be needed to facilitate 20% and 30% wind penetration levels across the Eastern Interconnection. To ensure economic energy delivery across a large geographical area, energy-based regional transmission planning is necessary to incorporate comprehensive economic assessment using production-cost simulations. By linking the markets across the entire Eastern Interconnection with large energy price differences, the benefits of such a regional transmission plan could outweigh its cost.

Because the JCSP also focused on a 20% scenario, the results from that effort served as an appropriate starting point for EWITS. Other regional transmission plans such as the Midwest ISO's Regional Generation Outlet Study: Phase I Executive Summary Report (Midwest ISO 2009; known as RGOS; Phase I of a 765-kV [kilovolt] wind outlet transmission overlay) and the SPP's Draft 2008 SPP EHV Overlay Report (SPP 2008) were considered to help facilitate the collection of the high-quality wind resources in the Great Plains and Upper Midwest. A similar level of regional detail was not available for other parts of the Eastern Interconnection.

The transmission development methodology is a sequential process that focuses on a snapshot of a single future year. The steps in the process follow:

1. Defining the location of "sinks" for energy (loads) in the year of interest.

2. Determining what generation capacity would be necessary to reliably serve the defined loads given the existing transmission infrastructure. This is accomplished through a formal generation expansion process that begins with the present and ends in the target year. Wind generation is accounted for by assigning an estimated capacity value, which is the fractional amount of nameplate rating that can be considered firm capacity for planning purposes. The expansion program then considers the new generation that must be built to meet regional planning margin requirements given the growth in loads and possible retirements of existing generators. Projected capital and operating costs over the planning horizon are used to optimize the expansion by minimizing total costs while maintaining resource adequacy.

3. Testing the result of the generation expansion step by running annual or multiannual hourly production simulations with the existing transmission network. Two cases are run:
   a. A "copper sheet" case, where limits on all transmission facilities are removed, so that energy flows from sources to sinks based purely on production economics. In this case, the price for energy in any hour is the same across the entire system.
   b. A constrained case, where transmission limits are applied. Congestion will result in unequal prices caused by less-than-optimal use of the generation fleet and likely curtailment of wind generation.
4. Comparing results of the copper sheet and constrained cases. Costs of congestion across major transmission lines and interfaces are totaled for the annual period.

5. Using the accumulated congestion charges as a guide for developing new transmission.

The EWITS project team carried out steps 1 through 5 for each of the four wind generation scenarios, and this process is described in the following sections.

APPLICATION OF EXPANSION METHODOLOGY

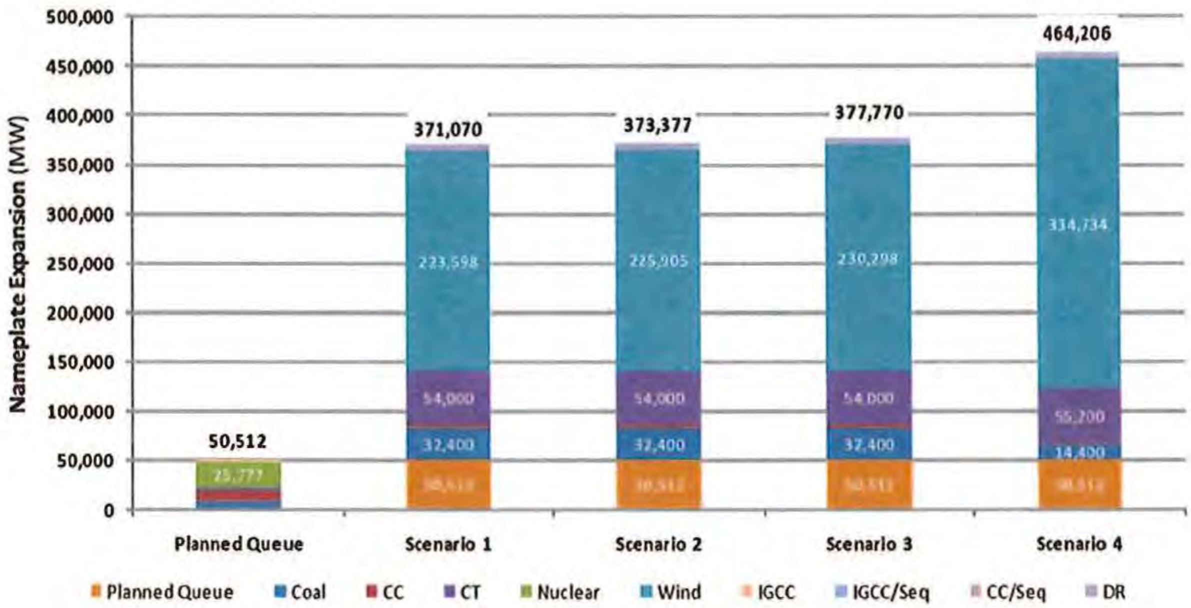
To begin the transmission development process, the study team used the Electric Generation Expansion Analysis System (EGEAS) tools described in Section 3 to conduct a regional capacity expansion analysis for each wind scenario. The objective was to maintain an approximate 15% reserve margin across the Eastern Interconnection in the 2024 study year. Based on analysis of the hourly wind production and regional load data, wind generation was assigned a uniform capacity value of 20% in the EGEAS runs.

EGEAS GENERATION EXPANSION

Each region identified in the assumptions was analyzed independently from the other regions. This assumes that regions will build capacity to be self-sufficient and will not depend on capacity in other regions for resource adequacy needs. For wind, however, the EWITS team assumed that a region would be given capacity credit for the wind needed to meet the scenario specifications of energy served and no more, whether located internally or not.

Figure 4-1 shows the nameplate capacity expansions required to meet the resource adequacy needs for each region. The information is, however, for the aggregate Eastern Interconnection. The first column represents generation capacity with a status of planned. This includes the signed Interconnection Agreement generation from the various Eastern Interconnection generation queues as well as a significant increase in nuclear capacity that has been recently proposed throughout the Eastern Interconnection.

The effect of wind on the capacity expansion model can be seen by comparing the three 20% wind energy scenarios to the 30% wind energy scenario. The added energy produced from the wind resources tends to be more competitive with the base-load generation in the off-peak hours. As a result, when increased wind resources are forced into the expansion model, the economic result is to remove base-load capacity (e.g., coal and nuclear) from the expansion and leave the more flexible peaking and intermediate capacity less affected.



Notes: CC = combined cycle; CT = combustion turbine; IGCC = integrated gas combined cycle; IGCC/Seq = integrated gas combined cycle with sequestration; CC/Seq = combined cycle with sequestration; RET Coal = coal plant retirements; Replacement CC = replacement combined cycle; DR = demand response.

Figure 4-1. Capacity expansion by scenario

SITING OF CAPACITY

The resources forecast from the expansion model for each of the scenarios are specified by fuel type and timing; these resources are not, however, site-specific at this point. A siting methodology to tie each resource to a specific bus in the PROMOD IV models is required to complete the process. The study team used a philosophy- and rule-based methodology, and industry expertise, to site the forecast generation.

The wind locations were dictated by the scenario definitions and the NREL wind data (AWS Truewind 2009). The thermal capacity was locally sited at various queue and brownfield locations.

It is important to note that the scenario definitions result in some areas being self-sufficient in wind capacity (wind energy requirements being met with local wind energy production) but others require support from wind located in external regions.

Areas that meet the target energy on a regional basis, by scenario, are as follows:

- Scenario 1: Midwest ISO, MAPP, SPP
- Scenario 2: Midwest ISO, MAPP, SPP, New England ISO (ISO-NE), New York ISO (NYISO)
- Scenario 3: MAPP, SPP, PJM, ISO-NE, NYISO
- Scenario 4: Midwest ISO, MAPP, SPP, PJM, ISO-NE, NYISO

Areas with less than the target amounts by scenario include the following:

- Scenario 1: ISO-NE, NYISO, PJM, Southeastern Electric Reliability Council (SERC), TVA, Entergy (operated as part of SERC)
- Scenario 2: SERC, TVA, PJM, Entergy
- Scenario 3: Midwest ISO, SERC, TVA, Entergy
- Scenario 4: SERC, TVA, Entergy

RESULTS

Figures 4-2 through 4-5 illustrate the final generation siting locations for Scenarios 1 through 4, respectively. With the same 20% wind penetration level, Scenarios 1, 2, and 3 have exactly the same thermal generation capacity and siting locations. With the increased 30% wind energy penetration in Scenario 4, base-load capacity decreases and gas-fired combustion turbine capacity increases because of its more flexible nature and lower capital cost.

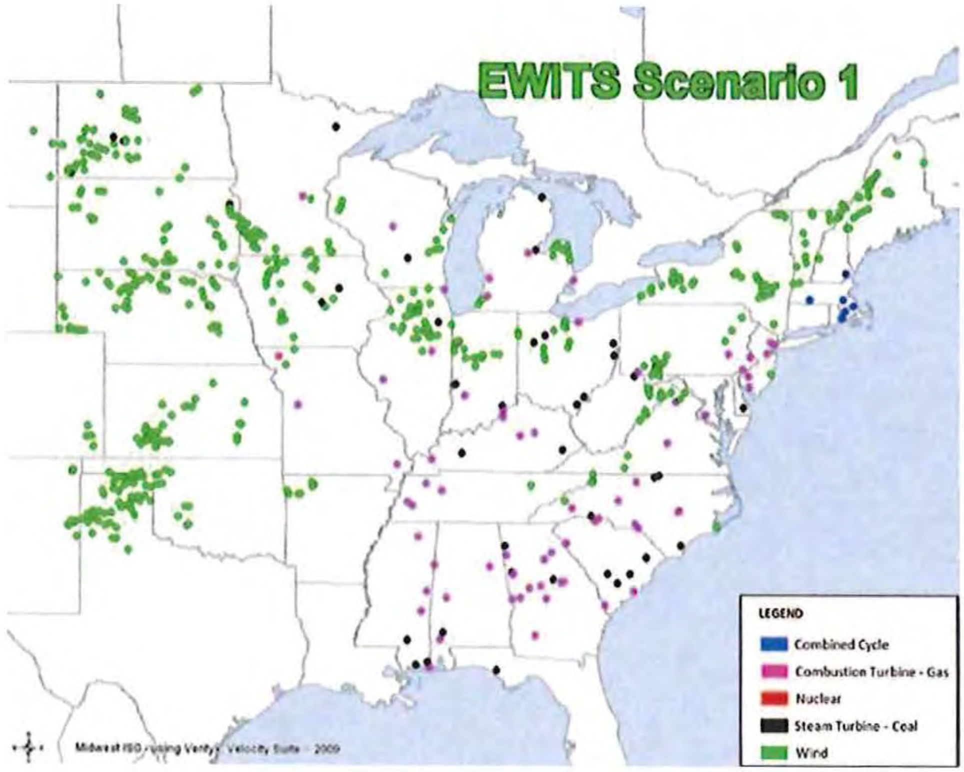


Figure 4-2. Scenario 1 installed capacity sites

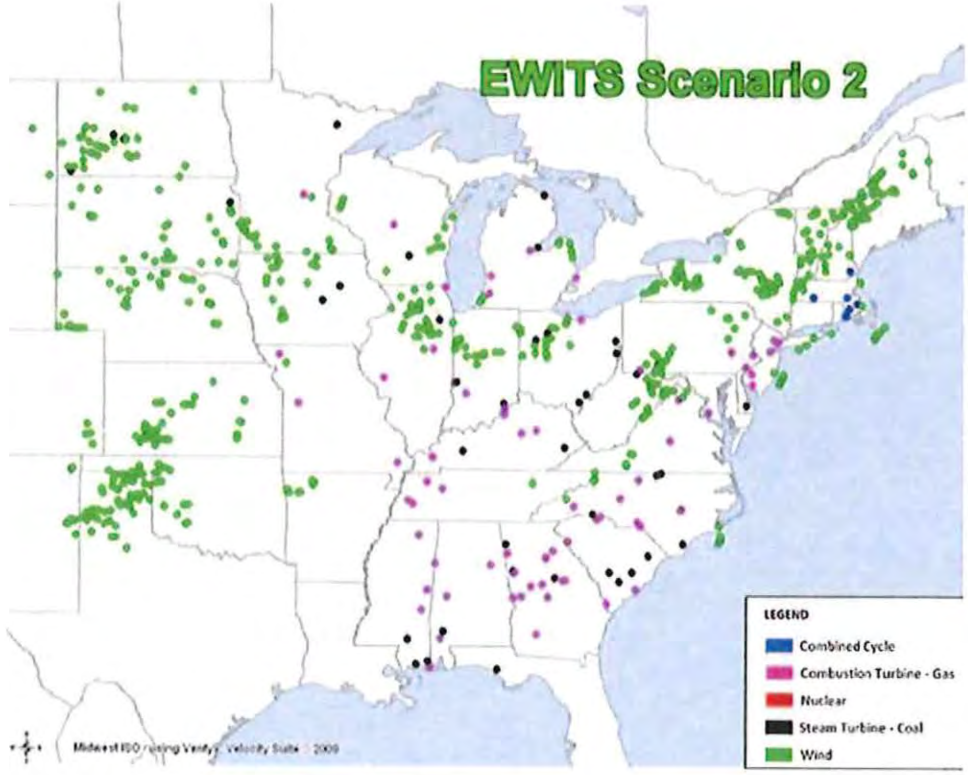


Figure 4-3. Scenario 2 installed capacity sites

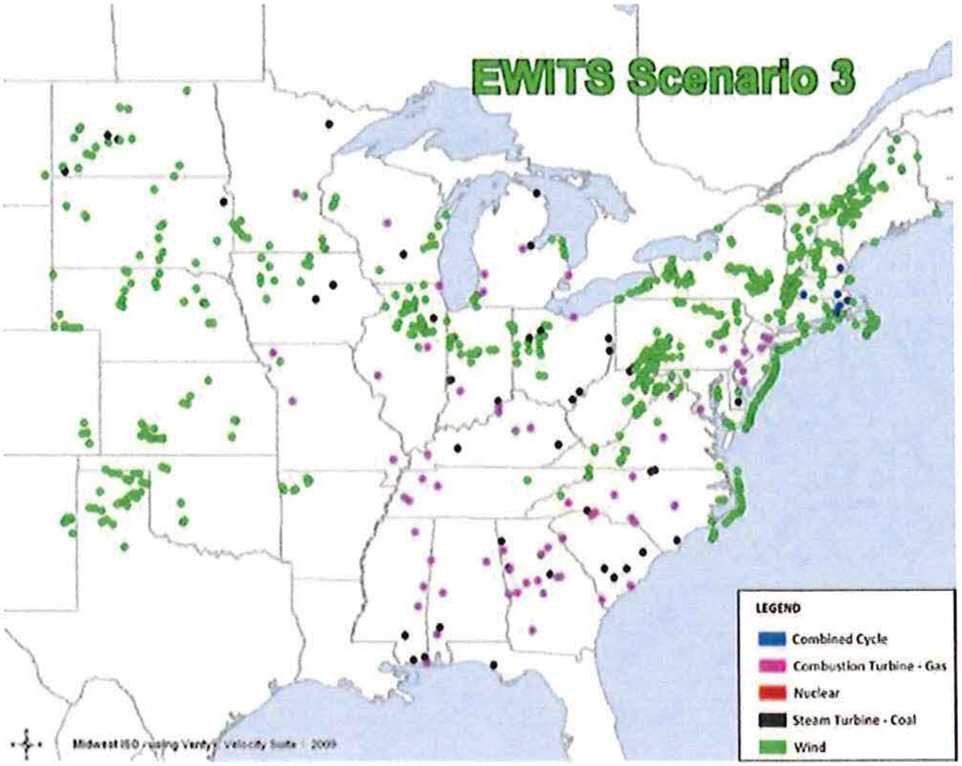
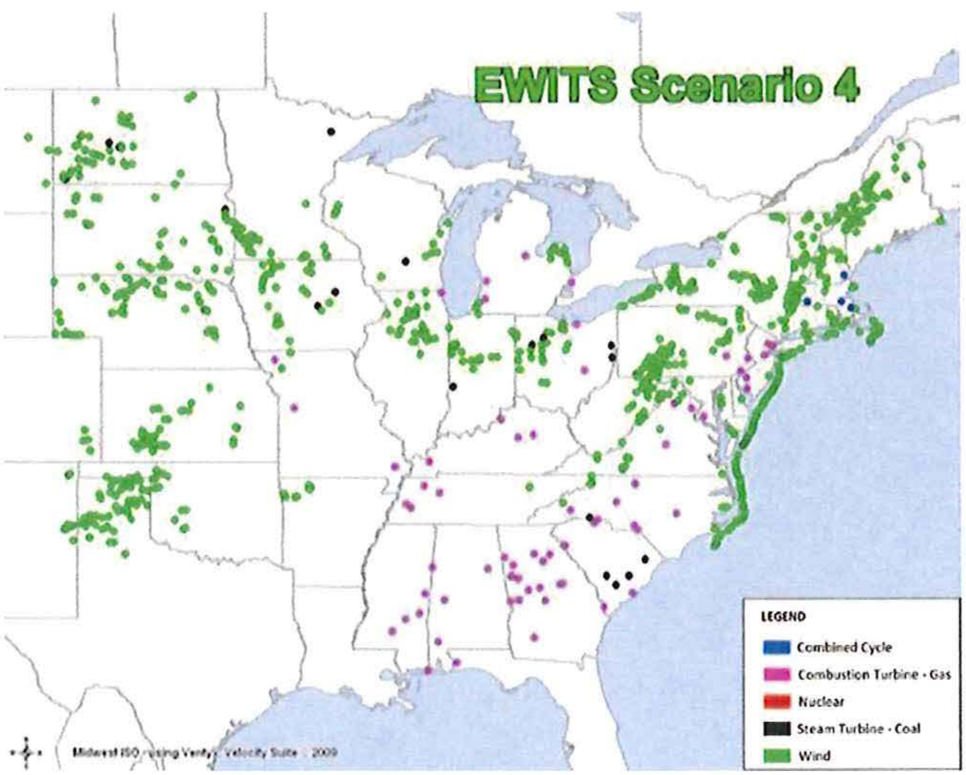


Figure 4-4. Scenario 3 installed capacity sites



4-5. Scenario 4 installed capacity sites

TRANSMISSION OVERLAY DEVELOPMENT

The following sections describe the interim steps of the transmission expansion methodology along with results for the study scenarios.

PRE-OVERLAY ECONOMIC ANALYSIS

The pre-overlay economic analysis results are the input information necessary for developing the conceptual extra high voltage (EHV) transmission overlay.

The study team first considered two PROMOD IV economic simulations, the constrained base case and the unconstrained case assuming no transmission constraints. Examining the differences between the two cases reveals the following:

- The areas of economic energy sources and sinks
- The interface flow changes to determine the incremental transfer capacity needs
- The total benefit savings, which gives a rough estimate for the potential budget.

Figure 4-6 shows the annual generation-weighted locational marginal pricing (LMP) contour map across the system for the constrained case in the 20% wind Scenario 2. The highest prices are on the East Coast. The price differentials are driven by a combination of transmission constraints and the cost of natural gas. Under economic market operation, energy tends to flow from low-cost areas to high-cost areas. The LMP contour map shows the direction where the energy would be likely to flow. To obtain the value from a transmission plan, the transmission should link the lower cost areas to the higher cost areas and relieve the transmission constraints. The more areas that are linked with the appropriately sized transmission, the greater the value the transmission can achieve.

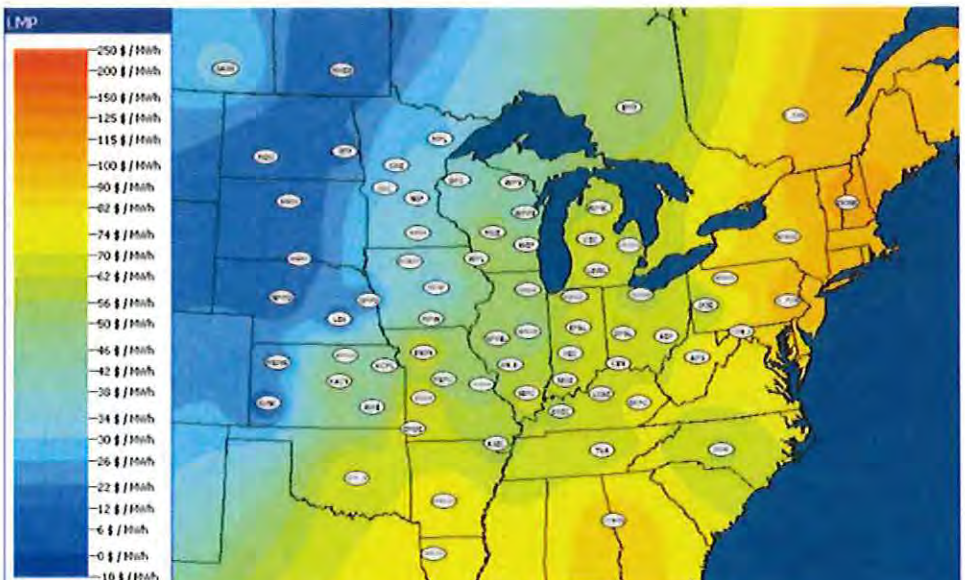


Figure 4-6. Scenario 2 annual generation-weighted LMP for Scenario 2

Figure 4-7 shows the annual generation difference between the unconstrained and constrained cases for Scenario 2. This helps define the energy source (red) and energy sink (blue) areas and gives insight into where the potential transmission lines and substations should be located. As seen in Figure 4-7, the price signal drives energy from low-cost source areas to high-cost sink areas if the transmission system is not constrained across the study footprint.

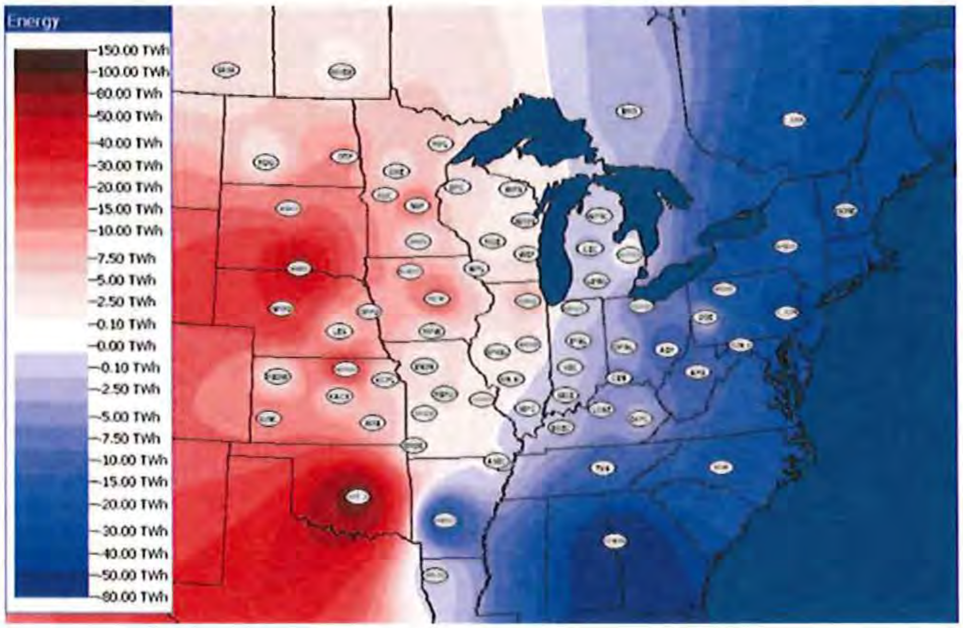


Figure 4-7. Scenario 2 generation difference between unconstrained case and constrained case

Designing an economically beneficial transmission plan requires considering the amount of energy that flows from sources to sinks in addition to the price difference. Figure 4-8 shows the annual energy differences between the unconstrained and constrained cases on each interface for Scenario 2; it shows the direction and magnitude of the interface flow changes. The red indicates the largest incremental flow change on the interface and the blue represents the smallest. The interface flows that tend toward red indicate where energy would flow more economically if there were no constraints in the system, and these are the candidate locations for overlay lines to increase power transfer.

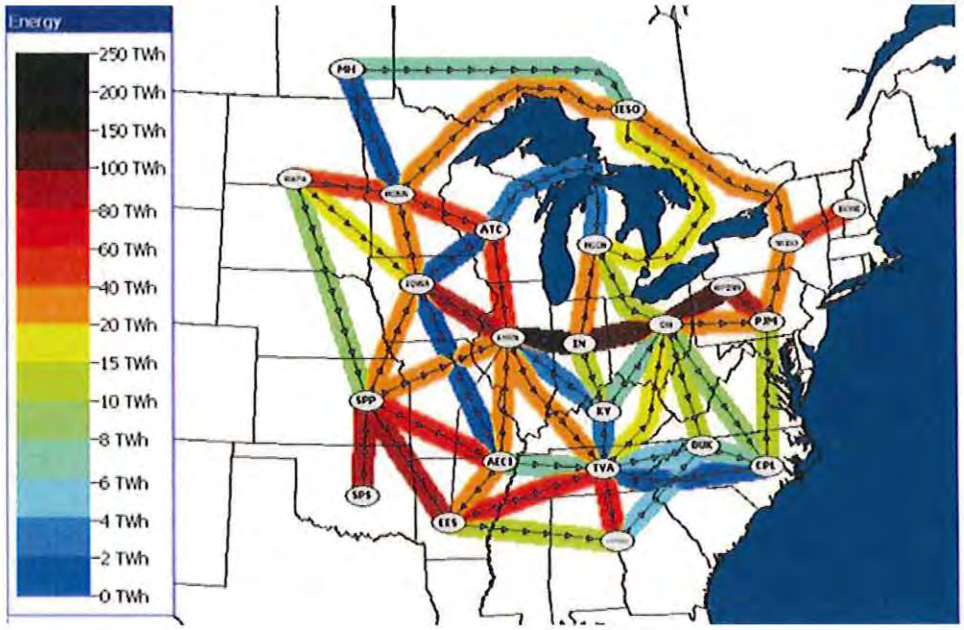


Figure 4-8. Scenario 2 interface annual energy difference between unconstrained case and constrained case

Table 4-1 lists the top 24 interfaces with the largest annual energy differences between the unconstrained and constrained cases for each wind scenario; it essentially shows in tabular form the same information depicted in Figure 4-8. The additional transfer needs are calculated to deliver 80% of the annual energy differences on each interface between the unconstrained and constrained cases. This information can be used to determine the type and size of the transmission lines and transformers.

TABLE 4-1. TOP 24 INTERFACES WITH THE LARGEST ANNUAL ENERGY DIFFERENCE					
INTERFACE[a]	JCSP 20% WIND	EWITS SCENARIO 1	EWITS SCENARIO 2	EWITS SCENARIO 3	EWITS SCENARIO 4
	ADDITIONAL TRANSFER NEEDS (MEGAWATTS [MW])	ADDITIONAL TRANSFER NEEDS (MW)	ADDITIONAL TRANSFER NEEDS (MW)	ADDITIONAL TRANSFER NEEDS (MW)	ADDITIONAL TRANSFER NEEDS (MW)
AMRN - IN	26,878	28,856	22,901	13,223	24,609
IN - OH	19,334	20,843	16,594	9,633	17,081
OH - EPJM	16,126	18,662	14,378	8,715	12,928
SPS - SPP	7,174	13,482	13,983	7,743	13,399
SPS - EES	12,567	12,551	11,598	6,417	12,160
IOWA-AMRN	12,204	15,173	11,150	6,040	14,084
EES-TVA	9,472	10,173	9,039	4,879	9,205
TVA-SOUTHERN	8,860	9,045	8,202	5,476	8,744
SPP-AECI	7,866	8,565	7,930	4,134	8,283
NYISO-ISONE	10,331	9,128	7,405	6,202	6,967
PJM-NYISO	8,430	8,457	7,086	6,115	6,631
WAPA-MINN	1,865	9,243	6,633	2,443	9,164
ATC-AMRN	8,068	8,771	6,586	3,878	7,663
MINN-ATC	6,575	8,647	6,260	3,186	8,148
SPP-IOWA	2,926	3,978	4,355	2,606	4,227
AECI-AMRN	4,618	4,585	4,300	2,142	4,512
SPP-AMRN	3,922	4,556	3,973	2,134	4,368
AMRN-TVA	4,691	4,571	3,925	2,367	4,224
IN-MICH	4,568	4,937	3,846	2,254	3,990
IESO-NYISO	8,678	4,971	3,817	2,630	3,499
MICH-IESO	4,184	4,070	3,238	2,349	2,801
AECI-EES	3,976	3,607	3,088	2,042	3,584
MINN-IOWA	3,424	4,102	2,866	1,425	3,931
WAPA-IOWA	2,392	4,343	2,847	994	4,262

[a] *Interface and state names are abbreviated in this column because of space considerations. Please refer to the Abbreviations and Acronyms list.*

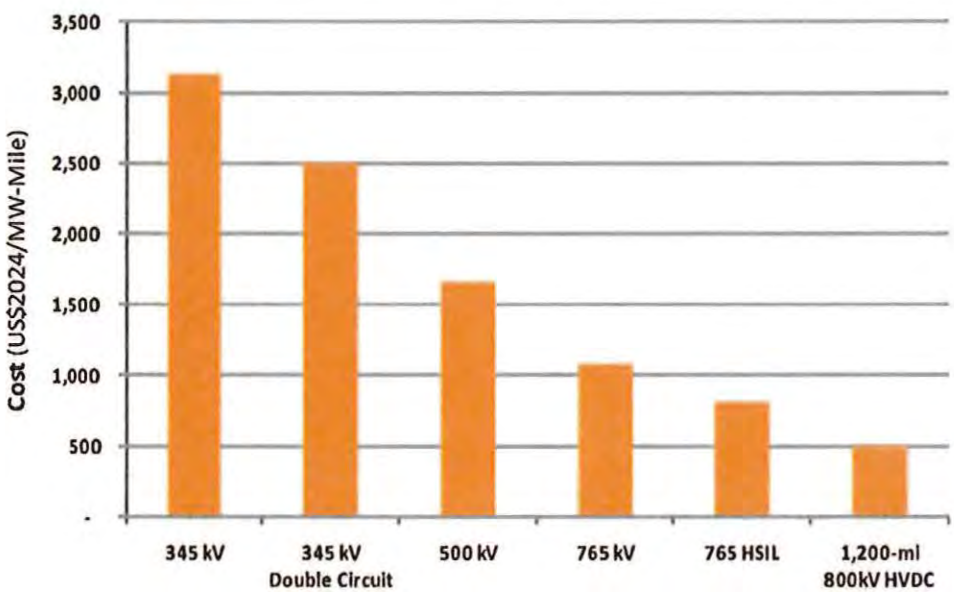
Adjusted production cost (APC) savings are calculated by taking the differences between the unconstrained and constrained cases for all four high-penetration wind scenarios. Table 4-2 lists the detailed APC savings for each region plus the entire Eastern Interconnection study footprint. The APC savings, which represent proxy estimates of potential budgets available for transmission development, are used as the economic benefit value metric for the transmission overlay.

TABLE 4-2. ANNUAL APC SAVINGS FOR EACH SCENARIO (US$2024, MILLIONS)				
REGION	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
PJM	4,682	3,169	1,588	2,768
MISO	2,529	1,832	1,288	2,883
TVASUB	789	661	590	1,500
MAPP	8,234	5,275	2,264	6,290
SPP	6,534	6,765	4,071	5,691
SERCNI	5,728	5,655	5,494	11,166
E_CAN	2,652	2,306	2,389	1,823
IMO	1,144	1,068	1,048	1,157
ISO-NE	3,794	2,117	1,079	1,432
MHEB	730	629	599	603
NYISO	4,851	3,424	1,872	2,499
ENTIRE EI	41,667	32,902	22,282	37,812

Notes: SERCNI, E-CAN and TVASUB are monikers used in EWITS for subregions in the PROMOD IV model. IMO = the independent electricity market operator that covers Ontario; MHEB = Manitoba Hydro Electric Board; EI = Eastern Interconnection.

TRANSMISSION DESIGN CONSIDERATIONS FOR EHV OVERLAY

Figure 4-9 demonstrates simple decisions that enable the transmission lines to be selected. If the lines can be loaded economically close to their power transfer limit, the cost to deliver energy is lower with the higher voltage lines. For large amounts of energy transfer, 765-kV (kilovolt) AC and 800-kV high-voltage DC (HVDC) lines are the low-cost options.



Note: HSIL = high-surge impedance loading

Figure 4-9. Transmission and substation costs per megawatt-mile

The architecture with a mix of multiple HVDC and EHV AC lines is necessary because of the high-penetration wind levels across the Eastern Interconnection. The 800-kV HVDC lines with bipolar configuration need to be used in groups of three or more to deliver energy more than 600 miles to remote load centers. EHV AC lines connected to the HVDC terminals are used for contingency backup, to collect energy from multiple wind resources that are geographically diverse, and to deliver energy to HVDC terminals. Because of the volumes of transaction energy and the distances between source and sink areas, HVDC was determined to be the least costly and was used in all the EWITS transmission overlays.

IDENTIFYING AND LOCATING NEW TRANSMISSION FACILITIES

The study team developed the conceptual transmission overlays for all four wind scenarios using the pre-overlay economic analysis results and input from the Technical Review Committee (TRC). Local and regional knowledge represented by the TRC members was used to locate terminals for new transmission facilities in the Eastern Interconnection system model.

Regional transmission plans in the western part of the interconnection were incorporated into the overlay design. Two existing conceptual plans with a regional focus were integrated into the overlays. Figure 4-10 shows a conceptual EHV plan developed by SPP and updated when Nebraska utility companies became part of the SPP RTO in 2008. RGOS Phase I transmission, which was initiated by the Midwest ISO, its state regulators, and stakeholders to develop transmission portfolios required to meet the renewable portfolio standards (RPS) or goals, is depicted in Figure 4-11.

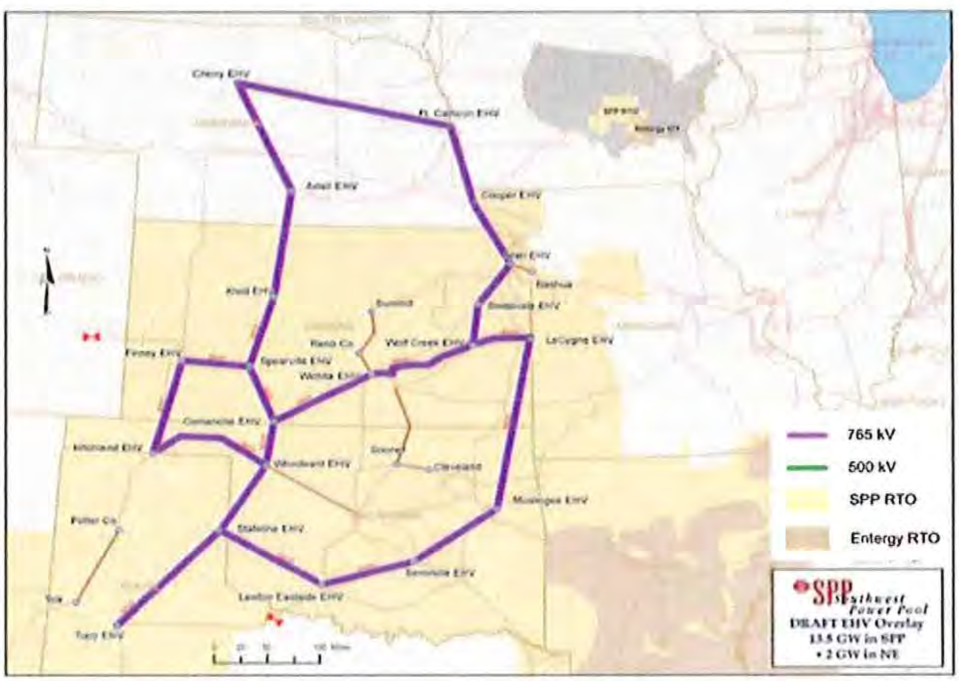


Figure 4-10. SPP EHV conceptual transmission plan

Figure 4-11. Midwest ISO RGOS, Phase I, Preliminary Scenario T, 765-kV (green)

Building on previous energy-driven transmission planning efforts, the inputs from the TRC were incorporated to create initial conceptual overlays for the three 20% wind scenarios and the 30% wind scenario. To improve benefits and relieve congestion, the study team made some additional refinements. The resulting conceptual transmission overlays for the four wind scenarios are shown in Figures 4-12 through 4-15.

All of the overlays are structured to allow a general west-to-east energy transfer. There are several reasons for such a bias. First, in all the scenarios, the western part of the interconnection has large amounts of wind generation and minimal load. Second, issues with loop flows in portions of the existing transmission system in roughly the geographical center of the interconnection favor west-to-east lines over more north-south orientations of long-distance facilities.

A third major reason for the general west-to-east orientation of the overlays involves the representation of Canadian provinces in this study. No wind generation data were available for Canada, which precluded detailed study of energy transactions between border regions of the United States and the provinces to the north. In this study, a firm import of 5 gigawatts (GW) over an asynchronous tie between New England and Quebec, represented as a market transaction, was the only consideration of wind generation outside the United States.

Canada has significant wind energy potential in addition to hydroelectric resources, and its proximity to the northeastern U.S. load centers in particular offers the northeastern portion of the United States access to wind generation that is relatively local compared to wind generation in the Great Plains. The TRC recommended that such a scenario be considered in the future, if and when compatible wind data are available for those provinces.

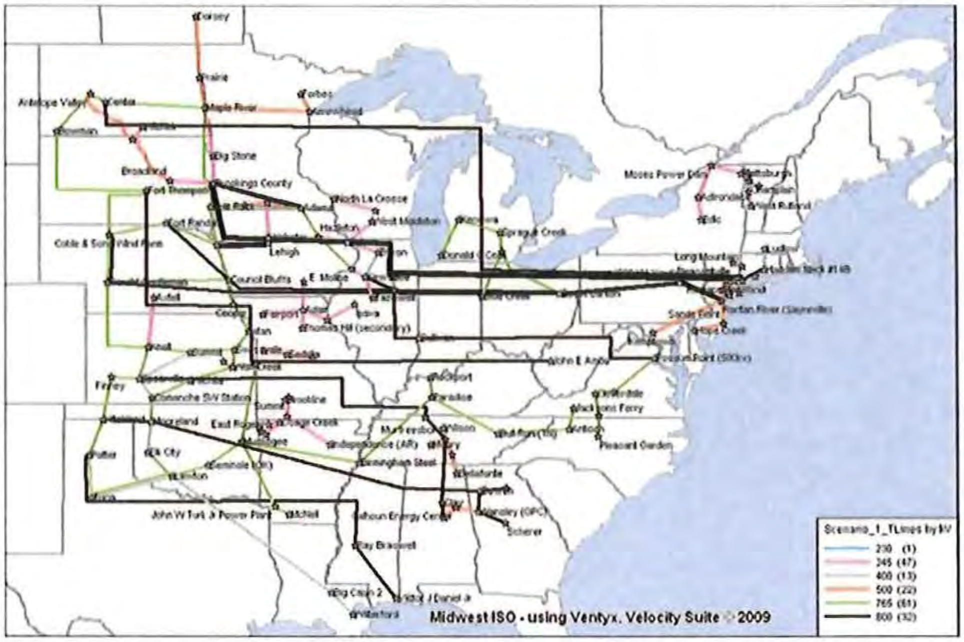


Figure 4-12. EWITS Scenario 1 conceptual transmission plan

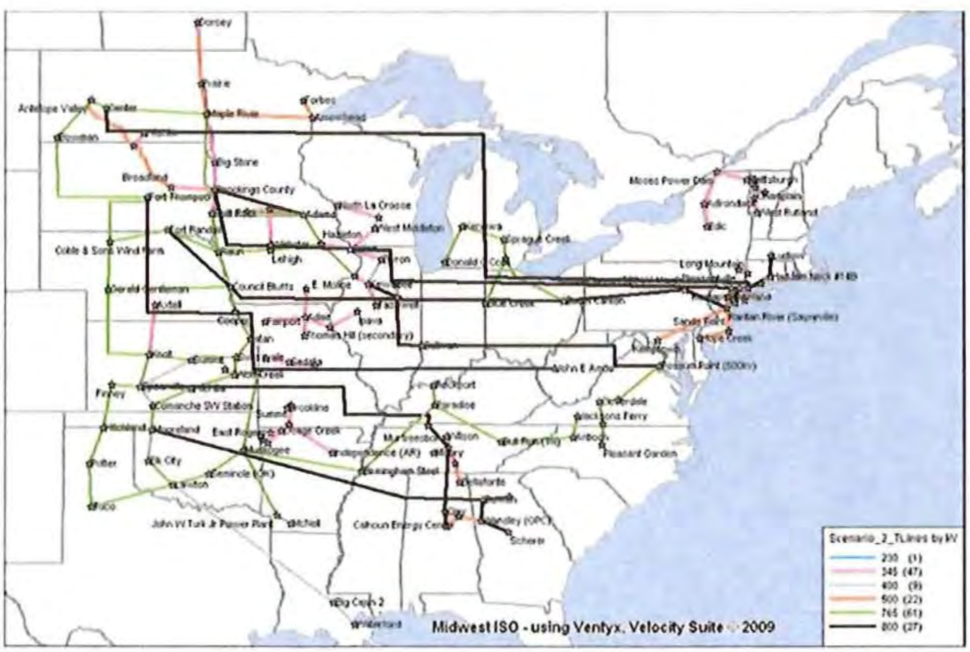


Figure 4-13. EWITS Scenario 2 conceptual transmission plan

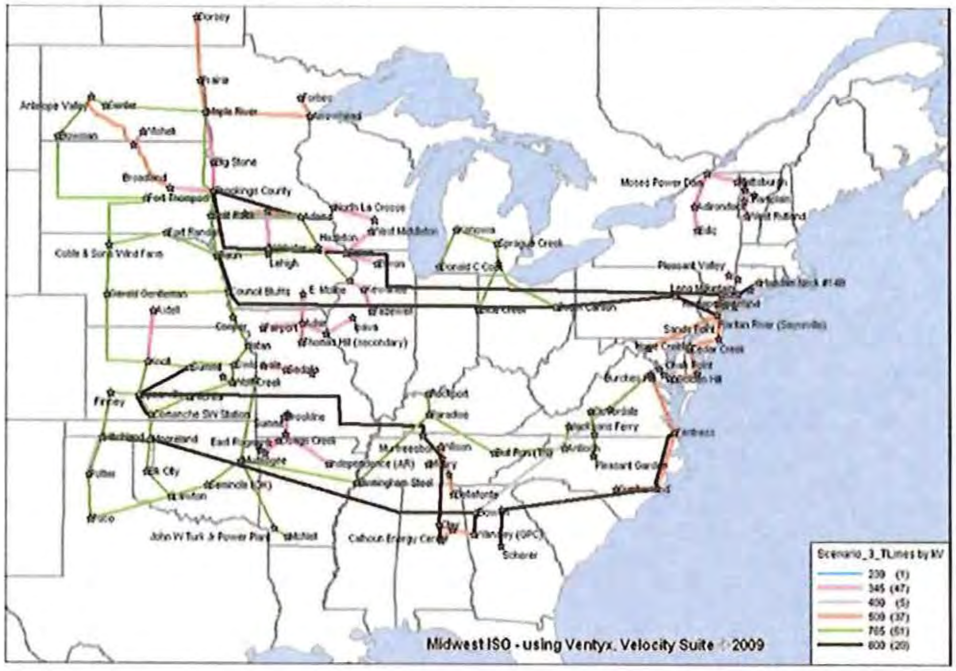


Figure 4-14. EWITS Scenario 3 conceptual transmission plan

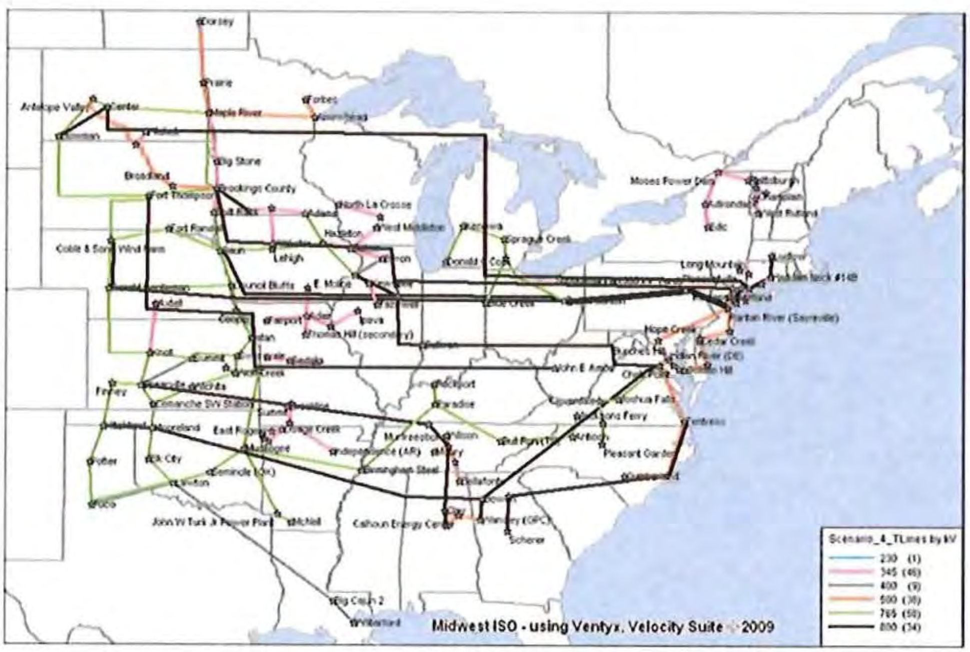


Figure 4-15. EWITS Scenario 4 conceptual transmission plan

POST-OVERLAY ECONOMIC ASSESSMENT

Tables 4-3 through 4-5 summarize the EWITS transmission construction cost-per-mile assumptions by voltage level and region, the estimated total line miles by voltage level, and the estimated cost in millions of US$2024 for the four wind scenario conceptual overlays. In Table 4-5, the total AC line costs include a 25% adder to approximate the costs of substations and transformers; the total HVDC line costs include terminals, communications, and DC line costs. The costs associated with an offshore wind collector system or some subregional transmission upgrades that would be required, which could be substantial, are not included in the total estimated cost. With approximately 21,666 miles of new EHV transmission, the transmission overlay for Scenario 4 has the highest estimated total cost at $158 billion.

The conceptual transmission overlays consist of multiple 800-kV HVDC and EHV AC lines for all four scenarios with similar levels of new transmission and common elements. In the three 20% wind energy scenarios, the highest quality wind resources in the western portion of the interconnection were used. The Scenario 1 transmission overlay has nine 800-kV HVDC lines and one 400-kV HVDC line. A reduced transmission overlay with seven 800-kV HVDC lines and one 400-kV HVDC line is applied for Scenario 2 (with some wind moving eastward). Because more wind is moved eastward and more offshore resources are used in Scenario 3, the transmission overlay has the least amount of HVDC lines: five 800-kV HVDC lines and one 400-kV HVDC line. To accommodate the aggressive 30% wind mandate and deliver a significant amount of offshore wind along the East Coast in Scenario 4, the overlay must be expanded to include ten 800-kV HVDC lines and one 400-kV HVDC line.

Compared to the JCSP 20% wind scenario overlay, more 765-kV lines are included in the four EWITS scenarios to ensure easy access to the high-quality wind resources in the Great Plains and Upper Midwest. Approximately 85% of the line miles are associated with at least 500-kV AC or HVDC lines for all four wind scenarios.

TABLE 4-3. COST PER MILE ASSUMPTION (US $2024, MILLIONS)

REGION	345 kV	345 kV AC (double circuit)	500 kV	500 kV AC (double circuit)	765 kV	400 kV DC	800 kV DC
MISO	3.2	3.9	5.6	9.4	7.1	3.8	6.0
SPP	1.9	3.2	3.0	4.3	4.5	3.8	6.0
PJM	7.2	12.0	9.2	15.4	16.0	3.8	6.0
ISO-NE/ NYISO	5.5	9.1	7.0	11.7	16.0	3.8	6.0

TABLE 4-4. ESTIMATED LINE MILEAGE SUMMARY (MILES)								
SCENARIO	345 kV	345 kV AC (double circuit)	500 kV	500 kV AC (double circuit)	765 kV	400 kV DC	800 kV DC	TOTAL
REFERENCE	3,054	299	567	494	2,631	1,188	1,968	10,203
SCENARIO 1	1,978	236	1,100	243	6,701	560	11,102	21,920
SCENARIO 2	1,978	236	1,100	243	6,674	560	8,352	19,143
SCENARIO 3	1,978	236	1,148	726	6,674	769	4,747	16,278
SCENARIO 4	1,886	236	1,240	726	6,445	560	10,573	21,666

TABLE 4-5. ESTIMATED COST SUMMARY (US$2024, MILLIONS)								
SCENARIO	345 kV	345 kV AC (double circuit)	500 kV	500 kV AC (double circuit)	765 kV	400 kV DC	800 kV DC	TOTAL
REFERENCE	12,308	1,820	2,356	5,912	27,789	4,403	11,752	66,340
SCENARIO 1	7,409	1,563	7,242	4,575	49,798	2,397	83,265	156,249
SCENARIO 2	7,409	1,563	7,242	4,575	49,640	2,397	62,640	135,466
SCENARIO 3	7,409	1,563	7,789	12,131	49,663	2,957	35,603	117,115
SCENARIO 4	7,040	1,563	8,436	12,131	47,520	2,397	79,298	158,385

An annual revenue requirement of 15% of the total overlay cost was used to calculate the annual cost of the overlay. All the dollar values represent the year 2024 only. Table 4-6 gives the annual transmission costs, APC savings, and benefit/cost (B/C) ratios for all transmission overlays. The transmission overlays and associated B/C ratios are indicative, and a further comprehensive B/C analysis of potential alternatives would be required before making any recommendations.

TABLE 4-6. BENEFIT AND COST COMPARISON (US $2024, MILLIONS)			
SCENARIO	2024 ANNUAL TRANSMISSION COST	2024 APC SAVINGS	2024 B/C RATIO
1	23,437	28,648	1.22
2	20,320	22,194	1.09
3	17,567	13,095	0.75
4	23,758	18,676	0.79

The EWITS team used an iterative process to target the development of conceptual transmission overlays that meet both economic and resource adequacy needs. The transmission overlay developed in EWITS entails more development of wind collector systems in the western portion of the interconnection and addresses more of the underlying system and the associated impacts. Because of time constraints, however, additional congestion problems remain to be tackled.

Tables 4-7 through 4-10 give more details on the estimated investments needed to mitigate the additional constraints for each scenario and fix the overloading lines. Further iterative refinement and more detailed resource adquacy analysis must be performed to ensure that the conceptual transmission overlays lower energy costs while meeting adequacy needs in the most efficient way.

TABLE 4-7. ESTIMATED ADDITIONAL TRANSMISSION INVESTMENTS FOR SCENARIO 1

VOLTAGE	TRANSMISSION OVERLAY		EXISTING 500 KV ABOVE		TOTAL
	NUMBER OF LINES	LINE MILEAGE	NUMBER OF LINES	LINE MILEAGE	ESTIMATED COST (US$2024, MILLIONS)
345 kV	3	67	0	0	188
345 kV AC (double circuit)	2	49	0	0	230
500 kV	0	0	13	574	2,063
500 kV AC (double circuit)	0	0	0	0	0
765 kV	9	1,619	0	0	10,372
TOTAL	**14**	**1,735**	**13**	**574**	**12,853**

TABLE 4-8. ESTIMATED ADDITIONAL TRANSMISSION INVESTMENTS FOR SCENARIO 2

VOLTAGE	TRANSMISSION OVERLAY		EXISTING 500 KV ABOVE		TOTAL
	NUMBER OF LINES	LINE MILEAGE	NUMBER OF LINES	LINE MILEAGE	ESTIMATED COST (US$2024, MILLIONS)
345 kV	2	54	0	0	152
345 kV AC (double circuit)	2	49	0	0	230
500 kV	0	0	12	660	2,372
500 kV AC (double circuit)	0	0	0	0	0
765 kV	11	1,861	0	0	11,922
TOTAL	**15**	**1,964**	**12**	**660**	**14,676**

TABLE 4-9. ESTIMATED ADDITIONAL TRANSMISSION INVESTMENTS FOR SCENARIO 3					
VOLTAGE	TRANSMISSION OVERLAY		EXISTING 500 KV ABOVE		TOTAL
	NUMBER OF LINES	LINE MILEAGE	NUMBER OF LINES	LINE MILEAGE	ESTIMATED COST (US$2024, MILLIONS)
345 kV	2	54	0	0	152
345 kV AC (double circuit)	2	49	0	0	231
500 kV	0	0	15	659	2,368
500 kV AC (double circuit)	1	142	0	0	849
765 kV	1	93	0	0	598
TOTAL	**6**	**339**	**15**	**659**	**4,198**

TABLE 4-10. ESTIMATED ADDITIONAL TRANSMISSION INVESTMENTS FOR SCENARIO 4					
VOLTAGE	TRANSMISSION OVERLAY		EXISTING 500 KV ABOVE		TOTAL
	NUMBER OF LINES	LINE MILEAGE	NUMBER OF LINES	LINE MILEAGE	ESTIMATED COST (US$2024, MILLIONS)
345 kV	2	54	0	0	152
345 kV AC (double circuit)	1	20	0	0	94
500 kV	0	0	21	795	2,857
500 kV AC (double circuit)	3	295	0	0	1,767
765 kV	7	1,202	10	10	7,764
TOTAL	**13**	**1,571**	**31**	**805**	**12,634**

ANALYSIS

Transmission overlays were added to the production simulation model for each scenario to test their impact.

REGIONAL GENERATION-WEIGHTED LMP CHANGES

Figure 4-16 shows the comparison of the annual generation-weighted LMPs across the study footprint for Scenario 1. The diagram on the left represents the hub LMPs for the constrained base case, and the one on the right represents the hub LMPs for the overlay case.

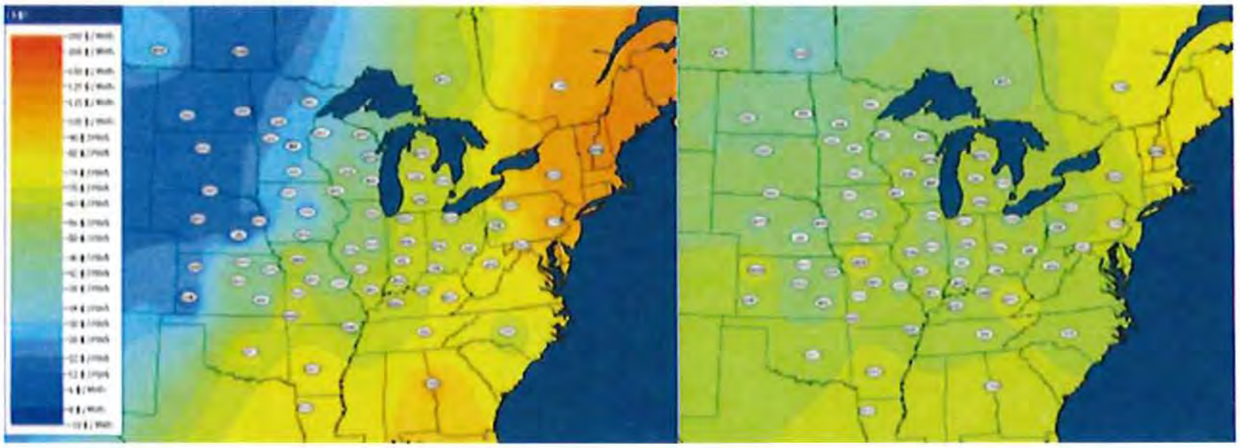


Figure 4-16. Scenario 1 annual generation-weighted LMP comparison

The LMP change demonstrates the ability of the conceptual transmission overlay to create a more competitive market in the Midwest ISO, thereby reducing costs to the East Coast. With the conceptual transmission overlay, more low-cost energy in the western regions is available to energy markets and is economically transferred to the high-priced East Coast regions. As the result of the economic energy transfer, LMPs increase in the western regions with the increased base-load generation output, but decrease in the eastern regions because the output of the high-priced generation is displaced by the imported low-cost energy.

With the increased LMPs in the western regions, significant amounts of the generation revenue benefits are achieved, which could potentially be reallocated back to end-use customers through regulatory mechanisms. Other mechanisms might have to be put in place to distribute the revenues back to load.

Figures 4-17 through 4-19 illustrate the comparison of the annual generation-weighted LMPs across the study footprint for Scenarios 2, 3, and 4, respectively.

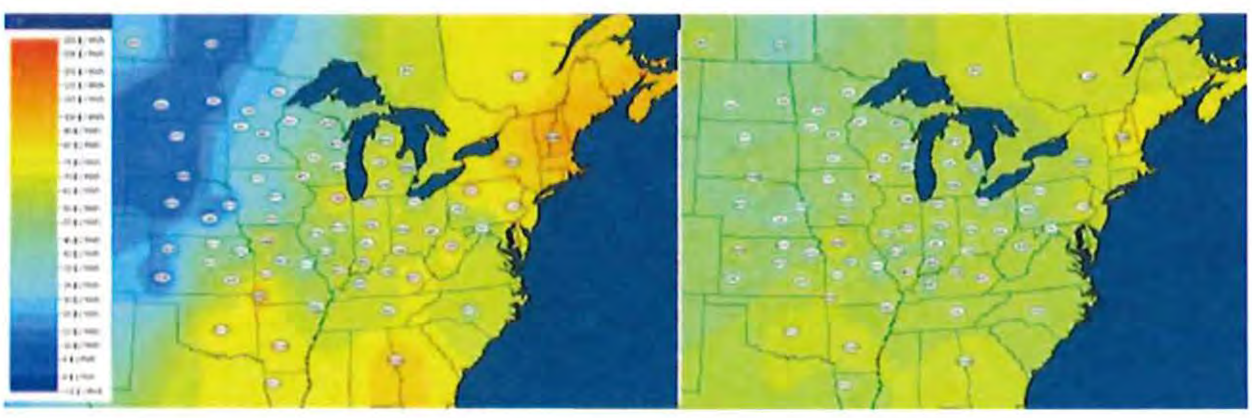


Figure 4-17. Scenario 2 annual generation-weighted LMP comparison

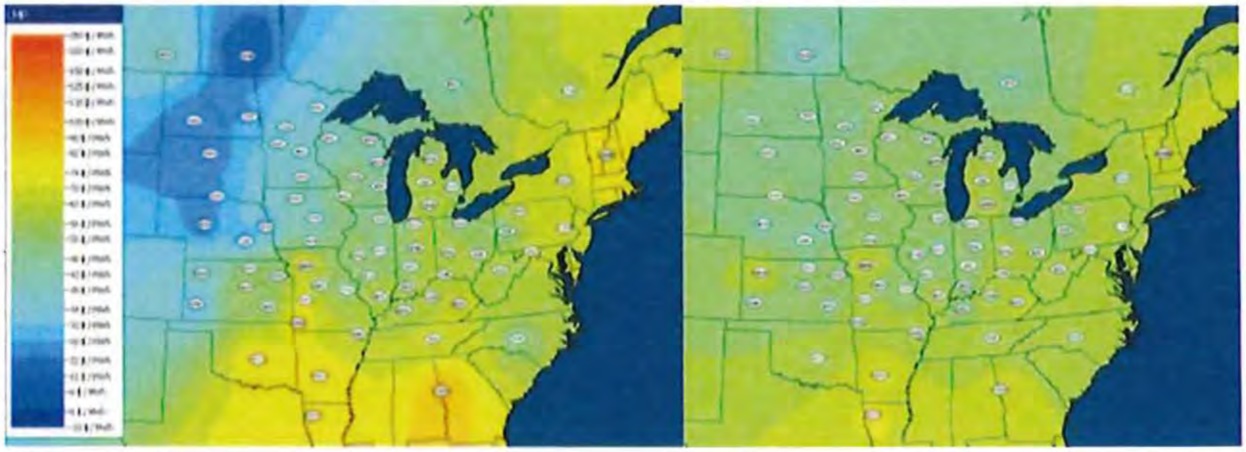


Figure 4-18. Scenario 3 annual generation-weighted LMP comparison

Figure 4-19. Scenario 3 annual generation-weighted LMP comparison

WIND CURTAILMENT

To accommodate increasingly high wind penetration levels, regional transmission infrastructure is needed to deliver substantial amounts of high-quality wind energy to remote load centers. Without new transmission corridors to access the wind resources, large amounts of wind curtailment would occur. To minimize the wind curtailment levels seen in the transmission overlay cases, the study team performed a sensitivity analysis to include negative wind dispatch price in the production-cost model. The renewable energy production tax credit (PTC) is the primary federal incentive to encourage wind power development. For this sensitivity analysis, a negative $40/ megawatt-hour (MWh) was assumed. This value includes the PTC along with renewable energy credits (RECs).

Table 4-11 summarizes the wind curtailment for the base constrained case, the transmission overlay case, and the transmission overlay case modeling the negative $40/MWh wind dispatch price. With the transmission overlays to move the wind energy, the curtailment drops down, ranging from 3.61% to 10.04%. And the curtailment is further reduced to the range between 1.05% and 3.83% with the negative $40/MWh wind dispatch price included. Section 6 discusses more detailed sensitivity analyses for this topic.

TABLE 4-11. WIND CURTAILMENT SUMMARY

SCENARIO	CONSTRAINED CASE (%)	TRASMISSION OVERLAY CASE (%)	TRANSMISSION OVERLAY WITH -40$/MWh WIND DISPATCH PRICE (%)
1	47.55	7.11	3.53
2	37.78	6.73	3.83
3	18.94	3.61	1.05
4	36.39	10.04	2.83

DESIGN OF HVDC OVERLAY TRANSMISSION

The HVDC transmission lines and the 765-kV and 500-kV AC systems for the EWITS scenarios form a self-contingent system that is designed not to overload existing underlying transmission. HVDC lines perform the task of bulk energy transfer mostly from west to east and west to southeast for Scenarios 1 and 2. For Scenario 3, the HVDC system also delivers energy from the northern half of the eastern part of the interconnection to the southeast. The AC system is used to collect wind energy and deliver the energy to the source terminals of the HVDC lines, to distribute energy from the HVDC lines at the sink terminals to the loads, and to transfer energy from an area with an HVDC terminal influenced by a fault or outage to other areas that have HVDC terminals with capacity to increase schedules and their associated AC systems.

Figure 4-20 shows a five 800-kV HVDC line (black, west-to-east horizontal) example tied by 765-kV lines (green, north-to-south vertical loops) and underlying 345-kV lines (red, north-to-south vertical loops). The HVDC 765-kV lines are part of the overlay, and the 345-kV lines are part of the underlying system.