Takeaway Materials

Skadden

Details	**Tuesday, May 9, 2017** 8:00 a.m. – 4:00 p.m.

- **Agenda**
- **Biographies**
- **Presentations**
  - U.S. Infrastructure Financing and Investment Panel
  - The "Complications" of Business Tax Reform
- **Articles**
  - Mexican Energy Sector Restructuring: New Opportunities for Renewables
  - Trump Infrastructure Plan May Open Opportunities for Projects
  - Oil and Gas Industry Seeks Steady Ground Following Year of Restructurings, Restrictive Lending
  - Bloomberg New Energy Finance: Record $30BN Year for Offshore Wind But Overall Investment Down
  - North American Power & Utilities Deal Insights Q1 2017
- **Supplemental Reports**
  - International Energy Agency: Mexico Energy Outlook
  - Build America Bureau: Credit Programs Guide
  - National Offshore Wind Strategy

21st Annual

Energy Projects Conference

Agenda

Monday, May 8

Reception
6:00 p.m.

Dinner & Keynote Address
7:00 p.m.

Pat Wood III
Principal / Wood3 Resources

Tuesday, May 9

Registration and Breakfast
7:30 a.m.

Welcome and Introduction
8:00 a.m.

Lance T. Brasher
Global Head, Energy & Infrastructure Projects Group / Skadden

Tax Reform Update
8:15 a.m.

Eric B. Sensenbrenner
Co-Head, Global Tax Group / Skadden

Paul W. Oosterhuis
Of Counsel, International and Corporate Tax Law / Skadden

Sean Shimamoto
Partner, Tax Group / Skadden

Morning Keynote
8:45 a.m.

Joseph Nigro
Chief Executive Officer, Constellation Energy / Executive Vice President, Exelon

Energy Project M&A
9:15 a.m.

Julia A. Czarniak
Partner, Energy & Infrastructure Projects Group / Skadden

Ethan M. Schultz
Partner, Energy & Infrastructure Projects Group / Skadden

David L. Giordano
Managing Director / BlackRock Renewable Power

Daniel M. Mitaro
Vice President, Infrastructure Investments / J.P. Morgan Asset Management

John Plaster
Managing Director, Global Power and Utilities Group and Head of Alternative Energy / Barclays Capita

Carl Weatherley-White
Chief Financial Officer / VivoPower International

Ray Wood
Managing Director and Global Head of Power and Renewables / Bank of America Merrill Lynch

Networking Break
10:00 a.m.

Infrastructure Financing and Investment
10:15 a.m.

Lance T. Brasher
Global Head, Energy & Infrastructure Projects Group / Skadden

Josh B. Nickerson
Counsel, Energy & Infrastructure Projects Group / Skadden

Christopher Elmore
Vice President / Goldman Sachs

Infrastructure Financing and Investment (cont'd) 10:15 a.m.	**Adam Hesketh** Chief Financial Officer, North America / Transurban **Tom Osborne** Executive Director, Infrastructure Group / IFM Investors **Ravi Purohit** Managing Director / Alinda Capital Partners
Current Trends in LNG Debt Financing 11:15 a.m.	**David P. Armstrong** Partner, Energy & Infrastructure Projects Group / Skadden **Tatiana Monastyrskaya** Partner, Energy & Infrastructure Projects Group / Skadden **Hamish Bunn** Managing Director, Project and Structured Finance / Morgan Stanley **Douglas Fleischmann** Vice President, Natural Resource Project Finance / Sumitomo Mitsui Banking Corp **Luisa F. Fuentes** Director, Energy and Project Finance / Société Générale
Lunch 12:00 p.m.	
Lunch Speaker: Energy Markets Briefing 12:30 p.m.	**Todd W. Filsinger** Senior Managing Director / Filsinger Energy Partners
Tax Equity Update 1:30 p.m.	**Sean Shimamoto** Partner, Tax Group / Skadden **Paul Schockett** Counsel, Tax Group / Skadden **Daniel M. Elkort** Executive Vice President and General Counsel / Pattern Energy **Ja Kao** President / Onyx Renewable Partners **Marshal Salant** Managing Director & Head of Alternative Energy Finance / Citigroup Inc. **James R. Stahle** Group Managing Director / CCA Group, LLC
Networking Break 2:00 p.m.	
Latin America Outlook 2:15 p.m.	**Paul S. Kraske** Partner, Energy & Infrastructure Projects Group / Skadden **Jorge H. Kamine** Counsel, Energy & Infrastructure Projects Group / Skadden **Ivan Oliveros** Executive Director, Head of Power and Renewables Latin America Project Finance / Sumitomo Mitsui Banking Corporation **Chuck Jordan** Partner / Arroyo Energy Investors **Juan J. Payeras** Chief Investment Officer / International Finance Corporation
Offshore Wind Projects 3:00 p.m.	**Paul S. Kraske** Partner, Energy & Infrastructure Projects Group / Skadden **Jeffrey Grybowski** Chief Executive Officer / Deepwater Wind
Closing Remarks 3:40 p.m.	**Lance T. Brasher** Global Head, Energy & Infrastructure Projects Group / Skadden
Reception 4:00 p.m.	

David P. Armstrong

Skadden

Partner, Toronto

Banking and Energy and Infrastructure Projects

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Education

LL.B., University of Toronto, 1999 (with honors)

B.A., Queen's University, 1995 (with honors)

Bar Admissions

New York

Licensed as a Foreign Legal Consultant in Ontario

Publications

"Warehouses Arise From Yieldcos," *Project Finance International*, May 5, 2016

"Market Intelligence: Project Finance - United States," *Getting the Deal Through – Project Finance*, May 2016

"Tenaska Goes Large on Imperial," *Project Finance International*, May 2, 2012

David Armstrong's practice focuses primarily on the representation of commercial and investment banks, as well as borrowers and issuers, in leveraged and other finance transactions, including project financings, acquisition financings, leveraged leases and other senior secured lending transactions, with a principal focus on the energy and industrial sectors. He has represented, among others:

- the administrative agent and coordinating lead arrangers in connection with the $780 million construction loan, term loan and working capital project financing of the approximately 925 MW Westmoreland gas-fired generating facility being developed by affiliates of Tenaska, Inc. and Diamond Generating Company in the PJM market;
- Morgan Stanley & Co. LLC, as administrative agent and lead arranger, in connection with the term loan B financing of the acquisition by affiliates of the Carlyle Group of the Rhode Island State Energy Center, a gas-fired power plant located in Rhode Island;
- SunEdison, Inc. in a first-of-its-kind, $1 billion "warehouse" debt financing that will fund the construction of its pipeline of renewable energy projects that it plans to drop down into its affiliated yieldco, TerraForm Power. The warehouse construction facility also included a $500 million third-party equity commitment from First Reserve Corporation;
- Morgan Stanley, Bank of America Merrill Lynch, Credit Suisse, RBC Capital Markets and J.P. Morgan Securities LLC in eight separate project bond financings for the Sabine Pass Liquefaction Project owned by Cheniere Energy Partners for the issuance of over $12.8 billion of senior secured notes. The proceeds of these offerings are being used for the construction of five natural gas liquefaction trains at Sabine Pass Liquefaction's facility in Cameron Parish, Louisiana. The original offering was named North America Midstream Oil & Gas Deal of the Year for 2013 by *Project Finance* magazine;
- Morgan Stanley Senior Funding, Inc., Standard Chartered Bank, Crédit Agricole Corporate and Investment Bank and HSBC Bank USA, N.A. as joint lead arrangers in a $400 million senior secured term loan to Cheniere Creole Trail Pipeline, L.P. The proceeds will be used to pay capital costs in connection with the construction of modifications to the pipeline necessary to service the affiliated Sabine Pass liquefaction facility and to finance the acquisition of the Cheniere Creole Trail Pipeline by Cheniere Energy Partners, L.P.;
- Morgan Stanley & Co. LLC as lead initial purchaser in a $575 million Rule 144A/Regulation S offering of 5.5% senior secured notes due 2032 by México Generadora de Energía, S. de R.L. (a subsidiary of Grupo México, S.A.B. de C.V.), which is developing a 500 MW gas-fired, combined-cycle generating facility in Mexico. This transaction was named "Power Finance Deal of the Year for 2012" by *Latin Finance*;
- Primary Energy Recycling Corporation in its term loan B refinancing of its electric generating assets;
- the lenders under an export credit agency-supported credit facility in connection with the refinancing of an existing project finance transaction for an independent power producer in the Dominican Republic;
- Mirant Corp. in its $2.6 billion acquisition and leveraged lease financing of generating facilities located in Maryland, Virginia and the District of Columbia;

- the agent and lead arrangers in connection with the $455 million construction, term and bridge loan project financing of the 150 MW (AC) photovoltaic solar electrical generating facility being developed by CSOLAR IV West, LLC in Imperial County, California;
- the agent and lead arrangers in connection with the $476 million construction, term and bridge loan project financing of the 130 MW (AC) photovoltaic solar electrical generating facility developed by CSOLAR IV South, LLC in Imperial County, California;
- the tax equity investors in connection with tax equity investments in various residential solar projects in California, Hawaii, Massachusetts and New Jersey;
- the agent and lead arranger in connection with the $169 million project financing of 70 MW (AC) of solar projects being developed by GCL Solar in California;
- the tax equity investor in connection with the financing of the 80 MW (AC) photovoltaic solar energy generation facility being developed by affiliates of Scatec Solar North America, Inc.;
- certain of the purchasers in connection with the 4(2) private placement of senior secured notes, the proceeds of which were used to refinance the construction financing for CSOLAR IV South, LLC;
- Philadelphia Energy Solutions Refining and Marketing in its $550 million term loan B and revolving credit financing of its refining assets;
- Mirant Asia-Pacific Limited in its term loan B refinancing and subsequent sale of its generating assets located in the Philippines;
- the agent in a $1 billion receivables financing for a natural gas trader in Canada and the United States;
- the initial purchasers in a $361 million high-yield offering to refinance the construction financing of an electric generation power plant in Alabama; and
- P.T. Paiton Energy in its $1.5 billion financing of the Paiton 3 power project, an 815 MW coal-fired power plant in East Java, Indonesia, which was named 2009 "Project Finance Deal of the Year" by the *International Financial Review*.

Mr. Armstrong was selected for inclusion in the project finance chapter of *Who's Who Legal: Canada 2015*.

Lance T. Brasher

Skadden

Partner, Washington, D.C.

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Education
J.D., Harvard Law School, 1990
(cum laude)

B.S., United States Naval Academy, 1982 (with distinction)

Bar Admissions
District of Columbia
New Mexico

Lance Brasher is global head of Skadden's Energy and Infrastructure Group. He has served for more than 20 years as lead lawyer in complex acquisition, financing and development transactions involving energy and infrastructure facilities in the United States and around the world. Mr. Brasher has advised energy companies, utilities, developers, investors and lenders in all phases of solar, wind and other renewable energy projects; gas and coal-fired power plants; transmission lines; electric distribution assets; LNG and gas processing facilities; natural gas pipelines; and sports facilities.

Mr. Brasher repeatedly has been recognized as a leading lawyer by *Chambers Global*, *Chambers USA*, *The Best Lawyers in America*, *IFLR1000* and other publications.

Representative transactions include:

- **Enel** in the sale to GE of an interest in 44 wind and hydroelectric power generation projects located in the United States and Canada and related joint venture arrangements;
- **A leading tax equity investor** in the acquisition of ownership and tax equity interests in solar and wind projects;
- **InterGen** in:
  - the acquisition of an ownership interest in the ESJ wind project in Mexico and related joint venture and financing arrangements; and
  - in a $1.8 billion refinancing of corporate bond, term loan, letter of credit and revolving credit facilities;
- **NextEra** in the formation of NextEra Energy Partners, a yieldco owning solar and wind generating assets in the United States and Canada;
- **NorthWestern Energy** in its $900 million acquisition of 11 hydroelectric generating facilities in Montana from PPL Montana and a related bridge financing facility, $450 million bond financing and $450 million equity issuance;
- **First Solar** in connection with:
  - in the formation of 8point3 Energy Partners, a joint venture yieldco with SunPower;
  - construction and the sale to MidAmerican Energy of the Topaz Solar Farm, a 550 MW solar PV located in California;
  - $1.46 billion financing, construction and sale of the 550 MW Desert Sunlight solar project in California, with financing led by Citi and Goldman Sachs;
  - $646 million financing, construction and sale to Exelon of Antelope Valley Solar Ranch One, a 230 MW solar project in California; and
  - $967 million financing, construction and sale to NRG Energy of the 290 MW Agua Caliente solar project in Arizona;
- **Samchully Asset Management** in its $170 million acquisition from Marathon Oil of an interest in a gas processing plant in Louisiana;

- **PensionDanmark** in the acquisition from E.ON Climate & Renewables of an interest in a 430 MW portfolio of U.S. wind farms and in a related private placement financing;
- **NV Energy** in the:
  - acquisition of a joint ownership interest in and capacity use arrangements for the One Nevada Transmission Line;
  - acquisitions of the Bighorn, Silverhawk and Lenzie gas-fired power projects — transactions totaling more than $1 billion and approximately 2,400 MW; and
  - construction of the Lenzie, Tracy, Clark and Harry Allen gas-fired generating stations, aggregating approximately 3,000 MW and more than $2 billion; and in development and construction arrangements for the proposed 1,500 MW, $2.5 billion coal-fired Ely Energy Center;
- **AEI** in its $1.5 billion term and revolving loan facility led by Credit Suisse and JP Morgan, and in financings relating to AEI's acquisition of interests in Luz del Sur of Peru, Promigas of Colombia and Del Sur of El Salvador;
- **Prisma Energy** in its $2.7 billion sale to AEI, including a related $1 billion financing of Prisma;
- **Bechtel** and **Shell** in the auction and $1.75 billion sale of Intergen, owner of 10 coal and gas-fired power plants totaling more than 7,800 MW in Europe, Asia, Mexico and Australia;
- **Enron** in the formation of Prisma Energy, into which Enron transferred its interest in 15 power generation, electricity distribution and natural gas services businesses located in South and Central America, Europe and Asia;
- **banks** and **other lenders** in the financings of FedEx Field for the Washington Redskins, the Nashville Predators' National Hockey League franchise and Invesco Field for the Denver Broncos; and
- **Dabhol Power Company** in the development and $2.9 billion financing of its proposed 2,450 MW power project and LNG regasification facility located in India.

Mr. Brasher's *pro bono* representations include the United Planning Organization of Washington, D.C., with respect to the development and construction of a Head Start Early Learning Center.

Following graduation from the United States Naval Academy, Mr. Brasher was an officer in the U.S. Navy, serving three years on the USS Harry W. Hill, a navy destroyer, and two years as an economist and operations analyst with the Center for Naval Analyses.

Publications

Co-Author with Michael Dailey, "Contracting for the Construction of Utility Scale Solar Projects," *North American Clean Energy* (May/June 2010)

Co-Author with Drew Baldinger, "Joint Ventures Between Regulated Utilities and Developers," *North American Clean Energy* (May/June/July 2009)

Co-Author with Mike Klaus and Len Rawicz, "US Power — Loan Guarantee Programs after the Stimulus Act," *Infrastructure Journal* (February 27, 2009)

Co-Author with Paul S. Kraske, "Renewable Energy Power Purchase Agreements," *The Journal of Structured and Project Finance* (Spring 2003)

Co-Author with Paul S. Kraske and Bruce Lundstrom, "Lessons Learned in Emerging Markets," *Infrastructure Journal* (July/August 2002)

Co-Author with Paul S. Kraske, "EPC Contracts: The Changing Nature of Construction Financing," *Infrastructure Journal* (March/April 2000)

Julia A. Czarniak

Skadden

Partner, New York

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Education

J.D., Georgetown University Law Center, 1997 *(Georgetown International Law Review)*

M.A., Yale University, 1993 (Fox Scholarship)

Experience

Legal Intern, Export-Import Bank of the United States, Spring 1997

Legal Intern, Hogan & Hartson LLP, Moscow, Spring 1996

Bar Admissions

New York

Languages

Russian

Julia Czarniak represents financial institutions, investors, underwriters and sponsors in all aspects of project development and project finance, particularly in the energy sector (including oil and gas, petrochemicals, LNG and power generation-related matters) and other infrastructure and industrial projects. She has handled complex project financings in the United States, Asia and the Middle East.

Ms. Czarniak has extensive experience in structuring and negotiating of joint ventures, project contracts and financing documents. She is representing or has represented:

- Exxon Mobil Corporation in its joint ventures with Rosneft;
- commercial lenders in connection with a $4 billion credit facility to Sasol for the construction of a petrochemical plant in Louisiana;
- the lending group, in Nakilat Inc.'s program financing, which raised over $7 billion in three tranches of debt, the proceeds of which were used to build a fleet of 27 LNG vessels to ship liquid natural gas from Qatar to various ports around the world;
- CMS Energy Corporation in its sale of a portfolio of generating assets in the U.S. and the Middle East to Abu Dhabi National Energy Company PJSC;
- National Grid USA in its divestiture of Ravenswood Generating Station to TransCanada Corporation;
- Citigroup Global Markets, Credit Suisse and HSBC Bank as joint bookrunners in a $2.23 billion senior secured Rule 144A/Regulation S bond offering by Ras Laffan Liquefied Natural Gas Company Limited (3) and guaranteed by Ras Laffan Liquefied Natural Gas Company Limited (II);
- Paiton Energy and its sponsors in connection with the development and financing of the $1.5 billion Paiton 3 Project, a power plant in Indonesia. The financing was provided by JBIC and a consortium of commercial banks, and required complex intercreditor and collateral sharing arrangements with the lenders to the existing Paiton 7/8 Project;
- BNP Paribas and HSBC in the $6.5 billion financing for a liquefication facility in Qatar and an LNG receiving terminal in England, which was named "Deal of the Year" in 2004 by Project Finance; and
- Schlumberger Limited in a $381 million financing for an eight-train gas compression facility in Venezuela.

Ms. Czarniak also works on general financing matters, including specialized structured financings, acquisition facilities, Rule 144A bond financings, and secured and unsecured letters of credit and loan facilities.

She repeatedly has been selected for inclusion in *Chambers Global*, *Chambers USA* and *IFLR1000*. Ms. Czarniak also was named a finalist in the Energy/Projects Lawyer of the Year category at the inaugural *Chambers USA* Women in Law Awards 2012. In 2014, she was included in the Expert Guides edition of *Women in Business Law* for Project Finance in the United States.

Chris Elmore
Vice President
Goldman Sachs

Mr. Elmore joined Goldman Sachs Public Sector and Infrastructure Banking Group full time in July 2008. Chris focuses on the firm's transportation clients, project financings, and P3 transactions. He has significant experience working on P3 and advisory transactions for the Chicago Transit Authority, Denver RTD Eagle P3 Project, US-36 Phase 2 Managed Lanes, Seagirt Marine Terminal, Port of Oakland Outer Harbor Terminal, and New York MTA / Triborough Bridge and Tunnel Authority, among others.

Chris has worked on senior managed transportation and project finance transactions for: San Joaquin Hills and Foothill/Eastern Transportation Corridor Agency, San Francisco 49ers, Capital Beltway, Denver RTD, New York MTA / Triborough Bridge and Tunnel Authority, Washington Metropolitan Area Transit Authority, Amtrak, Lehigh County Authority, Houston Metro, Mid-Bay Bridge Authority, Dormitory Authority of the State of New York, and Denver International Airport, among others. To date Chris has worked on over $13.5 billion of senior managed financings for transportation projects.

Mr. Elmore provides transit, transportation and P3 expertise, with an additional focus on federal transportation programs, initiatives and legislation, including TIFIA and RRIF programs.
Chris graduated from Stanford University with a BS in Mathematical and Computational Sciences.

Daniel M. Elkort
Executive Vice President and General Counsel
Pattern Energy

Mr. Elkort is the Executive Vice President and General Counsel of Pattern Energy. In addition to running the legal department, Mr. Elkort is also responsible for project finance at Pattern Energy. Prior to joining Pattern Energy, from 1996 to 2009, Mr. Elkort was responsible for managing the various project financings of Babcock & Brown's North American renewable energy projects and served as the senior legal officer in Babcock & Brown's North American Infrastructure Group. Before joining Babcock & Brown, Mr. Elkort was a partner with the law firm Jackson, Tufts, Cole and Black.

FILSINGER ENERGY PARTNERS

Todd Filsinger
Senior Managing Director
Filsinger Energy Partners

Todd W. Filsinger is Senior Managing Director of Filsinger Energy Partners (FEP), a company that provides the energy sector with:

- appraisal
- valuation
- commodity price forecasting, including generation, oil and gas forecast services
- financing and restructuring
- plant optimization services

Mr. Filsinger has been active in the in the energy sector for over 25 years and is recognized globally as a leader and turn-around specialist in the energy sector. As an interim executive leader hired to turn companies around and lead them through difficult situations, Mr. Filsinger has guided several utilities through industry restructuring. He has also led and managed some of the largest trading operations in the United States. Notably, Mr. Filsinger served as the lead energy advisor on the EFH/TCEH restructuring, Interim Chief Executive Officer and Interim Chief Financial Officer for Hawkeye Growth, and was a member of the President’s Energy Transition Team in 2008. He led a Global Energy Practice from 2002 through 2010.

Douglas Fleischmann
Vice President of the North American Natural Resource Project Finance Group
SMBC

Douglas Fleischmann is a Vice President of the North American Natural Resource Project Finance Group at SMBC. Doug is also a member of the Structured Placement Group where he specifically focuses on project related 4(a)2 private placements. Currently co-leading two financial advisory engagements, including a modular LNG facility in the U.S. and a Biofuel-to-Liquids project, Doug is also acting as placement agent for a merchant power project refinancing. The institutional clients involved in the advisory and placement mandates include insurance companies, U.S. financial institutions, private equity and hedge funds, as well as government agencies.

Doug previously led SMBC's efforts for many of the U.S. LNG related financings including each of the Cheniere and Freeport commercial bank facilities. Meanwhile, over the past 6 years, Doug has advised or executed a wide variety of complex transactions in the oil & gas, petrochemical, mining, renewable, thermal power, and infrastructure industries.

Doug became a CFA charter holder in 2010, received his MBA from New York University in 2016, and earned his undergraduate degree from the University of Colorado - Boulder, majoring in Finance and Accounting. Douglas holds FINRA Series 79 (Investment Banking Representative) and Series 63 (Securities Agent) securities licenses.

SOCIETE GENERALE
Corporate & Investment Banking

Luisa Fuentes
Director, Energy and Project Finance
Société Générale

Luisa Fuentes joined Société Générale's Advisory and Project Finance group in 2001, where she has focused on both advisory and debt arranging assignments across the U.S, Canada and Latin America. Luisa has over 15 years of experience in advising clients on benchmark transactions in the energy and power sectors as well as arranging financings in both the bank and capital markets. Ms. Fuentes has led several transactions including; initiatives on 'first of' LNG arranging mandates for Cheniere (Sabine, Corpus and CQP) and Elba LNG as well as Freeport LNG, Cameron LNG in addition to advisory efforts for Petronas and Tellurian; renewable arranging mandates for Pattern Energy, BP and EDF EN; and power deals for Invenergy, Staatkraft and Mitsui. Ms. Fuentes holds an MBA from Georgetown University and a BA in Political Science from Boston College.

David L. Giordano
Managing Director
BlackRock Renewable Power

David L. Giordano, Managing Director, is a member of the Renewable Power Group, within BlackRock Alternative Investors (BAI). As head of the North American Investment team, he is responsible for originating investment opportunities, establishing industry partnerships, and leading transactions associated with securing investment opportunities.

Prior to joining BlackRock in 2011, Mr. Giordano was the Chief Operations Officer and Chief Financial Officer for Community Energy Holdings, Inc., a regional utility-scale renewable energy developer. Previously, he was one of the original members of Babcock & Brown's North American infrastructure team where he closed $4 billion of wind transactions and worked closely in an advisory arrangement with the Airtricity North American team. Mr. Giordano's extensive energy industry experience also includes his work at FPL Energy (now NextEra) where he developed and acquired operating and development power assets and played a key role in the first non-registered 144A bond offering for a portfolio of wind assets.

Mr. Giordano earned a BA degree in Economics and Policy Management Studies from Dickinson College in 1991 and an MPA degree from Syracuse University's Maxwell School in 1996. Mr. Giordano is a member of ACORE's Executive Committee.

Adam Hesketh
Chief Financial Officer
Transurban

As Chief Financial Officer, North America, Adam is responsible for overseeing the accounting, procurement, corporate finance and treasury functions of Transurban's US operations. He also plays a key role in shaping, negotiating and financing new project developments and bid submissions, and has managerial and Board responsibilities on Transurban's US assets.

Adam has over ten years' experience in the Australian and US toll road sectors successfully closing over US$5 billion of financings on corporate and project-finance transactions. He has sourced funding from a range of countries, across bank and debt capital market facilities and transacted with private and public sector lenders.

Prior to Transurban, Adam worked at Qantas Airways. He holds bachelor degrees in Commerce and Information Systems from the University of Melbourne and is a registered CA with the Institute of Chartered Accountants, Australia.

Chuck Jordan
Partner
Arroyo Energy Investors

Chuck Jordan is one of the Founding Partners of Arroyo Energy Investors. Mr. Jordan oversees transaction origination, negotiation and execution, as well as directing the commercial activities of Arroyo's domestic and international investments.

Mr. Jordan was instrumental in establishing the Arroyo team in partnership with Bear Stearns in 2003 to make investments in energy infrastructure assets. When JP Morgan acquired Bear Stearns, Mr. Jordan became a senior member of JP Morgan's Global Commodities Group.

Over the past two years, Mr. Jordan has helped to lead the Arroyo team's transition out of JP Morgan in order establish an independent private equity fund. Arroyo Energy Investors Fund II has already made investments totaling more than $500 million in value to date. The Fund focuses on investments in the US, Mexico, Chile Peru and Columbia.

Prior to establishing Arroyo, Mr. Jordan was a Director for Mirant and Southern Company.

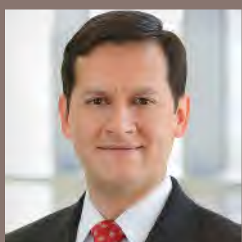
Mr. Jordan has a BS in Electrical Engineering from the University of South Alabama and an MBA from the University of Alabama.

Jorge H. Kamine

Skadden

Counsel, Washington, D.C.

Energy and Infrastructure Projects



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Education
J.D., Harvard Law School, 1998
B.A., Rice University, 1995 (*cum laude*)

Bar Admissions
District of Columbia
Texas
New York

Languages
Spanish
Portuguese

Jorge Kamine focuses his practice on all aspects of structuring, developing and financing international energy and infrastructure projects, as well as the acquisition and divestiture of energy and infrastructure assets. He has broad experience in the energy industry, including with renewable energy and gas power generation projects, as well as LNG and oil and gas exploration, development and transportation. He has advised clients with structuring and negotiating transactions involving multiple owners, project development, and various types of project and bank financings in which he represents lenders and borrowers.

Mr. Kamine's non-energy infrastructure experience includes projects involving water supply and sanitation, road and transport, and urban infrastructure.

Mr. Kamine has worked on matters throughout the world, including significant experience in the United States, Latin America and the Caribbean. His experience in Latin America and the Caribbean has included matters in Argentina, Bolivia, Brazil, Chile, Colombia, Dominican Republic, Ecuador, Guatemala, Guyana, Haiti, Honduras, Mexico, Nicaragua, Panama, Paraguay, Peru, Trinidad and Venezuela. His experience working in Africa includes transactions in Cameroon, Egypt, Nigeria and South Africa. He also has handled matters in Asia, including in Indonesia and Malaysia, as well as in Europe.

Some of Mr. Kamine's transactional experience includes the representation of:

- **SunEdison, Inc.** in the:
  - 81.7 MW solar photovoltaic power plants in the Republic of Honduras with a $146 million nonrecourse debt financing arrangement with the IFC, the Central American Bank for Economic Integration and the OPEC Fund for International Development (OFID). This is one of the first large-scale grid-connected solar projects in the country and diversifies the energy mix in Honduras while providing clean, renewable energy. It is also the largest solar power development in Central America to date;
  - 69.5 MW Javiera solar photovoltaic power plant in the Antofagasta region of northern Chile with up to a $130 million nonrecourse debt financing arrangement provided by Corpbanca and BBVA to finance the construction and a local Chilean peso VAT facility of $30 million provided by the same banks. When it closed, this financing represented the first financing of a solar project in Chile where senior debt was being provided entirely by commercial banks and it has been named "Latin American Solar Deal of the Year" for 2014 by *IJGlobal*; and
  - 72.8 MW Maria Elena merchant solar photovoltaic power plant in the Antofagasta region of northern Chile with a nonrecourse senior loan facility of up to $155 million provided by OPIC, the Inter-American Development Bank, the Clean Technology Fund, and the New York branch of Corpbanca and a local Chilean peso VAT facility of up to $35 million provided by Corpbanca. When it closed, the project was set to be one of the largest solar PV merchant power plants in Latin America;

- **Peru LNG S.R.L.** in the financing of its $3.8 billion LNG export project in Peru, consisting of $2.05 billion in senior secured bank financing provided by IFC, IDB, US EXIM, KEXIM, SACE and a syndicate of commercial banks, as well as a $200 million bond offering in Peru arranged by BCP, which was the first LNG export project in South America and the largest foreign direct investment in Peru's history at the time. This deal was named "Latin America Deal of the Year" for 2008 by *Project Finance International*, "Latin American Export Finance Deal of the Year" for 2008 by Euromoney's *Project Finance* magazine, "Deal of the Year 2008 Project Finance" by *Latin Lawyer* and the "Best Energy Deal of the Year" for 2008 by *LatinFinance*. Mr. Kamine also represented Peru LNG in obtaining a $75 million senior secured working capital facility that was renewed in 2012 and 2014. He continues to represent Peru LNG on ongoing matters related to the financing;
- **Shelf Drilling International Holdings, Ltd.**, a newly formed global provider of shallow water drilling services sponsored by Castle Harlan, Inc., CHAMP Private Equity and Lime Rock Partners, in the financing of its $1.05 billion acquisition of an international fleet of offshore drilling rigs from Transocean Ltd., which at closing were operating throughout Southeast Asia, India, West Africa, the Middle East and the Mediterranean. This transaction received the highest ranking in the Corporate & Commercial category in the *Financial Times*' 2013 "US Innovative Lawyers" report;
- **a publicly traded energy company** in a range of transactions related to the expansion of its solar energy business in South Africa and other countries in sub-Saharan Africa, including advising on potential joint ventures, acquisitions of projects and development assets, a suite of new solar module supply arrangements and agreements, and various corporate matters;
- **a global energy company** in their potential bid for various new natural gas pipeline projects proposed for bids by the Federal Electricity Commission (Comisión Federal de Electricidad) of Mexico;
- **Natixis, New York Branch**, as administrative agent and collateral agent, in connection with its ongoing administration of the senior secured credit facilities for the 620 MW, gas-fired Kleen Energy power plant in Connecticut;
- **Bank of America Merrill Lynch** in a $1.4 billion loan by the U.S. Department of Energy for Project Amp, the world's largest distributed rooftop solar generation project, which supports the installation of approximately 752 MWs of photovoltaic solar panels on 750 existing rooftops. The electricity generated from these panels will contribute directly to the electrical grid. This project was awarded 2011 "Finance Innovation of the Year" by *Renewable Energy World*; and
- **Bank of America Merrill Lynch** in its financing of SolarCity's SolarStrong project. SolarStrong, which will build more than $1 billion in solar power installations for privatized U.S. military housing communities across the country, would be the largest residential solar photovoltaic project in American history. The *Financial Times* "US Innovative Lawyers" report ranked our representation of Bank of America Merrill Lynch in its financing of SolarCity's SolarStrong project as one of only two matters in the top tier in the energy category for 2012.

Prior to joining Skadden, Mr. Kamine served as counsel at The World Bank, where he represented World Bank teams in developing, structuring and financing projects in Latin America and the Caribbean undertaken by sovereign and sub-sovereign governments and international and regional organizations, including regional climate change and mitigation projects, water supply, sanitation, transport and urban infrastructure projects, land administration, and macroeconomic and sectoral policy reforms.

Prior to joining The World Bank, Mr. Kamine was an attorney with a globally recognized international law firm, where he represented international energy companies and multilateral and commercial lenders in the acquisition and divestiture and financing of upstream and midstream oil and gas assets and power generation projects throughout the United States, Latin America and the Caribbean, including the divestment of a billion-dollar portfolio of assets located in several Latin American countries, a major oil refinery in Aruba and several pipelines in the United States, the acquisition, financing and ongoing ownership of offshore oil and gas concessions from Petrobras, and the financing of a floating offshore oil production facility, an industrial gas facility in Trinidad, and a portfolio of Brazilian power projects.

Mr. Kamine is a frequent commentator for Inter-American Dialogue's *Latin America Advisor* and *Latin America Energy Advisor* as well as for *Latinvex*, *LatinFinance* and *Latin Lawyer* magazines. He is fluent in Spanish and Portuguese, and regularly negotiates in those languages.

Jorge H. Kamine

Continued

Teaching/Lectures

Guest Lecturer, “Transactional Lawyer’s Perspective on International Commercial Arbitration,” a session of a class entitled “International Commercial Arbitration,” Duke University School of Law (Durham, N.C., April 8, 2014)

Guest Lecturer, “The Role of Private Investment in Development,” a session of a seminar entitled “Developing Countries in International Economic Law,” University of Virginia School of Law (Charlottesville, Va., April 16, 2013)

Panelist, “2012 Georgetown Energy and Cleantech Conference,” Georgetown University (Washington, D.C., Oct. 12, 2012)

Associations

Council on Foreign Relations (Term Member)

American Society of International Law (Corresponding Editor, International Legal Materials)

Inter-American Dialogue (Member of Board of Advisors for the *Latin America Energy Advisor* and Resident Associate)

Latin American and Caribbean Council on Renewable Energy (LAC-CORE) (Member and *Pro Bono* Counsel)

American Bar Association (Business and International Sections)

American Council on Renewable Energy (ACORE)

Harvard Law School Association (Vice President, Washington, DC Chapter and member of Latino Alumni Committee)

Hispanic National Bar Association

Hispanic Bar Association of D.C. (Former Member of the Board of Directors)

Hispanic Bar Association of Houston (President, 2004-2005)

Presentations

Panelist, “Long Term Energy Planning in Brazil,” Panel of the 3rd Annual Brazil Investment Conference presented by *Foreign Affairs*, the flagship publication of the Council on Foreign Relations (New York, Dec. 3, 2013)

Invited Speaker, “Lessons Learned From Financing Large Scale Distributed Generation Projects in the U.S.,” Inter-American Development Bank Brown Bag Lunch Session (Washington, D.C., June 6, 2013)

Steering Committee Member and Moderator, Third Annual Renewable Energy Finance Forum — Latin America and Caribbean (REFF-LAC) (Miami, April 30-May 1, 2013)

Moderator, First, Second and Third Annual Latin American and Caribbean Council on Renewable Energy’s (LAC-CORE) Renewable Energy Finance Briefings (New York, June 2011-2013)

Session Co-Chair, Second Annual Renewable Energy Finance Forum — Latin America and Caribbean (REFF-LAC) (Miami, April 24-25, 2012)

Participant, Institute of the Americas’ Workshop on the Project for Regional Electricity Markets and Interconnections in Central America (Washington, D.C., Oct. 26-27, 2011)

Moderator, Infocast’s Projects & Money in Latin America Conference (Rio de Janeiro, Brazil, June 2011)

Moderator of Oil & Gas Plenary, Brazilian-American Chamber of Commerce, Energy Conference (New York, Oct. 15, 2009)

Publications

Author, “Does Latin America’s Solar Industry Have a Bright Future?” *Latin America Advisor*, May 8, 2015. Printed in Chinese. The article originally was published in Inter-American Dialogue’s weekly *Energy Advisor*.

Co-author, “Insights Conversations: International Renewable Energy Projects,” *Skadden, Arps, Slate, Meagher & Flom LLP*, April 28, 2015

Author, “Introductory Note to the International Energy Forum Charter,” *International Legal Materials* (51 ILM 198 (2012))

Ja Kao
President
Onyx Renewable Partners L.P.

Ja Kao, President, Onyx Renewable Partners L.P. ("Onyx"). Onyx is a renewable energy development company established by funds managed by Blackstone Energy Partners. Onyx is focused on greenfield development and M&A opportunities in the North American solar and wind sectors. Ja has over 15 years of finance and legal experience, as an investment banker and tax lawyer, structuring and placing complex financial instruments and structuring and executing M&A transactions across sectors, including financial services, media, telecom, energy (both traditional and renewable), consumer products and industrials.

Prior to joining Onyx, Ja worked at The Blackstone Group, where she was a Managing Director on the Structured Solutions team of Blackstone Advisory Partners. While at Blackstone, she led the renewable energy investment banking practice, covering wind, solar and other technology companies. Ja structured multiple tax equity financing transactions for solar and wind projects. Prior to The Blackstone Group, Ja was a tax associate at the law firm of Shearman & Sterling, LLP in New York and worked on complex M&A, capital markets, cross-border finance and private client matters.

Ja received a JD, cum laude, from Georgetown University Law Center and a BA with a major in Economics from Brandeis University.

Ja serves on the Board of Directors for the American Counsel On Renewable Energy (ACORE), as Chairman of the Board of Assessment Review for the town of Pound Ridge, NY, and serves on the Board of Directors and Treasurer for the not-for-profit group, Internationals Network for Public Schools.

Paul S. Kraske

Skadden

Partner, Washington, D.C.

Energy and Infrastructure Projects

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Education

J.D., Harvard Law School, 1996 (*cum laude*)

MSc., International Relations, London School of Economics and Political Science, 1993

B.A., History, Yale University, 1992 (*cum laude*)

Bar Admissions

New York
District of Columbia

Paul Kraske regularly represents clients in connection with the development, financing and acquisition of energy and infrastructure projects in the U.S. and abroad. He has extensive experience preparing and negotiating all forms of relevant documentation, including joint development and ownership agreements, construction contracts, power purchase agreements, credit and investment documentation, and sale and purchase agreements. From 2000 to 2002, Mr. Kraske worked in Mumbai, India, as the general counsel of the Dabhol Power Project, where he had primary responsibility for legal issues arising out of the operation of an existing 740 MW power plant, as well as the construction of 1,440 MW of additional capacity and an associated LNG regasification terminal.

Mr. Kraske repeatedly has been selected for inclusion in *Chambers Global: The World's Leading Lawyers for Business*, *Chambers USA: America's Leading Lawyers for Business* and *IFLR1000*. He was recognized by *Chambers USA 2010* as "one of the USA's foremost experts on the development and financing of electric transmission projects." Mr. Kraske also was named as a 2014 "*Law360* MVP" in the project finance category.

Some of Mr. Kraske's continuing or completed transactions include his representation of:

- ArcLight Capital Partners, LLC, a private equity firm, in its sale of a 50.1 percent stake in Southeast PowerGen, LLC, a portfolio of gas-fired power plants, to The Carlyle Group LP;
- Citizens Sunrise Transmission LLC in its lease and private placement financing of 50 percent of the transfer capability of a 1,000 MW, 500 kV segment of the Sunrise Powerlink Project;
- Emera Inc. in its agreement to purchase three combined-cycle gas-fired electricity generating facilities with a total of 1,050 MW in New England from Capital Power Corporation. The generating facilities include Bridgeport Energy (520 MW), Rumford Power (265 MW) and Tiverton Power (265 MW);
- First Solar, Inc. in connection with the development, construction and $290 million financing by the Overseas Private Investment Corporation (OPIC) and the International Finance Corporation (IFC) of the 141 MW Luz del Norte solar power plant in the Atacama Desert in Chile. When completed, Luz del Norte will be the largest merchant solar project in the world;
- Hudson Transmission Partners, LLC in connection with the development and $850 million construction financing of a 660 MW HVDC converter station and associated HVAC transmission cables, which transmit electricity from New Jersey to Manhattan underneath the Hudson River;
- JPMorgan Infrastructure Investments Fund in its acquisition of a 50 percent joint venture interest in Sonnedix Power Holdings, an independent solar power producer;
- NSP Maritime Link Incorporated in the development of a transmission line connecting Nova Scotia and Newfoundland;
- Pattern Conejo in the financing by international commercial banks of a 104 MW solar project in the Antofagasta region of northern Chile;

- SolarReserve, LLC in connection with construction and O&M arrangements for the Crescent Dunes concentrating solar power project and the sale of a portion of the project to equity investors;
- SunEdison, Inc., and its affiliates in a:
  - $146 million nonrecourse debt financing arrangement with the IFC, the Central American Bank for Economic Integration (CABEI) and the OPEC Fund for International Development (OFID). The debt proceeds will be used to fund the construction of three solar photovoltaic power plants totaling 81.7 MW in the Republic of Honduras. This is one of the first large-scale grid-connected solar projects in the country, and diversifies the energy mix in Honduras while providing clean, renewable energy. It is also the largest solar power development in Central America to date;
  - $50 million debt financing by the European Bank for Reconstruction and Development (EBRD) and OPIC of a 23.8 MW DC solar power plant in the Ma'an Governate in Southern Jordan;
  - $212 million nonrecourse debt financing arrangement with the IFC and OPIC. The proceeds were used to finance the construction of a 100 MW solar power plant in the Atacama Desert in Chile. At the time construction was completed, this project was the largest solar facility in Latin America;
  - $100 million nonrecourse debt financing arrangement with OPIC and the IFC, the proceeds of which were used to finance the construction of the 50.7 MW San Andres solar power plant in the Atacama Desert in Chile. *Project Finance* magazine named this transaction the "Latin America Solar Deal of the Year" for 2013;
  - financing of the 72.8 MW Maria Elena solar power plant, a merchant facility located in the Antofagasta region of northern Chile; and
  - $130 million nonrecourse debt financing arrangement with CorpBanca and BBVA to finance the construction of the 69.5 WM Javiera solar photovoltaic power plant. This is the first financing of a solar project in Chile where senior debt is being provided entirely by commercial banks;
- SunEdison, Inc. and TerraForm Power, Inc. in the financing of their $2.4 billion acquisition of First Wind Holdings, Inc., a developer of wind projects; and
- TerraForm Power, Inc., a subsidiary of SunEdison, Inc., in securing a $400 million bridge acquisition facility from Goldman Sachs Bank USA. The bridge was used to purchase solar power projects to complete the initial portfolio of TerraForm Power, Inc. in advance of its proposed initial public offering. Skadden also represented TerraForm Power, Inc. in negotiating a takeout term loan and a revolving credit facility.

Publications

Paul Kraske, William Conway Jr. and J. Alexander Cooke, "Sun Shines on Independent Transmission," *Project Finance International*, September 5, 2012

Lance Brasher and Paul Kraske, "Renewable Energy Power Purchase Agreements: A Reflection of the Carrot-and-Stick Approach to Renewable Energy Legislation," *Journal of Structured and Project Finance*, Spring 2003

Jeffrey Christie, J. Alexander Cooke and Paul Kraske, "Financing US Transmission," *PFI*, February 11, 2009

Lance Brasher and Paul Kraske, "EPC Contracts: The Changing Nature of Construction Financing," *Infrastructure Journal*, March/April 2000

J.P.Morgan
Asset Management

Dan Mitaro
Vice President
J.P. Morgan Asset Management

Dan Mitaro is an investment principal in the OECD Infrastructure Equity Group at J.P. Morgan Asset Management (JPMAM). Dan is currently responsible for the day-to-day asset management of investments in Novatus Energy, Sonnedix Power Holdings and Summit Utilities on behalf of institutional investors advised by JPMAM, as well as the pursuit of new opportunities in the global power and regulated utility sectors. Prior to joining the group in 2013, Dan was a member of the investment banking coverage team at J.P. Morgan responsible for U.S. infrastructure and Public Private Partnership transactions. In that role, Dan supported the origination and execution of financing and advisory assignments for public and private sector clients. He graduated from Washington and Lee University with a B.S. in Business Administration and Politics.

Tatiana Monastyrskaya

Skadden

Partner, New York

Energy and Infrastructure Projects

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Education

J.D., George Washington University School of Law, 2004 (Order of Coif)

Ph.D., City University of Hong Kong, 2001

M.A., Moscow State University, 1999 (with highest honors)

B.A., Moscow State University, 1997 (with highest honors)

Bar Admissions

New York

Experience

Research Assistant, City University of Hong Kong (1999-2001)

Languages

Russian (native)
Korean (conversational)
German (conversational)

Tatiana Monastyrskaya represents financial institutions, including investment banks, commercial banks and private equity firms in various types of finance transactions, with an emphasis on project finance. She also represents the U.S. Department of Energy and the U.S. Department of Transportation in connection with energy and infrastructure projects, and private equity sponsors and developers in various tax equity transactions.

Her representations include the following:

- Alberta Investment Management Corporation as lender in a $250 million term loan facility for an affiliate of D. E. Shaw Renewable Investments, L.L.C to fund existing projects and to acquire new projects;
- Ameresco, Inc., in connection with a sale-leaseback transaction in the C&I solar space;
- Bank of Tokyo Mitsubishi, a syndicate of commercial banks, Islamic banks and Servizi Assicurativi del Commercio Estero (SACE), in the $3.6 billion Ras Laffan C financing of the power and water desalination facility in Qatar;
- Bank of Tokyo-Mitsubishi UFJ, Ltd. and Union Bank, N.A. (collectively, MUFG) as lead members of a lending group in a debt financing for Tenaska's Imperial Solar Energy Center South, a utility-scale photovoltaic solar generating plant in southern California;
- BNP Paribas in connection with a refinancing of Northeast Wind's portfolio of projects;
- CF Industries Holdings, Inc. in connection with two large expansion projects in Port Neal, Iowa and Donaldsonville, Louisiana; and in connection with an $8 billion combination with OCI N.V.;
- the U.S. Department of Energy as guarantor in a financing of a $1.24 billion utility scale solar project in connection with its Loan Guarantee Program;
- the U.S. Department of Transportation in connection with the 183-S toll road expansion in Texas;
- the Export-Import Bank of Korea, Korea Export Insurance Company, Lehman Brothers and Credit Suisse in the $4.3 billion Qatar Gas National Company Limited (Nakilat) ship financing;
- Goldman Sachs:
  - and other lead arrangers in connection with a bank facility for the Ivanpah solar project;
  - in connection with a number of inverted lease and partnership flip structures for solar facilities; and
  - as a lender in a $150 million term loan facility to DE Shaw Renewables in connection with its yieldco transaction;
- Morgan Stanley in a number of transactions, including a high-yield term loan financing of an ethanol plant;
- Merrill Lynch Commodities in connection with assignment of certain oil assets from JPMorgan and intermediation services to Philadelphia Energy Solutions;
- Onyx Renewables Partners, LP, in connection with an inverted lease with Credit Suisse and other ongoing transactions;

- Philadelphia Energy Solutions in connection with an asset-based revolver and supply and offtake (aka "intermediation") agreements with JPMorgan and in a Term Loan B financing;
- Santander in connection with a financing for EcoGrove Wind; and
- Société Générale and Morgan Stanley and a syndicate of commercial bank lenders in connection with a $635.7 million credit facility provided to a subsidiary of EIG Global Energy Partners (EIG) for the acquisition by EIG from Kinder Morgan, Inc. of a 49 percent interest in Elba Liquefaction Company, L.L.C.

Ms. Monastyrskaya has been selected for inclusion in *Chambers USA: America's Leading Lawyers for Business*. She is also an adjunct professor at Fordham Law School where she teaches International Project Finance.

Joshua B. Nickerson

Skadden

Counsel, Washington, D.C.

Project Finance, Energy and Sports Matters

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Education

J.D., University of Virginia School of Law, 1997

M.A., Tufts University, Fletcher School of Law and Diplomacy, 1997

B.A., Georgetown University, 1992

Bar Admissions

New York
District of Columbia

Mr. Nickerson represents clients in transportation, energy and sports-related transactional matters. He has more than 15 years of experience arranging and closing complex transactions involving project development and construction, debt financings and restructurings, equity investments, corporate and project acquisitions and dispositions, and partnerships and joint ventures.

Mr. Nickerson's work includes representation of:

- the U.S. Department of Transportation, as lender under the TIFIA program, in connection with:
  - financing for the Transform66 Outside the Beltway PPP in Virginia;
  - financing for the Portsmouth Bypass PPP in Ohio;
  - debt restructuring for the Pocahontas Parkway PPP in Virginia;
  - financing for the Dulles Corridor Metrorail Project (Silver Line Phase 2);
  - financing for the Downtown Crossing portion of the Louisville-Southern Indiana Ohio River Bridges project;
  - financing for the C-470 Express Lanes Project in Denver, Colorado;
  - financing for the I-15 Managed Lanes project in Riverside County, California;
  - debt restructuring for the Transbay Transit Center in San Francisco;
  - financing for the U.S. 301 project in Delaware;
  - financing for the 183-S project in Texas; and
  - financing for the Chicago O'Hare International Airport consolidated rental car facility;
- a bidder for the MBTA Automated Fare Collection System PPP in Massachusetts;
- a shortlisted consortium in the 2015 bankruptcy-related auction for the Indiana Toll Road concessionaire;
- a developer in the sale of three late-development stage, utility scale, photovoltaic solar power projects in California;
- Goldman Sachs in connection with an inverted lease tax equity financing for, and acquisition of, residential rooftop solar facilities;
- lenders, borrowers and investors in sports-related transactions, including financings for the DC United, Detroit Tigers, Houston Astros, Kansas City Chiefs and Minnesota Vikings, and other sports-related investment and development transactions;
- lenders to the winning bidder for the $2.5 billion proposed long-term concession of Midway Airport in Chicago, the first large air carrier hub airport to participate in the Federal Aviation Administration's airport privatization pilot program;
- the lenders to a shortlisted bidder for the PR-22/PR-5 long-term toll road concession in Puerto Rico;
- the state of New Jersey in developing a $35 billion proposed public-private partnership for the state's toll roads;
- SolarReserve, LLC in connection with a $737 million loan guarantee from the U.S. Department of Energy for the 110 MW Crescent Dunes concentrating solar power project near Tonopah, Nevada; and
- the lenders in the $1.8 billion non-recourse financing of Phase II of Dabhol Power Company's 2,450 MW generating station and liquefied natural gas regasification facility in India.

Paul W. Oosterhuis

Skadden

Of Counsel, Washington, D.C.

International and Corporate Tax Law

T: 202.371.7130
F: 202.661.8232
paul.oosterhuis@skadden.com

Education

J.D., Harvard University
(*cum laude*)

B.A., Brown University
(*magna cum laude*)

Experience

Legislation Attorney, Joint Committee on Taxation, U.S. Congress

Legislation Counsel, Joint Committee on Taxation, U.S. Congress

Adjunct Professor of Law, Georgetown University Law Center

Bar Admissions

District of Columbia
U.S. Tax Court

Paul Oosterhuis is an internationally recognized senior practitioner in the area of international tax. He has extensive experience in mergers and acquisitions, post-acquisition integration, spin-offs, internal restructurings and joint ventures. He also represents multinational companies in nontransactional international tax planning and assists clients in resolving high-stakes, complex tax controversies.

Mr. Oosterhuis has been ranked in the top tier of *Chambers USA* each year since the guide was first released in 2003. He also has been ranked in the top tier of *Chambers Global* each year since 2002. In addition, he repeatedly has been selected for inclusion in *Tax Directors Handbook*, *The Legal 500 U.S.*, *Who's Who Legal: Corporate Tax*, *IFLR1000* and *The Best Lawyers in America*. He also was named as a 2017 BTI Client Service All-Star.

Having worked for decades in complex and high-profile cross-border tax matters, he also frequently testifies on international tax policy matters before congressional committees, including the U.S. House Committee on Ways and Means at its 2013 hearing on "Tax Reform: Tax Havens, Base Erosions and Profit Shifting."

Mr. Oosterhuis has been involved in the tax aspects of some of Skadden's most significant transactions. Representative **cross-border mergers and acquisitions** include:

- **Daimler-Benz AG** in its $38.3 billion merger with Chrysler Corporation, forming DaimlerChrysler AG. This deal was the first German/American stock-for-stock merger and was named 1998's Deal of the Year by *Investment Dealers' Digest*;
- **Alcatel** in its $13.4 billion merger of equals with Lucent Technologies Inc.;
- **IBM Corporation** in its $3.5 billion acquisition of PwC Consulting firms around the world from PricewaterhouseCoopers. This deal was selected as Technology Deal of the Year for 2002 by *International Financial Law Review*; and
- **Pfizer Inc.** in its proposed combinations with Astra-Zeneca Ltd. and Allergan plc.

Representative **domestic mergers and acquisitions** include:

- **Schering-Plough Corporation** in its $41 billion acquisition by Merck & Co., Inc.;
- **Hewlett-Packard Company** in its $13.9 billion acquisition of EDS; and
- **Pfizer Inc.** in its $68 billion acquisition of Wyeth. This was named Americas Deal of the Year at the Americas M&A Awards by *mergermarket* and *Financial Times*.

Representative **spin-offs** include:

- **Hewlett-Packard Company** in the spin-off of its scientific and medical-testing instrument business into a separate publicly traded company called Agilent Technologies Inc.;
- **Pfizer Inc.** in the carve-out of its animal health business into a separate publicly traded company called Zoetis Inc. via a $2.6 billion initial public offering. Skadden also represented Pfizer Inc. in the tax-free split-off (valued in excess of $13 billion) of its remaining 80 percent interest in Zoetis Inc.; and
- **Hewlett-Packard Company** in the split-up of its computer and printer businesses and its corporate hardware and services operations into two separate companies. This was one of the largest spin-offs ever, which gave rise to two publicly traded companies, each with more than $50 billion in annual revenue.

In addition to specific transactions, Mr. Oosterhuis has played a key role in **internal restructurings** including:

- **the board committee of The Royal Dutch/Shell Group of Companies** with U.S. tax advice in connection with the company's restructuring to form Royal Dutch Shell plc;
- **General Electric Capital Corporation** in the restructuring and the sale by General Electric Company of most of GE Capital's assets; and
- **Visa Inc.** and **Visa U.S.A., Inc.** with the U.S. tax aspects of its global restructuring to form Visa Inc.

He also represents clients in audits and appeals before the IRS, including on transfer pricing matters. Mr. Oosterhuis has negotiated, on behalf of clients, various advance pricing agreements, prefiling agreements and competent authority agreements. He has been involved in some of Skadden's most significant **tax controversy and litigation** matters including:

- **GlaxoSmithKline plc** and its U.S. affiliate, **GlaxoSmithKline Holdings (Americas) Inc.**, as settlement counsel in the $3.4 billion settlement of a transfer pricing dispute with the IRS. This case was the biggest in the history of the IRS in terms of both the original amount sought by the IRS and the settlement amount;
- **The Bank of New York Mellon Corporation** in a tax dispute with the IRS in connection with $215 million in foreign tax credits related to taxes paid in the United Kingdom in 2001 and 2002;
- **Ingersoll-Rand** in resolving a complex dispute with the IRS over the treatment of intercompany debt. Under the resolution, the IRS released claims for more than $1 billion of tax and penalties; and
- **Hess Corporation** with respect to HOVENSA, a St. Croix petroleum refinery joint venture between Hess Corporation and Petroleos de Venezuela, in multiple lawsuits against the government of the U.S. Virgin Islands related to income tax refund and deficiency actions involving nearly $3 billion.

Selected Publications

"The Need for Second-Best Tax Reform Solutions," *Temple Law Review*, Vol.89 No. 2, Winter 2017

"Ethics and Tax Planning," *Tax Executive*, Vol. 69 No. 2, March/April 2017

"Transfer Pricing After BEPS: Where Are We and Where Should We Be Going," *TAXES — The Tax Magazine*, Vol. 95 No. 3, March 2017

"US Corporate Tax Reform — Stuck in Neutral," *Law360*, February 21, 2014

"Corporate Tax (Introduction)," *Chambers Legal Practice Guides*, 2014

"What's in Order for Assets Crossing the Border?" *TAXES — The Tax Magazine*, Vol. 88 No. 3, March 2010

"The Evolution of U.S. International Tax Policy — What Would Larry Say?" *Tax Notes International*, June 26, 2006

"Check-The-Box Planning in Cross-Border Transactions," *TAXES — The Tax Magazine*, Vol. 83 No. 3, March 2005

"Structuring an Exemption System for Foreign Income of U.S. Corporations," *National Tax Journal,* Vol. LIV No. 4, December 2001

"Taxing Cross-Border Combinations: Nationalistic Rules in a Global Economy," *TAXES — The Tax Magazine*, December 1997

"International R&D and Technology Transfer Arrangements," *TAXES — The Tax Magazine*, December 1995

"The Cost of Deferral's Repeal: If Done Properly, It Loses Billions," *Tax Notes International*, February 8, 1993

"US Stapled Stock Invites but Does Not Promise," *International Tax Review*, Vol. 3 Issue 3, February 1992

"Musings on Rev. Rul. 91-5 and Its Implications for Section 304 Transactions," *Tax Notes*, March 18, 1991

"Interest Deductibility Under the New US Earnings — Stripping Rules," *Intertax*, Vol. 53, No. 2, 1990

"The Export Source Rule: An Age-Old Rule With a Dubious New Interpretation," *Tax Notes*, June 26, 1989

"Research and Development Expenditures," *BNA Tax Management Portfolio*, 42-3rd T.M., 1987 (reprinted May 1992)

Ivan Oliveros
Executive Director, Head of Power & Renewables Latam
SMBC

Iván Oliveros joined SMBC in January 2010. He currently Heads the Latin American Power and Renewables Project Finance group at SMBC focusing on Debt and Equity Financial Advisory and Project Finance in the Power sector throughout Latin America.

Prior to joining SMBC, Ivan worked for BNP Paribas' Project Finance Latin America group and for Scotia Capital's Power & Utilities group both based in New York.

He has been actively involved in the origination, advisory, execution and syndication of large Project Finance transactions, involving commercial bank syndicated facilities, capital markets, ECA structured facilities and multilateral agencies for more than 12 years. He previously worked as an Engineering Consultant for projects in the Power, Natural Resources and Infrastructure sectors in Latin America for more than 8 years.

As Head of the Latam Power & Renewables sector for SMBC Ivan has overseen the execution and closing of more than 20 transactions in the Power sector in Latin America in the last three years, including Wind, Solar, Combined Cycle, Cogeneration and transmission line Financings executed through commercial bank financings, ECA facilities and capital markets debt offerings. Iván is bilingual in English and Spanish and understands Basic Portuguese.

He holds a BSc in Industrial and Environmental Engineering from Universidad Católica de Chile and an MBA from Columbia Business School. He also completed the coursework for a Master's of Engineering at Columbia's School of Engineering and Applied Science.

Tom Osborne
Executive Director
IFM Investors

Tom is responsible for the origination, analysis, structure and execution of IFM Investors' global infrastructure investments. Prior to joining IFM Investors, Tom was Head of Americas - Infrastructure in the Investment Banking Division of UBS. In this role, Tom was the founding group head of the Americas Infrastructure advisory practice with responsibility for strategic advice, mergers and acquisitions, lending and capital markets finance for major investors. At UBS, he also held the roles of Co-Head of US Infrastructure and Managing Director - Power and Utilities. Previously, Tom worked as a Director in the Power and Utilities Group at Credit Suisse First Boston and as a First Vice President - Utilities Group at PaineWebber Incorporated.

Juan Payeras
Chief Investment Officer
International Finance Corporation

Juan Payeras is a Chief Investment Officer in the Infrastructure Department of the International Finance Corporation, based in Washington DC. IFC, a member of the World Bank Group, fosters sustainable economic growth in developing countries by supporting private sector development, mobilizing private capital, and providing advisory and risk mitigation services to businesses and governments. Mr. Payeras has worked on financing water and sanitation, gas transmission and distribution, and renewable energy projects for over 20 years at the International Finance Corporation, including solar PV, wind, and both small and large hydropower projects throughout Latin America. He is currently focused on financing renewable energy projects in Argentina. Mr. Payeras has an BSc degree in Finance and Multinational Management from the Wharton School and an MBA from the Stanford Graduate School of Business

John Plaster

Managing Director, Head of Alternative Energy, Global Power Group

John Plaster is a Managing Director in the Global Power Group and Head of Alternative Energy at Barclays, based in New York.

Mr. Plaster has over 20 years of investment banking experience with Barclays and Lehman Brothers. He has extensive experience with renewable energy companies, IPPs and regulated utilities across a wide spectrum of disciplines including financial advisory, equity and equity-linked finance, leveraged finance, structured finance, restructuring and commodities.

Recent advisory assignments include:

- Lead financial advisor to sPower and FirTree Partners for the $1.7 billion sale of sPower to AES and Aimco
- Lead financial advisor to Everpower and TerraFirma exploring strategic alternatives for Everpower (ongoing)
- Exclusive financial advisor to Welspun Renewable Energy for $1.4 billion sale to Tata Power
- Exclusive financial advisor to Dominion Resources for sale of 425 MW solar portfolio to Sun Edison
- Financial advisor to NRG Energy for $2.6 billion acquisition of Edison Mission Energy

Mr. Plaster holds a JD degree, highest honors - Order of the Coif - from Vanderbilt University Law School and a BA in Economics, cum laude, from Wabash College.

Ravi Purohit
Managing Director
Alinda Capital Partners

Ravi Purohit is a Managing Director at Alinda Capital Partners, an independent private investment firm with approximately $10 billion of assets under management for infrastructure investments, where he focuses on corporate transactions, financings, portfolio management, and other related matters. Prior to joining Alinda in March 2008, he was associated with Skadden, Arps, Slate, Meagher & Flom LLP for several years and focused on mergers, acquisitions, and corporate finance transactions.

Ravi received a J.D. from Columbia University School of Law in New York, NY where he was a Harlan Fiske Stone Scholar for multiple years, President of the Student Senate, and Senior Articles Editor for the Columbia Business Law Review. He also received a B.A. in Political Science and International Relations, with honors, from Emory University in Atlanta, GA and was elected to Phi Beta Kappa, Pi Sigma Alpha and Omicron Delta Epsilon honor societies.

He currently serves on the Board of Visitors for Columbia Law School, the Board of Directors of South Asian Youth Action, Inc., a non-profit South Asian-focused youth development organization for K-12 students in need of support in New York City, and the Board of Directors of Aarogya, a non-profit organization providing complimentary blood testing for the underprivileged in Rajasthan, India.

Marshal Salant
Managing Director
Head of Alternative Energy Finance
Citi

Marshal Salant is the Global Head of Citi's Alternative Energy Finance (AEF) Group in the Capital Markets Origination Division. AEF focuses on providing full service financing solutions to Citi's Alternative Energy clients, including Construction Financing, Project Debt Financing in the Bank and Bond Markets (144A and 4(2) Private Placements), Tax Equity, Leasing, and Project Equity, as well as commodities, interest rate, and FX hedging for renewable energy projects. AEF also structures and leads warehouse/aggregation facilities and subsequent ABS securitization financings for pools of leases and loans. AEF provides alternative energy project financing advice, and helps clients access various Loan Guarantee Programs and other government incentive programs for renewable energy projects. AEF is active in Wind, Solar, and Geothermal Power projects, as well as Fuel Cells, Biomass, Synfuels, Waste-to-energy, and other new renewable energy technologies, and Energy Efficiency financings.

Marshal joined Citi from Morgan Stanley, where he was a member of the Capital Markets Management Committee and Head of the Global Structured Products Group. Mr. Salant has broad experience as a financial engineer in Structured Finance and New Product Development of new and complex financial instruments. During his years at Morgan Stanley, Mr. Salant led the development of the Structured Notes business, the Collateralized Bond Obligations business, the Structured Credit business, the Structured Tax business, the Structured Insurance Products business and the FIG Client Solutions business. While at Morgan Stanley, Marshal had significant experience in Synfuel and Alternative Energy Tax Credit/Tax Equity financings in the Wind, Solar, and Geothermal sectors. Mr. Salant oversaw the investment of more than $2 billion in Tax Equity and developed new financing structures, as agent and as principal, for numerous clients in the Alternative Energy industry.

Mr. Salant is a Trustee of The Johns Hopkins University. He received his MBA, with Distinction, from The Harvard Business School and holds BA and BES Degrees, with Honors, in Mathematical Sciences, from The Johns Hopkins University.

Eric B. Sensenbrenner

Skadden

Partner, Washington D.C.

Co-Head of the Global Tax Group

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Education

LL.M., Georgetown University Law Center, 1997

J.D., DePaul University College of Law, 1996

B.A., Connecticut College, 1993

Bar Admissions

District of Columbia
Illinois

Eric Sensenbrenner, co-head of the firm's Global Tax Group, represents clients on a broad range of U.S. and international tax matters. With a particular emphasis on transactional tax planning in the international context, Mr. Sensenbrenner has extensive experience in assisting clients in the planning and execution of mergers, acquisitions and spin-offs, and in structuring cross-border investments and capital markets transactions.

Mr. Sensenbrenner has worked on tax matters for The AES Corporation, Apple Inc., Becton, Dickinson & Co., Broadcom Corporation, Eli Lilly and Company, EMC Corporation, Ford Motor Company, Hewlett-Packard Company, IBM Corporation, Pfizer Inc., Visa Inc. and Yahoo! Inc.

Mr. Sensenbrenner regularly advises U.S. and international multinational companies in connection with cross-border mergers and acquisitions, and post-acquisition restructuring and integration transactions, and represents clients in connection with structuring cross-border investments, including the formation of U.S. and foreign joint ventures. Mr. Sensenbrenner also regularly advises clients with respect to international tax planning matters generally, including subpart F, the foreign tax credit and transfer pricing. He is a frequent author and lecturer on topics related to corporate and international taxation.

Mr. Sensenbrenner repeatedly has been selected for inclusion in *Chambers Global: The World's Leading Lawyers for Business* and was selected in *Chambers USA: America's Leading Lawyers for Business 2016*. He was a member of the deal team recognized by the *Daily Journal* with a 2016 California Lawyer Attorneys of the Year award for innovative work on behalf of Broadcom Corporation in its acquisition by Avago Technologies, which was named the Americas Technology and Telecom Tax Deal of the Year at the 2016 International Tax Review Americas Awards.

Publications

Co-Author, "Proposed Treasury Regulations Dramatically Alter Existing Debt/Equity Law," *Skadden, Arps, Slate, Meagher & Flom LLP*, April 7, 2016

Co-Author, "City of Chicago Expands Tax Reach to Internet Services," *Skadden, Arps, Slate, Meagher & Flom LLP*, July 13, 2015

"The Code Sec. 367(d) Paradox: Peering into the Abyss From a Safe Distance," *Taxes - The Tax Magazine*, March 2015

"Inversions: The American Experience," *Columbia Journal of Tax Law*, '*Tax Matters*', Fall 2014

Co-Author, "OECD Outlines Plans to Prevent Double-Tax Treaty Abuse," *Skadden, Arps, Slate, Meagher & Flom LLP*, March 20, 2014

Co-Author, "US Inversions Through European Merger," *Tax Journal*, June 2013

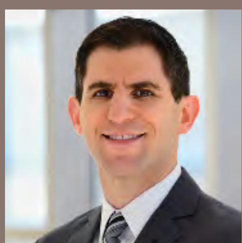
Co-Author "Sandwich Structures: The IRS Illuminates the Application of the DRD and Other Provisions," *International Tax Journal*, July-August 2010

Paul Schockett

Skadden

Counsel, Washington, D.C.

Tax



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Education

LL.M., New York University School of Law, 2006

J.D., Fordham University School of Law, 2005

B.S., Yale University, 2002

Bar Admissions

District of Columbia
New York

Paul Schockett advises public and private companies on a broad range of U.S. federal income tax matters, with particular focus on U.S. and cross-border transactions. Mr. Schockett's practice includes significant work involving the tax aspects of partnership acquisitions and dispositions, joint venture and investment fund formations, and corporate mergers and acquisitions. He also advises clients with regard to the taxation of debt and equity financings, initial public offerings, bankruptcy restructurings and internal reorganizations.

Mr. Schockett has worked on matters for Aflac Incorporated; Alcoa Inc.; ArcLight Capital Partners; Babcock & Brown Holdings Inc.; BlackRock Financial Management, Inc.; The Blackstone Group L.P.; Boise Inc.; Citigroup Inc.; Daimler AG; Deere & Company; Duke Energy Corporation; EMC Corporation; Ford Motor Company; Goldman Sachs; IBM Corporation; JLL Partners; Mars, Incorporated; Scripps Networks Interactive; State Street Bank & Trust; Textron Inc.; Visteon Corporation; and Yahoo! Inc.

Mr. Schockett frequently writes and lectures on tax-related topics, including partnership taxation, M&A transaction structuring, tax aspects of troubled company workouts, and renewable energy tax benefits.

Ethan M. Schultz

Skadden

Partner, Washington, D.C.

Energy and Infrastructure Projects

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Education
J.D., University of Pennsylvania Law School, 2005 (Executive Editor, *University of Pennsylvania Law Review*)

B.A., Rice University, 1999

Bar Admissions
District of Columbia
Pennsylvania
New Jersey

Associations
Law360, Project Finance Editorial Advisory Board (2013)

Government Service
Law Clerk, Hon. R. Barclay Surrick, U.S. District Court for the Eastern District of Pennsylvania (2005-2006)

Speaking Engagements
Panel Moderator, "Real World Aspects of Doing a Deal," Infocast Conference – Solar Power Finance & Investment 2015 (March 2015; San Diego, CA)

Ethan Schultz represents clients in connection with acquisitions and divestitures, joint ventures, financings, and other corporate and commercial transactions in the energy and infrastructure sectors. Mr. Schultz's clients include independent power producers, project developers, integrated utilities, private investment firms and financial institutions. His experience extends across a broad range of assets and services, including solar, wind, hydro, natural gas, coal, nuclear, LNG, petrochemicals and power marketing, as well as public-private partnerships involving toll roads and airports.

Recent representations include:

- First Solar in the:
  - formation and initial public offering of 8point3 Energy Partners, a new joint venture yieldco formed with SunPower, as well as in connection with 8point3 Energy Partner's $325 million term loan and revolving credit facilities;
  - construction and sale of joint venture interests in the North Star, Lost Hills and Desert Stateline solar projects to an affiliate of Southern Power Company;
  - construction and sale to MidAmerican Energy Holdings Company of the 550 MW Topaz solar project;
  - $967 million financing, construction and sale to NRG Energy of the 290 MW Agua Caliente solar project in Arizona; and
  - $646 million financing, construction and sale to Exelon of Antelope Valley Solar Ranch One, a 230 MW solar project in California.
- JPMorgan Asset Management in the acquisition of a 50 percent joint venture interest in Sonnedix Power Holdings, an independent solar power producer with projects in Spain, Italy, France, the U.K., Thailand, Japan, Puerto Rico, Chile and South Africa;
- Emera Energy in the:
  - $223.3 million sale of its 49 percent interest in Northeast Wind Partners, a 419 MW portfolio of wind projects, to First Wind Holdings; and
  - $541 million purchase of a 1,050 MW portfolio of three combined-cycle gas-fired generating facilities from Capital Power Corporation.
- ArcLight Capital in the:
  - sale to Carlyle Power Partners of a 50.1 percent interest in Southeast PowerGen, a 2,800 MW portfolio of gas-fired peaking plants;
  - acquisition by Southeast PowerGen of Mid-Georgia Cogen, L.P., a 308 MW gas-fired peaker, from Perennial Power Holdings; and
  - purchase of Mackinaw Power and AL Sandersville, a 2.5 GW portfolio of gas-fired generating facilities, and the related acquisition financings.
- InterGen in its purchase from IEnova of a 50 percent interest in Energía Sierra Juárez, a 155-MW wind facility and the first cross-border renewable project in Mexico;

- NorthWestern Energy in its $900 million purchase from PPL Corporation of a 633 MW portfolio of 11 hydroelectric generating facilities located in Montana;
- the U.S. Department of Transportation, as lender under the TIFIA program, in connection with the $1.9 billion financing of the Dulles Corridor Metrorail Project (Silver Line Phase 2);
- SunEdison in connection with the refinancing of its $265 million senior secured letter of credit facility, and SunEdison Semiconductor Limited in connection with its $260 million senior secured term loan and revolving credit facilities;
- InterGen in connection with the $1.8 billion refinancing of its senior secured debt and credit facilities, including a five-year two-tranche revolving credit facility ($350 million and £100 million), seven-year $300 million term loan, eight-year £175 million notes and 10-year $750 million notes;
- Électricité de France in connection with its $4.5 billion acquisition of a 49.99 percent interest in Constellation's nuclear generation business;
- Peru LNG, a joint venture between Hunt Oil, SK, Repsol and Marubeni, in the development and financing of a $4 billion LNG liquefaction facility and gas pipeline in Peru;
- the New Jersey State Treasurer in connection with the proposed $35 billion privatization of the state's toll roads; and
- the lenders to Midway Investment and Development Company LLC, the preferred bidder selected by the City of Chicago in connection with the $2.5 billion privatization of Midway airport.

Prior to law school, Mr. Schultz worked as a financial analyst for Enron Corporation and Project GRAD USA, a nonprofit focused on improving public education.

Sean Shimamoto

Skadden

Partner, Palo Alto

Tax

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Education

LL.M., New York University School of Law, 1997

J.D., University of Oregon School of Law, 1996

B.A., University of California, Los Angeles, 1993

Bar Admissions

California
District of Columbia

Sean Shimamoto, a partner in the firm's Palo Alto office, represents clients on a wide range of U.S. federal income tax matters, including mergers and acquisitions, partnership transactions and tax matters, various types of public and private debt and equity financing transactions, initial public offerings and restructuring transactions. Mr. Shimamoto represents both purchasers and sellers in connection with partnership acquisitions and dispositions and taxable and tax-free corporate transactions in the U.S. and cross-border contexts. Mr. Shimamoto also represents clients in connection with private letter ruling requests submitted to the Internal Revenue Service.

In addition, Mr. Shimamoto advises clients in the energy sector on a variety of tax matters involving the structuring, development, acquisition and/or disposition of renewable energy projects, and the related project financing, including the qualification for and monetization of tax credits and other tax benefits associated with such projects.

Mr. Shimamoto frequently writes and lectures on tax-related topics, including in programs sponsored by the American Bar Association, Federal Bar Association, Practising Law Institute, Tax Executives Institute and other organizations.

Selected representations include:

- **Lattice Semiconductor Corporation** in its $1.3 billion acquisition by Canyon Bridge Capital Partners Inc.;
- **First Solar, Inc.** in connection with the formation and initial public offering of 8point3 Energy Partners LP, a joint venture yieldco with SunPower;
- **Dynegy Inc.** and **Energy Capital Partners** (ECP) in connection with their $3.3 billion acquisition of ENGIE, S.A.'s U.S. fossil electric generation portfolio through a newly formed joint venture, Atlas Power, LLC. Also advising Dynegy in connection with the joint venture arrangements with ECP and ECP's related purchase of Dynegy's common stock for $150 million;
- **SunEdison, Inc.** in a first-of-its-kind, $1 billion "warehouse" debt financing that will fund the construction of its pipeline of renewable energy projects that it plans to drop down into its affiliated yieldco, TerraForm Power. The warehouse construction facility also included a $500 million third-party equity commitment from First Reserve Corporation;
- **NextEra Energy Partners, LP**, a growth-oriented limited partnership formed by NextEra Energy Inc. to own and operate clean energy projects, in its $467 million initial public offering of common units representing limited partner interests;
- **JPMorgan Infrastructure Investments Fund** in its acquisition of a 50 percent joint venture interest in Sonnedix Power Holdings;
- **DSP Merrill Lynch Limited**, **Axis Capital Limited**, **Edelweiss Financial Services Limited** and **YES Bank Limited** (as sole international counsel) as lead managers in the $163 million combined primary/secondary initial public offering and dual listing on the Bombay Stock Exchange and the National Stock Exchange in India of Inox Wind Limited (India), a provider of wind power solutions. The offering included a Rule 144A/Regulation S offering. This was the largest Indian IPO since June 2013;

- **J.P. Morgan Securities LLC** as sole bookrunner in a $2.3 billion Rule 144A/Regulation S high-yield offering of 9.75% senior secured notes due 2022 by FMG Resources (August 2006) Pty Ltd, a wholly owned subsidiary of Fortescue Metals Group Ltd (Australia), a producer of iron ore;
- **Barclays**, **Bank of America Merrill Lynch**, **BNP Paribas**, **Deutsche Bank**, **HSBC**, **Standard Chartered** and **DBS Bank Limited** as joint lead managers in a $1 billion Rule 144A/Regulation S offering of 4.375% senior notes due 2025 by Bharti Airtel Limited (India), a telecommunications company with operations in twenty countries across Asia and Africa. The notes were listed on the Singapore Stock Exchange;
- **TECO Energy, Inc.** in its $10.4 billion acquisition by Emera, Inc. (Canada); and
- **RPX Corporation** in its $232 million acquisition of Inventus Solutions, Inc. from investors led by Clearlake Capital Group, LP.

Selected Publications

"IRS Guidance Clarifies 'Begun Construction' Standard for Renewable Electricity Production Credit Property," *Skadden, Arps, Slate, Meagher & Flom LLP*, May 9, 2016

"Policies Accelerate Investment Shift Towards Renewable Energy," *Financier Worldwide*, April 2016

"Congress Extends Renewable Energy Tax Credits," *Skadden, Arps, Slate, Meagher & Flom LLP*, December 21, 2015

"An Overhaul Of Partnership Audit, Litigation Procedures," *Law360*, November 4, 2015

"Congress Overhauls Partnership Audit and Litigation Procedures," *Skadden, Arps, Slate, Meagher & Flom LLP*, November 3, 2015

"IRS Guidance Clarifies Renewable Energy Tax Credit," *Skadden, Arps, Slate, Meagher & Flom LLP*, August 12, 2014

"Renewable Energy REITs: A New Capital Source for Energy Funds and Developers," *Real Estate Finance Journal*, Summer 2013

"Green REITs, MLPs, and Up-Cs," *Fortnightly's Spark*, April 22, 2013

"IRS Guidance on the Commencement of Construction Requirements for Tax Credits for Qualified Energy Facilities," *Skadden, Arps, Slate, Meagher & Flom LLP*, April 17, 2013

"SEC Filing Illustrates Recent REIT Trend: Holding and Financing Renewable Energy Assets," *Skadden, Arps, Slate, Meagher & Flom LLP*, February 22, 2013

"Temporary 'Fiscal Cliff' Solution Yields Important Tax Changes," *Skadden, Arps, Slate, Meagher & Flom LLP*, January 3, 2013

James R. Stahle
Group Managing Director
CCA Group

Mr. Stahle is an original founding partner of CCA Group. He has been actively involved in the structured finance and asset finance business for over 28 years. His primary focus at CCA Group is working with institutional buy-side clients on acquisitions and investments in asset oriented transactions in the energy, infrastructure and transportation sectors. As the Managing Partner of CCA Group, he currently oversees the day to day activities of the firm, capital raising activities of the firm and its clients, and cultivating new institutional clients across the various business lines. Prior to establishing CCA Group, he was a Managing Director at Bank of Tokyo Mitsubishi, where he established the structured products platform to provide sell-side and buy-side advisory services to issuer and institutional clients, as well as syndication and distribution on principal and issuer mandates. He originally started his career as a Syndication Manager at the Bank of New England, distributing tax and non-tax transactions to investors on energy and transportation projects and raising capital for middle market and industrial companies.

To date, Mr. Stahle has been involved in over $28 billion worth of asset and project finance transactions as either a principal or advisor in renewable energy projects, oil and gas resource investments, thermal generation, transportation assets (commercial and industrial) and energy infrastructure for U.S. and foreign companies. Recent engagements advising on include multiple partnership investments in residential solar portfolios, raising capital from institutional investors utilizing Hybrid Joint Venture tax partnership structure on large scale utility solar projects and advising a number of new institutional investor clients on wind tax equity investments in the US market. His institutional clients include U.S. and foreign multinationals, domestic and international insurance companies, U.S. financial institutions, private equity and hedge funds. He is currently a board member of the Melmark New England School and a corporator serving the Hallmark Health Group. He holds a B.S. in Economics and Business Administration from Colby College.

He holds Series 7, 24, 63 and 79 licenses and is the President of CCA Capital LLC, the FINRA-registered broker dealer subsidiary of the CCA Group, LLC.

Carl Weatherley-White
CFO
VivoPower International PLC

Carl is CFO of VivoPower International PLC (NASDAQ: VVPR), which successfully completed an initial public offering in December 2016. He is responsible for US business development, capital raising, and the Company's financial reporting obligations. VivoPower recently announced the formation of a joint venture to develop 1.8 GW of utility scale solar projects in the US.

Previously he was President of Lightbeam Electric Company, a renewable energy company which completed the registration for an initial public offering (withdrawn due to market conditions In December 2015).

He was previously CFO for K Road Power Holdings, a private development portfolio company of Barclays, which successfully developed and sold 400 MW of solar power projects over a 2 year period.

He was global head of project finance at Barclays Capital and Lehman Brothers, and had over 15 years of project and tax equity financing experience at Credit Suisse.

A graduate of Brown University and the University of Cape Town, he is a CFA charterholder.

Pat Wood
Principal
Wood3 Resources

Pat Wood, III is Principal of Wood3 Resources, focusing on development of electric power and natural gas infrastructure. In addition to his work with Hunt Power/InfraREIT in power transmission, Wood is Board Chairman of independent power producer Dynegy, Lead Director of solar firm SunPower and Director of utility contractor Quanta Services.

Known for his vigorous advocacy of customer-focused competitive markets as a replacement for government regulation, Wood served under George W. Bush as Chairman of both the Public Utility Commission of Texas and the Federal Energy Regulatory Commission. He led the construction of the nation's most successful competitive electric market (Texas) and, while heading FERC, he expanded wholesale power competition across more than two-thirds of the nation's economy.

Wood has a B.S. in civil engineering from Texas A&M University and a J.D. from Harvard Law School. He and his wife, Kathleen, and their four sons are proud to call Houston home.

Raymond S. Wood

Managing Director, Global Head of Power, Utilities & Renewables

Ray serves as a Managing Director and Head of the Global Power, Utilities & Renewables Group at Bank of America Merrill Lynch. He leads coverage teams across the industry landscape of regulated utilities, independent power, clean energy and global manufacturing as well as private equity and infrastructure sponsors. Over Mr. Wood's 27-year career, he has assisted clients on noteworthy strategic transactions and financings, a number of which have been named "Deal of the Year." He has transaction expertise across the spectrum of mergers and acquisitions, initial public offerings, leveraged finance, structured finance, commodities and privatizations.

Recent Transaction/sector focus includes:

- Utility M&A and strategic advisory
- Yield Co(s) (Public & Private)
- Distributed generation
- Development companies (Wind, Solar & Storage) capital formation & monetization
- Gas fired generation recapitalization & monetization
- Cross border M&A/flotations

He received an M.B.A. from the MIT, Sloan School of Management and a B.A. from Dartmouth College. He serves on the following Board of Directors: AWEA, ACORE, MIT Sustainability Initiative and MIT Sloan North America Advisory Board as well as a BAML liaison to Stanford's Global Climate & Energy Policy Group.

U.S. Infrastructure Financing and Investment Panel

Lance T. Brasher, Joshua B. Nickerson

May 9, 2017

Current Status of U.S. Infrastructure

Skadden

- ASCE 2017 Infrastructure Report Card (March 9, 2017)
  - Overall Grade: **D+**
  - Most Recent Prior Grade (2013): **D+**
- Estimated $4.59 trillion needed by 2025 to raise grade to “**B**” (good, adequate for now)
- At current spending levels, investment shortfall of approx. **$2 trillion** over the next decade (2016-2025)
- Brookings: Annual government investment in public works has fallen by almost two-thirds (in terms of share of the economy) from 1980-2015

Private Investment in "Public" Infrastructure ("P3s")

- **Current Revenue Models:**
  - User Fees/Revenue Risk
  - Availability Payments/Capacity Payments

- **Asset Classes:**
  - Roads & Bridges
  - Rail
  - Transit
  - Water
  - Airports
  - Seaports
  - Parking
  - Universities (e.g., energy systems, parking, housing, etc.)
  - Social (e.g., courthouses)

Key Financing Programs that Support P3 Investments

- **TIFIA** - Transportation Infrastructure Finance and Innovation Act of 1998
- **PABs** - Private Activity Bonds
- **RRIF** - Railroad Rehabilitation & Improvement Financing Program
- **WIFIA(?)** – Water Infrastructure Finance and Innovation Act of 2014

Priority List – Emergency & National Security Projects[1]

Skadden

- **Energy (7 Projects)**
  - Chokecherry and Sierra Madre Wind Energy/Wyoming ($5 billion)
  - Atlantic Coast Pipeline ($4.5 - $5 billion)
  - TransWest Express Transmission ($3 billion)
  - Plains and Eastern Electric Transmission Line ($2.5 billion)
  - Champlain Hudson Power Express ($2.2 billion)
- **Roads & Bridges (11 Projects)**
  - 15 Bridges on I-95, Philadelphia ($8 billion)
  - Gordie Howe International Bridge ($4.5 billion)
  - Brent Spence Bridge ($2.5 billion)
  - Colorado I-70 Mountain Corridor ($1 billion)

[1] *Source: "Priority List – Emergency & National Security Projects*," by CG/LA Infrastructure, January 2017

Priority List – Emergency & National Security Projects (cont'd)

- **Rail & Transit (11 Projects)**
  - Gateway Program ($12 billion)
  - Texas Central High Speed Railway (12 billion)
  - Maryland Purple Line ($5.6 billion)
- **Water/Ports/River Transportation (16 Projects)**
  - Huntington Beach Desalination Plant ($350 million)
  - Port Newark Container Terminal Improvements ($500 million)
  - Augustin Plains Ranch underground water storage project ($600 million)
- **Airports/Aviation (4 Projects)**
  - Seattle Airport Expansion ($2 billion)
  - St. Louis Airport ($1.8 billion)
  - NextGen Air Traffic Control System ($10 billion)
- **Other (1 Project)**
  - National Research Lab for Infrastructure ($2 billion)

The “Complications” of Business Tax Reform

Eric B. Sensenbrenner, Paul W. Oosterhuis, Sean Shimamoto
May 9, 2017

Where Are We Now & How Did We Get Here?

- Ways and Means Chairman Dave Camp spent 2011 to 2014 developing a comprehensive tax reform bill (H.R.1 in the 113th Congress)
  - Top rate for corporations reduced to 25 percent; phased in over 5 years
  - Slower depreciation & amortization; 95% DRD for dividends from related foreign corporations; expands Subpart F
- Spring of 2016:
  - Speaker Ryan pushes for “visionary” proposals on tax reform to be a Republican Blueprint for 2016 elections
- June 2016 House Blueprint on tax reform outlines destination-based cash flow tax
  - Parallels President Bush’s 2005 Advisory Panel on Tax Reform proposal for Growth and Investment Tax (“GIT”)
  - Builds on thinking of Michael Devereux, Alan Auerbach and others for a “corporate tax for the 21st century”
  - Key Blueprint Features
    - Replace business income tax with a cash-flow tax that expenses all purchases and denies interest deductions
    - Makes tax destination-based by denying deduction for (or taxing) import costs and exempting export revenues
    - Taxes financial transactions (and financial institutions) on an income tax basis
    - Exempts related party dividends and capital gains, including from CFCs
    - Repeals subpart F provisions other than the foreign personal holding company rules
    - Reduces top individual rates to 33%, corporate rates to 20% and unincorporated business rates to 25%
- April 2017:
  - While House releases new tax proposal in a one-page summary

House GOP Blueprint & Trump Plan Compared

Skadden

Business Taxes	House GOP Blueprint	Trump Plan
Top corporate tax rate	20%	15%
Corporate AMT	Repealed	Unclear
Top pass-through rate	25%	15%
Future foreign earnings	▪ Exemption for exports and foreign-derived profits ▪ Exemption for dividends paid from foreign subsidiaries	“Territorial tax system to level the playing field for American companies”
Cost of imported goods	Disallows deductions for payments to foreign sellers	Unclear
Accumulated foreign earnings	Deemed taxable repatriation ▪ 8.75% for cash and equivalents ▪ 3.50% otherwise	“One-time tax on trillions of dollars held overseas”
Cost recovery	Immediate expensing only	Elective expensing for manufacturers
Interest on future loans	Net expense non-deductible	Unclear
Other business provisions	▪ Preserves R&D credit and LIFO ▪ Eliminates other “special interest deductions and credits”	“Eliminate tax breaks for special interests”

House GOP Blueprint & Trump Plan Compared (cont'd)

Individual Taxes	House GOP Blueprint	Trump Plan
Individual income tax rates	12%, 25%, 33%	10%, 25%, 35%
Individual AMT	Repealed	Repealed
Dividends and long term capital gains	Ordinary income with 50% deduction, effectively creating 6%, 12.5%, 16.5% brackets	Unclear, but repeal 3.8% net investment income tax
Estate tax	Repealed	Repealed
Standard deduction	Increased by ~90%	Doubled
Dependent care expenses	▪ Eliminates personal exemptions ▪ $1,500 child tax credit ▪ $500 non-child dependent credit	"Providing tax relief for families with child and dependent care expenses"
Charitable contribution deduction	Unchanged	Unchanged
Mortgage interest deduction	Unchanged	Unchanged
Other itemized deductions	Eliminates all other itemized deductions	▪ "Eliminate targeted tax breaks that mainly benefit the wealthiest taxpayers" ▪ Previously proposed capping itemized deductions

Key Tax Reform Considerations for Energy

- Tax Rate
  - Top corporate income tax rate — 15% to 28%?
  - Top unincorporated business tax rate — 15% to 35%?
- Deductions
  - Accelerated depreciation eliminated to fund lower tax rate?
  - Expensing of capital expenditures / no depreciation?
  - Non-deductibility of interest?
- Credits
  - Investment tax credit & production tax credits?
- Border Adjustments
  - No deduction for imported materials?

Next Steps

- Ways & Means hearings in May
- Fiscal 2018 budget June/July
- Other key dates
  - Memorial Day; 4th of July; August recess; etc.
- Necessary steps
  - Ways & Means markup
  - House floor action
  - Finance Committee markup
  - Senate floor action
  - Conference
- Budget reconciliation procedural restrictions
- Republican Goal: Enactment by end of 2017 or February 2018 at the latest

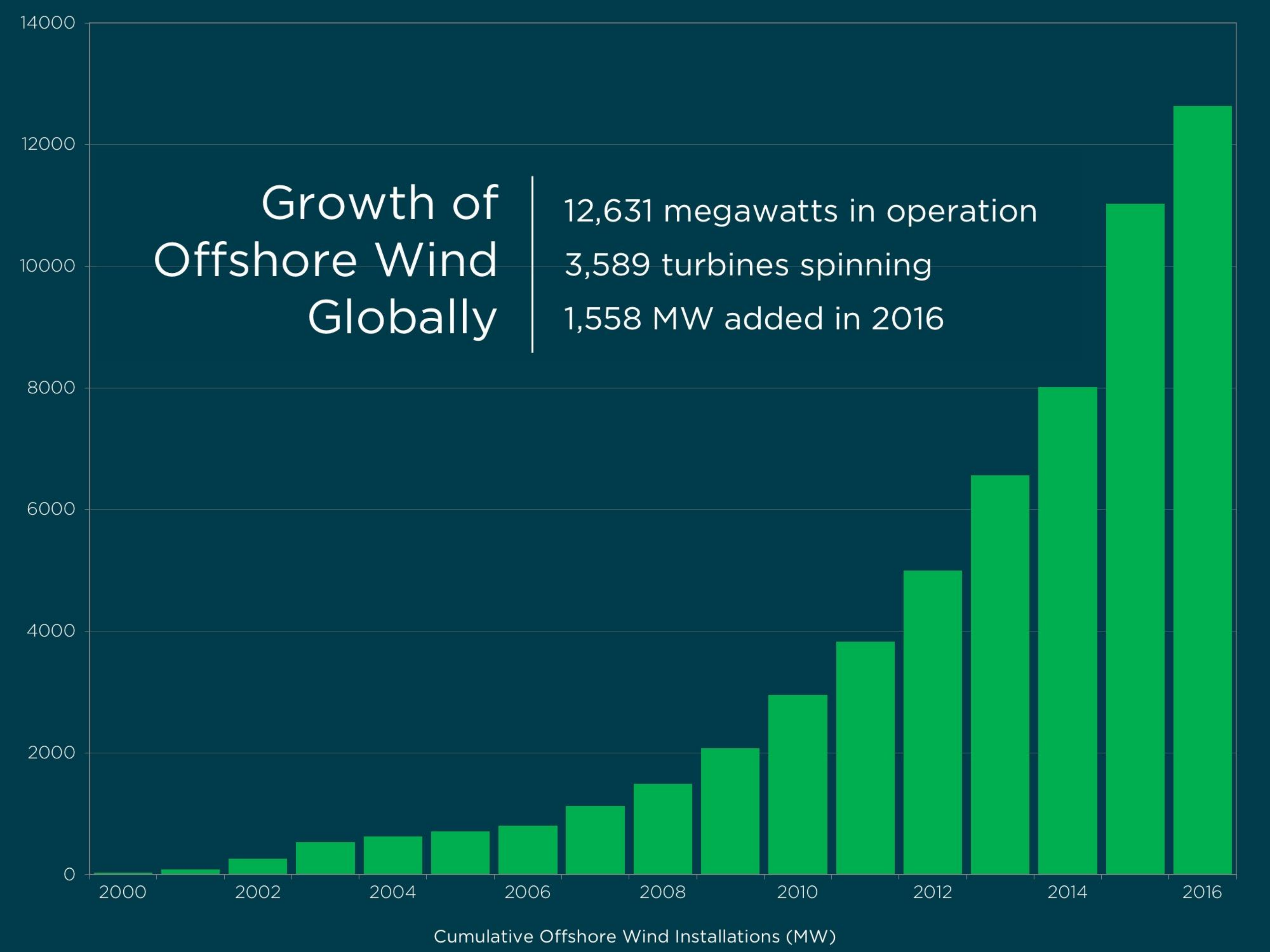

DEEPWATERWIND
Clean energy is just over the horizon.
Launching the U.S.
Offshore Wind
Industry

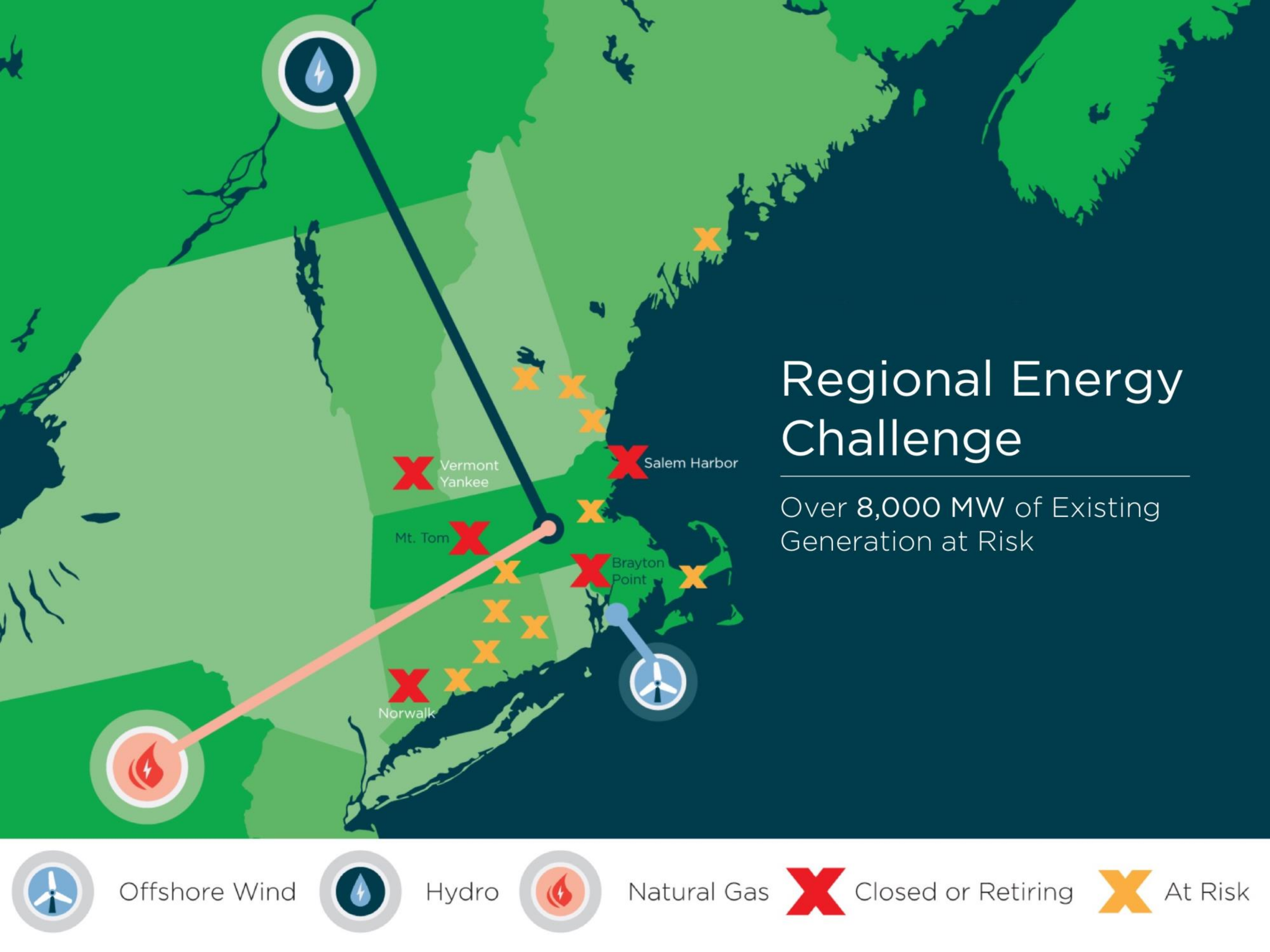
DEEPWATERWIND
Clean energy is just over the horizon.

- Developer of America’s first offshore wind farm
- Owner of three federal leases off the Atlantic Coast with over 2,000 MW of capacity

D E Shaw & Co

- Principal owner of Deepwater Wind
- More than $41 billion in investment capital as of January 1, 2017
- Leading US renewables owner with over $10 billion of raised capital for renewables

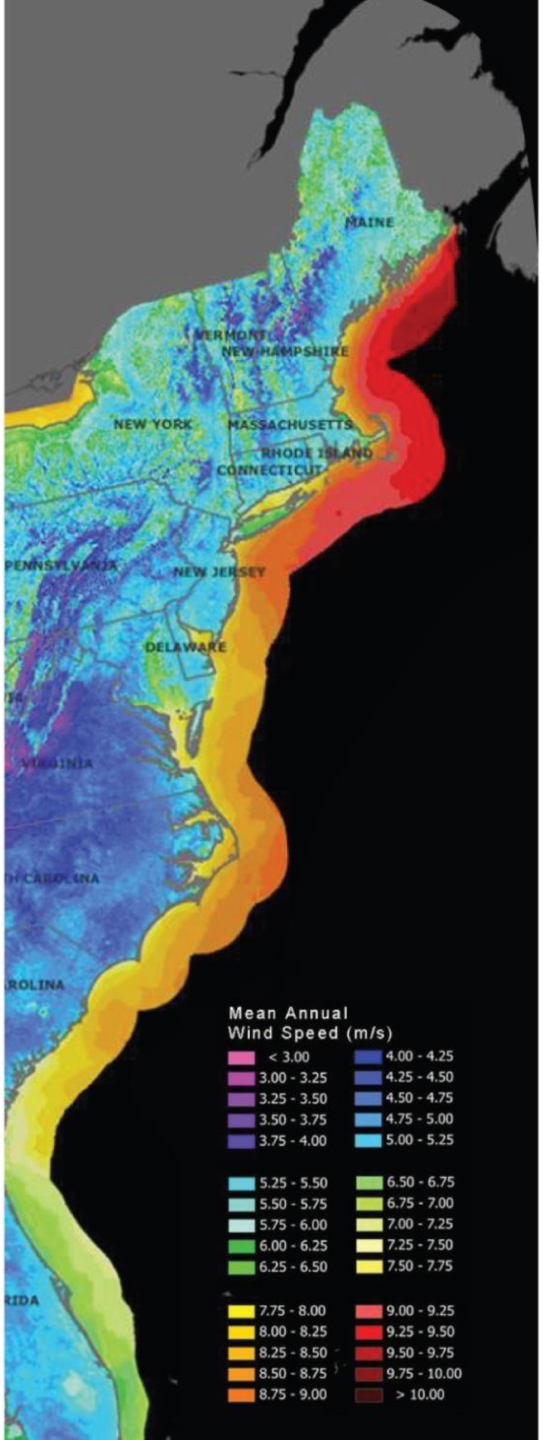

Growth of Offshore Wind Globally
12,631 megawatts in operation
3,589 turbines spinning
1,558 MW added in 2016
14000
12000
10000
8000
6000
4000
2000
0
2000
2002
2004
2006
2008
2010
2012
2014
2016
Cumulative Offshore Wind Installations (MW)



Regional Energy Challenge
Over 8,000 MW of Existing Generation at Risk
Vermont Yankee
Salem Harbor
Mt. Tom
Brayton Point
Norwalk
Offshore Wind
Hydro
Natural Gas
Closed or Retiring
At Risk

The Potential

Offshore wind delivers energy when and where it's needed most.




BLOCK ISLAND WIND FARM
America's First Offshore Wind Farm
Final day of installation
August 18, 2016

America's First Offshore Wind Farm is Now Operating

2008 Project proposed

2011 Final revenue contract approved

2012 Permit applications submitted

2014 Final permits approved

2015 Offshore installation begins

2016 Commercial operations

clf
conservation law foundation

Deepwater Wind

"Going Above and Beyond"

Tapping into the US Offshore Industry | Building Foundations in the Gulf of Mexico

GULF ISLAND FABRICATION, INC.

OFFSHORE MARINE CONTRACTORS OMC

Keystone ENGINEERING INC.

MONTCO OFFSHORE

ABS

The Result | A Commercial Model that Works

BLOCK ISLAND WIND FARM
America's First Offshore Wind Farm

D E Shaw & Co

Long-term Committed Owners

citi

Tax Equity Investors

GE Energy Financial Services

PFI AWARDS 2015

Project Finance International
Renewables Deal of the Year

SOCIETE GENERALE

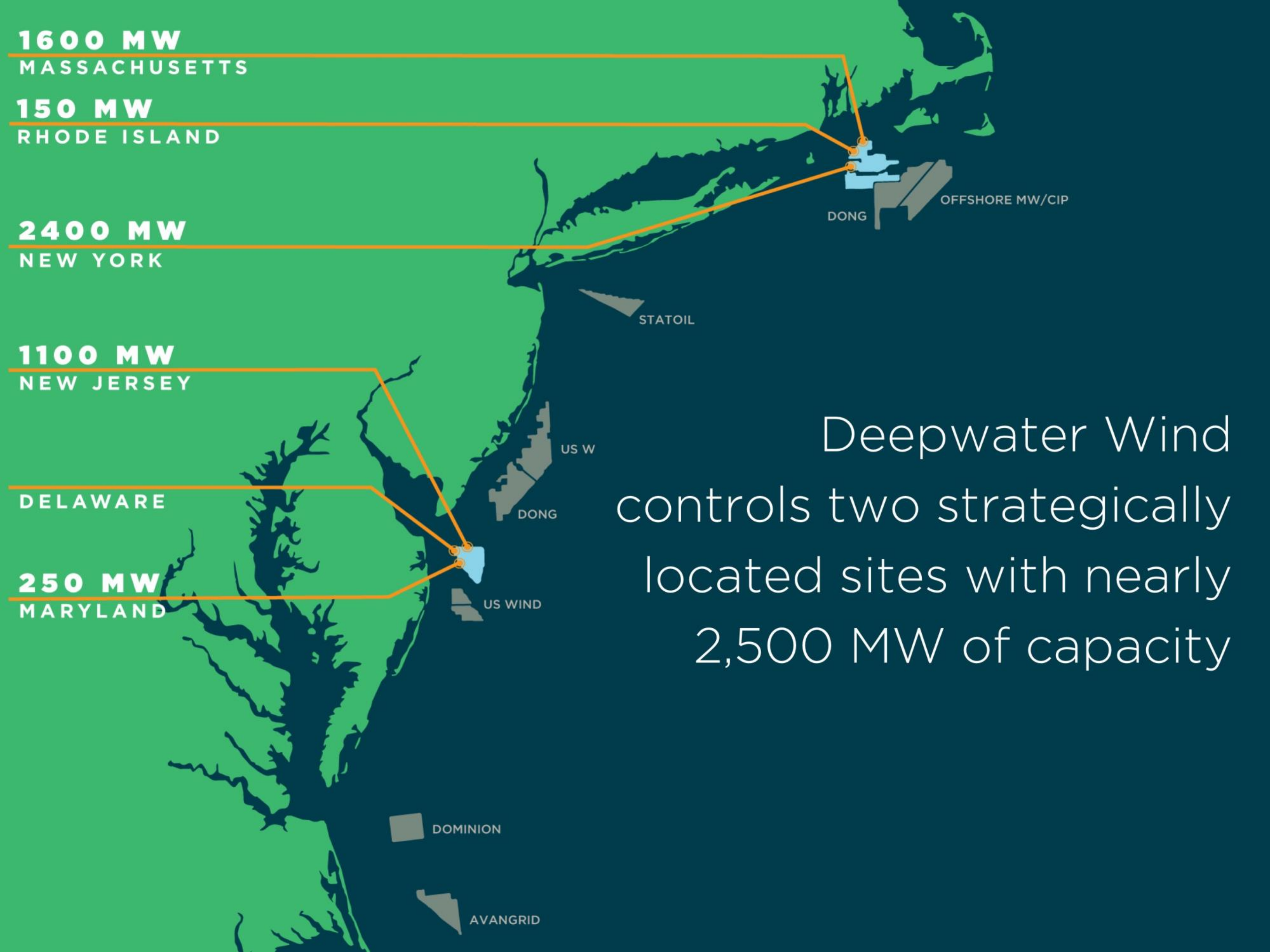
HSBC

SMBC

KeyBank

"la Caixa"

CoBANK



Deepwater Wind controls two strategically located sites with nearly 2,500 MW of capacity

15 turbines.

50,000 homes.

PPA approved January 2017.

Project coming online in 2022.

SOUTH FORK WIND FARM

SKIPJACK
WIND FARM

15 turbines.

Just over the horizon.

Affordable clean energy.

A local taxpayer.

1. Local government support through multiple elections
2. Power contract that works for a U.S. utility
3. Multi-agency and multi-governmental permitting approvals
4. Direct negotiation and compromise with stakeholders
5. Multiple primes contracting using U.S. firms and workers
6. Nimble legal strategies

Mastering an American Model for Offshore Wind

Power and Oil & Gas Market Update

FILSINGER ENERGY PARTNERS

May 2017

Todd Filsinger
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www.filsingerenergy.com
303.974.5884

Disclaimer

The contents of this document are the opinions of Filsinger Energy Partners (FEP) and represent our understanding of various markets and analysis of market conditions. It is entirely based on our interpretation of publicly available information.

Nothing in this presentation should be interpreted as a prediction of future prices or market clearing results.

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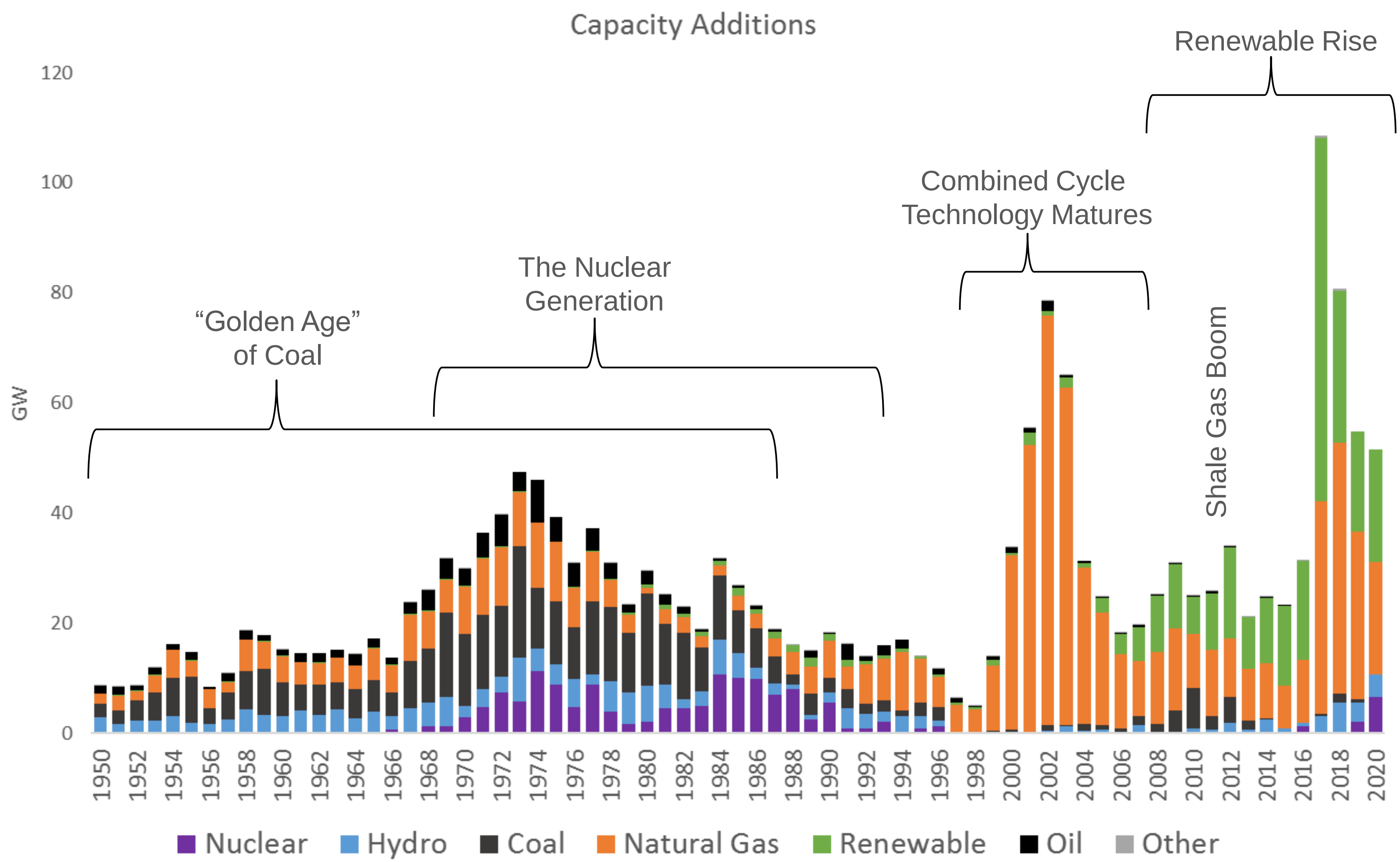
Impacts on Power Prices

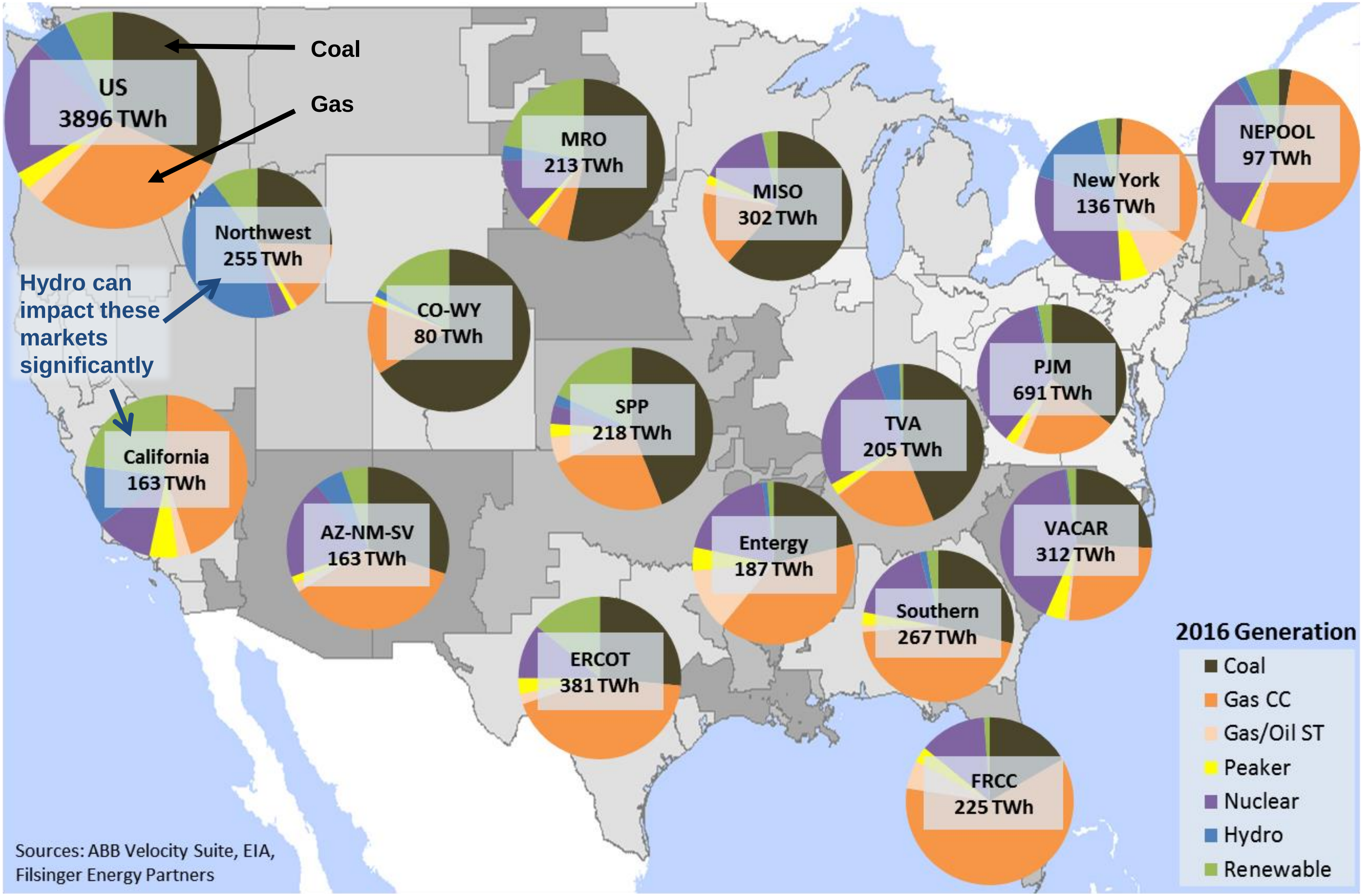
Where Do We Go From Here?

Generation has shifted over time



2017+ includes proposed and pending plant development

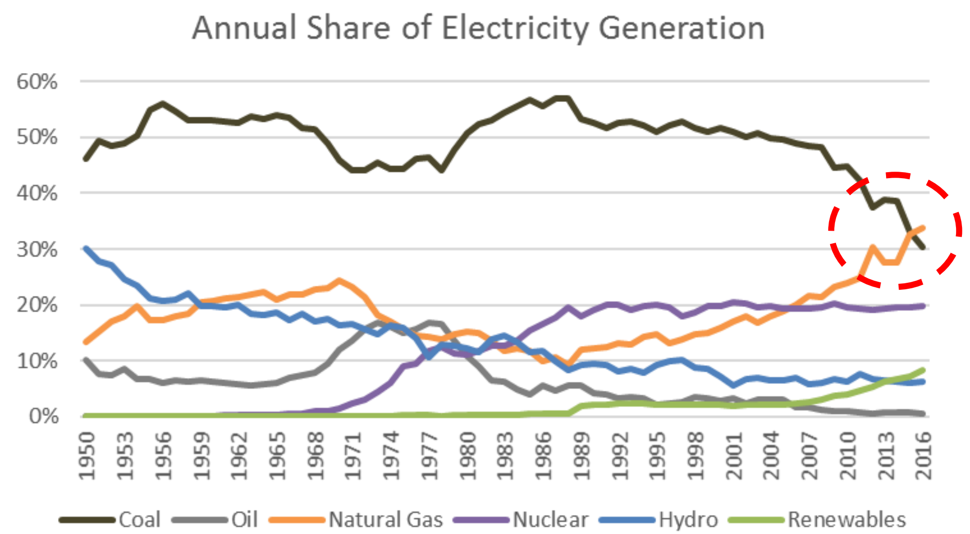
Energy from coal has dropped in recent years

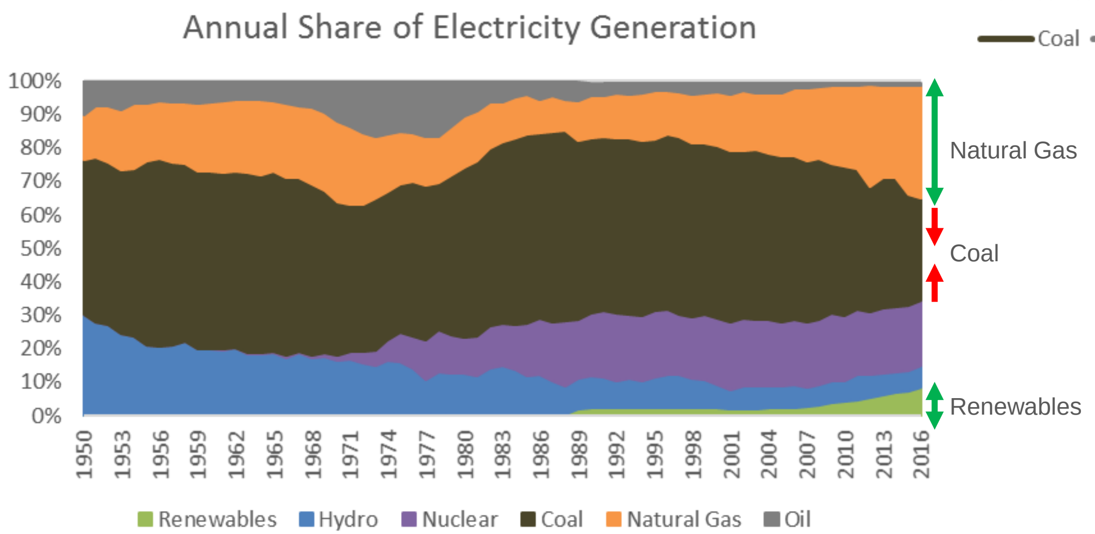


Source: ABB Velocity Suite, EIA, FEP

Natural gas and renewables have taken greater shares of the U.S. electricity markets

Since the early 2000s, generation from coal has been in continuous decline, with natural gas and renewables rapidly expanding





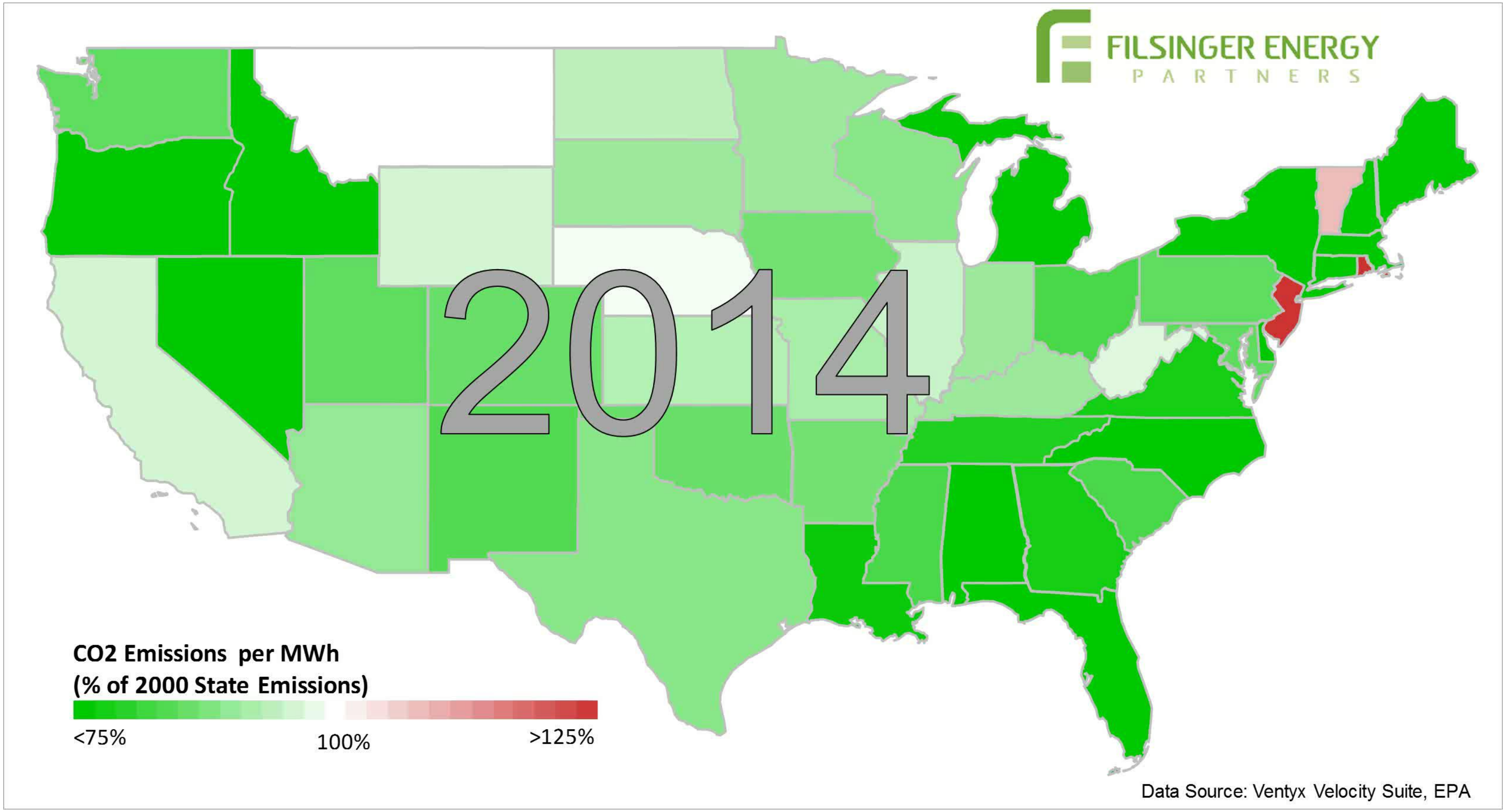
In 2016, generation from natural gas exceeded coal generation for the first time

Underlying fuel costs and environmental regulations have driven down coal's share of production

Source: EIA

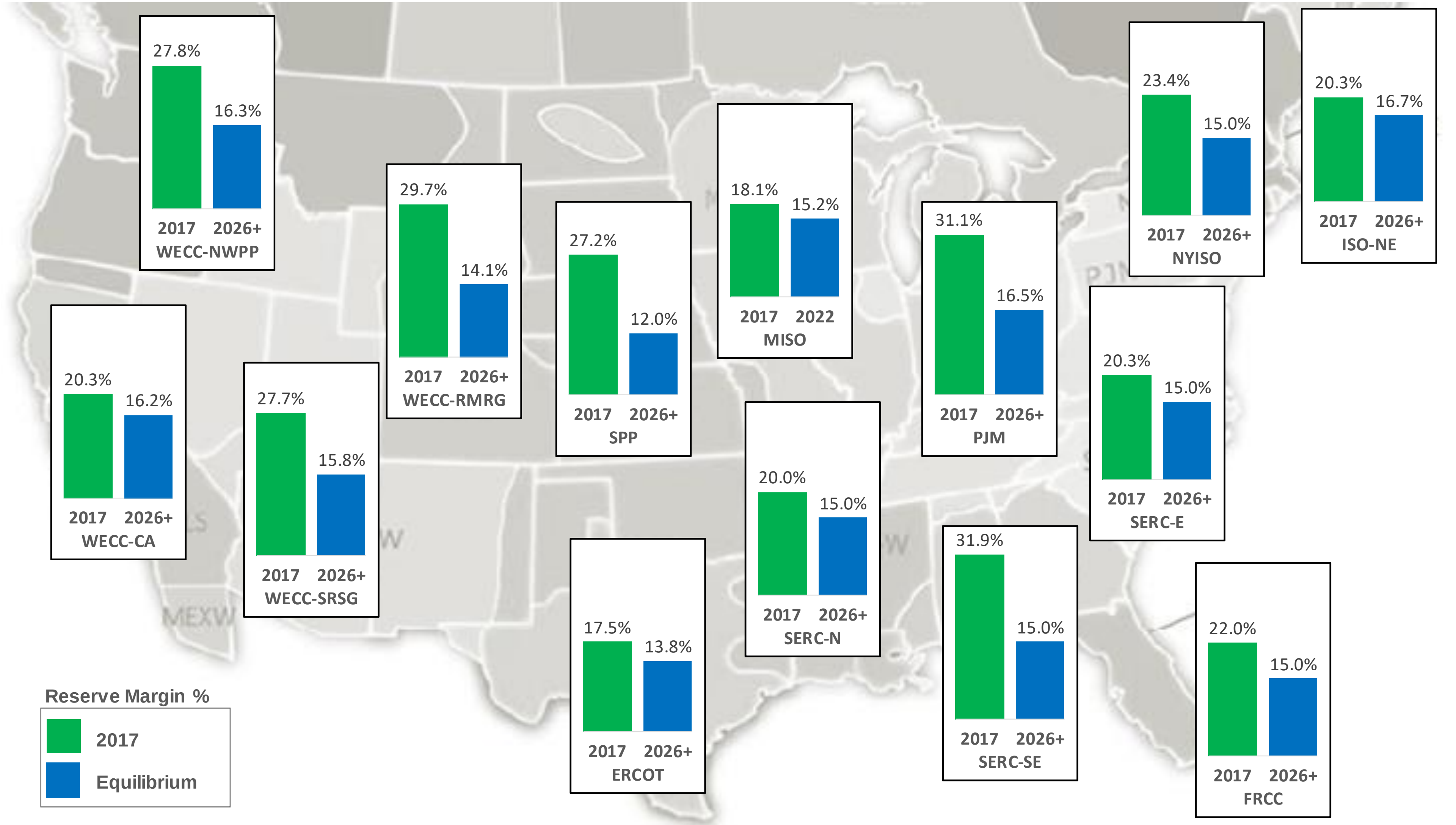
The shift in coal to natural gas generation has already impacted the U.S. carbon footprint

Video:



Higher natural gas and renewable utilization has resulted in lower carbon emission intensities

At the same time, the U.S. markets are overbuilt



Updated: December 29, 2016
Source: NERC 2016 LTRA, FEP

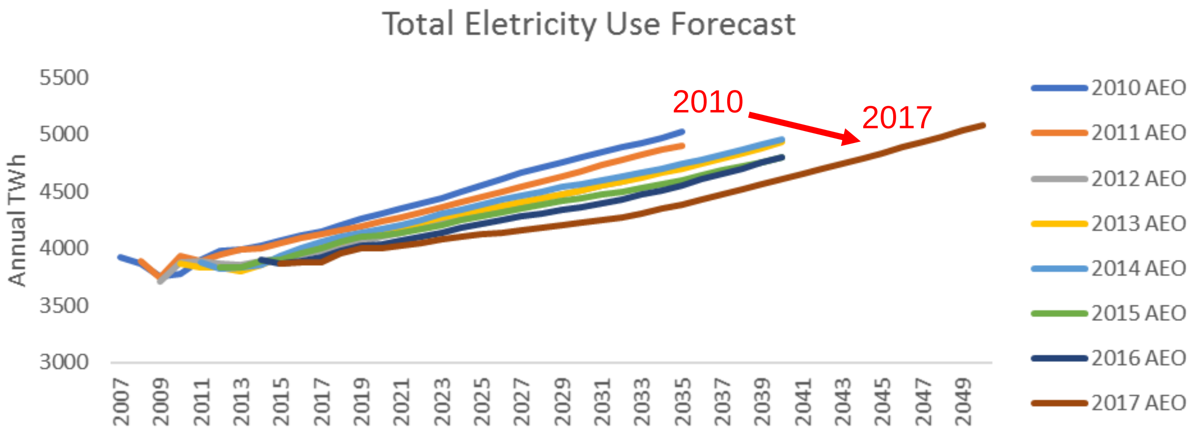
In the past, load growth would drive recoveries…

EIA projects long-term load growth ~0.8% per year

NERC's 2016 Long-Term Reliability Assessment projects NERC-wide annual demand growth of 0.73% for summer and 0.72% for winter.

These are the **lowest demand growth rates on record** in NERC LTRAs.

The EIA's Annual Energy Outlook demand forecasts have been declining with each new release



Source: EIA, NERC

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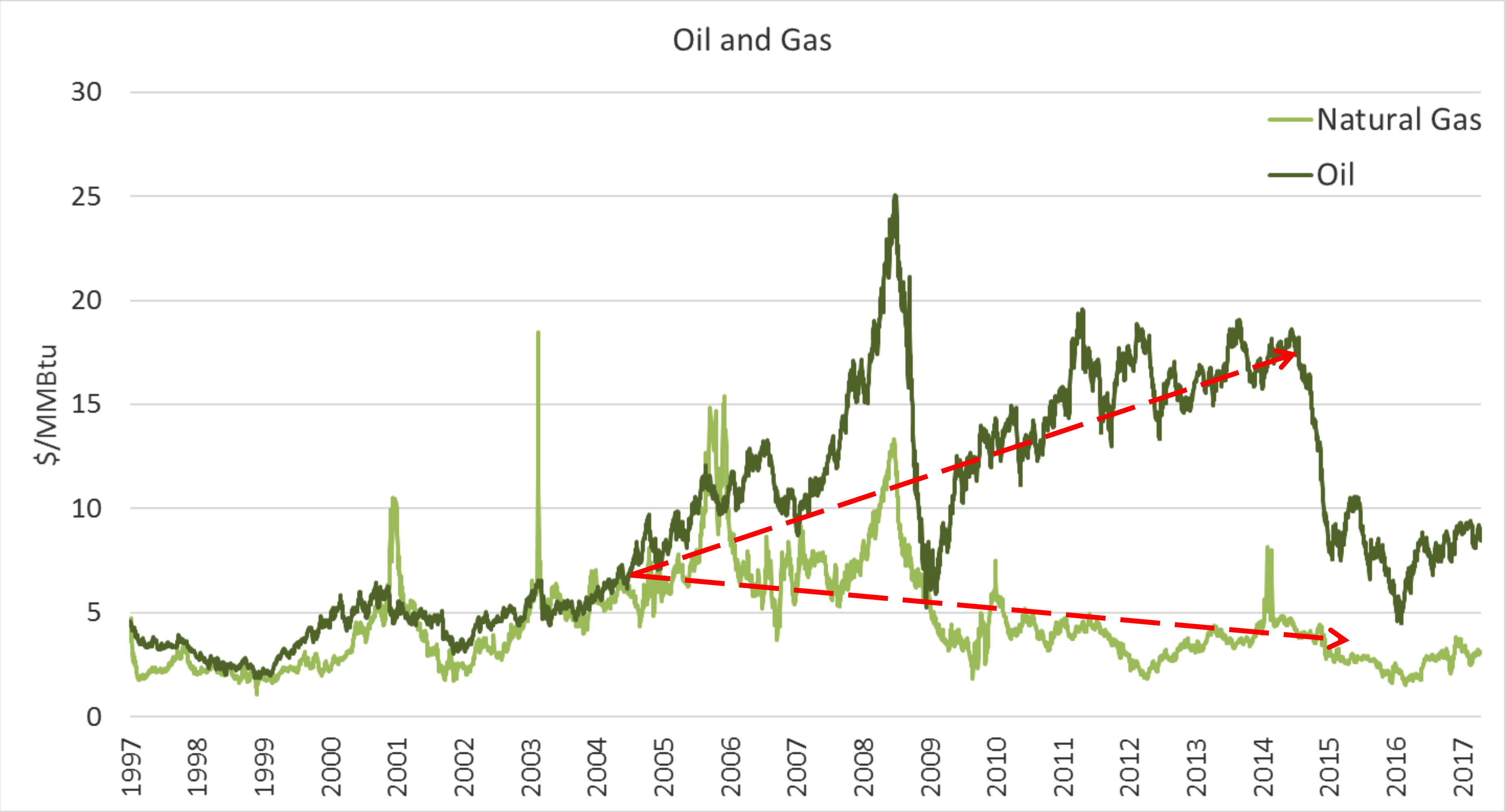
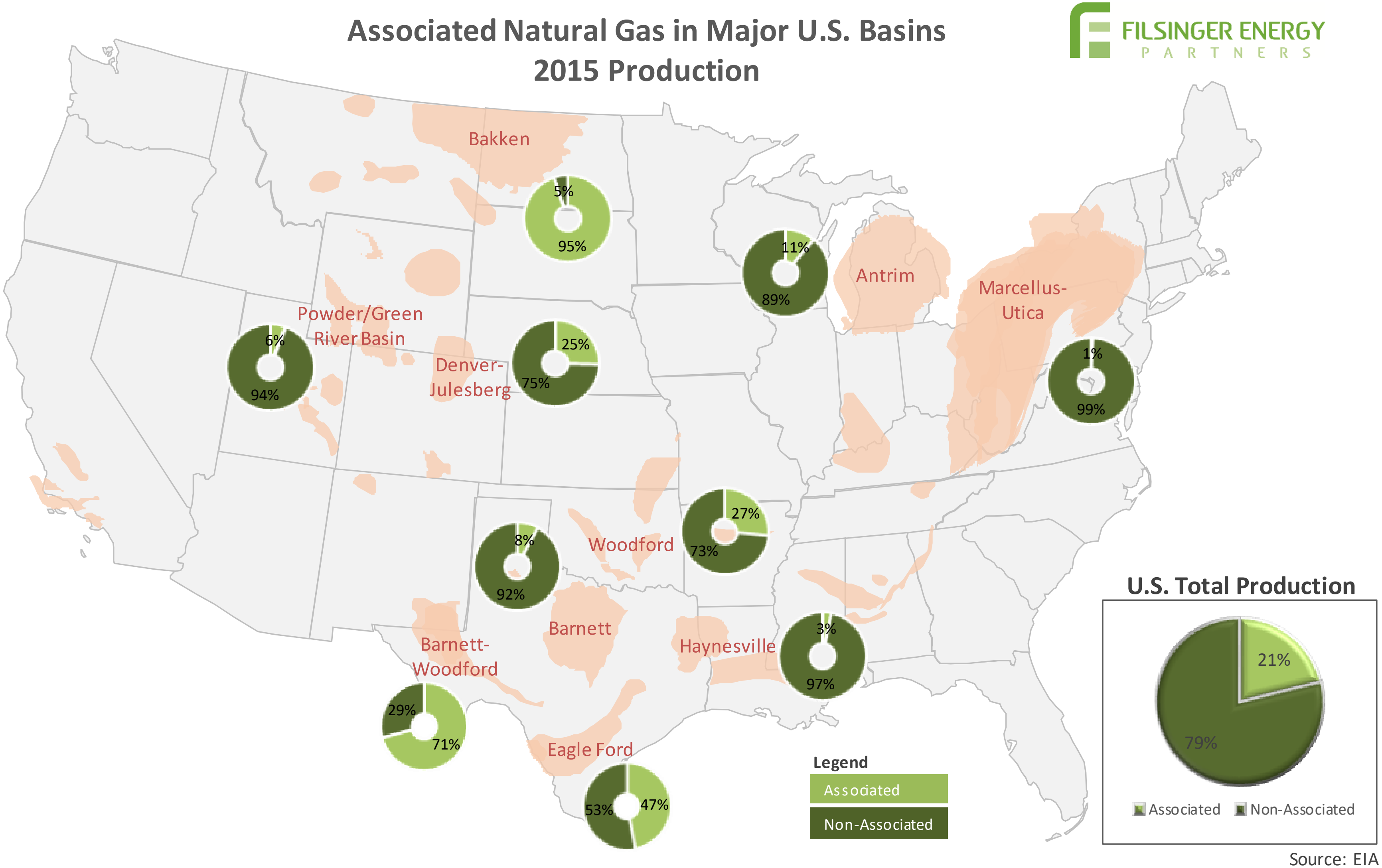
The dynamics between natural gas and oil prices have shifted over time



Natural Gas and Oil prices have nearly doubled since their respective lows in the beginning of 2016

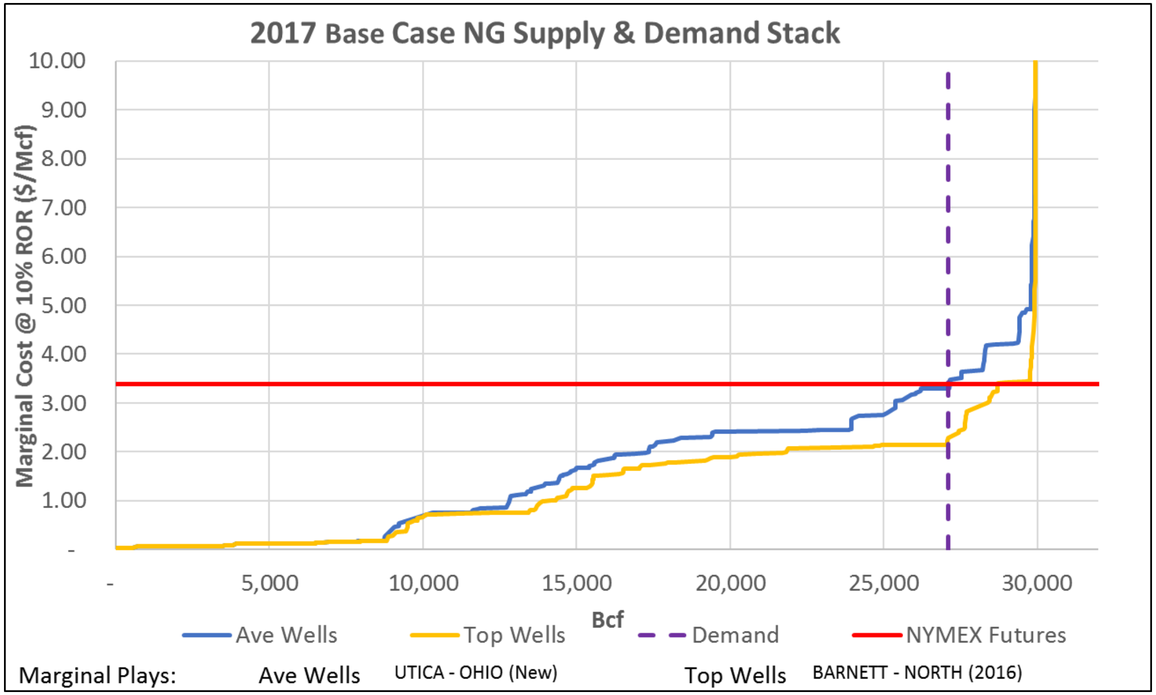
Data shown through April 24, 2017
Source: EIA

The level of "associated natural gas" varies



Source: EIA, FEP

Hence, natural gas breakeven costs at many plays remain low



2017 Break-Even Cost Estimates

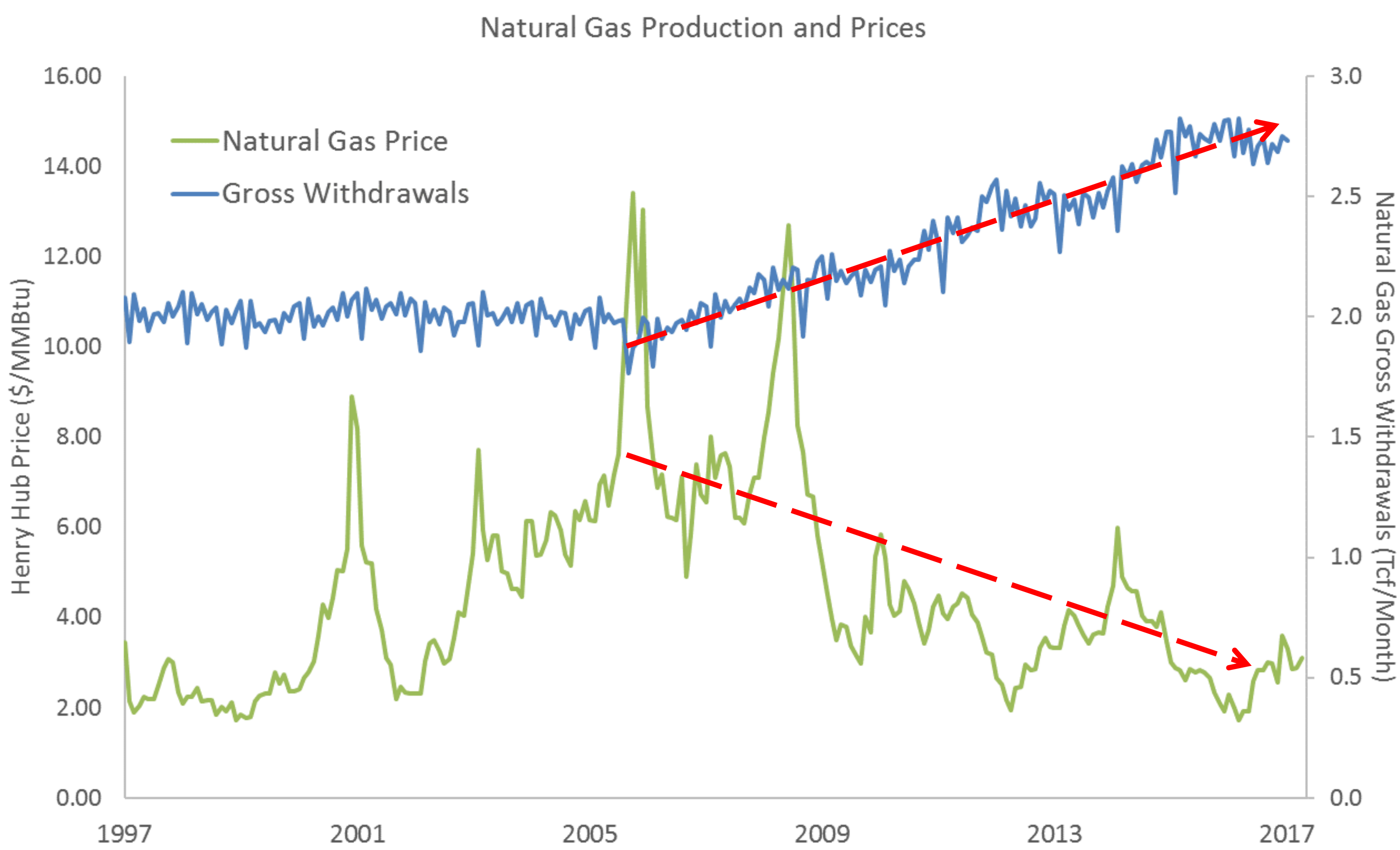
Play	Low	High
Bakken	$0.03	$0.21
Gulf of Mexico	$0.06	$0.06
Eagle Ford	$0.07	$0.42
Permian	$0.13	$0.13
Scoop	$0.15	$0.15
Niobrara	$0.15	$0.87
Mississippian Lime	$0.15	$0.15
Utica	$1.36	$4.45
Pinedale	$1.45	$2.80
Marcellus	$1.66	$2.75
Barnett	$1.69	$6.88
Haynesville	$1.76	$3.78
Woodford	$2.53	$6.10
Granite Wash	$3.04	$8.90

Values shown in $/MMBtu

Natural gas break-even costs vary widely over different plays

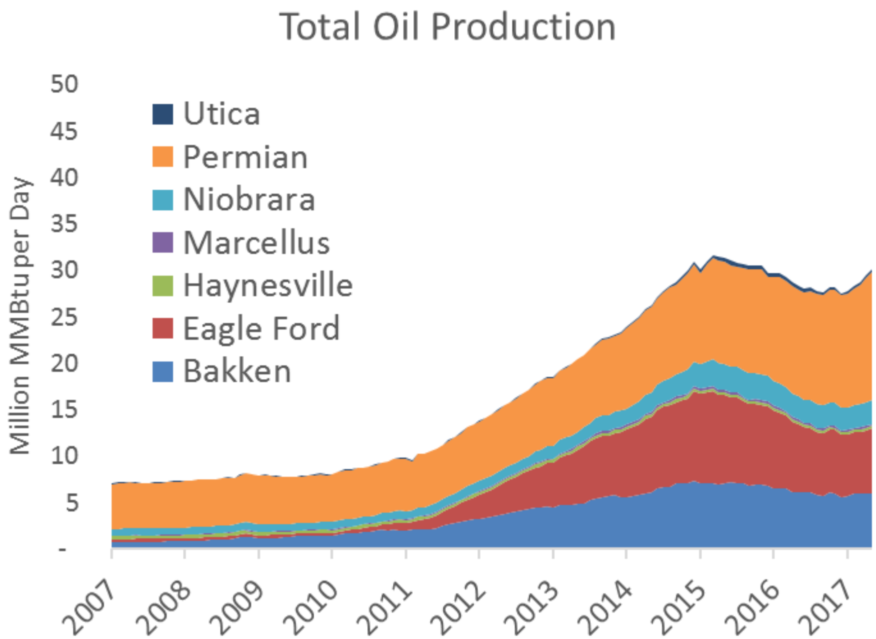
NYMEX shown as of February 1, 2017
Developed by FEP with data from PointLogic, EIA

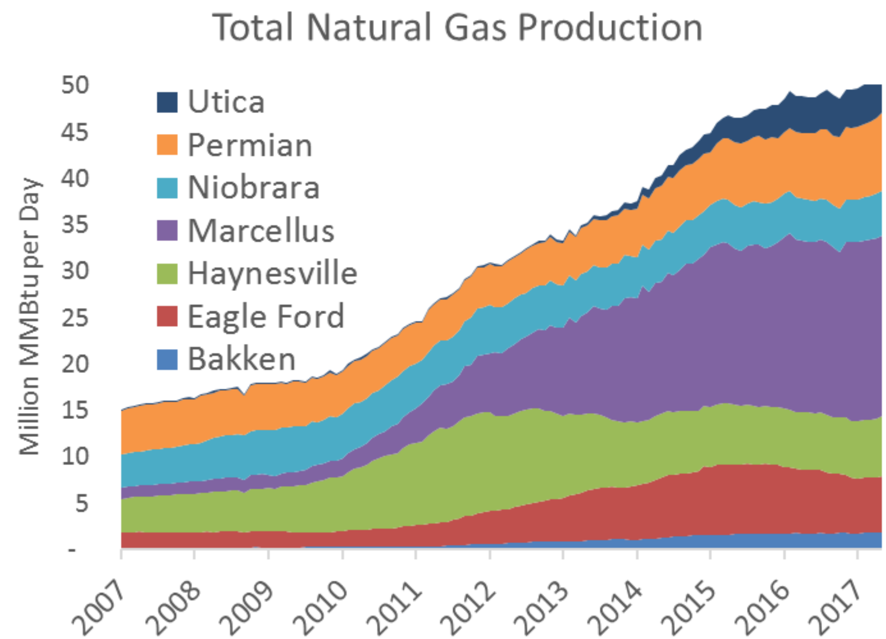
Natural gas production continues to rise despite falling prices

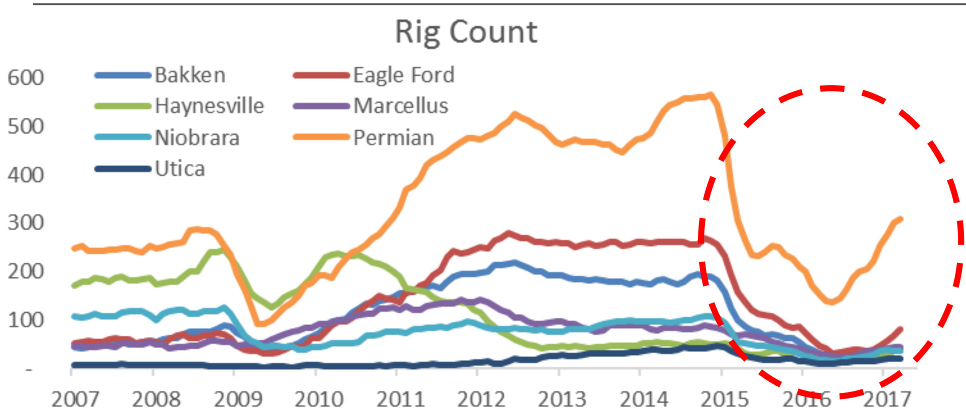


Data shown as of April 2017
Source: EIA, FEP

Low production costs and improved technologies have pushed U.S. oil and natural gas production to all-time highs



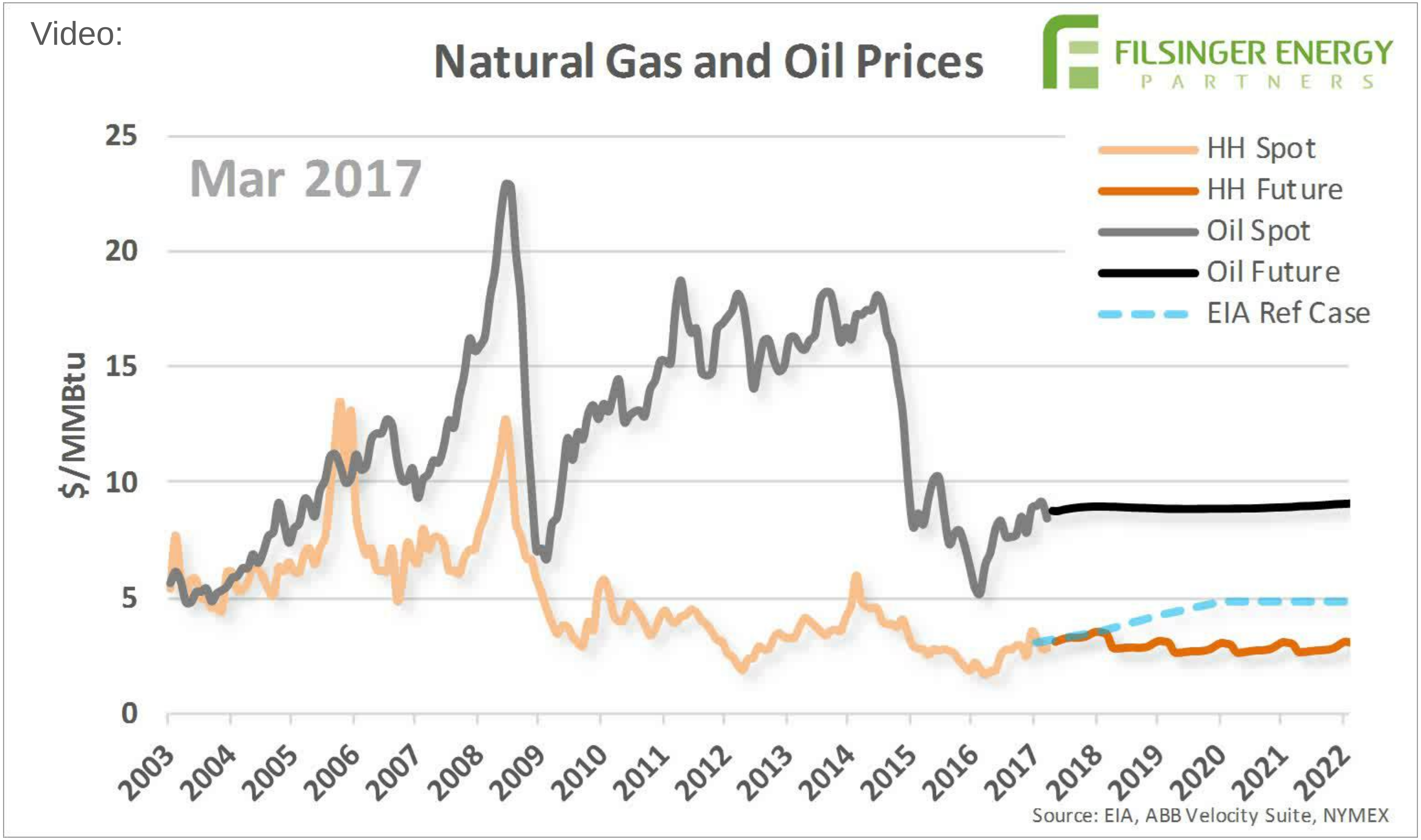




Since mid-2016, rig counts have begun to recover, while natural gas production has remained at all-time highs

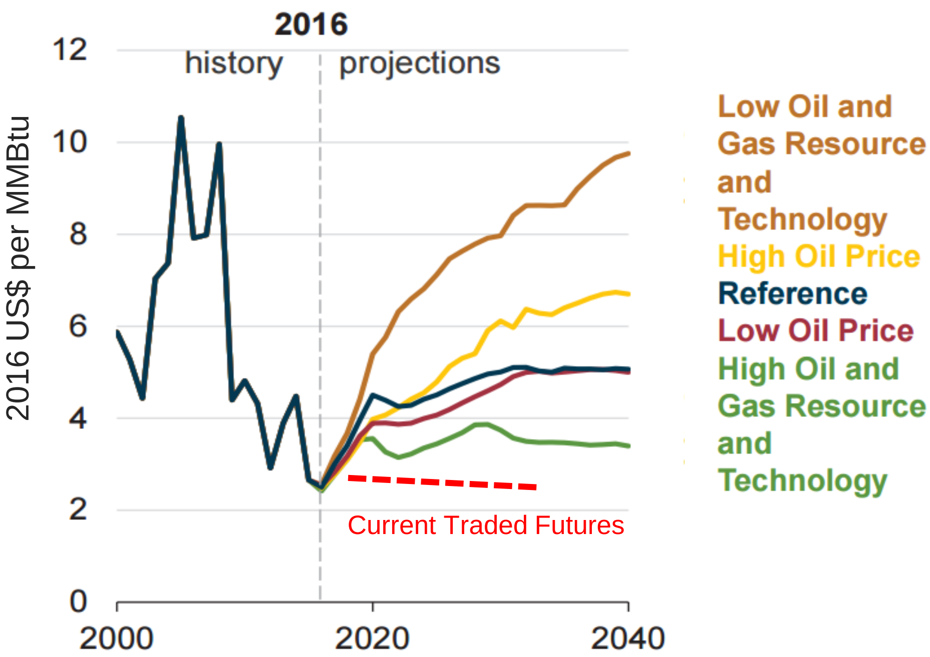
The futures tell the story

Video:

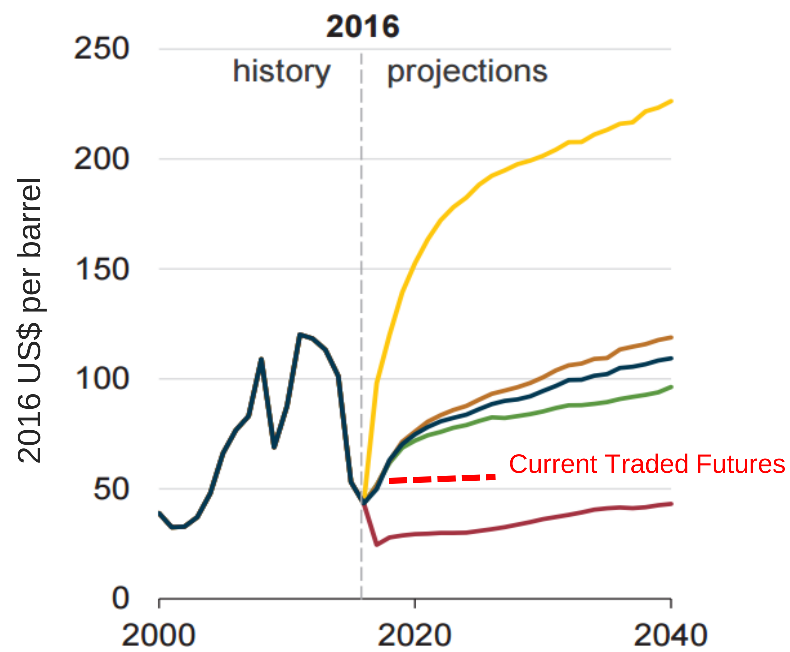


EIA forecast released in January maintains projections over current futures

Average Henry Hub spot prices in AEO



North Sea Brent crude oil prices in AEO



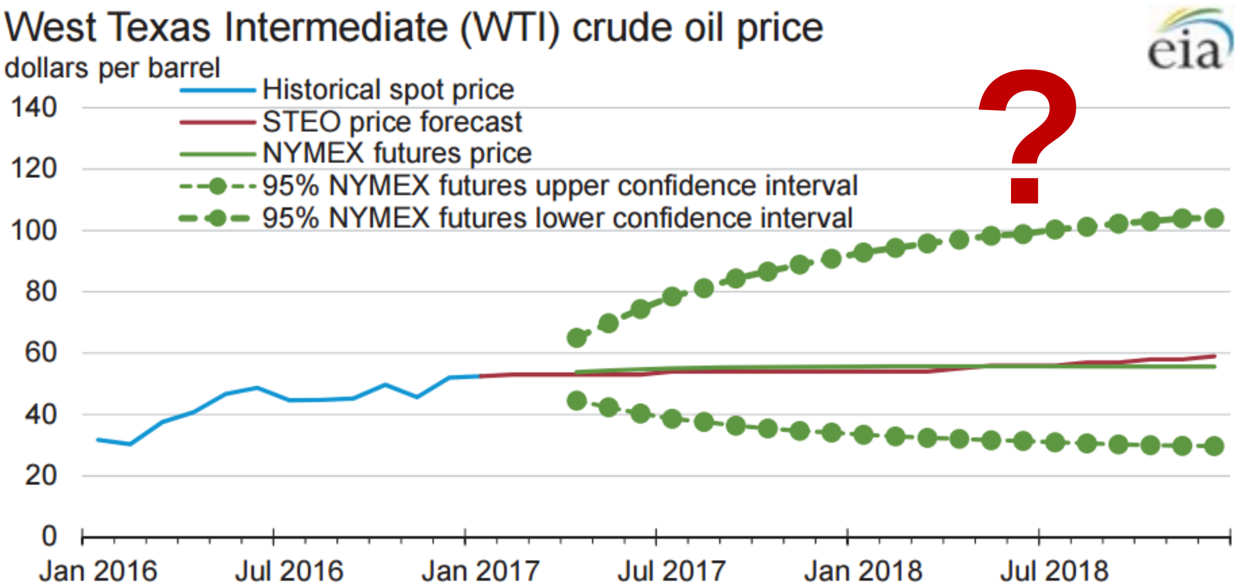
The EIA's 2017 Reference Case includes projections of **U.S. LNG exports** exceeding 10 Bcf per day by 2030.

EIA Reference Case Annual Growth Rates (2016-2050)

Natural Gas:	**2.5% over inflation**
Oil:	**3.0% over inflation**

Approximate futures shown as of April 2017
Source: 2017 EIA Annual Energy Outlook, NYMEX

EIA forecasts reflect significant uncertainty



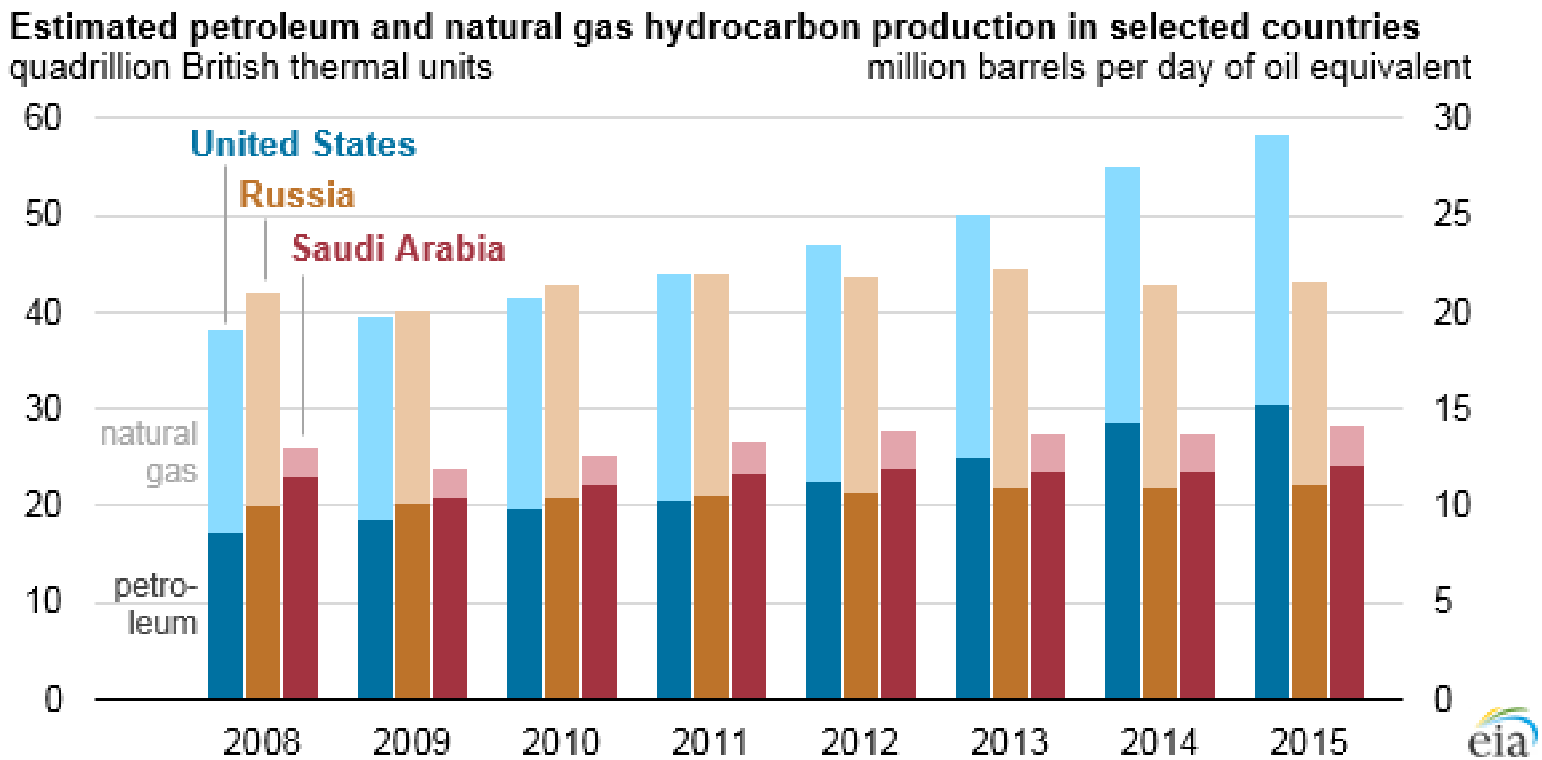
Note: Confidence interval derived from options market information for the 5 trading days ending Feb 2, 2017. Intervals not calculated for months with sparse trading in near-the-money options contracts.
Source: Short-Term Energy Outlook, February 2017.

EIA Short Term Forecast: 95% chance WTI will be between $35 and $90 by the end of 2017.

What is the “right” forecast?

Source: EIA STEO, February 2017

While the U.S. remains the largest producer of oil & gas…



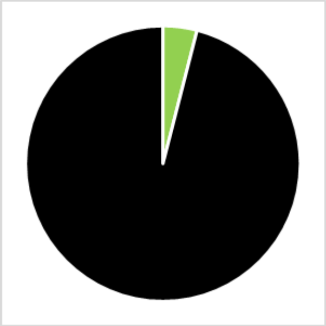
While Russia and Middle Eastern countries have significant proved reserves of oil & natural gas, America continues to lead the world in terms of natural gas and oil production, due to its amenable regulatory environment and incumbent status as the country which pioneered many unconventional drilling practices

Source: EIA

U.S. natural gas exports have not scaled to match production

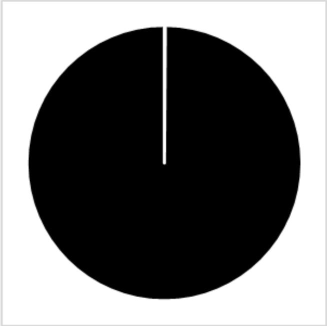
20%

Global Natural Gas Production



4%

Global Natural Gas Exports

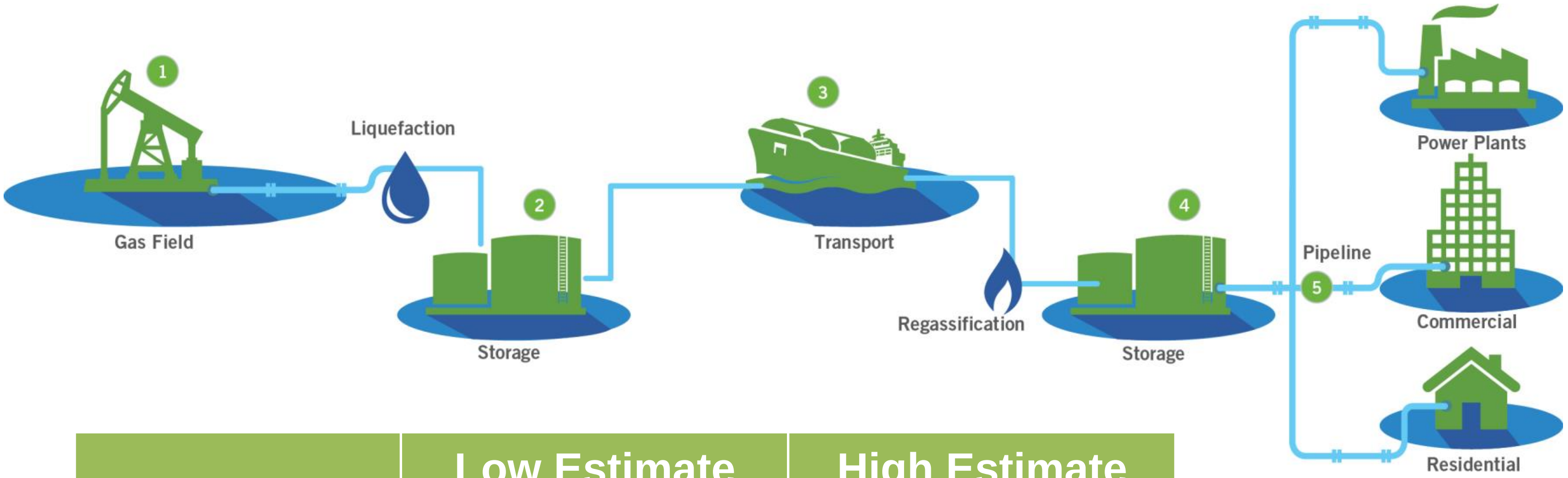


0.1%

Global LNG Exports

Sources: CIA World Fact Book, International Gas Union, FEP

In addition to commodity costs, LNG has additional delivery costs that need to be accounted for



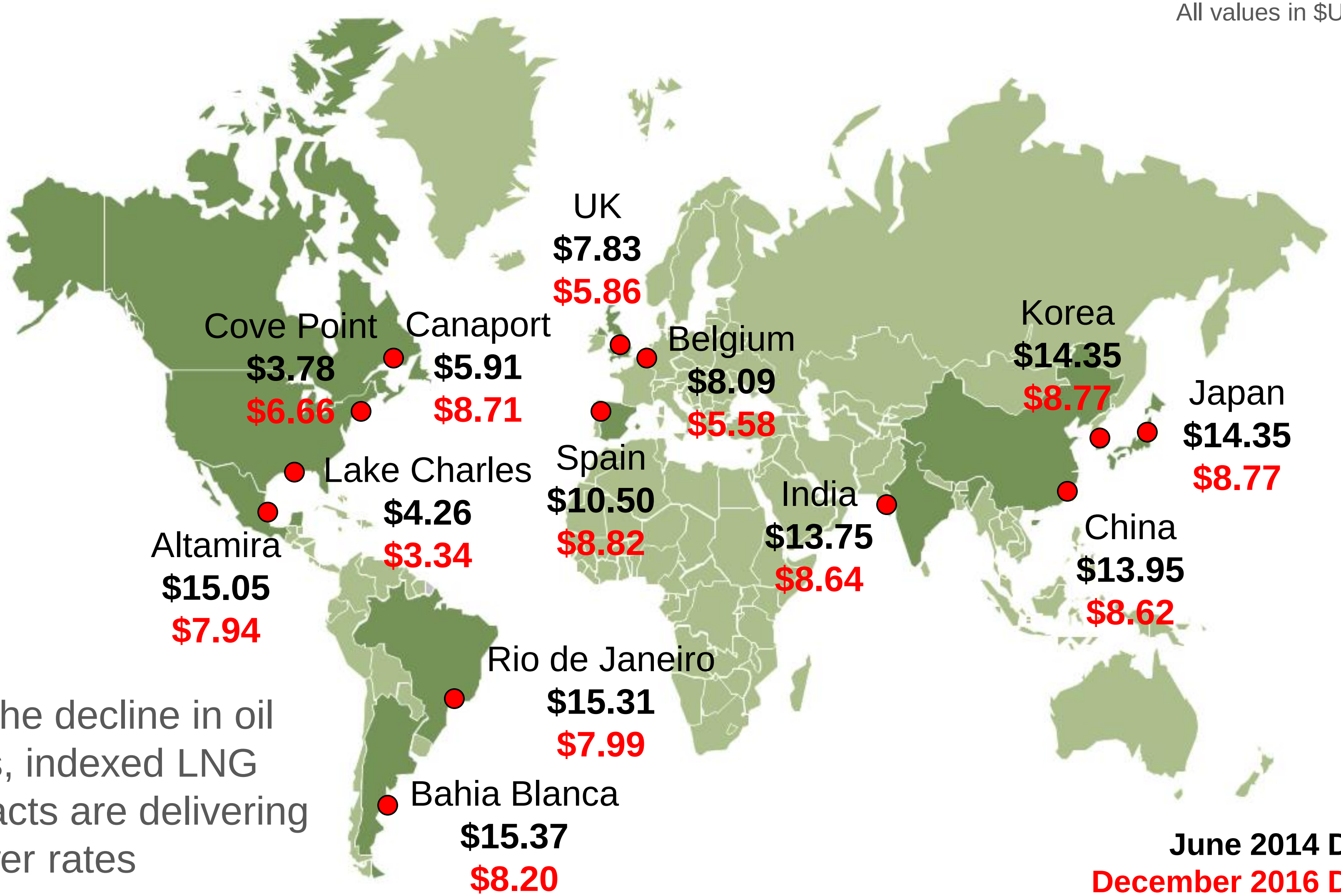
Component	Low Estimate ($/MMBtu)	High Estimate ($/MMBtu)
Liquefaction	$0.90	$3.00
Transportation	$0.30	$4.30
Regasification	$0.40	$0.70

Costs of liquefaction vary by region, and will likely be higher for planned projects that face materially higher forecast construction and development costs

Source: FEP, MIT, CEE, Jefferies

LNG economics are driven by BOTH natural gas price and oil price

All values in $US/MMBtu



With the decline in oil prices, indexed LNG contracts are delivering at lower rates

Dec 2016 delivery as of Jan 2017; June 2014 delivery as of April 2014
Source: FERC, Waterborne Energy, Inc.

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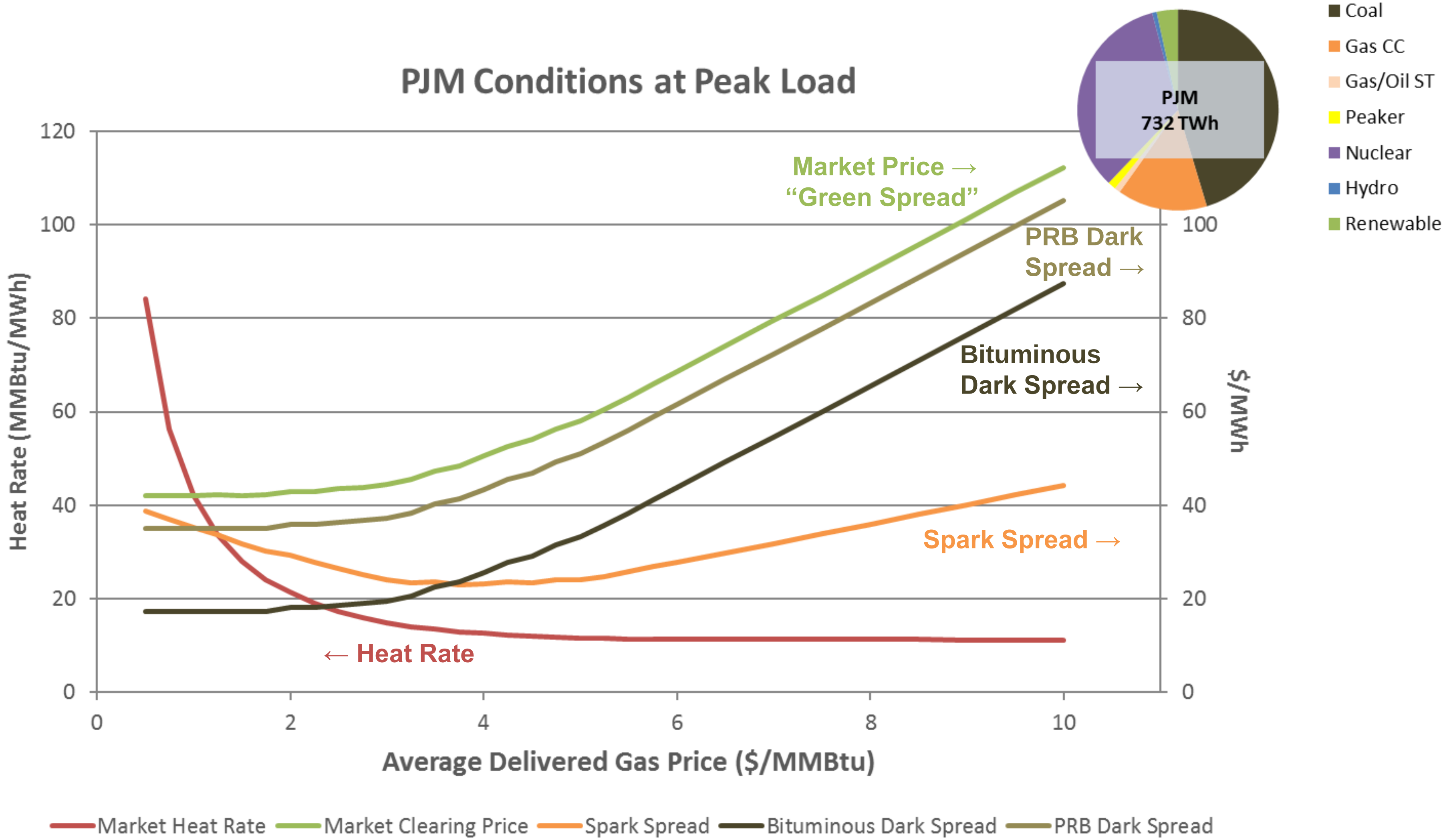
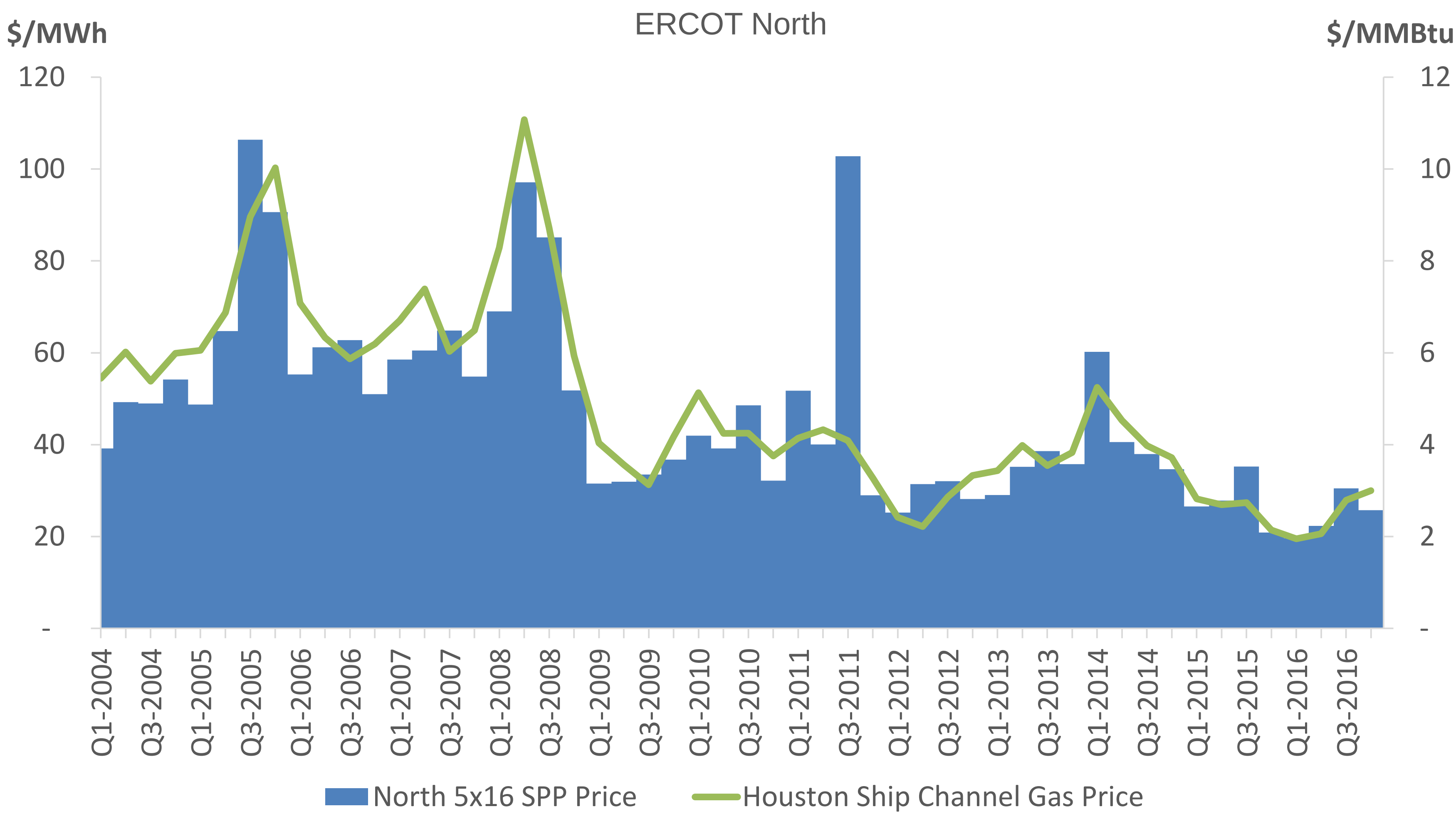
Value at various natural gas prices varies by fuel source



Note: Based on peak load conditions
Source: ABB Velocity Suite, FEP

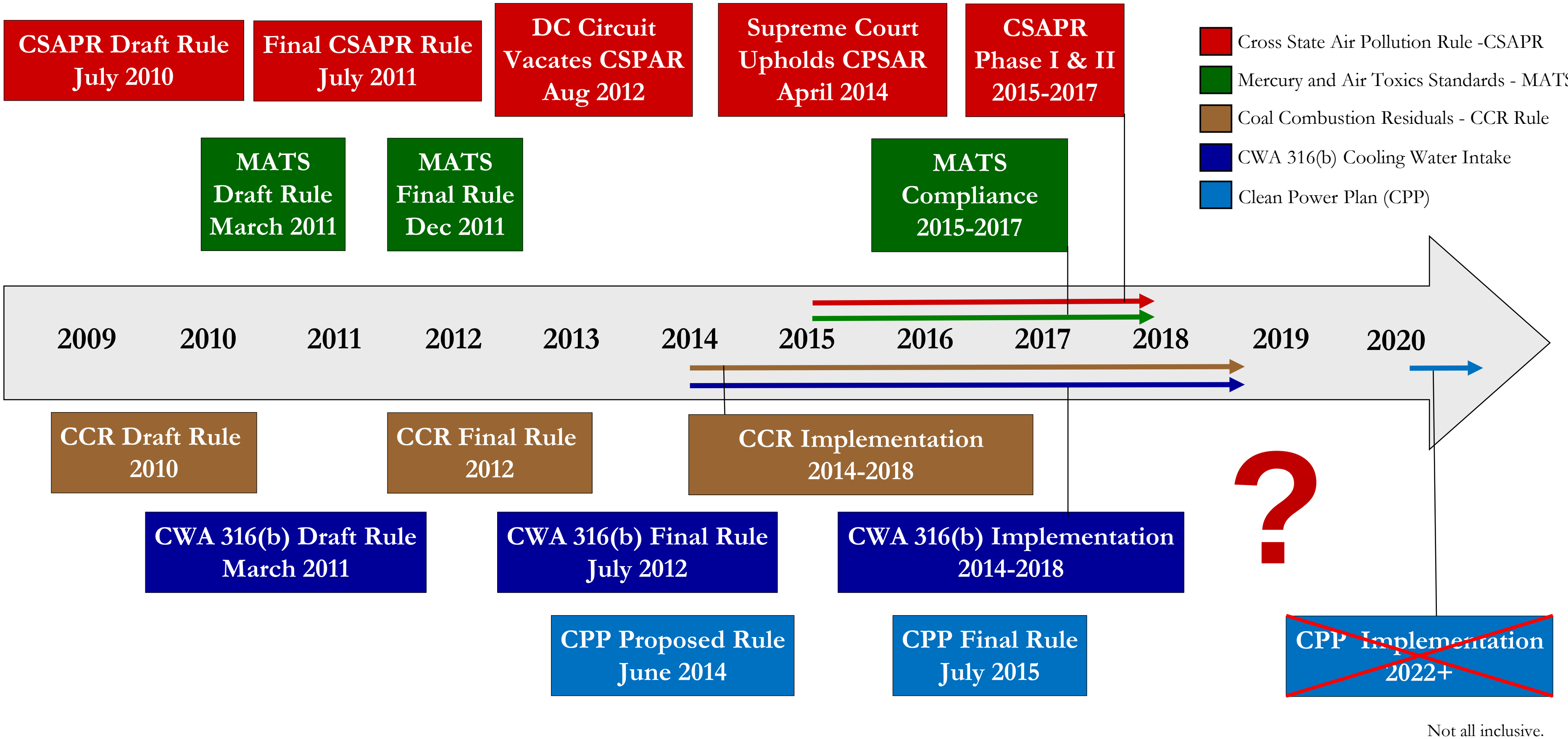
In most regions natural gas prices remain the primary driver of energy prices



SPP = Settlement Point Prices (includes ORDC adders)

Sources: SNL, FEP

Coal is less relevant and environmental rules alone will not be enough to save coal



The new presidential administration puts all plans for future regulations into doubt

Source: EPA, FEP

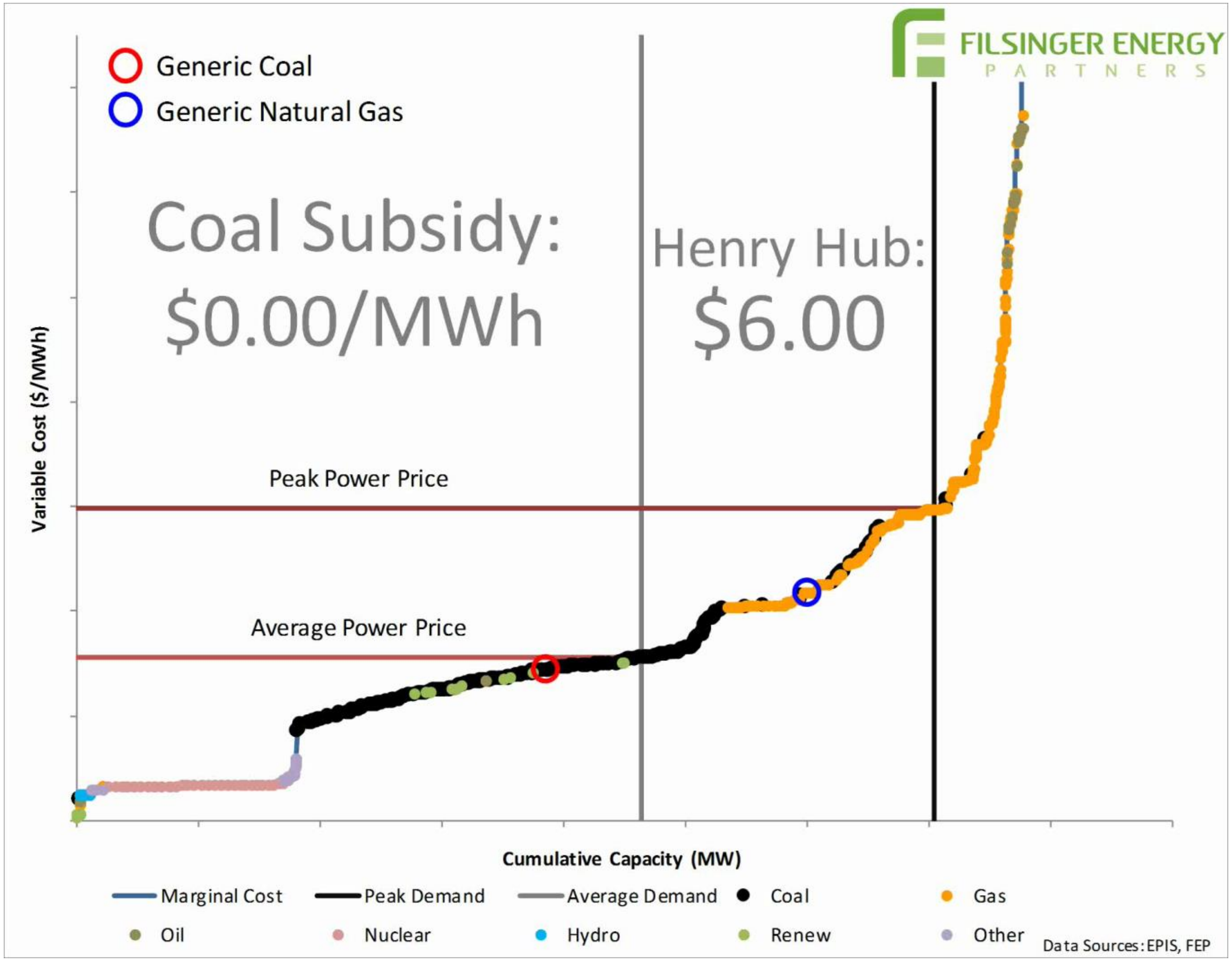
Decreasing regulatory pressures may change existing coal plants' timing for future plans

With uncertainty regarding the future of environmental regulations, many coal owners are considering delaying retirement plans

Source: ABB Velocity Suite, NERC, FEP

Trump cannot save coal at $2-3 gas without a subsidy

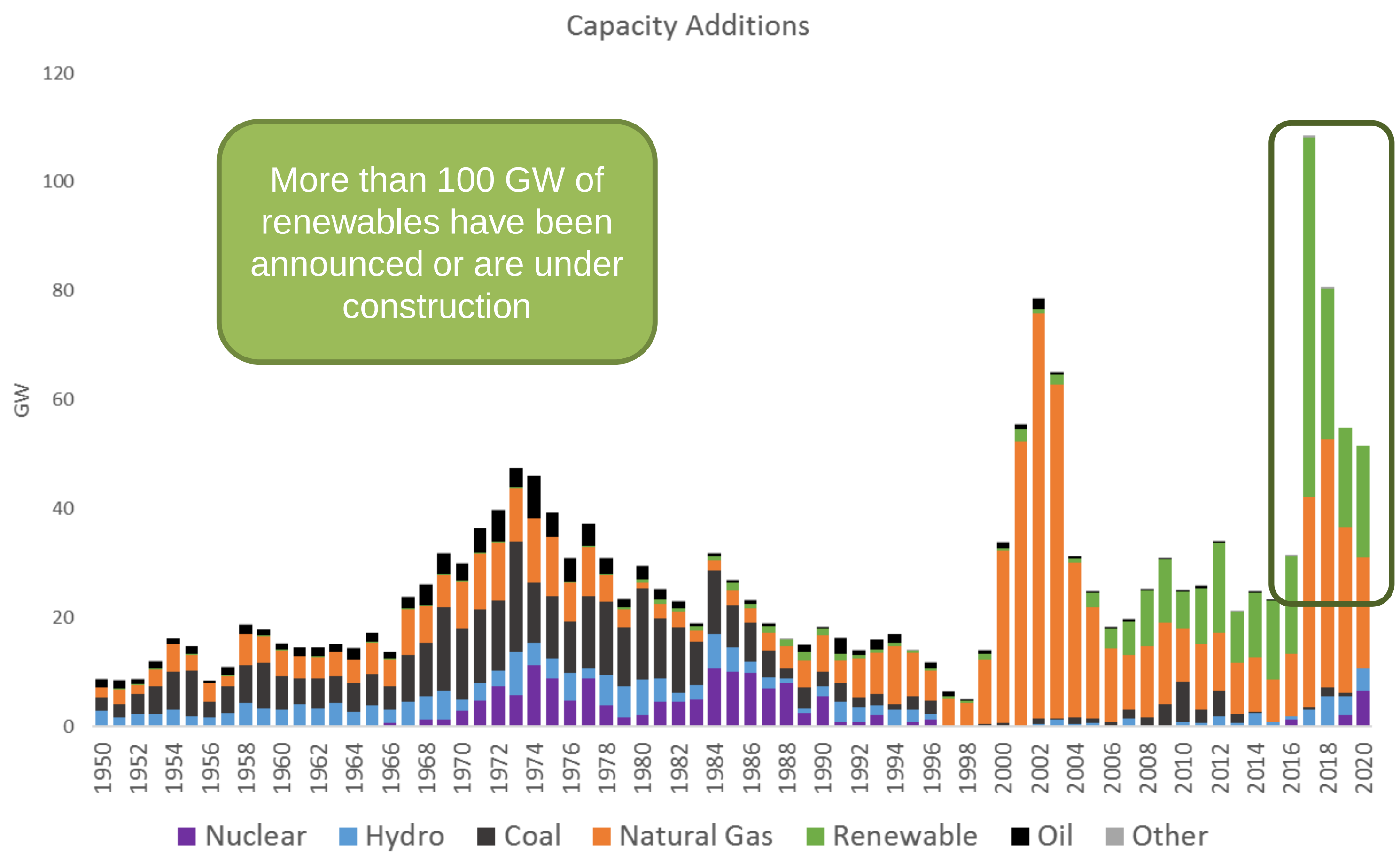
Video:



"Subsidy" price represents the additional revenue required by the highlighted generic coal plant to achieve parity with the highlighted generic natural gas plant. It is shown for illustration purposes only.

Generated with FStack. More information at www.filsingerenergy.com/fstack

And renewable development continues at a rapid pace

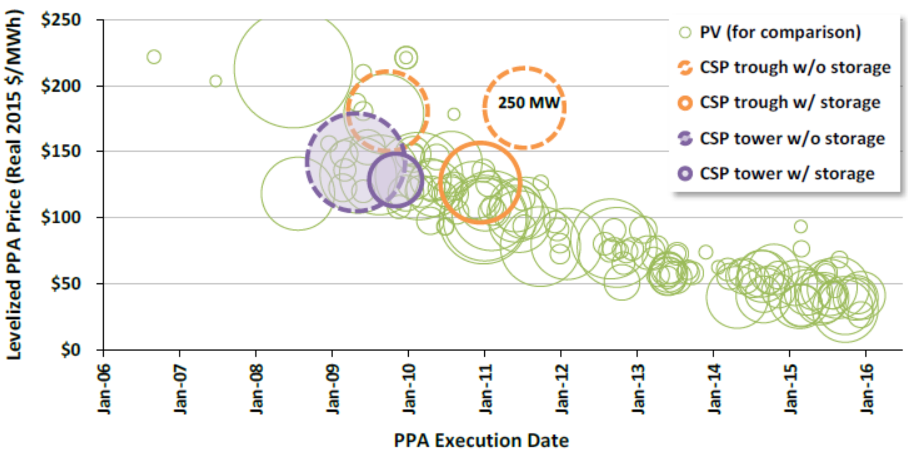


2017+ includes proposed and pending plant development

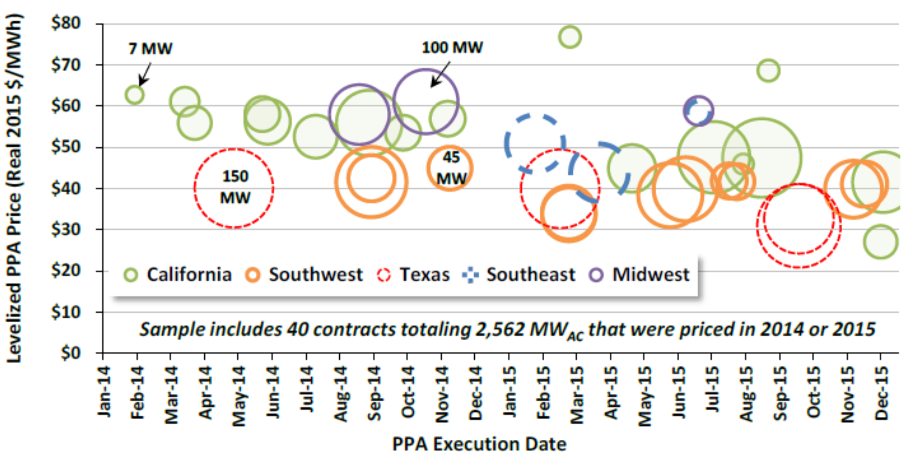
Source: ABB Velocity Suite, NERC

Aided by the fall in solar prices

Levelized PPA Prices by Technology, Contract Size and PPA Execution Date



Levelized PPA Prices by Region, Contract Size and PPA Execution Date



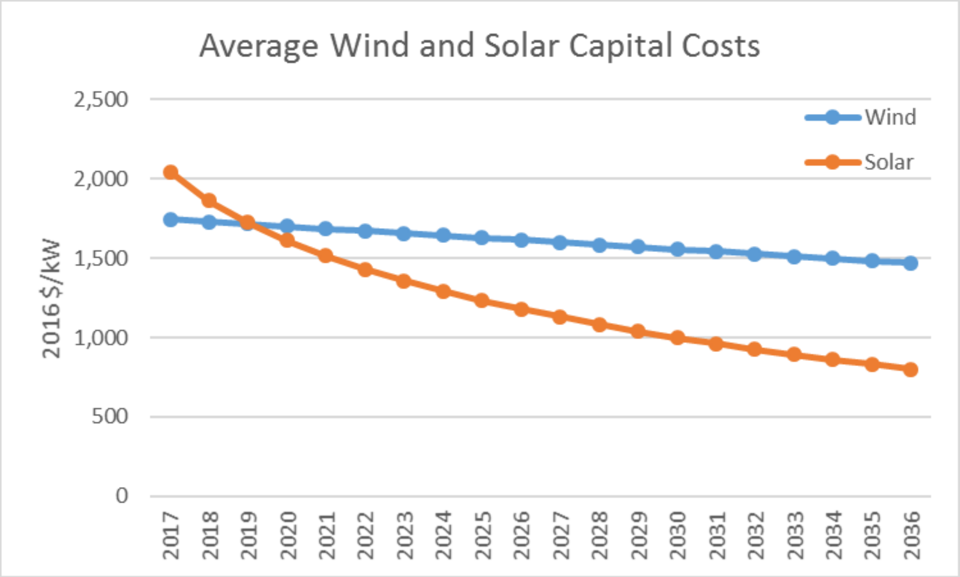
Technology improvements and tax incentives continue to drive costs for solar to levels that are competitive with other generation types

Utility-Scale Solar 2015 – An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, Lawrence Berkley National Laboratory, dated August 2016

Source: Data compiled by Berkley Lab and the Dept. of Energy from FERC Form 1, EIA 923 and other public filings

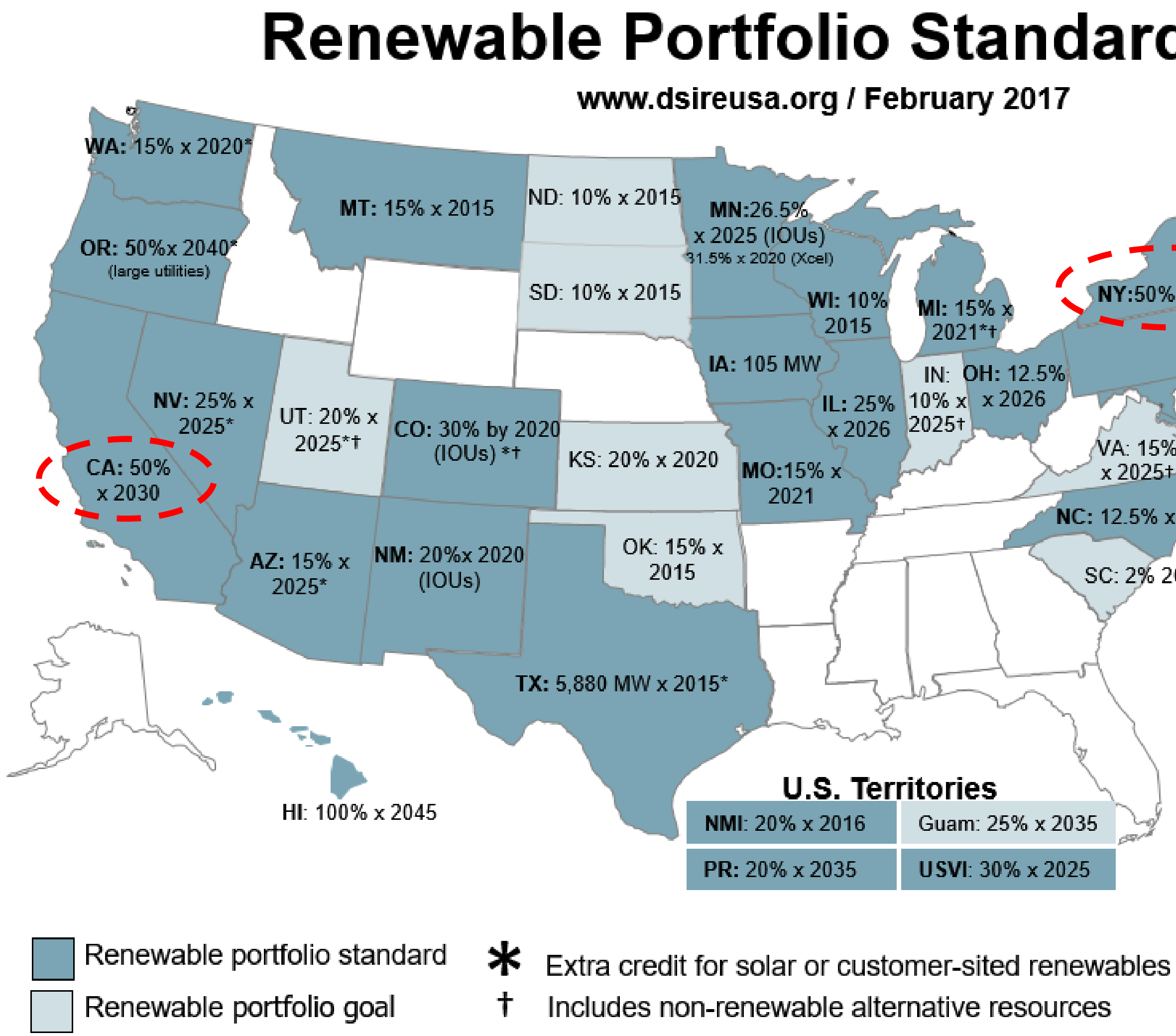
Renewable price declines will hit a point of diminishing returns

- Wind plant capital costs continue to decline
  - Increasing rotor diameter and hub heights
  - Optimized for lower wind speeds
  - Increasing capacity factors
- Utility-scale solar capital costs declining rapidly
  - Improvements in cell efficiency
  - Module prices as low as $0.30/W
  - Tracking and inverter costs declining
  - Balance-of-system costs targeted for significant reductions
  - Improving capacity factors



The decline in wind and solar capital costs is pushing the levelized-cost-of-electricity below that of natural gas plants in some locations

However, increasing state renewable portfolio standards continue to drive investment

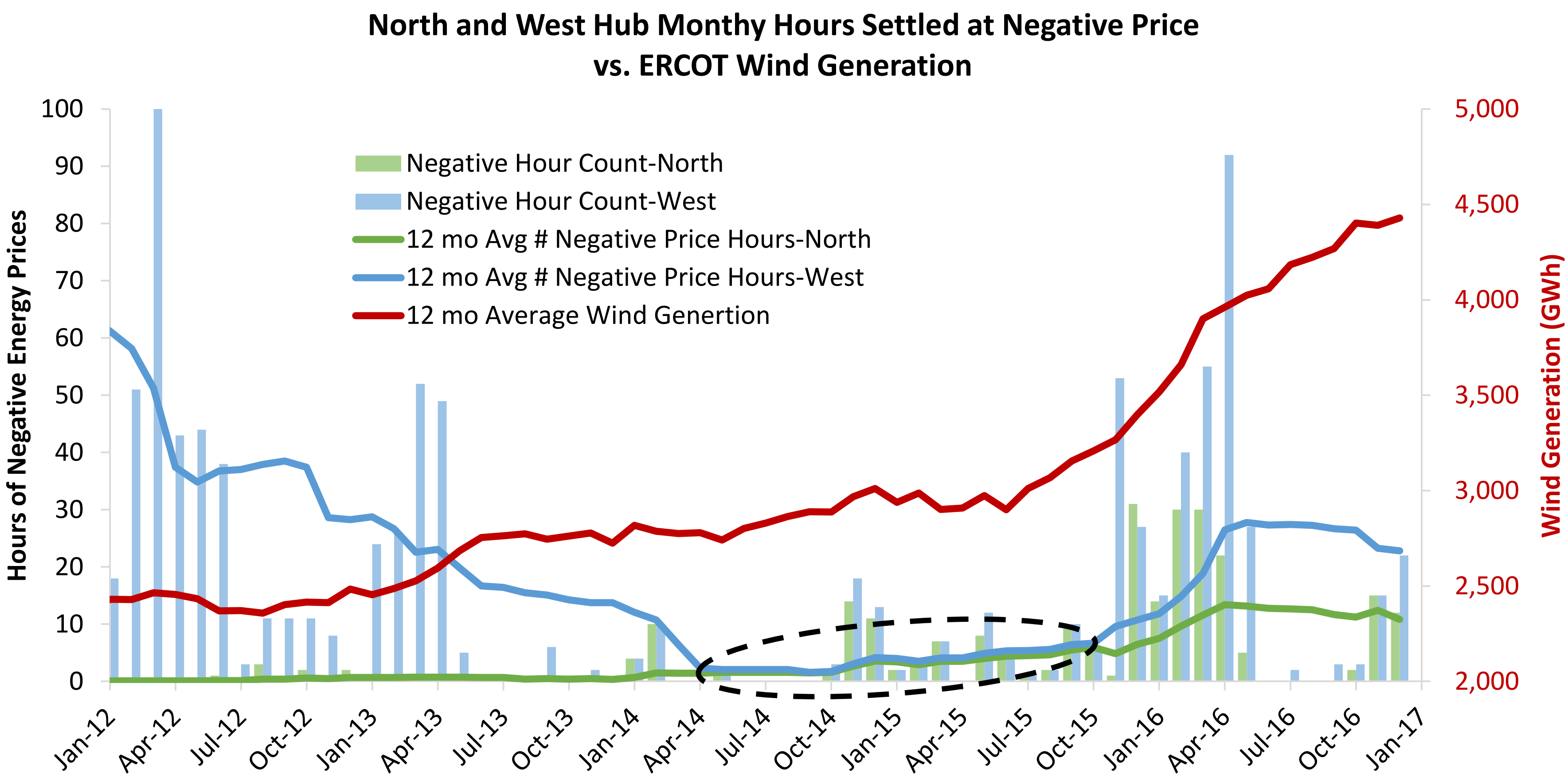


29 States + Washington DC + 3 territories have a Renewable Portfolio Standard

(8 states and 1 territories have renewable portfolio goals)

Source: DSIRE

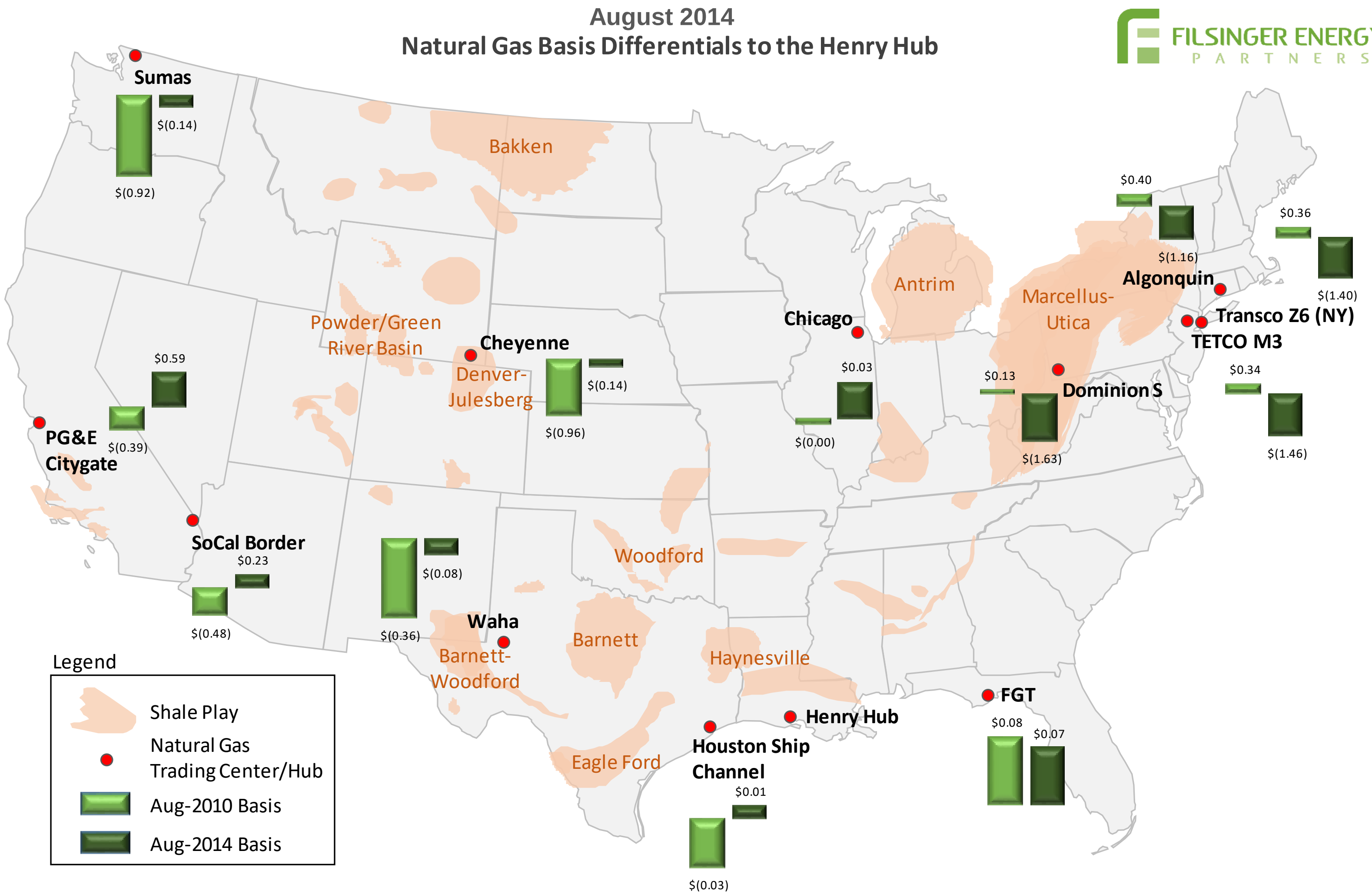
Renewables continue to place downward pressure on power prices



Year	2011	2012	2013	2014	2015	2016
Negative Price Hours-North	1	8	4	43	78	130
Negative Price Hours-West	760	339	165	50	129	274

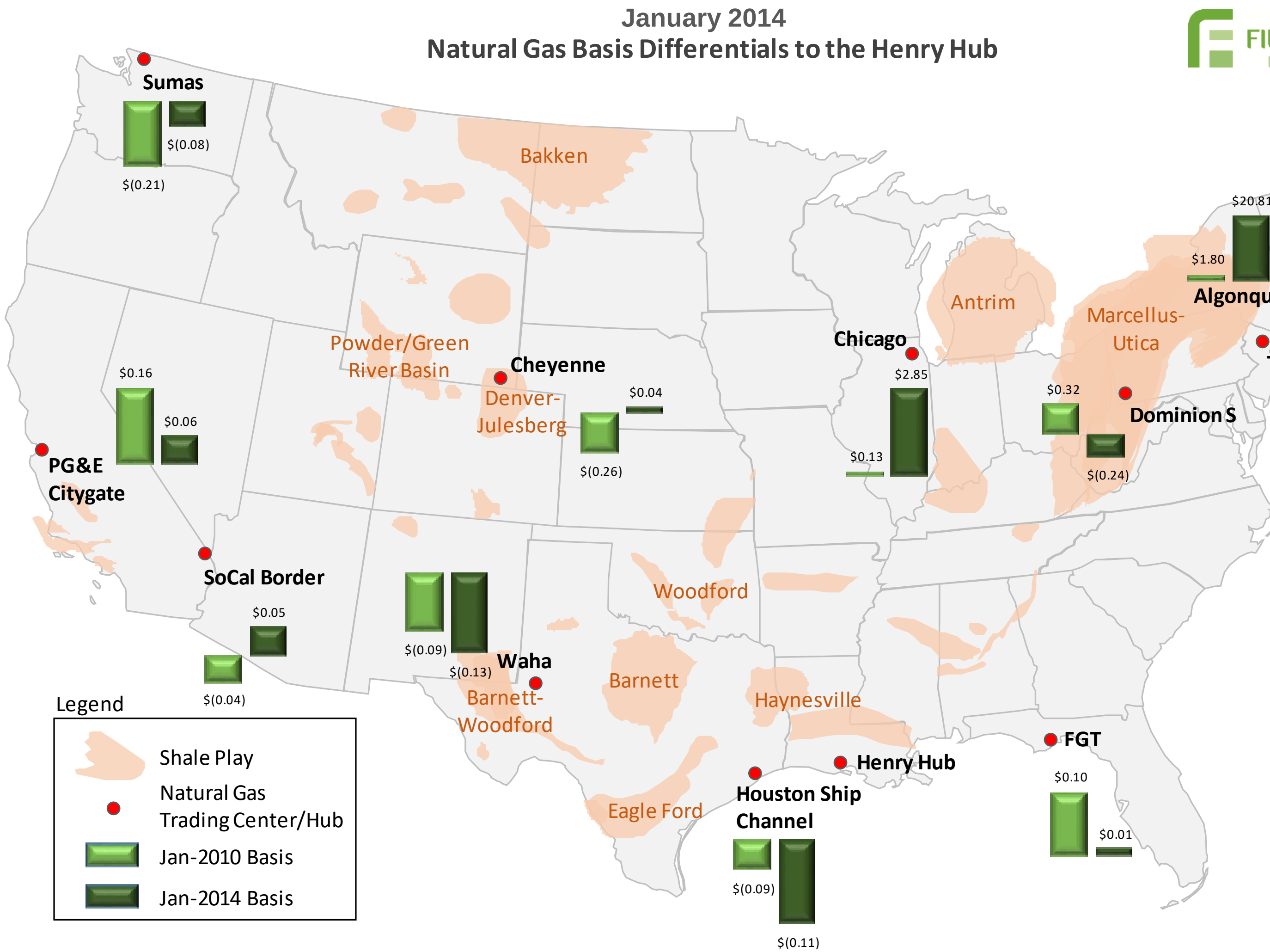
Sources: ERCOT, SNL, FEP

Weather adds another complexity…



Map produced by FEP based on data from EIA, FERC
Pricing data reported by SNL

January 2014 Polar Vortex exposed pipeline and physical infrastructure constraints

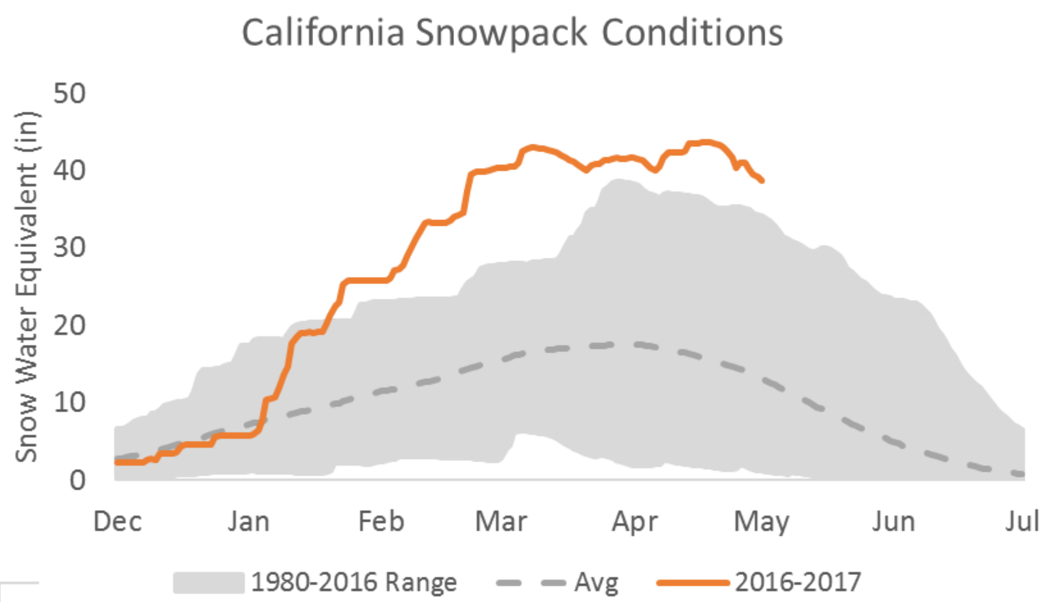


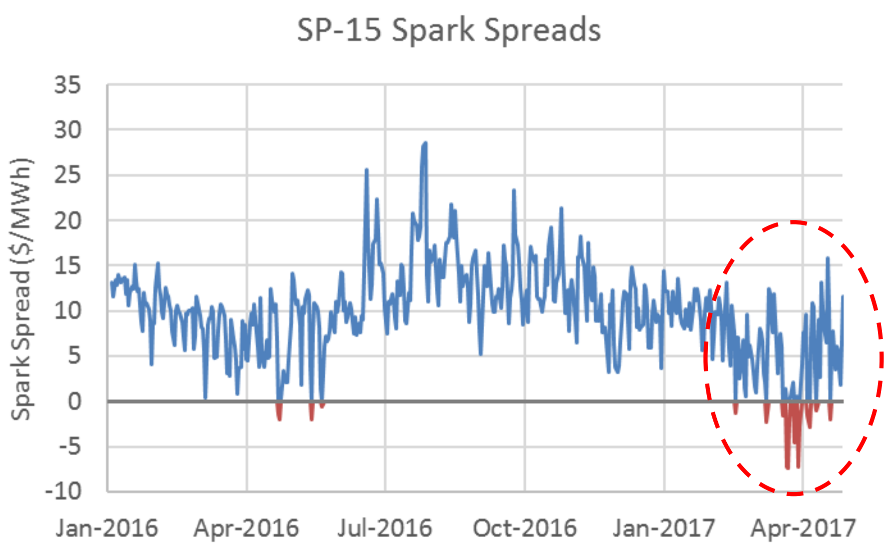
Map produced by FEP based on data from EIA, FERC
Pricing data reported by SNL

At the height of the Polar Vortex, day-ahead power prices exceeded **$400-600 per MWh** throughout PJM, NYISO and ISO-NE

And California's snowy winter is now bringing increased, cheap hydropower

The 2016-2017 winter brought some of the greatest snow accumulation on record to California



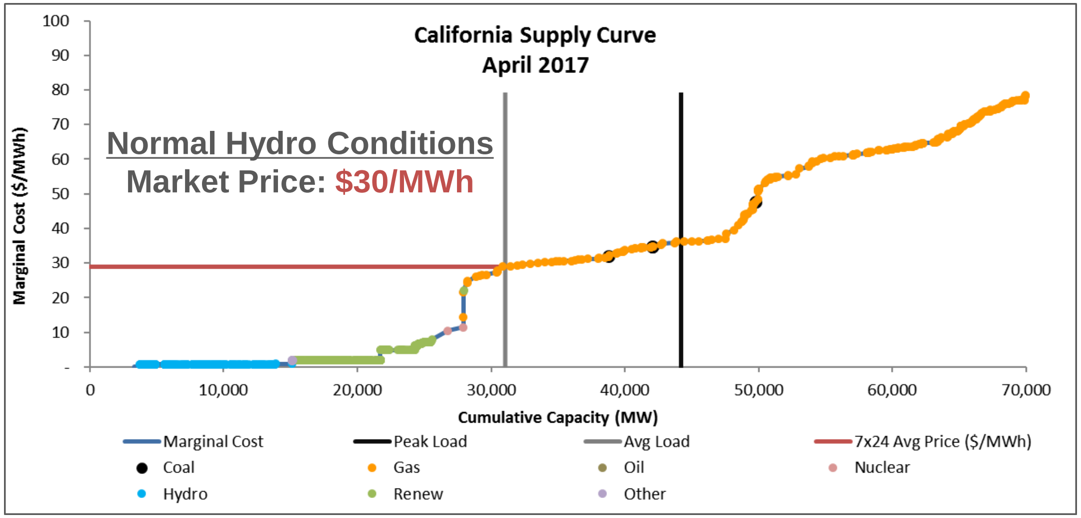


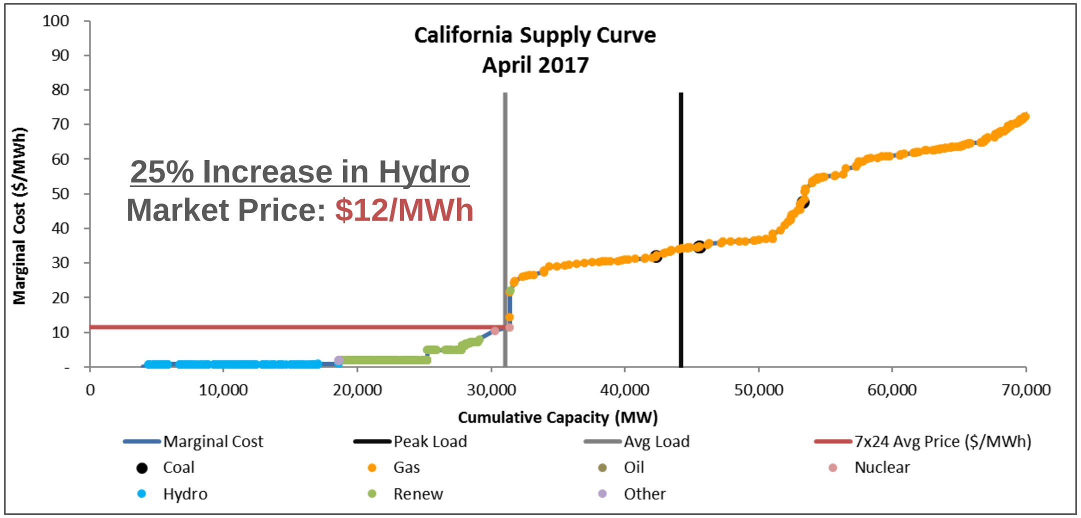
Increased hydroelectric production is leading to negative spark spreads throughout California

Snowpack data based on average of 34 SNOTEL sample locations
Source: USDA National Water and Climate Center, SNL Financial

Increased hydro production in California has severely depressed market prices in the west

Moderate to high snowpack conditions improve availability of hydroelectric power in California, resulting in a decline in market prices

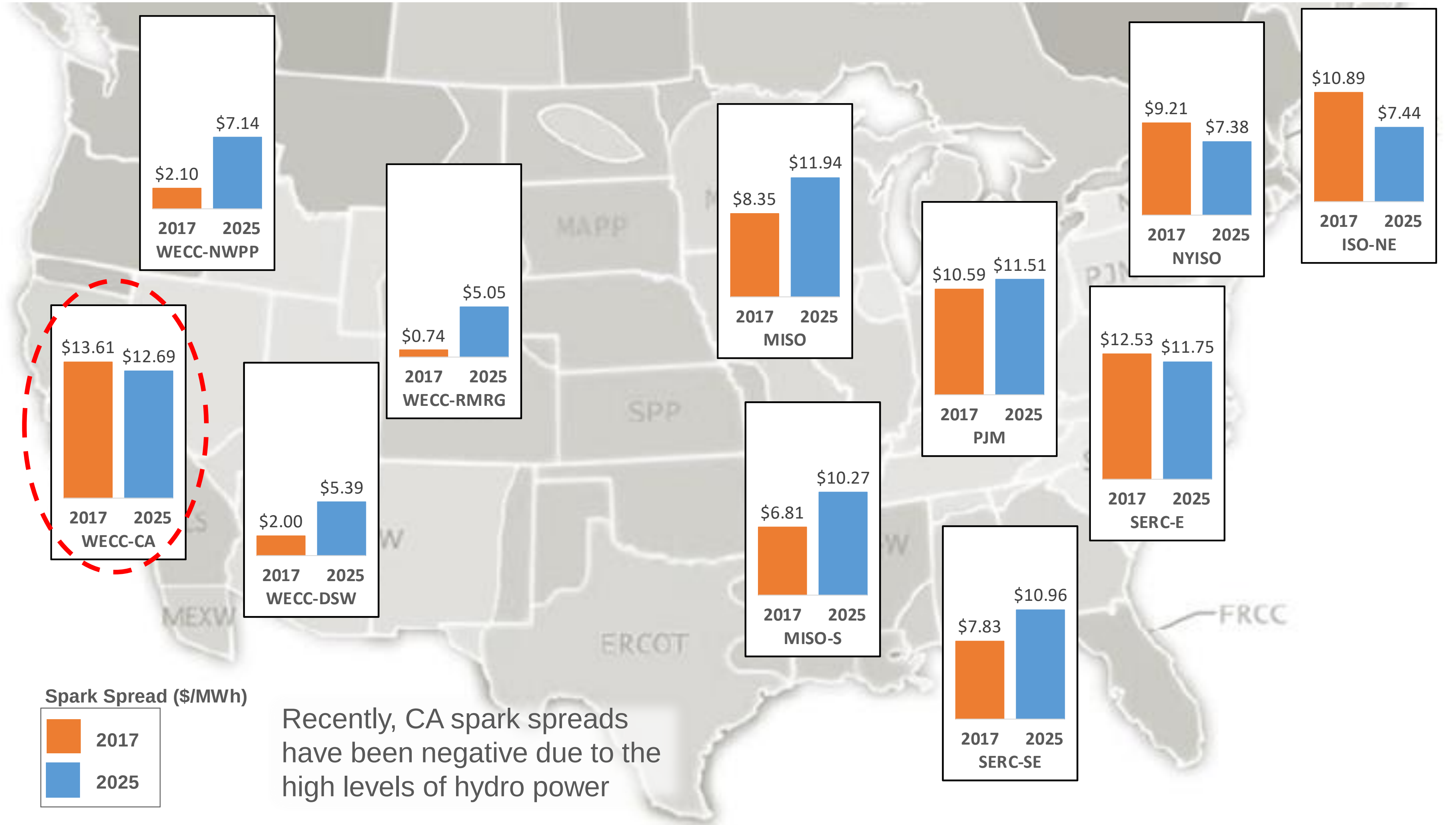




Note
Supply curve based on generic assumptions for illustration.
Not intended to predict actual market conditions.

Source: FEP, FStack

With these dynamics, there is not a spark spread recovery waiting around the corner



Recently, CA spark spreads have been negative due to the high levels of hydro power

Source: Generic Projections as of February 2017

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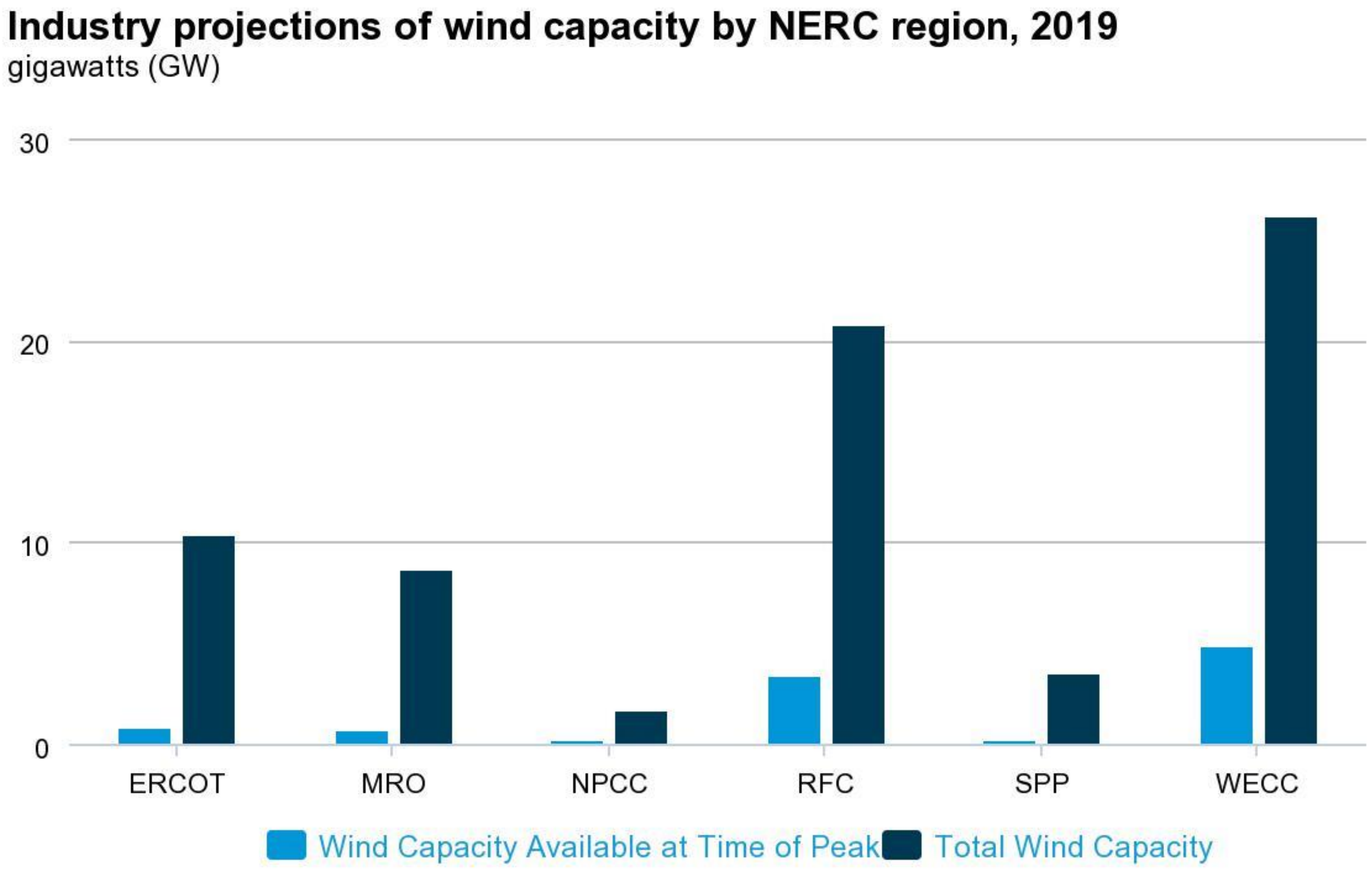
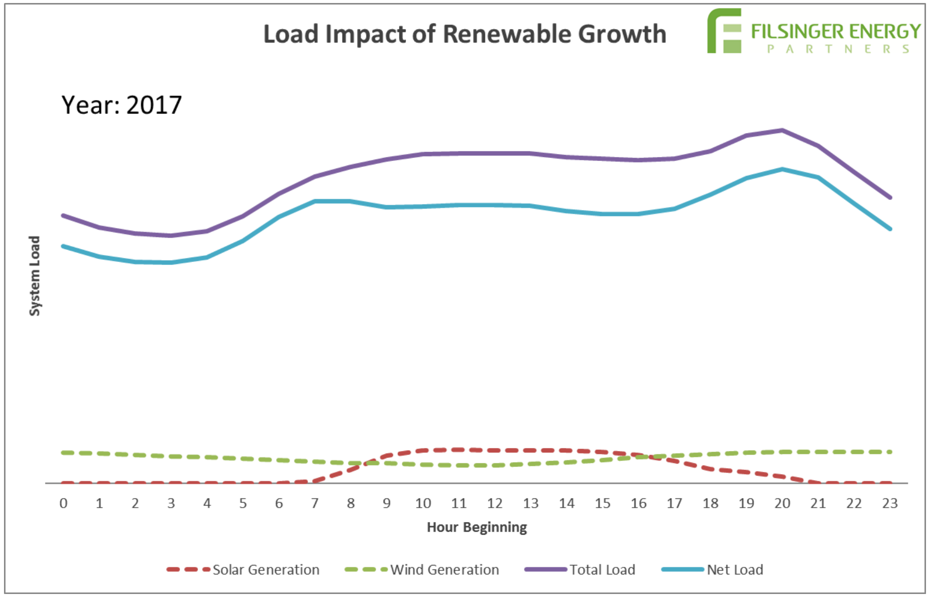
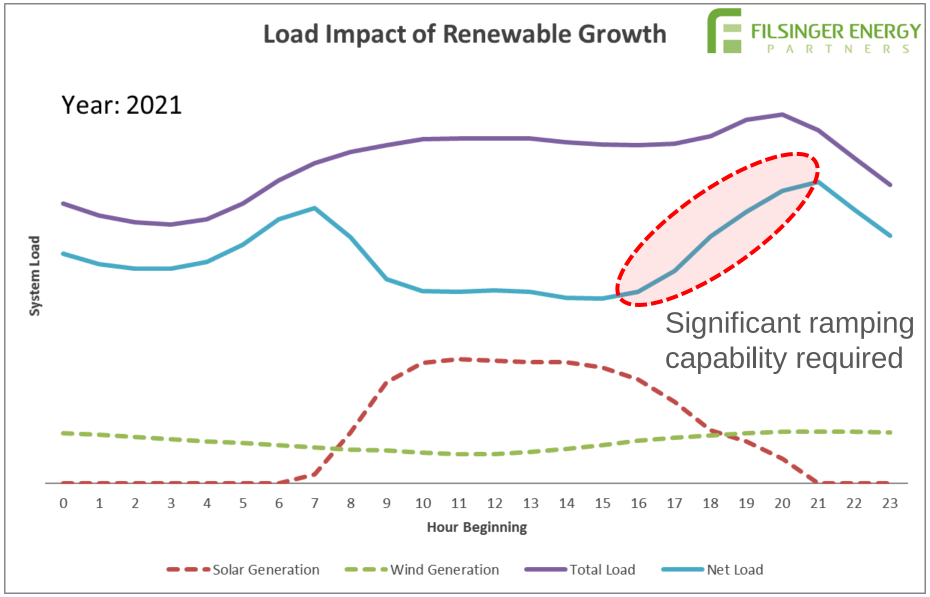
But wind and solar are not always reliable during peak times



Source: EIA

Increased renewable generation shifts the dispatchable demand curve





During the early evening, system load reaches a peak as people return to their homes. At the same time, solar generation becomes unavailable due to the setting sun.

Fast ramping generation is required to pick up this rapidly changing "net load"
This dynamic creates opportunities for flexible generation and storage options

Illustration intended to show qualitative impacts only

Thermal generation must adapt

- Operations & maintenance expenses
  - Technological advancements allow greater anticipation of maintenance, preventing unplanned outages
  - Greater focus on operational efficiencies during outages (especially in the nuclear fleet)
- Efficiency improvements
  - Small improvements in plant heat rates provide a greater benefit in this low gas price environment
- Differed capital expenditures
  - With uncertainty regarding future implementation of environmental regulations, coal plants that have not already installed new equipment may elect to delay installations

Plants must increase efficiency and lower costs

- FEP uses a Power Optimization Center (POC) to improve asset performance though improved thermal performance, lowered O&M expenses, and more efficient use of capital expenditures
- The POC provides state-of-the-art, 24x7 real-time monitoring of critical plant equipment coupled with advanced reliability and thermal performance analysis
- It has operated for over 10 years, with 22,000 MWs of capacity currently monitored, and it is credited for producing substantial cost savings and efficiency improvements

Power Optimization Center Monitoring and Diagnostic Services	
Thermodynamic Performance	Remote Control Room Functions
Generation Critical Equipment	Plant Startup and Coastdown Reviews
Boiler Tube Leak Monitoring	Cycle Isolation Monitoring
Process Controls and Instrumentation	Chemistry Trending and Analysis

- The POC leverages over a decade of monitoring and diagnostic experience to ensure that assets operate at maximum efficiency and with industry-leading levels of reliability

The POC improves operating efficiencies and financial performance at power plants for either single assets or portfolios of assets.

Conclusions – Where do we go from here?

- Natural gas will see short-term price increases, but long-term fundamentals do not support a paradigm shift
- LNG and oil exports remain opportunities at the right commodity prices
- There will be significant restructuring activity in the power markets in 2017-2018
- State mandates will continue to drive investment in renewables
- Renewables will create significant grid challenges
- Thermal plants must reposition to survive
- Storage has the potential to be a game changer, but it has economic challenges given the current overbuilds

What big event did I miss that we will talk about next year?


FILSINGER ENERGY
PARTNERS

Todd W. Filsinger

Todd Filsinger has been active in the energy sector for over 25 years and is recognized globally as a leader and turn-around specialist in the energy sector. As an interim executive leader hired to turn companies around and lead them through difficult situations, Mr. Filsinger has guided several utilities through industry restructuring; developed complex strategies for utilities and renewable energy companies; and has been involved with the restructuring of a majority of merchant power companies. He is currently the lead energy advisor on the EFH restructuring.

Mr. Filsinger has also led and managed some of the largest trading operations in the United States. Additionally, he has assisted commodity-based businesses, and helped both regulated and merchant utilities across the United States in the areas of strategy, regulatory compliance and filings, asset divestiture, and capital allocation techniques. Notably, Mr. Filsinger served as Interim Chief Executive Officer and Interim Chief Financial Officer for Hawkeye Growth and was the leader of PA Consulting Group’s Global Energy Practice from 2002 through 2010.

Filsinger Energy Partners Overview

Filsinger Energy Partners is an energy advisory firm that provides high-level strategy, restructuring, economic and market evaluation, gross margin forecasting, power and fuel price forecasting, risk management, independent engineering services, expert testimony, and complete interim management solutions to energy, industrial and manufacturing companies and their stakeholders

Todd Filsinger is the managing partner of FEP and is one of only a few ASA Accredited Senior Appraisers in the U.S.

FEP Services

- Transaction due diligence
- Coal, gas, nuclear and geothermal generation valuation and appraisal
- Power generation & fuel market analysis and forecasting
- Oil & gas resource analysis and projection
- Cost and capital expenditure analysis, timing and improvement
- Environmental analysis related to power generation assets and operations
- Feasibility and prudence analysis
- Contractual management, negotiation and restructuring
- Development and review of energy marketing and trading activities
- Interim management solutions
- Identification of and implementation of operational improvements
- Independent engineering and cost estimating
- Load forecasting
- Competitive retail electric market analysis and forecasting

Team & Experience Highlights

- FEP staff have led many of the major restructuring and financing assignments in the power sector on behalf of management, debtors, and creditors
- Over 100 years of combined energy industry experience
- Strong team of cost estimators, independent engineers, economists, and finance professionals unparalleled in the industry
- Expert testimony before FERC, federal, state and local jurisdictions, and international tribunals
- Industry thought leaders in energy market valuation, risk management, and independent engineering

Restructuring Experience:

- Energy Future Holdings Corp.
  - Lead energy advisor to the debtors
  - Compensation metrics expert
- Hawkeye Growth
  - Chief Executive Officer
  - Chief Financial Officer
  - Manager of Operations
- Calpine Corporation
  - Chief Operating Officer
  - Chief Commercial Officer
  - Chief Risk Officer

Mexican Energy Sector Restructuring: New Opportunities for Renewables

Skadden

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This article is from Skadden's *2017 Insights*.

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The ongoing effort to restructure the power sector in Mexico, together with Mexico's strong policy on combating climate change, have created compelling opportunities for investors in renewable energy projects that likely will persist this year. As Mexico continues to transition its electricity sector from a vertically integrated, state-owned and -controlled structure to an unbundled one with private and public ownership, investors will be required to bear more market and investment risks than before. However, these risks are familiar to investors in other mature electricity markets and do not represent insurmountable obstacles to capitalizing on new Mexican renewable energy opportunities.

Electricity Sector Restructuring

The "Secretaría de Energía," or Energy Ministry (SENER), is overseeing the restructuring of the electricity sector pursuant to the August 2014 "Ley de la Industria Eléctrica" (Electric Industry Law) and related legislation (Reform Legislation). The intention of the reform is to lower prices by shifting to a more competitive market and promoting renewable energy generation.

Prior to the Reform Legislation, the "Comisión Federal de Electricidad," or Federal Electricity Commission (CFE), was the state-owned enterprise responsible for operating the electricity sector. CFE controlled power purchasing, planning and transmission and was the primary generator that owned most of the total installed capacity and electricity production in the country. Opportunities existed for private entities to participate in generation but were mostly limited.

Under the new regime and for the near term, CFE continues as the primary retail supplier of electricity, but it has become a holding company with separate generation, transmission, distribution, supply and marketing subsidiaries that operate semi-independently. As a result, parties doing business with CFE must look to the specific credit profile and assets of the CFE entity with which they are contracting, and such parties can no longer rely on the asset and credit profile of the consolidated/integrated energy company. In addition, system operations have been transferred to the "Centro Nacional de Control de Energía," or National Energy Control Center (CENACE). This independent system operator (ISO) for the new wholesale power market plays a similar role to that performed by ISOs in the U.S., with responsibility for ensuring access to the grid, operating the system in a reliable manner and assuring availability of sufficient supplies to meet customer demand. This year, CENACE will introduce new market components, including the real-time wholesale market, the balancing capacity market and financial transmission rights. With these changes, the electricity sector will transition to a structure akin to markets such as the California ISO, which will be very familiar to independent power producers and financiers in the U.S. electricity market.

Power Contract Auctions

The Mexican government made an aggressive commitment to renewable energy with the 2012 General Law on Climate Change, requiring 35 percent of electricity production to come from renewable sources by 2024. A key component of that commitment is power supply solicitations in which CENACE auctions long-term (15-year) power contracts with CFE to renewable energy generators.

Two auctions have been held to date. At the first, 11 winning bids were selected for wind and solar projects totaling 1,720 megawatts (MW) of generating capacity with an average bid price of US$41.80 per megawatt-hour (MWh). The winning bids in the second auction represented 2,871 MW with an average bid price of US$33.47 per MWh. Each auction received bids from approximately 60 to 70 local and international prospective suppliers. A third auction is planned for April 2017.

The CENACE auctions are governed by the "Bases de Licitación de la Subasta de Largo Plazo," or Bid Rules for Long-Term Auction, which are published before each auction. Pursuant to these rules, bidders must provide a detailed construction schedule with specific milestones, including a fixed commercial operation date, certify their technical expertise and identify their contractor, among other details. The rules include a form of non-negotiable power purchase agreement (PPA) that winning bidders must execute with CFE. The new PPA contains terms that generally have been included in project financings in the U.S. and elsewhere but not some of the protections that benefited generators in previous power purchase agreements with CFE in Mexico.

New Terms of Agreement

The new PPA between a CFE subsidiary and the generator has a 15-year term that runs from the fixed commercial operation date. However, the uncertainty around pricing in the new wholesale electricity market is hampering developers' efforts to secure long-term financing extending into the period following expiration of the 15-year PPA. Under the PPA, the CFE counterparty makes payments in accordance with the actual amount of energy delivered each month and performs year-end reconciliations that aggregate the monthly amounts delivered to determine compliance with contracted quantities. Because ownership was a material consideration in securing the bid, there are some limitations on changes to generator ownership. However, CFE's restructuring and the new regime present credit, curtailment, construction and operational risks that were mitigated under the old regime.

CFE Credit Risk

Under the old regime, CFE's obligations were guaranteed by the government. Given this guarantee and CFE's formidable balance sheet, it enjoyed a favorable international credit rating that made the former PPA with CFE an attractive and bankable contract for investors and lenders alike. Under the new regime, while the government continues to own the CFE counterparty, it no longer guarantees the subsidiary's obligations. In addition, the CFE counterparty's balance sheet reflects the fact that it owns only a subset of the assets that its predecessor entity held, and it must be responsible for its respective share of long-term liabilities and obligations.

Anticipating concerns about credit, the Reform Legislation requires the CFE counterparty to post a guarantee equivalent to one year of its contractual obligations. It is unclear whether the government would ultimately backstop CFE through an implied guarantee if the market assigns a high-risk premium to project financings under the new arrangements. Also, in the event that a CFE counterparty default causes generator termination, the CFE counterparty must fund the full amount of the contract into a trust in order to cover the difference between spot market and contract prices. However, the CFE counterparty's contractual obligation does not eliminate the risk that the CFE counterparty may fail to comply with this funding obligation, either because it lacks the necessary financial resources or for other reasons.

The Reform Legislation contemplates further restructuring CFE, which could result in a CFE counterparty no longer being a subsidiary or affiliate of CFE. In that scenario, the CFE counterparty would be required to increase its posted guarantee, but the generator would still take the risk that the CFE counterparty might not post the requisite guarantee.

Curtailment Risk

Generators also are subject to certain curtailment risks under the new PPA. To be accepted and remain active in the market, generators must acquire and maintain their status as a market participant, which includes executing a market participant agreement with CENACE. Both this agreement and the new PPA require that the generator abide by CENACE's operational instructions. While the regulations governing CENACE indicate that dispatch decisions will be based on impartial criteria, the process for determining dispatch and curtailment priorities is not plainly defined, and it is unclear what factors might affect these decisions beyond reliability.

Under the new PPA, generators that are instructed not to deliver energy by CENACE are not compensated, and generators are allowed to terminate the agreement only after six months of curtailment. This change is a significant departure from the former PPA with CFE, where CFE generally was required to pay in the event of curtailment.

Construction and Operational Risks

Similar to the curtailment risk, projects developed under the new PPA will be subject to other construction and operational risks. For construction, generators are responsible for strictly meeting the schedule set forth in the auction bid rules and annexed to the PPA. While certain extraordinary events, such as civil disturbance or the occurrence of a *force majeure*, allow for a schedule delay, project holdups due to other factors will result in the developer incurring penalties per milestone missed. Furthermore, the CFE counterparty can terminate the PPA if commercial operation is not reached within 12 months of the fixed commercial operation date.

In addition, the PPA does not provide compensation in the event of project delays or other missed milestones resulting from government actions or inactions. For delays brought on by issues such as permitting or an inability to interconnect on time because of grid construction, the fixed commercial operation date may be delayed with no penalty to the generator; however, the generator is not compensated for the delay. The generator has the right to terminate the agreement after six months of delays due to government actions that affect the project schedule.

Conclusion

The restructuring of the electricity sector and Mexico's commitment to renewable energy present investors with attractive, long-term opportunities in renewable energy projects. However, changes to the market structure and regime remove important investment protections afforded to project owners under the previous regime. Investors will need to undertake careful diligence of curtailment and other risks that might not have been a focus previously.

Trump Infrastructure Plan May Open Opportunities for Projects

Skadden

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After nearly two decades of widening concern over the declining state of U.S. infrastructure, it was not surprising that infrastructure became a central theme in the 2016 election cycle. Improving our nation's transportation, water and energy infrastructure was one of the few issues to garner strong bipartisan support in the campaign, and President Donald Trump's infrastructure platform was notable in two key ways. First, it focused heavily on private investment, which President Trump sees as a key funding source for domestic infrastructure projects, and second, it set an ambitious target — $1 trillion of new infrastructure investment. If the Trump administration realizes its infrastructure-related objectives in any significant way, there should be a wave of new opportunities for capital providers, contractors and private developers in the infrastructure sector.

Navarro-Ross Tax Credit Proposal

During the campaign, the centerpiece of the administration's infrastructure plan was an aggressive use of tax credits to attract private investment. The most detailed proposal in this area was set forth prior to the election in a white paper authored by Peter Navarro, a business professor at the University of California, Irvine, whom President Trump selected to chair the White House National Trade Council, and Wilbur Ross Jr., a noted private equity investor and President Trump's nominee for secretary of Commerce. The Navarro-Ross plan calls for enacting federal legislation to establish an investment tax credit (ITC) for U.S. infrastructure projects sized at 82 percent of the invested equity. According to the Navarro-Ross analysis, President Trump's proposed $1 trillion infrastructure plan would require $167 billion in equity, which would give rise to approximately $137 billion in tax credits. The plan calls for the tax credits to be offset by increased tax revenues from project construction activities — specifically, through taxes on additional wage income and contractor profits — resulting in revenue neutrality for the federal government.

The Navarro-Ross tax credit proposal has been met with some skepticism as to its viability. Deficit hawks in Congress, many of them Republican, are not convinced that the plan is revenue-neutral. Industry analysts have expressed concern that many of the currently active investors in the infrastructure sector (*e.g.*, pension funds) are tax-exempt entities and would be unable to utilize the credits. Moreover, if Congress lowers corporate tax rates, it is unclear whether there will be sufficient tax capacity to absorb the full amount of the available investment tax credits. Perhaps in response to these critiques, infrastructure advisers to President Trump suggested in the days following his inauguration that the administration's infrastructure proposal may be cut nearly in half, to $550 billion.

There also is a more fundamental question: Are there a sufficient number of infrastructure projects that can benefit from the Navarro-Ross proposal? The ITC-based model, like other nonrecourse project financing structures, relies on an underlying project that generates a stream of revenue sufficient to service the project debt and provide the private investor with a return of and on its capital (supplemented by the benefits it receives from the tax credit). Widespread realization of the Navarro-Ross plan likely would require a significant increase in the use of public-private partnerships (P3s) — or analogous development and procurement models — in the infrastructure sector. While variations on the model exist, P3 transactions typically involve a private investor being granted the right, and undertaking the obligation, to design, build, finance, operate and maintain a public infrastructure project pursuant to a long-term concession arrangement. In return, the private investor receives demand-based revenues (*e.g.*, tolls) or, in some cases, an availability payment from the public authority for performance (regardless of demand). Approximately three dozen significant P3s have been financed in the U.S.

over the last 30 years, including surface transportation, public utility and social infrastructure projects. Major recent P3 projects include the $4 billion rebuild of the central terminal at LaGuardia Airport in New York City, the $3.4 billion Vista Ridge water pipeline project in Texas and the recently announced commercial closing for the $2.3 billion managed toll lanes project on Interstate 66 in northern Virginia.

However, P3 transactions require complex and lengthy planning and structuring efforts and, in many cases, a major shift both in strategic thinking by public sector agencies (which have developed projects without private involvement, for example, via tax-exempt bond financings) and in public sentiment regarding the delivery of essential services (where, as an example, members of the public face new or increased charges that accrue to a private investor). Consequently, P3 projects undergo several years of planning and permitting before the investment community is invited to submit qualifications and proposals. Without significant changes in the way P3 projects are structured and financed, only a handful of well-structured and "shovel ready" P3 projects may reach financial close in any given year. While new federal incentives may spur greater private sector interest in infrastructure, the use and success of P3s ultimately depends on projects that produce predictable revenue streams over the long term. Given the scale and complexity of these projects, implementing P3 procurement models on a large scale nationwide will take time.

Federal Credit Programs in the Trump Era

Infrastructure investors in the U.S. will need to monitor how the specific policies and legislative agenda advances in the coming months support or sideline federal credit programs that provide low-interest-rate financing to infrastructure projects, including P3s. Oversight of the primary credit programs has been consolidated under the Build America Bureau, which was established within the Department of Transportation in 2016 to provide a one-stop shop for federal financing for P3s and other significant transportation projects. The bureau's mandate is to streamline approvals of loans under two credit programs that provide long-term, low-interest-rate loans to surface transportation and rail projects, respectively, and to administer the private activity bond program, through which tax-exempt financing is made available to support P3s. The bureau also will manage the $800 million Fostering Advancements in Shipping and Transportation for the Long-Term Achievement of National Efficiencies (FASTLANE) grant program, established in December 2015 pursuant to the Fixing America's Surface Transportation (FAST) Act.

Investors also should be aware of new opportunities in the U.S. water infrastructure sector. The Water Infrastructure Finance and Innovation Act of 2014 (WIFIA) established a federal credit program administered by the Environmental Protection Agency for eligible water and wastewater infrastructure projects. WIFIA was further amended by the Water Infrastructure Improvements for the Nation Act of 2016, which included $20 million in budget authority ($17 million of which is available for loans and other credit support) to allow the WIFIA program to commence lending operations. This amount, which has been appropriated to the program, represents a credit subsidy cost, similar to a loan loss reserve. The actual credit assistance capacity of the program is expected to exceed $1 billion in credit facilities, with loans for private and public sector borrowers, supporting up to 49 percent of eligible project costs for water infrastructure projects.

Democrats' 'Blueprint to Rebuild America's Infrastructure'

Democrats in Congress, who are advocating for increased public sector spending, have responded to President Trump's plan with their own competing infrastructure proposal. On January 24, 2017, Senate Minority Leader Chuck Schumer, D-N.Y., and several Senate Democratic colleagues released "A Blueprint to Rebuild America's Infrastructure," which matches President Trump's vision of a $1 trillion investment in U.S. infrastructure over a 10-year period. Unlike President Trump's plan, funding under the Democrats' proposal would come entirely from taxpayer dollars at the federal level. The proposal would expand the use of popular federal grant and loan programs, such as Transportation Investment Generating Economic Recovery (TIGER) grants, the Transportation Infrastructure Finance and Innovation Act (TIFIA), Railroad Rehabilitation and Improvement Financing (RRIF) and WIFIA, and would lead to the creation of a national infrastructure bank to promote innovative infrastructure financing solutions. In this regard, the Democrats' plan carries on several Obama administration initiatives that failed to garner approval from the Republican-controlled Congress. The plan also proposes to reform the current system of energy tax incentives by consolidating a number of targeted incentives for renewable and clean energy into broader categories and by making those tax incentives permanent (*i.e.*, not subject to phase-outs).

Conclusion

It is still too early to gauge how the new administration's infrastructure agenda will incorporate specific facets of any prior policy proposal, including the Navarro-Ross plan. Any infrastructure legislation actually passed by Congress will bear the imprint of significant bipartisan negotiations. However, we expect that President Trump and his advisers' emphasis on private investment and more frequent use of P3s will significantly increase opportunities for private sector participants and spur financial innovation in the area of infrastructure project delivery.

Oil and Gas Industry Seeks Steady Ground Following Year of Restructurings, Restrictive Lending

Skadden

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This article is from Skadden's *2017 Insights*.

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Crude oil and natural gas prices reached multiyear lows of approximately $26 per barrel for crude oil (as of January 2016) and $1.50 per million British thermal units (mmbtu) for natural gas (as of March 2016). This represented a 75 percent decline in the price of oil from its peak of approximately $105 per barrel in mid-2014 and an 80 percent decline in the price of natural gas from its early 2014 peak of over $8 per mmbtu. At the time, many industry observers predicted that depressed commodity prices would result in numerous bankruptcy filings and an uptick in M&A activity.

Most oil and gas companies responded with heavy job and capital expense cuts. A slow but steady increase in prices during the past year — to over $50 per barrel for oil and over $3.50 per mmbtu for natural gas as of the end of 2016 — allowed many companies to avoid formal restructurings. However, the increase in oil prices arrived too late and was not enough for many others. Oilfield services companies and exploration and production (E&P) companies experienced more acute levels of distress — and accounted for the highest number of in-court restructurings in 2016.

Looking ahead, heavy debt loads among oil and gas companies are likely to slow the recovery of the industry as a whole, but if oil prices remain stable or increase, we expect far fewer restructurings this year. Opportunities for consolidation through acquisitions exist within the oil and gas space. Opportunistic buyers, including companies that recently have delevered through bankruptcy, may look to add attractive assets to their portfolios.

Oilfield Services. Beginning in mid-2014, oil prices began to fall sharply, decreasing 50 percent over the following six-month period and worsening in 2015. The prolonged, depressed oil prices meant that E&P companies reduced spending on oilfield services work, such as repairs and maintenance, putting pressure on oilfield services companies. When E&P companies did hire service companies, competitive pricing among the service providers added to that pressure. In 2016, 70 oilfield services companies filed for bankruptcy. Now that oil prices have risen, E&P companies are moving forward with deferred maintenance work, leading to higher demand for oilfield services companies and likely far fewer oilfield services bankruptcies this year.

Upstream. In response to declining oil prices, E&P companies substantially reduced their existing production operations and implemented severe cutbacks in capital spending. Moreover, because most companies use reserve-based loans (RBLs) to fund their drilling activities, they are subject to revaluation and redetermination of the value of their reserves twice annually — in the spring and fall (in addition to "wildcard" redeterminations under certain RBLs). The significant decline in prices, together with regulators' concerns about bank lenders' exposure to the oil and gas sector, constrained banks' ability to work with their borrowers during the redetermination process. Consequently, the spring 2016 redeterminations resulted in many E&P companies experiencing significant decreases in their borrowing bases and credit lines as banks took a more conservative approach to their price decks. This led to banks further lowering the forward-pricing curves they use to determine the borrowing bases.

Banks took additional steps to limit their exposure to the oil and gas sector, or to provide greater certainty regarding the ability of their E&P borrowers to repay their loans. Specifically, many lenders amended their credit agreements to tighten some of the covenants to which their borrowers are subject. For example, a number of banks imposed minimum liquidity requirements, effectively limiting their exposure to certain companies without reducing those companies' borrowing bases. Banks also added so-called anti-hoarding provisions in response to situations in which borrowers

Oil and Gas Industry Seeks Steady Ground Following Year of Restructurings, Restrictive Lending

drew down the maximum amount available under their facilities and later filed for bankruptcy. The severe decline in oil prices reduced the value of many E&P companies' assets and constrained their liquidity, forcing a number of companies to restructure. In 2016, approximately 69 E&P companies filed for bankruptcy, though the trend appears to be tapering off, with fewer E&P companies declaring bankruptcy in the past several months of the year. For 2017, while we expect continued activity for offshore drillers, the tapering should otherwise continue for E&P bankruptcies.

Midstream and Downstream. Many oil and gas companies are fully integrated (either directly or through their subsidiaries and affiliates) in E&P, midstream and downstream activities. However, in the last several years, some companies spun off their midstream and downstream businesses to focus solely on E&P, believing that establishing their midstream and downstream businesses as separate entities would enhance focus on the objectives of those businesses and their capital needs, with greater value for shareholders.

Midstream and downstream companies are involved in the gathering, transporting, processing, marketing or storing of oil or natural gas. (Downstream is sometimes defined to refer only to the sale and distribution of oil and gas and their by-products, with the refining, storing and transportation activities defined as midstream.) Produced oil and natural gas are transported to the end user through an extensive network of pipelines and gathering systems. New pipelines are constructed continually in high-growth regions, which is time-consuming and capital-intensive but integral to oil and natural gas production because hydrocarbons are difficult and expensive to transport by vehicle or vessel. The availability of adequate pipeline infrastructure and the cost to transport such crude oil and natural gas directly impact the profitability of any given crude oil and natural gas property. Accordingly, upstream E&P companies are dependent on seamless interaction with hydrocarbon gatherers, transporters and processors — participants in the midstream sector of the oil and gas industry — to maintain both profitable and environmentally compliant operations.

To date, the midstream sector has not suffered the same level of financial distress experienced by E&P or oilfield service companies. Midstream companies typically charge fees to use their pipelines and equipment (rather than drilling wells and operating rigs to produce oil and gas), and therefore are typically more insulated from commodity price cycles than E&P companies. In 2016, 12 midstream companies filed for Chapter 11 bankruptcy. Similarly, downstream companies did not experience nearly the level of distress as oilfield services and E&P companies, with only a handful of nonintegrated downstream companies filing for bankruptcy last year.

The midstream segment of the oil and gas industry seems likely to benefit from the Trump administration's change of course on the development of the Keystone XL and Dakota Access pipelines, as well as the administration's potential change of course on other major pipeline projects, providing opportunities for midstream oil and gas companies. If midstream infrastructures are improved, that should enhance economics for upstream operators as well — in particular, fully integrated oil and gas companies.

Factors to Consider in 2017. In November 2016, in an attempt to reduce record global oil inventories, the Organization of the Petroleum Exporting Countries (OPEC) agreed to its first production cuts in eight years. The agreement was broader than expected, extending beyond OPEC to include Russia and other non-OPEC countries. While the strength of the deal will depend on whether all parties deliver on their commitments, it seems unlikely oil prices will return to the $30-per-barrel levels seen in early 2016.

If the Trump administration opens more federal lands to drilling activities, which would be consistent with its emphasis on expanding U.S. oil and gas production, that could counterbalance OPEC's decision to cut production and may act as a downward pressure on oil and gas prices.

With higher energy prices, the need for financial restructuring decreases. Looking ahead, we see the need for additional restructurings in the oil and gas space even at current price levels, particularly for E&P offshore drillers who continue to experience insufficient demand for offshore rigs given the continued oversupply of oil. Even with fewer restructurings, we expect a significant amount of post-reorganization M&A activity, as credit-oriented hedge funds that now own equity of reorganized E&P companies look to monetize their investments and take advantage of increased oil prices.

Bloomberg
New Energy Finance

RECORD $30BN YEAR FOR OFFSHORE WIND BUT OVERALL INVESTMENT DOWN

Chinese slowdown and falling costs of solar power were two of the reasons global clean energy investment fell 18% in dollar terms last year

London and New York, 12 January 2017 – New investment in clean energy worldwide fell 18% last year to $287.5bn,[1] despite a record year for offshore wind financings, according to the latest authoritative figures from research company Bloomberg New Energy Finance.

The 2016 setback in global investment, signaled in advance by weak quarterly figures during the course of last year, partly reflected further sharp falls in equipment prices, particularly in solar photovoltaics. However, there was also a marked cooling in two key markets, China and Japan. Clean energy investment in China in 2016 was $87.8bn, down 26% on the all-time high of $119.1bn reached in 2015, while the equivalent figure for Japan was $22.8bn, down 43%.

Justin Wu, head of Asia for BNEF, said: "After years of record-breaking investment driven by some of the world's most generous feed-in tariffs, China and Japan are cutting back on building new large-scale projects and shifting towards digesting the capacity they have already put in place.

"China is facing slowing power demand and growing wind and solar curtailment. The government is now focused on investing in grids and reforming the power market so that the renewables in place can generate to their full potential. In Japan, future growth will come not from utility-scale projects but from rooftop solar systems installed by consumers attracted by the increasingly favorable economics of self-consumption."

Offshore wind was the brightest spot in the global clean energy investment picture in 2016. Capital spending commitments to this technology hit $29.9bn in 2016, up 40% on the previous year, as developers took advantage of improved economics, resulting from bigger turbines and better construction knowhow.

Last year's record offshore wind tally included the go-ahead for the largest ever project, Dong Energy's 1.2GW Hornsea array off the UK coast, at a cost of $5.7bn – plus 14 other parks of more than 100MW, worth anywhere between $391m and $3.9bn, in British, German, Belgian, Danish and Chinese waters.

Jon Moore, chief executive of BNEF, commented: "The offshore wind record last year shows that this technology has made huge strides in terms of cost-effectiveness, and in proving its reliability and performance. Europe saw $25.8bn of offshore wind investment, but there was also $4.1bn in China, and new markets are set to open up in North America and Taiwan."

Even though overall investment in clean energy was down in 2016, the total capacity installed was not. Estimates from BNEF's analysis teams are that a record 70GW of solar were added last year, up from

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[1] Excluding large hydro-electric plants of more than 50MW. BNEF will publish a separate estimate for large hydro investment in 2016 in the next few weeks.

56GW in 2015, plus 56.5GW of wind, down from 63GW but the second-highest figure ever.

Geographical split

Clean energy investment in the US slipped 7% to $58.6bn, as developers took time to progress wind and solar projects eligible for the tax credits that were extended by Congress in December 2015. Canada was down 46% at $2.4bn.

Investment in the whole Asia-Pacific region including India and China fell 26% to $135bn, some 47% of the world total. India was almost level with 2015, at $9.6bn, with several giant solar photovoltaic plants going ahead.

Europe was up 3% at $70.9bn, helped by offshore wind and also by the biggest onshore wind project ever financed – the 1GW, $1.3bn Fosen complex in Norway. The UK led the European field for the third successive year, with investment of $25.9bn, up 2%, while Germany was second at $15.2bn, down 16%. France got $3.6bn, down 5%, and Belgium $3bn, up 179%, while Denmark was 102% higher at $2.7bn, Sweden up 85% at $2bn and Italy up 11% at $2.3bn.

Among developing nations, many saw investment slip as projects that won capacity in renewable energy auctions during 2016 did not secure finance before the year-end. Investment in South Africa fell 76% to $914m, while that in Chile dropped 80% to $821m, Mexico fell 59% to $1bn and Uruguay 74% to $429m. Brazil edged down 5% to $6.8bn.

One of the emerging markets to go the other way was Jordan, which broke the $1bn barrier for the first time, its clean energy investment increasing 147% to $1.2bn in 2016.

2016 investment by category and sector

The biggest category of investment in clean energy in 2016 was, as usual, asset finance of utility-scale renewable energy projects. This totalled $187.1bn last year, down 21% on 2015. The biggest seven financings were all in offshore wind in Europe, but there were also large deals in Chinese offshore wind (the Hebei Laoting Putidao array, at 300MW and an estimated $810m), in solar thermal (the 110MW, $805m Ashalim II Negev plant in Israel), solar PV (the 580MW, 31 Dominion SBL Portfolio in the US, at an estimated $702m), biomass (the 299MW, $841m Tees project in the UK) and geothermal (the ENDE Laguna Colorada installation in Bolivia, at 100MW and $612m).

Among other categories of investment, small-scale projects of less than 1MW – including rooftop PV – attracted 28% less investment than the previous year, the 2016 total finishing at $39.8bn. Most of this year-on-year drop reflected falling costs of solar systems rather than a decline in interest from buyers.

Public markets investment in quoted clean energy companies was $12.1bn in 2016, down 21%. Most cash was raised by Innogy, the renewable power offshoot of German utility RWE, which secured just over $2.2bn of new money in an initial public offering, and BYD, the Chinese electric vehicle maker, which took just under $2.2bn via a secondary share issue.

Venture capital and private equity investment in clean energy firms rose 19% to $7.5bn, with the largest rounds coming from two Chinese electric vehicle businesses, Le Holdings and WM Motor Technology, raising $1.1bn and $1bn respectively. US solar developer Sunnova took the third most, at $300m.

Corporate research and development spending on clean energy fell 21% to $13.4bn, while government R&D moved up 8% to $14.4bn. Last but not least, asset finance of energy smart technologies surged 68%

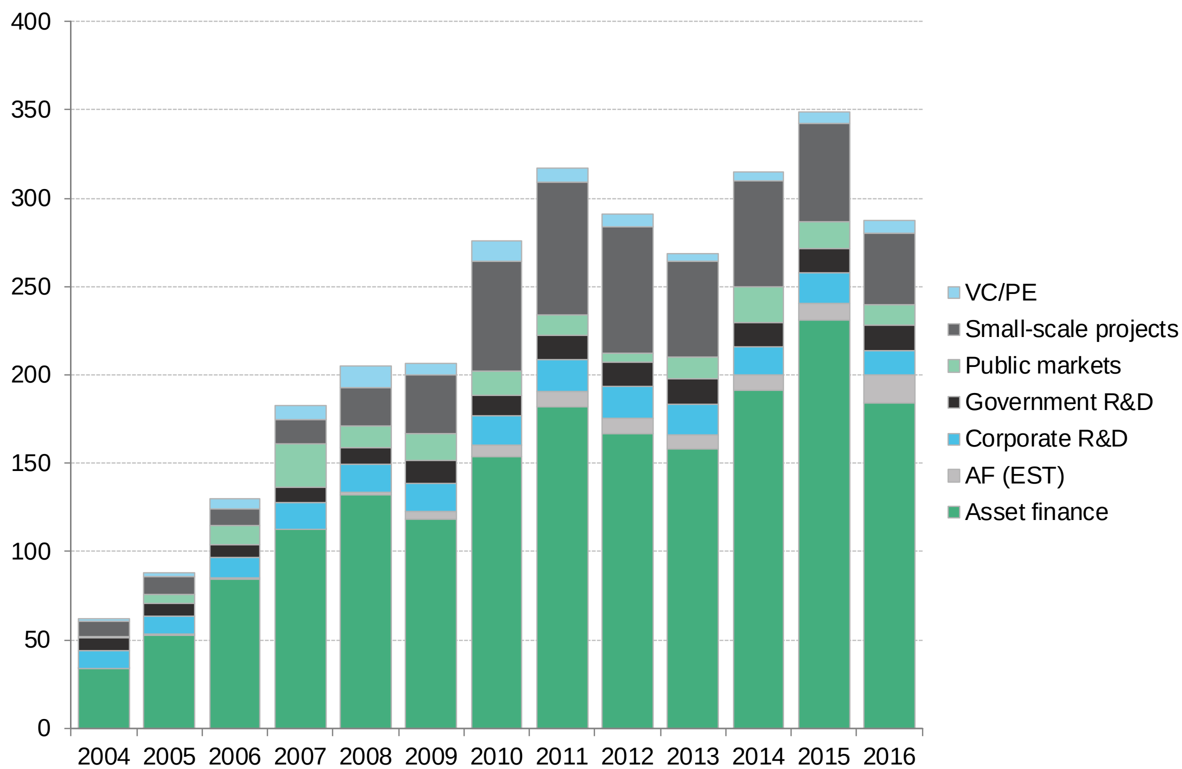
last year to $16bn, helped by a jump in global smart meter spending, from 8.8bn in 2015, to $14.4bn.

Taking all categories of investment into account, solar was the leading sector once again, at $116bn, but this was 32% down on 2015 levels, due in large part to lower costs per MW. Wind saw $110.3bn invested, down 11%, while energy smart technologies attracted $41.6bn, up 29%, biomass was more or less level on 2015 at $6.7bn, and biofuels secured just $2.2bn, down 37%. Small hydro showed a 1% dip in investment to $3.4bn, while low-carbon services attracted $4.3bn, up 5%, geothermal $2.7bn, up 17%, and marine energy $194m, down 7%.

Record acquisition activity

Also measured by BNEF, but not included in the figures for new investment, is acquisition activity in clean energy. This totaled $117.5bn in 2016, up from $97bn in 2015 and the first time this has broken the $100bn level. Behind the surge were a rise in renewable energy project acquisitions to $72.7bn and, in particular, a leap in corporate M&A to a record $33bn. The top takeovers included Tesla's acquisition of SolarCity for $4.9bn and Enel's buy-back of the minority holders in Enel Green Power for $3.5bn.

Global new investment in clean energy by category, 2004 to 2016, $bn



Source: Bloomberg New Energy Finance. Note: In this chart, asset finance is adjusted for re-invested equity. AF (EST) stands for asset finance of energy smart technologies projects, including smart grid, smart meters and energy storage. VC/PE stands for venture capital and private equity.

The updated totals for clean energy investment in past years are: $61.7bn in 2004, $88bn in 2005, $129.9bn in 2006, $182.5bn in 2007, $205.2bn in 2008, $206.8bn in 2009, $276.1bn in 2010, $317.5bn in 2011, $290.7bn in 2012, $268.6bn in 2013, $315bn in 2014, $348.5bn in 2015 and $287.5bn in 2016.

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Leveraging the most sophisticated new energy data sets in the world, BNEF synthesizes proprietary data into astute narratives that frame the financial, economic and policy implications of emerging energy technologies.

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PwC Deals

Optimize deals

North American Power & Utilities Deal Insights Q1 2017

Executive summary

In the first quarter of 2017, we saw continued focus on infrastructure as an investment thesis with AltaGas Ltd.'s (AltaGas) acquisition of WGL Holdings, Inc. (WGL). This deal represented the largest deal of the quarter, at $6.6 billion or 51 percent of total deal value, and also represented a continued theme of inbound interest from Canadian investors in US-based targets. There were two US inbound deals in the quarter, both from Canadian investors, representing $7.2 billion or 56 percent of total deal value. Renewables drove an additional theme for the quarter, with strong renewable deal activity accounting for nine of the 16 total deals in the quarter, or $4.3 billion in deal value.

By the numbers, overall deal activity in the power and utilities (P&U) industry was stronger quarter-to-quarter, but was down significantly from the same period in the prior year. Deal value in the quarter was driven by large Corporate deals, accounting for $9.1 billion or 71 percent of total deal value; however asset deals drove deal volume with 11 of the 16 deals in the quarter. Mega deals, deals greater than $1 billion, were down in Q1 2017 on a volume basis, with two total mega deals, as compared to four mega deals in Q4 2016 and seven in Q1 2016. Strategic investors dominated the deal landscape in Q1 2017, with $10.7 billion or 84 percent of deal value.

Value by the numbers

$12.8B

69% Decrease in deal value versus Q1 2016

46% Increase in deal value versus Q4 2016

Volume by the numbers

16

27% Decrease in deal volume versus Q1 2016

60% Increase in deal volume versus Q4 2016

Source: Thomson Reuters, S&P Capital IQ, and PwC analysis

> "Inbound deals returned to the forefront this quarter as opportunity to seize on growth aspects of changing supply make-up and infrastructure support in the US attracted continued interest."
>
> —**Jeremy Fago**
> PwC US Power & Utilities Deals Leader

Key trends & highlights

- Overall, Q1 2017 was a stronger quarter than the prior quarter with deal volume up by 60 percent and deal value by 46 percent. To the contrary, overall deal activity in Q1 2017 was significantly down from Q1 2016 with a 27 percent decline in deal volume and 69 percent decline in deal value.
- There were two mega deals in the quarter, as compared to four mega deals in the prior quarter and seven in Q1 2016.
- Deal activity continued to be driven by Strategic deals in Q1 2017, accounting for 84 percent of deal value, up from 51 percent in Q4 2016, but down from 92 percent in Q1 2016.
- Despite the higher deal volume of Asset deals, Corporate deals dominated deal value contributing 71 percent to total deal value in the quarter.
- Of the 11 Asset deals, renewable deals accounted for seven, and when combined with the two Corporate renewable deals, renewable deals accounted for $4.3 billion or 34 percent of total deal value in Q1 2017.
- After no inbound deals in Q4 2016, in Q1 2017 there were two inbound deals, both from Canadian investors investing in US-based targets.

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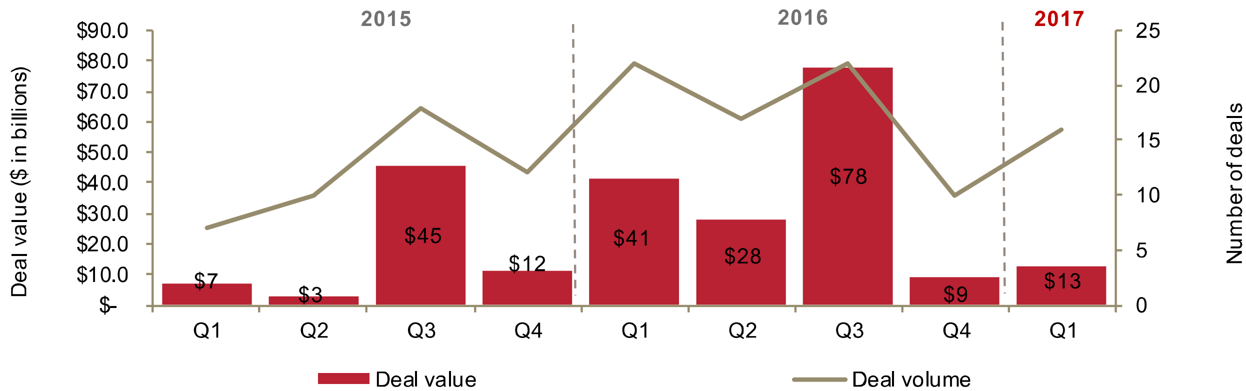
Highlights of Q1 2017 deal activity

P&U Deal Value and Volume (Deals > $50 million)



Source: Thomson Reuters, S&P Capital IQ, and PwC analysis

Key announced transactions

In Q1 2017, two mega deals were announced, including:

- The acquisition of Washington D.C. based WGL by the North American diversified energy infrastructure company AltaGas for $6.6 billion. According to the companies, the combined entity is expected to have an enterprise value of approximately $17 billion and approximately $3.4 billion in natural gas rate base assets. A continued expansion into the US market, the entity is expected to have an ability to target high growth markets and enhance its clean energy offering to customers, while maintaining a significant presence in Washington, D.C., the companies said.
- The AES Corporation (AES), Alberta Investment Management Corporation (AIMCo) and other investors agreed to acquire Sustainable Power Group, LLC (sPower), the largest independent owner, operator and developer of utility scale solar assets in the US, from Fir Tree Partners and its minority owners for $853 million in cash, plus the assumption of $724 million in non-recourse debt. In connection with the transaction, AES and AIMCo will each directly and independently purchase and own slightly below 50 percent equity interests in sPower. The transaction is expected to close by Q3 2017.

Mega deal volume down

There were two mega deals in Q1 2017, lower than the four mega deals in Q4 2016 and seven in Q1 2016. From a deal value perspective, Q1 2017 mega deals ($8.2 billion) were up 22 percent from the prior quarter ($6.7 billion), but down 79 percent from Q1 2016 ($39 billion).

Largest transaction

AltaGas' acquisition of WGL was the largest transaction of the quarter, accounting for 51 percent of total deal value in Q1 2017.

$6.6B

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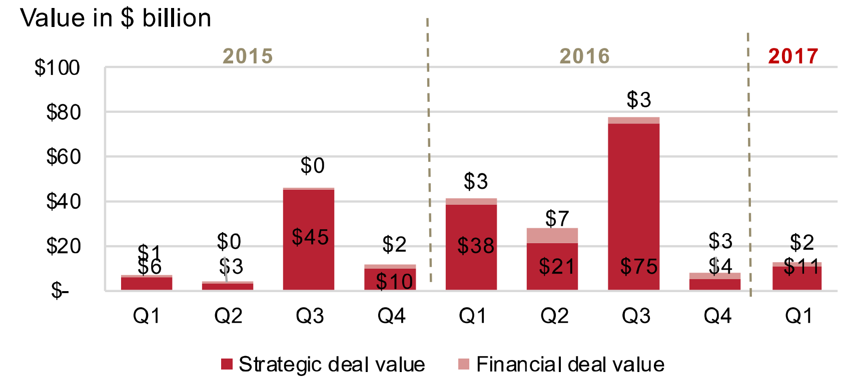
Highlights of Q1 2017 deal activity

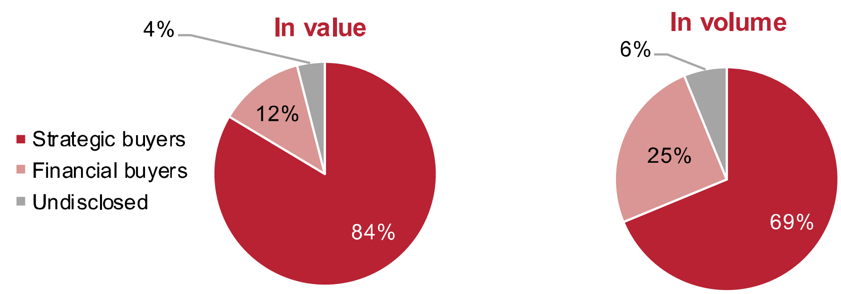
Strategic v. Financial deals

- Deal activity continued to be driven by Strategic deals in Q1 2017, accounting for 69 percent of total deal volume, up from 60 percent in Q4 2016, but down from 77 percent in Q1 2016.
- Strategic deals' share of total deal value rose to 84 percent in Q1 2017 from 51 percent in Q4 2016. However, Strategic deal value was down from Q1 2016, which accounted for 92 percent of total deal value.
- Financial deals' share of total deal volume reduced to 25 percent in Q1 2017 from 30 percent in Q4 2016, but up from 23 percent in Q1 2016. On a deal value basis, Financial deals contributed 12 percent to total deal value in Q1 2017, significantly lower than the 39 percent in Q4 2016, but an increase from the 8 percent in Q1 2016.
- Four of the top five deals in Q1 2017 were Strategic deals, including the only two mega deals of the quarter.
- There was one deal in the quarter with an undisclosed buyer, the acquisition of Veresen Inc.'s Power Generation Business, representing 6 percent of deal volume and 4 percent of deal value.

Strategic v. Financial Deals (Deals > $50 million)

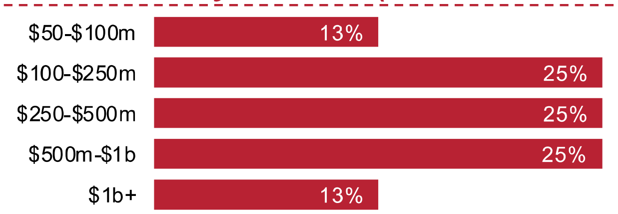


Q1 2017 Deals by Investor Group (Deals > $50 million)



Source: Thomson Reuters, S&P Capital IQ, and PwC analysis

Deal Volume by Deal Size (Deals > $50 million)



Totals may not sum to 100% due to rounding.

Source: Thomson Reuters, S&P Capital IQ, and PwC analysis

Deal size

- 13 percent of the Q1 2017 deal volume was driven by mega deals, which is a sizeable decrease from 40 percent in Q4 2016 and 32 percent in Q1 2016. However, these mega deals contributed 64 percent to total deal value in the quarter, down from 76 percent in Q4 2016 and 94 percent in Q1 2016.
- In addition to the mega deal category, the $100-$250 million deal-size category was the only other deal-size category to decline in volume as compared to Q4 2016. All the remaining deal size categories recorded an increase in deal volume as compared to the prior quarter.
- The $100-$250 million, $250-$500 million, and $500 million-$1 billion deal size categories each represented 25 percent of total deal volume, the largest representations of deal volume for the quarter.

Optimize deals

Highlights of Q1 2017 deal activity

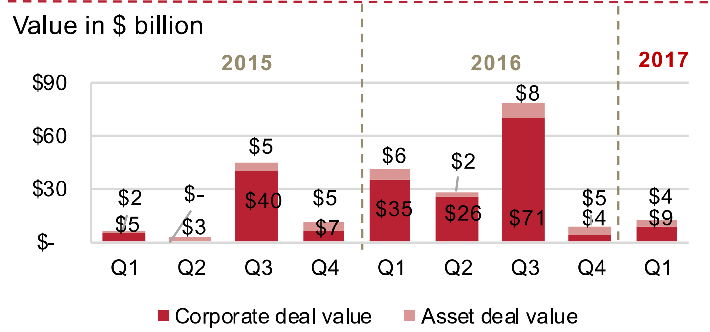
Corporate v. Asset deals

- In Q1 2017, Asset deals drove deal volume with 69 percent of total deal volume, in line with the 70 percent contribution in Q4 2016, and greater than the 59 percent contribution in Q1 2016. Of the 11 Asset deals, renewable deals accounted for seven of those Asset deals, which represented 58 percent of total Asset deal value in the quarter.
- Despite the higher deal volume of Asset deals, Corporate deals dominated deal value contributing 71 percent to total deal value in the quarter, an increase from 41 percent in the prior quarter, but lower than the 85 percent contribution from Q1 2016. Corporate deals contribution to total deal value was primarily driven by the two mega deals of the quarter, accounting for $8.2 billion or 64 percent of total deal value. These two mega deals accounted for 90 percent of the total Corporate deal value in Q1 2017.

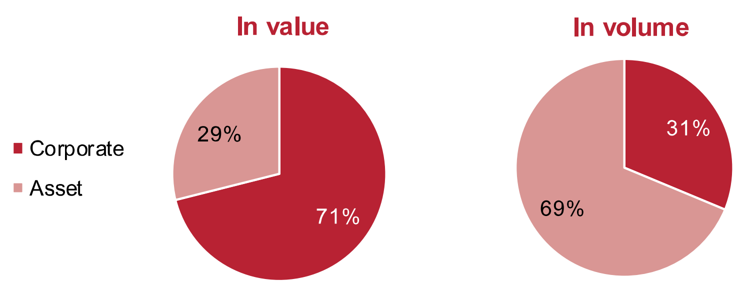
Inbound v. Domestic deals

- After no inbound deals in Q4 2016, in Q1 2017 there were two inbound deals, both from Canadian investors investing in US based targets. Despite it's smaller share of total deal volume at 13 percent, inbound deals accounted for 56 percent of total deal value in the quarter, or $7.2 billion in deal value. Much of this is due to the largest deal of the quarter being an inbound deal, constituting 91 percent of total inbound deal value for the quarter.
- Domestic deals continued to hold the larger share of total deal volume for the P&U industry in Q1 2017, accounting for 81 percent of total deal volume. The 13 domestic deals in the quarter represented $5.1 billion of deal value, or 40 percent of total deal value, down from 90 percent in the prior quarter.

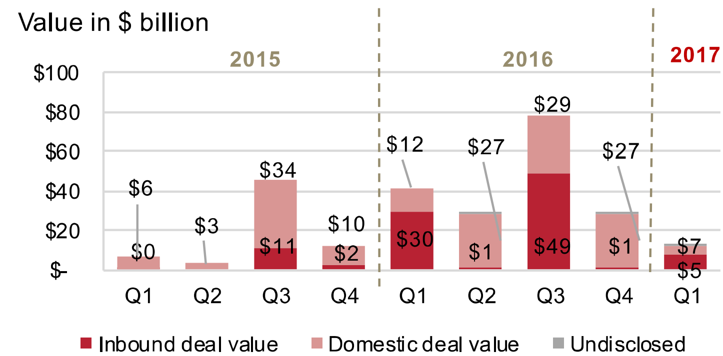
Corporate v. Asset Deals (Deals > $50 million)



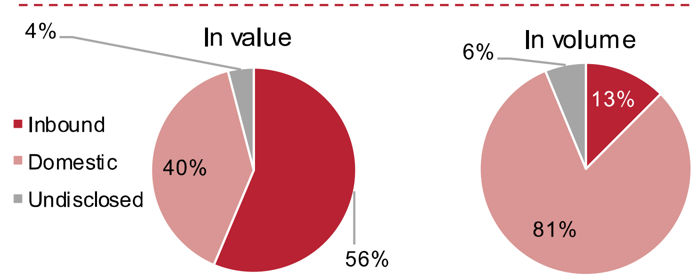
Q1 2017 Deals by Deal Type (Deals > $50 million)



Inbound v. Domestic Deals (Deals > $50 million)



Q1 2017 deals by Acquirer Geography (Deals > $50 million)



Source: Thomson Reuters, S&P Capital IQ, and PwC Analysis

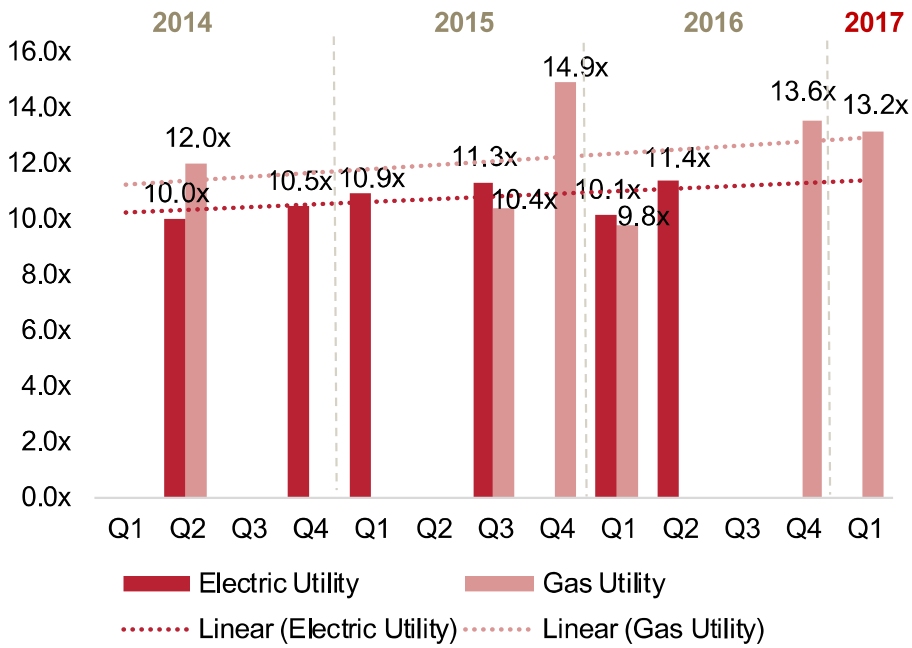
Optimize deals

Highlights of Q1 2017 deal activity

Transaction multiples

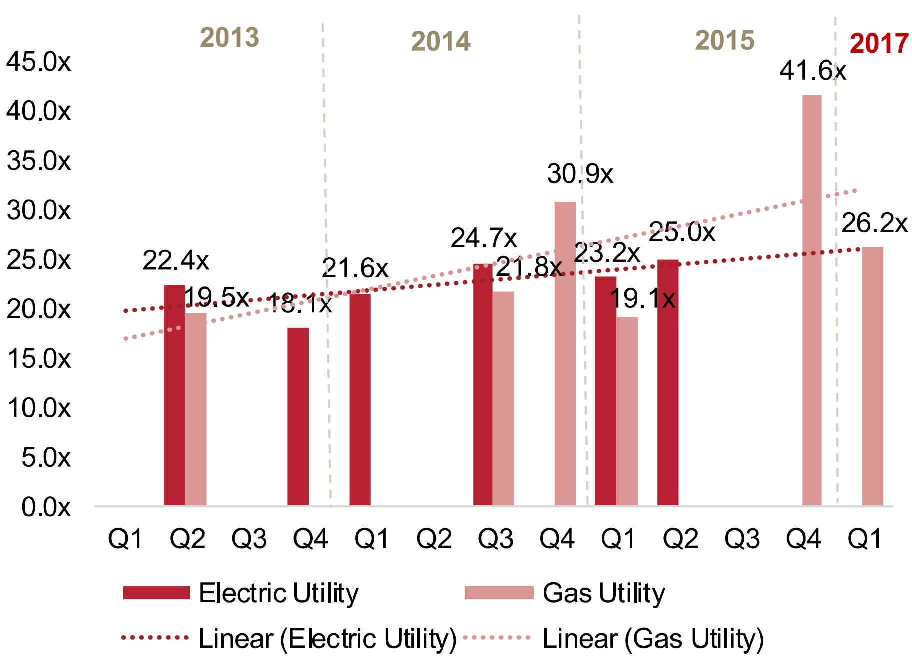
- Enterprise Value (EV)/Earnings before interest, taxes, depreciation and amortization (EBITDA) and Price/Earnings (P/E) transaction multiples have trended upward over time for electric utility and gas utility transactions.
- Small-and mid-cap utilities continue to remain potential acquisition targets, as the industry continues its trend of consolidation over the last few decades.
- Deal makers continue to remain interested in regulated yields, with the continued low interest rate environment, although recent increases in the risk-free rate and expectations for possible additional rate increases later this year could compress deal values as we move forward, holding all else equal.
- With the changing makeup of the nation's generation supply, deal makers also continue to remain interested in exposure to infrastructure, from both a gas infrastructure and transmission infrastructure standpoint.
- Comparing Q1 2017 transaction multiples to the same quarter in the prior year, EV / EBITDA and PE transaction multiples have increased for Gas Utility transactions, but have decreased from the prior quarter.

Transaction multiples – EV/EBITDA



Source: S&P Capital IQ

Transaction multiples – P/E



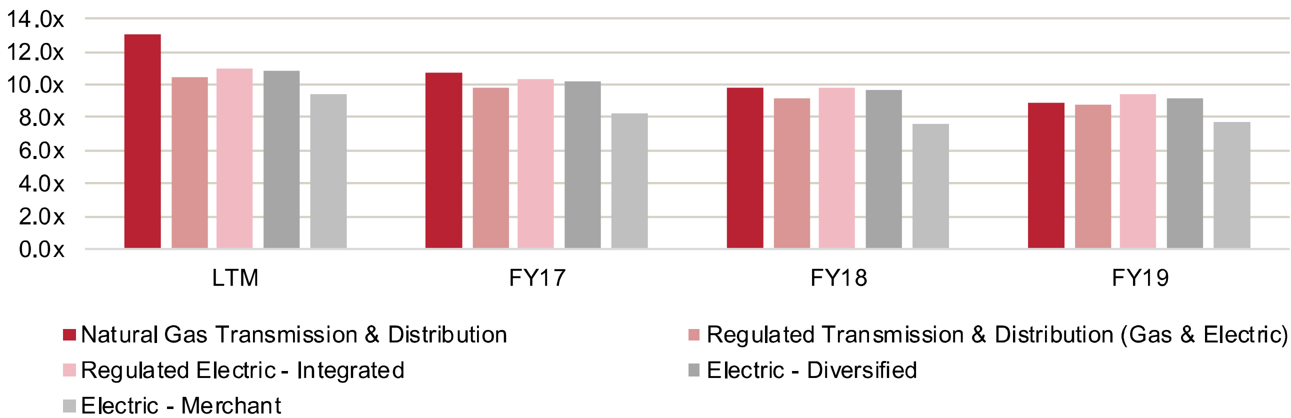
Source: S&P Capital IQ

Source: Thomson Reuters, S&P Capital IQ, and PwC Analysis

Highlights of Q1 2017 deal activity

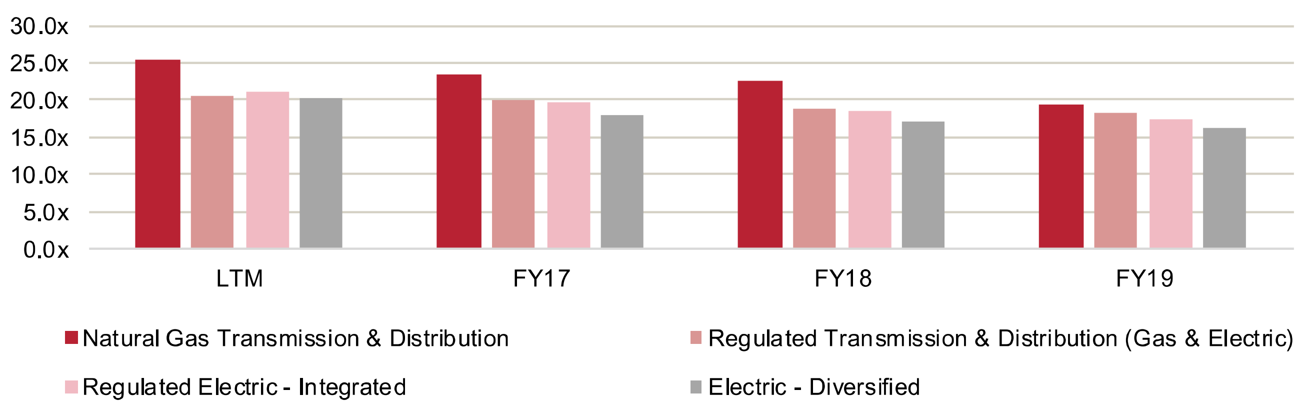
Trading multiples

EV/EBITDA



Source: S&P Capital IQ

P/E



Source: S&P Capital IQ

Trading multiples

- Natural Gas Transmission & Distribution trading multiples continue to set the high-end of the range of multiples for sub-sectors within the Power & Utilities industry, due to a number of factors including continued interest in this sub-sector provided growth opportunities with the rapidly changing makeup of our nation's generation supply.
- Electric - Merchants are currently setting the low end of the range of multiples for sub-sectors within the Power & Utilities industry, provided factors including exposure to commodity price volatility and market/ regulatory impacts.

Source: Thomson Reuters, S&P Capital IQ, and PwC Analysis

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Snapshot of Top 10 Deals

Q1 2017						
Rank	**Value ($ million)**	**Acquirer name**	**Target name**	**Transaction type**	**Investor group**	**Date announced**
1	**$6,610**	AltaGas	WGL	Corp	Strategic	1/25/17
Canada - AltaGas agreed to acquire WGL on January 25, 2017 for $6.6 billion in cash. A continued expansion into the US market, the entity is expected to have an ability to target high growth markets and enhance its clean energy offering to customers, while maintaining a significant presence in Washington, D.C.						
2	**$1,577**	AES, AIMCo, and Other Investors	sPower	Corp	Strategic	2/24/17
US - AES, AIMCo and other investors agreed to acquire sPower for $853 million in cash, plus the assumption of $724 million in non-recourse debt. In connection with the transaction, AES and AIMCo will each directly and independently purchase and own slightly below 50 percent equity interests in sPower. The transaction is expected to close by Q3 2017.						
3	**$750**	Gainesville Regional Utilities	Gainesville Renewable Energy Center, LLC	Asset	Strategic	1/31/17
US - The state-owned Gainesville Regional Utilities, planned to acquire Gainesville Renewable Energy Center LLC, an electric power generation facility operator, from American Renewables LLC, for $750 million in cash, via an unsolicited offer.						
4	**$622**	Brookfield Renewable Partners L.P and Orion US Holdings 1 LP	Undisclosed Stake in TerraForm Power, Inc.	Corp	Financial	3/7/17
Canada - Brookfield Renewable Partners L.P and Orion US Holdings 1 LP entered into an agreement to acquire an additional unknown stake in TerraForm Power, Inc. from SunEdison, Inc. and other shareholders for $622 million.						
5	**$594**	NRG Yield, Inc.	16 percent interest in Aqua Caliente and 50 percent interest in Utah Utility-Scale Solar Power Facilities	Asset	Strategic	2/28/17
US - NRG Yield, Inc. definitively agreed to acquire a 16 percent ownership interest in the Agua Caliente solar project of NRG Energy, Inc. in a privately negotiated transaction. Concurrently, the same parties definitively agreed to the acquisition of a 50 percent ownership interest in 7 utility-scale solar facilities located in Utah.						
6	**$517**	Undisclosed	Veresen Inc. Power Generation Business	Asset	Undisclosed	2/21/17
Undisclosed - An undisclosed buyer agreed to acquire the power generation business of Veresen Inc. for $517 million.						
7	**$480**	Spruce Generation, LLC (LS Power Equity Partners)	Armstrong Power, LLC and Troy Energy, LLC	Asset	Financial	2/23/17
US - Spruce Generation, LLC entered into a membership purchase agreement to acquire Armstrong Power, LLC and Troy Energy, LLC from Dynegy Inc. for $480 million.						
8	**$380**	Capital Power Corporation	Veresen Inc. Thermal Power Business	Asset	Strategic	2/21/17
Canada - Capital Power Corporation entered into an agreement to acquire the thermal power business of Veresen Inc. for $380 million.						
9	**$291**	Fiera Infra LP	50 percent interest in Cedar Point II, LP	Asset	Financial	1/25/17
Canada - Fiera Infra LP, a unit of Fiera Infrastructure Inc., acquired a 50 percent interest in the Cedar Point II wind power facility for $291 million.						
10	**$260**	Peoples Natural Gas	Delta Natural Gas Company, Inc.	Corp	Strategic	2/21/17
US - Peoples Natural Gas signed a definitive agreement to acquire Delta Natural Gas Company, Inc. for approximately $220 million. The transaction is subject to shareholder and regulatory approvals.						

Source: Thomson Reuters, S&P Capital IQ, BusinessWire, sPower company website

About PwC's Deals Practice

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For a deeper discussion on power and utilities deal considerations, please contact any one of our authors.

Smart deal makers are perceptive enough to see value others have missed, flexible enough to adjust for the unexpected, aggressive enough to win favorable terms in a competitive environment, and circumspect enough to envision the challenges they will face from the moment the contract is signed. But in a business environment where information can quickly overwhelm, the smartest deal makers look to experienced advisors to help them fashion a deal that works.

PwC's Deals group can advise power and utility companies and private equity firms on key M&A decisions, from identifying acquisition or divestiture candidates and performing detailed buy-side diligence, to developing strategies for capturing post-deal profits and exiting a deal through a sale, carve-out, or IPO. With more than 9,800 deals professionals in 75 countries, we can deploy seasoned teams that combine deep power and utility industry skills with local market knowledge virtually anywhere and everywhere your company operates or executes transactions.

Although every deal is unique, most will benefit from the broad experience we bring to delivering strategic M&A advice, due diligence, transaction structuring, M&A tax, merger integration, valuation, and post-deal services.

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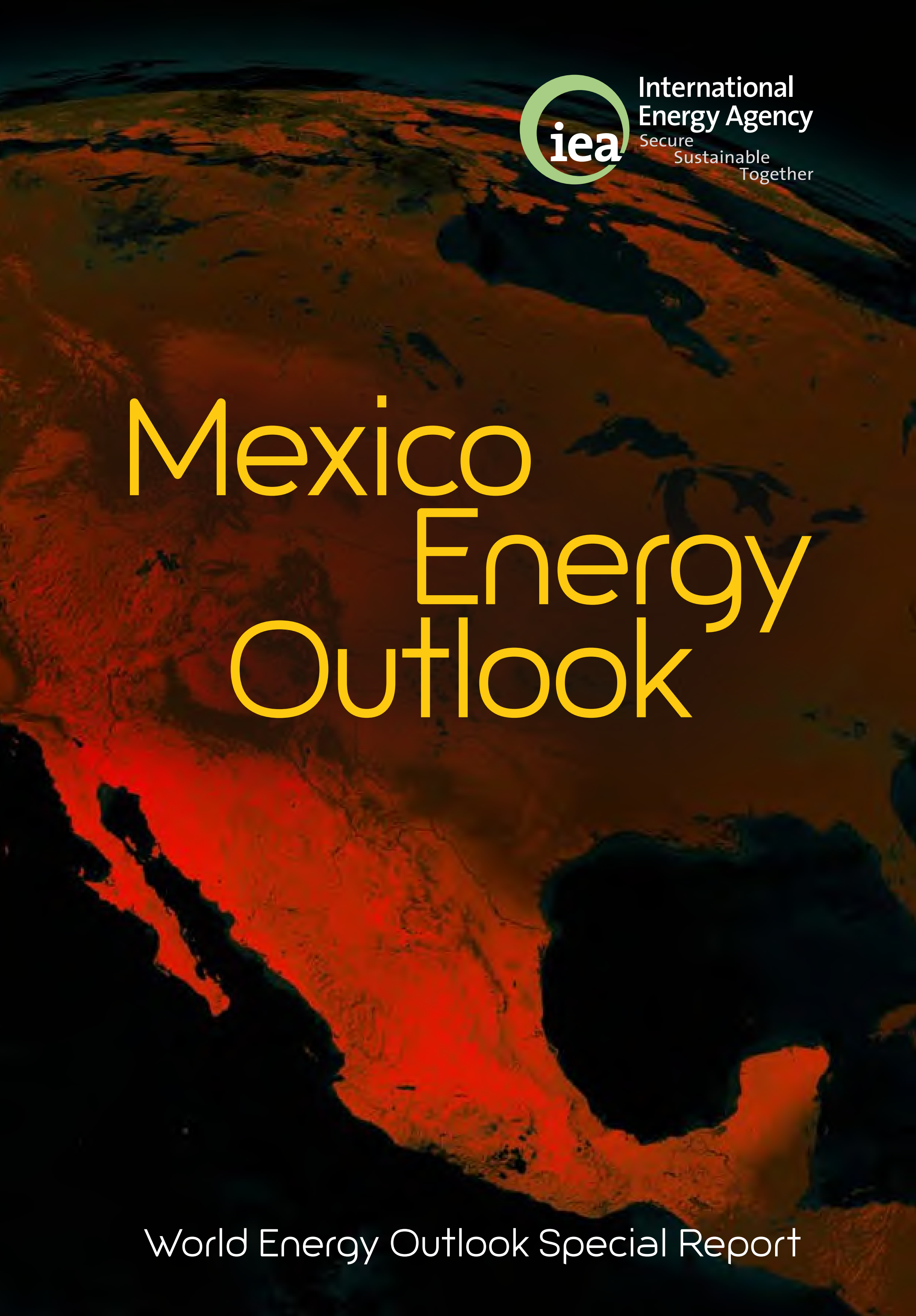
About the data

We define M&A activity as mergers and acquisitions where targets are North American-based (US or Canada) companies or assets acquired by either US or foreign acquirers. M&A activity reflects unregulated power generation and regulated (electric, gas and water) transaction activity.

We have based our findings on data provided by industry-recognized sources. Specifically, values and volumes used throughout this report are based on announcement date data for transactions with a disclosed deal value greater than $50 million, as provided by Thomson Reuters and/or S&P Capital IQ, and supplemented by additional independent research. Information related to previous periods is updated periodically based on new data collected by Thomson Reuters and/or S&P Capital IQ for deals announced during previous periods, but not reflected in previous data sets. Unless otherwise noted, all data and charts included in this report are sourced from Thomson Reuters and/or S&P Capital IQ.

Power and utility deals used in this report were developed using NAIC codes. In certain cases, we have reclassified deals regardless of their NAIC or SIC codes to better reflect the nature of the related transaction.



International Energy Agency
Secure Sustainable Together

Mexico Energy Outlook

World Energy Outlook Special Report

Mexico Energy Outlook

World Energy Outlook Special Report

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Luxembourg
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

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The European Commission also participates in the work of the IEA.

Mexico is recasting its energy sector. The *Reforma Energética* and Mexico's strong leadership on environmental issues underpin the vision of a modern energy system that meets the needs of a growing and modernising economy. The scale of ambition is truly impressive. The effects will be felt in Mexico and beyond.

Mexico and the International Energy Agency have longstanding ties, as befits a country that has for decades been a major energy player. The pace and scope of our co-operation has grown in recent years, culminating in the request made by Mexico – presented at the IEA Ministerial Meeting in November 2015 – to join the Agency. Closer ties with the IEA will not only enable Mexico to tap IEA member country experience in tackling their own energy policy challenges, but also enable the IEA to absorb lessons learned and innovative solutions developed with the Reform in Mexico. The procedures and steps required for Mexico's accession are well underway and I hope that they will be completed in 2017. Membership would not only be a milestone for Mexico and the IEA, it would also open the door to greater engagement by the IEA across Latin America.

As highlighted in this *World Energy Outlook Special Report*, Mexico's Energy Reform has already made remarkable progress, in no small part thanks to the leadership and vision shown by Secretary Pedro Joaquín Coldwell. The transformation is not yet complete and there are many tasks that still lie ahead, but there are good reasons to expect that progress will continue. I am sure the economic and social benefits will be felt by many generations to come. I trust that this report will provide useful insights to all stakeholders in Mexico, including policy-makers, the energy industry, energy experts and the general public alike. I also hope that this report will help to raise awareness elsewhere in the energy world about the scale and importance of the profound changes underway in Mexico.

The findings in the report are those of the IEA alone, but the process has been a collaborative one in which the *World Energy Outlook* team has worked closely with the Government of Mexico, especially with SENER, as well as with industry and leading Mexican research organisations, and international experts. I would like to extend my sincere appreciation to all those that have provided their support throughout this study.

Dr. Fatih Birol
Executive Director
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Mexico's energy sector is in a period of profound change, catalysed by the comprehensive Energy Reform the government has enacted since 2013. The Reform was spurred by the recognition that key energy indicators were moving in the wrong direction, with the attendant risk of a widening gap between the performance of the oil, gas and power sectors and the needs and aspirations of a modern Mexico. The Reform recasts the structures that have governed the energy sector for over 80 years, and seeks to bring in new investment and technology across the hydrocarbons value chain by ending the monopoly of *Petróleos Mexicanos* (PEMEX) and by attracting new players into the power sector to ensure cost-efficient investment into both traditional and low-carbon sources of electricity. The changes reflect both the government's broader vision of modernising the Mexican economy, as well as its intention to show leadership on environmental issues – Mexico was among the first countries to submit a climate pledge in advance of the COP21 meeting in Paris and to embed its clean energy target in domestic legislation.

The Reform has been complicated by the period of lower international oil prices. Even though Mexico's economy as a whole has diversified away from reliance on the hydrocarbons sector, oil revenue still accounted for around one-third of fiscal revenue in 2014, and so the decline in prices had a significant impact on government finances (the share of oil in fiscal revenue fell by more than half in 2015) as well as those of the major state energy companies. Crude oil production fell further in 2015 and exports followed suit, all but eliminating an energy trade surplus that stood at $25 billion as recently as 2011. However, lower prices have also had some upside: the increasing availability of relatively cheap natural gas imports from the United States has provided a welcome boost to Mexico's power sector. The government's determination to press ahead with the Reform has not diminished, as witnessed by successive and successful bid rounds for upstream oil and gas prospects, and competitive auctions for new electricity supply. The new projects promised in these bid rounds and auctions will need time to become operational, but the decisions and investments taken now are foundational for Mexico's energy future. The aim of this *World Energy Outlook (WEO)* Special Report is to assess the long-term impact of the changes brought by the Reform and to consider their potential ramifications for Mexico's economic development and environmental goals.

Time to turn the oil sector around

Mexico's projected crude oil output bottoms out at under 2 mb/d towards 2020 and then rises as the Reform efforts bear fruit, new projects – notably deepwater developments – start operation and higher oil prices improve profitability. By 2040, crude oil output returns to 2.4 mb/d, but adding in natural gas liquids and, by then, some tight oil takes total oil output in 2040 up to 3.4 mb/d. Mexico's long-standing position as one of the world's major producers and exporters has been weakened in recent years, with investment by PEMEX insufficient to arrest an output decline of more than 1 mb/d since 2004 (a loss of output greater even than Libya's over that period). The projected turnaround rests on three distinct pillars. In shallow water fields, which account for 70% of current production, the task is to mitigate current declines through enhanced oil recovery techniques and the development of satellite fields around the main existing producing complexes, Cantarell and Ku-Maloob-Zaap. The main source of future growth, however, is anticipated to come from deepwater fields. This is a new frontier for Mexico where PEMEX has less experience and where other players are anticipated, alone or in partnership with PEMEX, to play a prominent role: deepwater fields account for almost half of Mexico's projected offshore oil output by 2040. The final pillar is onshore, with Mexico's tight oil potential and the huge, but hard-to-develop Chicontapec field. Investment is likewise critical to revitalise Mexico's downstream sector, which is beset by poor performance that has pushed up gasoline imports to around 50% of total demand. Upgrades to refinery units help to push up utilisation rates from a very low 60% today towards 90% by 2040, increasing refinery runs and reducing gasoline imports to a more modest one-third of consumption (while virtually eliminating the need for imported diesel).

Imports from the United States provide a very competitive source of natural gas for Mexico, although domestic production – including shale gas – picks up in latter part of the projection period to reach 60 bcm in 2040. The rising role of gas in Mexico's energy mix is facilitated by extensive infrastructure development, the ready availability of relatively cheap gas via new pipelines from the southern United States, and regulatory and pricing reforms that are targeting a liberalised gas market by 2018. Most of Mexico's current domestic output is associated with oil production and its anticipated recovery in the 2020s is closely linked to that of oil. A key determinant of non-associated gas development, including unconventional gas, is the point at which projects can compete with imported gas supply from the US: in our projections, a gradual rise in the US wholesale gas price steadily improves the commercial case for new upstream gas projects within Mexico, triggering larger-scale development from the late 2020s. The prospects for shale gas (a projected 15 bcm in 2040, although the estimated resource base could support considerably higher output) depend also on action to ensure public acceptance, with water availability and responsible water management key issues in the most promising areas.

A clean break with the past in the power sector

Further opening of the power sector to private participation helps Mexico mobilise the $10 billion per year that it needs to meet an 85% increase in electricity demand to 2040: a more efficient power system brings a 14% decrease (in real terms) in industrial electricity prices to 2040, despite a projected increase in the natural gas price over the period. The unbundling of the *Comisión Federal de Electricidad* (CFE) and long-term auctions for energy, capacity and clean energy certificates provide new players with access to Mexico's power market on a competitive basis, as well as a cost-effective way to bring low-carbon generation into the mix. The first two auctions for new power supply, held in 2016, demonstrated strong private readiness to invest in new solar PV and wind generation, validating the innovative choice of market design. Investment in strengthening the grid and bringing down network losses, alongside a continued switch away from expensive oil-fired generation (which is all but complete by 2020), all help to keep the costs of electricity supply in check, providing a boost to Mexico's industrial competitiveness. This also provides an opportunity to reduce the costs of subsidies for residential electricity consumers, which currently run at $6 billion per year; we assume that these subsidies are removed gradually to 2035, in which case the cumulative subsidy bill would be around $90 billion.

The new policy and market design also provides a substantial boost to Mexico's clean energy efforts: more than half of the 120 GW of new power generation capacity installed to 2040 is renewables-based. This halves the emissions intensity of power generation (from more than 450 g CO_2/kWh in 2014 to 220 g CO_2/kWh in 2040) and even produces an absolute decline in power sector emissions over the *Outlook* period. A distinctive feature of Mexico's Reform in the power sector is that clean energy has been integrated into the Reform package from the outset. This eases the achievement of a 35% share of electricity generation sourced from clean energy by 2024 (a target written into the Energy Transition Law), plays a large part in moving Mexico towards its climate pledge to reduce greenhouse gas emissions by at least 25% below business-as-usual by 2030, and also reduces emissions of other air pollutants.

Efficiency measures can put Mexico on a healthier path to growth

Energy demand in Mexico has grown by a quarter and electricity consumption by half since 2000, but per-capita energy use is still less than 40% of the OECD average, leaving strong potential for further growth. Opportunities for energy savings also exist, with the energy intensity of Mexico's economy higher than the OECD average and showing only a limited improvement since 2000. The energy mix is dominated by fossil fuels, particularly oil, which accounted for more than half of total demand in 2014, making Mexico one of the most oil-reliant major economies in the world. Transport is by some distance the largest end-use sector, accounting for almost 45% of final consumption. The vehicle fleet has grown from 14 million in 2000 to more than 30 million today, leading to traffic congestion that has taken a toll on urban air quality — all of Mexico's largest cities far exceed the World Health Organization's upper recommended limit for particulate matter concentrations.[1]

In our main scenario, the economy doubles in size to 2040 but total primary energy demand grows only by around 20%: further growth is tempered by efficiency improvements and structural shifts in the economy that halve the energy intensity of Mexico's economy. Oil loses ground in the overall energy mix, its share declining to 42% in 2040 as that of gas continues to rise (reaching 38% by 2040) and low-carbon sources grow rapidly from a relatively low base. Among the main end-use sectors, robust growth in demand from industry, services and the residential sector is fuelled by gas and, particularly, by electricity, the latter accounting for almost half the increase in final energy consumption to 2040. Electricity demand grows at a pace more than three-times faster than the OECD

[1] See also "*Energy and Air Pollution: World Energy Outlook Special Report 2016*", available for free at: *www.worldenergyoutlook.org/airpollution*.

average, as rising incomes and living standards feed through into higher ownership levels of a range of electrical appliances, and demand for cooling increases three-fold. Efficiency improvements, motivated in large part by tighter standards and more stringent codes, play a prominent role in mitigating the rise of consumption. Yet the potential for further savings is substantial. For example, no fuel-economy standards have yet been announced for freight transport: heavy goods vehicles currently consume less than 15% of total transport energy demand but they are expected to account for more than half of the increase in transport fuel consumption to 2040.

A "No Reform Case" highlights what is at stake for Mexico's energy sector

Mexico's pre-Reform energy pathway was not a sustainable one: the cumulative gains in GDP from the Reform to 2040 are estimated at more than $1 trillion, compared with a case in which the reforms do not take place. A "No Reform Case" posits an outlook for Mexico in which none of the major reforms since 2013 are enacted, so the state monopoly is maintained in oil and gas and there is no additional private participation or restructuring in the electricity sector. The historical relationship between oil revenue and PEMEX upstream spending was used to derive an alternative outlook for upstream investment in the No Reform Case, a constraint that severely limits Mexico's capacity to fund expansion and enhanced recovery projects in legacy fields, and delays the start of technically challenging deep water and tight oil development projects. This results in oil production being some 1 mb/d lower by 2040 than in our main scenario. In the power sector, without the same efficiency gains made in networks and other parts of the system, the costs of electricity supply are higher, meaning higher prices for industry and an expanded subsidy bill for households (a cumulative $135 billion to 2040) to avoid sharper rises in residential electricity tariffs. Without specific policies to increase the role of clean energy, lower deployment of renewables leaves Mexico well short of its clean energy targets. The repercussions extend beyond the energy sector and into the wider economy: the net impact is to leave Mexico's economy 4% smaller in 2040 than in our main scenario.

Successful Energy Reform is essential to secure the investment in energy supply required in our main scenario, $240 billion in the power sector and $640 billion in the upstream, and an additional $130 billion in energy efficiency. Mobilising cost-efficient investment at average levels of $40 billion per year represents a constant challenge for Mexico's policy. Significant tasks remain, notably to ensure that the new regulatory bodies have the authority and capacity to oversee the transition to competitive, efficient and transparent market operation, that the reformed "state productive enterprises" of PEMEX and CFE focus on their strengths, and that effective regulation can allow other players to compete with them on an equal footing. But the initial signs are positive, in terms of the overall direction and design of the Reform effort, the readiness on the part of the government to ensure that the terms for investment remain attractive, and the response of the private sector in the bid rounds and auctions.

Energy in Mexico today

To improve is to change

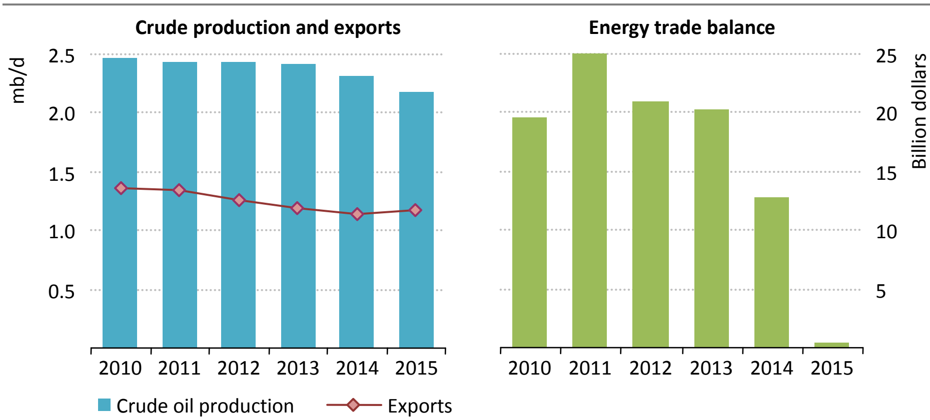
Highlights

- Mexico's Energy Reform (*Reforma Energética)*, initiated in 2013, is transforming the country's oil, gas and electricity sectors. A new regulatory and institutional framework has brought an end to long-standing monopolies, opening competition in all aspects of oil and gas supply, and power generation. Private investors can now participate, alongside PEMEX and CFE, the two large state-owned enterprises, in a wide range of the energy industry value chain, attracting capital and technology to areas that are in need of renewal.
- Total energy demand in Mexico has grown by a quarter since 2000 and electricity consumption by half, but per-capita energy use is still less than 40% of the OECD average, leaving scope for further growth. The energy mix is dominated by oil and gas, with oil accounting for around half of the total – a share higher even than that in the highly oil-dependent Middle East.
- Oil has traditionally played a major role as a fuel for power generation, but it is rapidly losing ground to natural gas, whose cost advantage has been reinforced by the shale gas boom in the United States. Non-fossil fuelled generation, primarily from hydropower and nuclear, currently accounts for one-fifth of the total. Wind power has gained a foothold, with capacity of around 3 GW in 2015; but this remains far below its potential. The market for solar PV is nascent, but is expected to grow rapidly: the first two auctions for new long-term power supply, held in 2016, demonstrated private sector willingness to invest in new solar and wind capacity.
- Mexico's long-standing position as one of the world's major oil producers and exporters has weakened in recent years, with oil production declining by over 1 mb/d since 2004. This fall in output is linked to a shortfall in the funds available to PEMEX for capital expenditure to slow declines in mature fields or to develop new ones. A combination of limited refining capacities and rising demand means that Mexico is a net importer of oil products. Natural gas output has also been in decline (most of the production is associated with oil) and imports now meet almost 50% of gas demand.
- Sustainability and climate change considerations are prominent in Mexico's energy policy. Mexico was among the first nations to submit a climate pledge in the run-up to COP21, and was among the countries that pushed hardest for a climate change agreement in Paris. It has legislated to adopt a binding climate target: the second country in the world to do so. With institutional changes that help promote clean energy, Mexico is embarked on a course towards a considerably more sustainable and efficient energy system in the future.

1.1 Introduction

In a fast-changing energy world, Mexico is a leading proponent of change. After a long period in which a state-run and oil-dominated energy system gradually lost direction and momentum, Mexico's energy sector has been shaken up by a bold *Reforma Energética* (Energy Reform), initiated in 2013 as part of a broader effort to modernise and diversify the country's economy and increase the competitiveness of industry. A cornerstone of the Reform is the objective to open the energy sector to private and international investment by ending the monopolies of various state-affiliated enterprises.[1] The overall aim is to provide for a more sustainable, efficient, transparent and productive energy sector, to increase the benefits drawn from the country's large hydrocarbon resource, while also encouraging low-carbon sources of growth (see section 1.3.2).

Figure 1.1 ▷ Crude oil production, exports and the energy trade balance in Mexico, 2010-2015



Key energy indicators in Mexico have been moving in the wrong direction

Note: mb/d = million barrels per day. Source: SENER.

Several considerations gave impetus to the Reform. The state-owned oil company, *Petróleos Mexicanos* (PEMEX), which had enjoyed a monopoly on upstream development, was not in a position to make the investments necessary to arrest declining oil production from ageing oil fields, resulting in a squeeze on the volumes available for export (a factor that, alongside the decline in the oil price, helps to explain the decrease in the energy trade balance from $25 billion in 2011 to just $325 million in 2015) (Figure 1.1). In the power sector, limited private sector participation in electricity generation and the monopoly position of the state utility, *Comisión Federal de Electricidad* (CFE) in the transmission, distribution and retail sectors, translated into inefficiencies across the system that have pushed up costs.

[1] In this report, we refer to the *Reforma Energética* as the Reform and the Energy Reform.

Meeting Mexico's rising energy demand in an efficient, secure, sustainable way depends on diligent effort to achieve the promise of the Reform. Bringing in new players, capital and technology requires careful design of the implementing measures and early creation, at the necessary scale, of the essential institutional structures. The intention of this special report is to provide a strategic input to this process by offering a coherent analytical framework against which Mexico's own policy choices can be tested.

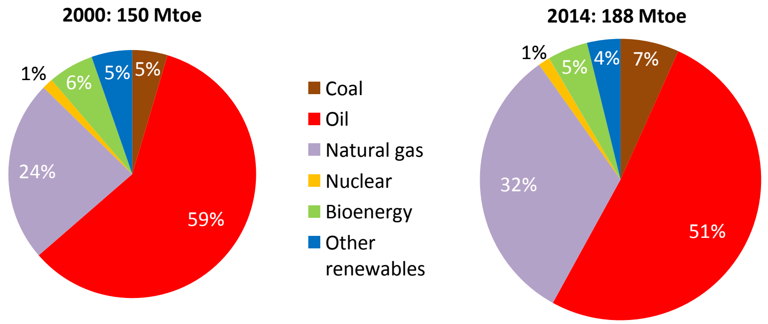
1.2 Key energy trends in Mexico

1.2.1 Energy demand

Primary energy demand

Primary energy demand in Mexico has increased by 25% since 2000, a rise that mostly matches the expansion of the economy, meaning that the energy intensity of Mexico's economy shifted only slightly over this period, from 0.180 tonnes of oil equivalent (toe) required for each $1 000 of gross domestic product (GDP) in 2000 to 0.168 toe/$1 000 in 2014. This pace of improvement is around one-third of that of the Organisation for Economic Co-operation and Development (OECD) average. The absolute level is also relatively high compared with an OECD average of 0.118 toe/$1 000, reflecting the structure of the Mexican economy – where the high value added but low energy use services sectors plays a smaller role than elsewhere in the OECD – as well as the opportunities that remain to improve energy efficiency. Mexico is also different from the OECD group as a whole in that there is substantial potential for further growth in energy consumption: per-capita energy demand in Mexico is the lowest among OECD countries, less than 40% of the average. While aggregate energy use in the OECD is set to decline in the decades to 2040 (despite growing economic activity), Mexico's energy use is set to rise.

Figure 1.2 ▷ Primary energy demand by fuel



Gas is rapidly expanding its role, but oil remains the dominant force in Mexico's primary energy mix

Fossil fuels dominate the primary energy mix, with oil, natural gas and coal collectively accounting for around 90% of primary demand for the past two decades. Oil remains the dominant fuel, with demand currently at 96.4 million tonnes of oil equivalent (Mtoe). Over the last decade, there has been a shift from oil towards natural gas, primarily in power generation, which has decreased the share of oil in the primary energy mix from 59% in 2000 to 51% in 2014 (Figure 1.2): this is still one of the highest such indicators in the world, above even the 48% share of oil in the Middle East. Demand for natural gas has increased by more than 70% since 2000, with its share in the primary energy mix increasing from 24% in 2000 to 32% in 2014. Fuel switching in the power sector, rising industrial demand and, more recently, the import opportunity that opened up for Mexico by the shale gas boom in the United States (and facilitated by Mexico's policy of constructing new gas import pipelines) have accelerated the use of gas. The overall share of renewable energy has fallen slightly, to 8.5% of total primary energy, reflecting in part the declining use of solid biomass, mainly fuelwood used by poorer households.

Sectoral demand

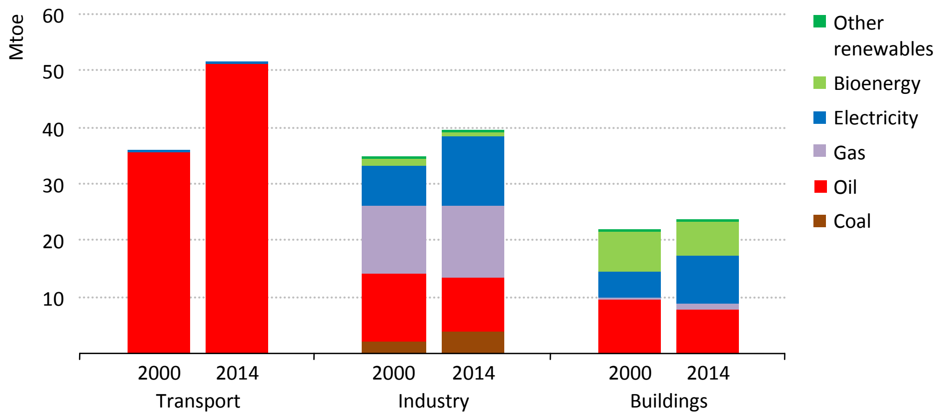
Energy demand for transport accounted for over 40% of total final consumption in 2014, significantly higher than the OECD average of 33%. The transport sector is the largest energy consumer of all end-use energy sectors in Mexico, well above industry (28%) and buildings (20%) (Figure 1.3). Energy demand for transport has been rising rapidly, at an average annual growth rate of 2.6% since 2000, as the passenger vehicle stock rose from around 9 million in 2000 to over 25 million in 2014, with rates of ownership more than doubling to over 200 vehicles per 1 000 people over the same period. Unsurprisingly, transport sector consumption is completely dominated by oil products, and the rise in demand has led to serious problems of traffic congestion and air pollution in the large cities. The policy response from the government has encompassed a range of measures (see section 1.3.4.), from tighter restrictions on the sulfur content of fuels to the "one-day-without-a-car" programme, which restricts private vehicles from circulating in Mexico City when air pollution exceeds specified levels.

Industrial energy demand[2] has increased by about 14% since 2000, while the contribution to GDP made by industry has grown by about 17% during the same period, meaning that industrial energy intensity, as measured by total industrial energy consumption/$1 000 of value added by industry, has remained almost flat during the period. However, this results from the combination of two contrary trends: the continuous decline in energy intensity in the major energy-intensive industries, counterbalanced by a rise in energy intensity elsewhere. Energy-intensive industries, such as iron and steel, chemical, cement, and paper and pulp industries, accounted for 45% of industrial energy demand in 2014 and their energy intensity has declined continuously over the past twenty years. For example, the energy intensity of the iron and steel branch of the industry sector (calculated as energy consumption/tonne of steel produced) has fallen by 40%, while that of the chemical

[2] Industry energy demand includes blast furnace, coke ovens and petrochemical feedstocks.

industries (calculated as energy consumption/tonne of high value chemicals produced) declined by 60%. Intense global competition in commodity markets has obliged these industries to take energy-saving measures in order to compete, which has resulted in lower energy intensity.

Figure 1.3 ▷ Energy demand by fuel in selected end-use sectors



The oil-dominated transport sector is growing fast and has by far the largest share of final energy consumption in Mexico

Taking advantage of relatively low labour costs in Mexico, proximity to the large United States market and free trade agreements in the region, many large companies, notably car manufacturers and their component suppliers but also other manufacturing firms, have set up operations in Mexico. As a result, Mexico's industrial electricity consumption has increased significantly in recent years, rising by almost 70% since 2000. Electricity consumption in the central-west and north-east regions of Mexico, where many automakers, auto parts and appliance factories are located, accounts for almost half of the growth in national electricity consumption over the last ten years (SENER, 2016). Ensuring reliable electricity supply, at competitive rates, is vital to support the role of these manufacturing industries in the Mexican economy.

In the buildings sector, energy consumption has increased by just 10% since 2000. This relatively moderate growth is largely due to efficiency gains as solid biomass is displaced as a residential fuel by electricity and natural gas. Within the buildings sector, electricity demand has increased rapidly – by more than 80% since 2000 – and has become the main source of energy as the household ownership rate of appliances such as televisions and refrigerators has grown to more than 80%. Nonetheless, on a per-capita basis, electricity consumption in the residential sector is still only around one-quarter of the OECD average, highlighting the potential for additional growth as incomes rise further. This also underlines the importance of energy-saving measures in the sector: a number of programmes are underway (Box 1.1).

Box 1.1 ▷ "Good light" for households in Mexico

Tapping Mexico's efficiency potential in the buildings sector is becoming an important policy priority, as rising incomes and urbanisation push up electricity consumption. Mexico has already implemented a variety of measures to foster efficiency in the buildings sectors, such as efficiency standards for lighting, appliances and insulation, although limited resources and capabilities, weak co-ordination between different levels of government and a lack of public awareness can result in indifferent enforcement of those measures. Energy efficiency standards for buildings, for example, have been developed at federal level, but local governments, which are responsible for incorporating them into local bylaws, enforcing and updating them, have limited capacity to do so.

There are, however, some positive examples of what can be undertaken, notably a massive programme for replacing inefficient light bulbs in households, known as *Ahórrate una Luz* (Save yourself a light). FIDE, a public-private fund promoting electricity savings, has launched this programme to give as many as 40 million ballasted compact fluorescent lamps (CFLs) to 8 million families in small Mexican towns (FIDE, 2016). The government expects to achieve annual savings in electricity bills and consumption of almost 2 400 gigawatt-hours (GWh), an amount corresponding to more than 3% of residential electricity consumption in 2014. As of November 2015, the programme has made steady progress towards its goal, providing 15.5 million CFLs to 3.1 million families. In addition, the government of Mexico has introduced a residential appliance replacement programme, whereby it provides subsidised loans to finance replacement of more than two million old refrigerators by more efficient ones. This is one example of a concerted effort to nurture a culture of energy saving in households.

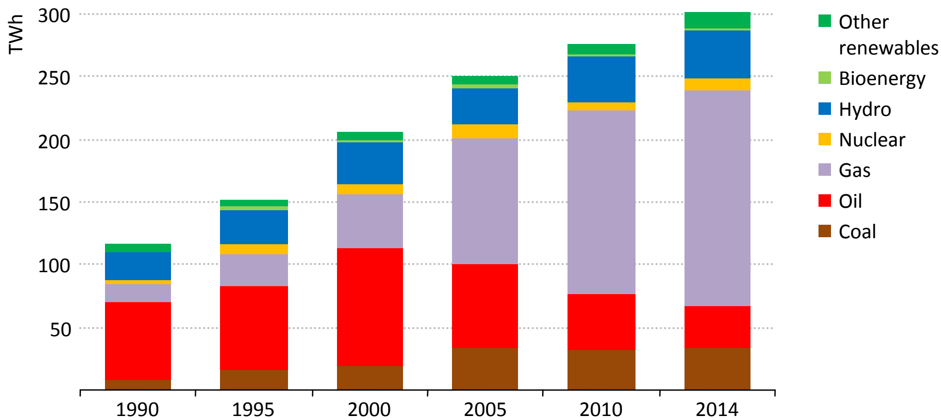
1.2.2 Electricity

Electricity demand and supply

Electricity demand in Mexico has more than doubled over the last 20 years and in 2014 accounted for around 18% of total final energy consumption (a level consistent with the global average share, albeit slightly below the OECD average of 22%). More than 99% of the population has access to electricity, but per-capita consumption is relatively low. Among the end-use sectors, industry accounts for well over half (56%) of final electricity consumption, much higher than the average elsewhere in the OECD. However, growth in electricity demand in the buildings sector, which constitutes almost 40% of final electricity consumption, has been faster since 2000, the annual growth rate being more than 4%.

On the supply side, generation is dominated by natural gas, which has supplanted oil as the main fuel for power generation (Figure 1.4). As recently as 2000, oil accounted for almost half of total generation, but the high cost of oil-based generation and rising concerns about local air pollution have led successive administrations to promote diversification of the power mix. Already in the 1990s, policies allowing the private sector to invest in power generation as well as in natural gas transmission, distribution and storage were introduced to encourage gas use in power generation. This resulted in 25 permits being issued for Independent Power Producer (IPP) projects for gas-fired power plants and more than 40 private companies becoming active in gas and electricity projects, the first such significant private sector participation in Mexico's electricity sector. Since 2014, IPPs generate around 30% of Mexico's electricity supply (SENER, 2016). Gas consumption for power generation has almost tripled since 2000 (while oil use has more than halved) and the share of gas-fired power generation overtook that of oil in 2003.

Figure 1.4 ▷ Electricity generation by fuel



Electricity generation in Mexico has more than doubled since 1990 and diversified away from a costly reliance on oil

Notes: TWh = terawatt-hours. Other renewables include geothermal, solar PV and wind.

As of 2015, Mexico had around 19 gigawatts (GW) of non-fossil fuel generation capacity (of a total installed capacity of 70 GW), providing around one-fifth of total generation. The largest share from non-fossil fuels comes from hydropower, followed by nuclear and wind. The main source of non-hydro renewables for power generation traditionally had been geothermal, but in recent years the contribution of wind power has grown rapidly. Renewable energy generation technologies are likely to see rapid expansion as the Reform opens investment opportunities to help meet Mexico's climate pledge and clean power targets (See section 1.3.2).

Transmission and distribution

During the past decade, the transmission and distribution (T&D) network in Mexico expanded by 2.6% on average annually. Technical losses, due to the poor state of the current network in parts of the country, are at 6% of generation in 2015. Together with non-technical losses of 7.9% due to theft, non-payment or inadequate billing arrangements, this means that 14% of the electricity fed into the T&D network is not paid for by users. This far exceeds the OECD average figure of 6.6%. The government has set the target of reducing T&D losses to 8% in 2024 and has initiated relevant programmes, including introducing smart grid technology, replacing metering equipment, ensuring efficient billing and bringing communities with illegal connections into the formal distribution system. Since 2014, the electricity market reform has allowed private sector players to participate in public tenders to construct T&D lines and gives CFE the option of offering contracts to private sector companies to manage distribution areas.

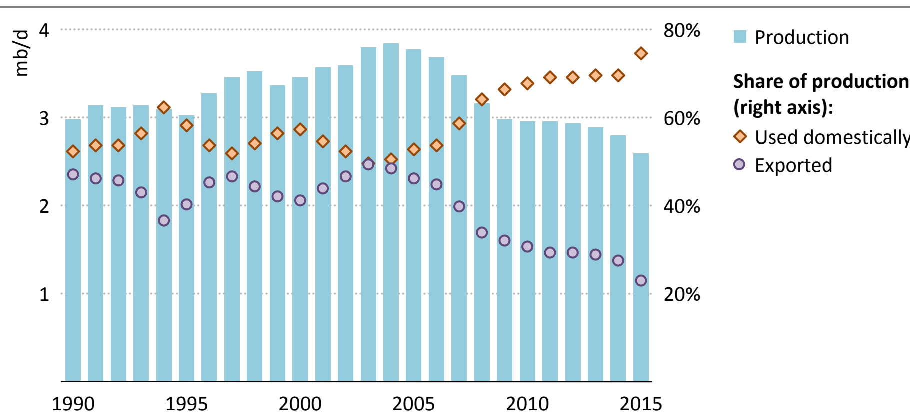
Currently there are 13 international connections between Mexico and neighbouring countries, of which 11 connections are with United States and 2 with Central America. The connections with United States consist of five for emergency purposes and six for routine exports and imports. Exports from Mexico to the United States (1 700 GWh in 2015) and imports from the United States to Mexico (1 630 GWh) are equivalent to only 4% of the volumes exchanged between the United States and Canada.

1.2.3 Energy resources, production and trade

Oil and oil products

Mexico is the eleventh-largest oil producer in the world, but has been confronted in recent years by a combination of declining oil production and rising demand. Oil production (crude and natural gas liquids) stood at 2.6 million barrels per day (mb/d) in 2015, well below the high point of 3.8 mb/d in 2004 (Figure 1.5). Overall production has been dragged down by declines at mature fields (notably the offshore Cantarell field that produced more than 2 mb/d in 2004, but where output has since fallen by over 80%) and by failure to develop sufficient new resources to compensate for these declines. The problem is not one of resource availability; Mexico has significant remaining resources, including those in deepwater and unconventional oil and gas. However, the pre-reform model that made PEMEX the sole player in oil and gas upstream development, coupled with government reliance on hydrocarbon revenue for other spending priorities, deprived the upstream of the investment and technology that it needed.

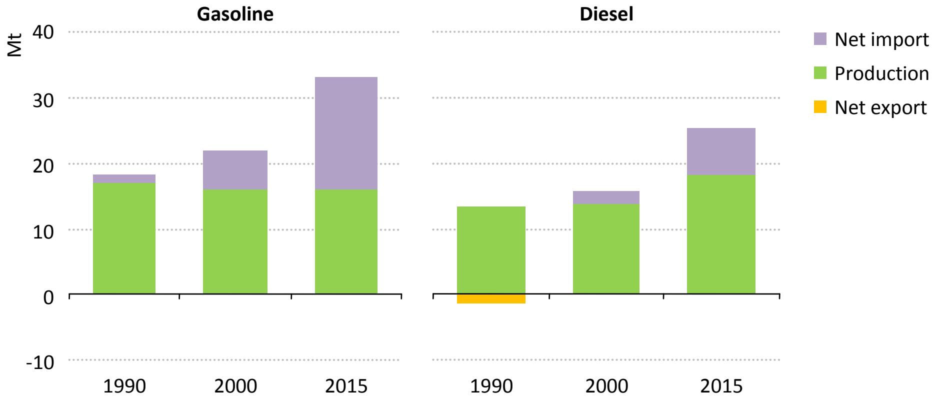
Figure 1.5 ▷ Oil production and exports, 1990-2015



Less than 25% of oil production is now exported, because of output declines and rising domestic needs

The falling trajectory of oil production and the steady rise in demand in the domestic market have squeezed the volumes of crude oil available for export: shipments fell to 1.2 mb/d in 2015 from a peak of 1.9 mb/d in 2004. Mexico's dependence on imports of refined products has also risen substantially: since 2000, net imports of gasoline and diesel have almost tripled, most of which are furnished by refineries in the United States (Figure 1.6).

Figure 1.6 ▷ Production and trade of gasoline and diesel



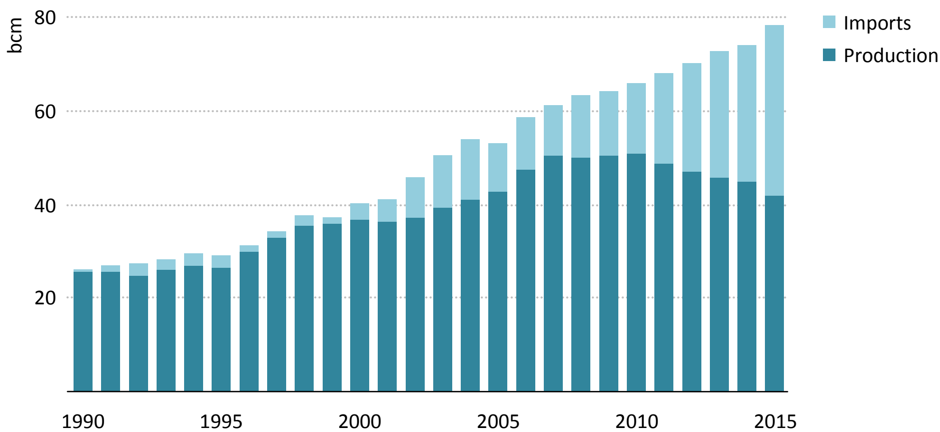
Rising demand for transport fuels in Mexico has been met mainly by an increase in imports from the United States

Mexico's own refinery capacity has not kept pace with the increase in domestic product demand and, in addition, some of the existing capacity is not well adapted to process Mexico's increasingly heavy crude slate. The six PEMEX refineries (with a joint capacity of 1.6 mb/d) were all built prior to 1980 and a shortage of investment capital – alongside the prohibition on private investment in oil – has stymied attempts to expand or modernise the refining sector. A partial fix for some of Mexico's refinery limitations has taken the form of joint ventures with US refiners, such as the Deer Park Shell-PEMEX refinery at the Houston Shipping Channel in Texas, which processes heavy Maya crude imported from Mexico and exports products back to the Mexican market. Over the longer term, investment in modern refinery capacity – by PEMEX and others – will be needed to avoid a further surge in product imports.

Natural gas

Around three-quarters of Mexico's natural gas production comes from associated gas and this means that gas output, like oil, has been on a declining trend in recent years. Production in 2015 was 42 billion cubic metres (bcm), down 18% from the peak in 2010 (Figure 1.7). As in the case of oil, the country's resources are sufficient to support significantly higher output of both conventional and unconventional gas. The US Department of Energy/Energy Information Administration has assessed Mexico's shale gas potential as the sixth-largest in the world. However, the incentive to develop Mexico's gas resources at scale has been weakened by the ready availability of gas for import, at very competitive prices, from southern US states. Gas imports from the United States have been increasing at an average annual rate of 26% over the past five years and now meet around 40% of Mexico's natural gas demand.

Figure 1.7 ▷ Production and imports of natural gas



Gas imports to Mexico have risen sharply to compensate for declining output and to benefit from the US shale gas boom

Today there are 17 cross-border natural gas pipelines between United States and Mexico, with total transport capacity of around 50 bcm per year. Further expansion is at hand: some 20 gas pipeline construction projects are in various stages of realisation, with four projects already in the construction phase and expected to be completed in 2016 (CFE, 2016). The government of Mexico has estimated that, by 2019, gas import pipeline capacity from the United States will increase to around 100 bcm, roughly twice the current level. Mexico also has three liquefied natural gas (LNG) regasification terminals, two of which are connected to the main gas grid. Around 30% of imported gas was sourced in 2014 under long-term contracts, mainly from Qatar, Nigeria and Peru. Additional pipeline imports from the United States are expected to displace this LNG from the Mexican market, with occasional LNG cargoes being used mainly to balance any shortages in supply from pipeline imports and domestic production.

Renewable energy resources

Mexico has abundant renewable energy resources, that – with the exception of hydropower – it has barely started to tap. Hydropower capacity, now at 12.5 GW, has been a long-standing part of Mexico's power generation mix, but arid conditions across much of the country leave relatively little scope for further expansion. By contrast, reliance on wind, geothermal and solar photovoltaic (PV) has been limited thus far, but the potential for growth is enormous and policies are increasingly supportive. The Energy Transition Law, published in 2015, together with the Electricity Law, provides the legal framework for accelerated deployment of power generation from clean energy, which it defines as renewable sources, nuclear, high-efficiency cogeneration, waste-based generation and thermal power plants with carbon capture and storage. Two electricity auctions were held in 2016, one in March and one in September. The two auctions awarded long-term contracts for around 4.9 GW of new capacity. The outcomes indicate a possible new direction for Mexico's power mix: in both auctions, solar PV and wind accounted for almost all the energy contracts awarded.

Mexico's solar power potential is based on average daily irradiation of around 5.5 kilowatt-hours per square metre (kWh/m^2) (SENER, 2012), roughly double the levels seen in Germany. While supportive policies in Germany have led to installed capacity reaching 38 GW by the end of 2015, the comparable figure for Mexico was less than 1% of this total. Efforts to develop wind power in Mexico are picking up pace; almost 3 GW of capacity are already in place and there is potential for further development across large swathes of northern and southern Mexico.

With around 900 MW of operating capacity, Mexico is the fifth-largest producer of geothermal energy in the world (after United States, Philippines, Indonesia and New Zealand). Geothermal generation capacity has been nearly flat over the last decade, but this could change in the coming years. In 2014, the Geothermal Energy Law was approved, providing a legal framework for further geothermal energy development which allows private sector participation. In July 2015, the Ministry of Energy (SENER) provided concessions to develop 13 geothermal sites to CFE, which could increase installed geothermal capacity by 450 megawatts (MW) (SENER, 2015). The prospect of these projects being fully realised are dampened by the stiff competition geothermal faces from increasingly competitive wind and solar power.

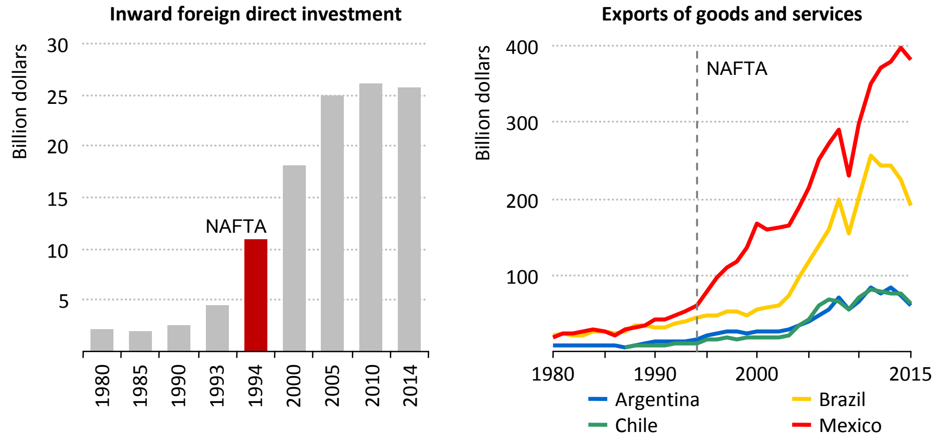
1.3 Factors affecting Mexico's energy development

1.3.1 Economy and demographics

Mexico's economy has grown by around 90% since 1990, following a profound reorganisation in the 1980s that transformed it from an inward-looking system focussed on local manufacturing, primarily with the aim of substituting imports, to a liberalised one open to foreign trade, investment and private sector participation. The signature of the North American Free Trade Agreement (NAFTA)[3] with the United States and Canada in 1994 provided a second impetus that effectively shifted Mexico's economy into its modern incarnation (Figure 1.8). Non-oil exports, notably from the manufacturing sector, now account for more than 90% of export revenue (INEGI, 2014). As of 2014, Mexico was the second-largest destination for US exports (after Canada) and the third-largest exporter to the United States (after China and Canada).

[3] Apart from eliminating import tariffs for several sectors, NAFTA extended protections for investors and set the mechanism for settlement of disputes.

Figure 1.8 ▷ Exports and inward foreign direct investment in Mexico and selected countries, 1980-2014



The conclusion of NAFTA in 1994 was an inflection point for Mexico's exports and inward foreign direct investment

Sources: IMF; United Nations Conference on Trade and Development.

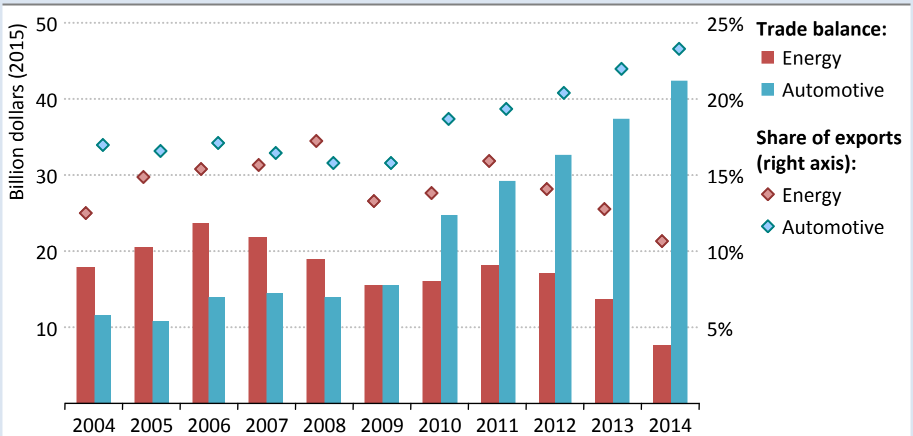
The success of the manufacturing sector rests on several factors. At the inception of the NAFTA, relatively cheap labour costs and a large neighbouring market in the US stimulated production of low value products (such as textiles). By 2000, increasing competition from China pushed Mexico into manufacturing higher value-added products such as computers, appliances, automotive parts and assembled cars (Box 1.2). Overall, Mexico's manufacturing sector has become a prime destination for inflows of foreign direct investment (FDI), which amounted to around $30 billion in 2013. This represents around two-thirds of total FDI inflows in Mexico, far above the amount going into mineral industries (including upstream oil and gas). Manufacturing industries employ more than 5 million people, almost a quarter of total employment in 2014.

Compared with other major hydrocarbon producers, Mexico now has a much more diversified economy, making it less vulnerable to fluctuations in the oil price. This is the case also for public finance, though oil-related revenue remains an important pillar of the country's fiscal balance. Over the ten years to 2014, oil-related revenue typically accounted for between one-third and 40% of total government income (Banco de México, 2015). As a result, the fall in oil revenue since 2014 has forced fiscal consolidation and budget cuts: 2016 spending was slashed by more than Mexican pesos (MXN) 132 billion (0.7% of GDP) – much of this in the form of reductions in PEMEX's budget for capital spending. Yet the fiscal impact was softened considerably by the Reform, which since 2013 has raised revenue from non-oil sectors of the economy: non-oil tax revenue rose by around 30% in 2015, compared with the previous year (Banco de México, 2016).

Box 1.2 ▻ In Mexico's trade, cars have overtaken energy

The boom in Mexico's industrial exports has been underpinned by a meteoric rise in automobile manufacturing. The automotive sector has grown by around 12% per year since 2004 (INEGI, 2014), attracting some of the world's largest automakers and allowing Mexico to take a larger share of global automotive foreign direct investment than China in 2013 (fDi Markets, 2015). This wave of investment has turned Mexico into the world's seventh-largest manufacturer of cars and light trucks, producing more than 3 million in 2014, and the world's fourth-largest exporter, after Germany, Japan and South Korea (PROMEXICO, 2016). It has a long way to go before coming close to the level of US annual car production, which is above 11 million, but it has already overtaken Japan to become the second-largest supplier of vehicles to the US market, after Canada. Along the way, automobiles have become a more important source of export revenue than energy (Figure 1.9). As of 2014, the value of the net exports of automobile products stood at more than $40 billion, a figure almost four-times higher than in 2005 and well ahead of the value of net exports of energy (excluding electricity), which decreased by 60% over the same period.

Figure 1.9 ▻ Trade in energy and automotive sectors, 2004-2014



The value of net automotive trade overtook that of energy in 2009 and has grown rapidly since then

Sources: World Trade Organization; IEA analysis.

Another measure that has afforded Mexico some protection against oil market volatility has been a price hedging strategy that serves as a partial check against boom-and-bust cycles. Hedging is a costly strategy that does not always bring returns; but the effect in 2015 – in return for a hedge cost in options premiums of some $770 million – was to guarantee a price considerably higher than the market rate (around $75/barrel versus a market rate of less than $50/barrel) for a share of Mexico's output. The pay out of more than $6 billion surpassed the previous record, from 2009, when Mexico received around $5 billion after prices plunged with the global economic crisis.

Reduced reliance on oil revenue does not mean insulation from broader global economic trends. As an economy with close trade and financial ties to the rest of the world, Mexico is exposed to the effects of any weakness in global growth or change in investor sentiment towards emerging markets. Reform in the energy sector is part of a wider set of structural reforms designed to bolster long-term growth. One challenge for Mexico is to increase its presence in industrial value chains by manufacturing more component parts within the country: currently Mexico imports around two-thirds of the intermediate products (often formed through energy-intensive processes) used in manufactured products that are subsequently exported (De La Cruz, et al., 2011). The ability of Mexico to do this rests on the ability of its firms to compete with suppliers in the United States; this, in turn, will depend heavily on the reliability and affordability of energy supply.

A strong economic and fiscal policy framework is essential to meet the needs of a growing population, which has expanded by almost 34 million since 1990 to reach 120 million. Over half of the population is under the age of 30, a young and growing labour force which provides a widening consumer and tax base. But there are challenges, including the need for the economy to create around 4 000 new jobs each day to absorb new entrants to the labour market. All the population growth has occurred in cities, often putting severe strain on the provision of infrastructure and services, as well as accentuating the problems of water stress and air quality.

1.3.2 Reform agenda and institutional framework

For much of the past eight decades, Mexico's energy sector has been constituted in the same way with state-owned companies enjoying monopolies throughout the value chain: PEMEX for upstream, midstream and downstream oil and gas; and the *Comisión Federal de Electricidad* (CFE) for power generation, T&D and retail sales. (Limited private sector participation in power generation was first allowed in 1992 through independent power projects, which were obliged to sell their electricity to CFE under long-term contracts or to sell to captive industrial customers). Reform of the energy sector has been a long-standing ambition of successive governments in Mexico. An attempt in 2008 failed because of the difficulty of making changes to three articles of the constitution (Articles 25, 27 and 28), which restricted private sector participation in oil and gas activities, and in the electricity sector.

Two enabling factors converged to allow new attempts at reform in late-2013. First, the two main political parties, the Institutional Revolutionary Party (PRI) and the National Action Party (PAN), came to an agreement that provided political backing to the agenda; and second, there was widespread recognition that PEMEX was not in a position to make the investments necessary to arrest declining production from existing fields, did not have the technical capacity to bring new production online from deepwater and shale resources and could not provide the refinery capacity necessary to meet the country's oil product needs. Underpinning the argument for reform was a context of slow economic growth and the realisation that inefficiencies in the power sector were driving costs higher than necessary, harming the competitiveness of the manufacturing sector.

The Energy Reform package[4] initiated in 2013 established new structures for the oil, gas and electricity industries in Mexico (Figure 1.10). Among other important changes, the Reform brought an end to the existing order in the energy sector, turning PEMEX and CFE into "state productive enterprises" whose portfolios of responsibilities (which previously included issues such as the country's energy security) have been pared back to focus on value creation. Crucially, the Reform law also ended the state monopoly on oil and gas production (though it maintains the inalienable national ownership of hydrocarbon resources) and on electricity retail sales. These changes have drastically altered the hue of policy and policymaking in Mexico, and therefore the outlook for energy prospects.

Key aspects of the constitutional amendments and the nine new secondary laws (and twelve newly amended ones) that have been passed are:

- **Electricity Law:** Creates a competitive electricity market by disaggregating the vertical structure of CFE, which since 1992 had controlled the generation market, been responsible for the operation of the national grid and exercised a monopoly over T&D. The law establishes a new regulatory regime that distributes policy, regulatory and market-control functions to SENER, the *Comisión Reguladora de Energia* (CRE) and to a newly decentralised agency *Centro Nacional de Control de Energía* (CENACE) respectively.
- **Hydrocarbons Law and Hydrocarbons Revenue Law:** Authorises and regulates the participation of the private sector in upstream activities, through the introduction of four contract types: licence contracts, production-sharing contracts, profit-sharing contracts and service agreements. The laws assign responsibilities for regulation to the *Comisión Nacional de Hidrocarburos* (CNH) and establish an independent operator, *Centro Nacional de Control de Gas Natural* (CENEGAS) for the gas pipeline network. The Hydrocarbons Law also gives SENER the authority to grant permits for: petroleum treatment and refining; processing of natural gas; import and export of crude oil, natural gas and petroleum products; and activities that were previously held exclusively by PEMEX.
- **PEMEX Law:** Codifies PEMEX's new responsibilities as a "state productive enterprise", including its obligations to pay dividends to the newly established "Petroleum Fund for Stabilization and Development". The law specifies a dividend of at least 30% of revenues in 2016, decreasing to 15% by 2020 and falling to 0% by 2026, by which time the Ministry of Finance and Public Credit (SHCP) will determine the dividend. The law also permits PEMEX to enter into partnerships with private companies at any point in

[4] This report refers to the constitutional amendments and the related laws as the Reform package.

the hydrocarbon value chain and to bid for exploration and extraction blocks in tenders held by the state.

- **CFE Law:** Codifies CFE´s new responsibilities as a "state productive enterprise", including its obligation to pay dividends to the federal government and introduces a corporate governance structure that includes the creation of a board of directors with, for the first time, four independent directors.
- The establishment of the **Mexican Petroleum Fund for Stabilization and Development**, under the management of the central bank and a board comprising the ministers of finance and energy, the chairman of the central bank and four independent members nominated by the president and ratified by the senate. All royalties and resource rents from the oil and gas sector will be held in this fund. The right to withdraw from this fund to finance the government budget is capped at 4.3% of GDP.

Figure 1.10 ▷ Main institutions influencing energy policy in Mexico

Cabinet-level departments

Ministry of Finance and Public Credit (SHCP)

In charge of setting the fiscal and economic terms of oil contracts and determining other bidding variables.*
Sets price range for certain petroleum products.

Secretariat of Energy (SENER)

Sets general energy policy in all areas, including energy efficiency. Defines which oil and gas fields to open to private bidding. Designs the oil contracts and the terms and conditions of the bids.

Ministry of Environment and Natural Resources (SEMARNAT)

Regulates and supervises the environmental impact and safety of operations of the hydrocarbons sector through the Environmental and Industrial Safety Agency (ASEA).

Independent regulators

National Hydrocarbons Commission (CNH)

Regulates upstream activity, conducts bids and administers oil contracts.

Energy Regulatory Commission (CRE)

Regulates electricity and mid and downstream hydrocarbon operations.

Operating companies

Petróleos Mexicanos (PEMEX)

A productive state enterprise focussed on oil and gas.

Comisión Federal de Electricidad (CFE)

A productive state enterprise focussed on electricity.

The Reform introduced fundamental changes to energy governance in Mexico

*These include parameters such as proposals for a programme of work, which is a factor in determining the winning bidder.

Energy governance has been transformed with the Reform. A number of responsibilities that were the domain of state-owned monopolies have been transferred to independent regulatory bodies. These include the CNH and the CRE. The Reform is part of a broader vision by the government to pursue energy policies that reconcile energy security imperatives with sustainability and efficiency considerations, and a general recognition of the need to shift to a low-carbon growth model. This underpins the National Energy Strategy (2014-2027); the Energy Transition Law (passed in December 2015) and the far-reaching climate pledge submitted in advance of the Paris COP21. The main features of Mexico's vision include:

- A commitment to increase the share of clean energy sources[5] in power generation from 21% today to 25% by 2018, 30% by 2021 and 35% in 2024.
- A commitment to reduce greenhouse-gas emissions (GHGs) by 22% and black carbon emissions by 51% by 2030, relative to a business-as-usual scenario.

The speed at which the Reform has been implemented, as well as its extent, has surpassed the expectations of many stakeholders. It will nonetheless take time for the new institutional arrangements and responsibilities to settle, for the designated productive state enterprises to organise for their new roles, and for private and international investors to navigate their entry to the market. The full restructuring of vertically and horizontally integrated companies whose remit has been drastically altered poses particular challenges. CFE, for example, has been legally unbundled to separate network activities from power generation and now has a number of individual subsidiaries, some of which compete with each other and with private players on the wholesale market. Ensuring that CFE's restructuring is consistent with the market-oriented principles underpinning the Reform requires that effective "Chinese walls" are put in place between the subsidiaries, a process that needs to be closely controlled by the regulator. This, and other newly formed entities that will handle responsibilities bequeathed to them from the old monopolies will need to be appropriately staffed to handle their tasks to ensure that bottlenecks do not form that could delay investments. As regards upstream oil and gas investments, SENER has proven adept at reacting to successive bidding rounds by altering the terms offered to better reflect the needs of both the state and private investors. However, the successful establishment of joint ventures between PEMEX and private companies for offshore oil production will require close co-operation between many other agencies too, including CNH, SHCP and PEMEX itself. Enhanced co-ordination, as well as a continuation of a policy of reacting to signals from successive bid rounds will maximise the chances of Mexico reaching its stated targets.[6]

1.3.3 Energy prices and subsidies

Energy price liberalisation has followed two diverging tracks in Mexico, with pricing for gasoline, diesel, natural gas and LPG increasingly reflecting market realities, while the price for electricity remains below cost for residential consumers. The move towards liberalisation of gasoline and diesel pricing has been gradual: reduction of subsidies started

[5] Clean energy resources in this regard include renewables, nuclear, high-efficiency cogeneration, waste-based generation and thermal power plants with carbon capture and storage.

[6] An in-depth review of Mexico's energy policies currently is being conducted by the IEA. The report and its recommendations are due to be published in early 2017.

in 2008, when the government introduced weekly increases to prices, largely to alleviate the financial burden on the state (gasoline subsidies alone are estimated by SENER to have cost the state over $20 billion in 2008). Such increases persisted until end-2014, by which time gasoline and diesel sales were generating positive earnings for the state totalling $1.2 billion (MXN 16.5 billion) in 2014 and $1.9 billion (MXN 30.3 billion) in 2015.

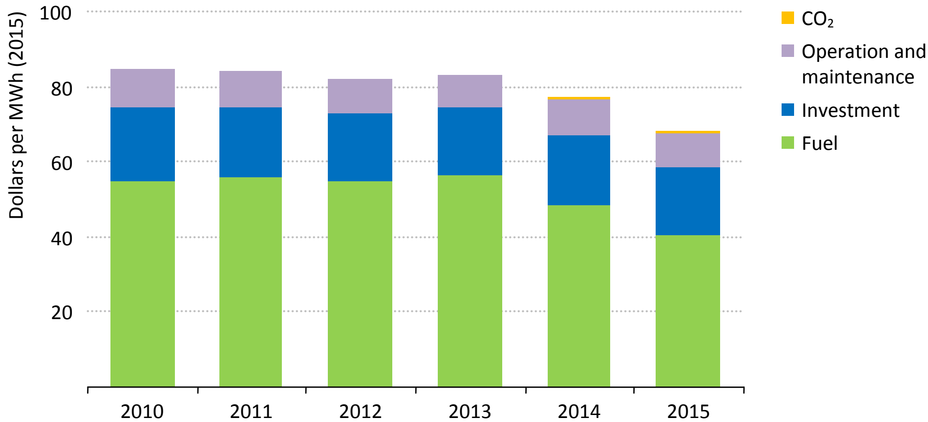
Gasoline and diesel market liberalisation feature heavily in the Energy Reform package currently being implemented. In April 2016, permits were issued for the first time allowing private companies to import gasoline and diesel, effectively ending PEMEX's monopoly over trading, storage, transportation, distribution and retailing of oil products. SHCP has proposed plans to introduce market-based pricing for gasoline and diesel in 2017. Until then, the SHCP has been tasked with setting a pricing range for products that takes into consideration the evolution of international prices and local inflation.

The price of natural gas sold by PEMEX is currently regulated by CRE, which sets prices that take into consideration the distance from the US border (for gas imported by pipeline). The Reform aims to move to a more fully market-based pricing for natural gas by end-2017, through the development of a competitive gas market in which private entities compete with the former monopoly to transport and market gas (see Chapter 2.3.3).[7] Reform of liquefied petroleum gas (LPG) pricing has been slower, reflecting its status as a "basic consumption good" relied upon by poorer segments of society. A price cap policy has effectively been in place since 2000 (a national maximum average price is set monthly). This practice will be continued until end-2016, after which LPG prices will be liberalised.

Residential electricity tariffs in Mexico do not adequately reflect the cost of electricity supply with CFE (until recently the state-controlled monopoly) absorbing much of the loss. Two factors, lower imported natural gas prices and the increasing switch from fuel-oil to natural gas in power generation, have helped reduce the average cost of supply by almost 20% since 2013 (Figure 1.11). Part of this reduction in cost has been used to reduce subsidisation, with the remainder spread to reduce average tariffs to consumers by around 10%. The Reform has partially transferred the subsidy burden from CFE to the treasury, introducing it as an explicit item in the national budget. This will increase oversight and inject impetus into finding ways of reducing the cost of the subsidy scheme in the future. Reducing electricity costs was one of the main goals of the Energy Reform, to be achieved by the profound restructuring of the sector so as to capture efficiency improvements and lower costs through competition, as well as alleviating the cost burden of subsidies on the state (or CFE). An examination of the current cost structure shows that in certain areas, significant savings could still be made. For example, bringing down technical and non-technical losses, which are currently significantly higher than elsewhere in the OECD, would reduce the need for investment in additional generation capacity, while improvements in operational efficiency in the newly unbundled CFE could significantly reduce the retailing component of the cost structure.

[7] *Política Pública para la Implementación del Mercado de Gas Natural* (The Gas Market Implementation Policy) was published in July 2016 by SENER, outlining short- and medium-term targets for the move towards a competitive natural gas market.

Figure 1.11 ▷ Composition of wholesale electricity costs in Mexico



Fuel switching to gas, and falling oil and natural gas prices have led to large reductions in wholesale power costs in Mexico

1.3.4 Social and environmental aspects

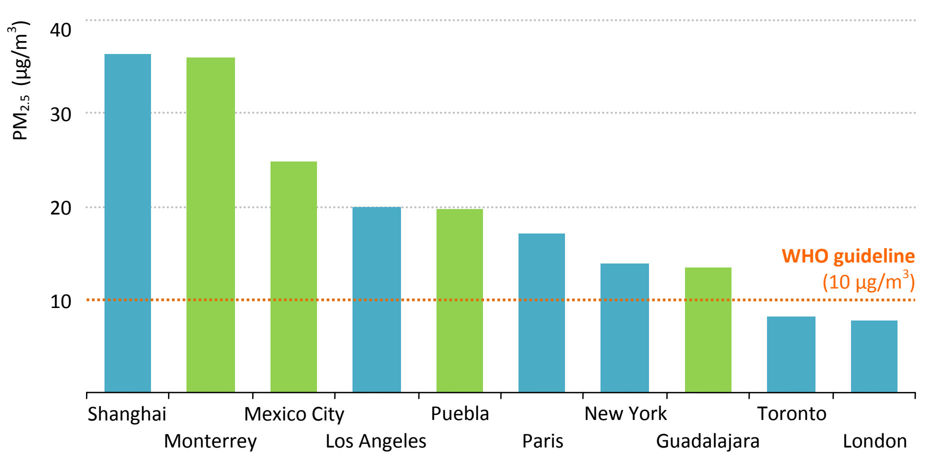
Local air pollution

High urbanisation rates, a rapid increase in demand for mobility and the dominance of liquid fuel in power generation have meant that local air pollution is a significant issue in cities across Mexico. A number of Mexico's largest cities have annual average particulate levels (PM)[8] that far exceed the World Health Organization's (WHO) upper limit of 10 micrometres per cubic metre (μg/m^3), with Mexico City and Monterrey both more than twice this level (Figure 1.12). This can be explained, in part, by the fact that three-of-the-five-largest cities in Mexico, including Mexico City, are situated at an elevation above 2 000 metres. At this altitude, atmospheric oxygen levels can be up to one-quarter lower than at sea level, causing the incomplete combustion of fuels. This leads to higher PM and carbon monoxide emissions from cars and trucks, and partially accounts for the fact that Mexico's transport sector has a PM emissions factor that is double that of the OECD average. The government is well aware of the problem and, in its climate pledge to COP21, it highlighted air quality as a main driver for its targets. It set one of the most aggressive targets for reducing black carbon emissions (a particularly harmful component of fine PM), pledging to reduce such emissions by 51% by 2030, compared with a business-as-usual scenario.

[8] Particulate matter is a mix of solid/liquid organic and inorganic substances that may be a primary or secondary pollutant. PM is linked to major detrimental health impacts for which size is an important factor: coarse particles are between 2.5 and 10 micrometres (μg) in diameter and fine particles are smaller than 2.5 μg. The adverse health impacts of PM_{10} are less severe than those of the fine particles ($PM_{2.5}$).

In response to a growing air pollution problem that has been taking an increasing toll on public health, the government has introduced a large number of policies and controls. The General Law of Ecological Balance and Environmental Protection (LGEEPA) is the overarching legal framework for air quality improvement. It assigns responsibility for implementing programmes to reduce emissions to the federal government. In practice, local authorities design their air quality programmes and submit them to the Ministry of Environment (SEMARNAT). The primary policy, PROAIRE, currently covers 13 metropolitan regions – the country's major urban centres. The detailed programme for each depends on the region in which it was designed, but each programme contains three components: monitoring of pollutants; annual vehicle emissions testing (with cars that fall below a certain standard being allowed to operate only four-out-of-five work days); and a contingency plan for days of particularly high pollution that can introduce a rotating ban on private car use and mandate the cessation of some manufacturing activity. These programmes have had a significant impact: in Mexico City, sulfur oxides (SO_X) and nitrogen oxides (NO_X) emissions are nearly three-times lower today than they were in 1992 (Ireland, 2014).

Figure 1.12 ▷ $PM_{2.5}$ levels in selected cities



Many cities in Mexico have $PM_{2.5}$ pollution levels well above WHO norms

Source: World Health Organization.

Land and indigenous rights

Land ownership and its use for private enterprise have historically been contentious in Mexico. Following the Mexican revolution in 1910, over half of the national territory was designated communal land and was made available to peasants and indigenous communities. Efforts at reform in the 1990s passed private title to the lands to those that had previously lived and worked on them, including provision for the new owners to lease or sell their plots, but did not drastically change the composition of ownership, as many have chosen to retain their titles. More than 5.6 million people still live and work on 31 500 "social properties" across the country. The 2014 Hydrocarbons Law introduces measures that seek to ensure local acceptance for projects before they are started: it compels the SENER to conduct a study that takes account of the social, political, environmental and cultural specificities of a proposed area, and to ensure that consultations with indigenous populations are conducted according to the Indigenous and Tribal Peoples Convention (International Labour Organization, 1989). The law does not permit land owners (whether private or social) to refuse to either sell, exchange, rent or lease their land to energy companies that are planning projects on the land. Land owners can negotiate compensation and royalty fees (in the case of upstream oil projects, temporary occupation can be agreed under terms offering 0.5% to 2% of profits), but have no right of ultimate refusal. As well as the possibility of growing resistance to these provisions, the difficulty of proving titles to boundaries that were established nearly 100 years ago (despite the proper titling of the majority of the "social" land) raises the risk of prolonged disagreement and delays to projects.

Issues of land rights are not restricted to oil and gas projects, but can also affect renewable energy power generation projects. The current auction process does not require firms bidding for clean energy supply contracts to have obtained all the necessary permits that would allow their projects to proceed. This is the case in the Yucatan Peninsula, where most of the solar capacity was awarded in the first electricity auction in March 2016 and where there are significant historical sites and indigenous communities. Engagement with local communities is indispensable to a positive outcome: in Oaxaca, an area with considerable wind resources (but also with an important tradition of active social and indigenous movements), a project to install 132 wind turbines, with a total capacity of 396 MW, has encountered repeated challenges despite an eight month preliminary consultation period (the first of its kind).

Water

Nearly two-thirds of Mexico is categorised as arid or semi-arid. The least water-stressed areas hold a relatively small share of the country's population and make only a limited contribution to economic output. Northern and central Mexico, which together hold 77% of the population and contribute 85% of GDP, hold only 32% of the country's renewable water resources.[9] Annual water demand of around 80 bcm is significantly greater than Mexico's sustainable supply of around 67 billion cubic metres, with the deficit met through unsustainable withdrawals. The issue is multifaceted. In Mexico City, for example, demand for water has doubled every twenty years, at a rate exceeding that of population growth, suggesting that losses, increased connections to the water supply network and increased per-capita consumption (associated with increased affluence) all play a part. To meet demand, Mexico City has to withdraw water from ever more distant sources, often over 100 km away (Valdez, et al., 2016). This imposes a considerable energy cost on the system:

[9] This refers to surface and groundwater resources generated via the hydrological cycle.

at 4.5 kilowatt-hours per cubic metre (kWh/m^3), water transported from a distance uses almost 20-times the amount of energy as that withdrawn from aquifers below the city. Put another way, despite contributing only 18% to supply, imported water consumes almost two-thirds of the electricity associated with the supply of water through the municipal network. The over-exploitation of underground aquifers under Mexico City is also contributing to the city's gradual subsidence (considered to be one of the most severe cases in the world). Among the impacts is that sub-surface pipes are being damaged, contributing to increased losses. Water stress could be a significant constraint on the exploitation of energy resources in Mexico, particularly of unconventional gas in the north. Some of the most promising resources are thought to be an extension of the Eagle Ford formation, which stretches into Coahuila state, Mexico's second-driest, which has a water stress index of 77% (meaning that 77% of the renewable water resources in the area are already allocated).

Climate change

Mexico is judged to be highly vulnerable to the negative impacts of climate change, particularly to the impacts of rising sea levels, increases in average temperatures and the increased frequency of severe weather events such as cyclones, hurricanes and droughts (90% of the country suffered drought in 2011). The greater vulnerability of low-income segments of the population to disasters, combined with increased exposure to climate risks, means that 319 municipalities (13% of the country) are considered "highly vulnerable" to climate change. More than two-thirds of Mexico's population have been impacted by a natural disaster in their lifetime. The National Climate Change Strategy recognises that 46% of PEMEX's infrastructure and over 30% of CFE's transmission lines are vulnerable to the impacts of climate change.

Mexico's CO_2 emissions profile is heavily skewed towards transport, which accounted for 35% of the total in 2014, and the power sector (32%). The ongoing effort to switch from oil- to gas-fired generation has reduced the carbon intensity of the sector by 23% since 2000 and further improvements are expected. The oil and gas sector is a significant emitter of methane, a potent greenhouse gas.

Although a country with a large endowment of oil and gas resources, Mexico has also been among the world leaders in integrating climate change objectives into policymaking. It was the second country in the world to pass a Climate Change Law (in 2012) which stipulates that the country should cut greenhouse-gas emissions by 30% by 2020 (rising to 50% in 2050) compared with levels in 2000, preferably by means of cost-effective actions that create co-benefits for the population. Mexico's climate pledge, submitted in advance of COP21 in 2015, further strengthens the commitment to reduce GHG emissions and follow a low-carbon and resilient path (See section 1.3.2.). It includes goals to reduce the emissions of short-lived climate forcers and contaminants, which have a direct impact on air quality and human health. GHG emissions would need to peak by 2026 in the mitigation scenario and start decreasing from then, with the emissions intensity of the economy needing to be reduced by 40% (compared with 2013 levels) by 2030.

A large part of the expected emissions reductions are dependent on actions in the energy sector, including increasing the share of clean energy in power generation to 35% by 2024 and 40% by 2035 and controlling methane leaks in the upstream hydrocarbon sector. In this regard, Mexico made a standing commitment during the 2016 North American Leaders' Summit to reduce its methane emissions by 40-45% relative to 2012 levels by 2025. Studies by ICF have shown that Mexico could significantly reduce its methane emissions from the oil and gas sector by targeting four known areas: offshore venting, leaking oil tanks, uncontrolled condensate tanks and reciprocating compressor seals (ICF International, 2015). Abatement in these areas is also shown to be cost effective; 54% of the onshore and offshore emissions reductions can be achieved at a net total cost of Mexican pesos 0.43 per million cubic feet (MXN/mcf) ($0.03/mcf) of methane reduced or for less than MXN 0.01/mcf of gas produced nationwide. This requires a capital investment of an estimated MXN 1.6 billion ($106 million). However, the cost of methane abatement projects remains uncertain, and PEMEX's strained budget may make allocation of capital towards such projects challenging, particularly in the short term.

A carbon tax was placed on fuels in 2014, with the price set according to the carbon content of each fuel. The current price range is $0.33 per tonne of CO_2 (tCO_2) to $2.66/$tCO_2$.[10] There is also broad recognition of the opportunities that energy efficiency measures offer in reaching Mexico's targets, including through improving the sustainability of buildings, harmonising the standards for vehicles and equipment traded through NAFTA, and promoting sustainable transport.

1.3.5 Investment

Investment in energy supply in Mexico over the last 15 years has averaged, in our estimation, around $30 billion per year, with oil and gas investments accounting for 80% of the total. This skew towards oil and gas projects means that investment is highly sensitive to oil price fluctuations. Despite accounting for the vast majority of supply investment, spending on upstream oil and gas projects is widely considered to have fallen well short of what is required, as illustrated by the 900 thousand barrels per day (kb/d) decrease in oil production since 2000 (see section 1.2.3.). The majority of the investment burden fell on PEMEX, whose own budget has been hit by falling production and prices, setting in motion a self-perpetuating cycle of low investment, low revenue and low production (Box 1.3). Reversing this trend is one of the primary motivations for the Energy Reform.

Under a "Round Zero" held in 2014, before the start of the open licensing rounds, PEMEX requested and was allocated a substantial part of Mexico's hydrocarbon resource, mainly in shallow water and onshore areas where it has existing operations, but also including some deepwater and unconventional acreage. The remainder (and any part of PEMEX's allocation that it chooses to develop jointly) is open in principle to other companies. The Reform legislation opens five ways in which private investors can take part in the development of

[10] Using an exchange rate of MXN 18.77 to 1 US dollar.

Mexico's oil and gas resources, in all cases after pre-qualification and taking part in a bidding process, conducted by CNH, except that service contracts can be agreed directly with PEMEX.

- Licence contracts: allow a company to book ownership of oil or gas assets (for financial purposes) at the wellhead after it has paid its tax dues, with the company paying a signing bonus, payments during exploration and royalties on production.
- Production-sharing contracts: allow a company to recover costs and a share of the operating profit, received as a portion of the oil or gas extracted.
- Profit-sharing contracts: allow a company to recover costs and a share of the profit, after it has marketed and sold the resource.
- Service contracts: a company is paid for specified project activities on behalf of PEMEX or the state.
- Farm-outs/migrations: allow a company to enter into a joint venture agreement with PEMEX in a project that has already seen exploration and production efforts.

In 2015, three phases of bidding under a "Round One" auction successfully awarded rights to 30 fields to a mix of local and international investors. Encouragingly, the Round One phases have been progressively more successful, reflecting the willingness of the authorities to listen to feedback from the private sector regarding the terms which will encourage investment. A critically important fourth phase, set to offer ten promising deepwater exploration areas, is due in December 2016. There has been a step-change in the amount of offshore seismic survey work conducted in Mexico since 2014, a tangible demonstration of private and international interest in the country's resource potential. Alongside the plans for conventional oil and gas, the government has also announced its intention to develop Mexico's unconventional resources. The bidding schedule for unconventional acreage has been subject to revision, but there is a strong intention to auction promising shale blocks.

Mexico's intention of attracting foreign and private capital into the energy sector is not confined to the oil and gas sector. The power sector is undergoing two transformations. The first is to bring about the reduction of oil-based generation in the short term (due to be completed by end-2017). The second is to ensure that future growth corresponds with the government's climate and environmental objectives, through the promotion of clean energy. In its efforts to attract the necessary investment in generation, the Reform has introduced various market instruments that aim to provide at least a measure of the long-term certainty sought by investors, including price signals and setting a value for clean energy. The measures taken include:

- Formation of a generation capacity market, designed to ensure capacity adequacy through remuneration of the fixed costs that are not recovered on the energy market.
- Establishment of Clean Energy Certificates as an integral part of the electricity market design. These aim to ensure the development of clean electricity generation by providing a source of income for clean energy electricity producers, to supplement revenue from selling electricity and capacity.

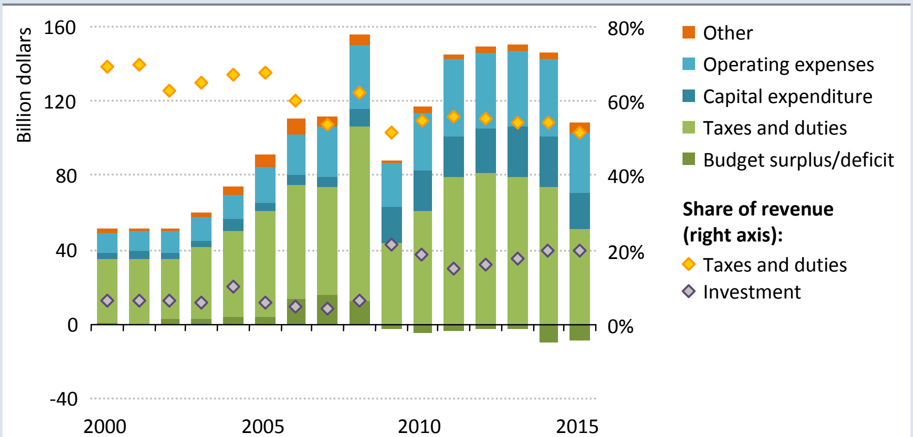
- Provision for long-term contracts and auctions, locking in prices for generators of clean energy (for a period of 15 year), capacity (15 years) and Clean Energy Certificates (20 years).

As noted, Mexico has already attracted investment into its newly liberalised power sector. Two electricity auctions held in 2016 have awarded contracts for around 4.9 GW of generation capacity to private investors (including several global players). The associated investment is expected to reach $6.6 billion by 2018, equivalent to almost three-times the average annual investment in power generation since 2000.

Box 1.3 ▹ PEMEX in transition

One of the aims of the Reform process is to transform the national oil company, PEMEX, into a "state productive enterprise" that would increasingly be subject to standard market and commercial disciplines. This transition was initially envisaged at a time of triple-digit oil prices: it has become both more urgent, and much more complex, in a lower price environment. PEMEX faces considerable financial challenges, reporting a full-year net income loss of $25 billion in 2015, and is looking at opportunities to reduce its spending by deferring some projects (including expensive deepwater projects) and cutting overheads and workforce. Despite assistance from the government, including a $4.2 billion aid package in April 2016 and reductions in its tax obligations, the decline in the company's oil production is adding to the pressure on its finances.

Figure 1.13 ▹ PEMEX revenue and expenditure, 2000-2015



For years, PEMEX revenue has primarily been used for operating expenses and taxation, rather than new investment

Note: Other includes finance costs, other operations, products for resale and other capital transfers from government.

Sources: PEMEX; IEA analysis.

Despite the difficult market conditions, some improvement has been achieved in recent years. The legacy of under-investment has been tackled with increases in capital spending between 2010 and 2014. The share of revenue going to taxes has fallen from around 70% in the early 2000s to about 50% currently. PEMEX is also intensifying efforts to make operational savings, although this is the area that remains most resistant to change. The overall Energy Reform process will increase the competitive pressure on PEMEX, but also open up new opportunities. The company will gradually migrate towards a more standard tax and corporate structure. It also now has the possibility to create joint ventures with companies able to offer capital, specialised technologies or operational expertise, or to farm out selected fields.

1.4 Projecting future developments

The projections in our *Mexico Energy Outlook* (the results of which are set out in Chapter 2) look out to 2040 and are derived from the overall methodological approach used in the *World Energy Outlook-2016*.[11] The central scenario in this *Outlook* is the **New Policies Scenario.** It takes into account existing policies and measures as well as Mexico's announced policy intentions. It therefore incorporates both existing progress and future intentions expressed in Mexico's Energy Reform programme, as well as other targets for the future, e.g. those related to clean energy and GHG emissions reductions. Where policy intentions are not backed by clearly defined implementing measures, then our assessment of possible regulatory, market, infrastructure and financing constraints determines how far and how fast these intentions are met.

We also refer to two additional scenarios modelled in *WEO-2016* and one case developed specifically for this report. The **Current Policies Scenario** depicts a path for Mexico shorn of all policy intentions that, as of mid-2016, had yet to be expressed in specific implementing measures. No allowance is made for changes in policies or measures beyond this point, regardless of announced intentions. The Current Policies Scenario can therefore be considered as the "default setting" for Mexico's energy system, with little or no change compared with what has already been agreed and settled. Its results provide a benchmark against which the impact of "new" policies can be measured. The **450 Scenario** describes a world in which countries take concerted action to limit the rise in global average temperatures to less than 2 degrees Celsius; at global level it sees an early peak and subsequent decline in global energy-related CO_2. The additional case, specific to this analysis, is the **No Reform Case**. This is an illustrative counter-factual case that deliberately seeks to portray what might have happened to Mexico in the absence of the Energy Reform announced in 2013. This case retains the pre-reform positions of PEMEX and CFE in Mexico's energy system and limits the extent to which new investment and technology can

[11] Chapter 1 of *WEO-2016*, which describes the scope of the analytical work and the underlying assumptions and price trajectories used, is available online at *www.worldenergyoutlook.org* (from 16 November 2016).

be attracted to these sectors. It provides an alternative baseline against which the impacts of the entire Reform process can be assessed and measured.

The data used in this modelling work was primarily sourced from IEA databases of energy and economic statistics, which were supplemented by data from governments, international organisations, energy companies, consulting companies and financial institutions. Data provided directly by SENER and other Mexican institutions have been invaluable. The starting year for the most of the projections is 2014, as reliable energy data were available only up to 2014 at the time of the modelling. However, where more recent data are available even on preliminary basis, they have been incorporated.

Economic growth

As in most other countries, economic growth is the principal driver of energy demand in Mexico. The GDP of Mexico has increased by more than 30% since 2000, reaching $2.2 trillion in 2014 (expressed in year-2015 dollars and in terms of purchasing power parity [PPP]). Mexico has enjoyed stable economic growth since 2000, with annual GDP growth averaging 2.1%, higher than the OECD average of 1.6%. In our projections, GDP growth assumptions are the same as in the main *WEO-2016* scenarios (New Policies Scenario, Current Policies Scenario, 450 Scenario) and are based primarily on International Monetary Fund (IMF) projections. GDP is assumed to grow by 3.1% over the period from 2015 to 2040, with prospects for growth and improvements in productivity (Table 1.1). By 2040, the size of the economy more than doubles to $4.8 trillion (year-2015 dollars, PPP terms). Average per-capita income rises from $18 000 to $32 000 by 2040.

Table 1.1 ▷ GDP assumptions in Mexico*

	GDP* ($2015 billion, PPP)		CAAGR**	Per-capita GDP ($2015, PPP)		CAAGR**
	2014	2040	2014-40	2014	2040	2014-40
Mexico	2 172	4 774	3.1%	18 127	31 665	2.2%
OECD	50 293	81 374	1.9%	39 525	58 372	1.5%
World	110 370	265 292	3.4%	15 213	28 987	2.5%

*Calculated based on GDP expressed in PPP terms. **Compound average annual growth rate.

The GDP assumptions used for Mexico reflect a methodology that is used uniformly across all countries in the *WEO-2016* analysis. They do, though, result in a compound annual average rate of growth that is lower than that used to generate SENER's central case for Mexico's energy development. We therefore conducted a sensitivity analysis for our energy projections in an **Enhanced Growth Case**, presented in Chapter 2, which uses a higher assumption of GDP. The No Reform Case, by contrast, has a slightly lower GDP outlook than that used in the main *WEO-2016* analysis: compound annual average growth of 2.9% to 2040 compared with 3.1% in New Policies Scenario. This differential was calculated by coupling the results of the IEA's World Energy Model with the OECD's computable general equilibrium model, ENV-LINKAGES.

Demographic trends

Demographic change is another important driver of energy demand and the pattern of energy use. Our assumed population growth rates are based on the medium-variant of the latest UN projections (UNPD, 2015). The population of Mexico in 2014 is estimated to have been 120 million and grows to more than 150 million in 2040, an annual average rate of 0.9%, a growth rate more than twice as fast as the OECD average. The population of those living in urban areas grows at an annual average rate of 1.2% and by 2040, around 130 million people, corresponding to almost 85% of total population, live in urban areas in Mexico. The working age population, aged between 15 years and 64 years, continues to grow during our projection period.

Energy prices

In the New Policies Scenario, we assume that energy prices (except electricity) are determined on the basis of global market prices, reflecting the government's intention to liberalise energy markets as a part of the Energy Reform. For example, the prices of oil products such as gasoline and diesel, as well as LPG, are assumed to be deregulated in 2017. Natural gas prices are assumed to remain linked to prevailing import prices, in particular US market prices, with the relevant transmission cost added, and are not regulated in retail marketing. In the case of electricity tariffs, we assume in the New Policies Scenario a gradual phase out of subsidies by 2035, helped by cost reductions in the power sector that come as a result of efficiency gains related to the Reform, a progressive tariff structure and greater disclosure of existing subsidies in the government budget, which will help the government to rationalise them in the long run and meet international commitments made in the G20.[12] International energy prices are taken from the broader *WEO-2016* modelling (see Chapter 1 of *WEO-2016*).

Policies

As a part of broader reforms such as those relating to climate change and clean energy, Mexico has set targets and initiated policies affecting many energy policy areas. Some of the key energy targets and policies assumed in the New Policies Scenario are listed in Table 1.2.

[12] G20 leaders reaffirmed their commitment to rationalise and phase out inefficient fossil-fuel subsidies at a G20 meeting held in China in 2016.

Table 1.2 ▷ Selected key energy policies and targets in Mexico

Energy supply
■ Constitutional amendments and subsequent legislation to attract investment and modernise the energy sector, which allows the private sector to participate in oil and gas upstream, mid and downstream sectors.
■ Exploration and production based on the Five-Year Plan and new contracting schemes.
Cross-cutting policies
■ Reduce GHG emissions by 25% compared with business-as-usual by 2030.
■ The National Program for Sustainable Use of Energy to promote optimal use of energy and reduce energy intensity in all sectors, formulated on the basis of the Energy Transition Law.
■ Excise (carbon) taxes for oil products, such as gasoline, diesel and fuel-oil.
■ Prices of gasoline, diesel and LPG are liberalised in 2017.
Power sector
■ Development of wholesale power market and establishment of CFE as a modified state enterprise, unbundled into power generation, T&D, load-serving entities and retail sectors to promote efficiency and competition.
■ Development of generation capacities and T&D networks based on the Development Program of the National Electric System 2016-2030.
■ Clean energy share of 25% in total electricity generation by 2018, 30% by 2021 and 35% by 2024. (Clean energy, defined by the Electricity Law, includes renewables, efficient cogeneration, nuclear and thermal power plants with carbon capture and storage).
■ Clean Energy Certificates which will provide additional revenues from selling electricity and development of wholesale market auctions.
■ Other incentives for clean energy, such as tax relief, soft loans and net metering schemes.
■ Enhanced efforts to strengthen the national grid and reduce T&D losses to 8% by 2024.
Transport
■ National standard for fuel economy and carbon emissions standard for light-weight vehicles.
Industry
■ Voluntary energy management systems in large industries and energy efficiency programmes for small- and medium-size enterprises.
■ National standard for motor efficiency.
Buildings
■ National standards for energy efficiency for building envelope and building components, such as thermal insulation and appliances.
■ Development of an energy efficiency code for buildings to promote the adoption of relevant building codes by local governments.
■ Replacement programmes for inefficient lightings and appliances.
■ Soft loans to sustainable housing.

Energy Outlook in Mexico to 2040

A clean break with the past?

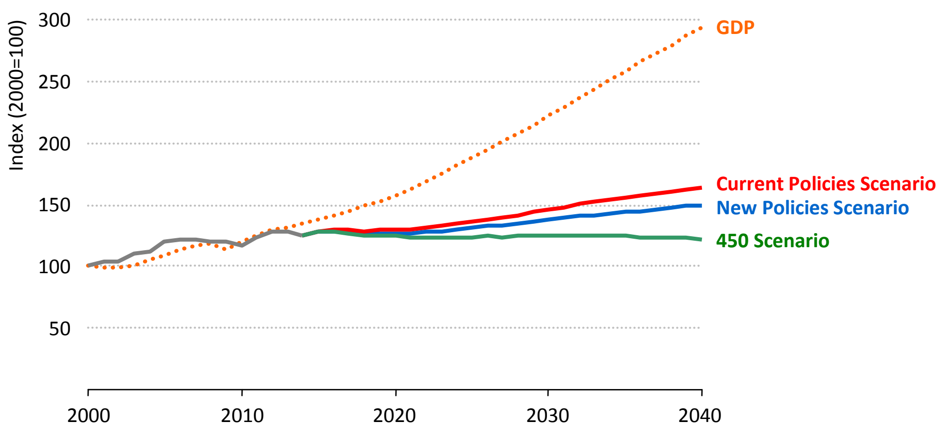
Highlights

- Mexico's economy expands to well over twice its current size in our projections to 2040, but total energy demand increases by only around 20%, highlighting a significant decoupling of energy demand from economic output. In the New Policies Scenario – our central scenario – almost all of the growth in demand is met by natural gas and renewables. The share of oil falls from 51% today to 42% in 2040: increased demand for transport and petrochemicals is offset by reduced use in power generation and the residential sector.
- Electricity demand grows robustly, by 85%. The largest growth comes from the buildings sector, but industry remains the largest consumer. The role of gas and low-carbon sources in lifting generation from 300 TWh to more than 500 TWh by 2040 heralds a sharp reduction in the greenhouse-gas emissions intensity of the power sector. Solar PV and wind account for around half of total investment in generation and half of generating capacity additions over the period, helping Mexico to achieve its long-term targets for electricity generation from clean power sources. CO_2 emissions from power generation are around 20% lower in 2040 than in 2014.
- In the end-use sectors, residential consumption of electricity almost doubles between 2014 and 2040. Rising incomes and living standards feed through into higher ownership levels of a range of appliances with demand for cooling increasing three-fold. Efficiency policies in buildings and industry are increasingly effective in tempering the rise in demand. The passenger vehicle stock grows by around half over the period to 2040, but improvements in fuel economy limit the impact on oil demand. The same is not true for road freight: trucks account for 13% of transport energy demand but, on the assumptions of our New Policies Scenario, generate more than half of the rise in transport energy demand to 2040.
- The outlook for developing Mexico's oil and gas resources has been re-shaped by the *Reforma Energética* (Energy Reform). The decline in total oil production bottoms out in 2018 at 2.3 mb/d, before climbing to 3.4 mb/d by 2040. Gas production follows a similar trajectory to oil, as much of the output is associated gas; but towards the end of the projection period, Mexico starts to see larger scale development of its considerable shale gas resources. Total gas production rises to 60 bcm, but Mexico remains a sizeable importer of gas from the United States throughout the period to 2040, benefiting from the availability of competitively priced imports. As Mexico's natural gas use increases, so does the importance of good interconnections and market operation, and gas storage to meet fluctuations in demand.

2.1 Pathways for Mexico's energy development

In the New Policies Scenario, the central scenario presented in the *World Energy Outlook*, Mexico's primary energy demand increases by around 20% in total between 2014 and 2040, the growth rate averaging 0.7% per year. In all of our global scenarios (the New Policies Scenario, Current Policies Scenario and 450 Scenario), energy demand growth decouples from economic growth (Figure 2.1), reflecting a structural shift in the economy that sees a growing prominence of the services sector and energy efficiency improvements over the projection period. Another trend common across the scenarios is robust growth of electricity demand. This surpasses the pace of growth in primary energy demand, with annual average growth ranging between 1.7% and 2.7% (Table 2.1). More than 99% of the population already has access to electricity, and an increasing population, rising incomes and a growing middle class, coupled with intensified urbanisation, underpins the increase in power demand.

Figure 2.1 ▷ Primary energy demand and GDP in Mexico by scenario, 2000-2040 (indexed to 2000 level)



Mexico's primary energy demand decouples from the anticipated rise in GDP

Energy demand in Mexico has historically been highly correlated to economic growth and, although this relationship is set to weaken in the future, gross domestic product (GDP) will remain an integral contributor to energy demand. As described in Chapter 1, our global GDP outlook in the New Policies Scenario is based on annual average economic growth of 3.1% between now and 2040. This falls within the range of the scenarios considered in the *Programa De Desarrollo Del Sistema Eléctrico Nacional* (PRODESEN), the Mexican national electricity system development plan, but is lower than the plan's central scenario (which projects 4% economic growth per year for the period to 2029). For this reason, we have also considered an alternative trajectory for Mexico in an Enhanced Growth Case. In that case the economy grows at an annual average of 4% to 2029, before slowing somewhat thereafter. The same assumptions regarding policies and the *Reforma Energética* (Energy Reform) apply as in the New Policies Scenario.

Table 2.1 ▻ Mexico key indicators in selected scenarios

		New Policies Scenario		Current Policies Scenario		450 Scenario	
	2014	2025	2040	2025	2040	2025	2040
Primary energy demand (Mtoe)	188	196	225	204	246	186	184
Share of fossil fuels (%)	92	89	86	89	88	87	74
Final consumption (Mtoe)	118	134	156	139	169	128	132
Electricity demand (TWh)	248	326	459	338	490	296	380
Energy intensity of GDP (2014 = 100)	100	75	54	78	60	71	44
Carbon intensity of power (2014 = 100)	100	64	48	66	53	59	27

Note: Mtoe = million tonnes of oil equivalent; TWh = terawatt-hours.

In the Enhanced Growth Case, the rise in primary energy demand is 1% on average annually, a pace significantly faster than in the New Policies Scenario (0.7%), while the carbon intensity of the power sector remains comparable to that in the New Policies Scenario, as renewables grow strongly and Mexico successfully achieves its clean energy targets (Table 2.2). This highlights the importance of a reformed power system in facilitating the transition to a low-carbon economy. Electricity demand in the Enhanced Growth Case grows by 2.8% on average annually, a growth rate comparable to that projected in the PRODESEN.

Table 2.2 ▻ Mexico key indicators: New Policies Scenario and sensitivity cases

		New Policies Scenario		Enhanced GDP Case		No Reform Case	
	2014	2025	2040	2025	2040	2025	2040
Primary energy demand (Mtoe)	188	196	225	207	245	200	226
Share of fossil fuels (%)	92	89	86	89	86	91	87
Final consumption (Mtoe)	118	134	156	144	174	134	155
Electricity demand (TWh)	248	326	459	344	505	327	450
Energy intensity of GDP (2014 = 100)	100	75	54	72	52	77	57
Carbon intensity of power (2014 = 100)	100	64	48	63	48	77	57

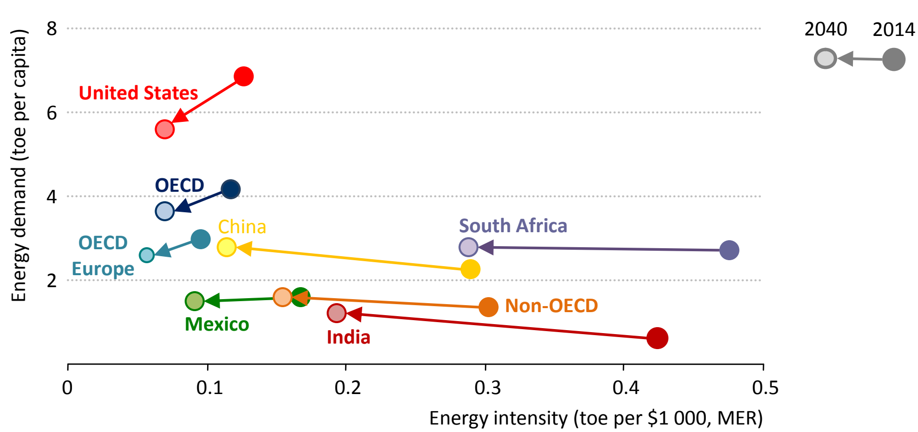
The policy changes stemming from the Reform are at the core of the projections in the New Policies Scenario (and in the Enhanced Growth Case). But in order to illustrate the importance of the Reform on the energy sector and the economy as a whole, we consider a No Reform Case, discussed in Chapter 3. This extreme hypothesis traces an alternative trajectory for Mexico in which the reforms do not take place – even those already translated into adopted policy measures. For example, *Petróleos Mexicanos* (PEMEX) retains its monopoly position in the oil and gas sectors, and there are no changes to *Comisión Federal de Electricidad* (CFE)'s structure or role in the power sector. Our analysis is coupled with a broader general equilibrium model for the economy, permitting our analysis of the outlook for oil, gas, electricity and other fuels to be accompanied by some wider reflections on the repercussions for growth in different parts of Mexico's economy.

2.2 Outlook by sector in the New Policies Scenario

2.2.1 Overview

In the New Policies Scenario, Mexico follows the trend of the OECD in general in being successful in loosening the ties between economic growth and energy consumption (Figure 2.2): by 2040 energy intensity declines by around 50%. This trend reflects a shift in the structure of the economy, with the services sector accounting for an increasing share of value added and considerable energy efficiency gains in industrial activity. Over the same period, primary energy demand per capita remains broadly stable, reflecting two trends that counteract each other. Demand for per-capita energy services increases as incomes rise, but the power sector (in particular) uses less energy per unit of electricity supplied, as the electricity mix switches to more efficient sources of power generation and the network delivers power to end-users with fewer losses along the way.

Figure 2.2 ▷ Energy intensity and per-capita energy demand for selected countries, 2014 and 2040

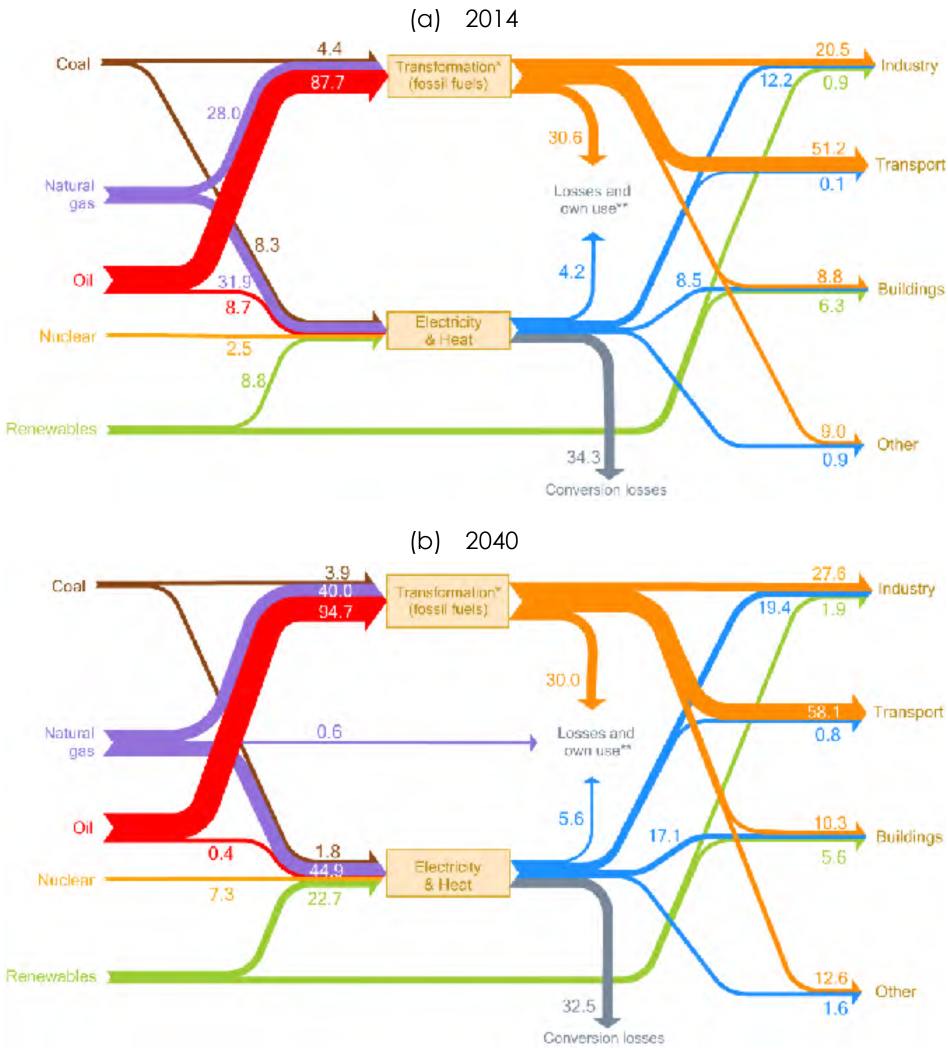


Improvements in the energy intensity of Mexico's GDP bring it in line with today's OECD average, while keeping per-capita demand flat

Note: toe = tonne of oil equivalent; MER = market exchange rate.

The features which characterised the evolution of the energy mix in Mexico over the past decade continue to be seen in our projection (Figure 2.3). Most notably, the shift continues from oil to natural gas, primarily in power generation, increasing the share of gas in total primary energy demand to 38% in 2040 (from 32% in 2014), while reducing the share of oil from 51% to 42%. Nonetheless, oil continues to be the principal source of energy in Mexico over the projection period, with transport, the largest energy-using end-use sector, accounting for around 60% of oil consumption. Coal consumption decreases by 55% by 2040, as some coal-fired power plants are retired and only small coal-fired capacity additions are made.

Figure 2.3 ▷ Mexico domestic energy balance, 2014 and 2040 (Mtoe)



Mexico's domestic energy balance in the New Policies Scenario highlights the expansion and diversification of the system

* Transformation of fossil fuels (e.g. oil refining) into a form that can be used in the final consuming sectors.
** Includes fuel consumed in oil and gas production, transformation losses and own use, generation lost or consumed in the process of electricity production, and transmission and distribution losses.

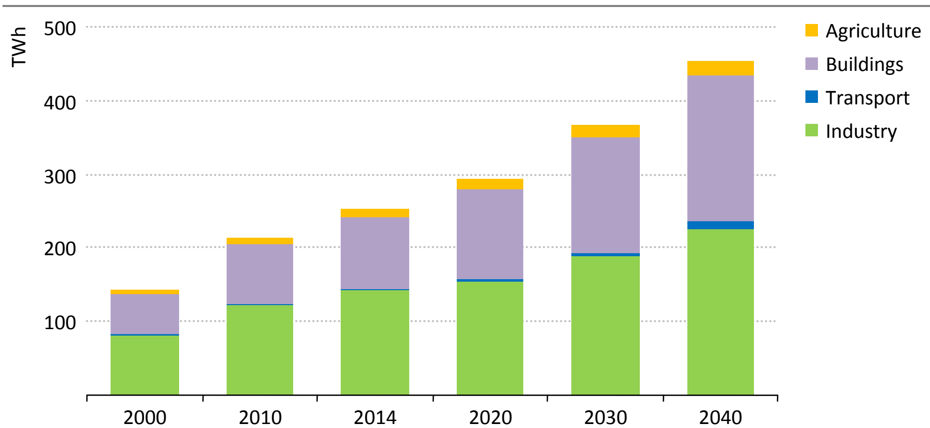
Renewable energy supply grows relatively fast, in line with Mexico's commitment to utilise wind and solar to reduce the energy sector's carbon footprint. The share of renewables in total primary energy demand increases from around 9% in 2014 to 14% in 2040. The share of bioenergy, used mainly in residential cooking and water heating, remains relatively stable over the projection period, as increased use in power generation and industry is offset by reduced use of solid biomass in households. Despite the rise in renewables, fossil fuels still remain the dominant source of energy, accounting for 83% of total primary energy demand in 2040.

2.2.2 Power sector

Electricity demand

Electricity demand in Mexico grows at an annual average rate of 2.4% between 2014 and 2040 in the New Policies Scenario, a pace that is more than three-times faster than the OECD average. Consequently, per-capita electricity demand also grows by around 50% from 2014 to 2040. Industry remains (just) the largest electricity-consuming sector, accounting for 50% of electricity demand in 2040, although this represents a decrease from over 56% in 2014 (Figure 2.4). Demand for electricity in non energy-intensive industries, composed of a range of entities including small- and medium-size enterprises (SMEs), accounts for 85% of the increase in industrial electricity demand between 2014 and 2040.

Figure 2.4 ▹ Electricity demand by sector in Mexico in the New Policies Scenario



Industry remains the largest electricity user in Mexico in the New Policies Scenario, although buildings sector demand rises more quickly

Note: TWh = terawatt-hours.

The largest growth in electricity consumption arises in the building sector (residential and services), which accounts for half of the total increase in final electricity consumption to 2040. The largest share of this increase comes from residential consumers, due to the steady rise in the ownership and use of appliances: residential consumption for electrical appliances almost doubles between now and 2040. Demand for cooling in households grows particularly rapidly, more than tripling over our projection period, as ownership and use of air conditioners expands with rising incomes and living standards. Electricity consumption in the transport sector rapidly increases, reflecting the effects of government support schemes for electric vehicles. These measures include tax exemptions for such vehicles and the installation of special electricity meters with preferential tariffs. To further promote the adoption of electric vehicles, the government is planning to introduce a tax incentive for charging stations in the 2017 Economic Package (SENER, 2016a). Despite the strong rate of increase, transport accounts for only around 2% of electricity demand in 2040.

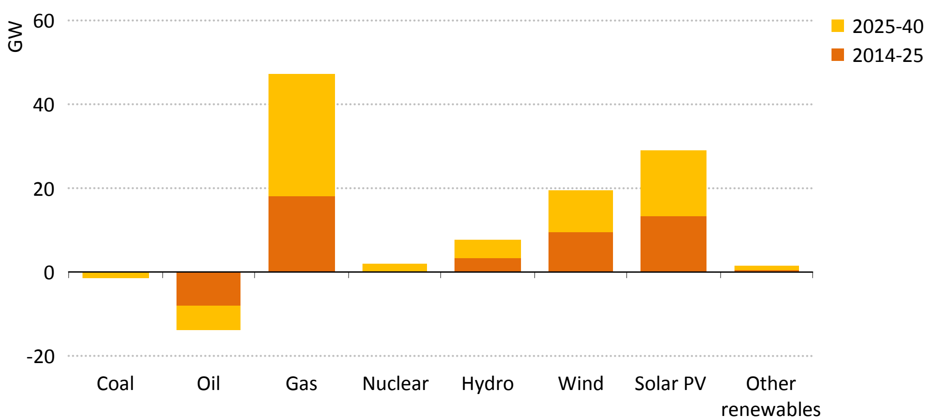
Electricity supply

In the New Policies Scenario, installed electricity generation capacity more than doubles, from 70 gigawatts (GW) in 2015 to almost 160 GW in 2040. Gas-fired plants account for half of the increase, meaning that Mexico accounts for 15% of the increase in gas-fired power plants capacity in the OECD to 2040. This reflects the ongoing switch in the medium term from oil to gas in Mexico for power generation, enabled by the expanded availability of gas from the United States and the requirement for capacity additions to keep pace with demand (Figure 2.5). Oil-fired electricity generating capacity decreases from 17 GW in 2015 to 3 GW in 2040, when they are used primarily to meet short-term peaks, because of their relatively high operating cost. Coal-fired power capacity decreases by 1.5 GW by 2040, as a portion of existing capacity is retired.

The electricity generation mix in Mexico is progressively decarbonised over the period to 2040 (Figure 2.6). The share of renewables-based electricity generation capacity rises from 25% to 46%, under the impetus of government policy to increase the use of clean energy (see Chapter 3). In volumetric terms, renewables-based capacity increases from 17 GW in 2015 (most of which is hydropower) to a much more diverse portfolio of 74 GW in 2040. Among the different renewable technologies, solar photovoltaic (PV) capacity grows rapidly, from 0.2 GW in 2015 to almost 30 GW in 2040. Wind power also contributes to the rapid expansion of renewable electricity capacity, with an additional 19 GW by 2040. The rise in hydropower is much slower, at 7.6 GW by 2040.

The rapid expansion of solar PV and wind is not a product of specific technology choices by the government as the auction system under which they are introduced to the market is technology-neutral among clean energy technologies. Rather, it reflects the good fit for wind and solar with the market design introduced under Mexico's power sector reform, which has built-in mechanisms to increase the share of clean energy in the mix. The relatively low barriers to participation in pre-qualification for the long-term auctions have encouraged private investors to enter the renewables market in Mexico. However, the fact that these players are not obliged to demonstrate acquired land rights – they need to apply for necessary permissions only after the announcement of the results of the auctions – does introduce risk that not all projects will be implemented as planned.

Figure 2.5 ▷ Change in power generation capacity in Mexico in the New Policies Scenario



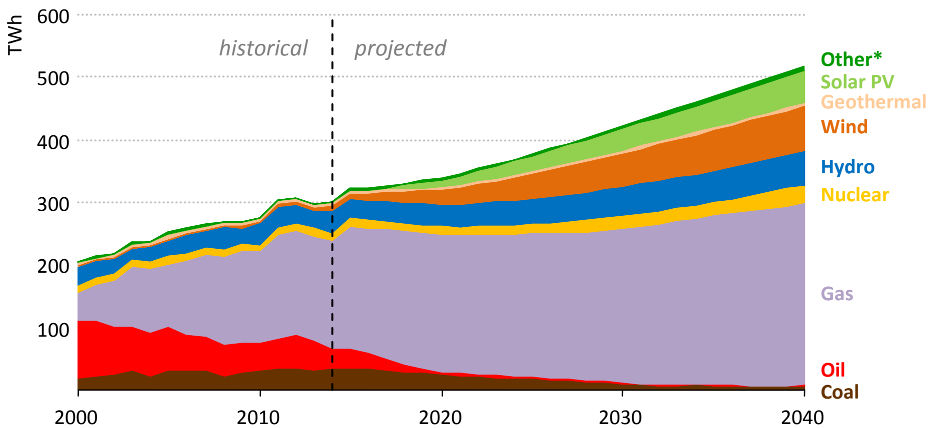
Natural gas and renewables-based power leads capacity increases in Mexico in the New Policies Scenario to 2040

Note: Other renewables includes geothermal, bioenergy and concentrating solar power.

In PRODESEN, 4 GW of nuclear capacity is expected to be built by 2030, in addition to the existing 1.5 GW at the Laguna Verde site. However, the high capital requirements for nuclear power plants create some uncertainty concerning the realisation of this plan. Although the Reform has opened up the power sector to participation by the private sector, nuclear power generation remains the exclusive responsibility of the state. The Electricity Law includes nuclear as a form of clean energy, so the same mechanism of auctions for energy, capacity and clean energy certificates could be expected to support the introduction of new nuclear power projects. However, the level of prices revealed in the auctions in March and September 2016 would be too low to support new nuclear construction based on the experience of other OECD countries. Plus the duration of the long-term contracts on offer (15 years for energy and capacity, and 20 years for clean certificates) is likely to be too short to incentivise nuclear power projects. Even our cautious assessment of an additional 2 GW of nuclear capacity built by 2040 may require some additional mechanism of support or guarantee. In addition, greenfield nuclear power projects are likely to face considerable opposition from local communities. The current policy of consultation needs to be developed, together with effective waste disposal and nuclear safety policies.

Power generation in Mexico rises to more than 500 terawatt-hours (TWh) in 2040, at an annual average growth rate of 2.1%, three-times faster than the OECD average of 0.6%. As renewables-based capacity grows, the generation mix in Mexico becomes increasingly diverse and less reliant on fossil fuels, and the share of fossil fuel-based power generation falls from 79% in 2014 to 58% in 2040. Gas remains the dominant source of power, accounting for around 60% of total electricity generation over the projection period, as additional capacity and import infrastructure become available. While the contribution of oil and coal fades, renewables play a much greater role, their share in total electricity generation more than doubling to 37% in 2040 and accounting for two-thirds of the rise in electricity generation to 2040. Wind and solar PV lead the growth in renewables-based power generation: the contribution of wind energy grows from 6.4 TWh in 2014 to 71 TWh in 2040, while that of solar PV jumps from 0.2 TWh in 2014 to 52 TWh in 2040. As discussed in more detail in Chapter 3, the electricity reform that opens the door to private investment in power generation is instrumental in the rapid transition of the power mix.

Figure 2.6 ▷ Electricity generation by source in the New Policies Scenario, 2000-2040



The power generation mix in Mexico becomes steadily more diverse and less carbon-intensive in the New Policies Scenario

*Other renewables include bioenergy and concentrating solar power.

Transmission and distribution

The electricity network in Mexico is divided into seven interconnected regional areas and three isolated areas (Baja California, Baja California Sur and Mulegé-Santa Rosalía). Different climatic conditions across Mexico produce differing demand profiles and peak demand periods, providing a powerful rationale for a well-interconnected network which can partially smooth the variations. The case for expansion and modernisation of the grid is strengthened by the rapid rise in electricity demand, the increased deployment of renewables and the current relatively high level of network losses.

Mexico plans to increase the length of the country's transmission lines to around 132 000 kilometres (km) transmission lines by 2030, up from 104 000 km in 2014 (SENER, 2016b). In our projection, which is consistent with the government programme, 46 000 km of new transmission lines are added by 2040 and around 70 000 km of ageing lines are replaced. Expansion of transmission lines has a positive impact on Mexico's ability to accommodate more renewables-based power in the electricity mix. For example, the Baja California region has strong wind, solar and geothermal power potential, with wind speeds reaching 12 metres per second (m/s) and daily solar radiation of up to 8.5 kilowatt-hours (kWh) (SENER, 2016b), but the region is isolated from the main power grid. Connecting the region to the main grid, as planned in PRODESEN, will allow Mexico to better exploit its significant renewable resources and optimise electricity supply over a larger area.

Distribution lines also need expansion and modernisation to accommodate rising residential demand and to reduce network losses. In the New Policies Scenario, the total length of distribution lines increases by one-third to 2040, from 770 000 km in 2014. The addition of new lines to meet increasing demand accounts for around 60% of the investment in the distribution systems. The government of Mexico is also making efforts to reduce non-technical losses, by measures such as reducing illegal connections and ensuring the effective operation of meters and billing systems. In the New Policies Scenario, such efforts serve to reduce transmission and distribution losses to 8.6% of net generation in 2040, a level closer to the OECD average today. Expansion and modernisation of the distribution network will also help Mexico to accommodate more distributed power generation, both of renewables and of efficient cogeneration plants with a capacity less than 0.5 MW, for which the government provides financial incentives to promote deployment.

2.2.3 End-use sectors

In the New Policies Scenario, the rise in final energy consumption by end-use sectors, underpinned by economic and population growth, and urbanisation, averages 1.1% annually to 2040. Growth is strongest in industry and buildings, although the transport sector continues to be the largest energy consuming sector (Table 2.3). The mix of energies consumed in end-use sectors reflects some of the trends seen in primary energy demand, with gas consumption increasing (mainly in industry and buildings) and the share of oil consumption decreasing. However, oil, mainly used for transport, is still the main source of energy demand in end-use sectors, accounting for more than 50% of total final energy consumption over the projection period (albeit down from 62% in 2014). The share of electricity in final energy demand increases substantially, from 18% in 2014 to 25% in 2040, as consumption in industry and buildings grows rapidly.

Table 2.3 ▷ Final energy consumption by sector in Mexico in the New Policies Scenario (Mtoe)

						Shares		2014-2040	
	2000	2014	2020	2030	2040	2014	2040	Change	CAAGR*
Industry	28	34	37	43	49	28%	31%	15	1.5%
Transport	36	51	53	57	59	43%	38%	8	0.5%
Buildings	21	24	26	29	33	20%	21%	10	1.3%
Other sectors**	10	10	12	14	15	8%	10%	5	1.6%
Total	**95**	**118**	**128**	**143**	**156**	**100%**	**100%**	**38**	**1.1%**
Industry, incl. transformation***	35	39	44	51	58	n.a.	n.a.	18	1.5%

*Compound average annual growth rate. ** Includes agriculture and non-energy use. *** Includes energy demand from blast furnaces and coke ovens (not part of final consumption) and petrochemical feedstocks.
Note: n.a. = not applicable.

Industry[1]

Energy demand in industry grows at an annual average rate of 1.5%, reaching 58 million tonnes of oil equivalent (Mtoe) by 2040, a level around 50% higher than in 2014. This makes industry the second-largest energy end-user, next to transport. Electricity consumption grows at an annual average rate of 1.8%, meeting one-third of industrial energy requirements in 2040. The increase in electricity consumption is spread across a wide range of businesses, including automotive and component manufacturers that use electricity as their major energy source, and SMEs, whose electricity consumption has grown at an annual average rate of 2.8% for the past decade (SENER, 2016c). Natural gas use also grows at an annual average rate of 1.9%, accounting for 35% of industrial energy consumption in 2040.

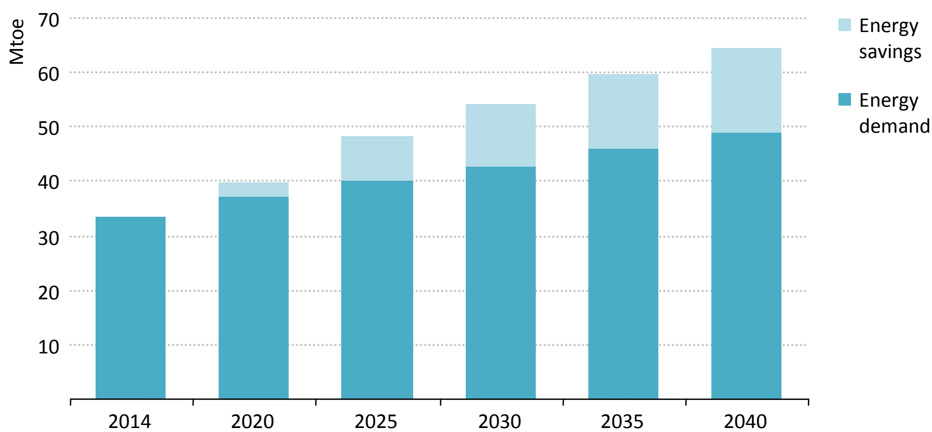
Energy-intensive industries[2] continue to account for around 40% of industrial energy consumption over the *Outlook* period. Around a quarter of the increase in industrial energy consumption between 2014 and 2040 comes from the chemicals industry, driven by ethylene production, which is projected to grow by 3.3% on average annually to meet growing demand for petrochemical products. Electricity accounts for a growing share of total industrial energy consumption, due in part to the increasing use in industry of heat pumps, as well as technical changes in industrial processes, such as the increased use of scrap–based steel production in the steel industry. Biomass use as a source of industrial heat increases in the chemicals, paper and pulp, and cement industries. In the New Policies Scenario, the success of policies to increase efficiency in energy use in energy-intensive industries, coupled with changes in industrial structure and processes, leads to a gradual decrease in energy intensity, measured as the amount of energy needed per tonne of output. However, the rate of decrease is slower than in the past, reflecting the fewer remaining energy saving opportunities for those industries.

[1] The industrial demand here includes energy used in blast furnaces, coke ovens and petrochemical feedstocks.

[2] Including iron and steel, chemicals, cement, and paper and pulp.

Energy consumption in non energy-intensive industries grows rapidly, at an annual average rate of 1.6%, and accounts for around 60% of the increase in energy demand in industry between 2014 and 2040. Electricity and gas consumption lead the growth and account for 50% and 30% of energy consumption in the non energy-intensive industry in 2040, respectively. The increased availability of gas imported from the United States facilitates the replacement of oil and coal as a source of heat, as well as wider use of electricity in manufacturing processes. Energy intensity in these industries is projected to improve quickly, by almost 30% between 2014 and 2040. Awareness of the potential for efficiency improvements is typically low in this sector, as energy costs account for a relatively low share of production costs, but government policies to promote efficiency among SMEs helps to realise some of the substantial savings available.

Figure 2.7 ▷ Energy demand and savings in industry in Mexico in the New Policies Scenario, 2014-2040



Efficiency policies and measures are effective in slowing the rise in industrial energy consumption in the New Policies Scenario

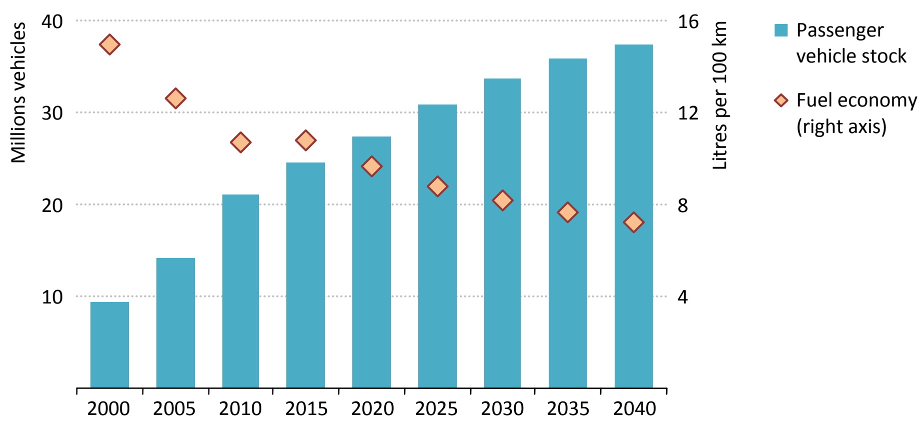
Note: The amount of energy efficiency savings reflects the cumulative effect of efficiency savings in different industrial sectors in the New Policies Scenario, based on a decomposition analysis of projected demand.

In the New Policies Scenario, cumulative savings linked to efficiency gains amount to around 16 Mtoe, equivalent to around 30% of industrial energy demand in 2040 (Figure 2.7). These gains are attributable to government policies to promote efficiency in industry, such as the adoption of energy management systems and the implementation of energy audits, as well as to industries' own efforts to improve efficiency. Large industrial energy users have recently started to introduce energy management systems on a voluntary basis, with the National Commission for the Efficient Use of Energy (CONUEE) providing support to implement the systems in 3 500 large energy users. Such measures are expected to be adopted more widely in the period to 2040, including by a larger number of SMEs.

Transport

Transport is the largest of Mexico's end-use energy sectors. It has been growing at a rate of 2.5% annually since 1990 and accounted for 43% of final energy consumption in 2014. The total number of passenger vehicles in Mexico has risen dramatically, from 9 million in 2000 to almost 25 million in 2014, making severe traffic congestion a major issue in cities and leading to poor urban air quality. A further challenge is the age of the vehicle fleet: while a restriction on imports of used cars is theoretically in place, with vehicles older than ten years banned, enforcement has been lacking and imports of old vehicles with low fuel-economy performance from the United States continue. As described in Chapter 1, comparison with other OECD countries suggests that there is room for additional growth in the vehicle fleet – the number of vehicles per 1 000 people is less than half the OECD average. The key question for Mexico is whether policy action can limit the adverse consequences of future growth in the number of vehicles in terms of energy demand and air pollutant emissions.

Figure 2.8 ▷ Passenger vehicle stock and fuel economy in Mexico in the New Policies Scenario, 2000-2040



Energy demand is driven by an increase in vehicle ownership, while vehicle fuel economy improves

Mexico succeeds in part in meeting this challenge in the New Policies Scenario. The passenger vehicle stock grows by around half by 2040 and road transport is responsible for almost all of the increase in transport energy demand, but efficiency policies limit this growth (Figure 2.8). The rise in road transport energy demand slows to an annual average rate of 0.6% over the period to 2040. This is much slower rate of growth than the historical rise in this sector in Mexico, but it remains significantly greater than the average rate in the OECD, where saturation in ownership levels, combined with efficiency policies, sees road transport energy consumption fall by an average of 0.9% per year to 2040.

Box 2.1 ▷ Transport solutions to Mexico's air pollution problem

The Mexico City metropolitan area is one of the largest in the world and has a population of 21 million. The city's car fleet of 5 million vehicles, consumes around 25 million litres of fuel per day and gives rise to the bulk of the city's transport-related carbon monoxide (98%) and nitrogen oxides (88%) emissions, four-fifths of black carbon emissions and half of greenhouse-gas emissions (SEDEMA, 2012). Although two-thirds of all journeys in the city are made by public transport, the public transport fleet is ageing and polluting. To address the joint air pollution and mobility crisis, the city government has developed the Metrobus project as one element of the PROAIRE policy (see Chapter 1). Metrobus is a Bus Rapid Transit (BRT) system based on dedicated bus lanes, enclosed stations, and large articulated and bi-articulated buses. It was implemented as an alternative to the costly construction of a subway system: constructing one kilometre of metro costs as much as building 22 kilometres of a BRT corridor.

The system currently serves more than one million passengers every day on more than 550 buses, 10% of which are hybrid (the first hybrid fleet in Latin America). The corridors, spanning 125 km, now cover 11 of the 16 municipalities of the metropolitan region, with future plans for expansion including a seventh corridor along the most emblematic avenue of Mexico City, *Paseo de la Reforma*, furnished with 90 double-decker Euro VI buses by 2017.

The Metrobus system has brought significant reductions in local air pollutants and greenhouse gases to Mexico City. The replacement of polluting buses, 1 500 of which have been scrapped, has improved not only the local environment but also the entire mobility framework. The Metrobus system was the first transport system in the world to commercialise carbon credits. During its operation, it has eliminated over 874 000 tonnes of carbon-dioxide equivalent (CO_2-eq). It has also achieved a significant modal shift: 17% of people using the Metrobus have chosen to leave their car at home in favour of the public transport system, accounting for a reduction of 187 000 passenger car journeys.

Metrobus is a highly energy-efficient transport system. To transport 1 000 people 10 km by car requires 835 private cars and consumes 650 litres of fuel. To transport the same number of people the same distance by the bus network requires only four bi-articulated buses and 40 litres of fuel, representing a 94% savings on fuel consumption. The BRT system has also had an important impact on public health: its implementation reduced commuters' exposure to carbon monoxide, benzene and particulate matter ($PM_{2.5}$) by a factor of between 20% and 70% (Wöhrnschimmel, 2008).

Fuel-economy standards for passenger cars in Mexico are currently based on the limits imposed in the United States (combination of Tier 1 and Tier 2) and the European Union (EURO 4). There is a major opportunity to reduce oil demand and carbon-dioxide (CO_2) emissions by improving these standards. The average new car sold in Mexico emits around 180 grammes of CO_2 per kilometre (g CO_2/km) (according to emissions test cycles), compared with a value of around 130 g CO_2/km in the European Union. More stringent standards are planned in 2018. In the New Policies Scenario, the fuel economy of new car sales in Mexico reaches almost today's level in the European Union by 2040, helping to achieve energy savings of 10% transport demand in 2040, compared with the Current Policies Scenario. Around one-fifth of the passenger vehicle stock is projected to have hybrid technology by 2040, compared with the situation today in which 95% of the passenger vehicles in Mexico are traditional combustion engines.

While improvements in efficiency are reached in the passenger light-duty vehicle fleet, energy inefficiency in the freight fleet becomes an increasingly significant issue in the period to 2040. Even though trucks are responsible for only around 13% of energy demand, in the absence of efficiency policies to mitigate energy demand (they do not feature in Mexican policies today, so similarly, are excluded in the New Policies Scenario), trucks are responsible for more than half the projected 8 Mtoe rise in transport energy demand over the period. However, policy actions are having an impact in other areas; efforts to promote public transport being a good example. Bus Rapid Transport, a system of giving priority road space to dedicated buses, is being increasingly used to promote good quality mass transit and is now in use in eight Mexican cities, including Mexico City (Box 2.1).

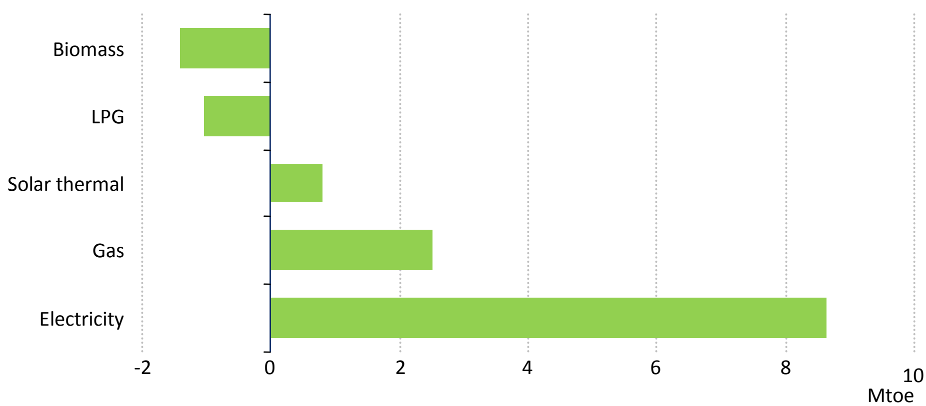
In terms of fuels, the transport sector in Mexico is set to remain relatively undiversified and oil-dependent in the New Policies Scenario. In contrast to the rest of the OECD where on average the share of oil is reduced to 80% of transport demand by 2040 (from 93% today), in Mexico, transport remains almost exclusively reliant on oil. This position is marginally challenged by natural gas in road freight (gas accounts for 2% of transport demand by 2040 as a result of compressed natural gas truck sales) and by electricity, through the limited uptake of electric passenger vehicles (which account for less than 1% of energy consumption in road transport in 2040). Electricity use in railways remains minute and freight transport is largely reliant on heavy trucks. As a result, energy consumption in trucks increases strongly, by around 70%, to 2040. Even though the share of biofuels use in transport in OECD countries grows from 4% to 10% share on average, in the absence of sustained policy support, biofuels do not find a place in Mexico's transport energy mix in the New Policies Scenario, since they do not feature in current plans.

Buildings

Energy demand in buildings (both the residential and services sectors) represents one-fifth of current total final energy consumption. Over the period to 2040, its nature and composition is projected to change substantially as energy use becomes more efficient, more reliant on modern fuels – especially electricity – and the role of solid biomass diminishes. The residential sector today accounts for more than 80% of total demand in buildings. In rural areas, around half of households – some 15% of the overall population – rely on biomass for cooking and water heating, so that biomass constitutes almost one-third of overall residential energy demand. This share declines steadily in the New Policies Scenario, to less than 20% in 2040. In the past, the main fuel to replace biomass has been liquefied petroleum gas (LPG) and this substitution continues to take place in some rural areas. However, natural gas takes a rising share of demand for cooking and water heating in our projections, as more and more households are connected to the grid. Overall, natural gas demand in the residential sector grows by 5% per year to 2040, while that of LPG declines by more than 1% per year.

The switch away from biomass represents a profound efficiency gain for residential energy use, keeping overall residential demand growth down to an annual average of 1% (reaching 25 Mtoe by 2040): if solid biomass were to be excluded, the rate of growth would increase to an annual average of 1.6%. The move away from biomass also represents a gain for welfare, as exposure to particulate matter from incomplete biomass combustion is a major health risk. In our estimation, around 12 500 premature deaths in Mexico were attributable to household air pollution in 2015. This value declines only marginally by 2040, even though the reduction in biomass use is significant (health problems are related to lifetime exposure to pollutants, so a change in energy use takes time to feed through into the projected health impacts). More could be done to bring these health impacts down further (IEA, 2016).

Figure 2.9 ▷ Energy demand growth by fuel in the buildings sector in the New Policies Scenario, 2014-2040



Electricity leads the demand growth in the buildings sector between 2014 and 2040

The largest increase in energy demand in the buildings sector comes from the demand for electricity (Figure 2.9). Residential electricity demand almost doubles over the period to 2040, electricity consolidating its position as the main source of final energy in the buildings sector (with its share rising from one-third to more than 50%). This increase in residential use is due mainly to increased use of cooling and major appliances. Electricity use for cooling systems grows rapidly, by an annual average of 4.8%, as the rate of household air conditioner ownership increases from 13% today to almost 40% in 2040. There is also a notable increase in the direct use of solar thermal for water heating, both in residential and in non-residential buildings.

Energy efficiency policies in the buildings sector have gained momentum in recent years, with Mexico making laudable efforts to reduce energy consumption through incentive-based subsidies, and by tying mortgages for households and developers to packages of "eco-technologies" (Box 2.2). The increased use of solar thermal for water heating is due, in part, to the large uptake of INFONAVIT's *Hipoteca Verde* (Green Mortgage Programme), as well as more recent initiatives, such as the ECOCASA Programme from *Sociedad Hipotecaria Federal* (Federal Mortgage Society). The government of Mexico has established a range of efficiency standards for buildings and their components, formulated a building energy code which works as a model for local authorities, but the implementation of efficiency policies in the buildings sector is complicated by the devolved policy responsibility to local jurisdictions. Limited resources and capabilities in local municipalities mean that only a limited number of cities, such as Mexico City, have adopted such building energy codes.

In our projections, without the efficiency gains stemming from the policies assumed in the New Policies Scenario, energy consumption in the buildings sector would be 20% higher in 2040. Beyond the policies mentioned above, specific measures include energy efficiency standards for windows, insulation and other building components, large-scale replacement of inefficient appliances and lighting, and loans for efficient housing.

Box 2.2 ▹ Mexico's push for sustainable housing

Mexico has pioneered some innovative programmes to tackle both the increase in energy demand from residential buildings and the shortage of adequate and sustainable housing for the most vulnerable parts of the population. CONAVI (National Housing Commission) and INFONAVIT (National Housing Fund for Private Sector Workers) started in 2007 as a joint effort to foster the construction of houses with energy-efficient and water-saving technologies (eco-technologies), and renewable energy solutions, like solar water heaters. INFONAVIT's Green Mortgage programme now accounts for 70% of all mortgages in the country, while CONAVI's *Esta es tu casa* (This is your house) subsidy programme for low-income home buyers has, since 2012, included sustainability and criteria in its selection process.[3] Both programmes aim to incentivise efficiency by increasing the amount of the mortgage or subsidy in cases where the property meets certain technology standards. Both programmes are credited with stimulating demand for low-energy consumption appliances and enabling low and middle-income households to access modern home designs that have reduced energy bills. They have also raised general public awareness of the importance of reducing energy and water consumption.

Mexico was the first country to submit to the United Nations Framework Convention on Climate Change a Sustainable Housing Nationally Appropriate Mitigation Actions (NAMA) in 2012, with support from a variety of national and international actors. This expresses its ambitions and goals regarding the reduction of greenhouse-gas emissions in residential buildings through affordable solutions for low-income households. According to estimates by the Mexican government, implementing the NAMA would

[3] INFONAVIT's *Hipoteca Verde* has provided an average of 376 000 green mortgages annually since 2011. CONAVI made 210 000 subsidies available between 2015 and 2016.

eliminate approximately 2 million tonnes of CO_2-eq emissions a year, equivalent to 0.5% of national energy-related CO_2 emissions in 2014.

The ECOCASA Programme, launched by the government in 2013, became the first pilot programme under the NAMA, providing housing developers with attractive loans if they offered designs that resulted in greenhouse-gas (GHG) emission reductions of at least 20% (compared to a determined baseline). Passive design solutions qualified as well as traditional ones (solar water heaters and insulation) for low- and middle-income households. The programme has so far awarded ECOCASA credits of approximately $200 million to 20 000 households and has already built more than 16 000 houses (of a total of 27 600 planned), which are expected to reduce an estimated 630 000 tonnes of CO_2 over the 40 year life of the houses (Sociedad Hipotecaria Federal, 2016). A second phase, with more ambitious sustainability criteria is planned, with the inclusion of multi-story sustainable houses for rent.

2.3 Outlook by fuel in the New Policies Scenario

2.3.1 Overview

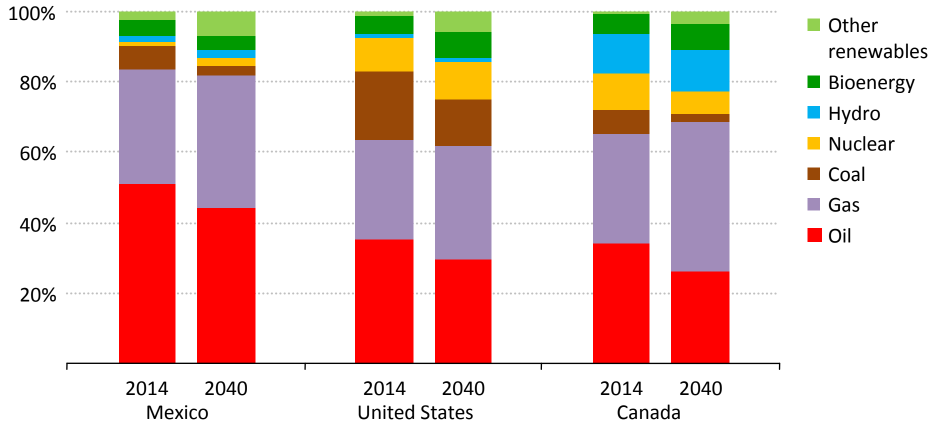
Mexico's energy mix is one of the most oil-dependent in the world, with oil products still accounting for more than half of total primary energy demand (Table 2.4). In the New Policies Scenario, the share of oil in the mix falls sharply, to 42%, but, at this level, it remains significantly higher than in the wider OECD. By contrast, the energy mix is one of the least dependent on coal: in our *Outlook*, coal is displaced almost entirely as coal-fired power plants are all but phased out. Natural gas demand grows by 1.3% per year, resulting in a significant increase in its share in the mix (from 32% to 38%). The share of renewables in total demand, including bioenergy and hydropower, increases from 8% in 2014 to 14%, with the majority of the increase attributable to the strong growth in wind and solar power generation (Figure 2.10).

Table 2.4 ▻ Primary energy demand by fuel in Mexico in the New Policies Scenario (Mtoe)

						Shares		CAAGR*
	2000	2014	2020	2030	2040	2014	2040	2014-2040
Fossil fuels	131	170	168	176	186	90%	83%	0.4%
Oil	89	96	91	95	95	51%	42%	-0.1%
Natural gas	35	61	68	74	86	32%	38%	1.4%
Coal	7	13	10	7	6	7%	3%	-3.1%
Renewables	17	16	19	25	31	9%	14%	2.7%
Hydro	3	3	3	4	5	2%	2%	1.4%
Bioenergy	9	9	9	9	9	5%	4%	0.6%
Other renewables	5	4	7	12	17	2%	8%	5.9%
Nuclear	2	3	3	5	7	1%	3%	4.2%
Total	**150**	**188**	**190**	**206**	**225**	**100%**	**100%**	**0.7%**

* Compound average annual growth rate.

Figure 2.10 ▻ **Primary energy mix in Mexico and selected countries in the New Policies Scenario**



Mexico's energy mix becomes more diverse, but is still more oil-dependent in 2040 than the United States or Canada are today

Note: Other renewables include geothermal, solar PV, concentrating solar power and wind.

2.3.2 Oil

Oil resources and production

Twelve geologic basins in Mexico are deemed to have active petroleum systems, but only six basins have established hydrocarbon production.[4] Mexico's oil and gas development has historically focused on onshore and shallow water basins surrounding the Gulf of Mexico, and while not the focus of the upcoming bid round in December 2016, both onshore and shallow water areas are estimated to still have significant resource potential.

Onshore oil production has taken place in Mexico since the early 1900s and over 20 billion barrels have been produced to date. We estimate that a further 21 billion barrels are technically recoverable from onshore regions (Table 2.5). Many of these are within the Tampico-Misantla Basin, which includes Chicontepec, a super-giant field, yet it is a very complex onshore field that has so far experienced very low recovery rates (Figure 2.11). Development of Mexico's shallow offshore fields began in earnest during the 1960s. Over 28 billion barrels have already been produced, the overwhelming majority from the Sureste Basin, home to Mexico's largest offshore production areas which are the Cantarell and Ku-Maloob-Zaap complexes. The Sureste Basin still has significant untapped potential, however, more than 20 billion barrels of remaining technically recoverable resources are estimated to exist in shallow offshore regions.

[4] A petroleum system exists if the following elements are present: mature source rocks expelling oil and gas, a migration pathway and reservoir rock trapping the migrated oil and gas under a seal.

Table 2.5 ▷ Remaining technically recoverable oil resources by category in Mexico, end-2014 (billion barrels)

	Technically recoverable resources	Cumulative production	Remaining recoverable resources	Remaining % of URR	Proven reserves
Conventional onshore	41.6	20.3	21.2	51%	3.0
Tight oil	13.1	0.0	13.1	100%	0.0
Shallow offshore	48.4	28.3	20.1	42%	7.8
Deep offshore	15.0	0.0	15.0	100%	0.0
Total Mexico	**118.0**	**48.6**	**69.4**	**59%**	**10.8**

Notes: Data include crude, condensate and natural gas liquids. URR = ultimately recoverable resources.

Sources: IEA; SENER.

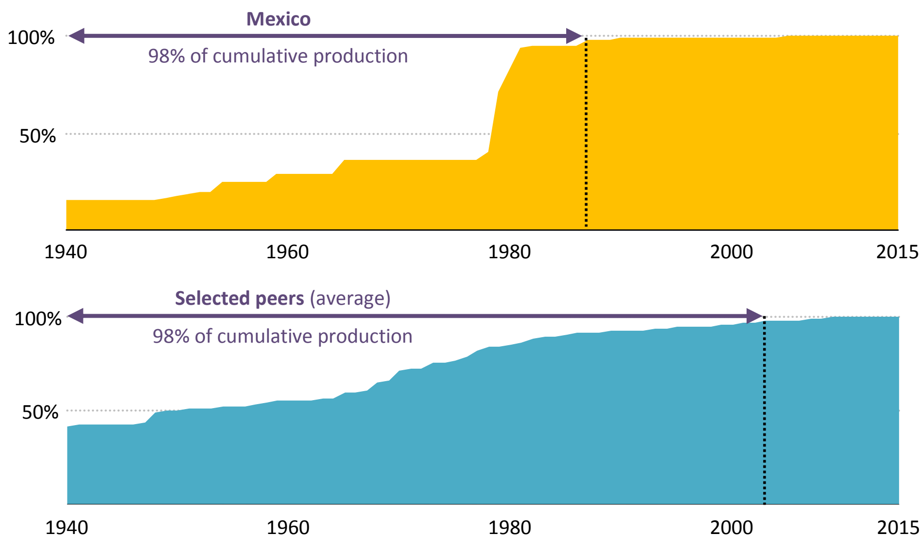
To date, there has been no production from tight oil prospects or from deep offshore regions in Mexico. Yet volumes of both are estimated to be large, collectively accounting for around 40% of Mexico's remaining resources: around 13 billion barrels of tight oil, predominantly in the Tampico-Misantla and Burgos basins, and 15 billion barrels in the deep waters of the Gulf of Mexico. Several basins, such as the Yucatan platform, Chihuahua, the Sierra Madre fold belt and the Vizcaino-La Purisma-Iray Basin have not been explored and resource estimates do not exist for these basins.

Figure 2.11 ▷ Hydrocarbon basins in Mexico

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The age (and very high decline rates) of Mexico's main producing oil fields is a notable feature of the upstream sector. PEMEX, the productive state enterprise, has concentrated investment for decades in several large offshore fields using aggressive recovery techniques. This has served the nation well as a reliable source of revenue, but it has created a lack of resource diversity. Only 2% of cumulative historical production in Mexico comes from fields in which production started in the last 25 years, compared with 7% in the United States, 8% in Venezuela and 35% in the United Kingdom. After 2004 at the Cantarell complex, which was Mexico's largest at the time, decline accelerated, leading to a drastic fall in national production (Figure 2.12).

Figure 2.12 ▷ **Cumulative oil production by year in Mexico and selected countries**



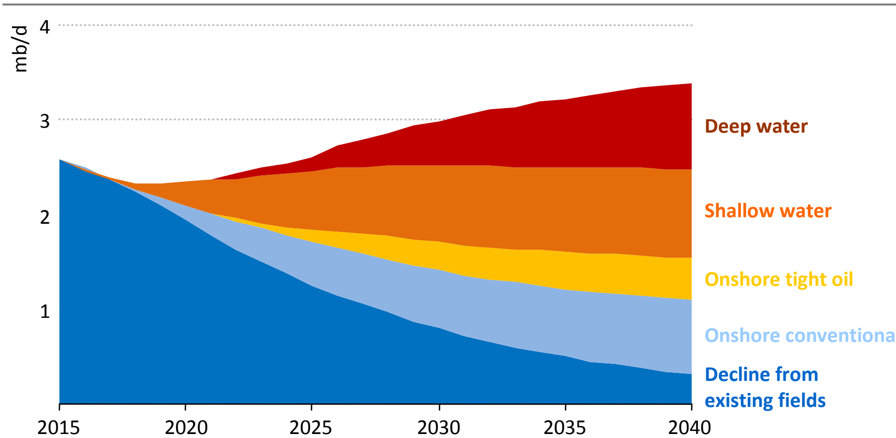
Almost all of Mexico's cumulative production to date comes from fields that started operation more than 25 years ago

Note: The selected peers are the United States, United Kingdom, Venezuela, China and Russia.

A marked increase in capital spending by PEMEX over the past six years has effectively added deepwater assets to Mexico's portfolio; but production results will not be seen for some time and total oil production fell by 7% in 2015, to an average of 2.6 million barrels per day (mb/d), due to a combination of budget constraints and the high decline rate at mature fields. Investment also went into boosting production at newer shallow water developments and slowing decline at older fields. These large investments, in conjunction with PEMEX's fiscal responsibilities to the Mexican economy, overwhelmed its budget, an effect compounded by the fall in oil prices in mid-2014. These factors added urgency to the implementation of the Energy Reform measures. Mexican oil supply in the New Policies Scenario relies heavily on two features. The first is timely implementation of the Reform measures, which allow the PEMEX association agreements and the bid rounds to proceed as documented in the Secretariat of Energy's (SENER) current five-year plan. The second requirement is the successful execution of a majority of the projects awarded to the new entrants to Mexico's upstream market (see Chapter 3).

In the New Policies Scenario, Mexico's oil production falls in the medium term, with PEMEX likely to continue to provide nearly all of Mexico's output. Conventional onshore production licences have already been awarded to winners of the round-one competition, but their scale is small and even investment made immediately is not likely to provide much of a production cushion to offset decline at the larger fields. There are opportunities to extend the lives of key assets like Ku-Maloo-Zaap through enhanced recovery schemes and our *Outlook* factors this in. Production from shallow waters will continue to play a major role in Mexico production, but the age of the resource base means that historic levels of shallow water output are unlikely to be seen again. After bottoming out at 2.3 mb/d towards the end of the current decade, by 2040 oil production is up to 3.4 mb/d, a net increase of 800 kb/d from 2015 (Figure 2.13).

Figure 2.13 ▷ Oil production in Mexico in the New Policies Scenario, 2015-2040



Mexico's oil output gets back on a rising path in the New Policies Scenario, but it takes time for new projects to offset declines

Oil product demand

In the New Policies Scenario, Mexico's total oil demand edges higher to reach nearly 2.1 mb/d in 2040 (Table 2.6). In this time, however, the product slate gets significantly lighter, as growth in transport and in industry (where volumes increase for petrochemical feedstocks), offsets a decline in consumption in the power sector (mainly heavy fuel oil) and in the residential sector.[5] Naphtha is the fastest growing oil product, albeit from a low

[5] In our discussion of product demand and trade, we include international aviation and marine bunkers as these are physically supplied by the country's infrastructure.

base, as growing petrochemical sector demand coincides with a largely flat outlook for natural gas liquids production, constraining ethane availability and use, and leaving naphtha (which can also be supplied by refineries) to take a higher share in cracker feedstocks.

2

Table 2.6 ▷ Oil demand by product in Mexico in the New Policies Scenario (mb/d)

	2014	2020	2030	2040	2014-2040	
					Delta	CAAGR*
Ethane	0.11	0.14	0.12	0.12	0.01	0.3%
LPG	0.31	0.27	0.26	0.26	-0.05	-0.6%
Naphtha	0.02	0.03	0.05	0.07	0.04	4.0%
Gasoline	0.75	0.75	0.76	0.76	0.01	0.1%
Kerosene	0.07	0.08	0.11	0.14	0.08	3.0%
Diesel	0.43	0.44	0.50	0.50	0.07	0.6%
Fuel oil	0.16	0.03	0.02	0.01	-0.15	-8.9%
Total oil demand**	**2.01**	**1.93**	**2.04**	**2.09**	**0.09**	**0.2%**

* Compound average annual growth rate. ** Total includes other products such as asphalt, waxes and lubricants. Note: total includes international bunkers.

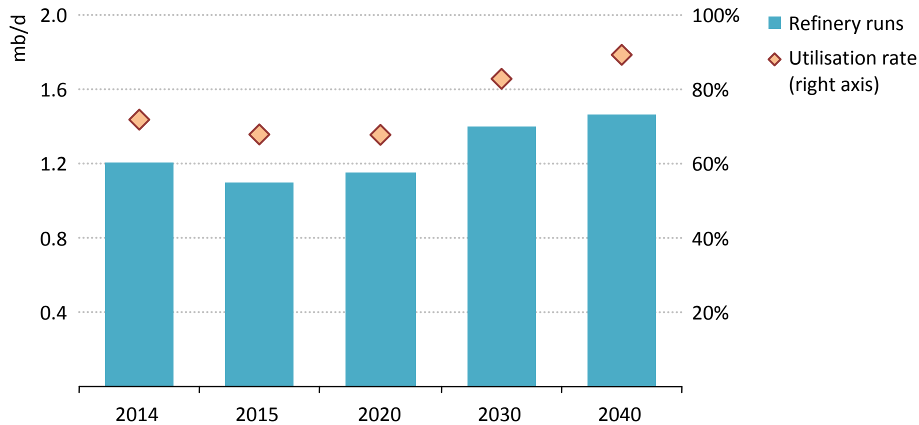
LPG demand bucks global trends, declining to 2040, primarily as a result of being replaced by natural gas in the residential sector. Kerosene is the fastest growing transport fuel, thanks to a doubling of international aviation bunkers. Gasoline sees modest growth, as increased mobility demand is offset, to a degree, by efficiency gains. Road freight demand pushes diesel use higher, offsetting declining consumption in the power sector. Fuel oil, used mostly in power generation, finds no alternative market and its use is almost entirely phased out.

Refining and trade

Mexico is the only large oil consumer[6] in the OECD where oil product demand in 2040 is higher than it is today. This creates an interesting perspective for developments in the refining sector. Mexico's refineries have performed rather poorly in recent years, their utilisation rates falling to just 60% in early 2016. The low utilisation rate reflects the inability of the refiners to run profitably at higher rates, as crucial upgrades, necessary to process the increasingly heavier crude slate into oil products with tightening specifications, have been long-delayed. In our projections, refiners are expected to overcome financing problems and invest in refinery upgrading units. While no new stand-alone refining capacity is expected to come online in the next two-and-a-half decades, improved equipment and units at the existing refineries, at an estimated cost of $20 billion, help to push utilisation rates to around 90% by 2040, resulting in refinery runs of almost 1.5 mb/d, (compared with only 1.1 mb/d in 2016) (Figure 2.14).

[6] Countries with oil demand over 1 million barrels per day.

Figure 2.14 ▷ Refinery runs and utilisation rate in Mexico in the New Policies Scenario, 2014-2040



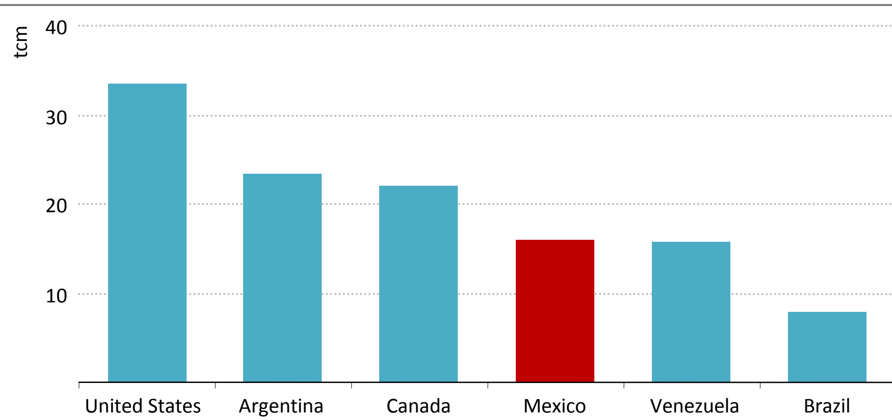
Upgrades at existing refineries help to push refinery runs up to 1.4 mb/d by 2040

2.3.3 Natural gas

Gas resources and production

Mexico's remaining conventional recoverable gas resource is estimated at about 3 trillion cubic metres (tcm), mostly located offshore in deep water in the Gulf of Mexico (accounting for around one-third of the conventional resource base). These resources in Mexico are considerably better understood than unconventional resources, with more certainty on the estimates of their size. Though, Mexico's unconventional gas resource is likely to be very sizeable (estimated by the US DOE/Energy Information Administration at about 16 tcm), almost all of it as shale (US DOE/EIA, 2015) (Figure 2.15).

Figure 2.15 ▷ Recoverable unconventional gas resources in selected countries



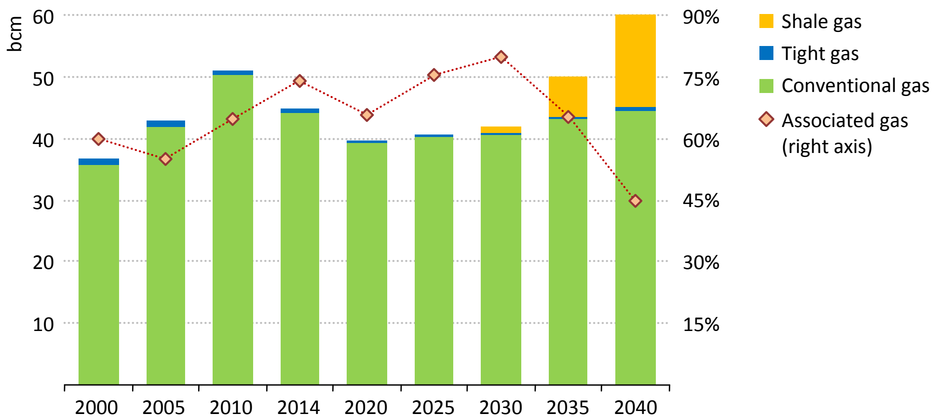
Mexico holds considerable promise for unconventional gas

Table 2.7 ▷ **Natural gas production, proven reserves and resources in Mexico** (tcm)

	Ultimate recoverable resource (URR)	Cumulative production	Remaining recoverable resources	Remaining % of URR	Proven reserves
Conventional	4.4	1.6	2.8	64%	0.4
of which Gulf of Mexico basin	1.6	0.0	1.6	100%	0.0
Unconventional	16.0	0.0	16.0	100%	0.0
of which Sabinas and Burgos basins	15.2	0.0	15.2	100%	0.0
Total Mexico	**20.4**	**1.6**	**18.9**	**92%**	**0.4**

The Burgos and Sabinas basins, for example, hold significantly larger resource promise than even Mexico's conventional plays (Table 2.7). Even if the shale gas resource were to prove to be significantly smaller than currently estimated, it could still represent a considerable source of gas for Mexico.[7]

Figure 2.16 ▷ **Natural gas production by type in Mexico in the New Policies Scenario**



Gas production is highly dependent on oil development until shale activity starts to ramp up in the late 2020s

In the New Policies Scenario, gas production increases by a little over one-third, to reach 60 billion cubic metres (bcm) by 2040 (by which time, around a quarter of total production is expected to come from shale resources). The timing of this increase is highly uncertain: the evolution of upstream costs and natural gas prices in the United States will have a large influence on the relative attractiveness of developments in Mexico (see Chapter 3). In the

[7] The *Comisión Nacional de Hidrocarburos* estimates Mexico's shale gas resources to be a quarter (or about 4.7 tcm) of the current US DOE/EIA estimate.

interim, our *Outlook* for gas production is closely linked to that of oil: the high share of associated gas explains the near-term fall in gas production and the partial turnaround in the 2020s (Figure 2.16). The share of associated gas in production starts to fall back notably towards the end of the projection period, due to the start of shale gas production, most probably sourced from the Burgos and Sabinas basins. Non-associated gas output is produced from dry and gas-condensate fields, the liquids produced in the latter boosting project economics considerably. The majority of such fields are thought to be located in the Gulf of Mexico, underlining again the importance of deepwater technology to the hydrocarbon outlook.

Gas demand and trade

The build-out of natural gas import infrastructure to the United States and the prospects for the development of local resources makes gas a mainstay for the energy system in Mexico to 2040. Gas accounts for almost 70% of the growth in primary energy demand to 2040, while oil demand is essentially flat and coal declines. Three sectors contribute to the rise in gas demand. First, the power sector alone accounts for over half of total growth, with gas-fired generation capacity increasing two-and-a-half times to 2040. Second is industry, including feedstock use in the petrochemicals manufacturing. The third relates to developments in upstream oil and gas services, where natural gas is used in the extraction process (compressors and auto-generation).

Domestic natural gas production, though rising strongly, does not keep up with rapidly increasing demand and therefore Mexico continues to rely on pipeline imports to 2040 (see Chapter 3). To facilitate the increasing prominence of gas in the energy mix (and to adapt to the rising need for imports), the Energy Reform includes a number of changes to the regulation of the gas market. They mostly relate to the end of PEMEX's monopoly on marketing and transmission activities, and the transition to a competitive gas market. In this regard, the Energy Regulatory Commission (CRE) has ruled that PEMEX must relinquish a portion of its gas supply contracts, a move that would reduce its market share to less than 30% by 2020. To facilitate private sector competition, the ownership of the transmission network (SISTRANGAS) has been transferred to CENAGAS, the newly created independent operator, and in mid-2016, SENER announced that CENAGAS and SISTRANGAS were to carry out an open season to allocate current transmission capacity. A supporting pillar of the gas liberalisation associated with the Energy Reform is the implementation of a new method to determine the first-hand sale price, which is to be referenced to prices in the southern United States. This aims to correct a number of market distortions, including the end-user subsidy that came as a result of PEMEX selling gas at a loss and to encourage private sector participation in natural gas foreign trade as well as domestic trading and marketing. These measures are part of the wider objective of moving to a fully competitive natural gas market in 2018, when the price of natural gas will be determined by the market, in the hope that accurate market signals will eventually encourage domestic gas production (SENER, 2016d).

SPOTLIGHT

What are Mexico's options for gas storage?

Today the natural gas network in Mexico is concentrated in two main areas; the north, near the border with the United States and the south, linking gas production centres with major consuming areas, notably Mexico City. Interconnections between the two areas are relatively few and gas storage is notably absent. Swings in gas demand, therefore, are currently met through line packing or the drawing down of liquefied natural gas (LNG) stored at the country's three LNG import terminals.

More interconnections and more gas storage, common in other countries and regions, offer major benefits, including optimisation of the use of key production and import infrastructure, improved competition, better supply reliability and energy security. These considerations become more important as Mexico moves to significantly increase gas-fired power generation. This implies that natural gas demand may become much more seasonal (as power use increases to meet summer air conditioning load), or even more variable on a daily basis. The Hydrocarbons Law gives SENER the power to determine and manage natural gas storage levels.

CENAGAS, the new body responsible for system planning and operation, has made a promising start. It has identified key transmission interconnections, tendered for their construction and is overseeing their building which, in several important cases, is well advanced. However, the picture for storage is considerably more complex.

Various types of natural gas storage facilities differ markedly in construction and operating costs and in terms of characteristics such as the maximum drawdown volumes and rates of drawdown. Hence their value in optimising system operation can vary markedly. Widely used in other countries, depleted gas and oil fields have a number of advantages over other types of storage facilities. Where available, they usually have existing delivery infrastructure and the gas inevitably remaining in place forms an important part of the essential cushion needed to permit stock drawdown. Both features generally mean much lower capital cost on a unit basis.

For a system operator, selection of the storage type, size, location and timing of operation all represent difficult choices, all conferring benefits but also often involving substantial costs. The monopoly character of some storage options, especially larger ones, argues for effective regulatory involvement, such as regulated tariffs and mandatory open access. However, these can be a barrier to investment, especially given the dynamic gas and power market environment likely to be seen in Mexico over the next decade.

IEA countries with liberalised gas and power markets have sometimes found it difficult to increase investment in storage. In the United Kingdom, for example, gas storage is relatively small in volume, at around 5 bcm. It is mostly located in salt caverns or exhausted gas fields in the North Sea. The United States has some 400 gas storage facilities, with depleted gas and oil fields accounting for four-fifths by storage volume. However, even the United States, with its well developed and flexible markets, has struggled to ensure adequate and well located gas storage over recent decades. In 2006, the Federal Energy Regulatory Commission relaxed open access provisions and allowed more unregulated operations in order to address this issue. In other IEA countries, major storage facilities date from a more regulated and centralised era. In some cases, the market has been slow to respond to the changing demand patterns, notably the greater use of gas-fired power to meet more volatile power demand.

From the viewpoint of CENAGAS, the transmission system operator in Mexico, a more market-oriented approach that encourages market-based returns may be necessary to encourage investment in gas storage, as well as a well-defined interim relaxation of open access requirements, spanning the first six-to-ten years, for example. This approach has been successfully used in the European Union to encourage investment in import infrastructure, notably in LNG terminals. It would seem likely to encourage a suite of technology types and storage locations to suit Mexican gas markets as they evolve.

The ample pipeline capacity to the United States and the proximity of Mexico's main demand centres to LNG facilities that can purchase shipments on the spot market at short notice, give the system a relatively high degree of flexibility. Future storage policy needs to be based on the rigorous assessment of the value attached to keeping physical storage on domestic territory.

2.3.4 Renewables

Mexico's abundance of renewable energy resource potential, particularly solar and wind, underpins the country's ambitions to decarbonise its energy system. Mexico is one of a small group of countries across the world to have translated its clean energy ambitions into law. The Energy Transition Law, approved in December 2015, sets a target of 35% of electricity generation from clean energy by 2024. To incentivise investment in renewables, the government has introduced clean energy certificates, a market instrument that is part of broader power sector Reform (see Chapter 3.3), designed to support the share of electricity consumption to be generated from clean energy sources.[8] The revenue from the sale of certificates, which are purchased by producers and large electricity consumers, is intended to be invested in other renewable energy projects.

In the New Policies Scenario, Mexico meets its interim targets (for 2018 and 2024) and surpasses its 2035 target. This is primarily due to robust expansion of wind and solar photovoltaic (PV) power projects, which together account for around three-quarters of the growth in clean energy to 2040. Renewables account for 37% of electricity generated by

[8] In 2015, the requirement was set at 5% to be reached by 2018 and is due to be reviewed periodically for possible increases in the mandate.

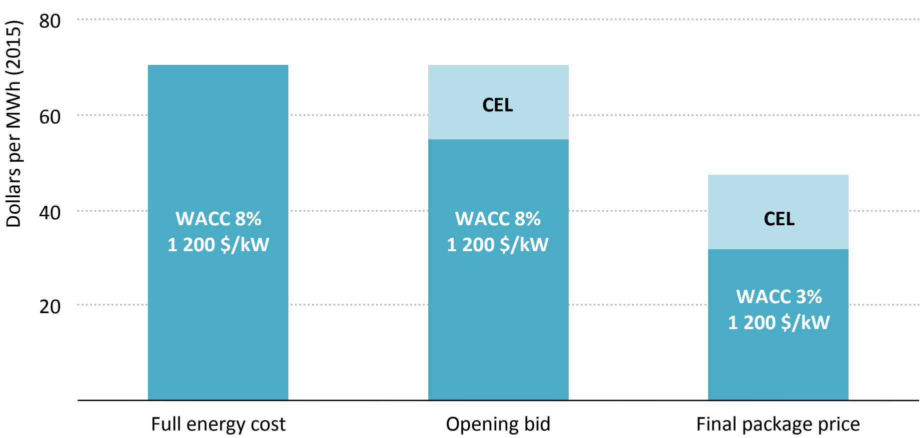
2040, of which 24% is from wind and solar power. Mexico's vast renewable energy potential offers the possibility of an even higher trajectory for their development. In the 450 Scenario, investment in renewables is almost 50% higher than in the New Policies Scenario to 2040. This allows for a significant increase in generation, with renewables meeting around 60% of electricity generated in the 450 scenario.[9]

Costs

To attract the desired investment for renewable energy development, the government has opted to hold auctions, underpinned by a guarantee for the winning bidder of a power purchasing agreement. Such agreements ensure a guaranteed rate for each unit of energy produced throughout the lifetime of the project. The results of the first two rounds of bidding show that this approach has proven an effective mechanism for minimising the cost of adding renewable electricity to the system (see Chapter 3.3.2).

Two factors have been particularly important in this regard: the availability of government-secured loans, which serve to reduce the cost of capital, and the strong incentive for bidding companies to pursue a cost-minimisation strategy, in the hope of establishing a foothold in a growing market. In the long term, as a result of better resource assessments and improved technology, we project a 30-50% reduction in cost for solar PV and a 5-20% cost reduction for wind power, which would contribute to a more profitable operation for companies (Figure 2.17).

Figure 2.17 ▷ Indicative cost and auction price for solar PV in Mexico



Auctions with long-term power purchasing agreements help to drive down the cost of increasing the use of renewables in the power system in Mexico

Notes: MWh = megawatt-hour; CEL = clean energy certificates; WACC = weighted average cost of capital; kW = kilowatt. These are indicative costs and prices for solar PV, showing how auctions can secure competitive bids and final prices.

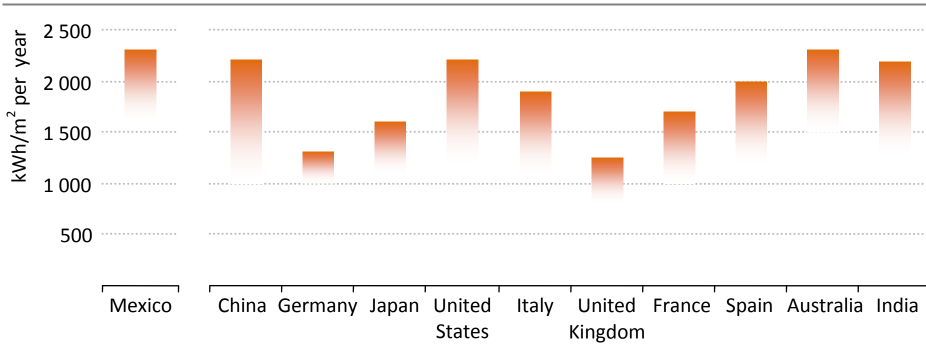
[9] As described in Chapter 12 of *WEO-2016*, this level of renewables-based power generation would require close attention to a suite of system integration measures.

Besides costs, full consideration is given in the auctions to the value of renewables to the system as a whole, and this has been a factor in determining the award of projects. In particular, the location and time profile of variable renewable energy sources is taken into account in the evaluation to determine the share of different clean technologies.

Solar

Mexico's solar resources are among the best in the world, with annual daily solar irradiance levels ranging between 4.4 kilowatt-hours per square metre (kWh/m^2) and 6.3 kWh/m^2. The entire country lies between 15 and 35 degrees latitude, which is commonly considered the band most favoured for solar resources (with the lowest average levels in Mexico comparing favourably with the highest averages in Germany and Japan, the world's second- and third-largest solar markets) (Figure 2.18). Mexico's total solar resources are estimated at 5 000 GW (SENER, 2014), equivalent to 70-times the total installed power generation capacity today. Mexico's installed capacity was 200 MW in 2014, in the form of utility-scale solar PV installations and 56 MW of distributed generation. Although the government has not released specific targets for solar PV capacity in its long-term electricity sector plan (PRODESEN), solar power is expected to play a prominent role in meeting the government's clean energy targets. The Energy Reforms are structured to help achieve these aims through the clean energy certificates system and clean energy auctions (see Chapter 3). The prices offered in the auctions to date compared favourably with those in projects across the world.

Figure 2.18 ▷ Average solar irradiance range in selected countries



Mexico's solar resource is among the best in the world

In the New Policies Scenario, solar PV, by some distance, is the fastest growing technology for power generation in Mexico, accounting for one-fifth of total capacity in 2040 (around 30 GW, making it the second-largest capacity after gas) and 10% of generation. The strong proliferation of solar PV, even though cost may be higher than wind turbines, reflects the inclusion in Mexico's market design of a measure of relative value to the system based on project location (see Chapter 3.2).

There are a number of risks that impact the *Outlook*, including those arising from land and indigenous rights, which the government has been seeking to allay (see Chapter 1.3.4). The actions taken include a provision in the Hydrocarbons Law that assigns SENER responsibility to carry out community consultation for such projects. In the 450 Scenario, solar PV and concentrating solar power capacity is almost 30% larger than in the New Policies Scenario, reaching almost 40 GW in 2040.

Wind

Mexico's total wind power potential is estimated at around 50 GW, with the strongest sites spread across the Isthmus of Tehuantepec in Oaxaca (which currently holds around 80% of total installed capacity). The average capacity factor for wind power is currently more than 20% higher than the global average and is estimated to increase by nearly 30% over the projection period, reflecting the ample availability of suitable sites for turbines across the country. In the New Policies Scenario, wind power increases to over 22 GW, making it the second-largest renewable energy source in terms of capacity (after solar PV) in Mexico's power mix by 2040. In addition, wind is the largest contributor to electricity generation from clean energy sources by 2040. Competition for market share with solar PV will be a key factor limiting the further uptake of wind power in Mexico. In the 450 Scenario, wind plays a larger role, generating 31 TWh more electricity than in the New Policies Scenario, from a capacity of almost 31 GW. The integration of high wind power capacity into the power system is facilitated by a high capacity factor of around 35%.

Geothermal

Geothermal is a well-established power source in Mexico, benefiting from high capacity factors (averaging around 85%, compared with 20-25% for solar PV and 30-40% for wind) and not beholden to variability issues, thus being able to provide baseload capacity. Installed capacity was 866 MW in 2015, generating over 6 TWh and making Mexico one of the largest producers of geothermal-based power generation in the world. The commissioning of a new plant "Los Azufres", due to open in 2018, will increase capacity by around 25 MW.

Estimates of Mexico's geothermal resource potential vary widely, with the government assessing the potential resource size at around 13.4 GW (though only 2% of this is considered proven). Mexico announced in 2015 plans to boost geothermal development by awarding five concessions to CFE, which will help to clarify the resource size. Exploitation of geothermal resources for power generation has been impeded, in the past, by the inability of CFE to invest in new development due to restrictions in the investment criteria for public projects (not least, the obligation to produce electricity at the lowest possible price) that are directly linked to the high initial capital investment required for geothermal power development, as well as its risk profile, which can be very high in the exploration phase.

In the New Policies Scenario, geothermal power generation capacity reaches 980 MW, with further growth curtailed by strong competition from other renewables, namely solar and wind power, on the one hand, and competition with relatively low-cost gas-fired generation on the other.

Hydropower

By far, hydropower currently is the largest source of renewable energy in Mexico, accounting for around 75% of renewables-based generation and almost one-fifth of total generation capacity. Current hydropower capacity stands at around 12.5 GW and is concentrated in the western and south-western regions, in basins that drain into the Pacific Ocean. The three largest dams on the Grijalva River (Chicoasen, Malpaso, Angostura), account for around one-third of the country's total hydropower capacity.

CFE has identified around 100 river basins deemed suitable for hydropower development, and is in the process of carrying out pre-feasibility studies on several sites. SENER expressed interest in late 2015 to secure the technical assistance of the World Bank on the issue of pumped storage. In the New Policies Scenario, hydropower capacity increases strongly, to 20 GW.

Our projection in the New Policies Scenario is based on the assumption that sensitivities regarding water use (see Chapter 1.3.4), concerns over drought (which has in the past taken off 900 MW of capacity) and local opposition (which led to the cancellation of the El Caracol power plant on the Balsas River) persist, capping project expansions and delaying further large-scale capacity additions.

Bioenergy

The use of bioenergy, which currently accounts for less than 5% of total energy demand, is projected to remain stagnant in the period to 2040, as a slight increase in bagasse use in power generation (accounting for less than 1% of the total), is almost entirely offset by decreased use of solid biomass in residential buildings, where it is gradually replaced by LPG and piped natural gas for cooking and heating. The outlook for bioenergy consumption could change based on developments in the transport sector. In April 2016, Mexico started a regional pilot project involving a 5.8% ethanol mandate, with six companies awarded rights to market this blend in Veracruz, San Luis Potosi and Tampaulipas.[10] Apart from reducing gasoline imports, the aim is to stimulate a local bioenergy industry.

2.3.5 Energy and the environment

Local air pollution[11]

With rising incomes and population, energy demand in Mexico is expected to increase by about one-fifth above current levels by 2040. Today's energy sector in Mexico is unique in that oil makes up more than half of total energy demand and natural gas another third, while coal plays a relatively minor role (7%), compared with other countries. As we have seen, the strong policy push expressed through existing regulation and the climate pledge

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[10] Estimated at 155-221 million litres of ethanol.

[11] The issue of air pollution in Mexico is covered in *Energy and Air Pollution: World Energy Outlook Special Report*, available at: *www.worldenergyoutlook.org/airpollution*.

made at COP21 will help to diversify this energy mix, in particular by increasing the use of renewables. The effects of government action can already be seen in declining sulfur dioxide emissions (SO_2), in particular, and our projections in the New Policies Scenario show a strong decline in oil-based power generation, helping to cut overall SO_2 emissions from the energy sector by half by 2040. Other pollutant emissions also decrease in our projections. Despite a continued rise in demand for mobility and industrial activity, nitrogen oxide (NO_X) emissions fall to 1 million tonnes (Mt) by 2040, a decrease of one-third below today's level, while particulate matter ($PM_{2.5}$) emissions decrease only modestly to almost 15% below today's level, as declines in emissions from the buildings and transport sectors are partially offset by increases in the industry and transformation sector.

2

Climate change

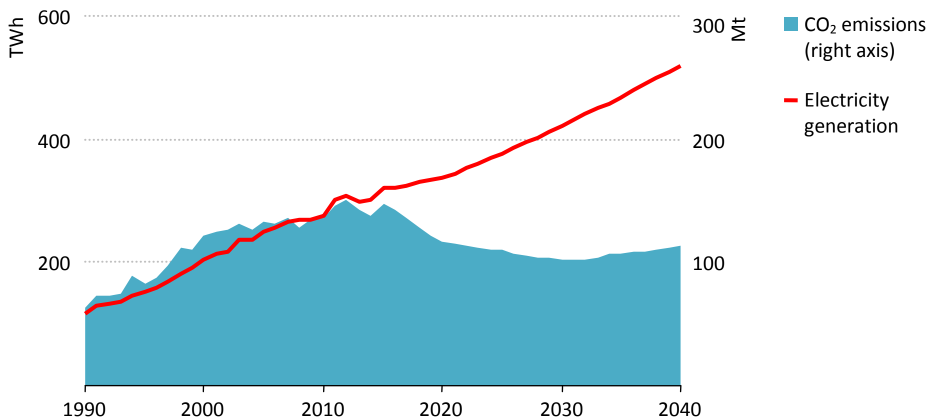
Climate change objectives are deeply entrenched in Mexico's current policymaking, not least in the Energy Reform. The country has a long history of commitment to addressing climate change issues and was the second country in the world to translate its climate change ambitions into law, and one of the first to publish a climate pledge ahead of the COP21 in 2015. The pledge includes an economy-wide target to reduce greenhouse-gas emissions and short-lived climate pollutant emissions by 25% below business-as-usual by 2030 (an unconditional target) and by up to 40%, subject to a range of considerations, including access to low-cost financial resources and technology transfer.

To meet these goals, Mexico is pursuing a number of concurrent strategies: it has set ambitious clean energy goals (see Chapter 1.3.2) and is in the process of designing a National Energy Efficiency Policy Strategy[12] which, among many benefits, is likely to help bring down Mexico's carbon intensity. In the New Policies Scenario, such measures help to cut the carbon intensity of the economy by more than half.

The strong proliferation of renewables in the power sector, where around one-in-two gigawatts of new capacity installed to 2040 is projected to be either wind or solar, coupled with a shift to natural gas from more polluting oil, makes a major contribution to the decrease in CO_2 emissions from the power sector (Figure 2.19). This is despite electricity generation increasing by 70%. CO_2 emissions related to power generation fall by almost 20% by 2040, implying a 52% drop in carbon intensity. In the transport sector, the largest emitter of CO_2 in Mexico, emissions continue to increase, but at a much more moderate pace compared with previous trends: between 1990 and 2014, CO_2 emissions increased by over 80%, to reach 151 Mt CO_2; by 2040, they are expected to reach 170 Mt CO_2, a 13% increase (while car ownership increases by more than one-fifth).

[12] This strategy was mandated by the Energy Transition Law, passed in December 2015, which provides a framework for clean energy, energy efficiency and GHG emission reductions.

Figure 2.19 ▷ Electricity generation and energy-related CO_2 emissions, 1990-2040



After years of parallel growth, Mexico successfully decouples electricity generation from power sector CO_2 emissions

Note: Mt = million tonnes.

Although Mexico reaches (and even surpasses) its clean energy targets in the New Policies Scenario, reaching the overall GHG mitigation goal will be a challenging endeavour. The lower bound of the pledged target requires GHG emissions in total to be reduced to around 760 Mt in 2030. In the New Policies Scenario, energy-related GHG emissions fall modestly to around 460 Mt in 2030, meaning that emissions from other sectors (such as agriculture or waste) would need to roughly stabilise at the present level if the lower end of the GHG target is to be achieved. The higher end of the pledge would require GHG emissions to drop to around 620 Mt in 2030, an emissions budget that without additional measures would already be largely absorbed by the energy sector.

Mexico's Energy Reform in focus

What's the benefit of a new direction?

Highlights

- Mexico's energy pathway in this *Outlook*, based on the assumptions of the New Policies Scenario, is determined in large measure by the *Reforma Energética* (Energy Reform) now being implemented. This secures a return to growth in the upstream oil sector and a more efficient, cost-effective and rapidly decarbonising electricity sector. The Reform generates a range of positive interactions with international markets, via flows of capital, technology and best practice, as well as energy trade via an increasingly interconnected North American energy system.
- A series of bidding rounds that began in 2015 is opening the oil and gas sectors to private investment and technology, leaving PEMEX to focus its resources and expertise on a narrower range of projects, either alone or in joint ventures. This new investment helps to slow the decline in output in shallow water areas — the traditional mainstay of Mexico's production — while bringing forward new projects in deepwater and developing new onshore resources, including tight oil. The rise in output to 3.4 mb/d in 2040 makes Mexico one of a handful of global producers that increase production over the period to 2040.
- The unbundling of CFE and a further opening of the power sector to private participation play a major role in mobilising the $10 billion per year that Mexico needs to upgrade the electricity network and to keep pace with growing demand. Long-term auctions for energy, capacity and clean energy certificates provide an entry point for new players on a competitive basis and a cost-effective way to bring low-carbon generation into the mix. A strengthened transmission and distribution system and reduced losses help to moderate the costs of electricity supply.
- A hypothetical No Reform Case considers what Mexico's energy outlook might have been in the absence of the Reforms introduced since 2013. Projecting the future on the basis of the historical relationship between oil revenue and PEMEX upstream spending permits an alternative outlook for upstream investment to be drawn. This severely limits Mexico's capacity to fund expansion and enhanced recovery projects in legacy fields, and delays the start of technically challenging deepwater and tight oil development projects. As a result, by 2040, oil production is some 1 mb/d lower than in the New Policies Scenario. In the power sector, without the efficiency gains made in networks and other parts of the system in the New Policies Scenario, the cost of electricity supply is higher. Without specific policies to increase the role of clean energy, lower deployment of renewables leaves Mexico well short of its clean energy targets. The No Reform Case leaves Mexico's economy 4% smaller in 2040 than in the New Policies Scenario.

3.1 Four angles on Mexico's Energy Reform

Mexico's oil, gas and electricity sectors are in a period of profound transformation, with far-reaching implications for all aspects of the country's energy provision, trade, investment and environmental performance. In this chapter, we assess in more detail the outlook for the sectors most affected by Mexico's Energy Reform. The results in the New Policies Scenario are set against the results of the "No Reform Case", which rolls back the profound Reform of recent years, assumes the state monopoly is maintained in oil and gas and excludes new private participation and restructuring in the electricity sector. This comparison provides a measure of the value unlocked by the Reform now in process, both for the energy sector and for the wider Mexican economy.

This chapter addresses four sets of questions:

- **Upstream oil**: How does the new configuration of the upstream sector shape the development of Mexico's oil potential? How do the challenges, players, costs and investment needs vary across shallow, deepwater and onshore resources?
- **Power market**: Can Mexico improve the efficiency of its power system, with lower generation costs and transmission losses, while simultaneously pursuing its clean energy goals?
- **North American energy integration**: How are Mexico's energy choices and prospects affected by its participation in a dynamic and increasingly interconnected regional market?
- **Value of reform**: What would Mexico's energy and economic outlook be like in the absence of reforms to the oil, gas and electricity sectors?

3.2 Mexico's upstream oil: fighting against decline

In the New Policies Scenario, Mexico's oil production initially continues to fall from the level of 2.6 million barrels per day (mb/d) seen in 2015, reaching a low point of around 2.3 mb/d before gradually rising again in the early 2020s as the impact of new investment starts to outweigh the field declines from existing production (Table 3.1). There are three main components to this outlook. The first is Mexico's shallow water production, which accounts for nearly 70% of current total output. This is an area in which Petróleos Mexicanos (PEMEX) has a long track record and unrivalled expertise, but where productive assets are ageing rapidly. Second there are the deepwater resources, a highly promising but demanding new frontier for Mexico. In addition, there are the untapped resources that lie onshore, including tight oil.

These three areas face very different challenges and require various approaches to unlock their potential, but a common denominator across the entire upstream is the need for investment. There has been a significant upswing in spending by PEMEX since the early 2000s, but average annual upstream investment over the last ten years – of around \$16 billion per year – is well short of the \$30-45 billion per year required, in our estimation, to lift Mexico's output from the lows reached in the early 2020s in the New Policies

Scenario up to the projected levels for 2040. Despite its deep competency in key technical areas, PEMEX has limited experience of deepwater development or tight oil. It would be a major challenge to quickly develop the required skills on its own.

Table 3.1 ▹ Oil production by type in Mexico in the New Policies Scenario (mb/d)

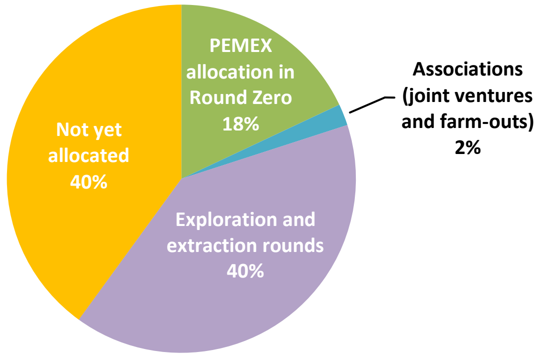
	2000	2005	2015	2020	2025	2030	2035	2040	2015-2040 Delta
Conventional	**3.5**	**3.8**	**2.6**	**2.4**	**2.5**	**2.7**	**2.8**	**3.0**	**0.4**
Crude oil	2.9	3.2	2.2	2.0	2.1	2.3	2.4	2.4	0.3
Existing fields	2.9	3.2	2.2	1.6	1.0	0.7	0.4	0.3	-1.9
New fields	-	-	-	0.3	1.0	1.6	1.9	2.1	2.1
Enhanced oil recovery	-	-	-	-	0.0	0.0	0.0	0.0	0.0
Natural gas liquids	0.6	0.6	0.4	0.4	0.4	0.4	0.5	0.5	0.1
Unconventional	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.3**	**0.4**	**0.4**	**0.4**
Tight oil	-	-	-	-	0.1	0.3	0.4	0.4	0.4
Total	**3.5**	**3.8**	**2.6**	**2.4**	**2.6**	**3.0**	**3.2**	**3.4**	**0.8**
Shallow water	*2.5*	*2.9*	*1.8*	*1.6*	*1.5*	*1.4*	*1.2*	*1.1*	*-0.6*
Deep water	*-*	*-*	*-*	*0.0*	*0.2*	*0.5*	*0.7*	*0.9*	*0.9*
Onshore	*1.0*	*0.9*	*0.8*	*0.8*	*1.0*	*1.2*	*1.3*	*1.3*	*0.5*

Note: Mexico possesses significant quantities of heavy oil, but these do not fit the *WEO* description of extra-heavy (unconventional) and are thus included in the conventional crude classification.

The 2013 Energy Reform package, which is carried through in the New Policies Scenario, is designed to open Mexico's oil and gas resources to outside investment, both foreign and domestic (see Chapter 1.3.2). Opening the sector should achieve a more efficient allocation of capital and skills, which will, in turn, give Mexico an excellent chance of returning production to a growth trend. Assets were requested by and assigned to PEMEX in the "Round Zero" auction, prior to opening of the competitive bid rounds, to reflect the intent of focusing PEMEX's attentions on areas where it has established experience.

A *World Energy Outlook* analysis of Secretariat of Energy (SENER) data suggests PEMEX now has rights to 20% of Mexico's remaining recoverable oil and gas resources, which can be developed either in association with others or solely by PEMEX (Figure 3.1). Although some of the assigned resources are onshore, the largest share is in southern Mexico's shallow offshore waters, adjacent to legacy fields developed and operated by PEMEX. This allows the company to concentrate its efforts in a region where it already has particular expertise. In addition to the shallow water allocations, an estimated 13% of the Round Zero assignment is in deepwater areas, including the Perdido area in the northern Gulf of Mexico, near the maritime border with the United States. PEMEX has already conducted a successful exploration programme there, but has yet to move to production. Partnership with experienced deepwater operators can facilitate faster development of Mexico's resources while allowing PEMEX to gain valuable experience, exposing it to less risk than doing it alone.

Figure 3.1 ▷ Total oil and natural gas resource allocation



The allocation of resources under SENER's five-year development plan leaves PEMEX in a strong position, while opening up broader opportunities in Mexico's upstream

Note: The PEMEX share includes resources allocated in Round Zero, plus future production from PEMEX fields already in production.

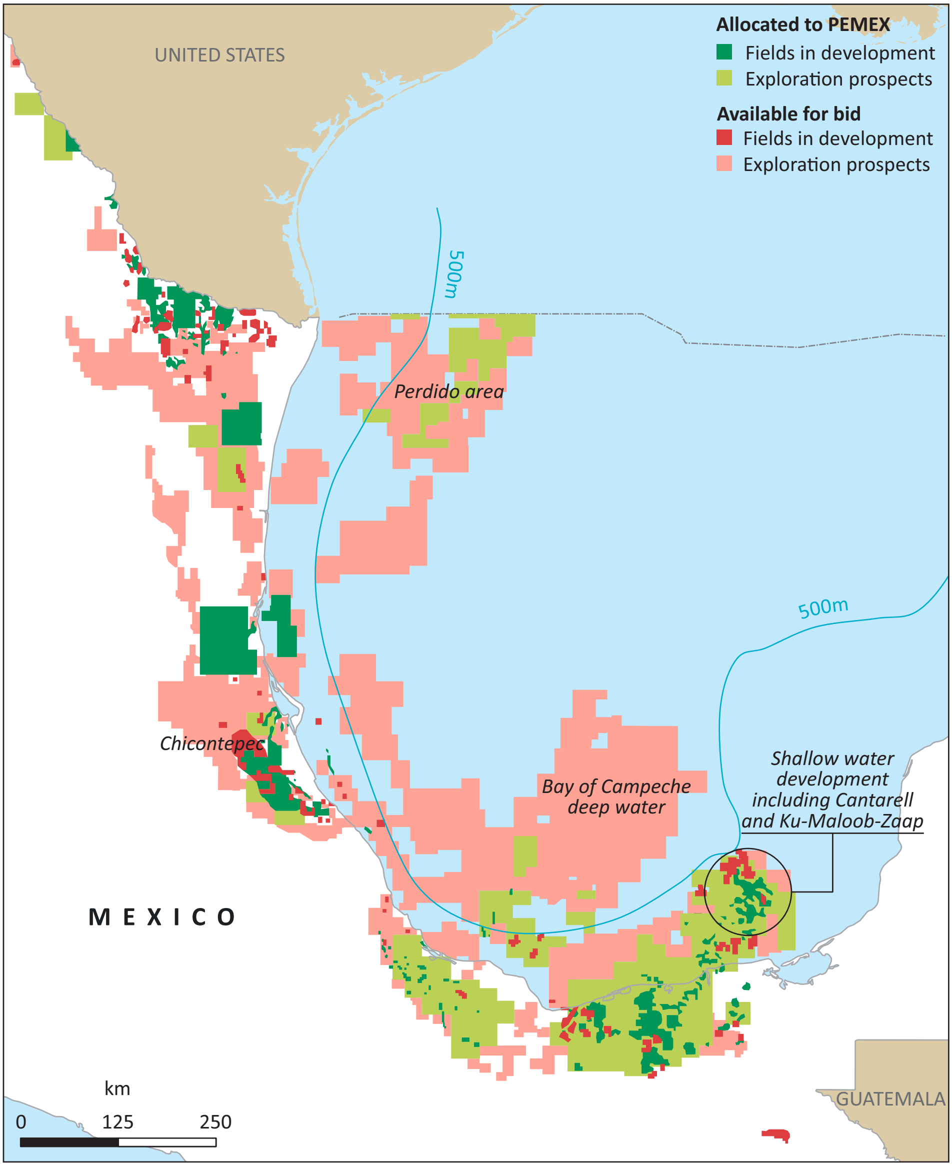
Sources: IEA analysis based on IEA databases and SENER documentation.

For the time being, the resources offered for association contracts (in partnership with PEMEX), are concentrated in areas in which PEMEX chooses to participate, but which currently lie either outside its preferred operational scope, such as the labour-intensive but low production Chicontepec field[1], or outside its set of core competencies, such as production of heavy oils from shallow water fields and deepwater development. An association with PEMEX for the Trion project in the northern Gulf of Mexico is one of the first deepwater opportunities to be offered to the private sector. This is aimed at speeding up deepwater production while allowing PEMEX to remain involved in operations as it gains experience. PEMEX also has the option to allocate assets for association in the future, as well as bidding against others for yet to be assigned assets in future bid rounds organised by *Comisión Nacional de Hidrocarburos* (National Hydrocarbons Commission) (CNH). Essentially, this means the allocations for PEMEX shown in Figure 3.1 may not be exploited exclusively by PEMEX.

A further estimated 40% of remaining recoverable oil and gas resources is allocated for the exploration and extraction rounds foreseen under the initial five-year allocation in the Energy Reform. The remaining 40% of oil and gas resources are yet to be allocated. These resources consist mainly of deepwater exploration blocks in the southern Gulf of Mexico, tight oil and gas prospects onshore in northern Mexico, and heavy oil fields in shallow waters off the central coast.

[1] Chicontepec is included in our onshore conventional figures, but discussed separately because it is estimated by SENER to be the play with the largest remaining resource. Recovery rates, however, are believed to be less than 10% range, making it unlikely that production will ever be commensurate with the size of the resource base.

Figure 3.2 ▷ **Resource allocation in SENER's current five-year plan**



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Investment alone, however, is not enough to guarantee success. Outcomes will also depend on the capacity and performance of the regulatory institutions that have responsibility for the upstream, including those charged with health, safety and environmental oversight. There are also other problems and opportunities, described in the next section, that could arise in meeting the production trajectory envisaged in the New Policies Scenario, bearing in mind that, although Mexico has a relatively large resource base, its largest fields are well past their days of peak production and the remaining reservoirs have varying degrees of complexity. More challenging resources, like deepwater reservoirs, some heavy oil prospects and tight oil, are essentially untouched. In most key aspects, resource types, geological and technical challenges and upstream players the future of Mexico's oil production looks very different from its past.

3.2.1 Offshore production

Shallow water - Gulf of Mexico

Shallow water fields contain Mexico's largest concentration of ultimately recoverable oil reserves (URR), at 48 billion barrels, with 20 billion barrels of remaining recoverable resource (RRR) (see Chapter 2.3.2). These fields have, therefore, been the mainstay of Mexico's oil production for decades, allowing PEMEX to develop first-class expertise in the sector. Even so, the company has not been in a position to exploit this resource efficiently. For example, a dearth of investment has meant that no major new producing assets have been added to the shallow water inventory in Mexico since 1987.

The combination of challenging geology in ageing assets and constrained investment in new ones mean that decline rates are relatively high. Natural decline rates reach in excess of 15% per year in many of the large fields. Observed decline (the decline that occurs despite continued investment in existing fields) has averaged 3% in recent years, but it increased to 7% in 2015. The largest of Mexico's fields are declining at a high rate, but investment by PEMEX during the past several years has resulted in expansion projects at the ageing Abkatún-Pol-Chuc and Ku-Maloob-Zaap complexes and fields in the Litoral de Tabasco region are still ramping up to design capacity. By 2020, nearly 700 thousand barrels per day (kb/d) of production from these fields will be lost due to decline.

The Cantarell complex in southern Mexico's shallow waters dominated oil production for nearly three decades before succumbing to sharp decline after 2004. The main producing area is the Akal field, which provides about half of the complex's production. There are multiple horizons of naturally fractured carbonate and sand, through which oil has high mobility, that have been relatively easy to produce.[2] Secondary recovery techniques have been used for some time in the mature fields. By the mid-1990s, PEMEX had decided on a massive application of nitrogen injection at Cantarell, which began in 2000. The intent was to temporarily stabilise reservoir pressure and to accelerate oil production from the fractures by gravity segregation, therefore bringing cash flow forward in time. The programme succeeded, but the (expected) associated rapid decline started in 2004, when production from the field reached 2.2 mb/d. By 2015, output was down to 350 kb/d and it continues to fall.

[2] Mobility refers to the ease at which oil flows through the reservoir. Oil sands have low mobility, while high porosity conventional oilfields typically have high mobility.

When oil is produced in a high permeability reservoir, gas that has accumulated at the top of the reservoir applies downward pressure, forcing oil towards the wellbore. Water from below displaces most of the oil and gas displaces the remainder. While this process is underway, the reservoir loses pressure as the gas expands in volume and oil is evacuated. Water has now invaded one of the flanks of Akal and, being quite mobile, has resulted in the closure of several hundred wells, hastening the field's production decline. Natural fractures also accelerate the water mobility. At the same time, reservoir pressure has fallen to 25-35% of its original level, as the gas cap grows steadily, further complicating extraction. In addition, the natural gas in the reservoir has been diluted by nitrogen, meaning that it now has limited value, other than for re-injection or consumption as fuel in the production facilities. Future enhanced recovery schemes need to address water mobility by using advanced techniques such as foamed nitrogen. Chemical solutions that change the properties of the oil remaining within the rock matrix, allowing it to be pushed from the pores, may also be employed. The Akal field at Cantarell provides a good example of the difficulties of enhanced recovery: the experience gained there can be useful elsewhere, particularly in other (albeit smaller) shallow water fields with similar geological characteristics. Many of these are at an earlier development stage, so it is not too late to incorporate enhanced recovery schemes into the design and thereby achieve higher recovery rates.

Ku-Maloob-Zaap and Ek-Balam are two large complexes adjacent to Cantarell, where development occurred later and at a slower pace. Ku-Maloob-Zaap is Mexico's largest producing asset today and it is set to remain an integral part of future supply. A substantial investment programme has been put in place, with the objective of maintaining output levels as long as possible. This programme expands the existing use of nitrogen injection, plus additional wells. Lessons learned at Cantarell may be of value, as Ku-Maloob-Zaap is believed to be early enough in its life to benefit greatly from a well-designed enhanced recovery programme.

Technologies to further enhance recovery exist, but they are expensive and are not available at scale in Mexico today. In the Round Zero bidding, triggered as a result of the Reform process, PEMEX retained ownership of the largest producing fields in shallow water and, with it, the burden of improving recovery from them. However, under the Reform, PEMEX can form joint ventures. If done with care, this approach could greatly improve the chances of applying new technologies to improve recovery from ageing fields in shallow waters, reducing the cost of operations through competition and sharing knowledge. Timing is important, because delay may result in the fields passing beyond the point at which enhanced oil recovery (EOR) programmes can be implemented most successfully.[3]

IEA analysis of the Energy Reform and the SENER five-year plan indicates that PEMEX is likely to be the operator of a dominant share of the remaining recoverable oil resources

[3] Adoption of EOR programmes are time and resource intensive, and payback time can be long. Therefore it is best to have EOR design in mind well in advance. If implementation is delayed too long, production may fall to the point at which EOR is not viable (see *World Energy Outlook-2013*).

that lie in shallow water (and the possibility of more when associations are included in the calculation). Although PEMEX was assigned shallow water exploration prospects, its prime task is the development of known reservoirs. Of the resources now available directly to new entrants, only about 25% are conventional developments, while the remainder are technically challenging heavy oil prospects.[4] The *Outlook* includes the assumption that all blocks on offer in the five-year plan are awarded and eventually developed, though with some flexibility in the start date to account for changes to the schedule of the rounds and the possibility of a block not being awarded in the designated round.

In the New Policies Scenario, production at shallow water fields falls during the projection period from a level of 1.8 mb/d in 2015 to 1.1 mb/d in 2040, despite the addition of more than some 900 kb/d of production from new shallow water projects. These projects include both new fields and investments designed to increase recovery from existing fields. Recovery from existing fields focuses on two aspects: superior reservoir management and the deployment of EOR techniques. Secondary recovery, through the use of nitrogen injection, is already used extensively and is expected to continue on a large scale; but enhanced recovery techniques, including chemical injection and the injection of miscible gases that change the properties of the oil are expected to play a growing role in future production.

Deepwater - Gulf of Mexico

The resources that lie in deep water in the Gulf of Mexico hold considerable promise, both for the Mexican authorities looking to maximise their value and for private companies that have shown an interest in investing. Our analysis of Mexico's deepwater production prospects is based on an estimate of 16 billion barrels of remaining recoverable oil. Exploration drilling has been conducted, but no production exists today. The greatest concentrations of Mexico's deepwater resources are thought to be within the Perdido fold-belt structure in northern Gulf of Mexico, and to the south in the Bay of Campeche. SENER believes that approximately 50% of the country's prospective conventional oil and gas resource lies in deep waters, which makes these resources an attractive proposition for international oil companies. PEMEX, though, has limited operating experience in this environment. Its first discovery was announced at the Trion 1 well, in the Perdido area, during 2012. Further discoveries have been made in the surrounding blocks and, based on test results, SENER estimates that the Perdido area holds about one billion barrels equivalent of recoverable oil and gas.

Although these discoveries were made and evaluated by PEMEX, a different set of skills is needed to bring them into production. The Perdido area includes the Trion Field, which PEMEX has said contains an estimated 480 million barrels equivalent of oil and gas. It will

[4] Although Mexico's heavy oil fields have a low API gravity, the oil in them is not distributed in a continuous fashion. This oil does not meet the *WEO* definition of extra-heavy oil, but still requires additional technical capacity than is currently available to PEMEX at scale. Therefore, Mexico's heavy oil resources are included in the shallow water conventional resource total.

be the first of Mexico's assets to be offered to bidders as an association prospect under the new hydrocarbons law, enabling PEMEX to gain deepwater production experience and reducing the time to first production. Although the Trion discovery lies about 200 km from the shoreline, it is only 40 km from Shell's Perdido complex on the US side of the maritime border, which is already in production. Such proximity offers Trion (and other blocks in the area) an opportunity to use existing infrastructure on the US side. Development by means of a floating production, storage and offloading vessel is another option. Trion will require some $11 billion to develop.[5] By comparison, the Perdido project on the US side of the border has required investments of an estimated $7.3 billion between inception and 2013, the year in which production peaked. Several billion additional dollars are expected to be required to keep the US based Perdido project running until it is eventually decommissioned.

As stated, the Perdido area lies far from shore and transportation is difficult compared with existing fields in the south. Mexico has done well by encouraging port expansions, including of Matamoros, near the US border. If the Matamoros expansion project is delayed, the alternative is to ship from the southern port of Cuidad del Carmen, which supports the projects operating in the Bay of Campeche. The distance from Cuidad del Carmen to Perdido is nearly four-times that of Matamoros to Perdido and this route is limited to relatively small vessels that can fit into existing port facilities. A positive aspect of logistics is that equipment not available in Mexico can be shipped from the United States with relative ease, in accordance with North American Free Trade Agreement (NAFTA) rules.

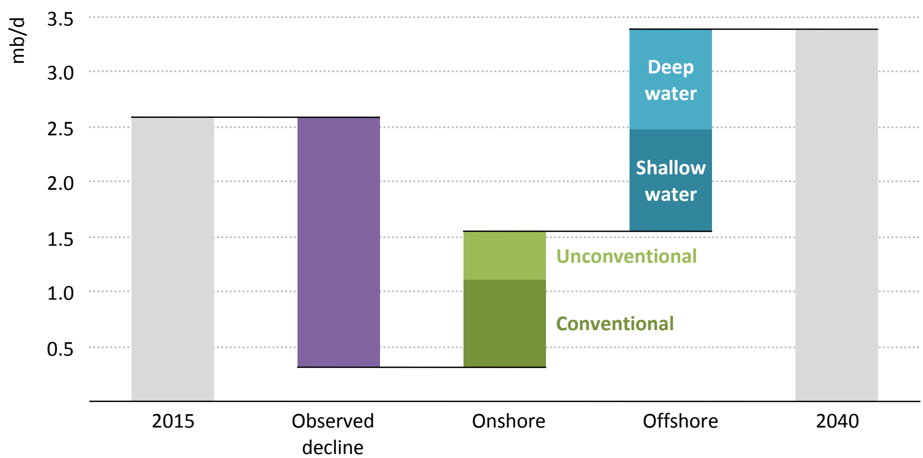
Despite relative proximity to Mexican support bases, many challenges remain for deepwater exploration and production in the Bay of Campeche in southern Gulf of Mexico. Water depths exceed 3 000 metres, a range at which only the most recent drilling rigs can operate. In addition, the sea floor is believed to be quite rugged which makes placement of sub-sea equipment difficult. Exploration wells have yet to be drilled. Despite these challenges, the area has attracted a high level of investment in surface exploration activities such as seismic surveying since the implementation of Reform. Processing these data is difficult and lengthy, and complete results are not likely to be available until 2017, but we nonetheless anticipate that some resources in the southern Gulf of Mexico are developed, as around half of the region's estimated resources are to be offered to bidders in the initial SENER five-year plan. The state holds the remainder, and our *Outlook* assumes the release of another three billion barrels of prospective resources after 2025.

Production from deepwater fields contributes the most to the growth in oil output projected to 2040, adding 900 kb/d to capacity (Figure 3.3). This will require considerable investment, with projects in deepwater accounting for almost 40% (about $215 billion between now and 2040). We have assumed lead times for the arrival of deepwater

[5] Mexico's Energy Reform was preceded by the United States-Mexico Trans-Boundary Hydrocarbons Agreement, signed in 2012. This lifted a moratorium on drilling in the border region that had been in place since 2000. The agreement also gave PEMEX and US companies the option to develop oil and gas resources that straddle the maritime border.

production of between four and six years between the award of a block and first production. The shorter term within this range was assigned to the Trion prospect, which is scheduled to be developed jointly by PEMEX and the winner of an association contract that is expected to be awarded in December 2016. Other concession blocks outlined in the five-year plan are assumed to start production between 2022 and 2025, given the additional time required to develop the necessary infrastructure. The time between a final investment decision and first production is likely to decrease later in the projection period.

Figure 3.3 ▷ Observed decline and production by type, 2015-2040



Production from a range of sources needs to be mobilised to offset decline in Mexico's existing fields

3.2.2 Onshore production

While enhanced recovery at Mexico's ageing giant fields offers a way to limit decline and deepwater developments have the best chance of eventually increasing national production, onshore tight oil (though challenging) and Chicontepec resources offer the potential to fill the gap while deepwater programmes develop. In the New Policies Scenario, onshore production reaches 1.3 mb/d in 2040, of which 150 kb/d is from existing fields. Most production is sourced from areas that are currently not producing. Tight oil production starts in earnest in the early 2020s, growing to 440 kb/d by 2040, while production from Chicontepec increases several years earlier and reaches 220 kb/d in 2040.

Conventional onshore fields requiring smaller operations are likely to gain renewed interest from local firms that can give more focus than PEMEX can. Small does not necessarily mean inexpensive, because age and the level of depletion can also push up operating costs dramatically. It is likely, however, that a nimble start-up company can find efficiencies that eluded PEMEX and ultimately bring on production at a lower cost per barrel.

Tight oil

There is currently no tight oil production in Mexico. But the extension of the US Eagle Ford play into Mexico's Burgos Basin, and other tight oil resources in the Tampico-Misantla Basin further to the south hold promise (gas may prove to be the dominant mode of production in Burgos, but some condensate and natural gas liquids are likely to follow). Low oil prices have delayed the launch of Mexico's unconventional resource bidding round. Despite this, SENER has indicated that nominations or requests by potential investors that certain assets be added to future bidding rounds have exceeded expectations in basins containing tight oil resources. Bids are not an unequivocal sign of future production, but are nonetheless a positive indicator.

Aside from a supportive oil price, three factors are needed for profitable development of a tight oil resource. The first is favourable geological conditions, over which a nation has no control. The majority of Mexico's 13.1 billion barrels of prospective tight oil resources are distributed between the northern Burgos Basin and the Tampico-Misantla Basin to the south. Explorers have noted that Mexico's portion of the Eagle Ford appears to have similar geology to its US neighbour, but it lies at greater depth, requiring more expensive wells to access. The prospective tight oil targets within Tampico-Misantla lie at shallower depths than in Burgos, which should improve the economics, but the geology is made more complex by faulting. The second factor for success in tight oil development is an efficient supply chain, on which policy-makers and regulators can have an immense impact. This is important because of the high number of wells needed to recover sufficient hydrocarbons (each well has a small drainage area), and the quantities of proppant and water needed to fracture each well. The proximity of water and sand or proppant resources to the oil field can make or break a project's economics. Transportation infrastructure is vital, whether rail or good-quality roads capable of supporting large volumes of heavy traffic.

The third is access to land, which can be achieved through a combination of sensitive regulation which wins confidence in the protection of communities and surface resources, and responsible behaviour by the exploration and production companies. Communities may not be willing to allow access to unconventional resources unless they are confident of effective support from state and federal governments. To ensure an environment that is conducive to investment, Mexico's regulators are increasingly working with the regional and local governments, who will seek to benefit from the new federal hydrocarbon laws (see Chapter 1.3.2). Without local government commitment, it will be difficult to attract the investment necessary to build and maintain the supply chain needed to make tight oil and gas profitable. Security is a related factor, as much of the tight oil and gas resources lie in areas currently troubled by drug-related violence.

Tight oil is first produced in the early 2020s in our *Outlook*, but in small quantities. Development of known reservoirs in the Tampico-Misantla Basin, using horizontal wells and multi-stage fracturing, is expected first. Production is likely to spread to the Burgos Basin later, when development of shale gas begins in earnest (see Chapter 2.3.3). Tight oil production reaches 300 kb/d by 2030 and 440 kb/d in 2040. Initial development costs are expected to be higher than those in the United States today. Though Mexico will certainly benefit from lessons learned at tight oil and gas projects in the United States, Canada and Argentina, such benefits are likely to be outweighed, at least in the medium term, by the high investments needed to build infrastructure and materials supply chains. Higher tight oil production than shown in our *Outlook* is possible, if solutions to the challenges described can be demonstrated early.

Chicontepec

The Chicontepec region is particularly interesting due to its combination of geographic extent, its low recovery factor and the commercial methods used to deliver production to date. SENER has estimated Chicontepec's resource size at an astonishing 42 billion barrels equivalent of oil and gas, but the reservoir quality is not homogenous and low porosity and permeability limit oil flow. This means that a large number of wells are needed to develop the area, which is vast. Chicontepec is similar to tight oil and gas in this respect[6]. The large number of wells needed means that the project economics are extremely sensitive to cost per well. In 2008, PEMEX proposed a drilling programme of 13 500 wells over a 13-year period with the intent of producing up to 1 mb/d from the field. By 2010, Chicontepec production was 55 kb/d, significantly less than the intended target for that year, which illustrates the complexity of producing this field. In the same year, PEMEX launched a programme that allowed engineering and service firms to develop parts of the field on a fee per barrel model. Some success was achieved and production reached 100 kb/d in 2013, but it has since fallen, due to a combination of decline and limited interest from bidders in a continuation of the service contract model. This had evolved from an early, simple fee per barrel system to a model that required the contractor to cover the development costs and receive compensation from PEMEX for each barrel produced, after recovery of operating costs using an elaborate formula.

Due to the heterogeneous reservoir quality across Chicontepec's vast area, and its low permeability and porosity, present recovery rates for the region are thought to be less than five percent of the resource in place. Mexico hopes to increase this low level by inviting foreign technology and investment. Due to its geological and topographical complexity, Chicontepec also requires a relatively high oil price to keep investment flowing. The necessary techniques and scale are beyond PEMEX's current comfort level and most of Chicontepec is expected to remain available to outside investors through the bidding rounds afforded by the Energy Reform. Even when oil prices return to profitable levels, attracting investment to the field will be contingent on the terms which must compete with the best on offer elsewhere, both in terms of the potential return on investment and the avoidance of undue contract complexity. Our projection is based on a slow resumption of drilling activity in Chicontepec towards the end of this decade, which will bring about

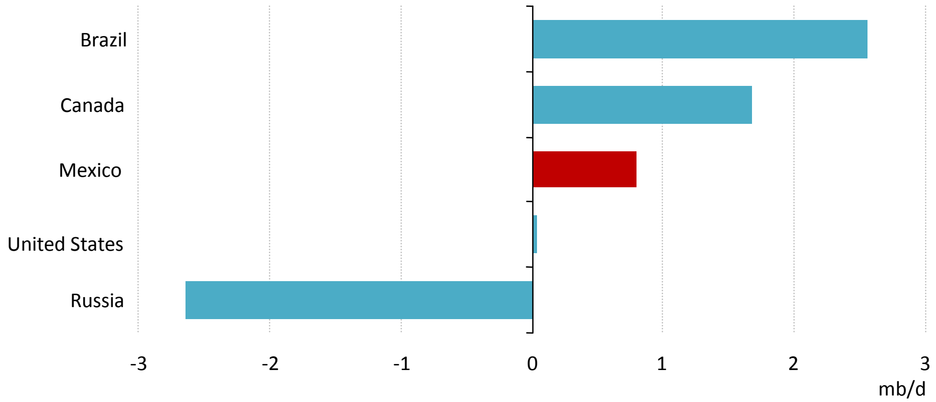
[6] Chicontepec shares some characteristics with tight oil fields, but does not currently use large-scale hydraulic fracturing and, accordingly, is included with onshore conventional oil in this *Outlook*.

40 kb/d of new production by 2020, steadily rising to 220 kb/d by 2040, so as to then provide around 20% of Mexico's total onshore production.

3.2.3 Implications for trade

Mexico's oil production returns to levels that provide a boost to the global balance reflecting the international market conditions prevailing in the New Policies Scenario, its large but challenging resource base and upstream investment triggered by the Energy Reform. It comes in a context where non-OPEC production in aggregate levels off in the mid-2020s and then starts a steady decline. Mexico is one of the very few countries that have higher production in 2040 than today (Figure 3.4). In this sense, the concentration of Mexico's growth in the second-half of our *Outlook*, i.e. post-2025, implies an important role in mitigating potential risks to oil security during a period of more concentrated reliance on output and export from a limited number of sources.

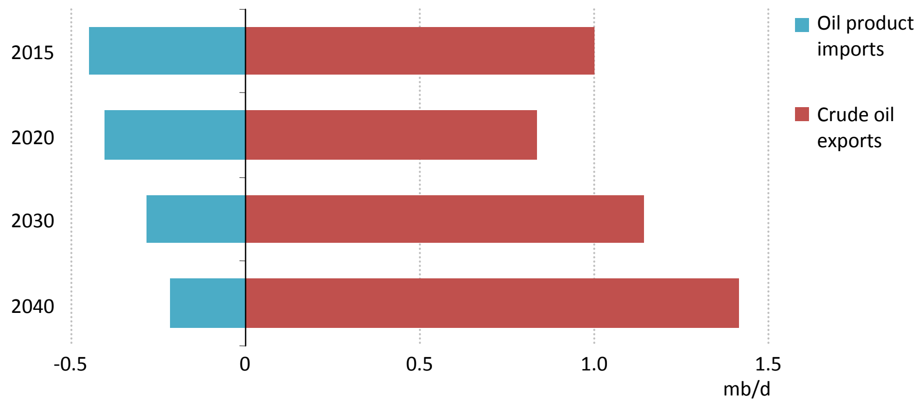
Figure 3.4 ⊳ Change in total oil production in selected non-OPEC producers to 2040



Mexico is one of the few non-OPEC countries to increase its production to 2040

Despite refining more of its oil domestically, Mexico's crude exports still grow, allowing it to play a significant role in turning the North American continent into a net exporter of crude oil to the rest of the world (Figure 3.5). Most exports go to the growing Asian refining centres, but some go to Europe. Increased production from the Americas as a whole does create some challenges for Mexico. Import dependency in the United States falls sharply, while production in Canada, Mexico and Brazil looks set to rise. This means there will be increased competition among North American and Latin American producers to ship crude oil and oil products to countries in Asia, where existing exporters – such as Russia and the Middle East – already have a strong foothold.

Figure 3.5 ▷ Crude oil exports and net refined product trade



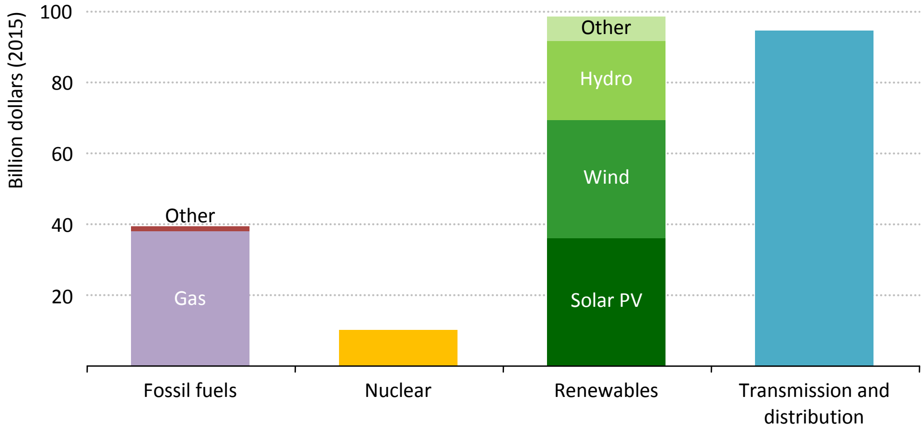
Rising crude exports and lower reliance on imported petroleum products improves Mexico's overall oil trade position

3.3 Power markets: can cleaner power come at lower cost?

The power sector component of the Energy Reform seeks to introduce vigour into a sector under the stewardship of an overburdened state-owned utility, *Comisión Federal de Electricidad* (CFE). At the onset of the Reform process, CFE owned more than 60% of power generation capacity, predominantly fossil-fuelled plants. In the future the company will function as a "productive state enterprise", charged to achieve commercial viability in a competitive market framework that is increasingly geared towards clean energy investments. In the New Policies Scenario, some $240 billion in capital investment – an annual average of around $10 billion – is required in the power sector over the period to 2040, of which $100 billion goes to new renewables-based capacity, primarily solar photovoltaic (PV), wind and hydropower (Figure 3.6). Attracting capital on this scale to the power sector in order to meet long-term clean energy objectives and at the same time reducing electricity unit costs represents a formidable task for the authorities, regulators and operating companies, but is one that – if accomplished – can bring major dividends.

Mobilising this level of investment will support an increase in electricity generation from around 300 terawatt-hours (TWh) in 2014 to more than 500 TWh in 2040 and enable Mexico to achieve its clean energy targets, as the share of renewable energy in electricity generation rises from 18% to almost 40% by 2040. Moreover, average wholesale electricity generation costs are projected to fall by around 10% by 2040, compared with 2014. In our analysis, we examine the market design and regulatory policies that promote efficient operation of the system and incentivise necessary investment, and the combination of factors that achieves an overall reduction in the total costs of electricity supply.

Figure 3.6 ▷ Cumulative investment to 2040 in power sector in Mexico in the New Policies Scenario



Renewables require the largest share of cumulative power sector investment to 2040 in the New Policies Scenario

Note: Other in fossil fuels includes oil and coal; other in renewables includes bioenergy, geothermal and concentrating solar power.

3.3.1 Market design, regulation and investment

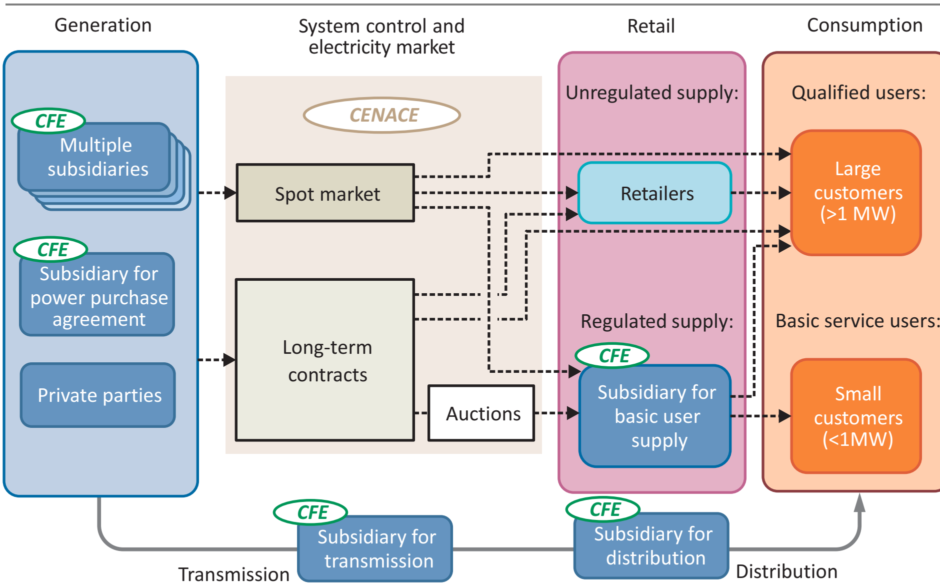
Primary elements in the Reform for the electricity sector are the restructuring of CFE and its unbundling, the introduction of competitive electricity markets for energy, capacity and ancillary services, financial transmission rights[7] and clean energy certificates. In 2015, CFE was transformed from a government administration into a "productive state enterprise" and unbundled, both vertically (generation, and transmission and distribution) and horizontally (into a series of companies) (Figure 3.7). Various generation companies inherited a portfolio of power plants, diversified by technology and geography, in order to lay the ground for competitive power markets. At this stage, however, all the generating companies are only managerially unbundled: they have different managements but they all remain subsidiaries of CFE and are state owned, though they can be turned into affiliates in future.[8] Responsibility for system operation has been transferred from CFE to a new, independent entity, the *Centro Nacional de Control de Energía* (CENACE).

[7] To cope with different energy prices at various nodes of the network, a system of financial transmission rights is foreseen to allow market participants to hedge against the risk of congestion. This mechanism has not been implemented at the same time as the other market reforms, reflecting its innovative character and the consequent need for a longer lead time before full implementation.

[8] Article 57 of the Electricity Industry Law allows CFE to turn its fully owned subsidiaries into affiliates (except for transmission and distribution). Though the affiliates are still owned by CFE, its ownership can be reduced to up to 51%. Establishment of an affiliate is subject to approval by CFE, which takes into consideration their economic viability and strategic importance to the government.

There are already private players involved in generation following previous reforms that date back to the 1990s. Independent power producers (IPPs) can and do own and operate power plants; but they must sell all power produced to CFE under long-term power purchase agreement.[9] In addition, large industrial consumers have been allowed to secure their own power, including by means of long-term supply contracts with private generators under a permission scheme. By 2015, IPPs accounted for some 20% of installed capacity and other privately owned capacity accounted for around 17%. By allowing private players to participate in the generation sector freely, the Reform intends to further increase competition in the generation sector over the coming years, leading to most new capacity being built by the private sector.

Figure 3.7 ▹ New structure of the power sector in Mexico



The power sector in Mexico is set to become competitive, as CFE is unbundled both vertically and horizontally

The transmission and distribution networks remain subsidiaries of CFE, although they have been legally unbundled from its other activities. Private sector companies can finance, design, build, operate and maintain networks with the approval of SENER. Against this backdrop, a strong and pro-active *Comisión Reguladora de Energía* (CRE) becomes increasingly important in order to ensure non-discriminatory access to the grid for all market participants, including new entrants. Price regulation remains in place for households and small industrial consumers, called "basic service users". Only qualified

[9] The existing IPPs will continue operating with the existing long-term power purchase contracts. A separate CFE subsidiary is charged with commercialising the energy procured from IPPs.

users (mainly large industry) can initially opt out of regulated tariffs and buy electricity directly from the market, but in coming years the eligibility threshold could progressively lower from the current 1 megawatt (MW), gradually allowing more competition at the retail level.

A key challenge for the new market is to ensure sufficient investment in new capacity. The New Policies Scenario projects that around 120 gigawatts (GW) will be required by 2040, including over 60 GW of renewables. To stimulate the needed investments to meet growing electricity demand, the new market design is based on the offer of long-term contracts for various products and services: a centrepiece of the Reform effort is an auction system for energy, capacity and clean energy certificates that allows new players into the market (Box 3.1).[10] The auctions offer long-term contracts (15 years for energy and capacity, and 20 years for clean energy certificates) that provide some certainty for future cash flows, reduce risks and consequently the cost of capital. The auctions are technology-neutral for clean energy options: the buyer (which in practice is CFE at this stage) sets out the requirements in terms of energy, capacity or clean energy certificates while the choice of technology is left to the market.

The markets for energy, capacity and ancillary services, transmission rights and clean energy certificates are under development in 2016. Once fully operational, they are intended to provide a sophisticated set of signals to the market about the costs and value of electricity at different locations and times, thereby providing incentives for investors to fill the gaps in the system in an efficient way. These markets are operated by CENACE.

The introduction of short-term wholesale electricity markets enables prices for energy and ancillary services to be calculated on an hourly basis for each node of the grid, refining the previous dispatching tool used by CFE. Reflecting the dominant position of CFE, the current market is strictly cost-based (meaning that the bids of each power plant have to reflect its marginal costs, which are monitored by SENER and CRE). A simplified version of the energy market, calculating day-ahead prices started in early 2016. Once fully implemented for the real-time market, the locational marginal pricing model aims to ensure economic dispatching of the least-cost power, while respecting the security constraints of the grid. In addition, energy prices will reflect the value of generation at different locations in the system by taking into account congestion in the network, sending signals to investors about where new clean generation investments might bring the best returns.

A second market is for capacity, to help generators recover fixed investment costs that may not be fully covered in an energy market strictly based on marginal cost. A unique characteristic of this market is that it is an *ex-post* market, an approach justified by the need to avoid handing undue advantage to CFE, which compensates only the capacity that actually performs when the system needs it. The capacity market will also remunerate

[10] Clean energy certificates are granted to companies that produce power from the designated clean energy technologies. All load serving entities including regulated suppliers (i.e. CFE) and qualified consumers participating in the market are required to purchase these tradable certificates.

clean energy, in particular wind and solar PV, according to their expected availability and generation during peak demand periods, although the detailed rules are yet to be defined and thus this is not featured in the underlying assumptions in the New Policies Scenario. The first stage of the capacity market is planned to be introduced in February 2017. This market functions as a backstop, to ensure that sufficient generation capacity is available in the short-term energy market.

Box 3.1 ▷ Locational signals and long-term electricity auctions in Mexico

Two long-term auctions for electricity under the new regime have been held in 2016. These have provided important momentum to the Reform effort. There was a high level of interest from bidders, including from international energy players. There were 18 successful bids from 11 companies in the first auction and 57 successful bids from 23 companies in the second auction, which won 15-year contracts to provide CFE with energy and capacity, and 20-year contracts for clean energy certificates, beginning in 2018. Solar PV and onshore wind power were the preferred technologies. A distinctive characteristic of the auctions in Mexico is that they seek to capture the relative value for the system of various generation technologies by location and production profile. Projects located in higher price areas of the country, or which are capable of delivering power at peak times, can earn higher revenues and therefore attract more attention from potential investors.

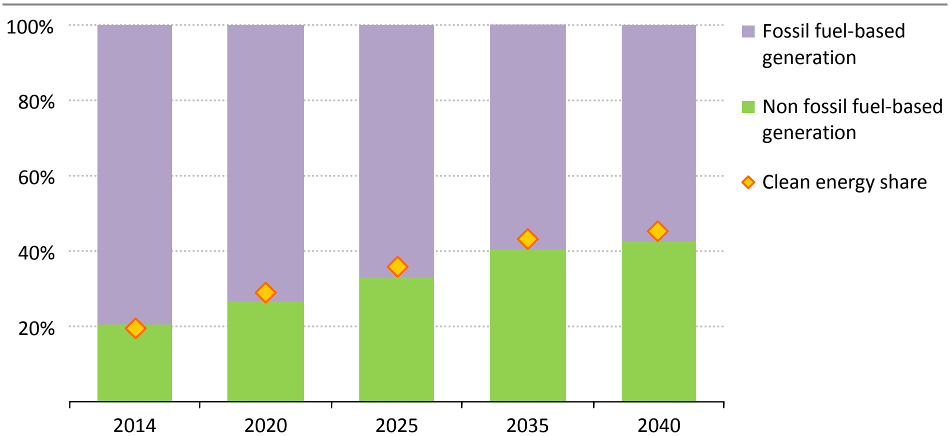
In the first auction, SENER calculated future electricity prices for various locations across Mexico to assess the expected value of new investments and adjusted bids in the auction on this basis. The impact of their methodology could be seen in the outcome. The lowest prices for solar PV were around $40 per megawatt-hour (MWh) – a resounding vote of confidence both in Mexico's power market design and in its solar potential. But several solar PV projects were also selected at higher prices (around $60/MWh) in the Yucatan peninsula (where future electricity prices are expected to be higher), because of their added value to the system as a whole. The result of the second auction, held in September 2016, has further succeeded in lowering prices with more market participants: the average price offered was $33/MWh, down by 30% from the first auction (SENER, 2016). As more clean energy is deployed and markets become more mature, the government may be able to move to a system in which participants are exposed directly to locational price signals coming from the market. The aim is not just to attract investment, but to ensure the choice of site and technology brings the most benefit to the system.

In addition, to promote clean energy investment, SENER has established requirements to use a percentage of clean energy that all load-serving entities, including retailers and large consumers, must fulfil by procuring required shares of clean energy certificates from CRE certified clean energy generators, or buying them in the market that will be put in place in 2018. A distinguishing feature of Mexico's Reform in the power sector is that clean energy obligations were integrated into the Reform package from the outset to take advantage of the country's exceptionally good wind and solar resources. In most other OECD countries, decarbonisation policies have been introduced at least ten years after the introduction of competitive markets.

In the New Policies Scenario, the share of clean energy rises to 35% by 2024 and 43% by 2035, allowing the government to meet its clean energy target, with gas-fired generation accounting for almost all of the rest as coal and oil are pushed out of the generation mix (Figure 3.8). The increased use of clean energy, together with a shift to natural gas leads to savings of around 120 million tonnes (Mt) of carbon dioxide (CO_2) in 2040, compared with the situation wherein the power generation retained its 2014 mix. In the absence of explicit carbon pricing in Mexico, the clean energy certificates allows the market to choose between a variety of technologies, in particular wind and solar. New investments are expected to be driven by long-term contracts, with the market for clean certificates becoming a residual market.

3

Figure 3.8 ▷ Share of clean energy in power generation in Mexico in the New Policies Scenario, 2014-2040



The share of clean energy in power generation rises to more than 40% by the 2030s in the New Policies Scenario

Note: Clean energy includes nuclear, hydropower, other renewables and efficient cogeneration, as defined by Mexico's Electricity Law.

An open question on the clean energy front is how the envisaged expansion of nuclear capacity will play out. Mexico plans to build 4 GW of nuclear capacity by 2030, in addition to the existing 1.5 GW at the Laguna Verde site. There is no specific financing mechanism for nuclear and currently the intention is that nuclear power projects should be financed through the same mechanisms of energy and prices, and clean energy certificates. The price levels from the auction held thus far and the duration of the available contracts (15 years for energy and capacity, and 20 years for clean energy certificates) raise questions about whether nuclear power plants can be financed under this system. In our projections to 2040, 2 GW of nuclear capacity are added, though this may, require additional intervention.

An IEA review of Mexican energy policies finds that the design of Mexico's electricity Reform is well-conceived and that the early results indicate that it is capable of delivering the required investments, including a step-change in investment in clean energy.[11] But implementation is still at an early stage and – even though the pace of change thus far has been impressive – much remains to be done to develop the regulatory framework, the institutions and the capacity to ensure that it continues to function well. In particular, the restructuring of CFE into a "productive state enterprise" is a vital aspect of the Reform process – and one that will take time and enduring political will to realise in full.

3.3.2 Generation, network and other costs

One of the key objectives of the Reform is to keep the costs of electricity under control, so that consumers can benefit from lower prices – or fewer price increases – and that the government can ultimately phase out the subsidies that it pays to keep down residential and agricultural end-user prices. There are a number of aspects to this: driving expensive oil-fired power out of the mix; ensuring efficient investment in new capacity to meet rising demand; pursuing efficiency gains within a restructured CFE; and reducing the high losses in the transmission and distribution network.

The switch away from oil-fired power generation has been underway for some time and the process is set to accelerate as new infrastructure is built to allow Mexico to benefit further from relatively cheap natural gas imports from the United States. CFE managed to reduce its generation costs by around 10% in the 2014-2015 period, helping to reduce electricity tariffs for industrial users by around 20%.[12] Thanks to measures already taken, the gap between electricity prices in the southern United States and in Mexico has narrowed considerably. In our projections, reliance on oil-fired power dwindles rapidly over the coming years and is almost completely eliminated by 2020.

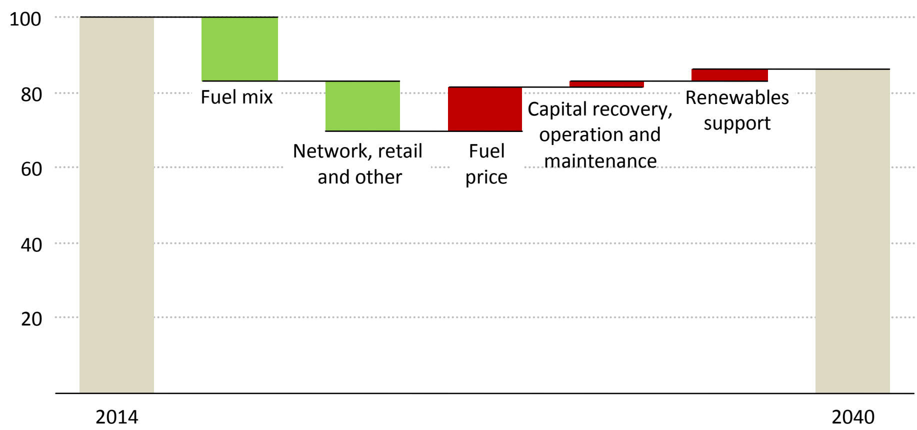
Fuel switching plays a major role in bringing down overall costs during the period to 2040, but it is not the only factor in play (Figure 3.9). Operational efficiency gains and reduced network losses also play a very significant role. The former stems largely from the competitive pressures on CFE to reduce costs in a market environment. The latter is the result of measures taken to improve billing and cut down on non-payment, as well as technical improvements. Some of these actions are already underway: new meters and investment in distribution lines have reduced network losses from 16% in 2010 to 13% in 2015. In the New Policies Scenario, network losses fall further to 8.6% by 2040, closer to

[11] IEA, *Energy Policies Beyond IEA Countries: Mexico*, 2017, OECD/IEA, forthcoming.

[12] The early cost reduction helps to foster support for the Reform process, but makes it more difficult for new entrants to compete with CFE, even for the industrial consumers that represent around 60% of electricity consumption.

today's average level for OECD countries. The average interruption time for supply per user has also fallen by around 40% since 2010 (to 35 minutes per year in 2015). A substantial increase in network investment is projected. In the New Policies Scenario, this amounts to more than $90 billion to 2040, or around $4 billion per year – a commitment of capital higher than that envisaged in the *Programa De Desarrollo Del Sistema Electrico Nacional* (PRODESEN). The Reform provides channels to keep investment at around these levels by allowing the private sector to participate in the financing, construction, and operation and maintenance (O&M) of the network.

Figure 3.9 ▷ Contributing factors to the changes in electricity supply cost for industry in Mexico (indexed to 2014 level)



The cost of electricity supply for industry falls by some 14% to 2040 in the New Policies Scenario

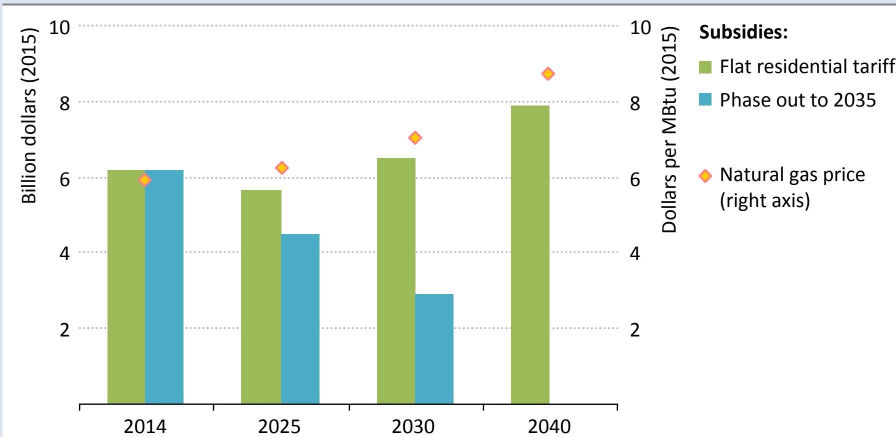
The cost reductions are offset by some upward pressures over the period to 2040. The main factor is the expected gradual rise in the cost of natural gas available to the power sector. As discussed in more detail in the next section, the intensive development of the shale resources in the United States means that operators there gradually have to move to less productive areas, pushing up production costs (despite continued upstream efficiency improvements). By the late 2020s, the projected price for natural gas at Henry Hub reaches $5 per million British thermal units (MBtu) in the New Policies Scenario and the gradual upward trend continues thereafter. This has the effect of incentivising more shale gas development in Mexico itself, but gas-fired power plants still find themselves facing higher input costs. Increased capital investment and support to renewables also play a role in pushing costs higher, but only to the extent of around 2-3% of electricity cost, thanks to the competitive market environment offered by the Reform and continued technology cost reductions for wind and solar PV over the period. The net effect is to create a much more favourable environment for electricity prices to consumers to become fully cost-reflective (Box 3.2).

Box 3.2 ▷ Impact of the Energy Reform on end-user prices

In the longer term, the sustainability of the Energy Reform will require a move towards fully cost-reflective prices. Maintaining regulated tariffs may be necessary as long as CFE continues to enjoy considerable market power, but, ultimately, a well-functioning power sector requires the phase-out of electricity subsidies. This is not an explicit part of the Reform agenda, but it is a process that would be greatly facilitated by the lower costs of electricity supply engendered by the Reform. The improved cost structure for electricity generation also helps Mexico to address the overhang of debt and unfunded pension liabilities that are part of CFE's legacy.

In the New Policies Scenario, industrial electricity prices decrease in real terms over the period to 2040: most of the large gains from the switch from oil to gas-fired power generation have already been realised, but productivity improvements in the power sector maintain downward pressure on industrial tariffs. The impact on residential tariffs depends on the tariff policy adopted by the government. For the moment, residential tariffs are heavily subsidised for all except the largest consumers. The subsidy bill was over \$6 billion in 2014. We assume that these residential electricity subsidies are gradually phased out over the projection period, such that they disappear completely by 2035. Mexico, as a member of G20 and APEC, has committed to phase out inefficient fossil-fuel subsidies and has taken an important first step by transferring part of the responsibility for the subsidy to the Ministry of Finance and including a specific item in the annual state budget (previously it was absorbed into CFE's balance sheet).

Figure 3.10 ▷ Residential electricity subsidies in the New Policies Scenario, 2014-2040



Maintaining today's residential electricity tariffs would become increasingly expensive to 2040

Phasing out residential electricity subsidies by 2035 and their replacement by more targeted support for vulnerable segments of the population are assumed in the New Policies Scenario. If, however, residential electricity prices were to be kept constant at today's levels, then – in our estimate – the overall cost of the annual subsidy would fall in the medium term but then rise steadily towards $8 billion per year in 2040, as the price of natural gas pushes up generation costs (Figure 3.10). This would represent a very substantial drain on public finances. In the absence of electricity sector reform, the cost of the subsidies would be also higher than in the New Policies Scenario, a case examined in the last part of this chapter. As it stands, the cumulative subsidy to 2040 with a flat residential tariff would be around $160 billion – almost 70% of the entire capital investment cost for the power sector.

3.4 Influence of North American energy market integration

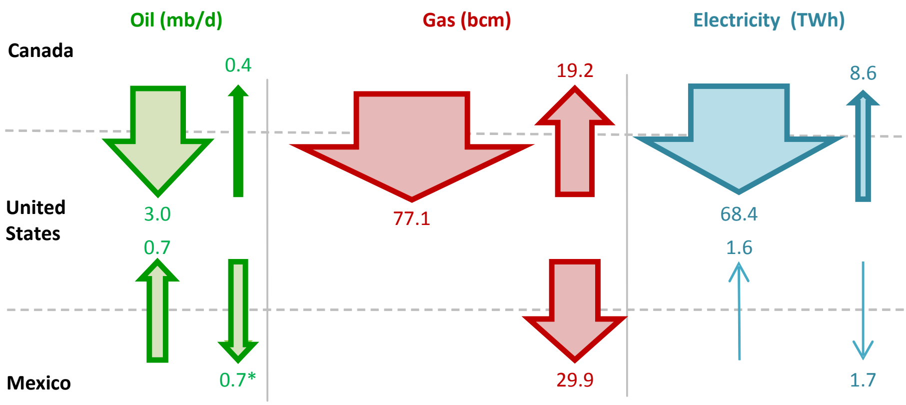
Energy integration in North America is an increasingly important element of the context for Mexico's Energy Reform. There is a policy element to this integration in the close alignment in energy and environmental priorities between Mexico, Canada and the United States.[13] There is also a strong market element, given the synergies between low-cost oil and natural gas production centres in the southern United States and the growing market in Mexico. This section examines the way in which more integrated energy markets shape Mexico's energy outlook to 2040, with a particular focus on trade in natural gas, crude oil and oil products. Reliable cross-border connections can have a strong positive impact on energy security, enabling more efficient allocation of resources, as well as providing an effective response to disruptions or fluctuations in demand. Energy integration and co-operation can also accelerate flows of investment and transfers of technology – including clean energy technologies – with a beneficial impact on the prospects for the Energy Reform and for attaining Mexico's greenhouse-gas emissions reduction goals.

The United States has traditionally been a large net recipient of regional cross-border energy flows, within North America as a whole, but imports have fallen rapidly since the start of the shale gas and tight oil boom. The main arteries of regional trade have been between the United States and Canada – and these remain considerably larger than those between the United States and Mexico (Figure 3.11). However, the importance of the United States-Mexico energy trade relationship has been growing fast. As of 2015, exports of crude oil from Mexico to the United States were roughly balanced by a reverse flow of petroleum products. Similarly, cross-border flows of electricity – albeit on a much smaller

[13] The North American Leader's Summit held in June 2016, for example placed clean energy at the centre of discussions, leading to the three countries agreeing to set a target of 50% for clean power across North America by 2025; Mexico joining a standing commitment to reduce its methane emissions by 40-45% by 2025; and the promise to align fuel efficiency standards by 2025 and greenhouse-gas emission standards by 2027.

scale – were roughly in balance.[14] But natural gas imports to Mexico from the southern United States have been on a sharply rising trajectory, more than tripling between 2010 and 2015. Geographic proximity and closer energy integration promises to have a significant impact on Mexico's energy outlook, in particular for natural gas and the supply of oil products.

Figure 3.11 ▷ Energy trade across North America, 2015



Mexico's energy trade links with the United States are growing, but are still some way short of those between US-Canada

*Refined products.

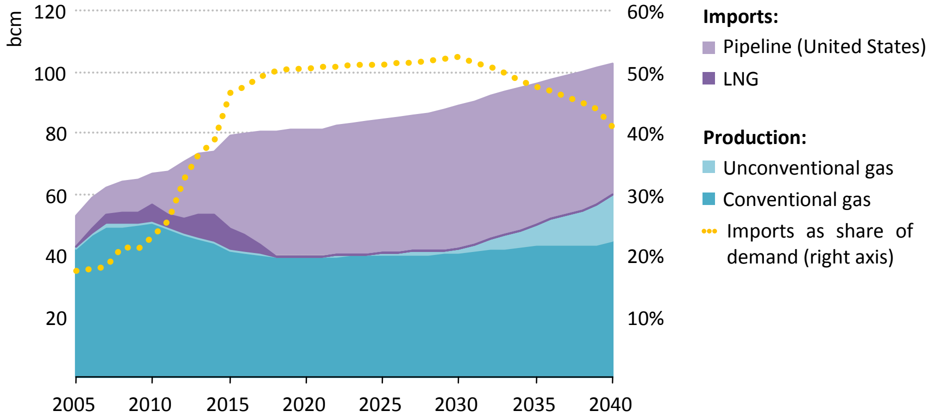
Natural gas

Mexico's imports of natural gas from the United States have a major impact on our projections in the New Policies Scenario. With natural gas being the main source of power generation in Mexico, these imports are critical both to the reliability and costs of electricity supply. They also act as a key determinant of the pace at which Mexico's own gas resources are developed. The upward trend in gas imports has been spurred by the US shale gas boom and the commercial case for importing gas remains strong throughout the period to 2040, although it diminishes somewhat over time with the gradual anticipated increase in US wholesale natural gas prices. Once domestic (primarily associated) gas is accounted for and liquefied natural gas (LNG) imports into Mexico are backed out[15], there is room for around 45 billion cubic metres (bcm) of imported US gas in Mexico's natural gas mix in the New Policies Scenario – making up more than half of total supply until the 2030s (Figure 3.12).

[14] US and Mexican data sources are not fully aligned on the metrics of electricity trade. We are using Mexican data as provided by *Comisión Federal de Electricidad* and *Centro Nacional de Control de Energia.*

[15] LNG imports began in 2006 but have become a more costly source than natural gas via pipeline from United States. We assume that LNG imports will continue to decrease rapidly over the coming three to four years, even if this were to result in Mexico having to pay a penalty for not taking the contracted LNG volumes (as would be the case under standard take-or-pay terms that are common in long-term supply contracts).

Figure 3.12 ▷ Natural gas production and imports by type, 2005-2040



Pipeline imports from the United States rise to more than half of Mexico's total gas supply

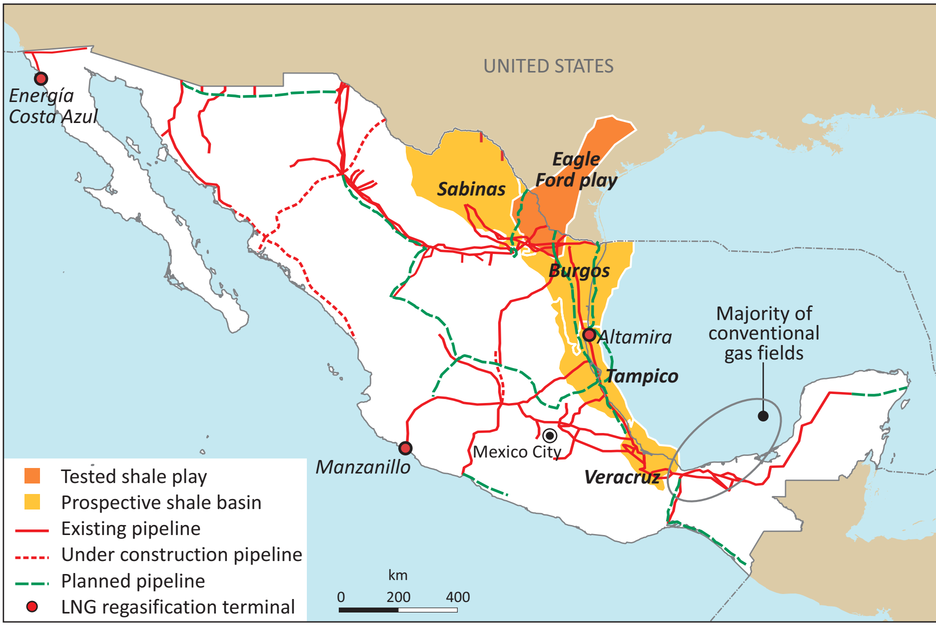
This reliance could be even higher. Pipeline developers and the Mexico's administration are making contingency plans for higher volumes of cross-border pipeline capacity and trade, over 100 bcm of imports by the end of this decade. This level of imports cannot be ruled out, but would require some combination of higher electricity demand (and consequently more gas demand for power generation[16]), more rapid expansion of the gas distribution grid to reach additional residential and industrial consumers, or the possibility that some of the gas would be shipped onwards from Mexico, either to Central America or exported as LNG.[17]

The future balance between imported and domestically produced natural gas depends on a range of market and policy elements – and a key uncertainty is the extent to which Mexico pursues development of its large unconventional gas resources. Current resource estimates for shale gas are more than adequate to meet Mexico's gas needs in full, but the resource base and regulatory framework, for now, are insufficiently defined and the shale gas industry and supply chain are still at a very nascent stage (relative to the United States) (see Chapter 2.3.3). Pemex's upstream monopoly was a world away from the proliferation of operators that enabled rapid learning-by-doing and cost reductions in the main US plays, meaning that shale gas development in the United States has had a significant head-start on its southern neighbour. And – as experience elsewhere in the world has amply demonstrated – it is far from simple to replicate US conditions in other jurisdictions, even allowing for the changes introduced by Mexico's upstream reforms.

[16] This would imply higher GDP growth than we assume in the New Policies Scenario, (see the sensitivity analysis on GDP in Chapter 2).

[17] Pemex has announced a proposal to convert an under-utilised LNG import facility on Mexico's Pacific Coast into a liquefaction terminal for export. Export of LNG is subject to approval by SENER and, if the feed gas is sourced from the United States, by the US Department of Energy. Our projections do not include LNG export from Mexico.

Figure 3.13 ▷ Natural gas resources and infrastructure in Mexico



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Over the longer term, Mexico does have strong potential for shale gas development, especially once – as we anticipate in the New Policies Scenario – the gradual depletion of US shale resources starts to push up production costs there. Four geological basins in Mexico are expected to contain oil and gas shale resources (Figure 3.13). While seismic data have been acquired to delineate the extent of the shale deposits, drilling is required to test the productivity of the shale formations. The main focus for operators thus far has been in the north, where the prolific Eagle Ford shale play in Texas extends across the border. This is where PEMEX has focused its exploration and appraisal drilling programme to date, with 18 wells over the last four years, albeit with mixed results. Resource uncertainty aside, the key question is whether there is much of an incentive for PEMEX or other operators (most likely US based or international majors) to invest in Mexico's shale gas development in the near to medium term, given that the United States provides operators with a known regulatory and operationally safer environment, with a well-developed, readily accessible gas infrastructure to bring gas to markets. For the moment, the estimated costs of developing Mexico's shale gas are well above those in the southern United States, meaning that imported gas remains a far more attractive value proposition. Social acceptance and water use are further issues which need to be addressed before large-scale shale development can take place in Mexico.

Currently Mexico plans to offer tight oil and shale gas blocks to investors through a bidding round in 2017, with tight oil likely to draw most of the initial interest. In our projections, the cost equation continues to work against Mexico's shale gas development until the latter part of the 2020s, by which time the Henry Hub price rises above $5/MBtu. In our view, given the additional transportation costs to bring gas to the Mexican market, this is the price level that can start to trigger larger scale unconventional resource development in Mexico. This is projected to pick up in the 2030s, to reach 7 bcm in 2035 and 15 bcm in 2040. This projection is based on the assumption that, in the interim, Mexico succeeds in developing a regulatory framework that caters to the specificities of unconventional resources, both in terms of fiscal and permitting issues, as well as social and environmental aspects. Applying the experience gained in the United States and Canada can do much to facilitate future development by putting in place appropriate regulation on responsible water management, high technical standards and industry transparency, and by establishing baselines against which the industry's environmental performance can be measured in the future. SENER and CNH are already working with other regulatory bodies – the Agency for Safety, Energy and Environment (ASEA) and the National Water Commission (CONAGUA) – to establish a co-ordinated and comprehensive regulatory framework for key environmental aspects and to put in place an appropriate system for reporting and monitoring.

As the analysis indicates, a key variable in our projection is the price at which US natural gas imports are available. Our projections are based on the assumption that the size of the remaining recoverable resource base of US shale gas is 22 trillion cubic metres (tcm) and assumptions about how the costs of producing it might evolve in the future. However, as examined in detail in the *WEO-2016*[18], resource estimates for the United States vary quite considerably: our analysis of the various estimates of US shale gas resources points to a conceivable range of 14-34 tcm. If the actual size were to be towards the top of that range, the commensurately higher availability of gas would allow for cheaper imports by Mexico for longer. This would affect Mexico's outlook by lowering electricity generation costs, although the benefit of lower electricity prices would be offset in some respects by diminished incentives to push ahead with indigenous gas production (beyond the associated gas that will come with upstream oil developments) and a consequently higher reliance on imported natural gas to satisfy demand. The example underlines the growing inter-dependencies that are taking shape in different domains across the continent (Box 3.3).

Box 3.3 ▹ A broader agenda for energy integration

SENER's long-term power sector plan places a premium on increasing interconnections and working towards more intensive transmission grid integration with Mexico's neighbours. To the southeast, Mexico is already an important supplier of electricity to Guatemala[19] and Belize, but there is significant potential to increase its position as a key energy exporter in the region, for example by joining the Central American Interconnection System (SIEPAC)[20], which has linked the grids of six countries across the

[18] See Chapter 4 of the forthcoming *World Energy Outlook-2016*, to be released on 16 November 2016.

[19] Plans to build a pipeline linking the existing network from Salina Cruz to Tapachula near the Guatemala border have been outlined in SENER's latest plans, presenting the possibility of greater trade with Central America.

[20] SIEPAC currently includes Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica and Panama.

region since 2013. Enhanced integration would allow a more efficient flow of energy; potentially alleviating the risk of shortages associated with variable renewables supply, and would allow companies in Mexico to monetise any excess energy they generate. Enhancing electrical and natural gas interconnections between Mexico and Central America could presage a widespread structural shift in electricity generation, with a shift from oil to gas, helping to reduce prices while reducing the carbon intensity of the generation mix.

To the north, Mexico shares 11 electricity transmission interconnections with the United States[21], but trade is limited, totalling just 4 TWh in 2014, with each country exporting around as much as it imports. Despite these limits, electricity trade, on occasion, has played an important role in maintaining security of electricity supply in response to power outages.[22] Mexico's Energy Reform increases the prospects of more collaborative projects between northern Mexico and southern US states, since the Reform, for the first time, allows private power producers, including in the United States, to sell their electricity in Mexico's wholesale market (such producers were restricted to selling to captive producers, or to CFE, under the previous regulatory regime). Such exports started in 2015 when the 524 MW Frontera power plant in Texas began exporting power to Mexico, with the intention of allocating its entire capacity to the Mexican market.

Just as an increasingly integrated North American market generates the economies of scale required to develop natural gas projects, increasing electricity grid interconnections would allow Mexico to capture rent from some of its most important renewables resources. For example, those in Mexico's Baja California peninsula, which has some of the best wind and solar conditions in the country, but where the population is small and sparse. The Sierra Juarez project in Baja California, for example, is a 156 MW wind power development that exports exclusively to the San Diego Gas and Electric Company through a 20-year power purchase agreement. Such a project is not likely to have been developed if it were restricted to sales to the Mexican market.

Crude and petroleum products

When considering trade in all types of energy carriers, crude oil and petroleum products usually require fewer formal intergovernmental agreements and land-based fixed infrastructure than other energy forms. In the absence of fiscal duties, as is the case in North America, it is price arbitrage on international markets that essentially defines where crude oil or products flow. Following the removal of the US crude oil export ban at the end of 2015, North American crude oil and product markets are almost entirely liberalised. However, certain infrastructure limitations and regulations in related industries have created a uniquely fragmented market system.

[21] This is due to increase to 12 interconnections, following SENER's instructions to CFE to build a new interconnection between Seonora (Mexico) and Arizona (US), which is planned to begin operation in 2018.

[22] An example is the emergency import of electricity generated in Mexico to support the system in Texas during outages in 2014: *www.oe.netl.doe.gov/docs/eads/ead100914.pdf*.

In recent years, the US Gulf Coast has become a major export source for petroleum products, with a refinery network that can process around 9 mb/d of crude oil. Most of these products are shipped outside the United States, instead of going into deficit areas in the northeast United States or parts of the west coast. For the northeast region, flows from the Gulf Coast are constrained by Jones Act regulations, which add to the shipping costs. Therefore, currently it makes more economic sense to import gasoline (and occasionally diesel) from Europe or Russia to the northeast United States, and to export gasoline from the Gulf Coast to Mexico, Latin America or Africa. Therefore growing import requirements for gasoline in Mexico have been welcome news for the US exporters that have large gasoline surpluses (see Chapter 2.3.2). Mexican crude oil, which has relatively easy access to seaborne terminals, also finds a natural outlet in US Gulf Coast refineries, as they are best-equipped with the cokers necessary to process heavy Mexican grades at a profit.

Even if Jones Act restrictions on US cabotage shipping[23] were to be lifted, and the US domestic market become more integrated, it would probably not immediately affect the product trade between the US Gulf Coast and Mexico. Geographic proximity and already well-established trading patterns mean that the Gulf Coast refiners are expected to remain a competitive force in Mexican markets, especially as Mexico's Energy Reform liberalises the trade and fuel retail sectors. In the New Policies Scenario, the refined products market in Mexico does not become self-sufficient, even though the import dependence for gasoline decreases, from 56% currently to 35% in 2040 (corresponding to a fall in imports from 450 kb/d to 270 kb/d), while diesel imports all but disappear. To achieve this, refinery throughputs are expected to reach 1.4 mb/d, up from current lows of 1.1 mb/d, thanks to upgrades that are projected to cost over $33 billion. Having the US Gulf Coast as a neighbour limits the economic prospects of an alternative strategy to attain self-sufficiency in refined products, or indeed to start exporting them, as this would require a considerably higher capital expenditure.

3.5 Measuring the impacts of Energy Reform: a No Reform Case

The New Policies Scenario presented in this *Outlook* outlines a pathway for Mexico that is determined in large measure by the Reform package and the effect that it has on investment. It includes a return to growth in the upstream oil and gas sector and the evolution of a more efficient, cost-effective and rapidly decarbonising electricity sector. But what would Mexico's outlook have looked like if there had been no Reform? To answer this question, we have modelled an additional No Reform Case, in which the Reform is wound back and pre-reform trends are resumed. We assess the ramifications of such a case for the oil and electricity sectors, and also the potential implications for the Mexican economy as a whole.

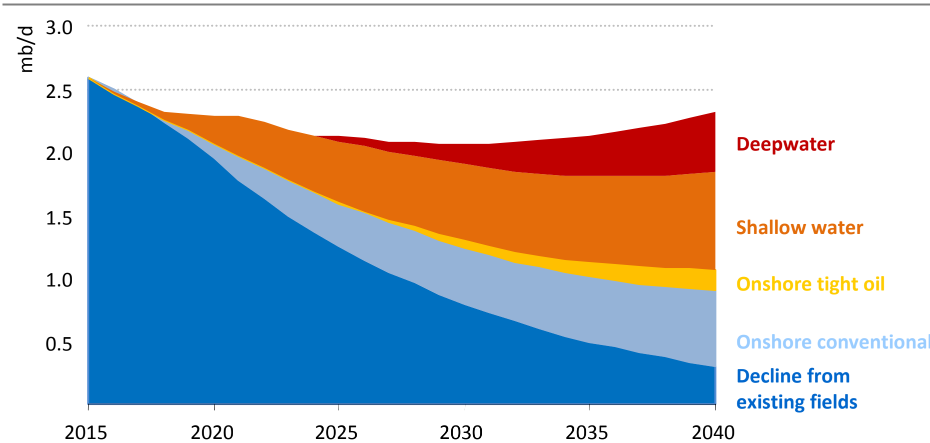
[23] Cabotage shipping is the transport of goods or passengers between two places in the same country by a transport operator from another country.

The oil industry has long been an important source of export earnings, as well as the largest single contributor to industrial value added in Mexico (15% in 2013). The Reform was aimed at reversing a steady decline in the performance of the sector, marked by declining output and a shortfall of new projects (both upstream and in refining). A "No Reform" trajectory would give rise to a much more difficult struggle to turn the oil production trajectory around, a continued squeeze on capital spending and diminished oil-related revenues for the state. Likewise, in the absence of Reform in the electricity sector, there would be higher costs in generation, continued inefficiencies in networks and other parts of the power system and – as a result - either higher prices for consumers or a much larger subsidy bill for the state. Concentrating on these two sectors, the No Reform Case presents a diminished outlook for Mexico, compared with the outcome in the New Policies Scenario.

3.5.1 The oil sector in a No Reform Case

The difference in projected oil production between the New Policies Scenario and the No Reform Case widens steadily over the period to 2040, by which time it exceeds 1 mb/d (2.3 mb/d versus the 3.4 mb/d reached in the New Policies Scenario) (Figure 3.14). The divergent trajectories take some time to become apparent, reflecting the lead times of the projects that are awarded in the New Policies Scenario but that fail to proceed in the No Reform Case. The key difference between the two trajectories is the amount of capital available for the upstream investment. In the New Policies Scenario, investment (and technology) comes from many sources. In the No Reform Case, the more limited capital available to PEMEX (especially in the current period of lower oil prices) needs to be spread over a wide range of assets, including capital-intensive deepwater projects. The company continues to do a commendable job (as it has done, for example, in exploring the deepwater Perdido area in the northern Gulf of Mexico), but the amount of upstream activity is significantly lower.

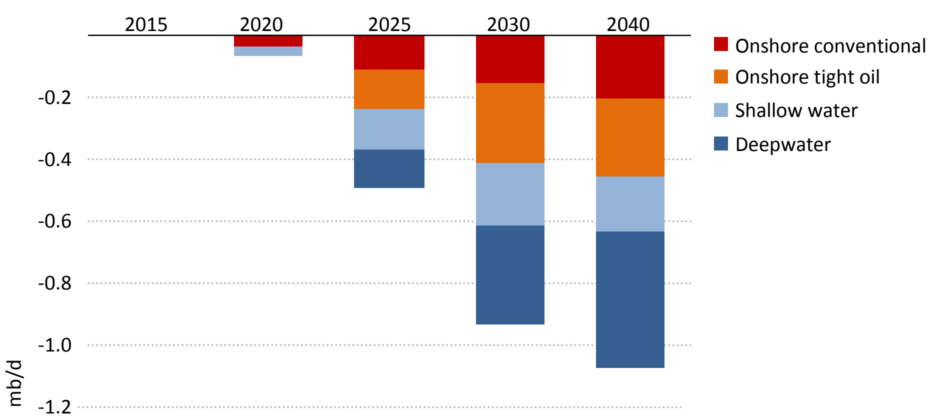
Figure 3.14 ▷ Oil production in Mexico in the No Reform Case



Mexico oil output stays lower for longer in No Reform Case

The investment constraint on PEMEX was modelled in the No Reform Case by calculating an indicative budget for capital spending, using as inputs the previous year's oil and gas production and expenditure, the oil price trajectory (essentially the same as in the New Policies Scenario) and historical PEMEX cost ratios.[24] The crucial difficulty for PEMEX is that, particularly in the early years of the projection, it is caught in a spiral of lower prices and falling production that severely limits the capital available to fund expansion and enhanced recovery projects in legacy fields and delays the start of technically challenging deepwater and tight oil development projects. By 2025, production in a No Reform Case is around 500 kb/d less than in the New Policies Scenario: the largest difference is in shallow water areas, where heavy oil projects are delayed and investment in enhanced recovery programmes is crimped (Figure 3.15). The New Policies Scenario includes some 120 kb/d of production from deepwater by 2025, which does not appear in the No Reform Case.

Figure 3.15 ▷ Oil production in the No Reform Case relative to the New Policies Scenario



The No Reform Case sees reduced investment straight away – and a sharp reduction in output by the mid-2020s

By 2030, oil output is around 900 kb/d below that of the New Policies Scenario. Legacy shallow water assets are in steep decline, and – given the assumption that PEMEX would continue to invest in deepwater and onshore assets – suffer from a reduction in funding for projects and enhanced recovery, compared with the New Policies Scenario. Despite some investment, the disparity in deepwater and tight oil production between the two trajectories rises to more than 550 kb/d by 2030 and continues to increase thereafter. PEMEX has already begun investments in these sectors, but would have difficulty in giving them the technical and capital attention needed for rapid development in the absence of the Reform. A partnership between PEMEX and service companies to develop tight oil,

[24] PEMEX revenues, costs and production quantities were sourced from the company's annual reports for 2000-2015.

similar to that used at Chicontepec cannot be ruled out in a No Reform Case, but it is unlikely to be able to deliver the same results as those seen in the New Policies Scenario.

Deepwater production takes the biggest hit in a No Reform Case by 2040. This is predicated on the assumption that PEMEX alone would not be able to sustain the high investment levels needed to support growth in deepwater production seen in the New Policies Scenario. It is likely that PEMEX would continue to invest in Perdido projects in the northern Gulf of Mexico, but would divert its remaining resources to enhancing production from shallow water fields, a realm in which its expertise currently excels. Large-scale investment in southern, deepwater exploration would therefore be less likely.

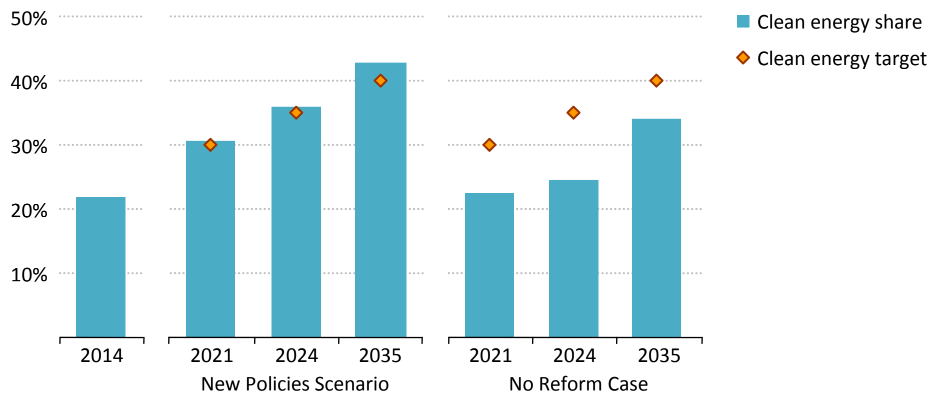
The lower oil output would have strong repercussions for the national oil balance. Oil demand is similar in the No Reform Case (as reduced demand due to the impact on gross domestic product [GDP], discussed below, is offset by increased oil use in power generation to compensate for lower renewables deployment), but oil production is hit hard and crude export revenue falls by almost half, meaning that the oil trade balance deteriorates sharply. Funds for refinery investment are limited, meaning that the capacity modernisation envisaged in the New Policies Scenario fails to materialise to the same extent and refinery runs remain at around the current level of 1.1 mb/d. The cumulative value of the lost oil output over the projection period amounts to around $650 billion, while cumulative upstream investment is lower by some $260 billion. The loss is felt in different parts of the economy, notably in fiscal revenue (which, as discussed below, would have to be made good either by higher taxation on other sectors, or lower expenditure). A No Reform Case would also have repercussions beyond Mexico, in that it would diminish an important source of global supply. The volumes would not necessarily be sufficient to have a significant impact on the oil price, but their loss would accelerate the pace at which the world becomes heavily reliant on a few large resource-holders for incremental supply.

3.5.2 The power sector in a No Reform Case

The Reform relies on several levers to achieve the stated objective of bringing down prices while promoting clean energy; the key elements that are missing in a No Reform Case are the unbundling and restructuring of CFE and the introduction of competitive electricity markets for energy, capacity and clean certificates. Their absence puts the power market in Mexico on a different trajectory and leads to a different electricity mix, compared with the New Policies Scenario. In terms of generation, even though electricity demand in 2040 is around 2% lower than in the New Policies Scenario (again, largely because of the adverse impact on GDP), almost the same amount of power needs to be generated in the No Reform Case, because the losses and inefficiencies in the network are not addressed with the same effectiveness.

Without specific policies to increase the role of clean energy in power generation, notably the introduction of clean energy certificates and the long-term auction system, the No Reform Case has a slower uptake of clean energy for power generation, especially of wind and solar power. Although efforts are assumed (encouraged by global cost reductions in renewable technologies) to deploy more renewable resources, the share of clean energy in power generation falls short of the government target of 40% by 2035 (as well as its intermediary targets in 2021 and 2024) (Figure 3.16). CO_2 emissions from the power sector also increase, by around 20% in 2040, relative to the New Policies Scenario, undermining the government's ambitions to cut greenhouse-gas emissions through the increased use of clean energy. Mexico's capacity to meet the obligations included in its COP21 climate pledge would be undermined.

Figure 3.16 ▷ Share of clean energy in power generation in Mexico in the No Reform Case



No Reform Case slows the deployment of renewables, meaning that Mexico misses its clean energy targets

Notes: Clean energy includes nuclear, hydropower, other renewables and efficient cogeneration. Clean energy targets for 2021 and 2024 are based on the Energy Transition Law. The clean energy target for 2035 is based on the Law for the Development of Renewable Energy and Energy Transition Financing.

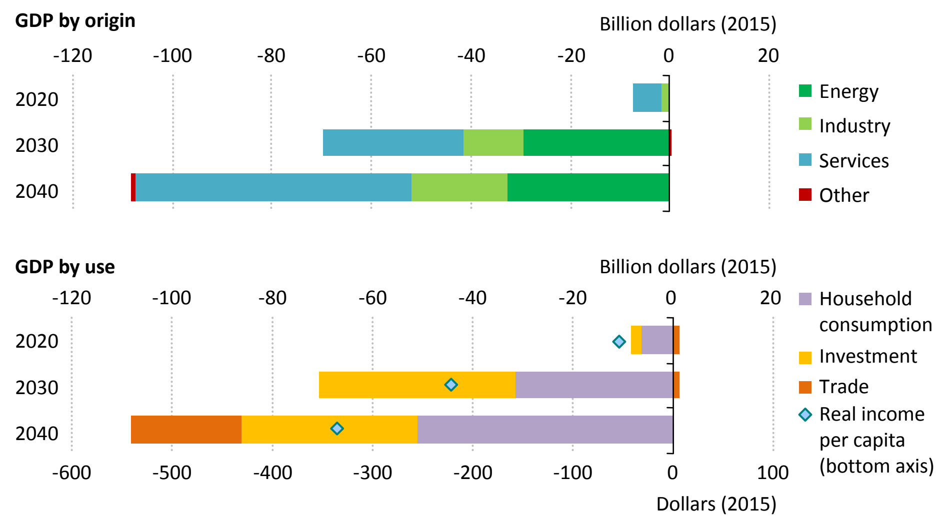
Fuel switching away from oil continues in the No Reform Case, as this is a continuation of a policy push that dates back to the late 1990s. However, the pace at which oil is replaced by gas is slowed, which, together with the slower improvement in transmission and distribution losses and lower operational efficiency, increases electricity prices in a No Reform Case: electricity prices for industrial consumers are around 14% higher in 2040 than the New Policies Scenario.

For residential consumers, we assume end-user prices at the same level as in the New Policies Scenario, in which electricity subsidies are phased out by 2035. In practice this translates to an additional subsidy bill in the No Reform Case (felt either as losses absorbed by CFE or explicit subsidies financed by the state budget) as the system as a whole is less efficient. The average cost of generating and delivering power to residential consumers in a No Reform Case is around 16% higher than in the New Policies Scenario. The cumulative additional subsidy bill over the period to 2040 is around $50 billion.

3.5.3 Repercussions for Mexico's economy of a No Reform Case

The reductions in investment in the oil and gas sector and the efficiency loss in the power system have implications well beyond the energy sector. These were assessed by coupling the results of the IEA World Energy Model with the OECD's computable general equilibrium model, ENV-LINKAGES. The decline in total investment in the economy in the No Reform Case is larger than the initial cut in upstream spending and leads to losses in other areas, including household consumption and trade, and the loss of value extends well beyond the energy sector (Figure 3.17).

Figure 3.17 ▻ Changes in GDP in the No Reform Case relative to the New Policies Scenario

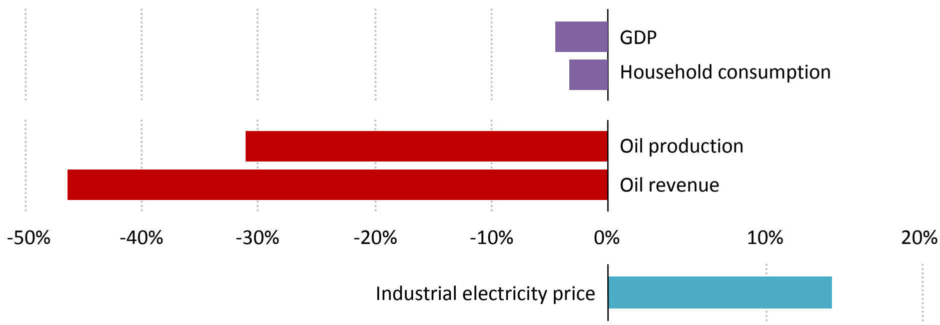


No Reform Case leads to a loss in value well beyond the initial impact on energy investment

The impacts are complex, but lower investment in the oil sector is felt not only by PEMEX itself, but by a range of companies that provide services or materials, such as the construction industry, equipment manufacturers and logistics firms. For all of these entities, lower output translates into lower revenue. For the government, the loss of fiscal revenue requires either higher taxes on other sectors to compensate or a decrease in expenditure. For individuals employed in the oil and gas sectors, or in related industries, lower incomes translate into lower consumption, which then reduces investment in other sectors of the economy, and so on.

Within the power sector, the failure to tackle inefficiencies results in a less productive sector. For the economy as a whole, it means inefficient allocation of investment. The government fiscal balance is hit by higher expenditure on electricity subsidies. Companies in different sectors of the economy face an increase in production costs, to which they respond either by reducing activity or cutting their margins. Either way, the knock-on effect is felt in lower investment. In this way, whether looked at from the supply or demand side of the economy, GDP is more than $100 billion lower by 2040 compared with the New Policies Scenario, meaning that Mexico's economy is more than 4% smaller (with cumulative loss of GDP above $1 trillion over the period as a whole) (Figure 3.18).

Figure 3.18 ▷ Changes in key economic variables in the No Reform Case relative to the New Policies Scenario



No Reform Case takes a toll on household budgets, industrial output and economic growth

Mexico projections

General note to the tables

The tables detail projections for *energy demand*, gross *electricity generation* and *electrical capacity*, and *carbon-dioxide (CO_2) emissions* from fuel combustion in Mexico. The tables present historical and projected data for the New Policies, Current Policies and 450 Scenarios, as well as the No Reform (NRC) and Enhanced Growth Cases (EGC).

Data for *fossil-fuel production*, *energy demand*, *gross electricity generation* and *CO_2 emissions* from fuel combustion up to 2014 are based on IEA statistics, published in *Energy Balances of OECD Countries*, *Energy Balances of non-OECD Countries*, *CO_2 Emissions from Fuel Combustion* and the *IEA Monthly Oil Data Service*. Historical data for *gross electrical capacity* are drawn from the Platts World Electric Power Plants Database (April 2016 version) and the International Atomic Energy Agency PRIS database.

Both in the text of this book and in the tables, rounding may lead to minor differences between totals and the sum of their individual components. Growth rates are calculated on a compound average annual basis and are marked “n.a.” when the base year is zero or the value exceeds 200%. Nil values are marked “-”.

Definitional note to the tables

Total primary energy demand (TPED) is equivalent to power generation plus other energy sector excluding electricity and heat, plus total final consumption (TFC) excluding electricity and heat. TPED does not include ambient heat from heat pumps or electricity trade. Sectors comprising TFC include industry, transport, buildings (residential, services and non-specified other) and other (agriculture and non-energy use). Projected gross electrical capacity is the sum of existing capacity and additions, less retirements. Total CO_2 includes emissions from other energy sector in addition to the power generation and TFC sectors shown in the tables. CO_2 emissions and energy demand from international marine and aviation bunkers are not included. CO_2 emissions do not include emissions from industrial waste and non-renewable municipal waste.

Mexico: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
TPED	**124**	**188**	**190**	**196**	**206**	**215**	**225**	**100**	**100**	**0.7**
Coal	4	13	10	8	7	6	6	7	3	-3.1
Oil	81	96	91	93	95	96	95	51	42	-0.1
Gas	23	61	68	70	74	80	86	32	38	1.3
Nuclear	1	3	3	3	5	5	7	1	3	4.2
Hydro	2	3	3	4	4	4	5	2	2	1.4
Bioenergy	9	9	9	9	9	9	9	5	4	0.2
Other renewables	4	4	7	10	12	15	17	2	8	5.9
Power	**27**	**60**	**59**	**61**	**65**	**70**	**77**	**100**	**100**	**1.0**
Coal	2	8	6	4	3	2	2	14	2	-5.8
Oil	15	9	1	1	1	0	0	14	0	-11.5
Gas	3	32	38	38	38	42	45	53	58	1.3
Nuclear	1	3	3	3	5	5	7	4	9	4.2
Hydro	2	3	3	4	4	4	5	6	6	1.4
Bioenergy	-	2	2	2	2	2	2	3	3	1.3
Other renewables	4	4	6	9	11	14	15	6	20	5.7
Other energy sector	**23**	**35**	**32**	**34**	**35**	**36**	**36**	**100**	**100**	**0.1**
Electricity	*1*	*4*	*4*	*4*	*5*	*5*	*6*	*12*	*15*	*1.1*
TFC	**83**	**118**	**128**	**134**	**143**	**150**	**156**	**100**	**100**	**1.1**
Coal	1	3	2	2	2	2	2	2	2	-0.3
Oil	51	73	76	77	80	81	81	62	52	0.4
Gas	14	14	17	19	21	23	25	12	16	2.3
Electricity	9	22	25	28	32	35	39	18	25	2.3
Bioenergy	9	7	7	6	6	6	7	6	4	-0.2
Other renewables	0	0	0	1	1	1	2	0	1	8.8
Industry	**26**	**34**	**37**	**40**	**43**	**46**	**49**	**100**	**100**	**1.5**
Coal	1	2	2	2	2	2	2	7	5	-0.4
Oil	7	6	6	6	6	6	6	17	11	-0.2
Gas	11	12	15	16	17	19	20	36	41	1.9
Electricity	5	12	13	15	16	18	19	36	40	1.8
Bioenergy	2	1	1	1	1	2	2	3	4	2.7
Other renewables	0	0	0	0	0	0	0	0	0	10.2
Transport	**28**	**51**	**53**	**54**	**57**	**59**	**59**	**100**	**100**	**0.5**
Oil	28	51	53	54	56	57	57	100	97	0.4
Electricity	0	0	0	0	0	0	1	0	1	8.4
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	-	0	0	0	0	1	1	0	2	17.1
Buildings	**18**	**24**	**26**	**27**	**29**	**31**	**33**	**100**	**100**	**1.3**
Coal	-	-	-	-	-	-	-	-	-	n.a.
Oil	7	8	7	7	7	7	7	33	20	-0.5
Gas	1	1	2	2	3	3	4	5	11	4.7
Electricity	3	8	10	12	14	15	17	36	52	2.7
Bioenergy	7	6	6	5	5	5	5	26	14	-1.0
Other renewables	0	0	0	0	1	1	1	1	3	6.6
Other	**11**	**10**	**12**	**13**	**14**	**14**	**15**	**100**	**100**	**1.6**

Mexico: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total generation	**116**	**301**	**339**	**377**	**422**	**469**	**518**	**100**	**100**	**2.1**
Coal	8	34	24	18	11	7	7	11	1	-5.6
Oil	62	33	5	4	2	2	1	11	0	-11.5
Gas	14	172	219	230	245	270	290	57	56	2.0
Nuclear	3	10	12	12	20	20	28	3	5	4.2
Hydro	23	39	37	43	48	52	55	13	11	1.4
Bioenergy	-	1	2	2	3	3	3	0	1	2.8
Wind	0	6	21	38	52	62	71	2	14	9.7
Geothermal	5	6	6	7	7	7	7	2	1	0.8
Solar PV	0	0	12	23	33	43	52	0	10	23.4
CSP	-	-	-	0	1	2	3	-	1	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total capacity	**69**	**87**	**106**	**124**	**142**	**161**	**100**	**100**	**3.3**
Coal	5	5	5	5	4	4	8	2	-1.3
Oil	17	11	9	5	4	3	24	2	-6.3
Gas	29	39	47	57	67	76	42	47	3.8
Nuclear	2	2	2	3	3	4	2	2	3.4
Hydro	12	14	16	18	19	20	18	12	1.8
Bioenergy	1	1	1	1	1	1	1	1	0.9
Wind	3	7	12	16	19	22	4	14	8.6
Geothermal	1	1	1	1	1	1	1	1	0.7
Solar PV	0	7	13	19	24	29	0	18	23.8
CSP	-	-	0	0	1	1	-	1	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2014	2020	2025	2030	2035	2040	2014	2040	2014-40
Total CO_2	**257**	**431**	**417**	**421**	**430**	**443**	**455**	**100**	**100**	**0.2**
Coal	15	48	37	31	24	20	20	11	5	-3.2
Oil	193	245	225	228	234	236	234	57	51	-0.2
Gas	48	137	155	162	172	187	200	32	44	1.5
Power	**64**	**138**	**117**	**110**	**103**	**107**	**114**	**100**	**100**	**-0.7**
Coal	7	34	24	18	11	7	7	25	6	-5.8
Oil	49	29	5	3	2	1	1	21	1	-11.6
Gas	8	75	88	88	90	99	106	54	93	1.3
TFC	**163**	**241**	**252**	**259**	**271**	**277**	**280**	**100**	**100**	**0.6**
Coal	4	10	9	9	9	9	9	4	3	-0.4
Oil	131	201	205	207	214	216	214	83	77	0.3
Transport	*83*	*151*	*156*	*159*	*167*	*169*	*169*	*63*	*60*	*0.4*
Gas	27	31	38	43	48	53	57	13	20	2.4

Mexico: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**194**	**219**	**246**	**186**	**187**	**184**	**100**	**100**	**1.0**	**-0.1**
Coal	10	8	7	10	6	4	3	2	-2.3	-4.2
Oil	95	101	106	90	84	67	43	37	0.4	-1.4
Gas	68	80	96	64	58	53	39	29	1.8	-0.5
Nuclear	3	5	7	3	7	12	3	6	4.2	6.0
Hydro	3	4	5	3	4	5	2	3	1.3	1.6
Bioenergy	9	9	10	9	13	18	4	10	0.4	2.8
Other renewables	6	12	16	7	15	25	6	14	5.5	7.5
Power	**62**	**70**	**85**	**57**	**56**	**63**	**100**	**100**	**1.3**	**0.2**
Coal	6	4	3	6	2	1	3	2	-4.0	-7.5
Oil	3	1	1	1	1	0	1	1	-9.9	-12.0
Gas	37	43	52	35	26	20	62	31	1.9	-1.9
Nuclear	3	5	7	3	7	12	9	18	4.2	6.0
Hydro	3	4	5	3	4	5	6	8	1.3	1.6
Bioenergy	2	2	2	2	3	4	3	6	1.3	3.0
Other renewables	6	11	15	6	13	22	17	34	5.5	7.1
Other energy sector	**33**	**37**	**40**	**31**	**30**	**25**	**100**	**100**	**0.5**	**-1.3**
Electricity	*4*	*5*	*6*	*4*	*4*	*4*	*16*	*16*	*1.7*	*-0.1*
TFC	**129**	**150**	**169**	**125**	**132**	**132**	**100**	**100**	**1.4**	**0.4**
Coal	2	2	2	2	2	2	1	1	-0.2	-1.2
Oil	77	85	91	75	71	58	54	44	0.8	-0.9
Gas	17	22	26	17	20	23	16	17	2.6	1.9
Electricity	26	33	42	24	27	32	25	25	2.5	1.6
Bioenergy	7	7	7	7	10	14	4	10	0.1	2.7
Other renewables	0	1	1	0	2	3	1	3	6.6	11.7
Industry	**38**	**44**	**51**	**36**	**38**	**41**	**100**	**100**	**1.6**	**0.8**
Coal	2	2	2	2	2	2	4	4	-0.3	-1.4
Oil	6	6	6	6	5	5	11	12	-0.1	-0.8
Gas	15	18	21	14	16	16	41	40	2.1	1.1
Electricity	14	17	20	13	14	15	40	38	2.0	0.9
Bioenergy	1	1	2	1	1	2	4	5	2.9	3.5
Other renewables	0	0	0	0	0	1	0	2	3.3	17.4
Transport	**54**	**61**	**66**	**53**	**54**	**48**	**100**	**100**	**1.0**	**-0.3**
Oil	54	60	65	52	49	36	98	75	0.9	-1.4
Electricity	0	0	0	0	1	2	1	4	5.0	12.2
Biofuels	-	-	-	-	3	7	-	15	n.a.	n.a.
Other fuels	0	0	1	0	1	3	1	6	16.6	22.0
Buildings	**26**	**31**	**37**	**25**	**26**	**28**	**100**	**100**	**1.7**	**0.7**
Coal	-	-	-	-	-	-	-	-	n.a.	n.a.
Oil	7	8	8	7	6	6	21	20	0.1	-1.2
Gas	2	3	4	2	3	3	11	11	5.1	3.9
Electricity	11	15	19	10	12	14	51	49	3.1	1.9
Bioenergy	6	6	5	6	5	4	14	16	-0.5	-1.1
Other renewables	0	0	1	0	1	2	2	6	5.2	8.7
Other	**12**	**14**	**15**	**12**	**13**	**15**	**100**	**100**	**1.7**	**1.6**

Mexico: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**346**	**448**	**559**	**323**	**361**	**424**	**100**	**100**	**2.4**	**1.3**
Coal	25	15	12	24	9	5	2	1	-3.9	-7.4
Oil	13	4	2	5	2	1	0	0	-9.8	-11.9
Gas	218	270	334	201	161	122	60	29	2.6	-1.3
Nuclear	12	20	28	12	26	44	5	10	4.2	6.0
Hydro	37	48	55	37	50	58	10	14	1.3	1.6
Bioenergy	2	3	3	3	6	8	1	2	2.8	6.7
Wind	21	49	67	21	58	102	12	24	9.4	11.2
Geothermal	6	7	7	6	7	9	1	2	0.8	1.5
Solar PV	11	31	49	12	40	66	9	16	23.1	24.5
CSP	-	1	2	-	3	8	0	2	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**88**	**128**	**166**	**84**	**118**	**158**	**100**	**100**	**3.4**	**3.2**
Coal	5	5	4	5	5	4	2	2	-1.3	-1.3
Oil	12	7	4	11	5	3	2	2	-5.3	-6.8
Gas	39	60	84	36	42	51	50	32	4.2	2.2
Nuclear	2	3	4	2	4	6	2	4	3.4	5.3
Hydro	13	17	20	14	18	21	12	14	1.8	2.1
Bioenergy	1	1	1	1	2	2	1	1	0.9	3.8
Wind	7	16	21	7	19	31	13	20	8.4	10.1
Geothermal	1	1	1	1	1	1	1	1	0.7	1.5
Solar PV	7	18	27	7	22	36	16	23	23.4	24.8
CSP	-	0	1	-	1	3	0	2	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2014-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**429**	**464**	**513**	**406**	**355**	**285**	**100**	**100**	**0.7**	**-1.6**
Coal	38	28	25	37	20	14	5	5	-2.4	-4.6
Oil	236	251	264	222	203	151	51	53	0.3	-1.8
Gas	155	185	224	147	132	119	44	42	1.9	-0.5
Power	**125**	**119**	**136**	**111**	**71**	**51**	**100**	**100**	**-0.0**	**-3.7**
Coal	25	15	12	24	9	4	9	9	-4.0	-7.5
Oil	11	4	2	5	2	1	1	2	-9.9	-12.0
Gas	88	100	123	82	60	46	90	89	1.9	-1.9
TFC	**256**	**287**	**311**	**249**	**239**	**198**	**100**	**100**	**1.0**	**-0.8**
Coal	9	9	9	9	8	6	3	3	-0.3	-1.7
Oil	208	228	242	202	187	141	78	72	0.7	-1.3
Transport	*159*	*178*	*192*	*154*	*144*	*106*	*62*	*53*	*0.9*	*-1.4*
Gas	39	50	60	38	45	50	19	25	2.6	1.9

Mexico: No Reform and Enhanced Growth Cases

	2020	2030	2040	2020	2030	2040	Shares (%) 2040		CAAGR (%) 2014-40	
	No Reform Case			Enhanced Growth Case			NRC	EGC	NRC	EGC
TPED (Mtoe)	**193**	**208**	**226**	**195**	**221**	**245**	**100**	**100**	**0.7**	**1.0**
Coal	10	6	6	10	7	6	2	2	-3.1	-2.8
Oil	95	98	97	95	104	106	43	43	0.0	0.4
Gas	69	77	88	68	78	92	39	38	1.4	1.6
Nuclear	3	5	7	3	5	7	3	3	4.2	4.2
Hydro	3	3	4	3	4	5	2	2	0.4	1.4
Bioenergy	9	11	14	9	9	9	6	4	1.7	0.3
Other renewables	3	6	11	7	14	19	5	8	4.2	6.3
Power (Mtoe)	**62**	**69**	**82**	**60**	**68**	**83**	**100**	**100**	**1.2**	**1.2**
Coal	6	3	2	6	3	2	2	2	-5.8	-5.8
Oil	5	4	3	1	1	0	3	0	-4.4	-11.4
Gas	39	44	50	38	41	49	61	59	1.8	1.7
Nuclear	3	5	7	3	5	7	9	9	4.2	4.2
Hydro	3	3	4	3	4	5	5	6	0.4	1.4
Bioenergy	3	4	7	2	2	2	8	3	5.2	1.3
Other renewables	3	6	10	6	13	17	12	21	4.0	6.1
TFC (Mtoe)	**128**	**142**	**155**	**133**	**156**	**174**	**100**	**100**	**1.0**	**1.5**
Coal	2	2	2	2	3	3	2	2	-0.3	0.1
Oil	76	80	81	80	89	92	52	53	0.4	0.9
Gas	17	21	26	17	23	28	17	16	2.4	2.7
Electricity	25	31	38	26	34	43	25	25	2.2	2.7
Bioenergy	7	7	7	7	7	7	5	4	0.0	-0.1
Other renewables	0	1	1	0	1	2	1	1	6.4	9.1
Generation (TWh)	**345**	**425**	**518**	**344**	**449**	**565**	**100**	**100**	**2.1**	**2.4**
Coal	26	11	7	24	11	7	1	1	-5.6	-5.6
Oil	21	14	10	5	2	1	2	0	-4.4	-11.3
Gas	228	283	321	223	260	317	62	56	2.4	2.4
Nuclear	12	20	28	12	20	28	5	5	4.2	4.2
Hydro	36	40	43	37	48	55	8	10	0.4	1.4
Bioenergy	4	10	16	2	3	3	3	1	9.8	2.8
Wind	11	27	53	23	60	81	10	14	8.4	10.2
Geothermal	6	7	7	6	7	7	1	1	0.8	0.8
Solar PV	2	12	29	12	38	62	6	11	20.6	24.2
CSP	-	1	3	-	1	3	1	1	n.a.	n.a.
CO_2 Emissions (Mt CO_2)	**435**	**446**	**466**	**431**	**465**	**503**	**100**	**100**	**0.3**	**0.6**
Coal	39	23	20	38	25	22	4	4	-3.3	-3.0
Oil	238	243	241	237	259	265	52	53	-0.1	0.3
Gas	158	180	205	157	180	216	44	43	1.5	1.8
Power (Mt CO_2)	**135**	**127**	**134**	**118**	**108**	**124**	**100**	**100**	**-0.1**	**-0.4**
Coal	26	10	7	24	11	7	5	6	-5.8	-5.8
Oil	18	12	9	5	2	1	7	1	-4.4	-11.4
Gas	91	104	118	89	95	115	88	93	1.8	1.7
TFC (Mt CO_2)	**253**	**270**	**280**	**265**	**301**	**317**	**100**	**100**	**0.6**	**1.1**
Coal	9	9	9	9	9	10	3	3	-0.5	-0.0
Oil	205	213	214	216	239	245	76	77	0.2	0.8
Transport	*156*	*164*	*165*	*167*	*189*	*196*	*59*	*62*	*0.3*	*1.0*
Gas	38	48	58	39	52	63	21	20	2.5	2.8

Definitions

This annex provides general information on terminology used throughout the report including: units and general conversion factors.

Units

Coal	Mtce	million tonnes of coal equivalent
Energy	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	mcf	million cubic feet
Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)
Monetary	\$ million	1 US dollar x 10^6
	\$ billion	1 US dollar x 10^9
	\$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 Watt x 10^3)
	MW	megawatt (1 Watt x 10^6)
	GW	gigawatt (1 Watt x 10^9)
	TW	terawatt (1 Watt x 10^{12})

Energy conversions

Convert to:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11 630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3 412	1

Currency conversions

***Exchange rates** (2015 annual average)*	**1 US Dollar equals:**
British Pound	0.65
Chinese Yuan	6.23
Euro	0.90
Japanese Yen	121.04
Mexican Peso	15.85

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U.S. DEPARTMENT OF TRANSPORTATION

BUILD AMERICA BUREAU

Credit Programs Guide

Transportation Infrastructure Finance and Innovation Act

Railroad Rehabilitation & Improvement Financing

March 2017

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Contacting the Build America Bureau

Feel free to write, fax, phone or e-mail the Bureau Credit Programs Office staff. General program contact information follows:

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Hearing- and speech-impaired persons may use TTY by calling the Federal Information Relay Service at 1-800-877-8339. Additional information, including the most recent edition of the program guide and application materials, can be obtained from the Bureau website at https://www.transportation.gov/buildamerica.

Chapter 1: Introduction to the Build America Bureau

The National Surface Transportation and Innovative Finance Bureau (referenced hereafter as the Build America Bureau or the Bureau) was established by the Secretary of Transportation on July 20, 2016, in accordance with the Fixing America's Surface Transportation (FAST) Act (Public Law 114-94).

The Build America Bureau is responsible for driving transportation infrastructure development projects in the United States. The Bureau streamlines credit opportunities and grants and provides access to the credit and grant programs with more speed and transparency, while also providing technical assistance and encouraging innovative best practices in project planning, financing, delivery, and monitoring. To achieve this vision, the Bureau draws upon the full resources of the U.S. Department of Transportation (DOT) to best utilize the expertise of all the modes within the Department while promoting a culture of innovation and customer service. This includes the administration of the application processes for the following programs:

- The Transportation Infrastructure Finance and Innovation Act of 1998 (TIFIA) credit program, and

- The Railroad Rehabilitation and Improvement Financing (RRIF) credit program.

The RRIF and TIFIA credit programs (together, the Credit Programs) operates under separate statutory authority, though as the implementation of the Bureau continues, we envision that the application processes described in this Program Guide are being consolidated and refined. This Program Guide, written for prospective TIFIA and RRIF applicants, describes how the Bureau's Credit Programs Office currently administers the TIFIA and RRIF Programs.

The Transportation Infrastructure Finance and Innovation Act of 1998 established a Federal credit program (the TIFIA Program) for eligible transportation projects under which the DOT may provide three forms of credit assistance – secured (direct) loans, loan guarantees, and standby lines of credit. The TIFIA Program's fundamental goal is to leverage Federal funds by attracting substantial private and other non-Federal co-investment to support critical improvements to the nation's surface transportation system. The DOT awards TIFIA credit assistance to eligible applicants, which include state departments of transportation, transit operators, special authorities, local governments, and private entities.

The Transportation Equity Act for the 21st Century (TEA 21) established the Railroad Rehabilitation and Improvement Financing Program (the RRIF Program). The RRIF Program provides direct loans and loan guarantees to finance the development of railroad infrastructure. Under this program, the DOT is authorized to provide direct loans and loan guarantees up to $35.0 billion to finance development of railroad infrastructure. Not less than $7.0 billion is reserved for projects benefiting freight railroads other than Class I carriers. The DOT awards RRIF credit assistance to eligible applicants, which include state and local governments, interstate compacts, government sponsored authorities and corporations, railroads, limited option rail freight shippers that own or operate a plant or other facility, and joint ventures that include at least one of the entities previously listed.

This chapter introduces each Credit Program's objectives and provides an overview of how each Credit Program operates. Chapter 2 details the required terms for individual credit instruments and describes how these instruments are funded. Chapter 3 describes the eligibility requirements concerning types of projects, activities, cost limits, and applicants. Chapter 4 describes the process by which potential applicants may apply for credit assistance. Chapter 5 describes the review process that the DOT uses to determine who receives credit assistance. Chapter 6 discusses the contractual documents, prerequisites for executing such documents, and the ongoing monitoring requirements. Chapter 7 discusses special issues related to loan guarantees.

Electronic copies of this Program Guide can be found on the Bureau website located at https://www.transportation.gov/buildamerica, as can all application materials and additional information regarding the Credit Programs.

Legislative Reference

The Transportation Infrastructure Finance and Innovation Act of 1998 was enacted as part of TEA 21 (Public Law 105-178, §§1501-04), as amended in 1998 by the TEA 21 Restoration Act (Title IX of Public Law 105-206), was further amended in 2005 by the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) (Public Law 109-59), was amended and restated in 2012, by the Moving Ahead for Progress in the 21st Century Act (MAP-21) (Public Law 112-141), and most recently, was amended in 2015 by the FAST Act. The TIFIA statute is codified within sections 601 through 609 of Title 23 of the United States Code (23 U.S.C. §§601-609), with supporting regulations appearing in part 80 of Title 49 of the Code of Federal Regulations (49 C.F.R. §80). These documents are available at: http://www.transportation.gov/tifia/legislation-regulations.

The Railroad Rehabilitation and Improvement Financing program was created in 1998 by the TEA-21 amendments (§7203 thereof) to a predecessor loan and loan guarantee program from the 1970s set forth in Title V of the Railroad Revitalization and Regulatory Reform Act of 1976 (Public Law 94-210), and was amended in 2005 by SAFETEA-LU, was further amended in 2008 by the Rail Safety Improvement Act of 2008 (Public Law 110-432), and most recently, was amended in 2015 by the FAST Act. The RRIF statute is codified within sections 821 through 823 of Title 45 of the United States Code (45 U.S.C. §§821-823)[1], with supporting regulations appearing in part 260 of Title 49 of the Code of Federal Regulations (49 C.F.R. §260). These documents will be made available at https://www.transportation.gov/buildamerica.

Policy Considerations

The public policy underlying the TIFIA Program asserts that the Federal Government can perform a constructive role in supplementing, but not supplanting, existing markets for

[1] Note that Title 45 of the United States Code is not positive law and citations thereto are used solely for ease of reference. For direct statutory references, please refer to the Railroad Revitalization and Regulatory Reform Act of 1976, as amended by FAST Act §§ 11601–11611.

financing large transportation infrastructure projects. Section 1502 of TEA 21 states that "a Federal credit program for projects of national significance can complement existing funding resources by filling market gaps, thereby leveraging substantial private co-investment." Because the TIFIA Program offers credit assistance, rather than grant funding, its potential users are infrastructure projects capable of pledging revenue streams generated through user charges or other dedicated funding sources.

A similar public policy underlies the RRIF Program. In addition, the RRIF Program dedicates funding to providing vital access to financing for shortline and regional railroads, which have historically lacked the access to private financing.

Identifying a constructive role for Federal credit assistance begins with the acknowledgement that, when compared to most investors, the Federal Government has a naturally longer-term investment horizon, which enables it to more readily absorb the relatively short-term risks of project financings. Absent typical capital market investor concerns regarding timing of payments and financial liquidity, the Federal Government can become the "patient investor" whose long-term view of asset returns enables the project's non-Federal financial partners to meet their investment goals, allowing the borrower to receive a more favorable financing package.

Funding Levels

The Credit Programs are subject to the Federal Credit Reform Act of 1990, which requires the DOT to establish a capital reserve[2] sufficient to cover the estimated long-term cost to the Federal Government of a Federal credit instrument, including any expected credit losses, before the DOT can provide TIFIA or RRIF credit assistance.[3]

TIFIA Program

Pursuant to the FAST Act, the DOT announced availability of funding authorized in the amount of $1.435 billion ($275 million in Federal Fiscal Year (FY) 2016 funds, $275 million in FY 2017 funds, $285 million in FY 2018 funds, $300 million in FY 2019 funds, and $300 million in FY 2020 funds (and any funds that may be available from prior fiscal years) to provide TIFIA credit assistance for eligible projects.[4] The FY 2016-2020 authorized funds are subject to an annual obligation limitation in accordance with appropriations law, as well as annual reobligation requirements, as further discussed in Section 2-5. Historically, each dollar of funding has allowed TIFIA to provide approximately $14 in credit assistance. As a result, these funding levels could translate to potentially $20 billion in TIFIA credit assistance.

RRIF Program

Under SAFETEA-LU, the RRIF Program was authorized to provide direct loans and loan

[2] Under the TIFIA Program, the capital reserve is referred to as the "credit subsidy" and under the RRIF Program it is referred to as the "credit risk premium."
[3] 2 U.S.C. §661c(b).
[4] FAST Act, Pub. L. No. 114-94, §1101(a)(2), (129 Stat. 1322) (2015).

guarantees totaling up to $35 billion.[5] Not less than $7 billion is reserved for projects benefiting freight railroads other than Class I carriers. For the current amount of available funding remaining, please refer to the Bureau Credit Programs website: http://www.transportation.gov/buildamerica. However, since the RRIF Program does not currently have an appropriation, the cost to the government of providing financial assistance must be borne by the RRIF applicant, or another non-federal entity on behalf of the applicant, through the payment of the credit risk premium.

Program Administration

Implementation of the TIFIA and RRIF Programs is the responsibility of the Secretary of Transportation (the Secretary). The FAST Act established the DOT Council on Credit and Finance to provide policy direction and make recommendations to the Secretary regarding the selection of projects for credit assistance.[6] The Council on Credit and Finance members include five representatives from the Office of the Secretary of Transportation (OST): the Deputy Secretary of Transportation (Chair), the Assistant Secretary for Budget and Programs (Vice-Chair), the Under Secretary of Transportation for Policy, the General Counsel, and the Assistant Secretary for Transportation Policy. The Administrators of the Federal Highway Administration (FHWA), the Federal Transit Administration (FTA), and the Federal Railroad Administration (FRA) also sit on the Council on Credit and Finance. Additionally, the Secretary may designate up to three DOT officials to serve as at-large members of the Council on Credit and Finance.

The Build America Bureau administers the TIFIA and RRIF Programs on behalf of the Secretary, including the evaluation of individual projects, and provides overall policy direction and program decisions for the TIFIA and RRIF Programs. Final approval of Bureau credit assistance is reserved for the Secretary.

Application Process Overview

All TIFIA and RRIF credit assistance will be awarded based on a project's satisfaction of TIFIA and/or RRIF (as applicable) statutory eligibility requirements. The summary below provides an overview of the TIFIA and RRIF application process. More information about eligibility requirements can be found in Chapter 3 and more information about the application process can be found in Chapter 4.

1. Build America Bureau Outreach and Project Development. The initial point of contact for Bureau engagement is a Project Development Lead (PDL) who works with each project sponsor to determine project needs and the specific ways in which the Bureau can provide TIFIA and RRIF credit assistance. Based on the specific questions, challenges, opportunities, and information needs related to a particular project, appropriate Bureau expertise is assigned and brought to bear for projects. This may require the assignment of more specialized PDL assistance for projects that involve greater complexity in terms of

[5] SAFETEA-LU, Pub. L. No. 109-59, §9003(d)(1), (119 Stat. 1921) (2005), codified at 45 U.S.C. §822(d).
[6] FAST Act, Pub. L. No. 114-94, §9002(a), (129 Stat. 1618) (2015), codified at 49 U.S.C. §117.

such factors as scope, modal elements, regulatory requirements, private-sector involvement, and financing plan. This approach helps ensure that the project has followed statutory and regulatory requirements and that it appears to be eligible. The intent of this process is to identify major hurdles that might delay a project early in the process. A customized project development team works closely with the project sponsor to navigate relevant Federal processes and to ensure that key program requirements are satisfied.

2. Submission of Letter of Interest/Draft Application. Although letters of interest (LOIs) may be submitted on a rolling basis (i.e. at any time), the Bureau recommends that project sponsors consult the Bureau before submitting LOIs to ensure that the relevant programmatic requirements are met and initial risk assessments are completed. This ensures that all key project elements are in place for an efficient underwriting process.

3. Creditworthiness Review. Once a project sponsor has completed the initial consultation process with a PDL and DOT makes a determination that the project is reasonably likely to satisfy all of the eligibility requirements of the applicable Credit Program(s), DOT can expeditiously accept the LOI, and formally move the Project into the credit underwriting process. Applicants interested in TIFIA credit assistance should use the Letter of Interest form and applicants interested in RRIF credit assistance should prepare a Draft Application using the Application form; both forms can be found at https://www.transportation.gov/buildamerica. The Letter of Interest and Application forms allow potential applicants to describe the project (including location, purpose, and cost), demonstrate the project sponsor's ability to meet the DOT's creditworthiness requirements, detail how the TIFIA and/or RRIF statutory eligibility requirements are met, and outline the proposed financial plan, including the requested TIFIA and/or RRIF credit assistance.[7]

   Potential applicants should submit these forms electronically via email at BureauCredit@dot.gov. The DOT will conduct an in-depth creditworthiness review of the project sponsor and the revenue stream proposed to repay the TIFIA and/or RRIF credit assistance. The creditworthiness review involves evaluation of the plan of finance, financial model, and feasibility of the anticipated pledged revenue or, in the case of RRIF loans where the proposed collateral is other than a dedicated revenue stream, the sufficiency of such other pledged collateral. In connection with this review, the DOT will ask project sponsors to provide any additional materials necessary to facilitate its review of the project's creditworthiness.

   Once the DOT has concluded that the project satisfies statutory eligibility criteria, including a preliminary review of a project's creditworthiness and, for TIFIA projects, satisfaction of readiness requirements,[8] the DOT will ask a project sponsor seeking

[7] 23 U.S.C. §601(a)(6) and 45 U.S.C. §823(a).

[8] To be eligible for TIFIA credit assistance, the applicant must demonstrate: (a) that it satisfies (or will have satisfied at the time of obligation of Federal credit assistance) all applicable Federal requirements, including all National Environmental Policy Act requirements, and (b) a reasonable expectation that the contracting process for construction of the project can commence no later than 90 days after the date on which the TIFIA credit assistance is obligated. Note that the readiness requirement for TIFIA loans to capitalize rural projects funds is different than

TIFIA credit assistance to provide a preliminary rating opinion letter from at least one nationally recognized statistical rating organization (Credit Rating Agency)[9] and will ask all project sponsors to submit to the DOT an upfront fee to cover the DOT's costs to procure outside financial and legal advisors (the Advisors' Fees Upfront Payment). This fee will be used, dollar-for-dollar, to cover the actual costs incurred for services provided by the DOT's outside financial and legal advisors in connection with the review of the Letter of Interest/Draft Application and application and the negotiation of the transaction documents. For both TIFIA and RRIF, the Advisors' Fees Upfront Payment amount is $250,000 (subject to availability of funds for assistance for TIFIA small projects, as discussed below). For RRIF projects, the Advisors' Fees Upfront Payment may be higher depending on the nature and complexity of the project. Project sponsors should consult with the Bureau to confirm the applicable amount of the Advisors' Fees Upfront Payment.

Assistance Available to Offset Advisors' Fees Upfront Payment:

TIFIA Program: For TIFIA projects with eligible project costs reasonably anticipated to be less than $75 million, the FAST Act requires the Secretary to set aside at least $2 million of the TIFIA Program's annual budget authority to be used in lieu of fees charged to the project sponsor to cover the costs of the DOT's outside advisors.[10] Project sponsors should indicate in their Letter of Interest whether they wish to be considered for this assistance (though the DOT cannot guarantee that funds will be available to satisfy all requests). To the extent a project sponsor is eligible for this assistance and sufficient funds are available, the Advisors' Fees Upfront Payment will be waived, and the cost of the DOT's outside advisors will be funded through this set-aside.

RRIF Program: The FY 2016 Consolidated Appropriations Act set aside $1.96 million to assist Class II and III railroads pursuing RRIF credit assistance. These funds are available to be used by the Bureau in lieu of fees charged to Class II and III railroads to cover the cost of the DOT's outside advisors.[11] These funds cannot be used to cover the CRP of a RRIF loan.[12] Class II and III railroads seeking RRIF credit assistance should indicate in their Draft Application whether they wish to be considered for this assistance (though the DOT cannot guarantee that funds will be available to satisfy all requests). To the extent a project sponsor is eligible for this assistance and sufficient funds are available, the Advisors' Fees Upfront Payment will be waived and the cost of the DOT's

that for traditional construction projects. (*See* 23 U.S.C. §602(a)(10) for readiness requirements and §602(c) for Federal requirements.)

[9] For TIFIA projects, the preliminary rating opinion letter must indicate that the senior obligations of the project have the potential to achieve an investment-grade rating and must include a preliminary rating opinion on the TIFIA credit instrument. 23 U.S.C. §602(b)(3).

[10] 23 U.S.C. §605(f).

[11] Consolidated Appropriations Act, 2016, Division L, §152, Pub. L. 114-113, December 18, 2015, 129 Stat. 2242, 2856 (2015).

[12] Consolidated Appropriations Act, 2016, Division L, §146, Pub. L. 114-113, December 18, 2015, 129 Stat. 2242, 2853 (2015).

outside advisors will be funded through this appropriation. These funds remain available beyond FY 2016 to the extent not expended.

4. Oral Presentation. Following completion of the DOT's in-depth review of the Letter of Interest/Draft Application and receipt of a preliminary rating opinion letter and the Advisors' Fees Upfront Payment, the DOT will request that the potential applicant give an oral presentation on the project and its plan of finance to the DOT, followed by a question and answer session. The DOT will provide guidance regarding the structure and content of the presentation at the time of the request.

5. Application. Once both the preliminary rating opinion letter and the Advisors' Fees Upfront Payment have been received, the project sponsor has made its oral presentation to the DOT, and the DOT has determined that the project satisfies all statutory eligibility requirements, including a full review of the creditworthiness of the project, the project sponsor will then be invited to submit a complete application with all required materials. The DOT will not review incomplete applications or applications for projects that do not fully satisfy eligibility requirements.

   Please note that an invitation by the DOT to submit an application does not guarantee that a project will receive credit assistance, which remains subject to a project's continued eligibility and final approval by the Secretary.

6. Notification of Completeness. No later than 30 days after the date of its receipt of the application, the DOT shall notify the applicant in writing that the application is complete or requires additional information or materials to complete the application.[13]

7. Project Recommendation. Based upon the written application, the oral presentation, and any supplemental information submitted by an applicant, DOT staff will prepare a project evaluation and recommendation for the DOT Council on Credit and Finance.

8. Project Selection. The DOT Council on Credit and Finance, in turn, provides a recommendation to the Secretary, who makes the final determination regarding project selection. The DOT will not obligate funds for a project that does not satisfy statutory requirements such as obtaining environmental clearances.

9. Notification of Project Approval. The DOT will notify the project sponsor regarding project approval or disapproval no more than 60 days after notifying the project sponsor that its application was complete.[14]

10. Term Sheet and Credit Agreement Execution and Funding Obligation. For each approved project, the DOT will prepare a term sheet for execution with the borrower. The term sheet sets forth the basic terms and conditions of DOT credit assistance. In addition, the DOT and the borrower will execute a credit agreement, which is the definitive agreement between the DOT and the borrower, memorializes all of the terms

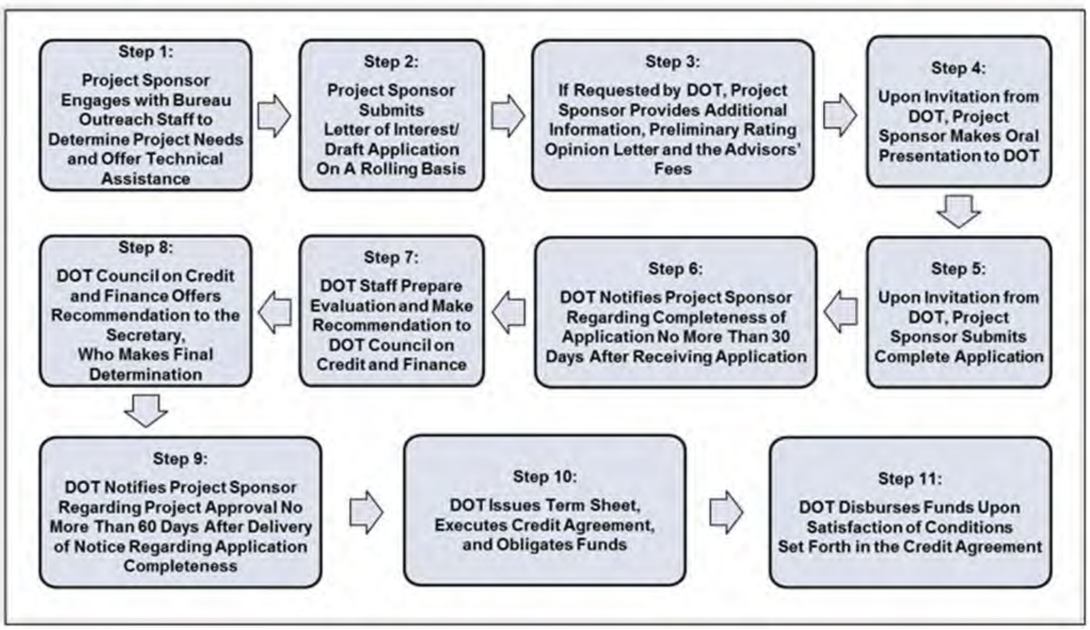
[13] 23 U.S.C. §602(d)(1) and 45 U.S.C. §822(i)(1).
[14] 23 U.S.C. §602(d)(2) and 45 U.S.C. §822(i)(3).

and conditions of TIFIA or RRIF credit assistance, and authorizes the disbursement of funds subject to satisfaction of the specified conditions. Prior to execution of the credit agreement, the borrower must satisfy all applicable TIFIA and/or RRIF Program requirements.

11. Disbursement of Funds. For all credit assistance, the DOT will disburse funds only to reimburse eligible project costs upon satisfaction of the conditions precedent set forth in the credit agreement.[15]

Exhibit 1-A below shows each of these eleven steps as a flow chart.

Exhibit 1-A: Selection and Funding of TIFIA and RRIF Projects



[15] 23 U.S.C. §§603(a), (e)(2), 604(a)(2) and 45 U.S.C. §822(b).

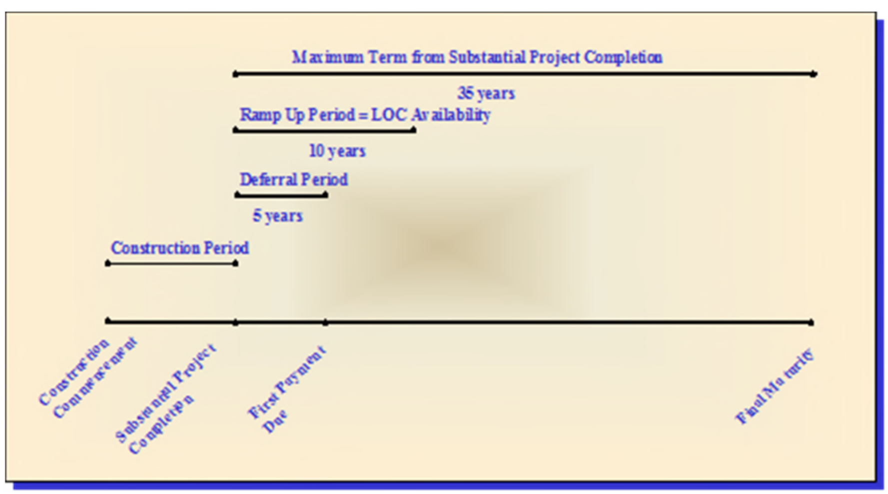
Chapter 2: Terms and Funding of Bureau Credit Instruments

The Bureau Credit Program's secured (direct) loans, loan guarantees, and standby lines of credit[16] may offer more flexible repayment terms and more favorable interest rates compared to other lenders. In addition, master credit agreements offer predictability and efficiency for planning purposes for projects with an identified source of revenue and solidified schedule for construction. This chapter summarizes the terms that apply generally to Bureau credit assistance and describes the major features of each credit instrument. A section on loan repayment and prepayment structuring provides information on financing structures and related repayment issues that may arise during negotiations. The chapter also provides an explanation of the funding controls that govern the amount of credit assistance available under each Bureau Credit Program.

Section 2-1
Summary of Basic Terms for Bureau Credit Assistance

Certain features of Bureau credit assistance are the same regardless of whether the credit assistance is provided under the RRIF Program or the TIFIA Program. For example, the maximum maturity of all TIFIA and RRIF credit instruments is the lesser of: (i) 35 years after a project's substantial completion or (ii) the useful life of the project being financed by TIFIA or RRIF.[17] The DOT, at its discretion, has the ability to defer the first TIFIA or RRIF payment up to five years after substantial completion, depending on the needs of the project.[18] Exhibit 2-A provides an illustrative repayment structure for the three credit instruments.

Exhibit 2-A: Illustrative Repayment Structure as Permitted by Statute



[16] Note that standby lines of credit are only available under the TIFIA Program and are not available under the RRIF Program.

[17] 23 U.S.C. §§603(b)(5), (e)(2) and 604(c)(2)(B) and 45 U.S.C. §822(g)(1). Note that for TIFIA loans to capitalize rural projects funds within a state infrastructure bank (SIB), the maximum maturity for the secured loan is 35 years after the date on which the TIFIA secured loan is obligated (23 U.S.C. §603(b)(5)(B)).

[18] 23 U.S.C. §603(c)(2), (c)(3), (e)(2), and 45 U.S.C. §822(j)(1). For TIFIA standby lines of credit, repayment can commence up to 15 years after substantial completion (23 U.S.C. §604(c)(2)(A)).

A Bureau credit instrument can be junior (i.e., subordinate) to the project's other debt obligations in the priority of its lien on the project's cash flow. In the event of bankruptcy, insolvency, or liquidation, the DOT is required by both the RRIF and TIFIA statutes to have a parity lien with respect to the project's senior creditors.[19] The credit agreement will clearly specify the DOT's interest in the pledged security relative to other creditors.

Other Key Limitations to Bureau Credit Assistance

TIFIA Program

The TIFIA statute places two other important limits on the Federal Government's exposure to credit risk. First, TIFIA credit assistance is limited to no more than 49 percent of reasonably anticipated eligible project costs for a TIFIA secured loan or loan guarantee and no more than 33 percent of reasonably anticipated eligible project costs for a TIFIA standby line of credit.[20] As noted below, TIFIA direct loans provided to date have only covered up to 33 percent of reasonably anticipated eligible project costs. Applicants requesting assistance in excess of this amount must provide a rationale for such additional assistance. The limitation in the DOT's total share of project costs is designed to ensure that the DOT shares the credit risk with other participants. Second, the applicant must obtain two investment-grade ratings (Baa3/BBB- or higher) on the senior debt obligations and two ratings on the TIFIA credit instrument, both from a Credit Rating Agency, in order to execute a TIFIA credit agreement.[21] If the TIFIA credit assistance is the senior and/or the only debt in the project, then it must receive two investment grade ratings.[22] If the total amount of debt in the project is less than $75 million, then the applicant must obtain only one investment-grade rating on the senior obligations and one rating on the TIFIA credit instrument from a Credit Rating Agency.[23] Chapter 3 provides further details on eligible project costs and credit ratings.

RRIF Program

As noted above, the RRIF Program does not currently have an appropriation of budget authority to cover the cost of RRIF direct loans and loan guarantees. As such, the cost to the government of providing financial assistance must be borne by the RRIF applicant, or another non-federal entity on behalf of the applicant, through the payment of the credit risk premium

[19] 23 U.S.C. §§603(b)(6), (e)(2), 604(b)(8), and 45 U.S.C. §822(l)(1). However, the TIFIA and RRIF nonsubordination requirements may be waived if certain specified conditions are satisfied: (i) the borrower is a public agency; (ii) the credit instrument receives a rating within the A category or higher from at least one Credit Rating Agency for RRIF credit instruments and at least two Credit Rating Agencies for TIFIA credit instruments; (iii) the credit instrument is secured and payable from pledged revenues that are not affected by project performance, such as a tax-backed revenue pledge or a system pledge; and (iv) the percentage of eligible project costs being financed by Bureau credit assistance is 33 percent or less for TIFIA credit assistance and 50 percent or less for RRIF credit assistance. However, in such cases for (x) TIFIA credit assistance, the maximum credit subsidy to be paid by the Federal Government may not be more than 10 percent of the principal amount of the TIFIA credit assistance, and the obligor is responsible to pay any remaining subsidy cost, and (y) for RRIF credit assistance, the DOT may impose limitations on the waiver of nonsubordination requirements if it determines that such limitations would be in the financial interest of the Federal Government. 23 U.S.C. §§603(b)(6)(B) and 604(b)(8)(B), and 45 U.S.C. §822(l)(2)(A).
[20] 23 U.S.C. §§603(b)(2) and 604(b)(2).
[21] 23 U.S.C. §602(a)(2)(A).
[22] 23 U.S.C. §602(a)(2)(B).
[23] 23 U.S.C. §602(a)(2)(A)(iv) and (a)(2)(B).

(CRP). The CRP attributable to each drawdown request must be paid on a pro rata basis prior to each disbursement.[24] Chapter 2 provides further information regarding the CRP.

In addition, the RRIF statute requires that RRIF credit agreements provide for certain specific terms and conditions regarding the sufficiency and availability of funds to cover ongoing operations. Those terms and conditions will require a RRIF borrower to agree:

- Not to use any funds or assets from railroad or intermodal operations for purposes not related to such operations if that use would impair the ability of the borrower or its partners to provide rail or intermodal services in an efficient and economic manner or would adversely affect the ability of the borrower or its partners to perform its obligations under the RRIF credit instrument;

- To maintain its capital program, equipment, facilities, and operations on a continuing basis, consistent with its capital resources; and

- Not to make any discretionary dividend payments that unreasonably conflict with its ability to maintain its capital program, equipment, facilities and operations.[25]

Section 2-2
Bureau Credit Instruments

The main features of direct loans, loan guarantees, lines of credit (TIFIA only), and master credit agreements are summarized below. These features are established by statute. This section also addresses the rules that govern the setting of interest rates, disbursement of funds, and repayment of TIFIA and RRIF credit assistance.

Secured/Direct Loans (23 U.S.C. §603 and 45 U.S.C. §822)

A direct loan[26] is a debt obligation involving the DOT as the lender and a non-Federal entity as the borrower. Actual terms and conditions will be negotiated between the DOT and the borrower, but the general characteristics include:

- Use of Proceeds. The proceeds of both RRIF and TIFIA direct loans must be used either to finance eligible project costs or to refinance debt that was issued to finance eligible project costs.

  TIFIA direct loans can only be used to refinance: (i) interim construction financing of eligible project costs; (ii) existing Federal credit instruments for rural infrastructure projects; or (iii) long-term project obligations or Federal credit instruments if the refinancing provides additional funding capacity for the completion, enhancement, or

[24] 45 U.S.C. §822(f)(4) and 49 C.F.R. §260.15(c).
[25] 45 U.S.C. §822(h)(1).
[26] Note that the TIFIA statute defines direct loans as "secured loans" and the RRIF statute uses the term "direct loans." For ease of reference in this Program Guide, we use the term "direct loans." (*See* 23 U.S.C. §601(a)(17) and 45 U.S.C. §821(3).)

expansion of an eligible project.[27] In the case of refinancing interim construction financing, the TIFIA direct loan may not refinance the existing debt (x) if that debt's maturity is later than 1 year after the substantial completion of the project, or (y) later than one year following substantial completion of the project.[28]

RRIF direct loans can only be used to refinance outstanding debt incurred for certain types of eligible projects, including debt incurred to acquire, improve, or rehabilitate intermodal or rail equipment or facilities, including track, components of track, bridges, yards, buildings, and shops, and costs related thereto, or to develop or establish new intermodal or railroad facilities.[29] RRIF direct loans cannot be used to refinance outstanding debt incurred for other eligible projects.

- Amount. The principal amount of a RRIF direct loan may not exceed available statutory authority.[30] The principal amount of a TIFIA direct loan (in combination with other TIFIA credit assistance, if any) may not exceed 49 percent of the reasonably anticipated eligible project costs.[31] To date, TIFIA direct loans have only covered up to 33 percent of reasonably anticipated eligible project costs in order to ensure other investors are sharing in project costs and associated risks. While TIFIA can fund up to 49 percent of reasonably anticipated eligible project costs, applicants requesting assistance in excess of 33 percent of reasonably anticipated eligible project costs must provide a strong rationale for requiring additional assistance. If the project is supported by debt senior to the TIFIA lien, the TIFIA credit instrument must be secured by the same revenues pledged to the senior debt. If the TIFIA secured loan is rated below investment grade, then the amount of the TIFIA loan may not exceed the amount of the senior debt.[32]

- Interest Rate. The interest rate on a TIFIA direct loan will be equal to or greater than the yield on U.S. Treasury securities of comparable maturity on the date of execution of the credit agreement.[33] The interest rate on a RRIF direct loan will be equal to the yield on U.S. Treasury securities of comparable maturity on the date of execution of the credit agreement.[34] The DOT identifies the Treasury rates through use of the daily rate tables published by the Bureau of the Public Debt for the State and Local Government Series (SLGS) investments. Adding one basis point to the SLGS rates produces the estimated average yields on comparable Treasury securities. The SLGS tables can be found on-line at https://www.treasurydirect.gov/GA-SL/SLGS/selectSLGSDate.htm. The daily 30-year Treasury rate can be found on the Bureau's website at

[27] 23 U.S.C. §603(a)(1).
[28] 23 U.S.C. §603(a)(2).
[29] 45 U.S.C. §822(b)(1).
[30] 45 U.S.C. §822(d). In addition, credit assistance for RRIF TOD Projects is limited to 75 percent of total project costs.
[31] 23 U.S.C. §603(b)(2)(A). Note that the maximum amount is limited to 33 percent where the nonsubordination requirement is waived, as described in footnote 17 above. Note also that the principal amount of a TIFIA direct loan to capitalize a rural projects fund within a SIB may not exceed $100 million.
[32] 23 U.S.C. §603(b)(2).
[33] 23 U.S.C. §603(b)(4)(A).
[34] 45 U.S.C. §822(e) and 49 C.F.R. §260.9.

https://www.transportation.gov/buildamerica. Interest begins to accrue on loan proceeds immediately upon disbursement of funds to the borrower.

TIFIA direct loans may be provided to rural infrastructure projects, or under the FAST Act, to capitalize rural projects funds within SIBs (these types of projects together, Rural Projects), at a discounted interest rate of one-half of the Treasury Rate.[35] The reduced interest rate is only available to TIFIA direct loans for Rural Projects where the subsidy cost of such loans is funded out of amounts set aside from the TIFIA Program's annual budget authority specifically for such reduced interest rate loans.[36] The TIFIA Program may set aside up to 10 percent of its annual budget authority to fund the subsidy costs of TIFIA direct loans to Rural Projects at the reduced interest rate.[37] The reduced interest rate is only available in any fiscal year to the extent sufficient funds are available in the set-aside for that fiscal year.[38] Any amounts set aside in a fiscal year to fund the subsidy cost of TIFIA direct loans to Rural Projects at the reduced interest rate that have not been obligated by June 1 of such fiscal year must be made available to fund projects not receiving the reduced interest rate to the extent sufficient funds are not otherwise available.[39]

In addition, the TIFIA statute allows project sponsors to buy down the interest rate on a TIFIA direct loan in the event the rate has increased between the date on which the project sponsor submitted its complete application and the date on which the secured loan is executed.[40] Project sponsors can reduce the interest rate by way of a limited buydown up to 1 1/2 percentage points (150 basis points) or the amount of the increase in the interest rate, whichever is less.

- Timing of Disbursements. The DOT will disburse funds as often as monthly, on a reimbursement basis, as costs are incurred for eligible project purposes.[41] The credit agreement will specify a draw schedule, which may be amended if necessary. Note that, for RRIF direct loans, the CRP attributable to each RRIF loan drawdown request must be paid to the DOT on a pro rata basis prior to each disbursement.[42]

- Maturity. The final maturity date of a direct loan must be no later than 35 years after the date of substantial completion of the project or the useful life of the project, whichever is less.[43] Note that, for a TIFIA direct loan to capitalize a rural projects fund within a SIB,

[35] 23 U.S.C. §603(b)(4)(B)(i).
[36] 23 U.S.C. §603(b)(4)(B)(ii).
[37] 23 U.S.C. §608(a)(3)(A).
[38] 23 U.S.C. §603(b)(4)(B)(ii).
[39] 23 U.S.C. §608(a)(3)(B).
[40] 23 U.S.C. §§601(a)(8) and 603(b)(4)(C). In addition, a limited buydown is available in the event a borrower has entered into a master credit agreement and the interest rate has increased between the date on which the master credit agreement was executed and the date on which an underlying TIFIA direct loan is entered into in connection with such master credit agreement.
[41] 23 U.S.C. §603(a)(1) and 45 U.S.C. §§822(b)(1) and (2).
[42] 45 U.S.C. §822(f)(4) and 49 C.F.R. §260.15(c).
[43] 23 U.S.C. §603(b)(5) and 45 U.S.C. §822(g)(1).

the final maturity date of the TIFIA direct loan must be not later than 35 years after the date on which the TIFIA direct loan is obligated.[44]

- Repayment Terms. Scheduled repayments must commence no later than five years after the date of substantial completion of the project.[45] Debt service will be structured based on project economics and risk to the DOT.[46] Debt service payments are scheduled semi-annually.

- Deferrals. In the event revenues are insufficient to meet scheduled loan payments, the DOT, in its sole discretion, may allow payment deferrals. Any interest payment that is deferred will be added to the outstanding balance of the direct loan and amortized over the existing term of the direct loan. Any principal payment that is deferred will continue to accrue interest on a current basis. In addition, (a) for TIFIA direct loans, any such deferral will be contingent on the project's meeting requirements established by the Secretary, including standards for reasonable assurance of repayment and (b) for RRIF direct loans, such deferral is limited to a maximum aggregate time of one year over the term of the direct loan.[47] There can be no assurance the Secretary will exercise this authority, however, so borrowers should only agree to a debt service schedule they are confident they can meet.

- Prepayment Conditions. In general, a direct loan may be prepaid in whole or in part at any time without penalty.[48]

- Lien Priority. The DOT's lien on pledged revenues can be subordinated to those of senior lenders to the project except in the event of bankruptcy, insolvency, or liquidation of the obligor. In such an instance, the DOT's lien would be on par with the lien of the project's senior creditors.[49] This provision will be implemented by way of incorporation into the TIFIA or RRIF credit agreement, as applicable, and any other appropriate financing agreements entered into at the time of execution of such credit agreement. As noted in Section 2-1 above, this provision can be waived under certain circumstances for public agency borrowers having senior bonds under preexisting indentures so long as certain conditions are met.[50]

Loan Guarantees (23 U.S.C. §603(e) and 45 U.S.C. §822)

A Bureau loan guarantee is a pledge by the DOT to pay a third-party lender all or part of the debt service on a borrower's debt obligation. The DOT will seek to recover from the borrower all funds paid to the guaranteed lender, pursuant to a reimbursement agreement executed simultaneously with the loan guarantee.

[44] 23 U.S.C. §603(b)(5)(B).
[45] 23 U.S.C. §603(c)(2) and 45 U.S.C. §822(j)(1).
[46] 23 U.S.C. §603(c)(1) and 45 U.S.C. §822(j)(1).
[47] 23 U.S.C. §603(c)(3) and 45 U.S.C. §822(j)(3).
[48] 23 U.S.C. §603(c)(4) and 45 U.S.C. §822(j)(4).
[49] 23 U.S.C. §603(b)(6) and 45 U.S.C. §822(l).
[50] 23 U.S.C. §603(b)(6)(B) and 45 U.S.C. §822(l)(2).

By statute, the guaranteed lender must be a non-Federal entity, and for TIFIA loan guarantees, the guaranteed lender must be a "non-Federal qualified institutional buyer" as defined in 17 C.F.R. §230.144A(a), including qualified retirement plans and governmental plans.[51] Prospective applicants and lenders should contact the DOT with any questions about what constitutes a "non-Federal qualified institutional buyer."

The DOT may give preference to applications for loan guarantees rather than other forms of credit assistance.[52] This preference is consistent with Federal policy that, when Federal credit assistance is necessary to meet a Federal objective, loan guarantees should be favored over direct loans, unless attaining the Federal objective requires a subsidy deeper than can be provided by a loan guarantee. Applicants requesting only a direct loan and/or a line of credit (TIFIA only) are required to specify in their application how the plan of finance for the project would be impacted if credit assistance was instead provided in the form of a loan guarantee.

Characteristics of a guaranteed loan include:

- <u>Use of Proceeds</u>. The proceeds of a guaranteed loan must be used either to finance eligible project costs or to refinance debt that was issued to finance eligible project costs.

  TIFIA guaranteed loans can only be used to refinance: (i) interim construction financing of eligible project costs; (ii) existing Federal credit instruments for rural infrastructure projects; or (iii) long-term project obligations or Federal credit instruments if the refinancing provides additional funding capacity for the completion, enhancement, or expansion of an eligible project.[53] In the case of a TIFIA guaranteed loan used to refinance interim construction financing, the guaranteed loan may not refinance the existing debt (x) if that debt's maturity is later than 1 year after the substantial completion of the project, or (y) later than one year following substantial completion of the project.[54]

  RRIF guaranteed loans can only be used to refinance outstanding debt incurred for certain types of eligible projects, including debt incurred to acquire, improve, or rehabilitate intermodal or rail equipment or facilities, including track, components of track, bridges, yards, buildings, and shops, and costs related thereto, or to develop or establish new intermodal or railroad facilities.[55] RRIF guaranteed loans cannot be used to refinance outstanding debt incurred for other eligible projects.

- <u>Amount</u>. The amount of a RRIF loan guarantee may not exceed available statutory authority.[56] In addition, a RRIF loan guarantee may not guarantee more than 80% of the

[51] 23 U.S.C. §601(a)(5) and 45 U.S.C. §821(7).
[52] Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-129, Policies for Federal Credit Programs and Non-Tax Receivables (2013) at Section II.B (pp. 4-5) and 49 C.F.R. §80.15(c).
[53] 23 U.S.C. §603(a)(1) and (e)(2).
[54] 23 U.S.C. §603(a)(2) and (e)(2).
[55] 45 U.S.C. §822(b)(1).
[56] 45 U.S.C. §822(d). In addition, credit assistance for RRIF TOD Projects is limited to 75 percent of total project costs.

guaranteed loan.[57] The amount of a TIFIA loan guarantee, in combination with any other TIFIA credit assistance, may not exceed 49 percent of the reasonably anticipated eligible project costs.[58] To date, TIFIA credit assistance has only covered up to 33 percent of reasonably anticipated eligible project costs and applicants requesting assistance in excess of this amount must provide a rationale for such additional assistance.

- Interest Rate. The interest rate on a guaranteed loan negotiated by the borrower and the guaranteed lender must be satisfactory to the DOT.[59] Interest payments on a guaranteed loan are subject to Federal income taxation.[60]

- Maturity. The final maturity date of the guaranteed loan must be no later than 35 years after the date of substantial completion of the project or the useful life of the project, whichever is less.[61]

- Repayment Terms. Scheduled repayments to the guaranteed lender must commence no later than five years after the date of substantial completion of the project.[62]

- Prepayment Conditions. The prepayment features on a guaranteed loan negotiated between the guaranteed lender and the borrower must be satisfactory to the DOT.[63]

- Default Feature. In the event of an uncured borrower payment default, the guaranteed lender will receive payment from the DOT for the guaranteed payment due.[64] The DOT will seek recovery from the borrower of all funds advanced, pursuant to a reimbursement agreement executed simultaneously with the loan guarantee.

- Lien Priority. The DOT's lien on pledged revenues can be subordinated to those of senior lenders to the project except in the event of bankruptcy, insolvency, or liquidation of the obligor. In such an instance, the DOT's lien would be on par with the lien of the project's senior creditors.[65] This provision will be implemented by way of incorporation into the TIFIA or RRIF loan guarantee agreement, as applicable, and any other appropriate financing agreements entered into at the time of execution of such loan guarantee agreement. As noted above, this provision can be waived under certain circumstances for public agency borrowers having senior bonds under preexisting indentures so long as certain conditions are met.[66]

[57] 49 C.F.R. §260.51(a).
[58] 23 U.S.C. §603(b)(2) and (e)(2).
[59] 23 U.S.C. §603(e)(2) and 45 U.S.C. §822(e)(2).
[60] 26 U.S.C. §149(b).
[61] 23 U.S.C. §603(b)(5) and (e)(2); 45 U.S.C. §822(g)(1).
[62] 23 U.S.C. §603(c)(2) and (e)(2); 45 U.S.C. §822(j)(1).
[63] *See* 23 U.S.C. §603(e)(2). The RRIF Program will apply a similar requirement for prepayment arrangements to be satisfactory to the DOT.
[64] 23 U.S.C. §601(a)(9) and 45 U.S.C. §823(g).
[65] 23 U.S.C. §603(b)(6) and (e)(2); 45 U.S.C. §822(l).
[66] 23 U.S.C. §603(b)(6)(B) and 45 U.S.C. §822(l)(2).

TIFIA Lines of Credit (23 U.S.C. §604)

In addition to direct loans and loan guarantees, the TIFIA Program also offers lines of credit. A line of credit provides a contingent loan that may be drawn upon after substantial completion of a project to supplement project revenues during the first 10 years of a project's operations.[67] The DOT will disburse funds only under certain conditions, which will be specified in the TIFIA credit agreement.[68]

Characteristics of a line of credit include:

- Use of Proceeds. The proceeds from a draw on a TIFIA line of credit may be used only to pay debt service on project obligations (other than a TIFIA credit instrument) issued to finance eligible project costs, extraordinary repair and replacement costs, operation and maintenance expenses, and/or costs associated with Federal or state environmental restrictions arising after the transaction closed.[69]

- Amount. The total principal amount of a TIFIA line of credit may not exceed 33 percent of the reasonably anticipated eligible project costs.[70] The total combined TIFIA credit assistance for a project receiving a TIFIA line of credit plus a TIFIA direct loan or TIFIA loan guarantee may not exceed 49 percent of eligible project costs.[71]

- Condition Precedent for Draws. A draw may be made only if revenues from the project are insufficient to pay the costs enumerated above in "Use of Proceeds." Reserve funds need not be tapped prior to a draw.[72]

- Availability. A TIFIA line of credit may be available for a period of 10 years following substantial completion of the project.[73]

- Interest Rate. The interest rate on a TIFIA direct loan resulting from a draw on a TIFIA line of credit will be equal to or greater than the yield on a 30-year U.S. Treasury security on the date of the execution of the TIFIA line of credit agreement.[74] The DOT identifies the Treasury rates through use of the daily rate tables published by the Bureau of the Public Debt for the State and Local Government Series investments. Adding one basis point to the SLGS rates produces the estimated average yields on comparable Treasury securities. The SLGS tables can be found on-line at The SLGS tables can be found on-line at https://www.treasurydirect.gov/GA-SL/SLGS/selectSLGSDate.htm. The daily 30-year Treasury rate can be found on the Bureau's website at http://www.transportation.gov/buildamerica. Interest accrual on loan proceeds begins immediately upon disbursement of funds to the borrower.

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[67] 23 U.S.C. §604(a)(1) and (b)(6).
[68] 23 U.S.C. §604(a)(1) and (b)(1).
[69] 23 U.S.C. §604(a)(2).
[70] 23 U.S.C. §604(b)(2).
[71] 23 U.S.C. §604(b)(10).
[72] 23 U.S.C. §604(b)(3)(B).
[73] 23 U.S.C. §604(b)(6).
[74] 23 U.S.C. §604(b)(4).

- Maturity. The final maturity date of a TIFIA direct loan resulting from a draw on a TIFIA line of credit must be no later than 35 years after the date of substantial completion of the project or the useful life of the project, whichever is less.[75]

- Repayment Terms. Scheduled repayments of a draw on a TIFIA line of credit must commence no later than five years after the end of the 10-year period of availability and be fully repaid no later than 25 years after the end of the 10-year period of availability.[76] Level debt service is not required.[77] Debt service payments should be scheduled semi-annually.

- Ratings Requirement. The project's senior obligations must receive an investment grade rating from two Credit Rating Agencies before the DOT will enter into a TIFIA line of credit.[78]

- Lien Priority. The DOT's lien on pledged revenues can be subordinated to those of senior lenders to the project except in the event of bankruptcy, insolvency, or liquidation of the obligor. In such an instance, the DOT's lien would be on par with the lien of the project's senior creditors.[79] This provision will be implemented by way of incorporation into the TIFIA credit agreement and any other appropriate financing agreements entered into at the time of execution of the TIFIA credit agreement. As noted above, this provision can be waived under certain circumstances for public agency borrowers having senior bonds under preexisting indentures so long as certain conditions are met.[80]

Master Credit Agreements (23 U.S.C. §602(b)(2) and 45 U.S.C. §822(m))

A master credit agreement is a contingent commitment of TIFIA or RRIF credit assistance for a program of related projects.[81] While these contingent commitments are not an obligation and do not guarantee receipt of RRIF or TIFIA credit assistance, as applicable, they represent an agreement between the DOT and a project sponsor to provide credit assistance subject to the satisfaction of all of the terms and conditions for credit assistance set forth under the RRIF or TIFIA statutes, as applicable, including satisfaction of Federal eligibility requirements (such as the National Environmental Policy Act of 1969) and the availability of budgetary authority for such credit assistance. The DOT will not enter into a credit instrument under and pursuant to a master credit agreement (and as such will not obligate funds) until the DOT has confirmed satisfaction of all such terms and conditions and the availability of sufficient budgetary authority to fund such credit instrument.

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[75] 23 U.S.C. §604(c)(2)(B).
[76] 23 U.S.C. §604(c)(2).
[77] 23 U.S.C. §604(c)(1).
[78] 23 U.S.C. §604(a)(4).
[79] 23 U.S.C. §604(b)(8)(A).
[80] 23 U.S.C. §604(b)(8)(B).
[81] In addition, a TIFIA master credit agreement can be utilized for a single project where current-year funds have been fully obligated to other projects and the project sponsor elects to wait until the fiscal year when additional funds are available for TIFIA credit assistance. (23 U.S.C. §602(b)(2)(B))

To be eligible for a master credit agreement, each project covered by the master credit agreement must be an eligible project under the statutory requirements of the relevant Credit Program. The master credit agreements will incorporate a list of eligible projects, the maximum amount of credit assistance available and the availability period for the contingent commitment. In addition, the master credit agreement will include the terms and conditions for providing the credit assistance as well as terms and conditions that will be common across all credit instruments issued under the master credit agreement.

Section 2-3
Direct Loan Repayment and Prepayment Structuring

The TIFIA and RRIF statutes give the DOT discretion to defer the commencement of debt service repayments for up to five years after substantial completion.[82] The DOT also has the flexibility to structure a debt service schedule so that repayment is aligned with projected cash flows.

1. Scheduled Debt Service. Projects are not entitled to debt service deferral. In exercising its discretion to defer the commencement of debt service repayments, the DOT will evaluate the economics and risks to the DOT of each project on a project-by-project basis to determine an appropriate repayment schedule. Factors in this assessment include:

   - *Availability of revenues for debt service*. Some projects are not true “project financings,” but rely on tax or other non-project revenues, which may be available for debt service even before the project is completed. In such cases, the DOT is likely to require commencement of debt service upon substantial completion, although the DOT may require commencement of debt service during construction for a project not financed with user revenues. Projects more likely to be favorably considered for interest deferral and backloading of principal are those where project revenues support the financing and borrowers anticipate a long ramp-up period.

   - *Amortization of senior debt*. When the financial plan includes other project debt senior to the TIFIA and/or RRIF credit instruments, the DOT expects that the capitalized interest period for the project’s senior debt is likely to end before the capitalized interest period for the TIFIA and/or RRIF loan(s). Thus, the DOT may agree to continue deferring an appropriate amount of its loan interest to ensure that revenue is adequate to pay full interest on the senior debt. However, the DOT will not increase its investment in a project by deferring interest when other creditors are withdrawing their investment. Therefore, the DOT’s policy is not to permit any amortization of a project’s senior debt while TIFIA/RRIF interest is being deferred.

   - *Returns on equity*. The DOT requires equity investors, who will be subordinate to the DOT, to defer commencement of their return. The DOT will not permit any distribution to equity until all currently accruing TIFIA/RRIF interest is paid. The

[82] 23 U.S.C. §603(c)(2) and (e)(2); 45 U.S.C. §822(j). Debt service payments on TIFIA direct loans issued under a TIFIA line of credit can be deferred for up to fifteen years after substantial completion. 23 U.S.C. §604(c)(2)(A).

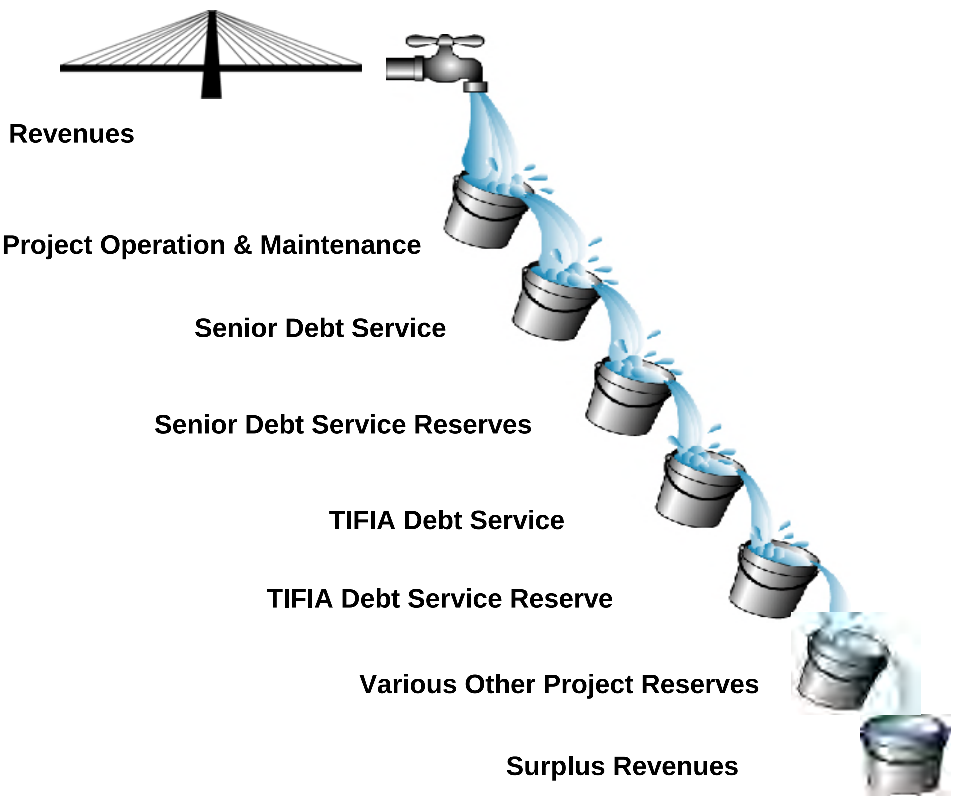
DOT will negotiate, on a project-by-project basis, the priority and relationship of TIFIA/RRIF repayment and equity distributions. As noted above in Section 2-1, the DOT will also prohibit RRIF borrowers from making any discretionary dividend payments that unreasonably conflict with the RRIF borrower's ability to maintain its capital program, equipment, facilities and operations.[83]

2. Prepayment and Refinancing. Although the Credit Programs provide long-term financing, the DOT does not intend that TIFIA or RRIF direct loans become part of a project's permanent capital structure where a strong revenue stream and vigorous project economics permit prepayment or substitution of the DOT credit instrument. The DOT will negotiate a debt service schedule that provides a high probability of repayment and avoidance of default. In return, the DOT typically requires that excess revenues – not needed for project or ongoing operational purposes – be applied to prepayment of the TIFIA/RRIF loan. The DOT also will seek to structure the financing in a way that encourages borrowers to replace the TIFIA/RRIF loan with capital markets debt at such time as project economics support refinancing.

3. Flow of Funds (Revenue/Project Financings). DOT credit instruments that are secured by revenues, such as toll or system revenues or sales tax revenues, will typically establish a flow of funds that sets forth a prescribed order of cashflows. This flow of funds will be documented in both the DOT credit instrument and ancillary documentation, such as a collateral agency agreement or an indenture. Exhibit 2-B on the following page shows a typical flow of funds for a public project financing secured by project-generated revenues, in this case a financing that includes both senior bonds and a subordinate TIFIA loan. In the example set forth below, senior debt service (as well as reserve accounts for the benefit of senior bondholders) accumulates revenues ahead of TIFIA debt service and reserve accounts for TIFIA debt service, if applicable. However, note that for public-private partnerships, the DOT will require that debt service on the DOT credit instrument must be paid before the funding of any senior debt service reserve accounts.

[83] 45 U.S.C. §822(h)(1)(C).

Exhibit 2-B: Example of TIFIA Public Sponsor, Project Revenue Flow of Funds



Section 2-4
Taxation Issues

Federal income tax law prohibits the use of direct or indirect Federal guarantees in combination with tax-exempt debt (section 149(b) of the Internal Revenue Code of 1986 (the Code). Neither the TIFIA nor RRIF statutes override or otherwise modify this provision of the Code. The DOT urges all applicants, and particularly those intending to use tax-exempt bonds in connection with direct loans or TIFIA lines of credit, to consult with the Internal Revenue Service, the U.S. Department of the Treasury, and/or bond and tax counsel.

Section 2-5
Credit Program Funding

The Credit Programs are subject to the Federal Credit Reform Act of 1990, which requires the DOT to establish a capital reserve[84] sufficient to cover the estimated long-term cost to the Federal Government of a Federal credit instrument, including any expected credit losses,

[84] As noted above, under the TIFIA Program, the capital reserve is referred to as the "credit subsidy" and under the RRIF Program it is referred to as the "credit risk premium."

before the DOT can provide TIFIA or RRIF credit assistance.[85]

TIFIA Program

Congress places limits on the annual subsidy amount available to fund the credit subsidy for TIFIA credit instruments.

The FAST Act authorized $275 million in FY 2016 funds, $275 million in FY 2017 funds, $285 million in FY 2018 funds, $300 million in FY 2019 funds, and $300 million in FY 2020 funds in TIFIA budget authority from the Highway Trust Fund to pay the subsidy cost of TIFIA credit assistance.[86] Additional funds may also be available from budget authority carried over from previous fiscal years. Any budget authority not obligated in the fiscal year for which it is authorized remains available for obligation in subsequent years.[87]

The TIFIA budget authority is subject to an annual obligation limitation that may be established in appropriations law. Like all funds subject to the annual Federal-aid obligation ceiling, the amount of TIFIA budget authority available in a given year may be less than the amount authorized for that fiscal year.

The amount of TIFIA budget authority available in a given year is subject to several factors, as described below.

- Federal-aid Highway Obligation Limitation. This obligation limitation pertains to most of the programs funded from the Federal Highway Trust Fund (including the TIFIA Program) and is determined through the appropriations process each year. As with appropriations processes for other Federal programs, this limitation typically reduces the total funds available for obligation in the year ahead.

- Program Administration Expenses. The TIFIA statute authorizes the DOT to use a specified amount of authorized budget authority for each fiscal year to administer the TIFIA Program.[88] In addition, the statute authorizes the DOT to collect and spend fees to cover expenses related to reviewing, negotiating, monitoring and servicing credit agreements.[89]

- Carry-over Resources. Any budget authority made available but not obligated in previous fiscal years may carry over and increase the amount of budget authority available in a given fiscal year.[90]

[85] 2 U.S.C. §661c(b).
[86] FAST Act, Pub. L. No. 114-94, §1101(a)(2), (129 Stat. 1322) (2015).
[87] 23 U.S.C. §608(a)(4).
[88] 23 U.S.C. §608(a)(5).
[89] 23 U.S.C. §605(b).
[90] 23 U.S.C. §608(a)(4).

RRIF Program

The RRIF Program is authorized to provide direct loans and loan guarantees up to $35 billion.[91] Not less than $7 billion is reserved for projects benefiting freight railroads other than Class I carriers. A direct loan can fund up to 100% of the eligible project costs[92], however, the DOT prefers applicants to provide equity to the project. For the current amount of available funding remaining, please refer to the Bureau Credit Programs website: https://www.transportation.gov/buildamerica.

However, since the RRIF Program does not currently have an appropriation, the cost to the government of providing financial assistance must be borne by the RRIF applicant, or another non-federal entity on behalf of the applicant, through the payment of the CRP. The main factors influencing the CRP calculation are the financial health of the applicant (credit rating for larger entities) and the value of the collateral being pledged (if any). Pursuant to the FAST Act, RRIF applicants may provide certain credit enhancements to the DOT, which the DOT will use as a basis for determining the CRP. These credit enhancements include: (1) state or local subsidy income or other dedicated revenues to secure the RRIF direct loan or loan guarantee, (2) adequate coverage requirements to ensure repayment, on a non-recourse basis, from cash flows generated by the project or any other dedicated revenue source, and (3) an investment-grade rating on the RRIF direct loan or loan guarantee.[93] The CRP attributable to each drawdown request must be paid on a pro rata basis prior to each disbursement.[94]

[91] 45 U.S.C. §822(d).
[92] However, note that for RRIF direct loans for transit oriented development projects, the DOT will require the borrower to provide a non-Federal match of not less than 25% of the eligible project costs. (45 U.S.C. §822(h)(4))
[93] 45 U.S.C. §822(f)(3). Note that if the total amount of the RRIF direct loan or loan guarantee is greater than $75 million, the applicant must provide an investment grade rating on the RRIF credit instrument from at least two Credit Rating Agencies for the DOT to incorporate such ratings into its calculation of the CRP (45 U.S.C. §822(f)(3)(C)).
[94] 45 U.S.C. §822(f)(4) and 49 C.F.R. §260.15(c).

Chapter 3: Eligibility Requirements

The TIFIA and RRIF statutes set forth several prerequisites for an award of credit assistance. This chapter describes the types of projects, costs, applicants, regulatory, and statutory requirements upon which TIFIA and RRIF credit assistance is conditioned.

Section 3-1
Eligible TIFIA Projects and Costs

Eligible Projects

Highway, transit, passenger rail, certain freight facilities, certain port projects, rural infrastructure projects, transit-oriented development projects, and SIB rural projects funds may receive credit assistance through the TIFIA Program.

- Eligible highway facilities include interstates, state highways, bridges, toll roads, international bridges or tunnels, and any other type of facility eligible for grant assistance under Title 23, the highways title of the U.S. Code (23 U.S.C.).[95] This also includes a category specifically permitted under the TIFIA statute, i.e., a project for an international bridge or tunnel for which an international entity authorized under Federal or State law is responsible.[96]

- Eligible transit projects include the design and construction of stations, track, and other transit-related infrastructure, purchase of transit vehicles, and any other type of project that is eligible for grant assistance under the transit title of the U.S. Code (Chapter 53 of Title 49 of the U.S. Code), including the installation of positive train control systems.[97] Additionally, intercity bus vehicles and facilities are eligible to receive TIFIA credit assistance.[98]

- Rail projects involving the design and construction of intercity passenger rail facilities or the procurement of intercity passenger rail vehicles are eligible for TIFIA credit assistance.[99]

- Public freight rail facilities, private facilities providing public benefit for highway users by way of direct freight interchange between highway and rail carriers, intermodal freight transfer facilities, projects that provide access to such facilities, and service improvements (including capital investments for intelligent transportation systems) at such facilities, are also eligible for TIFIA credit assistance.[100] In addition, a logical series

[95] 23 U.S.C. §601(a)(12)(A).
[96] 23 U.S.C. §601(a)(12)(B).
[97] 23 U.S.C. §601(a)(12)(A); *see also* 49 U.S.C. §5302(3) for a list of capital projects, including the installation of positive train control, that are eligible for Federal funding under Chapter 53.
[98] 23 U.S.C. §601(a)(12)(C).
[99] 23 U.S.C. §601(a)(12)(C).
[100] 23 U.S.C. §601(a)(12)(D)(i).

of such projects with the common objective of improving the flow of goods can be combined.[101]

- Projects located within the boundary of a port terminal are also eligible to receive TIFIA credit assistance, so long as the project is limited to only such surface transportation infrastructure modifications as are necessary to facilitate direct intermodal interchange, transfer, and access into and out of the port.[102]

- Eligible projects also include related transportation improvement projects grouped together in order to reach the minimum cost threshold for eligibility, so long as the individual components are eligible and the related projects are secured by a common pledge.[103]

- Rural Project Assistance: The TIFIA statute provides two different forms of assistance to rural infrastructure projects. The FAST Act expanded TIFIA eligibility to include capitalization of rural projects funds within SIBs, and it continued the DOT's ability to offer reduced interest rates to Rural Projects[104]:

    - The definition of rural infrastructure projects was narrowed under the FAST Act. As amended, the definition of a rural infrastructure project is a surface transportation infrastructure project located outside of an urbanized area with a population greater than 150,000 individuals, as determined by the Bureau of the Census.[105]

    - In addition, the FAST Act expanded TIFIA eligibility to enable the use of TIFIA credit assistance to capitalize a rural projects fund established by a SIB for the purpose of making loans to sponsors of rural infrastructure projects.[106] Prior to the FAST Act, SIBs were permitted to use Federal-aid funds to capitalize a highway, a transit, and a rail account within the SIB. The funds in those accounts could then be used to make loans to eligible highway, transit, and rail projects, respectively. The FAST Act permits SIBs to establish a fourth account (a rural projects fund) that can be capitalized by a TIFIA direct loan. [107] The SIB must use the funds in its rural projects fund to make loans for projects meeting the rural infrastructure project definition set forth above.[108] The maximum principal amount of a TIFIA direct loan to capitalize a rural projects fund within a SIB is $100 million and the minimum principal amount is $10 million.[109] A TIFIA loan

[101] 23 U.S.C. §601(a)(12)(D)(i)(V).
[102] 23 U.S.C. §601(a)(12)(D)(iii).
[103] 23 U.S.C. §601(a)(12)(D)(iv).
[104] As defined in Section 2-2 herein to refer to both rural infrastructure projects and projects to capitalize rural projects funds within SIBs.
[105] 23 U.S.C. §601(a)(15).
[106] 23 U.S.C. §601(a)(12)(F) and (a)(16).
[107] 23 U.S.C. §610(d)(4).
[108] 23 U.S.C. §610(e)(1)(B).
[109] 23 U.S.C. §603(b)(2)(B). Note that a TIFIA direct loan can capitalize 100% of a SIB's rural projects fund; the size limitations that apply to other TIFIA direct loans (49% of eligible project costs and 80% total Federal assistance) are applied to SIB capitalization loans through 23 U.S.C. §610(e)(3)(B).

capitalizing a rural projects find within a SIB must mature not later than 35 years after the date on which the secured loan is obligated.[110] Loans made by SIBs from a rural projects fund must comply with certain specific requirements, as set forth in section 610 of Title 23 U.S. Code[111], including: (i) the SIB loan cannot exceed 80% of the cost of carrying out the project;[112] (ii) the SIB loan must bear interest at or below the interest rate on the TIFIA loan used to capitalize the rural projects fund;[113] (iii) repayment of the SIB loan must commence not later than 5 years after completion of the project;[114] and (iv) the term of the SIB loan cannot exceed 30 years after the date of the first payment on the loan.[115]

- o As much as 10 percent of the TIFIA Program's budget authority can be set aside to fund the subsidy cost of secured loans for Rural Projects at a reduced interest rate equal to one-half of the Treasury Rate (see Section 2-2 for additional information regarding the calculation of interest rates on TIFIA direct loans).[116] The reduced interest rate is only available in any fiscal year to the extent sufficient funds are available in the set-aside for that fiscal year.[117] Any amounts set aside in a fiscal year to fund the subsidy cost of TIFIA direct loans to Rural Projects at the reduced interest rate that have not been obligated by June 1 of such fiscal year must be made available to fund projects not receiving the reduced interest rate to the extent sufficient funds are not otherwise available.[118]

- The FAST Act expanded eligibility to include projects to improve or construct public infrastructure that are located within walking distance of, and accessible to, a fixed guideway transit facility, passenger rail station, intercity bus station, or intermodal facility, including a transportation, public utility, or capital project described in 49 U.S.C. §5302(3)(G)(v), and related infrastructure (collectively, Transit-Oriented Development Projects or TOD Projects).[119] 49 U.S.C. §5302(3)(G)(v) sets forth a list of specific elements that would generally be included in a TOD Project once the DOT has determined a TOD Project is eligible. Subject to project-specific review, eligible elements could include: property acquisition; demolition of existing structures; site preparation; utilities; building foundations; walkways; pedestrian and bicycle access to a public transportation facility; construction, renovation, and improvement of intercity bus and intercity rail stations and terminals; renovation and improvement of historic transportation facilities; open space; safety and security equipment and facilities; facilities that incorporate community services such as daycare or health care; a capital project for, and improving, equipment or a facility for an intermodal transfer facility or

[110] 23 U.S.C. §603(b)(5)(B).
[111] Note that certain of these requirements differ for loans made from the SIB's other accounts (i.e., the highway, transit, or rail account). For a list of the specific requirements applicable to all SIB loans, see 23 U.S.C. §610.
[112] 23 U.S.C. §610(e)(3)(B).
[113] 23 U.S.C. §610(g)(4).
[114] 23 U.S.C. §610(g)(5).
[115] 23 U.S.C. §610(g)(6).
[116] 23 U.S.C. §§603(b)(4)(B) and 608(a)(3)(A).
[117] 23 U.S.C. §603(b)(4)(B)(ii).
[118] 23 U.S.C. §608(a)(3)(B).
[119] 23 U.S.C. §601(a)(12)(E).

transportation mall; and construction of space for commercial uses.[120] The DOT may also fund "related infrastructure;" however, the DOT will prioritize the use of TIFIA funds for TOD projects that are significantly integrated into the related transportation facility.

In reviewing Letters of Interest for TOD Projects, the DOT may prioritize TOD Projects based on:

(i) the TOD Project's distance from the transportation facility. This analysis may also include consideration of the distance pedestrians in the area of the TOD Project typically walk to access transportation facilities; and

(ii) the nexus between the proposed TOD Project and the transportation facility. In conducting this analysis, the DOT will consider the functional or physical relationship of the proposed TOD Project to the transportation facility. If the TOD Project is not physically connected to the transportation facility, the DOT may consider the extent of the functional relationship between the two, such as the extent to which the TOD Project enhances the use of, connectivity with, or access to the transportation facility.

Eligible Costs

TIFIA credit assistance is available to cover only eligible project costs.[121] A calculation of total eligible project costs is important to determine whether the project meets the eligibility test for minimum project size (as discussed in more detail in Section 3-7 below)[122] and whether the credit request does not exceed applicable thresholds of reasonably anticipated eligible project costs (as discussed in more detail in Sections 2-2 and 3-7),[123] as required by statute.

The TIFIA statute, codified at 23 U.S.C. §§601-610, defines eligible project costs as those expenses associated with the following:

- Development phase activities, including planning, feasibility analysis, revenue forecasting, environmental review, permitting, preliminary engineering and design work, and other pre-construction activities;[124]

- Construction, reconstruction, rehabilitation, replacement, and acquisition of real property (including land related to the project and improvements to land), environmental mitigation, construction contingencies, and acquisition of equipment;[125]

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[120] This list specifically applies to capital projects eligible under 49 U.S.C. §5302(3)(G) and is meant for demonstrative purposes only with respect to other TOD projects. An analysis of eligibility will be required in all cases and will be based on the specific facts and circumstances of the project, including environmental approvals.
[121] 23 U.S.C. §§603(a)(1)(A), 603(e)(1) and 604(a)(2).
[122] 23 U.S.C. §602(a)(5).
[123] 23 U.S.C. §§603(b)(2), 603(e)(2) and 604(b)(2).
[124] 23 U.S.C. §601(a)(2)(A).
[125] 23 U.S.C. §601(a)(2)(B).

- Capitalized interest necessary to meet market requirements, reasonably required reserve funds, capital issuance expenses, and other carrying costs during construction; and[126]

- Capitalizing a rural projects fund.[127]

Capitalized interest on TIFIA credit assistance may not be included as an eligible project cost.

Also, TIFIA administrative charges, such as application fees, transaction fees, loan servicing fees, credit monitoring fees, and the charges associated with obtaining the required preliminary rating opinion letter, will not be considered among the eligible project costs.[128] In all cases, eligible project costs should be calculated and presented on a cash basis (that is, as year-of-expenditure dollars) with the year of planned expenditure clearly identified.[129]

In determining eligible project costs, the following two clarifications should be considered:

- <u>Acquisition of Real Property</u>. While acquisition of real property is eligible for TIFIA reimbursement, such property must be physically and functionally related to the project. If excess land surrounding the project's immediate right-of-way is acquired for development, the cost of this real property may not be included among eligible project costs. The acquisition of real property must be in accordance with the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970 (see page 3-6).[130]

- <u>Costs Incurred Prior to Application</u>. It is permissible for an applicant to incur costs prior to submitting an application for TIFIA credit assistance. However, these costs may be considered eligible project costs for TIFIA purposes only upon approval from the DOT.[131] Generally, such costs will be confined to development phase or right-of-way acquisition expenses. This eligibility determination will be made on a case-by-case basis, depending on the nature and timing of the costs. Project sponsors that intend to request the inclusion of such costs as eligible project costs are encouraged to provide the DOT with supporting materials and information for such costs as early as possible to provide adequate time for DOT staff to review and make a determination as to eligibility.

Section 3-2
Eligible RRIF Projects and Costs

<u>Eligible Projects</u>

RRIF credit assistance may be available to:

[126] 23 U.S.C. §601(a)(2)(C).
[127] 23 U.S.C. §601(a)(2)(D).
[128] 49 C.F.R. §§80.5(b) and 80.17(b).
[129] 49 C.F.R. §80.5(a).
[130] 42 U.S.C. §4601 et seq.
[131] 49 C.F.R. §80.5(b).

- Acquire, improve, or rehabilitate intermodal or rail equipment or facilities, including track, components of track, bridges, yards, buildings, and shops, and costs related to these activities, including pre-construction costs. Note that this category of eligible activities includes the installation of positive train control systems;[132]
- Develop or establish new intermodal or railroad facilities;[133]
- Reimburse planning and design expenses relating to activities listed above;[134]
- Refinance outstanding debt incurred for the purposes listed above;[135] and
- Finance transit-oriented development, as described in more detail below.[136]

<u>RRIF Transit-Oriented Development</u>:
In addition to the activities described above, the FAST Act expanded eligible purposes to include financing economic development, including commercial and residential development, and related infrastructure and activities, that (i) incorporate private investment, (ii) is physically or functionally related to a passenger rail station or multimodal station that includes rail service, (iii) has a high probability of the applicant commencing the contracting process for construction not later than 90 days after the date on which the RRIF loan or loan guarantee is obligated, and (iv) has a high probability of reducing the need for financial assistance under any other Federal program for the relevant passenger rail station or service by increasing ridership, tenant lease payments, or other activities that generate revenue exceeding costs (Transit-Oriented Development Projects or TOD Projects).[137] Note that RRIF credit assistance for TOD Projects is only available until December 4, 2019.[138] Sponsors of TOD Projects are therefore encouraged to begin working with the Bureau as early as possible to ensure adequate time to prepare a RRIF Draft Application, Application, and enable the Bureau to evaluate the TOD Project's satisfaction of the eligibility criteria discussed above and elsewhere in this Chapter 3, including creditworthiness and compliance with Federal requirements.

<u>Eligibility Criteria:</u>
In reviewing Pre-Applications for TOD Projects, the DOT will evaluate TOD Projects for satisfaction of the above criteria, as further described below, and may prioritize projects based on:

i. <u>Economic Development, Including Commercial and Residential Development, and Related Infrastructure and Activities</u>: The extent to which the TOD Project will anchor transformative, positive, and long-lasting

[132] 45 U.S.C. §822(b)(1)(A).
[133] 45 U.S.C. §822(b)(1)(C).
[134] 45 U.S.C. §822(b)(1)(D).
[135] 45 U.S.C. §822(b)(1)(B).
[136] 45 U.S.C. §822(b)(1)(E).
[137] 45 U.S.C. §822(b)(1)(E).
[138] 45 U.S.C. §822(b)(3).

changes that will result in increased investment in the economic competitiveness of the neighborhood and region; increased transportation choices to decrease household and/or business transportation costs and provide other benefits; improved transportation access to employment centers, educational opportunities, and essential services, particularly for disadvantaged communities, which include low income populations, minority populations, older adults, and persons with disabilities; provide affordable housing; and support walkable communities, and improved quality of life. This also includes a consideration of whether the TOD Project targets Federal funding toward existing communities; reduces our dependence on oil; improves air quality, and promotes public health; and expands location- and energy-efficient housing choice.

ii. Private Investment: The extent to which the TOD Project incorporates private investment into the overall economic development in and around the TOD Project and the related station.

- To the extent the sources of funding for the TOD Project do not include private equity, the DOT will consider how and to what extent private investment is incorporated into the overall plans for the economic development of which the TOD Project is a part to determine satisfaction of this criterion.

iii. Physical or Functional Relationship: The nexus between the proposed TOD Project and the station. In conducting its analysis of the nexus between the TOD Project and the station, the DOT will consider the functional or physical relationship of the proposed TOD Project to the station. If the TOD Project is not physically connected to the station, the DOT will consider the extent of the functional relationship between the two, such as the distance between the TOD Project and the station, and the extent to which the TOD Project enhances the use of, connectivity with, or access to the station.

- In considering the distance between the TOD Project and the station, the DOT may consider the distance pedestrians and cyclists in the area of the TOD Project typically traverse to access transportation facilities.

iv. Project Readiness: The project sponsor must demonstrate that the construction contracting process for the TOD project can commence no more than 90 days after the execution of a RRIF credit instrument.

v. Reduction in Other Federal Assistance: The project sponsor must demonstrate that the TOD Project is highly likely to reduce the related station’s or service’s need for financial assistance under any other Federal program.

- As part of this demonstration, the project sponsor should describe how and to what extent the completion of the TOD Project will benefit the rail station or service such that the station's or service's need for Federal financial assistance will be demonstrably reduced.

The RRIF Program is generally focused on financing new or improved railroad infrastructure. The DOT prioritizes projects that provide public benefits, including benefits to public safety, the environment, economic development, and rail or rail-related intermodal service.[139] All projects, including new construction, purchase of new or existing goods, and refinancing of existing debt, are subject to the DOT's Buy America policy for RRIF projects as described in Section 3-4. Financial assistance under the RRIF Program cannot be used for railroad operating expenses.

Section 3-3
Federal Requirements

Generally Applicable Requirements: RRIF and TIFIA

There are several common Federal statutes and regulations that apply to all projects receiving DOT credit assistance, whether TIFIA or RRIF. In addition, certain laws and regulations apply to specific types of projects, such as highway, transit, or rail projects. Applicants seeking DOT credit assistance must comply with all applicable modal and Federal laws and regulations. We encourage project sponsors to coordinate with the Bureau (BuildAmerica@dot.gov), which can facilitate discussions with the relevant modal staff, early in their planning process to ensure satisfaction of all Federal requirements. This Section discusses some of the key Federal requirements that apply to projects receiving DOT credit assistance.

National Environmental Policy Act of 1969 (NEPA)

To comply with NEPA[140], each proposed project receiving credit assistance must be evaluated to determine its impact on the environment. The DOT will not obligate funds for a project until it has received a final agency decision, including (if necessary) a Record of Decision (ROD).[141] The three scenarios for addressing NEPA requirements are outlined below.

- Categorical Exclusion. Some projects, such as minor widening, rehabilitation, safety upgrading, or bus replacements, do not individually or cumulatively affect the environment significantly. These projects are termed Categorical Exclusions, and thus are exempt from the requirement to prepare an Environmental Assessment or an Environmental Impact Statement (EIS).

- Environmental Assessment. An Environmental Assessment is usually prepared for a project that does not qualify as a Categorical Exclusion. The Environmental Assessment may reveal that the project's impacts are not significant, in which case a Finding of No Significant Impact (FONSI) is issued for the project.

[139] *See* Notice Regarding Consideration and Processing of Applications for Financial Assistance Under the Railroad Rehabilitation and Improvement Financing (RRIF) Program, 75 Fed. Reg. 60165 (September 29, 2010).
[140] 42 U.S.C. §4321 et seq.
[141] 23 U.S.C. §602(c)(2).

- Environmental Impact Statement and Record of Decision. Assuming that a project does not qualify for a Categorical Exclusion or FONSI, the project sponsor is required to prepare a draft EIS. For major investments, the draft EIS must include an analysis of various alternative solutions. A variety of agencies and the public at large have the opportunity to comment on the draft EIS. These comments are addressed during the preparation of the final EIS. This second iteration ensures that adequate consideration has been given to public comments and the anticipated effects of the project. Depending on the nature of the project, the FHWA, FRA, FTA, or MARAD issues a Record of Decision to signify Federal approval of the final EIS.

  We encourage project sponsors to coordinate with the Bureau early in their planning process to ensure full compliance with and satisfaction of all NEPA requirements. The Bureau can facilitate discussions with relevant modal agencies to answer any questions about the NEPA process.

  To ensure project readiness to receive credit assistance and appropriately deploy DOT resources, an applicant must have circulated a draft EIS at the time it submits an application, unless the project has received either a FONSI or a Categorical Exclusion.

Buy America Requirements

This Program Guide collectively refers to domestic steel, iron and manufactured products content requirements for projects receiving DOT credit assistance as "Buy America" requirements. Buy America provisions were established pursuant to Section 165 of the Surface Transportation Assistance Act, of 1982 to ensure that transportation infrastructure projects are built with American-made products.[142] Since 1982, the Buy America requirements that apply to highway, transit, rail, and other projects have been further developed pursuant to implementing legislation and regulation on a modal level:

- Highway Projects: For highway and other projects eligible for TIFIA credit assistance under Title 23, the relevant Buy America provisions can be found at 23 U.S.C. §313 and 23 C.F.R. Part 635. Additional information can be found at https://www.fhwa.dot.gov/construction/cqit/buyam.cfm.

- Transit Projects: For transit and other projects eligible for TIFIA credit assistance under Chapter 53 of Title 49, the relevant Buy America provisions can be found at 49 U.S.C. §5323(j) and 49 C.F.R. §661. Additional information can be found at https://www.transit.dot.gov/regulations-and-guidance/buy-america/buy-america.

- Rail Projects: For rail projects eligible for TIFIA and RRIF credit assistance pursuant to the TIFIA and RRIF statutes, the DOT expects recipients of TIFIA and RRIF credit assistance to comply with the domestic steel, iron, and other manufactured products content requirements that apply to FRA passenger rail grant programs. These requirements are described in 49 U.S.C. §24405(a). Additional information can be found at http://www.fra.dot.gov/Page/P0185.

[142] 49 U.S.C. §5323(j).

- All Other Projects: As with other project types, the DOT expects recipients of TIFIA and RRIF credit assistance to comply with the domestic steel, iron, and other manufactured products content requirements of the applicable modal agency by law or policy.

For additional information regarding the DOT's Buy America program, as well as specific information regarding project types not described above, please contact the Bureau at BuildAmerica@dot.gov.

Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970

Project construction may displace current residents or businesses. Under the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970,[143] every displaced resident must be offered a comparable replacement dwelling that is decent, safe, and sanitary. Additionally, relocation advisory services must be furnished and payments made to those residents who must relocate. Such payments cover moving expenses, the cost of replacement housing, and certain incidental expenses. Businesses, farms, and non-profits must also be reimbursed for moving and related expenses.

Title VI of the Civil Rights Act of 1964

Title VI of the Civil Rights Act of 1964 states that no person in the Unites States shall, on the grounds of race, color, or national origin, be excluded from participation in, be denied the benefits of, or be otherwise subjected to discrimination under any program or activity for which the recipient receives Federal assistance.[144] Companion legislation extends these protections such that no person shall be subjected to discrimination on the basis of sex, age, or disability. As applied to transportation programs, regulations to implement this statute appear at 49 C.F.R. Part 21.

Prevailing Wage and Employee Protection Requirements

Projects receiving RRIF credit assistance and transit projects receiving TIFIA credit assistance must comply with specific prevailing wage and employee protection requirements.

- Prevailing Wage Requirements:

    - The RRIF statute requires all recipients of RRIF credit assistance to comply with the prevailing wage requirements applicable to Amtrak pursuant to 49 U.S.C. §24312 in the same manner Amtrak is required to comply with such standards for construction work financed under an arrangement made with a rail carrier or regional transportation authority under 49 U.S.C. §24308(a).[145]

    - 23 U.S.C. §113 and 49 U.S.C. §5333(a) implement Davis-Bacon prevailing wage protections for highway and transit projects, respectively, receiving Federal financial assistance. Pursuant to the implementation of Davis-Bacon for highway and transit projects, the DOT must ensure that all labor contracts executed by

[143] 42 U.S.C. §4601 et seq.
[144] 42 U.S.C. §2000d et seq.
[145] 45 U.S.C. §822(h)(3)(A).

project sponsors adhere to prevailing wage rates as determined by the Secretary of Labor before credit assistance can be obligated.

- Employee Protection:

  - The RRIF statute requires all recipients of RRIF credit assistance to comply with the requirements to ensure adequate arrangements exist to protect the interests of railroad employees who may be adversely affected by projects for which RRIF financing is utilized.[146]

  - 49 U.S.C. §5333(b) requires the DOT to receive certification from the Department of Labor that protective arrangements are in place to protect the interests of mass transit employees, including that protective arrangements are in place to provide for the preservation of rights and benefits of mass transit employees and the protection of individual employees against a worsening of their positions in relation to their employment, before credit assistance can be obligated for a project. As such, prior to receipt of TIFIA credit assistance for a transit project, the DOT must have received this certification from the Department of Labor.

Program-Specific Requirements: TIFIA

In addition to the generally applicable requirements described above, TIFIA projects are subject to certain modal requirements depending on the project type (i.e., highway, transit, or rail projects). Some of the key modal requirements related to typical TIFIA projects are listed below.

Title 23 – Highway Projects

Title 23 of the U.S. Code and related implementing regulations in Title 23 of the Code of Federal Regulations set forth the rules that govern the design, construction, and operation of federally assisted highway infrastructure projects, including projects financed with TIFIA credit assistance. These rules cover a broad range of activities. The following bullet points provide an example of some of the relevant regulations:

- Design. Part 625 of 23 C.F.R. requires that all federally assisted roads, highways, and bridges adhere to minimum design standards and specifications. Generally speaking, the regulations refer all sponsors of projects eligible under Title 23 for Federal assistance, whether grant or credit assistance, to the relevant standards and specifications published by the American Association of State Highway and Transportation Officials.

- Procurement. Part 172 of 23 C.F.R. prescribes policies and procedures related to procurement of engineering and design related services. Part 636 of 23 C.F.R. describes FHWA policies and procedures relating to design-build projects financed under Title 23. Part 635 of 23 C.F.R. covers many topics related to purchasing materials and procuring construction services. For example, Section 635.107 requires the applicant to

[146] 45 U.S.C. §822(h)(3)(B).

affirmatively encourage disadvantaged business enterprise participation in the highway construction program. Section 635.410 (part of FHWA's Buy America implementing regulations) limits the amount of foreign-produced steel and iron that may be used on Federal-aid projects.

- Construction. Part 633 Subpart A relates to required contract provisions for Federal-aid construction contracts. Part 635 contains construction and maintenance procedures and includes a number of labor and employment rules that apply to employees working on a Federal-aid construction project. For example, the minimum wage rates that the Secretary of Labor determines to be prevailing for the same type of work on similar construction in the same locality must be part of the construction contract. Labor rules also state that no construction work may be performed by convict labor unless the convicts are on parole, supervised release, or probation.

Title 49 – Transit and Public Transportation Projects

As with Title 23, Title 49 of the U.S. Code and related regulations in Title 49 of the C.F.R. concern a wide range of activities. Just as all highway projects must comply with all Federal laws and related regulations detailed in Title 23, all transit projects must comply with Chapter 53 of Title 49 and related regulations. For example, drug and alcohol rules specific to FTA-funded projects appear at 49 C.F.R. §655. In other cases, the regulations appearing in 49 C.F.R. apply common types of rules specifically to transit-oriented concerns, such as the procurement of buses and rail cars. For example, FTA's Buy America implementing regulations appear at 49 C.F.R. §661 and provide that Federal funds may not be obligated unless steel, iron, and manufactured products used in FTA-funded projects are produced in the United States, unless a waiver has been granted by the FTA, or the product is subject to a general waiver. The FTA has published a best practices manual on transit procurement regulations. This manual can be found on-line at: https://www.transit.dot.gov/funding/procurement/best-practices-procurement-manual.

The regulations that implement Chapter 53 of Title 49 apply to all Federally-assisted transit projects, including those receiving credit assistance under the TIFIA Program.

Program-Specific Requirements: RRIF

In addition to the generally applicable requirements described above (including the specific prevailing wage and labor protection requirements set forth in the RRIF statute), the rail safety standards set forth in 49 C.F.R. §§209-244 detail minimum safety requirements for railroad track that is part of the general railroad system of transportation. The RRIF regulations also require specific maintenance standards where RRIF credit assistance was used for track, roadbed, equipment, or facilities.[147]

[147] 49 C.F.R. §260.39.

Section 3-4
Eligible Applicants

Both the TIFIA and RRIF statutes specify types of entities that are eligible to apply for credit assistance. This section describes the types of entities that are eligible to apply under both Credit Programs.

Eligible Applicants: TIFIA

Public or private entities seeking to finance, design, construct, own, or operate an eligible surface transportation project may apply for TIFIA credit assistance. Examples of such entities include state departments of transportation; local governments; transit agencies; special authorities; special districts; railroad companies; and private firms or consortia that may include companies specializing in engineering, construction, materials, and/or the operation of transportation facilities.[148]

All applicants must demonstrate relevant experience, strong qualifications, a sound project approach, and financial stability, as each of these items ultimately has a bearing on the project's creditworthiness.

Applicants also must meet various Federal standards for participation in a Federal credit program as well as modal-specific requirements, among other factors, to receive TIFIA credit assistance.[149] For example, applicants may not be delinquent or in default on any Federal debts.[150] Such requirements will be specified in the contractual documents between the DOT and each applicant.

In the context of a public-private partnership, where multiple bidders may be competing for a concession such that the obligor has not yet been identified, the procuring agency must submit the project's Letter of Interest on behalf of the eventual obligor.[151] The DOT will not consider Letters of Interest from entities that have not obtained rights to develop the project.[152] However, the DOT is able to work with the procuring agency to better facilitate the integration of the TIFIA application process into the public-private partnership procurement. In this context, the DOT may negotiate a preliminary indicative term sheet with the procuring agency that sets forth the general intent of the DOT, which the procuring agency may provide to potential bidders. An indicative term sheet will assist private bidders in understanding certain basic terms and conditions for TIFIA credit assistance and will help to reduce any delays in the application process and ultimate negotiation of a credit agreement. Prior to awarding credit assistance to the selected bidder, the private entity must demonstrate state support for the project through the project's inclusion in the state's planning documents (the long-range plan and the STIP), as noted in Section 3-5 below.

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[148] *See* 23 U.S.C. §602(a)(4).
[149] 23 U.S.C. §602(c).
[150] Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-129, Policies for Federal Credit Programs and Non-Tax Receivables (2013).
[151] 23 U.S.C. §602(a)(1)(A), (a)(8).
[152] 23 U.S.C. §602(a)(10).

Eligible Applicants: RRIF

To be eligible to receive RRIF credit assistance, a project sponsor must be an eligible applicant.[153] Entities that are eligible to receive RRIF credit assistance include:

- State and local governments;
- Interstate compacts consented to by Congress under Section 410(a) of the Amtrak Reform and Accountability Act of 1997;[154]
- Government sponsored authorities and corporations;
- Railroads;[155]
- Limited option freight shippers that own or operate a plant or other facility (solely for the purpose of constructing a rail connection between a plant or facility and a railroad); and
- Joint ventures that include at least one of the above entities.

The FAST Act expanded the last category of eligible applicants listed above, that of joint ventures. Previously, an eligible joint venture needed to include at least one railroad. Under the expanded FAST Act language, a joint venture may include any of the other categories of eligible applicants (Eligible Applicants)[156]. A joint venture is an agreement between at least one Eligible Applicant and one or more other entities with the shared goal of accomplishing the project receiving the RRIF loan. The agreement between the parties can be memorialized in a contract, a memorandum of understanding, or other arrangement that describes the mutual consideration exchanged in order to accomplish the project. To the extent that the joint venture includes any entity that is not an Eligible Applicant, the parties to the joint venture must be able to demonstrate (i) that all parties have made (or will make) a meaningful contribution to (or for) the project and (ii) the benefit to all parties of the project.

- An example of an eligible joint venture in the context of a RRIF TOD project is as follows:
  - Joint venture parties:
    - A private entity undertaking a TOD Project to be constructed adjacent to a multimodal station that included rail service, and
    - The railroad providing rail services to that station.

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[153] 45 U.S.C. §822(a).
[154] 49 U.S.C. §24101 note.
[155] Note that the FAST Act added a definition for the term “railroad” as used in the RRIF statute. Pursuant to such amendment by the FAST Act, the term “railroad” as used in the RRIF statute has the meaning given the term “railroad carrier” in 40 U.S.C. §20102.
[156] The list of Eligible Applicants can be found at 45 U.S.C. §822(a), items (1) – (4) and (6).

- o Railroad contribution: Railroad owns the parcel of land needed to construct the TOD Project and sells that parcel to the private sponsor.

- o Railroad benefit: Railroad will receive a portion of the annual lease revenues derived from the TOD Project upon completion.

Section 3-5
Threshold Requirements

A project's eligibility to apply for TIFIA and RRIF credit assistance depends on its satisfaction of certain additional requirements beyond project and applicant eligibility. This section details these statutory threshold requirements to eligibility.

Total Eligible Costs

The two Credit Programs have different cost threshold requirements: the TIFIA Program has specific total eligible cost threshold requirements, whereas the RRIF Program does not have such requirements.

TIFIA Program

With certain exceptions noted below, the project's eligible costs, as defined under 23 U.S.C. §601(a)(2), must be reasonably anticipated to be at least (i) $50 million or (ii) 33 1/3 percent or more of the state's Federal-aid highway apportionments for the most recently completed fiscal year, whichever is less.[157] The DOT will revisit apportionments to states annually, to determine if any states qualify under the alternative test.

The FAST Act set a lower eligible cost threshold for intelligent transportation system projects, TOD Projects, Rural Projects, and local infrastructure projects.

- For projects that principally involve the installation of an intelligent transportation system (ITS), eligible project costs must be reasonably anticipated to total at least $15 million. This $15 million threshold applies only to projects for which the ITS component is the central feature of the project and not an ancillary component.[158]

- For TOD Projects[159] and local infrastructure projects, eligible project costs must be reasonably anticipated to total at least $10 million.[160] Local infrastructure projects are projects (i) for which the sponsor is a local government or instrumentality or public authority, (ii) that are located on a facility owned by a local government, and (iii) for which a local government is substantially involved in its development, in the determination of the Secretary.[161]

[157] 23 U.S.C. §602(a)(5)(A).
[158] 23 U.S.C. §602(a)(5)(B)(i).
[159] See Section 3-1 for the definition of TIFIA TOD Projects.
[160] 23 U.S.C. §602(a)(5)(B)(ii) and (iv).
[161] 23 U.S.C. §602(a)(5)(B)(iv).

- For Rural Projects[162], eligible project costs must be reasonably anticipated to total at least $10 million but not exceed $100 million.[163]

In addition, eligible costs include costs for related improvement projects grouped together to meet the eligible cost threshold, so long as the individual components are eligible and the related projects are secured by a common pledge.[164]

In all cases, the principal amount of the requested credit assistance is limited to 49 percent of reasonably anticipated eligible project costs for a TIFIA secured loan or loan guarantee and 33 percent for a TIFIA standby line of credit.[165] Applicants should calculate and represent all costs, including both eligible project costs and the credit assistance request, on a cash (year-of-expenditure) basis.[166]

RRIF Program

The RRIF Program does not have minimum project cost thresholds; however, as noted in Chapter 2 above, the principal amount of RRIF credit assistance may not exceed available statutory authority. In addition, credit assistance for RRIF TOD Projects is limited to 75 percent of total project costs.[167]

[162] As defined in Section 2-2, Rural Projects include rural infrastructure projects and projects to capitalize rural projects funds within SIBs.
[163] 23 U.S.C. §602(a)(5)(B)(iii).
[164] 23 U.S.C. §601(a)(12)(D)(iv).
[165] 23 U.S.C. §§603(b)(2) and 604(b)(2). As noted in Section 2-2 above, TIFIA secured loans provided to date have only covered up to 33 percent of reasonably anticipated eligible project costs. Applicants requesting assistance in excess of this amount must provide a rationale for such additional assistance.
[166] 49 C.F.R. §80.5(a).
[167] 45 U.S.C. §822(h)(4).

Creditworthiness and Dedicated Revenue Source

All RRIF and TIFIA projects must satisfy the DOT's creditworthiness requirements. The DOT will review the project's plan of finance, financial model, and feasibility of the anticipated pledged revenue or, in the case of RRIF loans where the proposed collateral is other than a dedicated revenue stream, the sufficiency of such other pledged collateral. In order for a project to satisfy the creditworthiness evaluation, the DOT must determine with a reasonable degree of confidence that the credit assistance is able to be repaid. However, as far as pledged collateral and a dedicated revenue source, the TIFIA and RRIF statutes differ. The TIFIA statute requires a dedicated pledged revenue source for repayment of TIFIA credit assistance. The RRIF statute does not require collateral, however, the calculation of the CRP is affected by any collateral, such as a dedicated revenue source, pledged in repayment of the RRIF credit assistance. The DOT interprets "dedicated revenue sources" to include such levies as tolls, user fees, special assessments, tax increment financing, and any portion of a tax or fee that produces revenues that are pledged for the purpose of retiring debt on the project. The Secretary may accept general obligation pledges or corporate promissory pledges and will determine the acceptability of other pledges or forms of collateral as dedicated revenue sources on a case-by-case basis. Without exception, the Secretary will not accept a pledge of Federal funds, regardless of source, as security for a credit instrument.

TIFIA Program

The TIFIA statute requires that TIFIA credit instruments are repayable, in whole or in part, from tolls, user fees, payments owing to the borrower under a public-private partnership, or other dedicated revenue sources that also secure the senior project obligations.[168] For a TIFIA direct loan to capitalize a rural projects fund within a SIB, the DOT may consider dedicated revenue sources available to the SIB, including repayments from the SIB's loans for rural infrastructure projects.[169] In addition, the TIFIA statute requires all projects to satisfy applicable creditworthiness standards.[170] See Section 5-1 for additional discussion of the creditworthiness evaluation process.

RRIF Program

While the RRIF Program cannot require a borrower to provide collateral, any collateral pledged to the repayment of the RRIF credit instrument will be relevant to the calculation of the CRP.[171] In addition, as part of the DOT's creditworthiness assessment of a project and an applicant prior to awarding credit assistance, the DOT must have made a determination that the credit assistance can reasonably be repaid, which determination can be based on the value of any collateral pledged.[172]

Project Readiness

Because credit assistance cannot be awarded until a project has received a final NEPA determination (as described above in Section 3-3), all applicants for credit assistance must

[168] 23 U.S.C. §§602(a)(6), 603(b)(3)(A)(i), and 604(b)(5)(A)(i).
[169] 23 U.S.C. §603(b)(3)(A)(i)(V).
[170] 23 U.S.C. §602(a)(2).
[171] 45 U.S.C. §822(h)(2) and (f)(2)(A) and (f)(3).
[172] 45 U.S.C. §822(g)(4).

demonstrate in the Letter of Interest/Draft Application that the project for which credit assistance is being sought is reasonably likely to have completed the NEPA process prior to the anticipated financial closing date. In addition, all applicants for TIFIA credit assistance (other than in connection with projects to capitalize a rural projects fund within a SIB) must demonstrated that the construction contracting process for the project can commence no more than 90 days after the execution of a TIFIA credit instrument.[173]

Advancement of DOT Policy Goals

In addition to the evaluation criteria set forth above with respect to both RRIF and TIFIA projects, both statutes sets forth certain additional evaluation criteria with respect to DOT policy goals.

TIFIA Program

For all TIFIA projects, including the capitalization of a rural projects fund in a SIB (with the exception noted below), the DOT must make a determination that Federal credit assistance would satisfy the following statutory mandates:

- *Foster Partnerships that Attract Public and Private Investment to the Project*: The extent to which assistance would foster innovative public-private partnerships and attract debt and/or equity investment from private capital.[174]

- *Ability to Proceed at an Earlier Date or Reduced Lifecycle Costs (Including Debt Service Costs)*: The likelihood that assistance would enable the project to proceed at an earlier date than the project would otherwise be possible.[175] This includes documenting how the applicant has been unable to obtain credit assistance from private sources on reasonable terms. In addition, the applicant may describe how the costs of traditional financing would constrain their ability to deliver the project, or that delivery of this project through traditional financing approaches would constrain their ability to deliver additional components of their capital programs.

- *Reduces Contribution of Federal Grant Assistance for the Project*: The extent to which assistance would reduce the contribution of Federal grant assistance to the project.[176]

RRIF Program

The RRIF statute specifies certain policy criteria for consideration in evaluating potential RRIF projects.[177] The DOT will give priority to projects that:

- *Enhance public safety, including projects for the installation of a positive train control system (as defined in section 20157(i) of title 49)*: This is DOT's highest programmatic priority. The DOT will prioritize projects that ensure safe and efficient transportation choices. The DOT's goal is to improve public health and safety by reducing

[173] 23 U.S.C. §602(a)(10).
[174] 23 U.S.C. §602(a)(9)(A).
[175] 23 U.S.C. §602(a)(9)(B).
[176] 23 U.S.C. §602(a)(9)(C).
[177] 45 U.S.C. §822(c).

transportation-related fatalities and injuries and improving the safety experience for all transportation system users, including passengers, employees, pedestrians, and motorists.

- *Enhance the environment*: The DOT will prioritize projects that promote environmental sustainability of transportation through investments that focus on energy efficiency and environmental quality, including investments that reduce carbon emissions and protect the human and natural environment.

- *Promote economic development* and *Enable United States companies to be more competitive in international markets*: The DOT will prioritize projects that build a foundation for economic competitiveness and target its investments in projects that serve the travelling public and freight movement to bring lasting economic and social benefit to the Nation. Note that this criteria is directly related to the Buy America discussion set forth in Section 3-3 above.

- *Are endorsed by the plans prepared under section 135 of title 23 or chapter 227 of title 49 by the State or States in which the projects are located*: Similar to the planning and programming requirements applicable to all TIFIA projects, as discussed below in Program-Specific Threshold Requirements: TIFIA sub-part of this Section, the DOT will give priority to projects requesting RRIF credit assistance that are incorporated in the applicable statewide planning documents. See the discussion below regarding the TIFIA planning and programming requirements for additional information on these documents.

- *Improve railroad stations and passenger facilities and increase transit-oriented development*: The DOT will prioritize projects that incorporate eligible transit-oriented development elements and that improve railroad stations and passenger facilities.

- *Preserve or enhance rail or intermodal service to small communities or rural areas* and *Enhance service and capacity in the national rail system*: The DOT will prioritize projects that support the development of interconnected, livable communities and that provide transportation choices and improve the quality of life for all Americans.

- *Materially alleviate rail capacity problems which degrade the provision of service to shippers and would fulfill a need in the national transportation system*: The DOT will prioritize projects promoting a state of good repair for transportation assets to ensure a reliable and safe rail system.

These criteria are described in more detail in the Federal Register *Notice Regarding Consideration and Processing of Applications for the Financial Assistance Under the RRIF Program*.[178]

Program-Specific Threshold Requirements: TIFIA

The TIFIA statute conditions a project's receipt of TIFIA credit assistance on the project's satisfaction of all applicable planning and programming requirements.[179] That generally

[178] Notice Regarding Consideration and Processing of Applications for Financial Assistance Under the Railroad Rehabilitation and Improvement Financing (RRIF) Program, 75 Fed. Reg. 60165 (September 29, 2010).
[179] 23 U.S.C. §602(a)(3).

means inclusion in both the state's long-range transportation plan and the approved State Transportation Improvement Program (STIP).[180]

State transportation plans extend as far as 20 years into the future and are often geared to setting general priorities rather than listing individual projects. Therefore, at the time of submitting an application, each applicant must certify that the proposed project is consistent with the transportation plan(s) of the affected state(s). For projects in metropolitan areas, the applicant must also demonstrate that the project is or can be included in the metropolitan transportation plan.[181]

In contrast to the long-range state transportation plan, the STIP focuses on specific projects to be funded in the near term; STIPs typically look ahead no more than three years. The TIFIA statute requires that the project satisfy planning and programming requirements of Section 134 (Metropolitan Planning) and Section 135 (Statewide Planning) of Title 23, at such time as a TIFIA credit agreement is executed.[182] Therefore, the applicant must demonstrate that the proposed project is part of the appropriate STIP(s) which reflects the requested TIFIA credit assistance amount programmed in the Federal fiscal year of expected financial close before the DOT will issue a term sheet and obligate funds.[183]

Program-Specific Threshold Requirements: RRIF

The RRIF statute sets forth certain additional prerequisites to receipt of RRIF credit assistance. Those are as follows:

- The RRIF credit assistance is justified by present and probable future demand for rail services or intermodal facilities;[184] and

- The applicant has given reasonable assurances that the facilities or equipment to be acquired, rehabilitated, improved, developed, or established with the proceeds of the RRIF credit assistance will be economically and efficiently utilized.[185]

Invitation to Submit Application

Each potential applicant seeking DOT credit assistance must demonstrate its ability to meet the statutory eligibility requirements, including an in-depth review of a project's creditworthiness, at the Letter of Interest/Draft Application stage. A project sponsor may only submit an application once a determination of eligibility, including a satisfactory review of a project's creditworthiness, is made and the project sponsor has received an invitation from the DOT to submit a formal application. A downloadable version of the TIFIA and RRIF application forms can be found on the Bureau website at https://www.transportation.gov/buildamerica.

[180] 49 C.F.R. §80.13(a)(1).
[181] 49 C.F.R. §§80.7(b)(1) and 80.13(a)(1).
[182] 23 U.S.C. §602(a)(3).
[183] 49 C.F.R. §§80.7(b)(1) and 80.13(a)(1).
[184] 45 U.S.C. §822(g)(2).
[185] 45 U.S.C. §822(g)(3).

Section 3-6
Rating Opinions

The RRIF and TIFIA Programs differ in their requirements with respect to credit ratings. The TIFIA statute requires project sponsors to submit both a preliminary indicative rating letter in connection with the submission of a Letter of Interest and two ratings letters prior to closing on a TIFIA credit instrument. RRIF applicants are not required to obtain a credit rating in order to apply for RRIF credit assistance, though a potential RRIF applicant may submit a recent investment-grade credit rating to be used by the DOT in its determination of the CRP for RRIF credit assistance.[186] This Section describes the credit rating requirements applicable to projects seeking TIFIA credit assistance.

Preliminary Rating Opinion Letter

Each potential applicant for TIFIA credit assistance must provide a preliminary rating opinion letter from at least one Credit Rating Agency[187] indicating that the project's senior obligations (which may include the TIFIA credit instrument) have the potential to achieve an investment grade rating and providing a preliminary rating opinion on the TIFIA credit instrument and provides rating rationales for both preliminary ratings.[188] Before the DOT completes its review of a Letter of Interest and renders a determination of eligibility, the DOT will request that a project sponsor provide this preliminary rating opinion letter.

The preliminary rating opinion letter must address the creditworthiness of both the senior debt obligations funding the project (i.e., those which have a lien senior to that of the TIFIA credit instrument on the pledged security) and the TIFIA credit instrument. The letter must conclude that there is a reasonable probability for the senior debt obligations (or the TIFIA credit instrument if there are no debt obligations senior to the TIFIA facility) to receive an investment grade rating.[189] This requirement applies to all potential TIFIA applicants, even those with current credit ratings on other debt instruments. The DOT will not complete its review of a TIFIA Letter of Interest and make a determination of eligibility until a project sponsor has provided a preliminary rating opinion letter. As part of the DOT's review, the DOT will also request that the TIFIA applicant provide copies of all documents submitted to the Credit Rating Agency in connection with the preliminary rating process. The DOT will use the preliminary rating opinion letter for two purposes.

1. Potential for Senior Obligations to Receive Investment Grade Rating. The letter must indicate that the senior obligations funding the project have the potential to receive an investment grade rating. This preliminary assessment by the Credit Rating Agencies will

[186] 45 U.S.C. §822(f)(3). Note that if the total amount of the RRIF direct loan or loan guarantee is greater than $75 million, the applicant must provide an investment grade rating on the RRIF credit instrument from at least two Credit Rating Agencies for the DOT to incorporate such ratings into its calculation of the CRP (45 U.S.C. §822(f)(3)(C)).
[187] According 23 U.S.C. §601(a)(14), "the term 'rating agency' means a credit rating agency identified by the Securities and Exchange Commission as a nationally recognized statistical rating organization (as that term is defined in section 3(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78c(a))." The complete list of nationally recognized statistical rating organizations can be found at http://www.sec.gov/answers/nrsro.htm.
[188] 23 U.S.C. §602(b)(3).
[189] 23 U.S.C. §602(b)(3).

be based on the financing structure proposed by the applicant. The DOT will not consider projects that do not demonstrate the potential for their senior obligations to receive an investment grade rating.

2. Default Risk. The DOT will also use the preliminary rating opinion letter to assess the project's overall economic, legal, and financial viability and the default risk on the requested TIFIA instrument and on any senior project obligations. Therefore, the letter should provide a preliminary rating and rating analysis of the financial strength of the overall project and the default risk (i.e., without regard to recovery potential) of the requested TIFIA credit instrument and the project's senior debt.

Pre-Closing Rating Opinion Letters

Prior to execution of a TIFIA credit instrument, the senior debt obligations for each project receiving TIFIA credit assistance must obtain investment grade ratings from at least two Credit Rating Agencies and the TIFIA credit instrument must obtain ratings from at least two Credit Rating Agencies unless the total amount of the debt is less than $75 million, in which case only one investment grade rating on the senior debt obligations and one rating on the TIFIA credit instrument are required.[190] The TIFIA debt cannot exceed the amount of the senior obligations unless the TIFIA credit assistance receives two investment grade ratings.[191] If the TIFIA credit instrument is proposed as the senior debt, then it must receive two investment grade ratings, unless the total amount of the debt is less than $75 million, in which case only one investment grade rating is required.[192] The applicant must provide confirmation of the assigned ratings at least two weeks prior to execution of a TIFIA credit instrument.[193]

The rating requirement offers security to the DOT only if the same repayment source is being pledged to both the senior debt obligations and the subordinate TIFIA credit instrument. In such a structure, the investment grade ratings for senior debt helps the DOT evaluate its credit risk as a subordinate lender. To maintain the value implied by the senior debt rating, the TIFIA debt cannot exceed the amount of the senior obligations unless the TIFIA credit instrument receives two investment grade ratings.[194]

Both the preliminary rating opinion letter and the final credit ratings must be based on the contemplated tenor of both the project's senior debt obligations and the TIFIA credit instrument.

The DOT's Use of Credit Ratings

Credit ratings on TIFIA-supported projects are used for three purposes:

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[190] 23 U.S.C. §602(a)(2)(A).
[191] 23 U.S.C. §603(b)(2).
[192] 23 U.S.C. §602(a)(2)(B).
[193] Note that the DOT can work to accommodate, on a case-by-case basis, situations where ratings are not able to be provided two weeks prior to closing for structural or procedural reasons.
[194] 23 U.S.C. §603(b)(2).

1. Statutory Rating Requirement. By statute, a project cannot receive TIFIA credit assistance unless the senior debt obligations funding the project, i.e., those obligations having a lien senior to that of the TIFIA credit instrument on the pledged security, receive investment grade ratings from at least two Credit Rating Agencies, as discussed above. Therefore, even though a project may be selected for TIFIA credit assistance, this credit assistance will not be provided (i.e., the DOT will not close on the credit agreement) until two Credit Rating Agencies assign an investment grade rating to the project's senior debt obligations, or the TIFIA facility itself if there are no debt obligations senior to the TIFIA credit instrument.

2. Capital Allocation Requirement. Default risk is a key component of the DOT's assessment of expected losses related to the TIFIA Program. The Federal Credit Reform Act of 1990 requires Federal agencies with credit programs to allocate capital, in the form of budget authority, to cover these expected losses.[195] The DOT uses the TIFIA Capital Allocation Model to estimate credit exposure. The model employs such variables as the repayment structure, the drawdown assumptions, the nature of the dedicated revenues securing the TIFIA credit instrument, and the ratings assigned to the TIFIA credit instrument.

3. Annual Capital Reserve Adjustments. As part of its ongoing portfolio monitoring, the DOT is required to annually adjust, or "reestimate," its allowance for credit losses based on updated loss expectations.[196] The DOT will incorporate information from credit surveillance reports, including changes in credit ratings, on TIFIA-supported projects in this annual reassessment process.

Ongoing Rating Requirements

Throughout the life of the TIFIA credit instrument, the borrower must obtain annually, at no cost to the Federal Government, current credit evaluations of the project, the project obligations, and the TIFIA credit instrument.[197] The current credit evaluations must be performed by a Credit Rating Agency.[198] By "current credit evaluation," the DOT means: (i) in the case of a project with a published rating, either a current rating or the borrower's certification stating that the rating and outlook are unchanged from the previous year, and (ii) in the case of a project without a published rating, a current rating of the project obligations and the TIFIA credit instrument.

Use of Underlying Ratings

Neither the preliminary rating opinion letter nor the credit ratings should reflect the use of bond insurance or other credit enhancement that does not also secure the TIFIA credit

[195] Note that because the RRIF Program does not currently have an appropriation, this capital allocation must be borne by the RRIF applicant, or another non-federal entity on behalf of the applicant, through the payment of the credit risk premium.
[196] Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-11, Preparation, Submission, and Execution of the Budget (2012).
[197] 49 C.F.R. §80.11(d).
[198] 49 C.F.R. §80.11(d).

instrument.[199] The assessment of the senior obligations' investment grade potential and the default risk for the TIFIA credit instrument and the senior obligations should be based on the underlying ratings of the unenhanced debt obligations and the project's fundamentals.

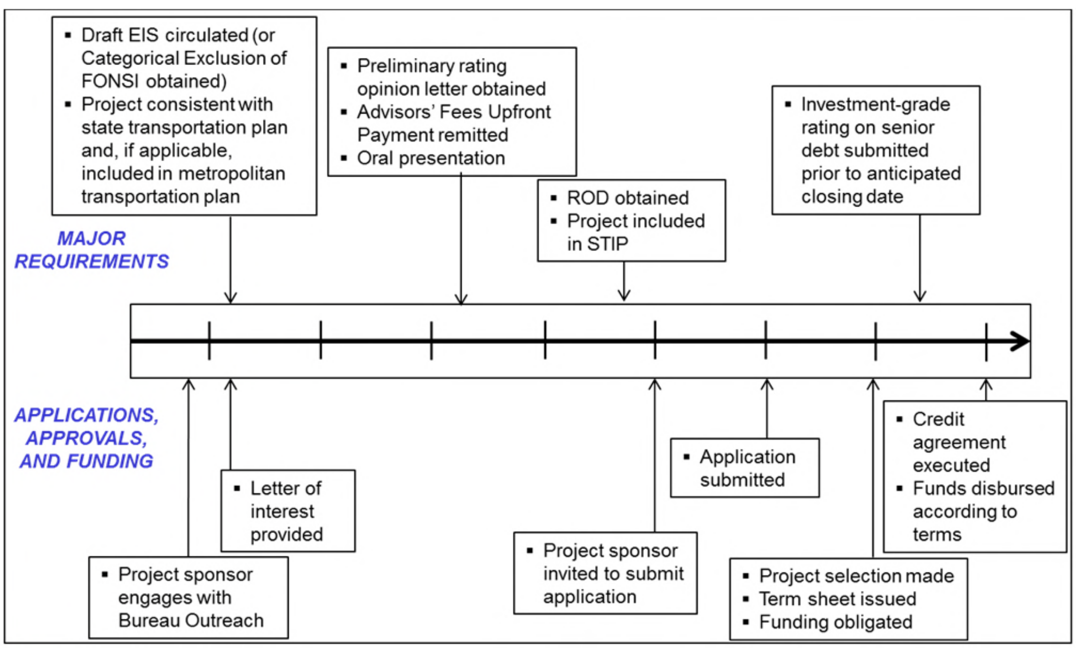
Applicant Questions about Rating Requirements

Applicants should contact the Bureau with any questions about the rating process and the requirements for a preliminary rating opinion letter, two investment grade credit ratings on the senior obligations' and two ratings on the TIFIA credit instrument. The Credit Rating Agencies will be able to answer questions concerning fees, timing of assessments, information requirements, and surveillance practices associated with obtaining preliminary rating opinion letters, credit ratings, periodic rating updates, and credit surveillance reports.

Section 3-7
Timing of Environmental, Planning, and Credit Documents

Requirements for environmental, planning, and credit documents correspond with the application and selection processes, which are described in Chapters 4 and 5, respectively. Exhibit 3-A provides an overview of how these requirements relate to the various stages of the application and selection processes.

Exhibit 3-A: Major Documentation Required During the Application and Selection Processes



[199] 49 C.F.R. §80.11(c).

Chapter 4: Application Process

This chapter describes the process to apply for DOT credit assistance. The DOT welcomes informal consultations with prospective applicants at any time. Prospective applicants can contact BuildAmerica@dot.gov for additional information or assistance.

Section 4-1

Initial Steps: Build America Bureau Project Development and Letter of Interest/Draft Application Submission

Regionally-focused Project Development Leads (PDLs) are members of the Bureau's Outreach and Project Development Team who serve as the initial point of contact for Bureau engagement. PDLs work with project sponsors to determine project needs and the specific ways in which the Bureau can provide TIFIA and RRIF credit assistance. Prospective applicants can contact BuildAmerica@dot.gov or call (202) 366-2300.

Based on the specific questions, challenges, opportunities, and information needs related to a particular project, appropriate Bureau expertise is assigned and brought to bear for projects. This may require the assignment of more specialized PDL assistance for projects that involve greater complexity in terms of such factors as scope, modal elements, regulatory requirements, private-sector involvement, and financing plan. This approach helps ensure that the project has followed statutory and regulatory requirements and that it appears to be eligible and ready for credit assistance. The intent of this process is to identify major hurdles that might delay a project early in the process. A customized project development team works closely with the project sponsor to navigate relevant Federal processes and to ensure that key program requirements are satisfied.

Emerging Projects Agreements

The Bureau offers sponsors of capital programs consisting of high-priority projects in the early stages of development with technical assistance in the development and planning of the projects in the form of an emerging projects agreement. Emerging projects agreements are not credit instruments. However, they are a tool the Bureau offers to provide heightened technical assistance to large capital programs of national significance. An emerging projects agreement will establish a framework for the provision of technical assistance by the Bureau to the project sponsor prior to the project sponsor's submission of a Letter of Interest/Draft Application. Sponsors of programs of projects that meet the criteria listed below will be considered for an emerging projects agreement. However, satisfaction of the criteria does not automatically guarantee that the DOT will enter into an emerging projects agreement, which is a determination made at the discretion of the DOT.[200]

[200] Note: A decision by the DOT to not enter into an emerging projects agreement with a project sponsor does not disqualify a project from ultimately receiving credit assistance from a Credit Program through the traditional application process, as described in more detail in this Program Guide.

- The program consists of at least two related projects, each of which are usable by the public even if the other projects are not completed;
- Each project must be an eligible project under the statutory requirements of the relevant Credit Program[201];
- The estimated total cost of the program of projects is no less than $5 billion (as evidenced by a preliminary budget included with the request for the emerging projects agreement);
- The projects within the program are located in multiple states or in multiple counties within a metropolitan area;
- The program of projects is critical to the continued mobility and economic health of the region in which it is located and is of national significance;
- Each project is being carried out by, or is receiving material financial support from, multiple state, local, or regional governmental authorities;
- Construction of the first project is expected to begin within 5 years; and
- The sponsors of the Project Program have demonstrated the need for heightened technical assistance from the Department.

Letters of Interest/Draft Applications

Although Letters of Interest for TIFIA credit assistance and Draft Applications for RRIF credit assistance are required as part of DOT's credit approval process, and may be submitted on a rolling basis (i.e. at any time)[202], the Bureau recommends that project sponsors consult the Bureau before formally submitting these documents to DOT to ensure that the relevant programmatic requirements are met and initial risk assessments are completed. (This ensures that all key project elements are in place for an efficient underwriting process.) Once these milestones are complete, DOT can expeditiously accept the Letter of Interest or Draft Application, as the case may be, and formally move the Project into the credit underwriting process. Project sponsors will be notified by the DOT if it is determined that their projects are not eligible or are lacking key programmatic requirements.

Projects seeking both RRIF and TIFIA credit assistance for the same project can use the TIFIA Letter of Interest form and add, to the extent necessary, any additional information requested in the RRIF Draft Application. All credit assistance will be awarded based on a project's merits and its satisfaction of the eligibility requirements discussed above and, for RRIF projects, prioritization will be given to projects that satisfy the criteria described in Section 3-5 above.

[201] See Chapter 3 for additional information regarding Credit Program eligibility criteria.
[202] However, as described in Section 4-1 below, the TIFIA Program may establish a date by which Letters of Interest for Rural Projects should be submitted. The date for these submissions will be provided on the Bureau website.

The Letter of Interest/Draft Application must: (i) describe the project and the location, purpose, and cost of the project, (ii) outline the proposed financial plan, including the requested credit assistance and the proposed obligor, (iii) provide a status of environmental review, (iv) provide information regarding satisfaction the eligibility requirements of the applicable Credit Program(s), and (v) for TIFIA Letters of Interest, indicate whether the project sponsor would like to use the TIFIA streamlined application process and, if so, how the project satisfies the criteria for that process.[203] The DOT templates for the required Letter of Interest and Draft Application for the specified Federal fiscal year can be found on the Bureau website, which can be found at: https://www.transportation.gov/buildamerica. The DOT will be updating the Letter of Interest/Draft Application forms to reflect changes made to the TIFIA and RRIF Programs by the FAST Act and to consolidate them into one consolidated Letter of Interest form that can be used for TIFIA, RRIF, or joint credit assistance. Pending publication of the updated forms, potential applicants should continue to use the forms posted on the Bureau's website. Potential applicants must submit detailed Letters of Interest/Draft Applications so the DOT can review creditworthiness and the other statutory eligibility requirements detailed in Chapter 3. The DOT requests that project sponsors submit the Letter of Interest/Draft Application by attaching it via email to BureauCredit@dot.gov.

Currently, the Bureau will review requests for the reduced interest rate available for Rural Projects[204] on a rolling basis. However, to the extent that the demand for the reduced interest rate exceed amounts available in the set-aside,[205] the DOT will establish a date by which sponsors of Rural Projects should submit their TIFIA Letters of Interest. In the event such a date is established, the Bureau will post the applicable date for each fiscal year on its website: https://www.transportation.gov/buildamerica.

Upon receipt of a satisfactory Letter of Interest/Draft Application and upon making a determination that the project is reasonably likely to satisfy all of the eligibility requirements of the applicable Credit Program, the DOT will conduct an in-depth creditworthiness review of the project sponsor and the proposed revenue stream identified to repay the DOT credit assistance, as well as any other collateral proposed to secure the DOT credit instrument. In connection with this review, the DOT will request that the project sponsor provide a feasibility study (as applicable) and a fully functional Microsoft Excel-based financial model. In addition, for projects requesting TIFIA credit assistance, the DOT will also request the preliminary rating opinion letter described in more detail in Section 3-6 above. At this time, the project sponsor will also be required to submit the Advisors' Fees Upfront Payment in the amount of $250,000 to the DOT in order to continue the review process.[206] As noted in

[203] For Letter of Interest and Application contents, see 23 U.S.C. §601(a)(6) and 49 C.F.R. §260.23-260.27, and for the streamlined application process, see 23 U.S.C. §603(f).

[204] As defined in Section 2-2 herein to refer to both rural infrastructure projects and projects to capitalize rural projects funds within SIBs.

[205] As noted above, 23 U.S.C. §608(a)(3)(A) limits TIFIA budget authority available for Rural Projects receiving the reduced interest rate to not more than 10 percent of the total TIFIA budget authority in any fiscal year. In addition, the TIFIA Program must make funds set aside for Rural Projects available to projects not receiving the reduced interest rate after June 1 of each fiscal year pursuant to 23 U.S.C. §608(a)(3)(B).

[206] Note that, for RRIF projects, the Advisors' Fees Upfront Payment may be higher depending on the nature and

Chapter 1 above, these funds will be used to cover the costs incurred by the DOT for services provided by the DOT's outside financial and legal advisors in connection with the review of the Letter of Interest/Draft Application and, in the event the project sponsor is invited to submit an application, the review of the project sponsor's application, and the negotiation of the transaction documents. After the Advisors' Fees Upfront Payment has been received, the DOT will engage an independent financial advisor to prepare a report and recommendation to the DOT. The DOT may also engage an independent legal advisor and other advisors to help complete its review of a project's eligibility. For projects seeking more than $1 billion in credit assistance, two financial advisors will be hired to produce independent financial evaluations and recommendations to the DOT. The DOT will not complete its creditworthiness review until the project sponsor has provided all requested information and materials, including, for TIFIA credit assistance, a preliminary rating opinion letter, and, for all forms of credit assistance, the Advisors' Fees Upfront Payment necessary to enable the DOT to engage its outside financial and, as and when necessary, legal advisors.

In the context of TIFIA credit assistance for a public-private partnership, where multiple bidders may be competing for a concession such that the obligor has not yet been identified, the procuring agency must submit the project's Letter of Interest on behalf of the eventual obligor. The DOT will not consider Letters of Interest from project sponsors that have not obtained the legal rights to develop the project. However, as noted in Section 3-4 above, the DOT can assist procuring agencies in integrating the TIFIA application process with the procurement process. In these circumstances, the DOT may negotiate a preliminary indicative term sheet with the procuring agency that sets forth the general intent of the DOT, which the procuring agency may provide to potential bidders.[207]

Components of the Letter of Interest/Draft Application

The Letter of Interest/Draft Application should describe the project and the proposed financial plan, identify the proposed borrower, detail how the applicable statutory eligibility requirements are met, and discuss the benefits of the proposed project and its use of credit assistance. The Letter of Interest/Draft Application should also summarize the project's status in the environmental review process. As noted above, the DOT will be updating the Letter of Interest/Draft Application forms to reflect changes made to the TIFIA and RRIF Programs by the FAST Act and to consolidate them into one unified Letter of Interest form that can be used for TIFIA, RRIF, or joint credit assistance. Pending publication of the updated forms, potential applicants should continue to use the forms posted on the Bureau's website.

- Project Description. The Letter of Interest/Draft Application should describe the project, including its location, purpose (including quantitative or qualitative details on public benefits the project will achieve), design features, estimated capital cost, development

complexity of the project. Project sponsors should consult with the Bureau to confirm the applicable amount of the Advisors' Fees Upfront Payment.

[207] 23 U.S.C. §602(a)(1)(A), (a)(8). While the RRIF statute does not contain parallel language to the forgoing sections of the TIFIA statute, the DOT will consider requests for a similar process for RRIF projects being procured as public-private partnerships on a case-by-case basis.

schedule, and other relevant descriptions of the project.[208] If the potential applicant is seeking credit assistance for a RRIF or TIFIA TOD project, the Letter of Interest/Draft Application should detail how the project satisfies the criteria for a RRIF and/or TIFIA TOD Project, as described in Sections 3-1 and 3-2, respectively.

- <u>Proposed Plan of Finance</u>. The project sponsor should detail the plan of finance in sufficient detail to assist the DOT in its creditworthiness assessment.[209] The Letter of Interest/Draft Application should include the proposed sources and uses of funds for the project. For requests for TIFIA credit assistance, the sources and uses of funds for the project should demonstrate that total Federal assistance does not exceed 80% of the TIFIA eligible project cost. In addition, the Letter of Interest/Draft Application should include, if applicable, a proposed flow of funds of the revenue source that will be used to satisfy repayment of credit assistance as well as any other project obligations, and state the type and amount of credit assistance to be sought from the DOT, including whether the project sponsor is requesting a master credit agreement. The discussion of proposed financing should also identify the source(s) of revenue or other security that would be pledged to repay the credit instrument. Additionally, the Letter of Interest/Draft Application should address the status of any revenue feasibility study. In both the Letter of Interest/Draft Application and in the subsequent application, the project sponsor should propose a single financing structure representing the most likely scenario. The DOT may ask applicants to develop alternative scenarios, as necessary. If the project sponsor has requested TIFIA credit assistance in excess of 33 percent of reasonably anticipated eligible project costs, the project sponsor should provide a rationale for the amount of TIFIA credit assistance requested and explain the flexibility in the financial plan to finance the project with a reduced percentage of TIFIA credit assistance. If the potential applicant is seeking a TIFIA direct loan at the reduced, rural interest rate, the TIFIA Letter of Interest should also either detail how the project meets the definition of a rural infrastructure project or indicate that the loan will be used to capitalize a rural projects fund.[210]

- <u>Environmental Review</u>. The Letter of Interest/Draft Application should summarize the status of the project's environmental review, and it should state specifically whether the project has received a Categorical Exclusion, Finding of No Significant Impact, or Record of Decision, or whether a draft Environmental Impact Statement has been circulated.

- <u>Satisfaction of Eligibility Requirements.</u> The Letter of Interest/Draft Application should provide information regarding satisfaction the eligibility requirements of the applicable Credit Program(s), including all generally applicable and program-specific requirements (see Chapter 3 for more information regarding Federal requirements and threshold criteria). The Letter of Interest/Draft Application must demonstrate how the project satisfies applicable creditworthiness standards and must include proposed indicative

[208] 23 U.S.C. §601(a)(6)(A) and 49 C.F.R. §260.23(e).
[209] 23 U.S.C. §601(a)(6)(B) and 49 C.F.R. §§260.23(f) and 260.25(b).
[210] *See* 23 U.S.C. §601(a)(15).

terms sought for the credit assistance (including proposed lien position, amortization schedule, and debt service coverage ratios) (see Sections 3-5 and 6-1 for additional discussion regarding creditworthiness requirements). In addition, the project sponsor should explain in the Letter of Interest/Draft Application how the project satisfies the DOT's policy goals, as set forth in Section 3-5. For project sponsors seeking TIFIA credit assistance, the Letter of Interest should demonstrate that the construction contracting process for the project will commence no more than 90 days after the execution of a TIFIA credit instrument.

- Proposed Participants. The Letter of Interest/Draft Application should describe the proposed borrower's organizational structure, identify the entity that will serve as the applicant, identify if the applicant and borrower will be the same entity, list significant members of the project team, describe the proposed borrower's relationship to subsidiaries or affiliates, if any, and provide a website link where additional information can be found. A public agency that seeks access to credit assistance on behalf of multiple competitors for a project concession must submit the project's Letter of Interest/Draft Application. Although the public agency would not become the borrower, nor even have yet identified the eventual applicant, it must provide information sufficient for the DOT to evaluate the project against the criteria and objectives described in Chapter 3. The DOT will not consider Letters of Interest/Draft Applications from entities that have not obtained rights to develop the project. For joint ventures seeking RRIF credit assistance, the RRIF Draft Application should detail how the joint venture satisfies the joint venture eligibility criteria, as described in Section 3-4.

- Planning. The Letter of Interest/Draft Application should confirm that the project is endorsed in the statewide and metropolitan planning documents or the state rail plans described in Section 3-5 above, or provide a schedule for the incorporation of the project into those planning and programming documents.[211]

- Schedule. The Letter of Interest/Draft Application should detail the timetable for requesting credit assistance, demonstrate that the application could be prepared within a short timeframe, and explain any potential factors that could impact the timetable. The Letter of Interest/Draft Application should include the project's anticipated procurement and construction contracting scheduling (including the anticipated dates for bidder selection and contract execution), the schedule for finalization of the feasibility study (where applicable), and the timeline for achieving financial close.

- Contact Information. The Letter of Interest/Draft Application should identify a key contact person with whom all communication should flow.

- Additional Information. The Letter of Interest/Draft Application should provide the additional information requested in the Letter of Interest/Draft Application form, including certification as to no delinquency or default on any Federal debt or debarment

[211] As required under the TIFIA statute (23 U.S.C. §602(a)(3)) and as a priority consideration under the RRIF statute (45 U.S.C. §822(c)(5)).

from participation in any Federal programs,[212] and any other relevant information that could affect the development and financing of the project, such as congressional districts impacted, type of jurisdiction (rural/urban), community support, pending legislation, or litigation. In addition, RRIF Draft Applications should include the additional information specified in 49 C.F.R. §§260.23-260.27 to the extent not already covered by the above.

When preparing the Letter of Interest/Draft Application, applicants must utilize the formats provided on the TIFIA website. In cases where there are differences between the guidance in this document and the guidance on the applicable website form, the website form will govern and project sponsors should conform their responses to the form.

Oral Presentation

Following the Bureau's acceptance of the Letter of Interest/Draft Application and receipt of a preliminary rating opinion letter and the Advisors' Fees Upfront Payment, the DOT will request that the potential applicant give an oral presentation to the DOT, followed by a question and answer session. In addition to Bureau staff and outside advisors, other officials, including members of the Bureau's Credit Review Team and the DOT Council on Credit and Finance, may attend the presentation. This presentation is intended to clarify the potential applicant's proposed development plans for the project, including the financing structure, and to resolve other issues relating to the Letter of Interest/Draft Application. The structure and content of the presentation will be discussed with each potential applicant at the time of the request. At the presentation, the DOT may require the potential applicant to provide additional information, including clarifications regarding cash flows, sources and uses, and/or other issues.

Section 4-2
Application

After concluding its in-depth review of the creditworthiness of a project and related information submitted by potential applicants, along with the independent financial analysis report from the DOT's independent financial advisor, and after the project sponsor's oral presentation, the DOT will invite sponsors of eligible projects to submit complete applications. Upon receiving an invitation from the DOT, the applicant may submit an application. The RRIF and TIFIA application forms for the current fiscal year required to request credit assistance is available on the Bureau website, which can be found at: https://www.transportation.gov/buildamerica. As with the Letter of Interest/Draft Application forms, the DOT will be updating the application form to reflect changes made to the TIFIA and RRIF Programs by the FAST Act and to develop one consolidated application form that can be used for TIFIA, RRIF, or joint credit assistance. Pending publication of the updated forms, applicants should continue to use the forms posted on the Bureau's website.

The DOT must inform each applicant whether its application is complete, or, if not complete,

[212] Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-129, Policies for Federal Credit Programs and Non-Tax Receivables (2013).

identify additional materials needed for completion, within 30 days of receiving the application.[213] No later than 60 days after issuing such notice, the applicant will be notified whether the application is approved or disapproved.[214]

An invitation to submit an application for credit assistance does not guarantee the DOT's approval, which will remain subject to evaluation, based on all of the statutory evaluation criteria, and the successful negotiation of terms and conditions acceptable to the Secretary.

Components

RRIF and TIFIA applications request information covering the following general categories of information regarding the applicant(s) and the project.

- Applicant Information. These questions request information about where and how to contact the applicant, the applicant's organizational structure, any other parties who will be involved in the project, and the applicant's prior experience.

- Project Information. These questions request information about the project, including a description of the project and project purpose, a timeline of the project's construction, the type and amount of credit assistance requested, cost estimates, and a description of the applicant's operations and maintenance plans for the project and, if applicable, the related system (e.g., rail or transit system).

    - If the applicant is requesting a master credit agreement, the timing and amount of each credit instrument to be provided thereunder should be described.

    - In the case of a TIFIA applicant that has been invited to apply for consideration as a Rural Project, a description of how the project meets the applicable definition of a Rural Project, including satisfaction of the project cost ceiling and floor applicable to Rural Projects.[215]

    - If the applicant is requesting credit assistance for a RRIF or TIFIA TOD Project, a description of how the project meets the eligibility criteria described in Sections 3-1 and 3-2 above.

- Financial Information. These questions request information necessary for the DOT to determine whether the project and the applicant meet the applicable creditworthiness standards, such as a cash flow pro forma, credit ratings, revenue/feasibility/market studies, and a description of the dedicated revenue source or collateral, as applicable.

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[213] 23 U.S.C. §602(d)(1) and 45 U.S.C. §822(i)(1) and (2).
[214] 23 U.S.C. §602(d)(2) and 45 U.S.C. §822(i)(3). Note that for RRIF applications, this notice is provided within 60 days after a notice that the application is complete has been provided pursuant to 45 U.S.C. §822(i)(1), i.e., under the RRIF statute, the 60-day timeline is not triggered by a notice of an incomplete application, whereas under the TIFIA statute, the 60-day timeline is triggered by a notice of an incomplete application.
[215] For Rural Projects, eligible project costs must be reasonably anticipated to total at least $10 million but not exceed $100 million (23 U.S.C. §602(a)(5)(B)(iii)). See Section 3-5 for more information about project cost threshold requirements.

- Federal Requirements. These questions request information regarding the project and the applicant's satisfaction of the generally applicable Federal requirements and the Credit Program-specific requirements described in Section 3-3, such as the status of environmental review of the project and the incorporation of the project into the applicable planning and programming documents.[216]

- Threshold Requirements. These questions request information regarding the project and the applicant's satisfaction of the other threshold requirements described in Section 3-5, including the policy-based requirements applicable to each of the Credit Programs, such as, for TIFIA projects, a description of how the project fosters partnerships that attract private investment and how TIFIA credit assistance would (1) enable the project to proceed at an earlier date than the project would otherwise be able to proceed or would reduce lifecycle costs for the project and (2) reduce the project's need for Federal grant assistance.

- Federal Debts and Delinquencies; Other Information. The application forms request information regarding any of the applicant's outstanding Federal debts to the U.S. Government and certifications as to no delinquency or default on any Federal debt or debarment from participation in any Federal program.

The application forms also require applicants to submit certain supplementary exhibits to document or evidence the information provided in response to the questions described above.

Submission

The applicant must submit at least one original copy of the complete application package with all supporting exhibits and related documentation as well as additional hard copies (the specific number of both originals and copies are set out in the application form).[217] In addition, applicants must submit a CD-ROM containing electronic versions of the entire application with attachments, including, as applicable, separate files for any excel-based attachments, such as the cash flow pro forma and financial plan, which must be executable electronic files, not in PDF or "values" format.

As of the date of the applicant submits an application, the applicant must have commenced the Federal System for Awards Management (SAM) registration process. To complete the SAM registration process, the applicant must first obtain a Data Universal Number System (DUNS) number. Applicants should expect the DUNS process to take some time, so this step should be done well in advance of seeking SAM registration. In addition, a Tax Identification Number or a Federal Employer Identification Number must be provided to

[216] As required under the TIFIA statute (23 U.S.C. §602(a)(3)) and as a priority consideration under the RRIF statute (45 U.S.C. §822(c)(5)).

[217] The current RRIF application form requests one original, compiled copy and four (4) hard copies. The current TIFIA application form requests two (2) original, compiled copies and three (3) hard copies of just the application form, without attachments. As noted above, both application forms will be updated to reflect changes made to the TIFIA and RRIF Programs by the FAST Act and to develop one consolidated application form that can be used for TIFIA, RRIF, or joint credit assistance. Pending publication of the updated forms, applicants should continue to submit the number of original and hard copies of the application forms that are noted in the applicable form.

satisfy Internal Revenue Service tax reporting requirements. Upon completing the SAM registration process, the applicant will receive a Commercial and Government Entity code.

Charges

As noted in Chapter 1 and in the Letter of Interest/Draft Application discussion in Section 4-1 above, the DOT requires applicants for and recipients of DOT credit assistance to reimburse the Federal Government for its out-of-pocket costs for its outside legal counsel and financial advisors needed to review an applicant's Letter of Interest/Draft Application and application, and to negotiate and close the credit agreement.[218] These charges are not considered as eligible project costs.[219]

(1) Upon request by the DOT, project sponsors must pay the DOT the Advisors' Fees Upfront Payment in the amount of $250,000[220] as part of the Letter of Interest/Draft Application review process, which amount is not refundable. As noted in Chapter 1, these funds enable the DOT to hire outside financial and, as and when necessary, legal advisors as part of the Letter of Interest/Draft Application review process. These funds are used, dollar-for-dollar, to cover the actual costs incurred for services provided by the DOT's outside advisors in connection with the review of the Letter of Interest/Draft Application and application and the negotiation of the transaction documents. For projects with multiple sponsors that may be pursuing different loans and/or credit structures, the DOT will require each entity to submit the Advisors' Fees Upfront Payment upon request during the review of the Letter of Interest/Draft Application. In addition, each party would be responsible for the final cost of the individual evaluation (including review by both the DOT's financial and legal advisors).

Assistance Available to Offset Advisors' Fees Upfront Payment:

TIFIA Program: For TIFIA projects with eligible project costs reasonably anticipated to be less than $75 million, the FAST Act requires the Secretary to set aside at least $2 million of the TIFIA Program's annual budget authority to be used in lieu of fees charged to the project sponsor to cover the costs of the DOT's outside advisors.[221] Project sponsors should indicate in their TIFIA Letter of Interest whether they wish to be considered for this assistance (though the DOT cannot guarantee that funds will be available to satisfy all requests). To the extent a project sponsor is eligible for this assistance and sufficient funds are available, the Advisors' Fees Upfront

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[218] *See* 23 U.S.C. §§603(b)(7), (e)(2), 604(b)(9), and 605(b), and 45 U.S.C. §823(l)(1).
[219] 49 C.F.R. §80.17(b). While the RRIF statute and regulations do not contain parallel language to the forgoing sections of the TIFIA statute, the DOT will apply the same principle to these charges in respect of RRIF applications, consistent with 2 C.F.R. Part 200, Subpart E.
[220] Note that, for RRIF projects, the Advisors' Fees Upfront Payment may be higher depending on the nature and complexity of the project. Project sponsors should consult with the Bureau to confirm the applicable amount of the Advisors' Fees Upfront Payment.
[221] 23 U.S.C. §605(f).

Payment will be waived and the cost of the DOT's outside advisors will be funded through this set-aside.

RRIF Program: The FY 2016 Consolidated Appropriations Act set aside \$1.96 million to assist Class II and III railroads pursuing RRIF credit assistance. These funds are available to be used by the Bureau in lieu of fees charged to Class II and III railroads to cover the cost of the DOT's outside advisors.[222] These funds cannot be used to cover the CRP of a RRIF loan.[223] Class II and III railroads seeking RRIF credit assistance should indicate in their Draft Application whether they wish to be considered for this assistance (though the DOT cannot guarantee that funds will be available to satisfy all requests). To the extent a project sponsor is eligible for this assistance and sufficient funds are available, the Advisors' Fees Upfront Payment will be waived, and the cost of the DOT's outside advisors will be funded through this appropriation. These funds remain available beyond FY 2016 to the extent not expended.

(2) As projects advance through the application review process as well as the negotiation and documentation phase, additional funds may be necessary to cover the costs of the DOT's advisors in the event that they cumulatively exceed the \$250,000[224] paid as the Advisors' Fees Upfront Payment. DOT's total advisors' fees for a typical transaction generally range between \$400,000 and \$700,000. However, the amount of this fee may vary significantly depending on the complexity of the project.[225] The Advisors' Fees Upfront Payment is used dollar-for-dollar to cover these costs and only to the extent the DOT's actual costs exceed \$250,000 will additional fees be charged to the applicant. These amounts reimburse the Federal Government for out-of-pocket costs for its outside legal counsel and financial advisors needed to review the Letter of Interest/Draft Application and application and negotiate and close the credit agreement. For projects seeking more than \$1 billion in credit assistance, two financial advisors will be hired to produce independent financial analyses and recommendations acceptable in form and content to the DOT. **By submitting a Letter of Interest or Draft Application, the proposed borrower acknowledges that it is responsible for payment of these fees regardless of whether the credit agreement is executed.**

[222] Consolidated Appropriations Act, 2016, Division L, §152, Pub. L. 114-113, December 18, 2015, 129 Stat. 2242, 2856 (2015).

[223] Consolidated Appropriations Act, 2016, Division L, §146, Pub. L. 114-113, December 18, 2015, 129 Stat. 2242, 2853 (2015).

[224] Note that, for RRIF projects, the Advisors' Fees Upfront Payment may be higher depending on the nature and complexity of the project. Project sponsors should consult with the Bureau to confirm the applicable amount of the Advisors' Fees Upfront Payment.

[225] Projects with a straightforward capital structure and a highly rated revenue source that is not dependent upon construction or other high-value collateral and streamlined documentation will likely have lower advisor costs than projects with a complex financing structure and extensive ancillary documentation such as intercreditor or interagency agreements, compliance agreements, equity funding agreements, etc.

TIFIA Program: As noted above, to the extent a project sponsor is eligible for fee assistance described above and sufficient funds are available, these incremental fees will be covered by funds in the set-aside but only to the extent of available funds in the set-aside.

RRIF Program: As noted above, to the extent a project sponsor is eligible for fee assistance described above and sufficient funds are available, these incremental fees will be covered by appropriated funds but only to the extent of available appropriated funds.

(3) An annual servicing fee, indexed to inflation, of approximately $13,000 for each credit instrument approved, is required for each project that receives credit assistance. The servicing fee will be collected based on the DOT's out-of-pocket costs to administer the credit instruments, including accounting, collections, document maintenance, and financial reporting. This fee is due by November 15 each year during the life of the credit instrument.

(4) Project monitoring fees are charged to borrowers in cases where the DOT incurs costs in connection with monitoring the performance of a project, the enforcement of credit agreement provisions, amendments to the credit agreement and related documents, and other performance-related activities. The DOT includes a provision requiring the borrower to reimburse the DOT for such costs in each credit agreement.

The DOT periodically will announce in the Federal Register changes to the types and amounts of fees for applicants and program participants, and in some cases may provide more current information than this Program Guide. Applicants should be sure to check the Federal Register for the most current information.

Chapter 5: Selection Process

This chapter describes the project review and selection process for both the TIFIA and RRIF Credit Programs.

Section 5-1
Project Review

TIFIA Streamlined Application Process

The FAST Act required that the DOT develop a streamlined application process for certain TIFIA requests for credit assistance.[226] The Bureau has developed such a process, identifying potential reductions in processing time while preserving an appropriate level of due diligence. Eligibility for this streamlined application process is dependent on satisfaction of certain project criteria. In general, projects that inherently present lower risks to the Government, such as requests for credit assistance of not more than $100 million and dedicated revenue sources that are not affected by project performance (e.g., sales tax revenue pledges), are eligible for the streamlined process. Smaller loan requests backed by highly-rated pledges would be expected to incur less review and underwriting time than larger requests for credit assistance, lower-rated credits, or projects with complex legal considerations. Applicants that agree to DOT's standard terms for secured loans would likely experience a reduction in Letter of Interest and application review time and the cost of DOT's outside advisors due to the minimal negotiation required to document the transaction.[227] In addition, the Bureau may consider offering a streamlined application process to qualified projects on a case-by-case basis. Please contact the Bureau for more information about the streamlined application process, including the applicable eligibility criteria.

Submission of the Letter of Interest and Invitation to Submit an Application

Chapter 4 describes the process of engaging with the Bureau for purposes of seeking credit assistance. The DOT conducts an in-depth creditworthiness review of the project sponsor and the revenue stream proposed to repay the TIFIA and/or RRIF credit assistance. The creditworthiness review involves evaluation of the plan of finance, financial model, and feasibility of the anticipated pledged revenue or, in the case of RRIF loans where the proposed collateral is other than a dedicated revenue stream, the sufficiency of such other pledged collateral. Concurrently with this review, the DOT will ask project sponsors requesting TIFIA credit assistance to provide a preliminary rating opinion letter. In addition, at this time, the DOT will ask project sponsors to submit the $250,000[228] Advisors' Fees Upfront Payment to enable the DOT to hire outside financial and, as and when necessary, legal advisors to complete its review of the project. (See Section 4-2 for additional

[226] 23 U.S.C. §603(f).
[227] The TIFIA loan agreement templates for P3 and public borrowers are available on the Bureau's website: https://www.transportation.gov/buildamerica.
[228] Note that, for RRIF projects, the Advisors' Fees Upfront Payment may be higher depending on the nature and complexity of the project. Project sponsors should consult with the Bureau to confirm the applicable amount of the Advisors' Fees Upfront Payment.

discussion of the Advisors' Fees Upfront Payment, including regarding the availability of DOT-funded assistance for TIFIA projects with costs anticipated to be less than $75 million.) In addition, the DOT will request that the potential applicant give an oral presentation to the DOT followed by a question and answer session. As noted above, potential applicants will be invited to submit a formal application only once the DOT has satisfactorily completed its review of a project's eligibility, including a satisfactory review of the creditworthiness of the project. See Chapters 1 and 4 for a step-by-step description of the application process.

Eligibility Criteria

The preliminary review team led by a Project Development Lead from the Bureau's Outreach and Project Development Team (as described in Section 4-1) ensures satisfaction of the threshold requirements described in Chapter 3, including satisfaction of Federal requirements, Credit Program-specific requirements, and project readiness. Such team also reviews the Letter of Interest/Draft Application for completeness of information. The DOT employs the services of an independent financial advisor to assist with financial and credit risk assessments of the project.

The Project Development team's preliminary review will focus on certain key eligibility elements to ensure the relevant project is ready for the more in-depth creditworthiness review. These key preliminary items are:

- Project Eligibility. The preliminary review team will first verify that the project and the potential applicant satisfy the program-specific requirements applicable to the relevant Credit Program. This review will determine whether the project is eligible for credit assistance under the requested Credit Program and the potential applicant is an eligible applicant.

- Federal Requirements. The preliminary review team will verify whether certain preliminary Federal requirements either have been satisfied or are on schedule to be completed in sufficient time to continue the review process. The Federal requirements most likely to delay the Letter of Interest/Draft Application process are Buy America and NEPA, however, the preliminary review team will flag all Federal compliance issues it discovers during the initial Letter of Interest/Draft Application review.

- Credit Program-Specific Requirements. In addition to the generally applicable Federal requirements, the preliminary review team will verify whether the other threshold criteria described in Section 3-5 have been (or are reasonably likely to be) satisfied. For example, the review team will determine whether the amount of the requested credit assistance exceeds the statutory authority for the applicable program (such as a request for a TIFIA loan in excess of 49 percent of eligible project costs,[229] or combined RRIF and TIFIA credit assistance in excess of 80 percent of eligible project costs in the aggregate[230]) or the project size does not meet the applicable Credit Program's

[229] 23 U.S.C. §603(b)(2)(A).
[230] 23 U.S.C. §603(b)(9)(A).

requirements (such as a request for TIFIA credit assistance for a non-rural, non-local project with anticipated eligible costs of $40 million[231]). This review will also confirm whether the project has been reflected in the applicable state planning and programming documents[232] and satisfies the applicable readiness requirements[233].

After concluding its initial review and upon making a determination that the project is reasonably likely to satisfy all of the eligibility requirements of the applicable Credit Program, the DOT will conduct an in-depth creditworthiness review of the project sponsor and the proposed plan of finance. This review focuses on the following eligibility criteria set forth in the RRIF and TIFIA statutes, as applicable:

- Creditworthiness: The DOT will review the creditworthiness of the project. This includes a demonstrated capacity to repay the Federal credit assistance as well as a determination that the project has appropriate security features, such as appropriate coverage ratios, rate covenants and reserves, as applicable. For requests for TIFIA credit assistance, project sponsors will need to specifically demonstrate the following:

    i) Ability to satisfy applicable creditworthiness standards;[234]

    ii) Rate covenant, if applicable;[235]

    iii) Adequate coverage requirements to ensure repayment;[236] and

    iv) Ability to obtain investment grade ratings on senior debt.[237]

- Repayment Source. While the RRIF statute does not require a borrower to pledge a dedicated revenue source to the repayment of RRIF credit assistance, for both the RRIF and TIFIA Programs, the DOT will analyze the revenue stream proposed to repay the DOT credit assistance to determine whether there is adequate assurance that the credit assistance can be repaid, including under downside scenarios. In addition, the TIFIA statute requires that both project debt generally and TIFIA debt specifically must be repaid in whole or in part by a dedicated revenue source(s) as discussed in Section 3-5 above.[238] The DOT will require that revenues pledged to the TIFIA obligation be of substantially similar credit quality to those securing the senior debt, except with respect

[231] 23 U.S.C. §602(a)(5)(A).
[232] As required under the TIFIA statute (23 U.S.C. §602(a)(3)) and as a priority consideration under the RRIF statute (45 U.S.C. §822(c)(5)).
[233] For requests for RRIF credit assistance, this review and the NEPA status review will one and the same; for requests for TIFIA credit assistance, the review team will determine whether the project sponsor has demonstrated that the construction contracting process for the project can commence no more than 90 days after the execution of a TIFIA credit instrument.
[234] 23 U.S.C. §602(a)(2).
[235] 23 U.S.C. §602(a)(2)(A)(i).
[236] 23 U.S.C. §602(a)(2)(A)(ii).
[237] 23 U.S.C. §602(a)(2)(A)(iii).
[238] 23 U.S.C. §602(a)(6).

to TIFIA's lien position, which can be junior (i.e., subordinated) the project's other debt obligations.[239]

- Rating Opinion (TIFIA). The DOT will not complete its review of a TIFIA Letter of Interest and render a determination of eligibility before the project sponsor has submitted at least one preliminary rating opinion letter from a Credit Rating Agency. This preliminary assessment of the project's proposed financing structure must indicate that the senior obligations funding the project have the potential to receive an investment grade rating.[240] The DOT will not consider projects that do not demonstrate the potential for the obligations senior to the TIFIA obligation to receive an investment grade rating. The preliminary rating opinion letter should also provide a preliminary assessment of the likely rating category for the requested TIFIA credit instrument. In addition, the preliminary rating opinion letter should provide a preliminary rating assessment of the financial strength of the overall project and the default risk (i.e., without regard to recovery potential) of the requested TIFIA credit instrument.[241] See Section 3-6 for additional discussion regarding the DOT's use of credit ratings.

- DOT Policy Goals. The preliminary review team will review the Letter of Interest/Draft Application, and any supplemental materials, to determine whether and to what extent a project satisfies the DOT policy goals described in Section 3-5 above. (See Section 3-5 for a description of the applicable policy goals.) For requests for TIFIA credit assistance, the review team must make a determination that the policy goals described in Section 3-5 are satisfied in order for the project to be eligible for TIFIA credit assistance. Failure to achieve the RRIF policy goals described in Section 3-5 is not a bar to eligibility, but will be used to determine the prioritization of projects and failure to satisfy any or all of the goals identified may result in a project not receiving RRIF credit assistance.

With respect to public-private partnerships (P3s) seeking Bureau credit assistance, the DOT expects a partnership in which all parties will work together to ensure that the project is successful from construction through loan maturity. The terms within the P3 concession agreement are critical to the DOT's analysis. Prior to execution of a concession agreement, typically when the public sponsor finalizes a draft concession agreement for the Request for Proposals process, the DOT will review the agreement with a focus on credit underwriting. The DOT's review will ensure the concession terms are incorporated into the overall credit due diligence process and will identify terms that may negatively impact the repayment of the project's debt. The Department may require changes to the concession agreement to reach a finding of creditworthiness. To ensure that all parties will work together during the concession period while the loan would be outstanding, particularly in distress situations, the DOT will review previous experience by private entities in making a creditworthiness

[239] As noted in Section 2-1 above, the TIFIA lien on pledged revenues can be subordinated to those of senior lenders to the project except in the event of bankruptcy, insolvency, or liquidation of the obligor. In such an instance, the TIFIA lien would be on par with the lien of the project's senior creditors. However, this provision can be waived under certain circumstances for public agency borrowers having senior bonds under preexisting indentures so long as certain conditions are met, as further discussed in Section 2-1 above.
[240] If there are no debt obligations senior to the TIFIA credit instrument, then the TIFIA credit instrument itself must be shown to have the potential to obtain an investment grade rating. 23 U.S.C. §602(b)(3).
[241] 23 U.S.C. §602(b)(3).

determination.

After concluding its review of each Letter of Interest/Draft Application and related information submitted by potential applicants, along with the independent financial analysis report from the DOT's independent financial advisor, and after the project sponsor's oral presentation, the DOT will invite sponsors of eligible projects to submit complete applications. In addition to the foregoing requirements, project sponsors must have circulated a draft EIS by the time it submits an application, unless the project has received either a FONSI or a Categorical Exclusion. The DOT will not obligate funds for a project before a ROD (if required, or the equivalent final agency decision) has been issued for that project. (See Sections 3-3 and 3-7 for additional discussion regarding NEPA requirements). Further, applicants must certify in their application that they are not delinquent on any Federal debt, including tax debt.[242]

Credit Subsidy/Credit Risk Premium Calculation

Based on the financial information presented in the Letter of Interest/Draft Application and application (and any supplemental materials), the DOT will estimate the credit subsidy/CRP for the proposed credit assistance. This preliminary calculation, reflecting the DOT's estimated credit risk, will determine, for TIFIA credit assistance, the amount of TIFIA budget authority the project would consume if selected for credit assistance, and for RRIF credit assistance, the size of the CRP payment the applicant will ultimately be required to pay to the DOT.[243]

Section 5-2
Project Recommendations

Based on work of the technical review team, Bureau staff will prepare a recommendation regarding TIFIA credit assistance and present it, first to the Bureau's Credit Review Team, a team of DOT staff drawn from credit and modal expertise throughout the Department. After the Credit Review Team has reviewed and affirmed the Bureau's recommendation, the Bureau will present its recommendation to the DOT Council on Credit and Finance.

Section 5-3
Project Selection

The DOT Council on Credit and Finance provides recommendations to the Secretary, who will make the final determination regarding award of Bureau credit assistance. The Secretary's approval, if received, will instruct the Bureau to proceed to finalize the

[242] See 31 U.S.C. §3720B, 31 C.F.R. §285.13, and Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-129, Policies for Federal Credit Programs and Non-Tax Receivables (2013), at Section III(A)(1)(b).

[243] As noted in Chapter 2, since the RRIF Program does not currently have an appropriation, the cost to the government of providing financial assistance must be borne by the RRIF applicant, or another non-federal entity on behalf of the applicant, through the payment of the CRP. See Chapter 2 for additional information regarding the credit subsidy/CRP.

negotiation of the documentation for the credit assistance. Once terms and conditions acceptable to the DOT have been finalized, the parties will execute a term sheet, which obligates the credit assistance, a definitive credit agreement, which sets forth the terms and conditions of the credit assistance, and the other documents necessary to provide credit assistance, and close the transaction. The typical transaction documents utilized in connection with DOT credit assistance are described in Chapter 6.

Section 5-4
Summary of the Bureau Selection Process

Exhibit 5-A provides a summary of the Bureau application and selection processes addressed in Chapters 4 and 5.

Exhibit 5-A: The Bureau Application Process

Action	Responsible Party
Bureau Outreach and Project Development • Project Sponsor Engages with Bureau Outreach Staff.	• Project Sponsor
Initial Project Assessment: • Establish a preliminary review team to review the Letter of Interest/Draft Application. • Determine whether the prospective project meets statutory eligibility requirements. • Provide additional information (if requested by the DOT).	• DOT • DOT • Project Sponsor
Letter of Interest: Prepare the Letter of Interest and submit it to the DOT.	• Project Sponsor
In-Depth Creditworthiness Review: • Review creditworthiness of the project sponsor and the revenue stream proposed to repay the credit assistance. • Upon request from the DOT, provide a feasibility study (as applicable), and a fully functional Microsoft Excel-based financial model. • For TIFIA applicants, upon request from the DOT, provide the preliminary rating opinion letter. • Upon request from the DOT, provide the $250,000 Advisors' Fees Upfront Payment to enable the DOT to hire outside financial and legal advisors in order to continue project review.	• DOT • Project Sponsor • Project Sponsor • Project Sponsor
Oral Presentation: • After initial determination of eligibility and receipt of the Advisors' Fees Upfront Payment and, for TIFIA applicants, the preliminary rating opinion letter, and upon request from the DOT, present the project to the review team and advisors, as well as representatives of the Bureau and the DOT Council on Credit and Finance.	• Project Sponsor
Application: • After successful determination of eligibility, oral presentation, and receipt of the Advisors' Fees Upfront Payment and, for TIFIA applicants, the preliminary rating opinion letter, notify selected projects that have been invited to submit an application. • Prepare and submit the complete application (with the appropriate number of copies).	• DOT • Project Sponsor
Application Review: • Based on the written application and oral presentation, reassess the project's satisfaction of the applicable eligibility criteria, with particular focus on creditworthiness. • Calculate the credit subsidy cost/CRP estimate.	• DOT • DOT
Recommendations to Bureau Credit Review Team, DOT Council on Credit and Finance and Secretary: • Prepare and present a recommendation for the project to the Bureau's Credit Review Team. • If approved by the Credit Review Team, present a recommendation for the project to the DOT Council on Credit and Finance. • Review, approve, or revise recommendation and forward to the Secretary for final decision on approval.	• DOT • DOT • DOT Council on Credit and Finance
Approval and Notifications: • Approve project, as appropriate, and authorize the issuance of a term sheet and completion of negotiations of a credit agreement. • Advise applicant of Secretary's determination.	• Secretary • DOT

Chapter 6: Transaction Documents and Ongoing Monitoring Requirements

This chapter describes the process by which the DOT will commit to provide credit assistance to a selected borrower (also termed "obligor"). The chapter also describes the two major contractual documents used for the TIFIA and RRIF Programs: the term sheet and the credit agreement. The term sheet establishes the DOT's legal commitment and triggers the obligation of budget authority for the project. The credit agreement is the definitive agreement between the DOT and the borrower, containing all of the terms and conditions pursuant to which the DOT's credit assistance is provided. The DOT will not execute the term sheet or the credit agreement until the Credit Review Team and the Council on Credit and Finance have recommended the approval of an application, and the Secretary has approved the application and instructed the Bureau to execute these agreements. As described in Chapter 5, the Bureau will not present an application to the Credit Review Team and Council on Credit and Finance until all prerequisite to receipt of credit assistance, such as receipt of a final NEPA determination, receipt of a preliminary rating opinion letter (for TIFIA credit assistance), and satisfaction of the eligibility requirements described in Chapter 3, have been satisfied.

If a project is also financed with other DOT funds, the recipient of credit assistance is required to comply with applicable modal project requirements and approvals as well as the applicable Credit Program's requirements. These may include approval for innovative contracting approaches and "mega project" procedures, such as submission of a financial plan and plan updates. The Bureau process minimizes duplication of effort by borrowers, while ensuring effective oversight and monitoring of the Federal investment for projects. The applicant can choose to take advantage of the coordinated processes as long as the timing of the submission of required documents fulfills both the Credit Program and the other applicable Federal program requirements. The credit agreement will specifically address financial plan requirements and monitoring procedures.

Section 6-1
Term Sheet

The term sheet is a contractual agreement between the DOT and the borrower that sets forth certain business terms and conditions of the credit assistance for the project.[244] The DOT's issuance of this document triggers the DOT's obligation (*i.e.*, legal commitment) of budget authority.

<u>Term Sheet Prerequisites</u>

Before issuing a term sheet, the DOT will confirm that all prerequisites for the obligation of funds have been satisfied. These prerequisites are described in detail in Chapter 3.

[244] Note that this term sheet is a different instrument from the indicative term sheet the Bureau offers to negotiate with public sponsors conducting P3 procurements. The term sheet described above will be executed for all transactions receiving credit assistance and is necessary for the DOT to obligate funds.

The term sheet obligates budget authority and binds the DOT and the borrower to the specified terms; it does not bind the DOT to details of the borrower's application. Further, the term sheet does ***not*** trigger a disbursement of funds to the borrower. Disbursements are made pursuant to the credit agreement, which is the definitive financing agreement between the borrower and the DOT.

Term Sheet Contents

General rules concerning the terms for secured loans, loan guarantees, and standby lines of credit are summarized in Chapter 2. More specific terms will be determined on a project-specific basis. The DOT commitment in the term sheet, and the terms and conditions applicable to the DOT's credit assistance, are subject in all respects the terns of the credit agreement.

Because term sheets serve primarily as obligating instruments for TIFIA and RRIF credit assistance, they include only basic terms and conditions related to the DOT's provision of credit assistance. Typically, the following will appear in every term sheet:

- Parties to the agreement (*e.g*., lender, borrower, and guaranteed lender, as applicable);
- Type(s) of credit instrument (*i.e*., secured loan, loan guarantee, or line of credit);
- Description of the project;
- Estimated total project costs and total eligible project costs;
- Maximum amount of TIFIA and/or RRIF credit assistance;
- Method for establishing the interest rate;
- Estimated final maturity date;
- Source of payment and security, if applicable, including lien priority of the credit instrument;
- Requirement to reimburse the DOT for all costs in excess of the Advisors' Fees Upfront Payment;
- Conditions, if applicable, for execution of a credit agreement; and
- Covenants such as limitations on additional bonds, minimum coverage ratios, and any required reserve funds.

Section 6-2
Credit Agreement

The credit agreement is the definitive agreement between the DOT and the borrower (and the guaranteed lender, if applicable). It specifies all terms and conditions of the credit assistance and authorizes the disbursement of credit assistance to the project.

Credit Agreement Prerequisites

In order for the DOT to execute the credit agreement and disburse funds, the borrower must satisfy at a minimum any requirements set forth in the term sheet. Also, for TIFIA credit assistance, the borrower must have received two investment grade ratings on the senior debt obligations and two ratings on the TIFIA credit instrument, as described in Section 3-6. If the TIFIA debt is intended to be the senior debt, it must receive two investment grade ratings.

Prior to closing a credit agreement, the borrower will be required to submit updates to both the financial plan and project management and monitoring plan.

The DOT reserves the right to review and, as appropriate, approve all related project documents, including, but not limited to design-build contracts, concession agreements, development agreements, financing agreements, and funding agreements with third parties.

In addition to satisfying the requirements set forth above, prior to executing the credit agreement, the applicant must complete the Federal System for Award Management (SAM) registration process. To complete the SAM registration process, the applicant must first obtain a Data Universal Numbering System (DUNS) number. In addition, a Federal Employer Identification Number (FEIN, also known as a Federal Tax Identification Number) must be provided to satisfy the IRS tax reporting requirements. Upon completing the SAM registration process, the applicant will receive a Commercial and Government Entity code. The DOT will verify that the applicant has active registration status in SAM, has no active exclusions in SAM, and will require evidence of the applicant's DUNS number and FEIN prior to executing a credit agreement.

Credit Agreement Contents

The contents of the credit agreement will include both standard provisions and transaction-specific provisions. The borrower and the DOT will execute the credit agreement for a secured loan or line of credit; the guaranteed lender, the DOT, and the borrower will execute the loan guarantee agreement or instrument for a loan guarantee. Additionally, for a loan guarantee, the guaranteed lender will execute a separate loan agreement with the borrower, and the borrower will execute a borrower's certificate, compliance, and loan agreement with the DOT. Depending on the nature of the transaction, additional documents, such as an intercreditor agreement or collateral agency agreement, may also be necessary. The DOT will require the borrower to provide copies of the bond or loan documents, as applicable, and other agreements material to the flow of funds or to the DOT's security for its review of the project's creditworthiness. The DOT may also review any disclosure with respect to the transaction that the borrower includes in offering documents.

Generally, borrowers can expect credit agreements to include, in addition to the items listed under "Term Sheet Contents," the following:

- Detailed description of the dedicated revenue source and pledged security, if applicable;
- Credit enhancement features (*e.g.*, rate covenants, additional bonds tests, and coverage requirements);

- Flow of funds;
- Repayment terms, including amortization schedule and final maturity;
- Representations and warranties;
- Borrower covenants;
- Annual disbursement schedule and conditions for draws;
- Financial plan requirements; and
- Monitoring and reporting requirements.

The credit agreement will also include the form of requisition for disbursements and the form of bond/note. Each borrower under a direct loan agreement executes a bond or note, as applicable, evidencing the obligation to repay the loan.

Section 6-3
Closing Activities

When the parties to the transaction have completed negotiations and finalized the credit agreement and other related financing documents, the pre-closing and closing occur. This process is very similar to a bond transaction closing.

At closing, authorized representatives of the borrower, the DOT, and the guaranteed lender (if applicable) execute the legal documents. Documents requiring execution by persons not attending the closing are signed in advance. Copies of the agreements are made and distributed to the appropriate parties. The timing of the closing is typically tied to the closing of the senior financing, if applicable. The closing of the senior debt and the DOT credit instrument can be simultaneous, but the TIFIA and/or RRIF transaction can close ahead of the senior financing so long as the senior documents have been substantively finalized and execution is within a week of the TIFIA and/or RRIF closing. In those circumstances, the DOT credit agreement will include conditions subsequent to closing that will terminate the commitment if the senior financing does not close by an outside date (not more than a week after the TIFIA and/or RRIF closing) or is on terms and conditions different than the forms of senior financing documents agreed when the TIFIA and/or RRIF loan(s) closed. Standard transaction closing documents are required, including various legal opinions.

Following the closing, a binder is prepared which includes all the legal documents, project documents, condition precedent materials from the DOT transaction, and other closing documents. The Bureau uses this closing binder as the source of project information for accounting, budgeting, and program monitoring systems. Exhibit 6-A contains a sample checklist for a secured loan closing.

Exhibit 6-A: Sample Loan Closing Checklist for a TIFIA or RRIF Direct Loan

1. Organizational Documents of the Borrower

   If the Borrower is a public entity:

   a. Approval resolutions approving project and authorizing official to execute documents
   b. Copies of enabling legislation, bylaws, minutes of meetings regarding the project

   If the Borrower is a private entity:

   a. Articles of incorporation, partnership agreement or similar documents, as appropriate
   b. Good standing certificate
   c. Bylaws
   d. Incumbency certificate
   e. Resolutions authorizing officials to execute documents
2. TIFIA/RRIF Loan Agreement
3. TIFIA/RRIF Term Sheet
4. TIFIA/RRIF Promissory Note
5. Intercreditor Agreement
6. Development agreements (including design/build or concession agreements) and any other construction contracts
7. Borrower's Officer's Certificate (certifying to project documents, incumbency, and other matters)
8. Evidence of project's inclusion in State Transportation Improvement Program (if applicable)
9. Evidence of consistency with other State or metropolitan transportation plans (if applicable)
10. Evidence of all necessary approvals
11. Environmental Record of Decision, Finding of No Significant Impact or Categorical Exclusion
12. Evidence of active registration in SAM
13. Insurance Documents
14. Borrower Non-Debarment Certificate (certifying that the borrower has not been suspended or debarred from participation in any Federal program)
15. Independent Engineer's Report
16. Feasibility Study/Traffic and Revenue Study
17. Working Financial Model (not in .pdf or values format) and Financial Plan
18. Credit rating(s) (if applicable)
19. Opinion of borrower's counsel (addressing legal authority of Borrower, execution of documents, etc.) and of bond counsel (addressing legality and validity of security interests and validity, priority and perfection of lien, if applicable, and due authorization, legality, and binding nature of the credit instrument)
20. For Senior Project Bonds (tax-exempt or taxable bonds):
    a. Enabling legislation and other documentation of issuer of senior project bonds
    b. Borrower's resolution
    c. Trust indenture
    d. Bond purchase agreement
    e. Official statement
    f. Continuing disclosure agreement
    g. Bond insurance policy or other credit enhancement

Section 6-4
Oversight and Monitoring Requirements

The DOT requires certain ongoing, periodic reporting with respect to project receiving Bureau credit assistance. This periodic review has three purposes: (i) to provide the DOT with an oversight tool for ensuring the borrower's compliance with the provisions of the credit agreement; (ii) to monitor the overall status of the project; and (iii) to assist the DOT and the Office of Management and Budget (OMB) in identifying any changes to the credit risk posed to the Federal Government under individual credit agreements. The credit instrument will specify the scheduled annual and project milestone reporting requirements, as well as any other ad hoc or periodic reporting requirements.

As part of its oversight and monitoring of TIFIA and RRIF projects, the DOT will routinely update its information on credit quality, construction schedules, legal issues, revenue forecasts, financial projections, and project performance. Accordingly, borrowers will be required to covenant in the credit agreement to provide ongoing financial and project information not only during construction, but so long as any Bureau credit instrument is outstanding and/or until any debt obligation to the Federal Government is fully repaid. Documentary evidence that may be requested for each project includes: audited financial statements, updated budget and cash flow projections, audit reports, sources and uses of funds, coverage ratios, project schedules, operating statistics, and management updates (no more than 180 days following the borrower's fiscal year-end). In addition, the credit agreement will obligate the borrower to provide the DOT with an annual update to the project's financial plan in accordance with specified requirements. Financial plans must show full funding for the project and are subject to review and approval by the Bureau. Each borrower will be required to give notice to the DOT of material events, including litigation, which could affect project development or the credit quality of the project.

Borrowers of TIFIA credit assistance are also required to provide annually, at no cost to the Federal Government, ongoing credit evaluations of the project and all project debt, including the TIFIA credit instrument.[245] These surveillance reports must be prepared by a Credit Rating Agency throughout the life of the TIFIA credit instrument.[246] By "current credit evaluation," the DOT means: (i) in the case of a project with a published rating, either a current rating or the borrower's certification stating that the rating and outlook are unchanged from the previous year, and (ii) in the case of a project without a published rating, a current rating of the project obligations and the Federal credit instrument. The DOT will also require periodic updates to the rating rationale to the extent that it is not included as part of the annual rating letter. The borrower must furnish the DOT with any other credit surveillance reports on the TIFIA-assisted project as soon as they are available.

The DOT's oversight and monitoring may also include site visits, periodic status meetings with the borrower, and reviews of independent engineer and/or other relevant reports. The

[245] 49 C.F.R. §80.11(d).
[246] 49 C.F.R. §80.11(d).

Bureau will coordinate oversight and monitoring activities with the appropriate DOT field offices.

Each credit agreement between the DOT and a borrower will specify the types of ongoing documentation required by the DOT and the frequency of such information requests. The credit agreement will also authorize the DOT to commence increased monitoring and reporting, as may be necessary, to ensure the continued credit quality of the project and minimize the Federal Government's risk. With respect to P3 projects financed by DOT, in the event that issues arise during the concession term, all parties must make a good faith effort to resolve the situation, which may include discussions regarding the feasibility of additional equity infusions, changes to concession terms or any other corrective measure that could stabilize the financial condition of the project.

Section 6-5
Loan Servicing

The DOT may retain outside assistance to perform loan servicing for Bureau credit instruments, including credit accounting, collections, maintenance of documents, and financial reporting.[247] To offset in part the DOT's costs, a borrower is charged an annual fee for loan servicing activities associated with each credit instrument, which is adjusted periodically based on inflation.[248]

The DOT will provide general payment instructions to the borrower in each credit agreement. Prior to each repayment date, the DOT's loan servicer will notify the borrower of the date and amount due in accordance with the payment schedule in the credit agreement. The loan servicer will also bill each borrower annually for servicing fees, for the DOT's account, in accordance with the provisions in the credit agreement.

[247] 23 U.S.C. §605(c)(1) and 45 U.S.C. §823(l)(3) and 45 U.S.C. §823(l)(1) and (3).
[248] 23 U.S.C. §605(b)(2) and 45 U.S.C. §823(l)(2).

Chapter 7: Special Issues Related to Loan Guarantees

By guaranteeing a loan, the DOT promises to pay a guaranteed lender in the event that the borrower defaults on its scheduled payments of the guaranteed loan. By statute, the guaranteed lender must be a non-Federal entity, and for TIFIA loan guarantees, the guaranteed lender must be a "non-Federal qualified institutional buyer" as defined in 17 C.F.R. §230.144A(a), including qualified retirement plans and governmental plans.[249]

The DOT must have confidence that the guaranteed lender has entered into a reasonable loan agreement with the borrower and also is capable of fulfilling its loan servicing responsibilities. To this end, the DOT has established basic eligibility criteria to evaluate and approve guaranteed lenders prior to execution of a loan guarantee agreement. This chapter outlines these eligibility criteria as well as the guaranteed lender's major responsibilities.

Section 7-1
Guaranteed Lender Eligibility

The guaranteed lender and the terms of the guaranteed loan must be approved by the DOT. The DOT will evaluate prospective guaranteed lenders with respect to the criteria set forth below. These criteria are derived from the TIFIA and RRIF statutes and regulations. While some provisions appear solely in one or the other, the DOT will harmonize the requirements among the two Credit Programs with respect to loan guarantees and guaranteed lenders.

- The guaranteed lender must meet the definition of "lender" set forth in the TIFIA statute (23 U.S.C. §601(a)(5)). While the RRIF statute does not mirror the TIFIA statute with respect to the criteria for an eligible guaranteed lender, the DOT will evaluate prospective guaranteed lenders under the RRIF Program using the definition applicable to the TIFIA Program unless a borrower makes a compelling justification for departing from that definition. Any such justification must demonstrate an acceptable level of credit quality for the transaction and level of risk to the DOT.[250] The definition set forth in the TIFIA statute is as follows:

  > "… any non-Federal qualified institutional buyer (as defined in Section 230.144A(a) of Title 17, Code of Federal Regulations (or any successor regulation), known as Rule 144A(a) of the Securities and Exchange Commission and issued under the Securities Act of 1933 (15 U.S.C. 77a et seq.)), including:
  >
  > (A) A qualified retirement plan (as defined in Section 4974(c) of the Internal Revenue Code of 1986) that is a qualified institutional buyer; and

[249] 23 U.S.C. §601(a)(5) and 45 U.S.C. §821(7).
[250] See 49 C.F.R. Subpart F, including §260.51(a) and (c) and §260.53(b) for additional information regarding the DOT's evaluation of loan guarantee requests and potential guaranteed lenders.

(B) A governmental plan (as defined in Section 414(d) of the Internal Revenue Code of 1986) that is a qualified institutional buyer."[251]

- The guaranteed lender must not be debarred or suspended from participation in any Federal program.[252]

- The guaranteed lender must not be delinquent on any Federal debt or loan.[253]

- The guaranteed lender must be duly organized and legally authorized to enter into the transaction.[254]

- The guaranteed lender must demonstrate experience in originating and servicing loans for large-scale developments.[255]

- The guaranteed lender must demonstrate that it has sufficient capital to originate the loan and disburse for its own portfolio.

- If a guaranteed lender chooses to use a subservicer, the guaranteed lender must demonstrate that the subservicer is capable of handling the servicing responsibilities under the credit agreement. (The guaranteed lender shall remain responsible to the DOT for all servicing responsibilities under the credit agreement.)

- The guaranteed lender must provide certifications as specified in the loan guarantee agreement with the DOT and must maintain lender eligibility conditions.

- The guaranteed lender must provide periodic financial information to the DOT's loan servicer in accordance with requirements specified in the loan guarantee agreement.[256]

Section 7-2 Guaranteed Lender Responsibilities

The guaranteed lender may perform the following types of activities. The DOT may request documentation demonstrating the guaranteed lender's capacity to handle such responsibilities.

- Loan and application processing;

- Loan file compilation and retention;

- Loan disbursement;

[251] 23 U.S.C. §601(a)(5).
[252] Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-129, Policies for Federal Credit Programs and Non-Tax Receivables (2013).
[253] Office of Mgmt. & Budget, Exec. Office of the President, OMB Circular No. A-129, Policies for Federal Credit Programs and Non-Tax Receivables (2013).
[254] See 49 C.F.R. §260.51(c).
[255] *Id*.
[256] See 49 C.F.R. §260.55(d).

- Collection and accounting of all amounts due and received under the terms of the loan, including release of liens for pay-off at maturity and prepayments;
- Maintenance of reserve accounts (if applicable);
- Supervision of construction (if applicable);
- Supervision and quality control of subservicing (if applicable);
- Negotiation and restructuring of loans - loan workouts as approved by the DOT;
- Coordination with senior lender/trustee (if applicable);
- Immediate notifications in the event of payment delinquency and/or default, other defaults under the loan guarantee, potential corrective action plans, potential workout plans, change in borrower status, change in lender status, change in project status, failure of borrower to meet terms of the loan, etc.

See 49 C.F.R. §260.53 for a more detailed list of typical guaranteed lender responsibilities.

Section 7-3
Loan Guarantee Provisions

Requirements for the Guaranteed Lender

After the DOT has approved a guaranteed lender and a project has satisfied all conditions for Bureau credit assistance, a loan guarantee agreement or instrument will be negotiated and signed by the borrower, the guaranteed lender, and the DOT. The DOT will monitor the borrower and the guaranteed lender according to the conditions and requirements specified in the loan guarantee agreement. The DOT may periodically perform on-site reviews of the guaranteed lender's business operations or may request audited financial statements or updated certifications from the guaranteed lender indicating that the eligibility requirements are being maintained.

If the guaranteed lender fails to meet its obligations or to maintain the eligibility requirements, the DOT will advise the guaranteed lender of corrective actions that must be performed. If these corrective actions are not performed within the specified timeframe, the DOT may require a transfer of loan servicing to another entity and/or pursue legal remedies.

Interest Rate

The interest rate on the guaranteed loan is negotiated between the guaranteed lender and the borrower, subject to the DOT's approval.[257]

[257] 23 U.S.C. §603(e)(2) and 45 U.S.C. §822(e)(2).

Payment Process

Under a loan guarantee, the DOT commits to pay to the guaranteed lender, upon the occurrence of a payment default by the borrower, the full amount of the defaulted payment, as specified in the loan guarantee agreement.

In the event of a payment default, the guaranteed lender will issue a notice of default to the borrower and copy the DOT. If the lender then makes a draw on the guarantee from the DOT, the payment initiates a loan between the DOT and the borrower. So long as the borrower makes its payments to the DOT on this new loan, there is no default of the DOT's loan. The guaranteed lender may enter into a loan workout or similar agreement with the borrower as approved by the DOT. In the event of assignment of the guaranteed loan to the DOT, the guaranteed lender is responsible for transferring all the guaranteed loan documents to the DOT.

For Further Information

For further information regarding the Bureau's Credit Programs or for comments to this Program Guide, please contact the Bureau at BureauCredit@dot.gov. Additional information regarding Bureau Credit Programs can be obtained from the Bureau's website: http://www.transportation.gov/buildamerica.

Appendix A: Acronyms

C.F.R.	Code of Federal Regulations
DOT	United States Department of Transportation
DUNS	Data Universal Number System
EIS	Environmental Impact Statement
FAST	Fixing America's Surface Transportation
FEIN	Federal Employer Identification Number
FHWA	Federal Highway Administration
FONSI	Finding of No Significant Impact
FRA	Federal Railroad Administration
FTA	Federal Transit Administration
ITS	Intelligent Transportation System
MAP-21	Moving Ahead for Progress in the 21st Century
MARAD	Maritime Administration
NEPA	National Environmental Policy Act of 1969
OMB	Office of Management and Budget
OST	Office of the Secretary of Transportation
ROD	Record of Decision
RRIF	Railroad Rehabilitation & Improvement Financing
SAFETEA-LU	Safe, Accountable, Flexible, Effective Transportation Equity Act: A Legacy for Users
SAM	System for Awards Management
SIB	State Infrastructure Bank
SLGS	State and Local Government Series
STIP	State Transportation Improvement Program
TEA 21	Transportation Equity Act for the 21st Century
TIFIA	Transportation Infrastructure Finance and Innovation Act of 1998
TOD	Transit-Oriented Development
U.S.C.	United States Code

NATIONAL OFFSHORE WIND STRATEGY

Facilitating the Development of the Offshore Wind Industry in the United States

U.S. DEPARTMENT OF ENERGY

U.S. DEPARTMENT OF THE INTERIOR

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Introductory Message

There has never been a more exciting time for offshore wind in the United States. By the end of 2015, the U.S. Department of the Interior awarded 11 commercial leases for offshore wind development that could support a total of 14.6 gigawatts of capacity. In May 2016, the U.S. Department of Energy identified three innovative demonstration projects that have made significant progress toward producing power. In addition to these noteworthy achievements, we are looking forward to the first commercial offshore wind energy facility in the United States—the Block Island Wind Farm—beginning commercial operation before the close of 2016.

With almost 80% of U.S. electricity demand located in coastal states and total offshore wind energy technical potential equal to about double the nation's demand for electricity, offshore wind energy has the potential to contribute significantly to a clean, affordable, and secure national energy mix. Realizing the potential of offshore wind energy in the United States will require addressing key challenges in technology and cost, supporting effective stewardship of our natural resources, and increasing understanding of offshore wind's benefits and costs.

Our agencies are uniquely poised to provide leadership in addressing these key challenges. Recognizing the significant opportunity for our nation, we have worked closely together and solicited significant public input over the past 18 months to compose a joint national offshore wind strategy. This report highlights the potential value of offshore wind to the nation, and presents a credible set of approaches and actions to facilitate the responsible development of a U.S. offshore wind industry.

On behalf of the offices we represent, we express our deep gratitude to the hundreds of individuals across federal and state governments, industry, academia, research institutions, and the environmental community for their meaningful contributions to this national strategy for offshore wind. Their expertise, vision, and passion herald a bright future for offshore wind energy in the United States.

We are confident that our nation stands at the forefront of a strong domestic offshore wind industry. It is our hope that this document will continue to serve as a guide for key decision-makers within our agencies, as well as within the broader offshore wind energy community, over the next 5 years and beyond.

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List of Acronyms

AEP	annual energy production
BOEM	Bureau of Ocean Energy Management
CapEx	capital expenditure
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
GHG	greenhouse gas
GW	gigawatt
ITC	investment tax credit
lidar	light detection and ranging
LACE	levelized avoided cost of energy
LCOE	levelized cost of energy
metocean	meteorological and oceanographic
MW	megawatt
nm	nautical mile(s)
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
m	meter(s)
O&M	operation and maintenance
OCS	Outer Continental Shelf
OREC	Offshore Renewable Energy Credit
OpEx	operational expenditure
PTC	production tax credit
PPA	power purchase agreement
R&D	research and development
REC	Renewable Energy Credit
RFF	Request for Feedback
RODEO	Real-time Opportunity for Development Environmental Observations
RPS	renewable portfolio standard
TIV	turbine installation vessel
WEA	wind energy area

Executive Summary

Offshore wind energy holds the promise of significant environmental and economic benefits for the United States. It is an abundant, low-carbon, domestic energy resource. It is located close to major coastal load centers, providing an alternative to long-distance transmission or development of electricity generation in these land-constrained regions. Once built, offshore wind farms could produce energy at low, long-term fixed costs, which can reduce electricity prices and improve energy security by providing a hedge against fossil fuel price volatility.

Realizing these benefits will require overcoming critical challenges in three strategic themes: 1) reducing the costs and technical risks associated with domestic offshore wind development, 2) supporting stewardship of U.S. waters by providing regulatory certainty and understanding and mitigating environmental risks of offshore wind development, and 3) increasing understanding of the benefits and costs of offshore wind energy.

The U.S. Department of Energy (DOE), through its Wind Energy Technologies Office, and U.S. Department of the Interior (DOI), through its Bureau of Ocean Energy Management (BOEM), have jointly produced this updated national strategy to facilitate the responsible development of offshore wind energy in the United States. In doing so, the agencies accounted for progress made since the last national offshore wind strategy released in 2011, and utilized significant input from the offshore wind community. This strategy highlights the gaps that need to be addressed by the offshore wind community as a whole, and provides a suite of actions that DOE and DOI are positioned to undertake to address these gaps and help the nation realize the benefits of offshore wind development.

The United States Needs a National Approach to Offshore Wind Development

The national energy landscape has changed significantly since the first national strategy for offshore wind was released in 2011. The first domestic offshore wind farm is scheduled for commercial operation in 2016, and there are now 11 active commercial leases along the Atlantic Coast. The United States took steps toward a low-carbon future through its commitments at the Paris Climate Conference, the promulgation of the Clean Power Plan,[1] and legislative action, such as the extension of the renewable energy production tax credit and investment tax credit. Coastal states have increased their demand for renewable energy deployment through renewable portfolio standards and other mandates. Many legacy fossil fuel, nuclear, and renewable generators are set to retire because of age, cost, or as part of the move toward lower-carbon sources of electricity. Land-based wind energy generation in the United States has increased nearly 60% and utility-scale solar generation increased more than 1,300% [1] relative to 2011. Most of this renewable generation is located far from coastal load centers, and long-distance transmission infrastructure has not kept pace with this rapid deployment. At the same time, the offshore wind market has matured rapidly in Europe, and costs are now falling. These trends suggest that offshore wind has the opportunity to play a substantial role as a source of domestic, large-scale, affordable electricity for the nation.

DOE and DOI developed this strategy as a joint document and have a single overarching goal in its implementation, which is to facilitate the development of a robust and sustainable offshore wind industry in the United States. The agencies will coordinate on the implementation of many of the specific actions they intend to undertake to support achievement of this goal. In recognition of their unique and complementary roles, and consistent with their missions and authorities, DOE and DOI each identified the actions they plan to address, and set individual objectives against which they will measure progress. These objectives are as follows:

- DOE aims to reduce the levelized cost of energy through technological advancement to compete with local electricity costs, and create the conditions necessary to support DOE's *Wind Vision*[2] study scenario levels [2] of deployment by supporting the coexistence of offshore wind with the environment, coastal communities, and other users of ocean space.
- DOI aims to enhance its regulatory program to ensure that oversight processes are well-informed and adaptable, avoid unnecessary burdens, and provide transparency and certainty for the regulated community and stakeholders.

DOE and DOI solicited significant stakeholder and public input to inform this document through a DOE Request for Information and a DOI Request for Feedback, as well as a jointly hosted public workshop. Feedback received through these efforts was critical to DOI and DOE in defining the challenges facing offshore wind presented in this document, as well as suggesting potential federal actions to address them.

Offshore Wind Represents a Significant Opportunity to the Nation

A number of factors demonstrate the realistic and substantial opportunity that offshore wind presents to the United States:

- **U.S. offshore wind resources are abundant.** Today, a technical potential of 2,058 gigawatts (GW) of offshore wind resource capacity are accessible in U.S. waters using existing technology. This is equivalent to an energy output of 7,200 terawatt-hours per year—enough to provide nearly double the total electric generation of the United States in 2015.
- **Significant siting and development opportunities are available today in U.S. waters.** By the end of 2015, DOI had awarded 11 commercial leases for offshore wind development that could support a total of 14.6 GW of capacity in areas already vetted for preliminary siting conflicts through extensive intergovernmental and stakeholder coordination. BOEM has a number of potential wind areas that are currently in the planning stages.
- **Electricity demand growth and scheduled power plant retirements in coastal states provide significant opportunity for offshore wind development.** If the 86 GW of offshore wind studied in the *Wind Vision* study scenario[3] were developed by 2050, offshore wind would make up 14% of the projected demand for new electricity generation in the coastal and Great Lakes states.
- **In some locations, offshore wind could be competitive with incumbent forms of generation in the next decade.** A new cost analysis by the National Renewable Energy Laboratory shows credible scenarios for cost reductions below $100/megawatt-hour by 2025 in some areas of the United States, and more widely around the country by 2030. Assuming near-term deployment of offshore wind at a scale sufficient to support market competition and the growth of a supply chain, development of offshore wind energy in markets with relatively high electricity costs, such as the Northeast, could be cost-competitive within a decade.
- **Deploying offshore wind could lead to significant electrical system benefits for system operators, utilities, and ratepayers.** Because of its low marginal costs of production and the fact that offshore winds in many regions tend to be strong at times of peak demand, offshore wind energy can lower wholesale electricity prices in many markets. Offshore wind can also decrease transmission congestion and reduce the need for new long-distance transmission.
- **A robust offshore wind industry would lead to significant positive environmental and economic external benefits.** Assuming the *Wind Vision* study scenario deployment level of 86 GW offshore wind by 2050, national benefits could be:
  - **Reduced greenhouse gas emissions.** A 1.8% reduction in cumulative greenhouse gas emissions—equivalent to approximately 1.6 billion metric tons of carbon dioxide—could save $50 billion in avoided global damages.
  - **Decreased air pollution from other emissions.** The United States could save $2 billion in avoided mortality, morbidity, and economic damages from cumulative reductions in emissions of sulfur dioxide, nitrogen oxides, and fine particulates.
  - **Reduced water consumption.** The electric power sector could reduce water consumption by 5% and water withdrawals by 3%.
  - **Greater energy diversity and security.** Offshore wind could drive significant reductions in electricity price volatility associated with fossil fuel costs.
  - **Increased economic development and employment.** Deployment could support $440 million in annual lease payments into the U.S. Treasury and approximately $680 million in annual property tax payments, as well as support approximately 160,000 gross jobs in coastal regions and around the country [2].[4]

Key Challenges Remain

To support a robust and sustainable offshore wind industry in the United States, challenges across three strategic themes need to be overcome.

- **Reducing costs and technology risks.** Today, the cost of offshore wind energy is too high to compete in most U.S. markets without subsidies. However, continued global market growth and research and development investments across the following three action areas could significantly reduce the costs of offshore wind toward competitive levels:
  - **Offshore wind power resource and site characterization.** A better understanding of the unique meteorological, ocean, and seafloor conditions across U.S. offshore wind development sites will allow for optimized designs, reduced capital costs, greater safety, and less uncertainty in preconstruction energy estimates, resulting in reduced financing costs.

- Offshore wind plant technology advancement. Increasing turbine size and efficiency, reducing mass in substructures, and optimizing wind plants at a systems level for unique U.S. conditions can reduce capital costs and operating expenses and increase energy production at a given site.
- **Installation, operation and maintenance, and supply chain solutions.** The complexity and risk associated with installation and operation and maintenance activities requires specialized infrastructure that does not yet exist in the United States. Reducing or eliminating the need for specialized assets, along with leveraging the nation's existing infrastructure, will reduce capital and operating costs in the near term and help unlock major economic development and job creation opportunities in the long term.

- **Supporting effective stewardship.** Effective stewardship of the nation's ocean and Great Lakes resources will be necessary to allow for the development of a sustainable offshore wind industry in the United States. DOI, through BOEM, oversees the responsible development of energy on the Outer Continental Shelf. Offshore wind developers, financiers, and power purchasers need confidence in a project's ability to navigate regulatory and environmental compliance requirements in a predictable way. To improve this balance and support effective stewardship, action is needed in the following two areas:
  - **Ensuring efficiency, consistency, and clarity in the regulatory process**. Further work can be done to improve consistency and identify and reduce unnecessary burdens in BOEM's existing regulatory process. This may include establishing more predictable review timelines and maintaining a reasonable level of flexibility given the early stage of the industry's development.
  - **Managing key environmental and human-use concerns**. More data need to be collected to verify and validate the impacts of offshore wind development on sensitive biological resources and existing human uses of ocean space. Improved understanding and further collaboration will allow for increased efficiency of environmental reviews and tighter focus on the most important issues.
- **Increasing understanding of the benefits and costs of offshore wind.** Building a better understanding of the impacts of offshore wind on the electricity grid, unique electricity market costs and benefits, and environmental externalities can help create the conditions needed for near-term deployment.
  - **Offshore wind electricity delivery and grid integration**. Impacts of significant offshore wind deployment on grids need to be better understood at state and regional levels, and the costs and benefits associated with different offshore transmission infrastructure configurations and strategies need to be characterized.
  - **Quantifying and communicating the benefits and costs of offshore wind**. The environmental and economic benefits and costs associated with offshore wind need to be quantified and communicated to key stakeholders to inform decisions on near-term offtake agreements, other project-specific matters, and policies affecting offshore wind.

A Robust and Credible Plan for Federal Action

Federal government action can supplement the work of states, utilities, the wind industry, the environmental community, researchers, and other stakeholders to facilitate offshore wind development. DOE and DOI aim to provide essential federal leadership to help overcome certain challenges and help the nation to realize the benefits of offshore wind. This strategy lays out 34 concrete actions in seven action areas that DOE and DOI can take to facilitate responsible, robust, and sustainable offshore wind development in the United States.

Notes

1. The Clean Power Plan is a policy aimed at combating anthropogenic climate change (global warming) that was first proposed by the Environmental Protection Agency in June 2014, under the administration of President Barack Obama. The final version of the plan was unveiled by President Obama on August 3, 2015. On February 9, 2016, the Supreme Court stayed implementation of the Clean Power Plan pending resolution of legal challenges to the plan in the D.C. Circuit. *https://www.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants*.
2. The *Wind Vision* study takes America's current installed wind power capacity across all facets of wind energy (land-based, offshore, and distributed) as its baseline and assesses the potential economic, environmental, and social benefits of a scenario in which U.S. wind power supplies 10% of the nation's electrical demand in 2020, 20% in 2030, and 35% in 2050 [2].
3. The study scenario is not a goal or future projection for wind power. Rather, the *Wind Vision* scenarios comprise an analytical framework that supports detailed analysis of potential costs, benefits, and other impacts associated with future wind deployment. The study scenario comprises a range of cases spanning plausible variations from central values of wind power and fossil fuel costs.
4. Cumulative benefits are reported on a Net Present Value basis for the period of 2013 through 2050; annual benefits reflect the impact in current dollars for the year noted (e.g., 2050). Greenhouse gases, air pollution, and water benefits are estimated from the combined land-based and offshore wind system impact and proportionately allocated to offshore based on its share of total wind generation. In contrast, gross jobs, lease payments, and property taxes are estimated specifically for offshore wind based on expected capacity additions and servicing requirements anticipated in the *Wind Vision* study scenario.

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1.0 Introduction

1.1 Opportunity for the Nation

In 2015, the U.S. Department of Energy (DOE) released *Wind Vision: A New Era for Wind Power in the United States* [2], a landmark report evaluating future pathways for the U.S. wind industry and analyzing, for the first time, the full benefits and costs of a future in which wind delivers 35% of U.S. electricity by 2050. The report looked at some of the economic, energy system, and environmental benefits of offshore wind, and found that realizing the *Wind Vision* study scenario of 86 gigawatts (GW) of offshore wind deployment by 2050 would have significant benefits to our nation. These include:

- **Reduced greenhouse gas (GHG) emissions**. A 1.8% reduction in cumulative GHG emissions—equivalent to 1.6 billion metric tons of carbon dioxide—through 2050 could save $50 billion in avoided global damages.
- **Decreased air pollution from other emissions**. The United States could save $2 billion in avoided mortality, morbidity, and economic damages from cumulative reductions through 2050 in emissions of sulfur dioxide, nitrogen oxides, and fine particulates.
- **Reduced water consumption**. The electric power sector could reduce annual water consumption by 5% and annual water withdrawals by 3% in 2050.
- **Greater energy diversity and security**. The nation could experience significant reductions in electricity price volatility associated with fossil fuel costs.
- **Increased economic development and employment**. This increase could amount to $440 million in annual lease payments to the U.S. Treasury and approximately $680 million in annual property tax payments, as well as support approximately 160,000 gross jobs in coastal regions and around the country [2].[5]

The potential of offshore wind as a renewable energy resource in the United States is enormous. A robust and sustainable U.S. offshore wind industry could decrease GHG emissions, diversify the nation's energy portfolio, generate affordable power for homes and businesses, and revitalize key economic sectors [2–4]. With nearly 80% of the U.S. electricity demand located in coastal states and a total offshore wind resource roughly double the national consumption of electricity [1], offshore wind has the potential to contribute significantly to a clean, affordable, and secure national energy mix.

Though the United States generates more electricity from land-based wind than any other country, there are presently no offshore wind turbines operating in U.S. waters [5–6]. The first U.S. project is expected to commence operation offshore Block Island, Rhode Island, in late 2016, and several more could be operational before 2020. The offshore wind market is maturing quickly in Europe and Asia; as of the end of 2015, more than 12 GW of offshore wind capacity had been installed globally [7], and the cost of offshore wind energy is now trending downward in Europe through experience, increased competition in the offshore wind market, and innovation. Recent analysis suggests that much of the cost-reduction progress seen in European markets can translate to the United States as developers leverage best-available European technologies and adapt them to the unique conditions of the United States [5].

Realizing the substantial benefits of offshore wind in the United States, however, will require overcoming a number of key technological, regulatory, environmental, and market challenges. For example, the costs of offshore wind need to fall substantially, and the supply chain needs to be developed. The regulatory process for offshore wind could be further optimized, and data gaps associated with environmental impacts need to be addressed. The unique set of costs and benefits associated with offshore wind energy needs to be better quantified and communicated to policymakers and stakeholders to allow for their full consideration in decisions about offshore wind projects and policies.

The federal government can play a leadership role in addressing these challenges. DOE and the U.S. Department of the Interior (DOI) have come together to develop this strategy document, which highlights the potential value of offshore wind to the nation and presents a credible set of approaches and actions to facilitate the responsible development of a sustainable and robust offshore wind industry in the United States.

1.2 Key Trends Motivating the National Offshore Wind Strategy

Much has changed in the U.S. energy landscape and the offshore wind industry since DOE, in collaboration with DOI, released the first national offshore wind strategy document in 2011 (see text box) [8]. The policy environment has evolved to include stronger directives and incentives at the federal and state levels for the reduction of greenhouse gases and the expansion of renewable energy in which offshore wind can play a significant part. Lower projected costs and maturing markets in Europe and Asia signal the potential viability of offshore wind energy technology in the U.S. market [5]. In this context, the industry needs a new assessment of the costs and benefits of offshore wind to the country, and an updated strategy for federal engagement and investment in offshore wind research, development, demonstration, deployment, and federal oversight of offshore wind projects.

Falling Costs Globally

As of mid-2015, 250 GW of offshore wind capacity had been announced in the global development pipeline [5]. Studies indicate that there is significant potential for further cost reduction through continued deployment and learning curve effects, investment in research and development (R&D), industrialization of the supply chain, and improvements in financing. In the European market, achieving European Union goals for the offshore wind levelized cost of energy (LCOE) of 100 € per megawatt-hour (MWh) (approximately $112/MWh) by 2020 appears increasingly likely [9–13].

Emerging Federal Climate and Renewable Energy Policies

In 2015, the Environmental Protection Agency finalized the Clean Power Plan, which sets standards to reduce carbon dioxide emissions in the electricity sector by 32% by 2030 from 2005 levels [14]. Under the plan, states will be required to develop and submit plans to reduce electricity sector emissions through the development of low-carbon generation sources and other investments. Offshore wind resources can significantly increase the potential for some land or transmission-constrained coastal states to meet targets with in-state renewable resources, and reduce the difficulty and, potentially, the cost of achieving their targets under the Clean Power Plan.[6]

In 2015, the United States also made substantial commitments to reduce GHG emissions to 26%-28% below 2005 levels by 2025 under the Paris Agreement on climate change reached at the United Nations Framework Convention on Climate Change's 21st Conference of the Parties (COP 21) in December 2015. The Clean Power Plan is a key building block to reaching this commitment. The United States also joined 20 countries and private investors to launch Mission Innovation, an international group of public and private sector global leaders aiming to "reinvigorate and accelerate global clean energy innovation with the objective to make clean energy widely affordable" [15]. Under Mission Innovation, the United States has pledged to double its government clean energy R&D investment over the next 5 years.

A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States [8]

In 2011, DOE, in collaboration with DOI, released *A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States* [8]. This strategy outlined the actions DOE and DOI would pursue to support and accelerate the development of an offshore wind industry in the United States by reducing the cost of energy and decreasing deployment timelines. In this report, DOI announced the development of a new initiative to facilitate siting, leasing, and construction of new projects. DOE, for its part, launched a series of investments totaling more than $250 million in targeted technical research and development, partnerships to address market barriers, and implementation of demonstration projects to showcase advanced technologies with the potential to reduce offshore wind costs in the United States.

In December 2015, Congress enacted a multiyear extension of the renewable energy production tax credit (PTC) and business energy investment tax credit (ITC) in the 2016 Consolidated Appropriations Act (P.L. 114-113). The wind energy PTC and ITC were thereby extended through 2016 at 100% of their 2015 value. After 2016, the PTC and ITC will decrease in 20% annual increments to 40% of their 2015 value in 2019. This longer-term policy approach is significant to the industry, and renewable energy projects starting construction prior to the end of the period will qualify.

State Renewable Energy and Climate Objectives

States have also taken significant steps that support offshore wind development. As of June 2016, 29 states and the District of Columbia now have renewable portfolio standards (RPSs) that require utilities to sell a specified percentage or amount of renewable energy. Several states in particular have established aggressive renewable energy targets. Both California and New York, for instance, include a 50% target by 2030, whereas Hawaii has set a goal of 100% by 2045 [16]. A few states also have specific mechanisms that provide special consideration for offshore wind. For example, the Maryland Offshore Wind Energy Act of 2013 provides for Offshore Renewable Energy Credits (ORECs) for sourcing up to 2.5% of the state's electricity supply from offshore wind energy starting in 2017. It requires consideration of peak load price suppression and limiting rate impacts [17].

U.S. Offshore Wind Deployment Begins

The first commercial offshore wind project in the United States completed construction off the coast of Rhode Island in August 2016. The 30-MW Block Island Wind Farm is expected to be operational by late 2016. If successful, the project will mark the beginning of offshore wind's contributions to the nation's energy portfolio, and could signal the advent of a viable U.S. offshore wind energy market and provide invaluable lessons learned to support future development. Several additional projects could be operating by 2020, including three DOE Advanced Technology Demonstration Projects in New Jersey, Ohio, and Maine—Fishermen's Energy Atlantic City Windfarm, Lake Erie Energy Development Corporation's Icebreaker project, and the University of Maine's New England Aqua Ventus I—which, as of August 2016, are in the final design and planning phase. A total of nearly 16 GW have been proposed for development in the United States [5].

1.3 The Federal Government's Role in Domestic Offshore Wind Energy

The U.S. government has a substantial role to play in facilitating the development of a robust and sustainable offshore wind industry in the United States. For example, the federal government can move forward with investments in research and development that are not being undertaken by industry as a result of real or perceived cost or risk, or because of the long payoff times associated with these investments. These programs can result in technological innovations that reduce cost and environmental impacts of energy technologies. Furthermore, federal programs can engage other agencies to leverage resources and co-address issues related to wind energy development, or, where appropriate, develop partnerships with or facilitate technology transfer to industry to ensure that innovations make it to market.

The Wind Energy Technologies Office within DOE's Office of Energy Efficiency and Renewable Energy supports the development, deployment, and commercialization of wind energy technologies. DOE works with a variety of stakeholders to identify and support R&D efforts that improve technology performance, lower costs, and help responsibly deploy technologies that efficiently capture the abundant wind energy resources in the United States. DOE provides R&D funding across a number of areas, including Offshore Wind Advanced Demonstration Projects; wind plant technology advancement, manufacturing advancement, and testing; grid integration; wind resource assessment; the mitigation of market barriers such as environment and siting challenges; stakeholder engagement and outreach; and workforce development.

DOI's Bureau of Ocean Energy Management (BOEM) is responsible for ensuring that offshore renewable energy development in federal waters takes place in a responsible and sustainable manner. BOEM currently regulates offshore wind projects through four distinct phases: planning, leasing, site assessment, and construction and operations. BOEM engages key stakeholders throughout this process, and early communication with interested and potentially affected parties is critical to managing possible conflicts. BOEM's offshore wind authorization process includes establishing intergovernmental task forces; issuing leases, including commercial leases, limited leases, and research leases; and reviewing plans that describe specific offshore wind project proposals. Under its statutory authority, BOEM is responsible for ensuring fair return to the American public for the use of submerged lands to generate revenue from the production of electricity. Since 2009, BOEM has made more than 1.18 million acres of submerged land available on the Outer Continental Shelf (OCS) for potential wind development, and generated more than $16.4 million through competitive auctions for its leases.

1.4 Development of a Robust Offshore Wind Strategy

Significant public engagement informed the development of this document. In May 2015, DOE issued a Request for Information to solicit stakeholder feedback regarding the implementation of the 2011 strategy, the key challenges currently facing domestic offshore wind energy, and potential paths forward for continued investment in offshore wind energy technology [2–4]. DOE received 40 responses from a wide variety of stakeholders on issues ranging from the need for power purchase mechanisms to technology development concerns.

In addition, BOEM issued a Request for Feedback (RFF) in September 2015, inviting public comments on any aspects of the agency's renewable energy program that are either particularly effective or ineffective and burdensome. BOEM received 57 responses from a range of stakeholders, relating to numerous aspects of its renewable energy program [18]. When developing this strategic planning document, BOEM carefully considered the comments received in response to the RFF.

In December 2015, DOE and DOI convened a public workshop in Washington, D.C. The goals of the workshop were twofold: identify stakeholders' top priorities to better enable DOE and DOI to facilitate the development of the offshore wind industry in the United States, and articulate each agency's respective role in the offshore wind energy development process. The workshop presented information on DOE's and BOEM's actions in offshore wind energy to date, and a 2016 analysis by the National Renewable Energy Laboratory (NREL) on the major costs and benefits of offshore wind energy deployment in the United States. Specific discussions were held in a number of topic areas. Feedback from these sessions directly informed the actions that are outlined in Chapter 3 and Chapter 4 [19].

1.5 A Framework for Federal Action to Facilitate Offshore Wind Development in the United States

This document presents a framework for federal action intended to help facilitate the responsible development of a robust and sustainable offshore wind industry in the United States. DOE and DOI collaboratively developed this strategy, and will continue to coordinate on its implementation. Consistent with their individual authorities and missions, DOE and DOI also developed complementary, agency-specific objectives against which progress can be measured within each agency:

- DOE aims to reduce the LCOE through technological advancement to compete with local electricity costs, and create the conditions necessary to achieve *Wind Vision*-level deployment through market-barrier-reduction activities.
- DOI aims to enhance its regulatory program to ensure that oversight processes are well-informed and adaptable, avoid unnecessary burdens, and provide transparency and certainty for the regulated community and stakeholders.

To meet these agency-specific objectives, DOE and DOI will coordinate their activities across three strategic themes and seven action areas as shown in Table 1.1. These themes and action areas are intended to address the critical issues identified through analysis as well as feedback from stakeholders described earlier.

Three chapters follow this introduction. Chapter 2 presents the value proposition represented by offshore wind in the United States, based both on the findings of the *Wind Vision* and a new NREL analysis of the U.S. offshore wind resource, opportunities for growth, and cost reduction pathways. Chapter 3 outlines the key challenges facing offshore wind across the three strategic themes and seven action areas, describes progress made to date, and articulates the remaining gaps for future action by all offshore wind stakeholders to ultimately overcome these challenges. Finally, Chapter 4 identifies the specific actions that DOE and DOI plan to undertake to achieve their objectives under this strategy.

Table 1.1. Key Strategic Themes and Action Areas

Strategic Themes	Action Areas
1. Reducing Costs and Technology Risks	1. Offshore Wind Power Resource and Site Characterization 2. Offshore Wind Plant Technology Advancement 3. Installation, Operation and Maintenance, and Supply Chain Solutions
2. Supporting Effective Stewardship	1. Ensuring Efficiency, Consistency, and Clarity in the Regulatory Process 2. Managing Key Environmental and Human-Use Concerns
3. Increasing Understanding of the Benefits and Costs of Offshore Wind	1. Offshore Wind Electricity Delivery and Grid Integration 2. Quantifying and Communicating the Benefits and Costs of Offshore Wind

Notes

5. Cumulative benefits are reported on a Net Present Value basis for the period of 2013 through 2050 using a discount rate of 3%; annual benefits reflect the impact in current dollars for the year noted (e.g., 2050). Greenhouse gas emissions, air pollution, and water benefits are estimated from the combined land-based and offshore wind system impact and proportionately allocated to offshore based on its share of total wind generation. In contrast, gross jobs, lease payments, and property taxes are estimated specifically for offshore wind based on expected capacity additions and servicing requirements anticipated in the *Wind Vision* study scenario.

6. On February 9, 2016, the Supreme Court stayed implementation of the Clean Power Plan pending resolution of legal challenges to the plan in the D.C. Circuit.

2.0 The Value of Offshore Wind

2.1 Introduction

Demonstrating a significant potential for offshore wind to achieve economic viability over a wide range of sites in the United States is central to facilitating its development. The value of offshore wind depends not only on achieving lower life-cycle costs, but also on a number of building blocks, including an abundant wind resource; substantial siting and development opportunities; sufficient market opportunity; a credible path to achieve competitive cost; demonstrated economic potential; and offshore wind's wider energy system, environmental and economic development benefits as shown in Figure 2.1. This chapter highlights these value proposition building blocks that can enable commercial success, which point to significant future economic potential for offshore wind in the United States as a significant contributor to a cost-effective, reliable, low-carbon U.S. energy portfolio.

Abundant Resource

The technical potential of U.S. offshore wind is more than double total U.S. electricity consumption [20]. A 2016 resource analysis done by NREL updates the previous national resource assessment studies [21] and refines and reaffirms that the available offshore wind resource is sufficient for offshore wind to be viable and a large-scale contributor to the electric energy supply. Experience from other renewable technologies, such as land-based wind and solar energy, shows that site development is highly selective, representing a small percentage of the overall resource potential. Abundant resources allow for siting flexibility so that projects may avoid the most conflicted areas. As such, the DOE *Wind Vision* study scenario for 2050 would require the United States to use only 4.2% of the total technical resource potential area.

Substantial Siting and Development Opportunities

As of May 2016, there are 11 active commercial leases in the Atlantic Ocean with the potential to support initial deployment of about 14.6 GW of offshore wind [5].[7] Since 2011, the siting and regulatory process for offshore wind energy has matured and advanced significantly in the United States. In federal waters, BOEM has implemented a process through careful planning and public outreach by which offshore wind resource areas are screened to avoid or mitigate many potential conflicts.

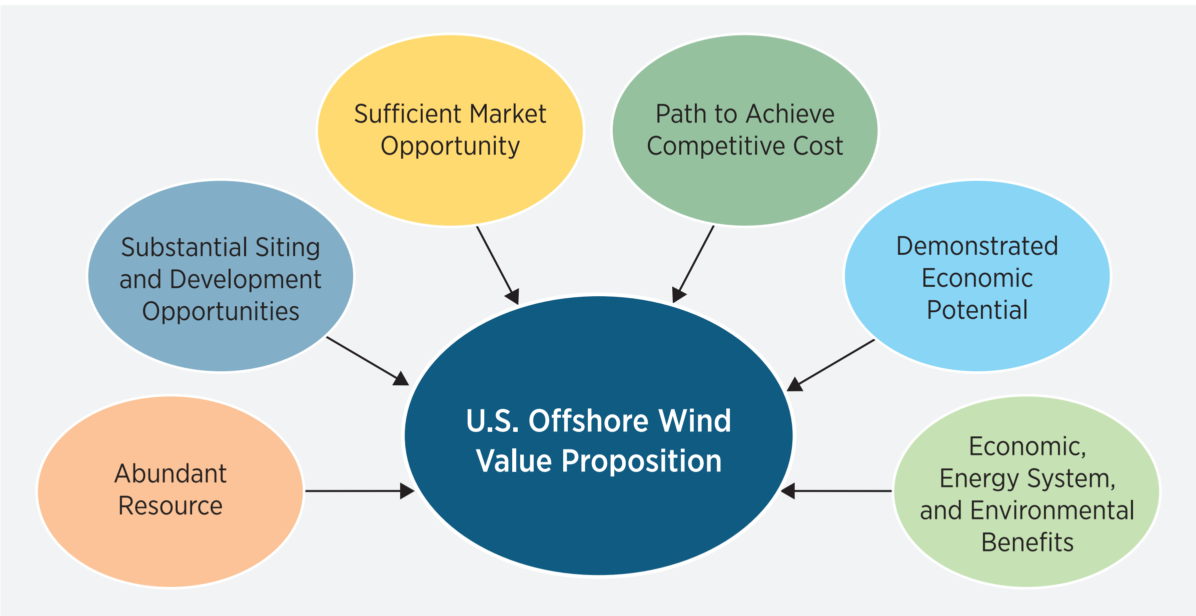


Figure 2.1. Building blocks comprising the offshore wind value proposition for the United States

Sufficient Market Opportunity

The *Wind Vision* study scenario deployment of 86 GW by 2050 would meet 14% of the projected demand for new generation in the coastal and Great Lakes states in 2050. As the existing fleet of electric-generating units ages and retires and the demand for electricity increases over time, the need for new electric-generation supply grows, creating opportunities for a new type of generation to be built. Recent analysis reveals that the opportunity space in the electricity generation market will be large enough to include newcomers like offshore wind while maintaining a diversity of generation on the grid [22].

Path to Achieve Competitive Cost

Through technology improvements, efficiencies gained through economies of scale, and deployment experience, offshore industry cost models now show credible scenarios for cost reductions below $100/MWh at many sites in the United States by the year 2030 [23]. Although the LCOE for offshore wind in 2015 is still high relative to other, more mature energy sources, this analysis of trends over the next 15 years substantiates possible cost reduction pathways that lead toward economic viability with little or no incentives for some U.S. coastal regions [23]. Specific challenges associated with these cost reductions, as well as actions required to achieve them, are explored in more depth in Chapter 3 and Chapter 4.

Demonstrated Economic Potential

The economic potential for offshore wind in the United States cannot be determined by LCOE alone. The economic viability of offshore wind depends heavily on the system prices for electricity being sold in local and regional markets where offshore wind might be deployed. To identify sites that are the most economical, researchers evaluated offshore wind LCOE relative to local electricity prices using a geospatial model [23]. The study results revealed competitive LCOE values under future scenarios that are highly dependent on local electricity prices, and which varied significantly among U.S. coastal locations [1].

Economic, Energy System, and Environmental Benefits

Offshore wind offers the potential for a unique set of tangible economic, environmental, and energy system benefits, such as higher capacity value, wholesale electricity price suppression, and transmission congestion relief.

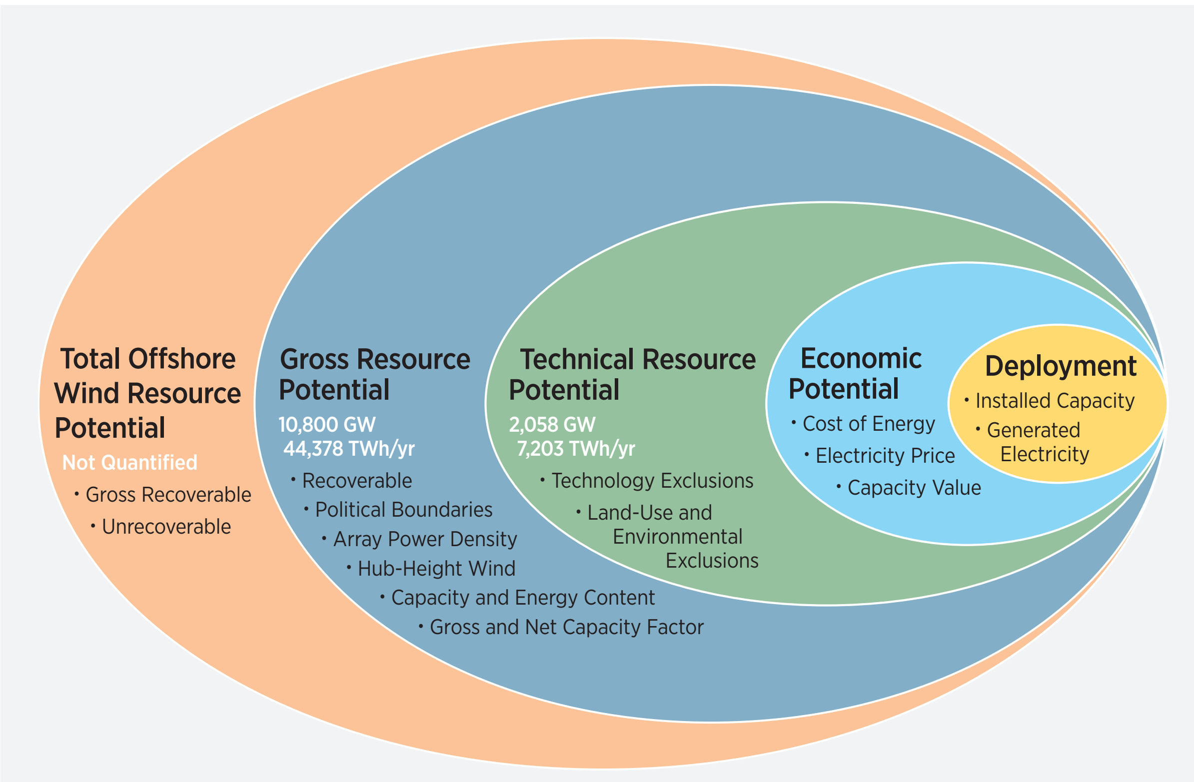


Figure 2.2. Offshore wind energy resource classification framework [24]

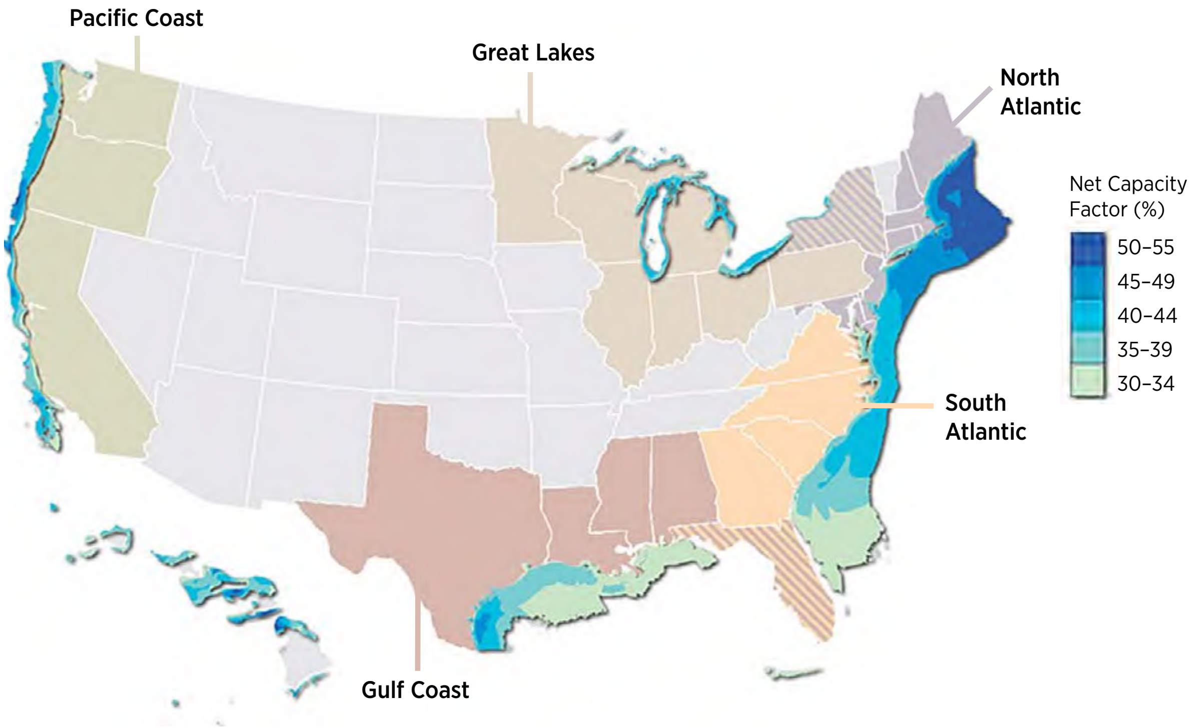


Figure 2.3. Net capacity factor for technical potential energy resource at 100 m with technical exclusions for five U.S. offshore wind resource regions

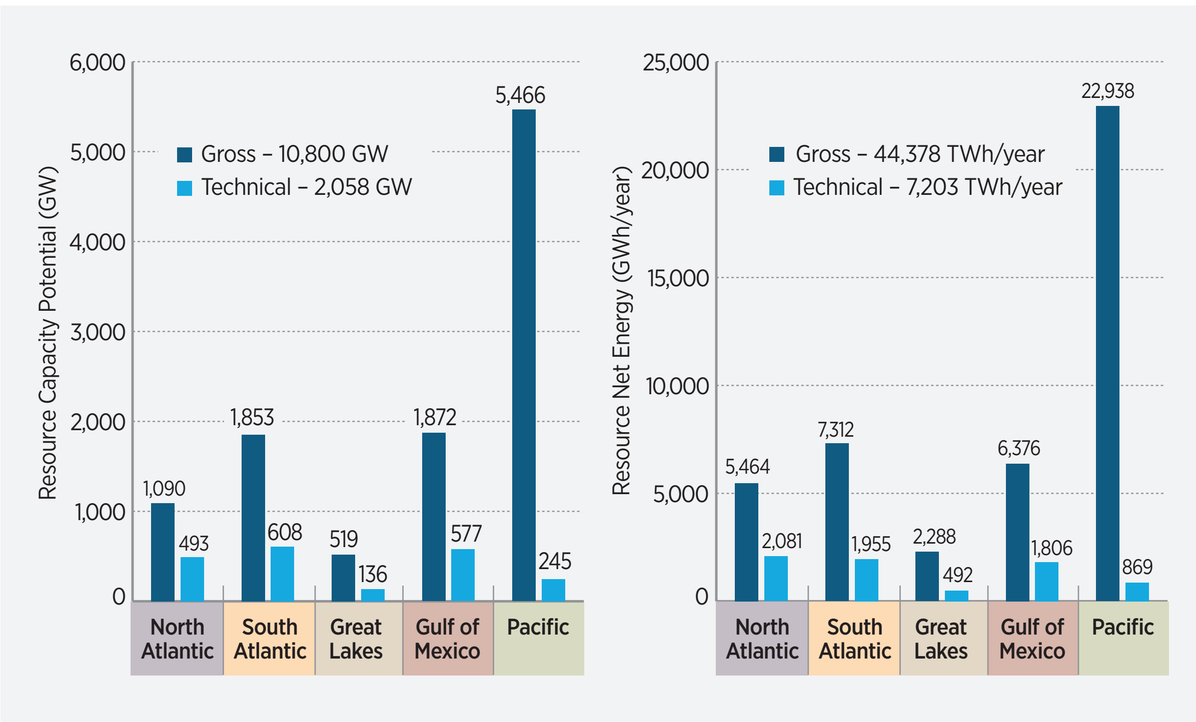


Figure 2.4 Capacity (left) and net energy (right) offshore wind resource estimates for five U.S. offshore wind resource regions

Offshore wind also offers societal benefits normally associated with low-carbon renewables. For example, the *Wind Vision* study scenario shows offshore wind could reduce GHG emissions by nearly 2%, add 160,000 domestic jobs, and reduce water consumption by the electric power sector by 5% by 2050 [2]. These benefits are likely to raise the value of offshore wind in many states or regions. Although they may not contribute directly to the bottom line for offshore wind project developers, these advantages can be added to other societal benefits commonly associated with low-carbon renewables [25].

2.2 Abundant Resource

The expansive offshore wind resource is the foundation of the offshore wind value proposition. The U.S. resource is robust, abundant, and regionally diverse, allowing for offshore wind development to be located near load centers with some of the highest electric rates in the United States [26]. In many of the most populated regions, these coastal wind resources can provide in-state power generation at a large scale. The Atlantic Ocean, Great Lakes, Gulf of Mexico, West Coast, and Hawaii all contain significant offshore wind resources, and projects have been proposed in each of these areas.

In 2010, the first U.S. offshore wind energy resource assessments were completed by NREL [21]. Using current industry knowledge, an updated 2016 offshore wind resource assessment [20] refined and reaffirmed the abundance of the available offshore wind resource. The updated resource assessment also provides a framework for resource classification (see Figure 2.2) [24], that describes the offshore wind resources in terms that help promote consistency with broader renewable resource potential capacity classification schemes [27]. Some of the significant highlights and changes featured in the *2016 Offshore Wind Energy Resource Assessment for the United States* include:

- Expanding the gross resource area from 50 nautical miles (nm) to 200 nm from the territorial sea baseline to correspond to the U.S. Exclusive Economic Zone [26], using wind speed data provided from the Wind Integration National Dataset Toolkit [28]
- Increasing the reference hub height to 100 meters (m) (previously 90 m) to reflect projected 5-year technology trends for the U.S. market [5]
- Lowering the capacity power density from 5 MW/square kilometer (km^2) to 3 MW/km^2 to adjust for greater array spacing [29–30], and to provide consistency with the *Wind Vision*
- Assessing energy production potential, including geospatial estimates of gross and net capacity factor
- Applying technical exclusions to count resources only in regions with wind speeds over 7 meters per second, water depths over 1,000 m, and icing environments where current technology is feasible[8]
- Applying land-use and environmental exclusions to eliminate areas with known conflicts [31].

With the expansion of the gross recoverable resource potential capacity area to the 200-nm Exclusive Economic Zone boundary, the U.S. gross recoverable resource potential capacity is calculated at 10,800 GW, compared to the 4,150 GW gross potential in the 2010 study. On an energy basis, the U.S. gross recoverable resource potential capacity was calculated to be 44,378 terawatt-hours (TWh) per year. In moving from the gross recoverable resource potential capacity to the technical potential capacity, about 80% of the OCS area was unsuitable using the current technology. The remaining technical potential capacity is 2,058 GW, with an energy generation potential of 7,203 TWh/year, which is almost double the electric consumption of the United States.[9]

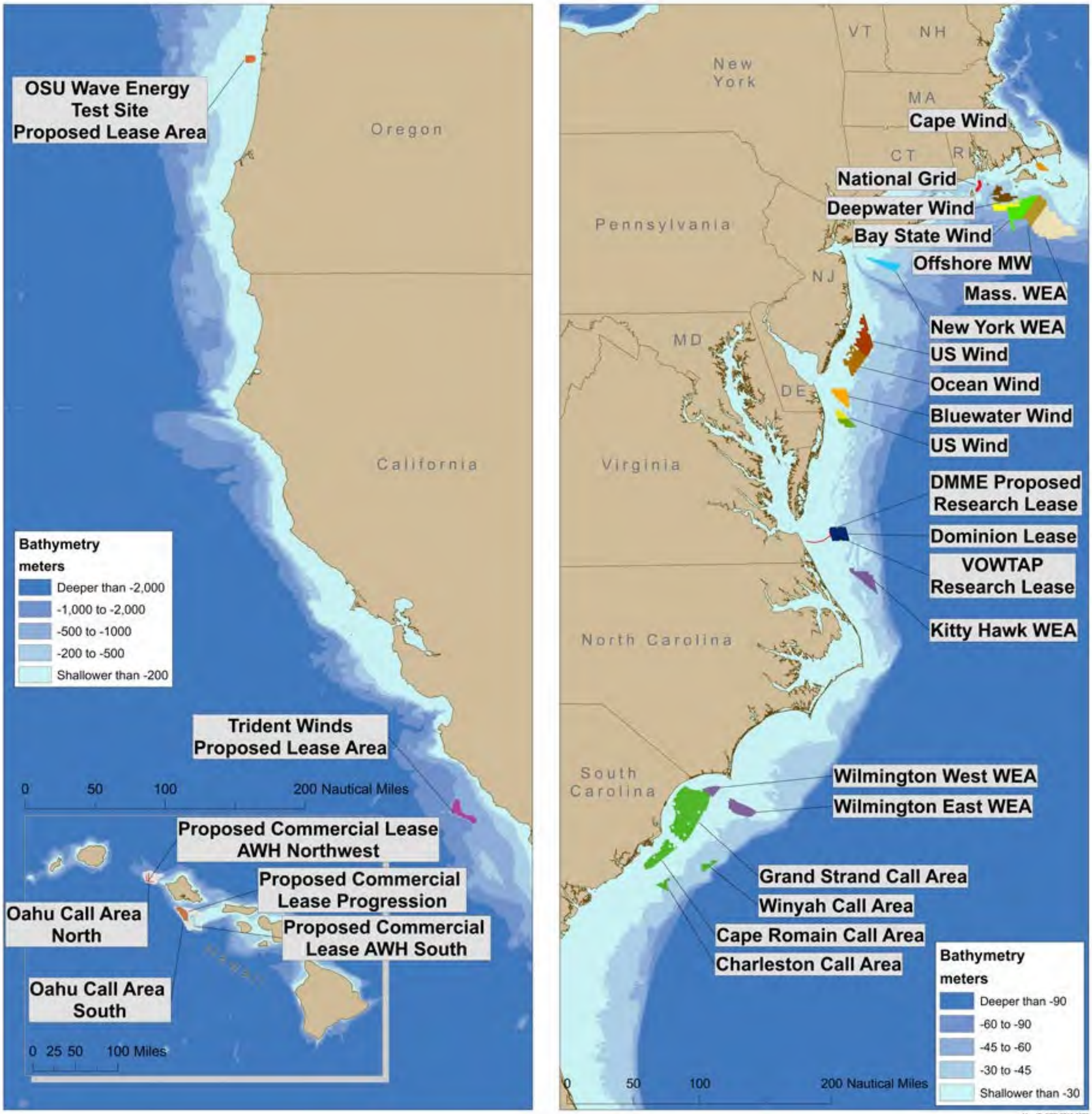
These U.S. resource totals have been divided into the five regions shown in Figure 2.3 (as defined in the *Wind Vision*). Taking into account potential wind plant system losses ranging from 12% to 23% (e.g., wake effects, electric power transmission, and offshore accessibility), the net capacity factor for the technical resource potential capacity is also shown in Figure 2.3.

Figure 2.4 shows the abundance of the U.S. offshore wind technical resource potential capacity and how it is distributed among all five *Wind Vision* regions.

Assuming the DOE *Wind Vision* study scenario deployment of 86 GW is realized, approximately 4% of the technical resource area (about 1% of the gross resource area) would need to be developed. This would equate to approximately 7% of the U.S. electric consumption [2]. Each region is capable of contributing to a viable offshore wind industry by supporting significant deployment and the development of a robust supply chain and supporting infrastructure.

2.3 Substantial Siting and Development Opportunities

An efficient, clearly defined federal regulatory process that encourages collaboration with stakeholders is essential for the development of the nascent offshore wind industry in the United States, and is a necessary building block of the offshore wind value proposition. As of 2016, there are 11 active commercial leases in the Atlantic Ocean, with the potential to support initial deployment of about 14.6 GW of offshore wind based on a standard capacity density assumption of 3 MW/km^2 [5]. BOEM's leases provide the exclusive right to submit development plans and conduct any BOEM-approved activities. It is vital that the offshore wind development



Source: BOEM

Figure 2.5. BOEM-defined areas for potential renewable energy development as of August 2016

process be conducted in a manner that is environmentally responsible, transparent, fair, and safe. This will help instill confidence in developers, utilities, and investors that future markets will materialize.

Since 2011, the siting and regulatory process for offshore wind energy in U.S. federal waters has matured and advanced significantly under the management of BOEM. Although there has been activity in both state and federal waters, the 2016 *Offshore Wind Energy Resource Assessment for the United States* reports that more than 88% of the technical offshore wind resource potential capacity area (over 606,000 km^2) in the United States is in federal waters [20]. As such, to build the 86 GW of offshore wind by 2050 in the *Wind Vision* study scenario, most of the development would likely take place on the OCS under federal jurisdiction. Figure 2.5 identifies the current location and approximate size of BOEM's proposed wind energy areas (WEAs) and other wind development zones that have been proposed, leased, or are under development in federal waters. Several other projects have also been proposed in areas outside the designated WEAs and in state waters that can be added to the number of total sites available.

Currently, BOEM has a number of potential wind areas in the planning phase. In addition, developers can submit unsolicited lease requests for offshore wind development outside of designated WEAs, as is currently being done offshore of the Pacific Coast and Hawaii [5]. In the next decade, the commercial development of floating wind technology that can be deployed in deeper waters (greater than 60 m) is expected. This capability would allow for the leasing of new areas that are located farther from shore (e.g., off the Atlantic Coast), or in areas like the Pacific Coast where current fixed-bottom technology would not be possible at a large scale. Finally, offshore wind development in the Great Lakes is poised to open up freshwater sites that are outside of BOEM's jurisdiction [5]. Together with a stable pipeline of potential power purchase agreements (PPAs), these existing and future siting opportunities can provide the necessary development capacity to support the development of a pipeline sufficient to justify the development of a robust and sustainable domestic supply chain and infrastructure.

2.4 Sufficient Market Opportunity for Offshore Wind in U.S. Coastal Regions

As the existing fleet of electric-generating units ages and retires and the demand for electricity is projected to increase, on average, over time [32], there is a growing need for new generation to be built. Recent studies show that there will be enough demand for new power in the coastal regions of the United States (including the Great Lakes region)[10] such that growth in offshore wind consistent with the *Wind Vision* study scenario between 2015 and 2050 can, in principle, be accommodated when considering electricity demand and retirements [22].[11] Further analysis will need to refine these findings to identify any operational, economic, or transmission-related constraints. Demonstrating sufficient market opportunity provides an essential building block for the offshore wind value proposition and can assist policymakers in regional and national energy planning for an initial assessment of future electricity needs.

The opportunity space is defined as the difference between the expected generation from existing power plants and the expected electrical load at a defined point in the future. To determine the opportunity space, retirements from the existing electricity-generating fleet are compared to projected electrical load growth based on Energy Information Administration [32] projections. Scheduled and age-based retirements are taken into account without consideration for early retirements or lifetime extensions caused by policy or project economics. Projecting into the future, the opportunity space increases because electrical demand is expected to grow by an average annual load growth of 0.66% (compound annual growth rate) in the United States through 2050 [22]—a time period when many power plants are expected to reach their life expectancy and retire. The opportunity space can be filled by any generation source that satisfies the system needs. Figure 2.6 shows the electrical load for U.S. coastal regions compared to the expected electric generation by major generation type (i.e., coal, gas/petroleum, nuclear, and renewables) between 2015 and 2050.

In Figure 2.6, the opportunity space is the yellow wedge that grows over time as generation plants retire and electrical demand increases. Table 2.1 compares these data to the prescribed *Wind Vision* study scenario for 2020, 2030, and 2050.

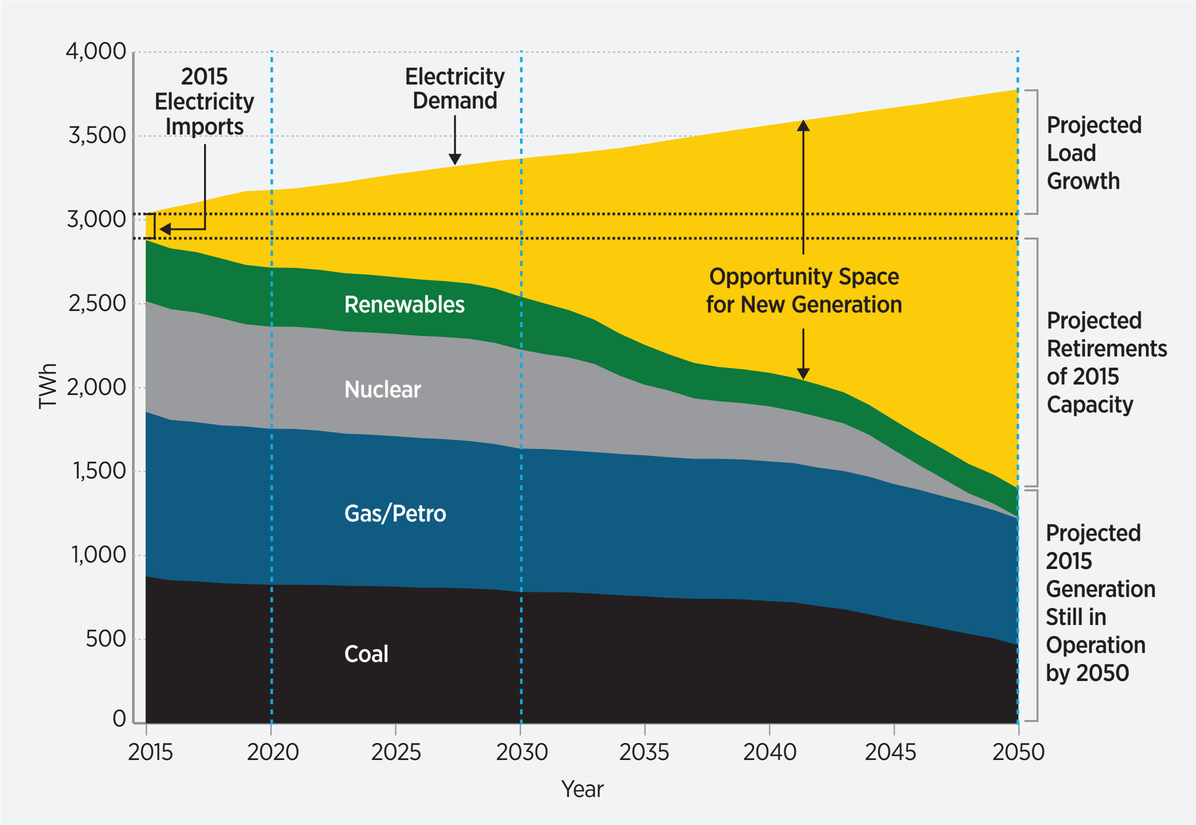


Figure 2.6. Scheduled and age-based retirements and load growth create opportunity for new offshore wind generation in coastal regions [22]

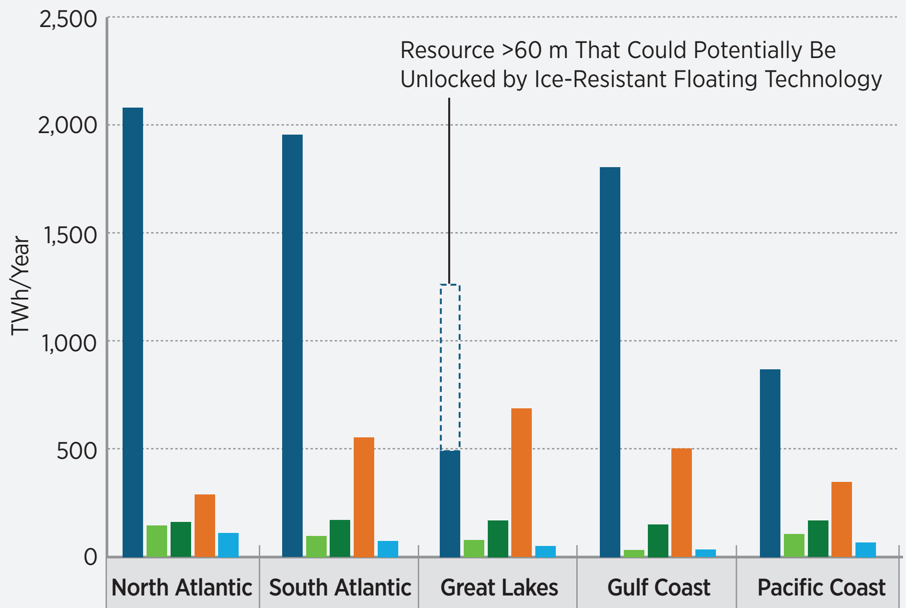
Table 2.1. Offshore Wind Market Opportunity for U.S. Coastal Regions Compared to the *Wind Vision* [2], [22]

	2020	2030	2050
Wind Vision Capacity Installed (GW)	3	22	86
Wind Vision Energy Delivered (TWh/yr)	12	87	339
Opportunity Space (U.S. Coastal Regions) (TWh/yr)	462	821	2,380
Opportunity Space Utilization by Offshore Wind	3%	11%	14%

The opportunity space for offshore wind development is far greater than the *Wind Vision* study scenario deployment. As shown in Table 2.1, from 2020 to 2050, the utilization of the opportunity associated with the *Wind Vision* study scenario increases from only 3% to 14% of the entire U.S. coastal region opportunity space.

For detailed energy planning, however, regional data and additional analysis are needed. Figure 2.7 shows the opportunity space in relation to the offshore wind technical resource potential (Figure 2.3) for each *Wind Vision* target year: 2020, 2030, and 2050, in each of the five regions. It also compares these numbers to the regional energy production associated with the *Wind Vision* study scenario.

Offshore wind resources are significantly greater than the market opportunity, meaning that the *Wind Vision* study scenario of 86 GW of deployment by 2050 would entail developing only a small fraction of the total U.S. technical potential. In the Great Lakes, however, the market opportunity space actually exceeds the technical potential by 2050. This excess is because the market opportunity space is relatively high (688 TWh/yr) and because of a limited technical resource given the analysis criteria imposed. Water depths greater than 60 m were not considered as technical resource potential in the Great Lakes because a technology for floating foundations able to resist surface ice floes in freshwater does not yet exist. However, Figure 2.7 illustrates the Great Lakes resource potential capacity that could become available if new technologies for floating foundations were developed to address this limitation.



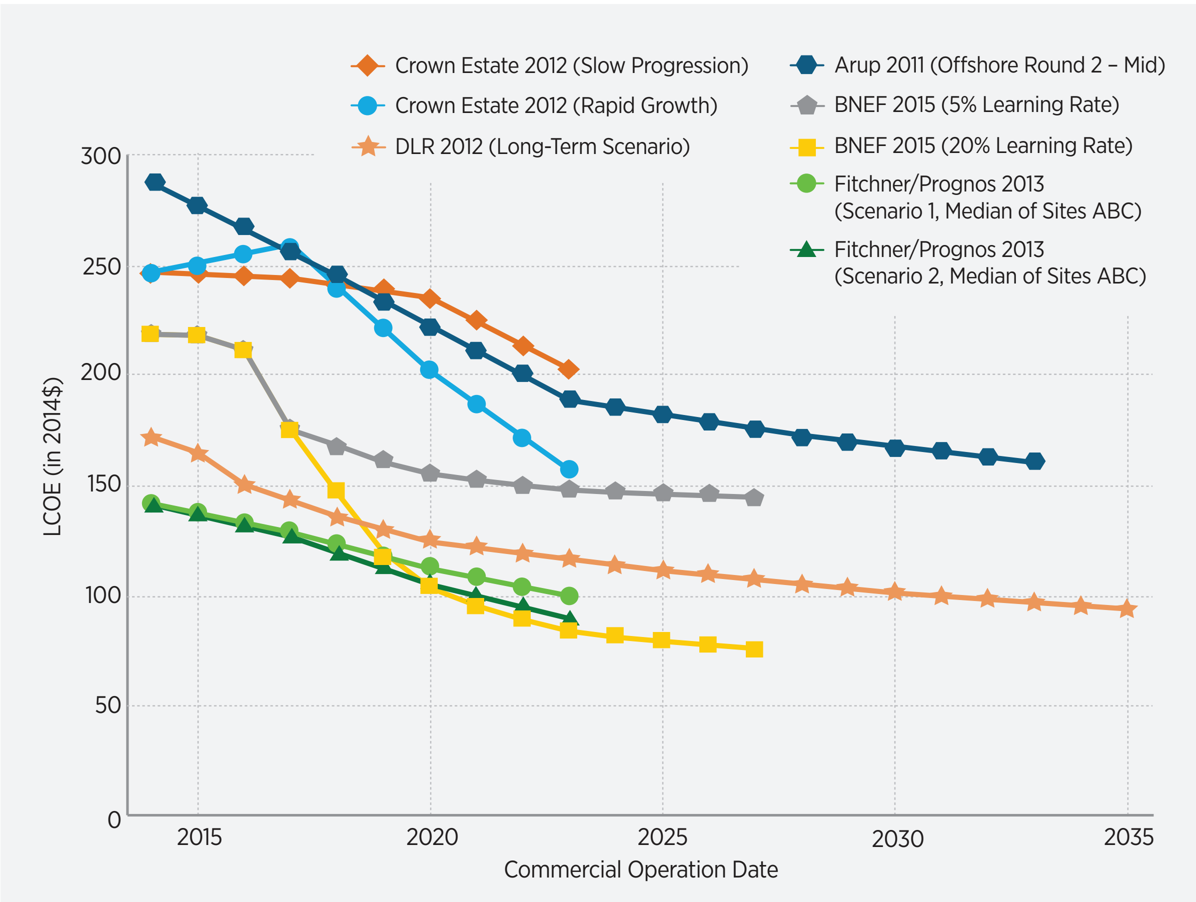
	North Atlantic	South Atlantic	Great Lakes	Gulf Coast	Pacific Coast
Technical Resource Potential	2,081	1,955	492	1,806	869
2020 Opportunity Space	145	98	80	33	106
2030 Opportunity Space	161	170	170	151	168
2050 Opportunity Space	289	555	688	502	348
2050 Wind Vision Scenario	112	75	51	34	68

Figure 2.7. Resource potential energy and opportunity space exceed requirements for the 86-GW *Wind Vision* study scenario[12] [2], [22]

2.5 Path to Achieve Competitive Cost

The offshore wind industry in Europe has realized significant cost reductions as the industry and supply chain have grown and matured. Analysis of projects installed or reaching final investment decision between 2010 and 2014 have indicated the LCOE of offshore wind projects installed in the United Kingdom has reduced from £136/MWh to £121/MWh, representing an 11% reduction in LCOE [33]. This evidence suggests that the United Kingdom will be able to reach its cost reduction trajectory of £100/MWh by 2020. The European Commission has set slightly more aggressive targets for offshore wind LCOE reduction with goals of less than €100/MWh by 2020 and less than €70/MWh by 2030 [34].

Recent spatial-economic modeling of the U.S. offshore wind technical resource area shows that offshore wind has the ability to achieve cost levels at or below $100/MWh by 2030 [23]. This level of LCOE has the potential to be competitive in many U.S. regions with relatively high electricity prices. The economic model shows that between 2015 and 2030, average cost reductions of approximately 5% can be achieved annually, and by 2030, offshore wind may become competitive in parts of the North Atlantic. These modeled U.S.-based cost data correspond to recent European cost reduction estimates as shown in Figure 2.8. The alignment of these cost reduction trends strongly depends on continued global technology innovation (e.g., increase in turbine size) in conjunction with increasing levels of domestic deployment and future market visibility, leading to the near-term establishment of a sustained domestic supply chain [23, 35].[13]



Sources: Crown Estate 2012 [9]; Department of Energy and Climate Change Offshore Round 2 [36]; ARUP Offshore Round 2 [37]; Bloomberg New Energy Finance (BNEF) [38]; German cost reduction study [10]

Figure 2.8. International levelized cost of electricity estimates for offshore wind (2014–2033)

Renewable technologies have historically seen considerable cost decreases as a result of technology advancements, large-scale production, and commercialization. For instance, between 2008 and 2014, costs for land-based wind in the United States decreased by approximately 40% [2] as deployment levels grew by a compound annual growth rate of 17% [39]. Cost reduction is a key requirement for long-term growth of the offshore wind industry. In 2011, the *National Offshore Wind Strategy* [8] focused on developing cost reduction strategies as one if its primary goals. The emphasis on cost reduction continues to be the critical driver for the industry. Industry-wide technology innovations, deployment experience from Europe and Asia, and maturing European supply chains can be leveraged by the first U.S. offshore wind projects. Further cost decreases can be realized through reducing risk (and risk perception) to early projects, addressing U.S.-specific challenges (e.g., hurricanes, deeper water), and incentivizing markets to stimulate local supply chains and infrastructure development [5].

In 2015 alone, more than 3,000 MW of new offshore wind projects began operations globally, reaching a total of 12,105 MW by year-end [7, 40]. These project developments, primarily in Europe, offer cost data that can serve as the baseline for U.S. cost projections and to identify cost reduction pathways. Because the first U.S. offshore wind project will not come online for commercial operation until late 2016, U.S. developers will leverage European offshore wind technology and industry experience heavily while accounting for significant physical and economic differences.[14] Similarly, current cost models and cost reduction pathway analysis will help establish baseline and cost trends from the global offshore wind experience ([2]; see Figure 2.8).

Figure 2.9 shows potential LCOE reductions over time for sites across the entire offshore wind technical potential area. LCOE ranges widely at any given point in time. In 2015, LCOE values ranged from \$130/MWh to \$450/MWh, reflecting the wide diversity of U.S. site conditions, including variations in the quality of the wind resource, water depth, distance from shore, and meteorological ocean criteria for operation and maintenance (O&M). The decrease in LCOE from \$185/MWh (fixed bottom) and \$214/MWh (floating) in 2015 to \$93/MWh (fixed bottom) and \$89/MWh (floating) in 2030 [23] for the cost reduction scenarios demonstrates the substantial cost reduction potential and significant

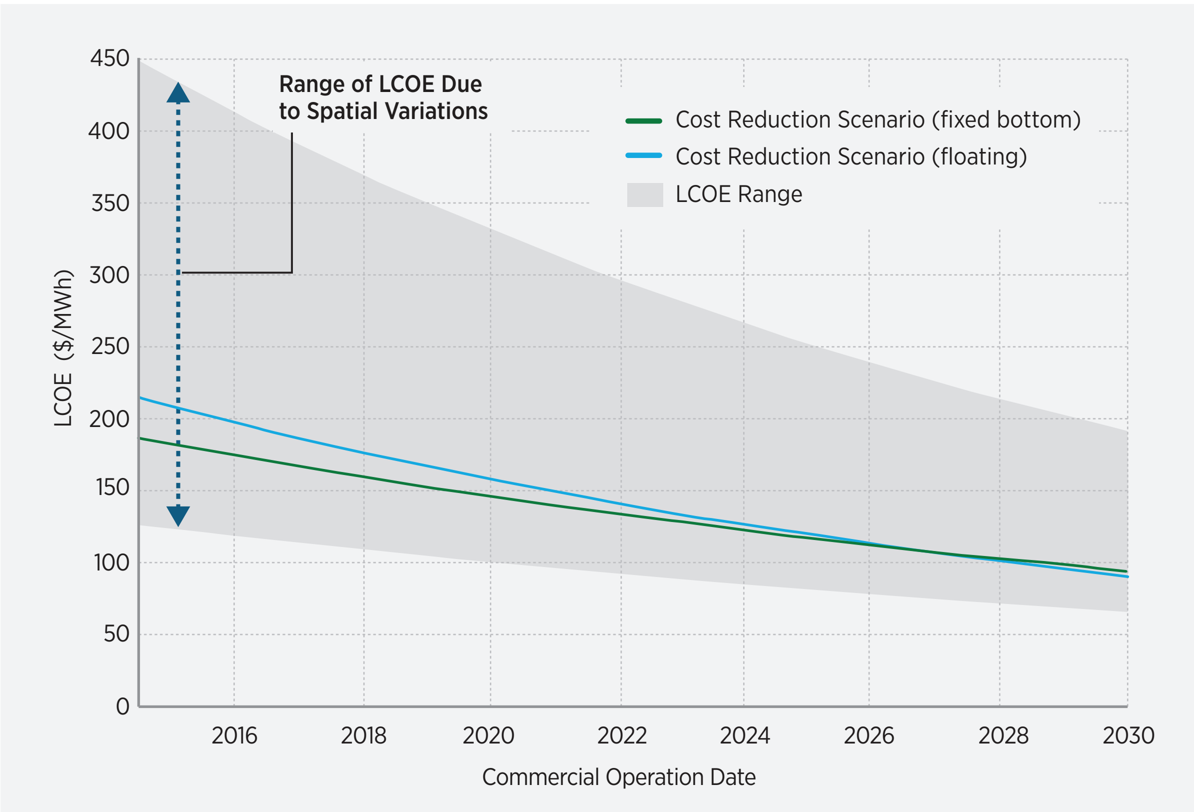
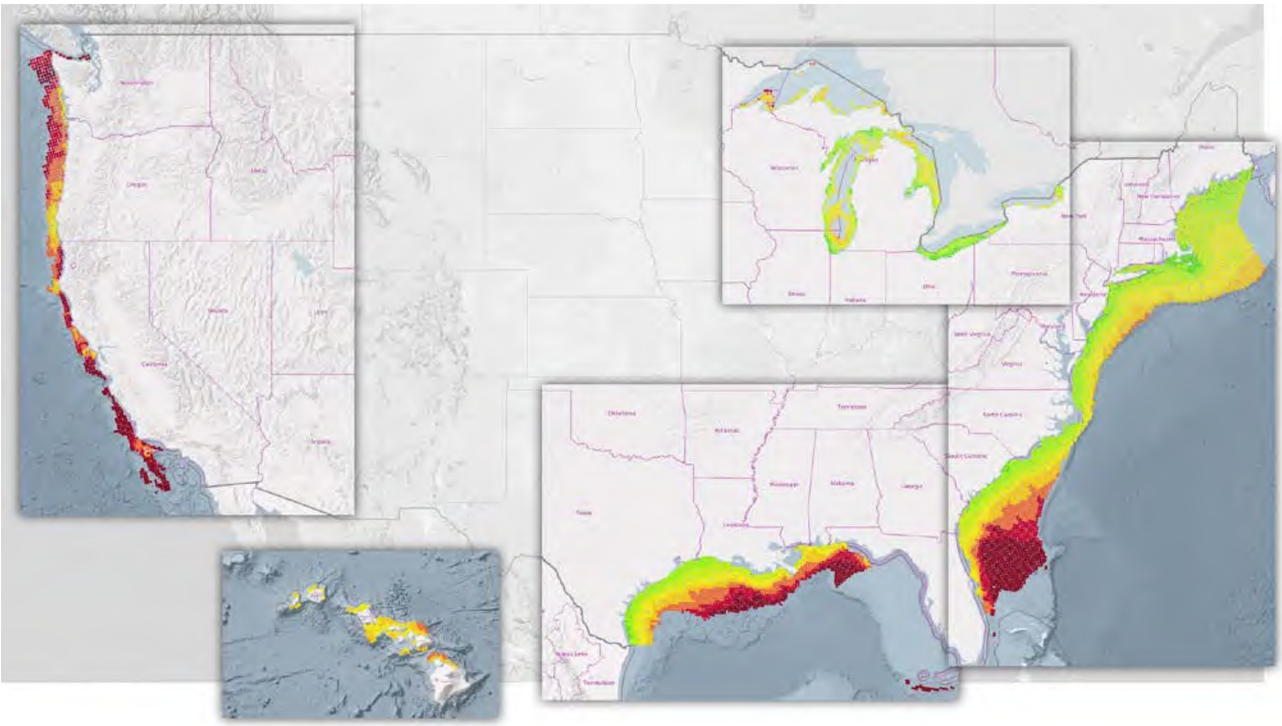


Figure 2.9. Levelized cost of electricity for potential offshore wind projects from 2015 to 2030 over technical resource area [23]

Commercial Operation Date – 2015



Levelized Cost of Energy ($/MWh)

<=100 · 100–125 · 125–150 · 150–175 · 175–200 · 200–225 · 225–250 · 250–275 · 275–300 · >300

Figure 2.10. Regional heat maps of levelized cost of electricity for project commercial operation dates of 2015 (above), 2022, and 2027 (p. 17). [23]

variation among local resource and costs in U.S. coastal regions. Although the model used in this analysis does not consider LCOE reduction as a function of deployment or supply chain maturity, the full realization of the cost reductions presented above strongly depends on near-term deployment, as well as sustained investment in technology and the supply chain. The impact of those investments on LCOE will be discussed in Chapter 3.

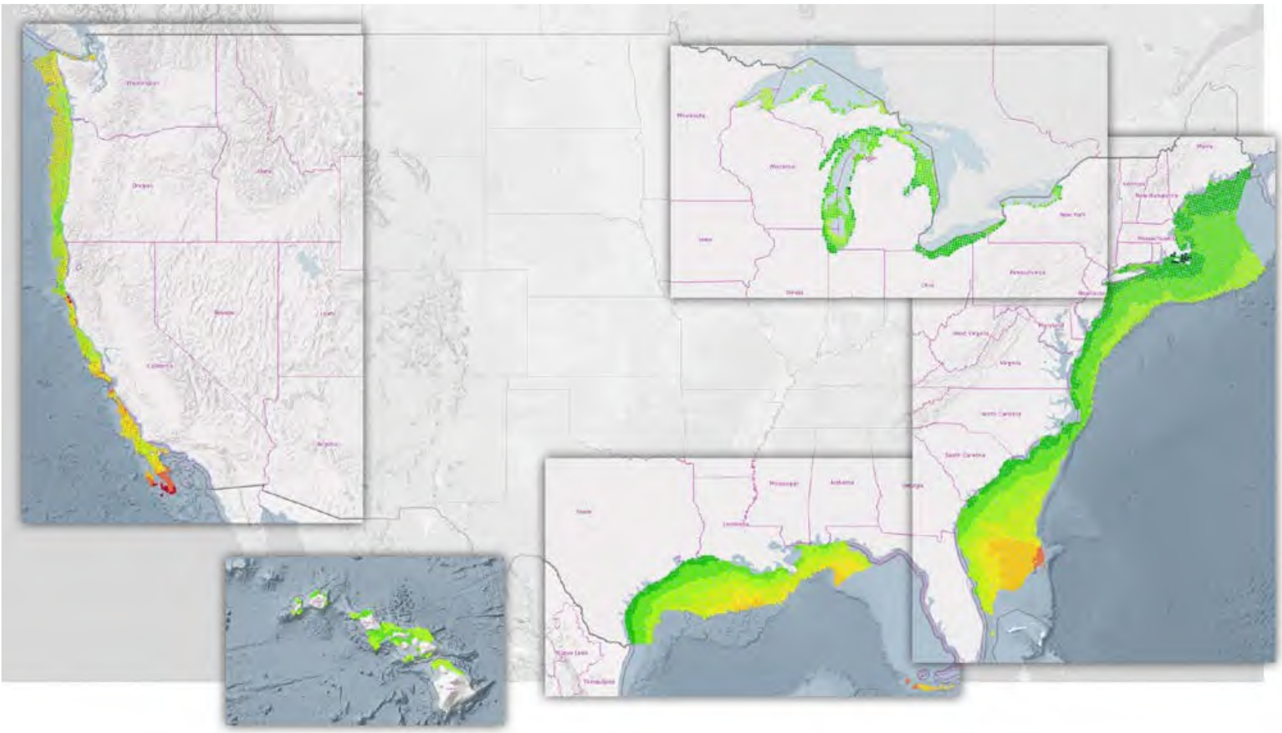
Figure 2.10 illustrates the same data spatially, showing LCOE for a range of sites for project commercial operation dates of 2015, 2022, and 2027 over the technical resource area described in Section 2.3.[15] For a given year, the maps show a wide range of modeled LCOE values across a region that represent a comprehensive set of geospatial cost variables including:

- The quality of the wind resource
- Turbine accessibility as a result of varying sea states
- Distance from shore
- Water depth
- Substructure suitability
- Availability of critical infrastructure.

Not surprisingly, the maps show lower LCOE in the regions where wind speeds are known to be higher and water depths are lower. They also show that sites closer to shore have lower LCOE because electric transmission and O&M costs are lower.

Figure 2.10 also shows reductions of LCOE from year to year at a given location, with green shades indicating lower LCOE values. These temporal changes in LCOE are generally the result of a different set of factors related to technology advancement and market development. Among the drivers of these time-dependent cost reductions are technology advancements that lower the cost for capital expenditures (CapEx), such as turbine, substructures, and electrical infrastructure; operations; or financing, or conversely, factors that raise annual energy output of the turbines. The maps show that the benefits of technology and market advancement are realized at most sites uniformly in time.

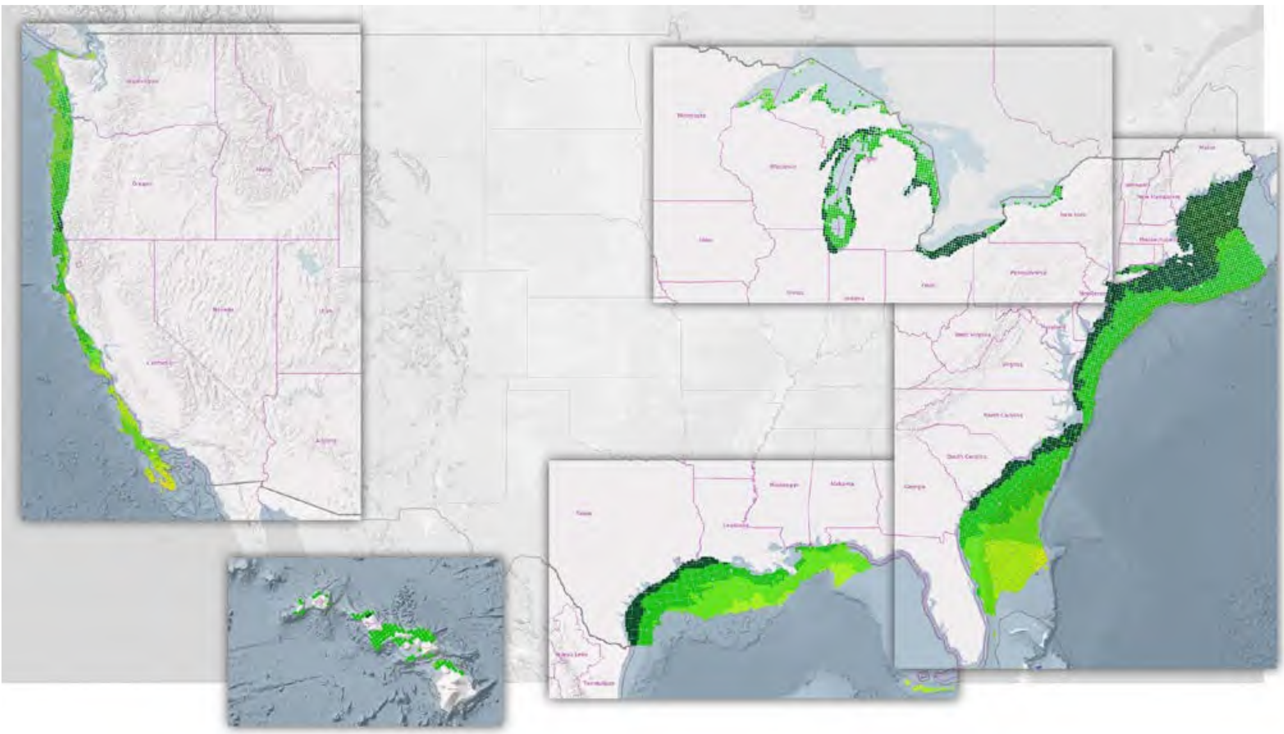
Commercial Operation Date – 2022



Levelized Cost of Energy ($/MWh)

● <=100 ● 100–125 ● 125–150 ● 150–175 ● 175–200 ● 200–225 ● 225–250 ● 250–275 ● 275–300 ● >300

Commercial Operation Date – 2027



2.6 Demonstrated Economic Potential for Offshore Wind Energy

The economic potential for offshore wind energy cannot be determined by LCOE alone. The economic viability of offshore wind also depends on the prices for electricity and capacity being sold in local and regional markets in which offshore wind might be deployed. Economic models reveal that a significant number of offshore wind sites with relatively low LCOE that coincide with high electricity prices may be economically viable with limited or no subsidy by 2030 [23]. Because of the high geographic variation in costs and electricity prices among U.S. coastal areas, the timing of when certain sites might achieve economic viability through technology advancement and cost reduction varies considerably (Figure 2.11). Among U.S. coastal areas, offshore wind sites in the Northeast region are among the most likely to be cost-competitive within the next 10–15 years. To realize these cost reductions, near-term (and higher-cost) projects would need to move forward to enable the learning, deployment experience, and supply chain development that will likely be necessary—along with technology research and development needs and actions like those described in Chapters 3 and 4—to achieve competitive costs in the future.

Although the cost of offshore wind, which is often expressed in terms of LCOE, is a fundamental component of the technology's economic viability and competitiveness in the market, the wider electricity system value from offshore wind is equally important. Offshore wind projects depend on future wholesale electricity prices and capacity market prices within their local electricity market region. These factors can be represented through levelized avoided costs of energy (LACE),[16] a measure of the potential revenue from wholesale electricity prices and capacity that is available to a new generator absent other revenue streams such as tax credits or Renewable Energy Credits (RECs) [32]. LACE varies regionally and by technology and

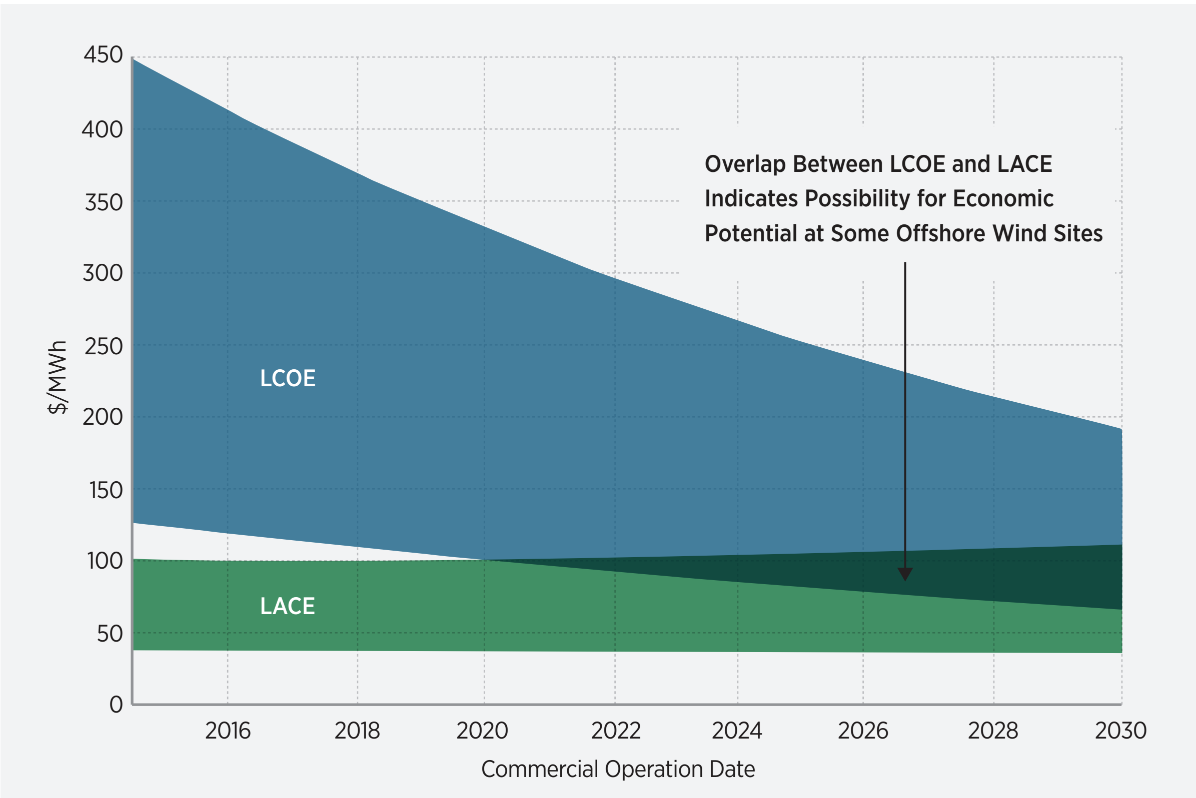


Figure 2.11. Comparison of levelized cost of energy and levelized avoided cost of energy estimates from 2015 to 2030

represents “a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project” [32]. A comparison of LCOE and LACE can provide an indication of whether the value from a project exceeds its costs at a given location and this difference may be compared with other available technologies to determine the technology with the highest net economic value.

A 2016 spatial-economic analysis for offshore wind [23] includes a comparison of offshore wind LCOE with LACE at thousands of potential sites in U.S. waters. Figure 2.11 depicts the declining offshore wind LCOE together with the range of LACE estimates from 2015 to 2030 on a national scale. LACE across U.S. coastal areas is generally expected to increase gradually over time “as a result of rising costs for power generation and delivery” [32]. The lower-bound LCOE and higher-bound LACE start to overlap by 2019, and the coincidence of LCOE with LACE estimated for potential U.S. offshore wind sites increases over time. This indicates that a growing number of U.S. offshore wind sites will be able to find their required costs met by available revenue from prevailing pricings for electricity and capacity even without any project-specific government support schemes. The LCOE-LACE comparison in Figure 2.11 [23] can serve as a high-level indicator of the economic market potential for offshore wind within the next 15 years. In other words, offshore wind sites that achieve this market potential indicated by LACE greater than LCOE are likely competitive relative to other contenders vying for the new electric generation market opportunity space. Moreover, the analysis shows that in the future there could be ample sites with this economic market potential to meet growing offshore wind demand.

2.7 Economic, Energy System, and Environmental Benefits of Offshore Wind Energy

The value of offshore wind extends well beyond the wholesale electric cost at which it can provide electricity to consumers. Projected reductions in LCOE and increases in the technology’s system value, LACE, over time indicate that offshore wind energy is likely to offer electricity at increasingly competitive rates. However, offshore wind like all sources of generation offers a set of additional benefits to consumers, utilities, and local economies that are unique to its production profile, generation sites, and technology that are not counted in the modeled LCOE data shown in Figure 2.10. These additional benefits may add substantial value. Most of these benefits, shown as they relate particularly to offshore wind in Figure 2.12, can be quantified or even monetized to help supplement the case for economic viability or to support policy decisions.

Marginal Price Suppression

The marginal cost of energy in deregulated electricity markets is generally set by the highest-priced available generator required to support demand at any given point in time. With no fuel costs and comparatively low variable operating costs, the marginal generating costs of offshore wind—like most renewables—is close to zero. As such, the low marginal generation costs associated with offshore wind can displace more expensive generating assets from the dispatch stack, which in turn can reduce the market clearing price that is paid to all generators. Therefore, offshore wind has the potential to suppress wholesale and retail electricity prices. GE Power [41] estimates that with 20% wind energy penetration in the service territory of the Independent System Operator of New England, the locational marginal price across this region could be reduced by $9/MWh if high wind speed offshore locations were developed. Similarly, despite a first-year above-market PPA price of $187/MWh, it was estimated that the 468-MW Cape Wind project would decrease wholesale electricity prices by an average of $1.86/MWh [42], and the associated total cost savings to the consumer was projected to average $286 million annually, totaling $7.2 billion over 25 years. DOE’s *Wind Vision* [2] indicates that offshore wind may have a more significant impact in lowering wholesale electric prices in coastal states than land-based wind has in other regions. This additional advantage is attributed to the tendency for offshore wind to coincide with peak summer loads and have a diurnal pattern aligned with peak demand.

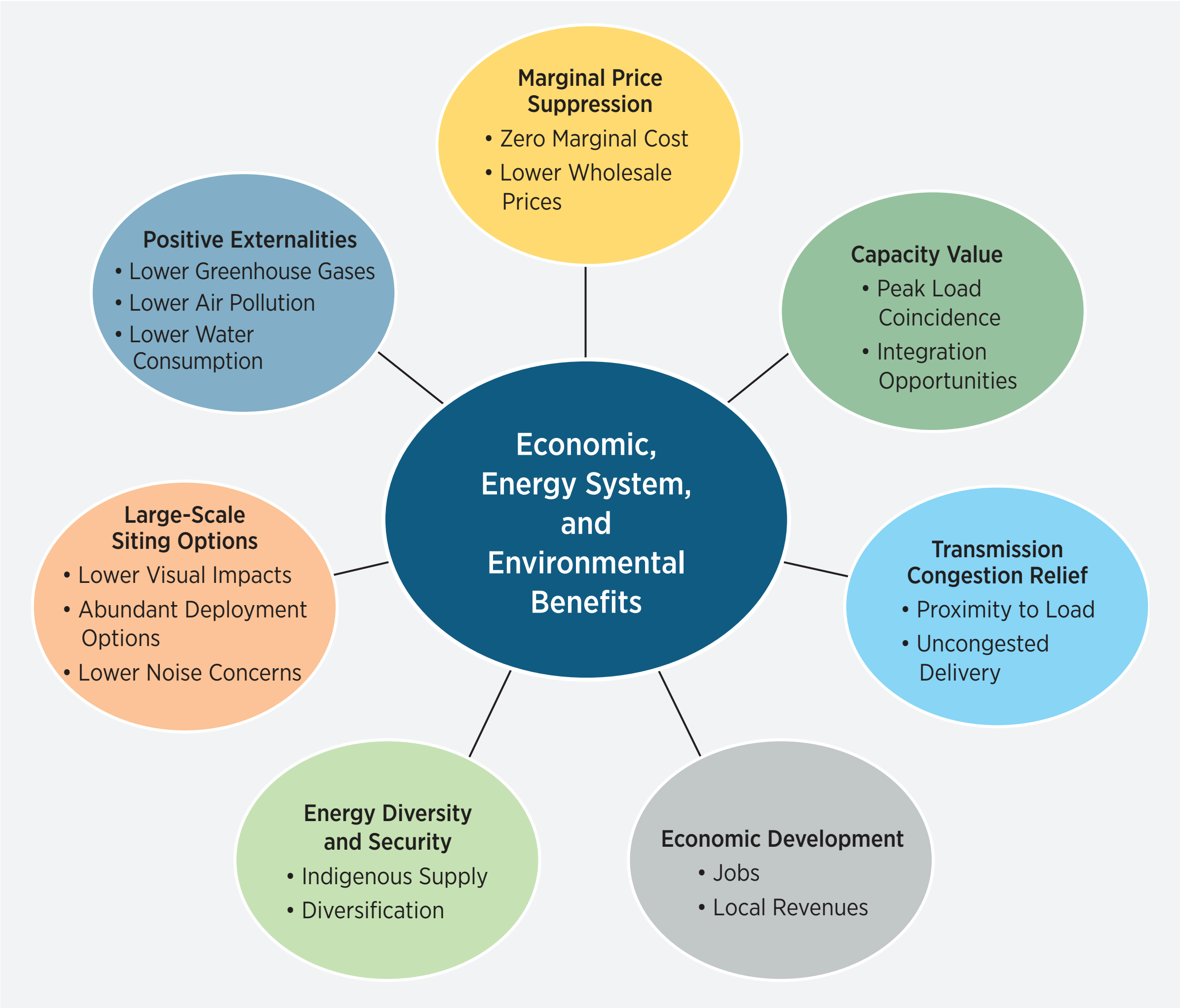


Figure 2.12. Economic, energy system, and environmental benefits of offshore wind

Capacity Value

The capacity value of offshore wind is the amount of generation that can be relied on to meet load during peak hours. Offshore wind can play an integral part in ensuring system reliability during times of peak demand or in the event of a mechanical or electrical failure from other generators. Winds are typically more energetic and less turbulent offshore than on land, and the resource availability and production characteristics of offshore wind tend to coincide better with load peaks [43]. Offshore wind also exhibits a comparatively stable and less variable average power output. These characteristics have been shown to lower system costs. A recent study commissioned by DOE found that deploying 54 GW of offshore wind around the country would reduce annual production costs by $7.68 billion, delivering a value to the system from offshore wind of $41/MWh [44]. In certain regions, offshore wind characteristics can also complement some other renewable generation sources such as land-based wind or solar photovoltaics [45]. In California, offshore winds show afternoon and evening diurnal peaks that coincide with peak loads, whereas land-based winds tend to peak at night. Estimated capacity values for offshore wind range between 24% for California [46] to 40% for New York [47]. An analysis from GE Power [41] estimated the 3-year average capacity value for offshore wind in Independent System Operator of New England territory to range from 47% to 51% in a scenario with the best-suited wind sites available for development. The corresponding capacity values for land-based wind ranged from 34% to 35%.

Offshore Wind May Help Enable Greater Renewable Energy Penetration: The California Case

California recently enacted an increase in its renewable energy electric generation mandates to 50% by 2030, up from a realized total 25% in 2014 [48]. Diversity in renewable generation as it expands can help reduce the cost of meeting these targets and mitigate some of the challenges posed by large contributions by any one resource type. In California, offshore wind can play a significant role to complement and enable greater penetration by the state's vast solar and land-based wind resources.

Figure 2.13 shows how offshore wind may help mitigate challenges associated with the "Duck Curve." Shown below, this figure shows net load (modeled load minus land-based wind and solar generation) on March 31 in years 2012–2020 [49]. As more solar generation is added to the grid during this time, it is able to meet an increasingly large portion of daytime load, but the grid also requires increasing amounts of other generation to ramp up to meet evening peaks as the sun goes down. Preliminary investigation of some possible California offshore wind sites, from near the Channel Islands to the Oregon border, indicate that available offshore wind peaks in the late afternoon into the evening, with substantial generation throughout the evening hours. Diversifying the portfolio with offshore wind could therefore help to reduce evening ramping requirements and ease the path toward 50% renewables by 2050.

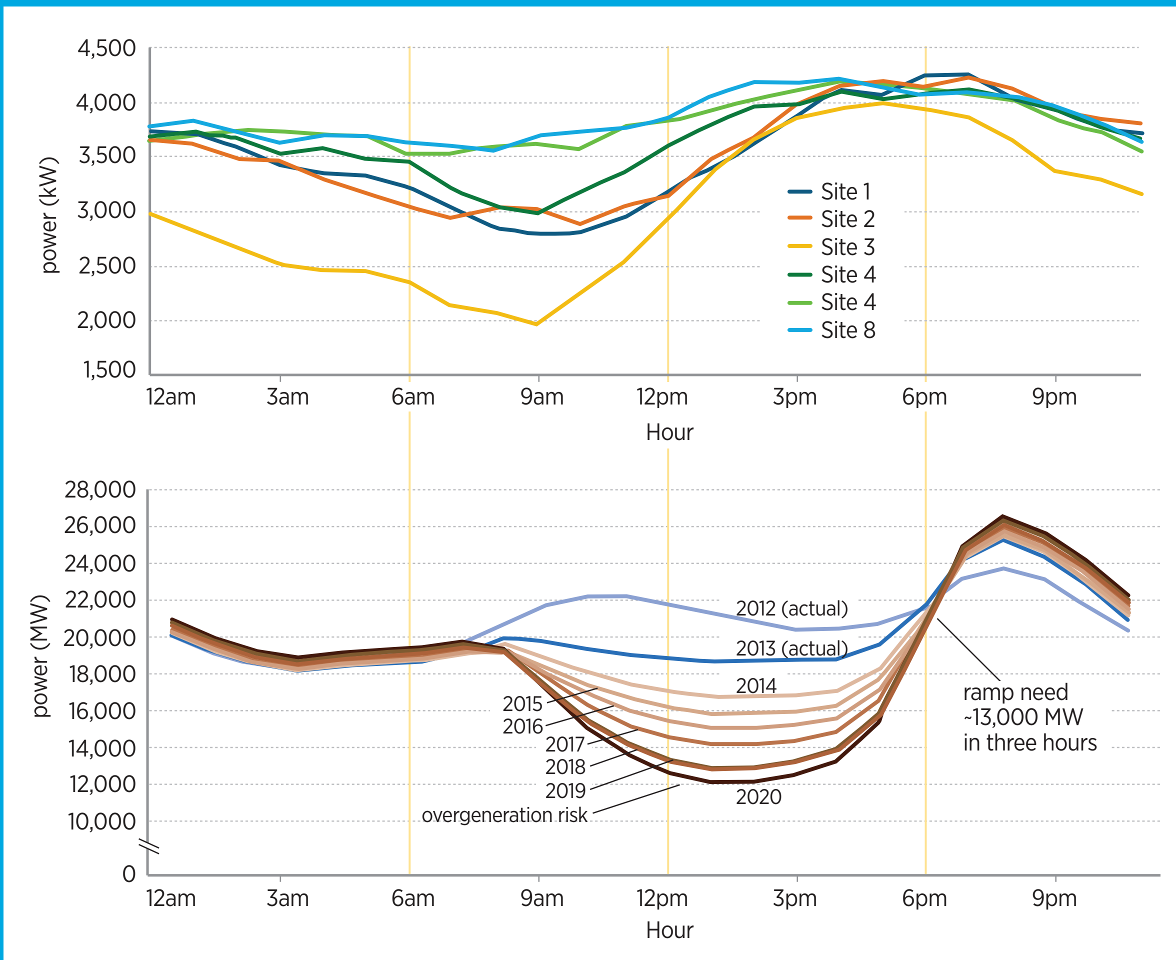


Figure 2.13. The "Duck Curve" and modeled generation profiles for 6-MW offshore wind turbines at six California sites. Adding offshore wind into California's electricity portfolio may help alleviate overgeneration and ramping challenges as solar and land-based wind penetration continue to grow [49–50].

Transmission Congestion Relief

Offshore wind can also provide a hedge against the need to build new transmission. It can be located near the highly populated coastal load centers that have some of the highest electricity rates in the United States [8]. It can provide an alternative to long-distance transmission of land-based wind power from the interior to the coasts [2], while reducing grid congestion and associated electric transmission costs and losses. Transmission congestion, particularly on the Eastern Seaboard and in California, has led to curtailment of economic resources and higher energy prices for electricity consumers.

Economic Development

The offshore wind industry requires a local infrastructure, which in turn may lead to local economic benefits, including jobs and economic growth. By the end of 2014, the European offshore segment employed 75,000 workers [51]. The *Wind Vision* study scenario [2] estimates that 32,000–34,000 offshore wind-related jobs around the country could be created by 2020, increasing to 76,000–80,000 in 2030 and 170,000–181,000 by 2050. In addition, by 2050, the *Wind Vision* study scenario estimates that $440 million in annual lease payments and $680 million in annual property tax payments could flow into local economies.

Energy Diversity and Security

Development of offshore wind can provide a physical hedge against uncertain fuel prices and provide insurance against the impact of volatile and unpredictable fuel prices or changes in emissions policy [52]. Thirteen out of 28 coastal states, which tend to have the highest electricity prices in the nation, import out-of-state electricity to support electricity demand [53]. With land and transmission constraints that may prevent the large-scale exploitation of land-based wind, solar, or other renewables in coastal states, offshore wind could also allow states to generate power using in-state renewable resources and increase control over their energy supplies.

Large-Scale Siting Options

Siting land-based wind or other utility-scale renewable energy projects is complex because of concerns about impacts to human communities, other land uses, and wildlife. Although potential impacts to wildlife and other users of the ocean can present siting conflicts offshore, BOEM's process provides a structured approach to minimizing impacts, and issues such as noise from operational turbines as well as visual impacts to adjacent residents diminish with distance from shore. In coastal states with high population densities and limited available land, BOEM has made available sites representing gigawatts of potential capacity that would be difficult to replicate for land-based wind or other large-scale renewable energy development.

Positive Externalities

Offshore wind can claim many of the same positive externalities as other renewable resources, which in most areas of the United States are often not valued through policy incentives, but can be quantified and compared to the social cost of other energy sources [25]. According to the *Wind Vision* study scenario, these benefits can include:

- **Reduced greenhouse gas emissions.** The study indicates that 1.8% reduction in cumulative GHG emissions (1,600 million tonnes of carbon dioxide equivalents) through 2050, saving $50 billion in associated global damages.
- **Reduced public health impacts as a result of lower air pollution.** Under the *Wind Vision* study scenario, approximately $2 billion in avoided mortality, morbidity, and cumulative emissions in sulfur dioxide, nitrogen dioxide, and fine particulate matter can be realized by 2050.
- **Lower water usage in the electric sector.** The study estimated 5% less water consumption and 3% less water withdrawals for the electric power sector annually [2].

Notes

7. The New Jersey WEA auction was held in late 2015, which added approximately 4.2 GW of potential generating capacity to the 10.4 GW potential reported in [5]. The 14.6 GW also does not include call areas and wind energy areas (WEAs) that have not yet been auctioned. Note that the lease area capacity density values presented here may vary slightly from WEA capacity values levels published by BOEM because of differences in the estimation methods.
8. Excluded areas include water depths greater than 1,000 m [54], wind speeds lower than 7 meters per second [21], and water depths greater than 60 m (in the Great Lakes). Note that when the depth exclusions are considered, the resource area shrinks significantly on the West Coast because of a narrower continental shelf and deeper waters close to shore. Yet, it is important to note that there are several areas on the East Coast where the resource area extends beyond the previous 50-nm boundary.
9. The Energy Information Administration estimated total U.S. electricity consumption in 2014 to be about 3,863 terawatt-hours (TWh) [55].
10. U.S. coastal regions assessed in [22] include states in the Pacific Coast, Gulf Coast, Great Lakes, and North and South Atlantic as defined in the *Wind Vision* [2].
11. The NREL study used a methodology derived from the *Wind Vision* [2].
12. The *Wind Vision* prescribes fractions of the 2050 energy (339 TWh/yr from Table 2.1) offshore wind generation by region according to the following percentages: North Atlantic 33%, South Atlantic 22%, Great Lakes 15%, Gulf Coast 10%, and Pacific Coast 20%.
13. It is important for U.S. offshore wind stakeholders to acknowledge that domestic cost reductions of a magnitude similar to those predicted in Europe can only be achieved with a U.S. supply chain that can generate the learning and scaling effects needed for substantial cost reductions, including the necessary labor skills development and infrastructure (e.g., assembly ports or vessels [56]). A pipeline of U.S. offshore wind projects is critical for the establishment of a domestic supply chain. European supply chain development has been incentivized by “ambitious national programmes and financial incentives that limit risk, and [have] thus attract[ed] investors to the sector” [57] and driven by a pipeline of projects.
14. Some key differences between European and U.S. markets include currency exchange rates, existing infrastructure, supply chain maturity, vessel availability (e.g., Jones Act requirements), workforce readiness, and physical characteristics of the offshore wind siting environment. The cost could also be influenced by U.S.-specific political considerations, including regulatory structure, tax code, and incentive programs [5].
15. The analysis was conducted for the entire lower 48 United States and Hawaii.
16. Levelized avoided cost of energy is a “measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project” [32]. It captures the marginal value of energy (or electricity prices as a proxy) and capacity value to represent the potential revenue available to a project owner from the sale of energy and generating capacity [32]. The capacity value can vary among different technologies and may be one of the benefits of offshore wind (see Chapter 3).

3.0 Major Action Areas for U.S. Offshore Wind Industry Development

To facilitate the responsible development of a robust and sustainable offshore wind industry in the United States, as well as realize the benefits of offshore wind deployment, a number of challenges need to be addressed. The solutions associated with these challenges can be grouped into three broad strategic themes. First, to be competitive in electricity markets, offshore wind costs and U.S.-specific technology risks need to be reduced. Second, environmental and regulatory uncertainties need to be addressed to reduce permitting risks and ensure effective stewardship of the OCS. Third, to increase understanding of the benefits of offshore wind to support near-term deployment, the full spectrum of the electricity system and other economic, social, and environmental costs and benefits of offshore wind need to be quantified and communicated to policymakers and stakeholders. This chapter looks at each of these strategic themes and ties them to seven discrete action areas (see Table 3.1) in which further work is needed to overcome the challenges mentioned here.

Table 3.1. National Offshore Wind Strategy Strategic Themes and Action Areas

Strategic Themes	Action Areas
1. Reducing Costs and Technology Risks	1. Offshore Wind Power Resources and Site Characterization 2. Offshore Wind Plant Technology Advancement 3. Installation, Operation and Maintenance, and Supply Chain Solutions
2. Supporting Effective Stewardship	1. Ensuring Efficiency, Consistency, and Clarity in the Regulatory Process 2. Managing Key Environmental and Human-Use Concerns
3. Increasing Understanding of the Benefits and Costs of Offshore Wind	1. Offshore Wind Electricity Delivery and Grid Integration 2. Quantifying and Communicating the Benefits and Costs of Offshore Wind

3.1 Strategic Theme 1: Reducing Costs and Technology Risks

As established in Chapter 2, the current estimated cost of offshore wind is too high to support widespread deployment; however, investments in technology, an expanded supply chain, and building the industry knowledge in the United States can have significant cost-reduction impacts. Modeled deployment and cost-reduction scenarios reveal that offshore wind can become competitive with local electricity costs in many parts of the country by 2030 [23]. They also reveal that there are significant cost savings to be realized through continued global market growth and R&D to reduce capital and operating expenditures across the following three broad action areas:

- **Offshore wind power resource and site characterization**. A better understanding of the unique meteorological, ocean, and seafloor conditions at sites proposed for development in the United States will allow for optimized designs, reduced capital costs, greater safety, and less uncertainty in preconstruction energy estimates, which can reduce financing costs.

- **Offshore wind plant technology advancement**. Increasing turbine size and efficiency, reducing cost in substructures, and optimizing wind plants at a system level for unique U.S. conditions can reduce capital costs and increase energy production at any given site.
- **Installation, O&M, and supply chain solutions**. The complexity and risk associated with installation and O&M activities require specialized infrastructure that does not yet exist in the United States. Identifying strategies to reduce the need for specialized assets, along with leveraging the nation's existing infrastructure will reduce capital and operating costs in the near term and help unlock economic development opportunities in the long term.

Action Area 1.1: Offshore Wind Power Resource and Site Characterization

Problem Statement

Physical site conditions along the U.S. coastline bear some similarities to those in the established European market. However, there are key differences requiring additional scientific and engineering assessment. Currently, there is a significant lack of data describing meteorological, oceanographic, and geologic/man-made conditions at potential project sites offshore of the United States. There is also a lack of standardized methodologies for gathering these data. This deficiency translates into increased uncertainty and risk, and ultimately increases the capital costs of offshore wind projects.

Current Baseline

More than 2,000 GW [24] of offshore wind energy technical potential exists in the United States. Excluding Alaska,[17] these resources cover more than 10,000 miles along the U.S. coastline—including the Atlantic, Gulf, and Pacific Coasts of the continental United States, Great Lakes, and Hawaii—and vary significantly in their meteorological and oceanographic (metocean), and geological conditions.

High-quality U.S. coastal and offshore wind and oceanographic observations exist, such as those gathered in the National Oceanic and Atmospheric Administration's (NOAA's) National Data Buoy Center network. But they collect only near-surface measurements of the atmosphere and are often too far from potential WEAs to determine specific oceanographic conditions at a given site. Very few wind observations are collected at hub height, and without the existence of U.S. meteorological towers similar to the German FINO metocean research stations [58-60],[18] it is difficult to validate wind observation and model data. New technologies, such as light detection and ranging (lidar) buoys, have recently been deployed in the North Atlantic and the Great Lakes.

Observational data on extreme conditions at wind turbine hub height are also scarce. Tools such as the Weather Research and Forecasting Model have the potential to supplement and augment the observational data, but are currently not validated for U.S.-specific conditions in the offshore environment. Efforts are underway to improve these models for land-based wind.[19] Similarly, promising models exist for producing modeled data of hurricanes, which would benefit from observational data available to validate these models [61].

Site-specific metocean characterization studies are required for the design and development of each planned offshore wind project. At present, there are no consensus standards or guidelines for the collection and interpretation of site-specific metocean data with respect to design and operation of offshore wind energy projects in the United States. As a result, data collection for wind resource assessment and estimation of extreme environmental conditions is pursued in a variety of ways. This can potentially result in uncertain or varied reliability for projects developed on the OCS.

A considerable body of observational geological data exists for the OCS, but is not well suited for use in offshore wind energy development. These observational data sets are largely confined to nearshore areas or the shelf/slope break, whereas potential offshore wind development sites are typically located between these two areas.

Work to Date

To advance the state of offshore wind site characterization in the United States, DOI and DOE have funded a number of projects in meteorological, oceanographic, and geological assessment, as well as project planning and design for the purpose of facilitating safe and cost-effective project development.

Work at DOI consists of a number of efforts to support the development of consensus site characterization guidelines and assess and advance site assessment methods. For example, DOI is undertaking a geophysical and geotechnical methodologies study that analyzes the advantages and disadvantages of various methodologies and equipment choices that are used for assessing site conditions and cultural resource identification. In addition, BOEM has an ongoing study that investigates, verifies, and recommends identification and site clearance methodologies to identify and address unexploded ordinance. The data collected in these studies will support the submission of Construction and Operations Plans (COPs) consistent with federal regulations.

DOI has also published guidelines to clarify the information requirements for COPs, including survey results and other information needed for compliance with the OCS Lands Act, National Environmental Policy Act (NEPA), and other applicable laws and regulations. In addition, DOI funded geological survey work in an area offshore Virginia and benthic habitat mapping and assessment for areas offshore North Carolina and South Carolina to inform and support its renewable energy leasing processes.

A 2011 DOE Funding Opportunity Announcement (FOA) resulted in 12 research projects that aimed to advance the characterization of wind resources and other data critical to wind plant feasibility assessment, siting, and facility design. Other projects funded at DOE national laboratories included metocean data collection from the DOE Advanced Technology Demonstration Project sites, providing offshore wind resource characterization through lidar buoys and reference facility research, as well as sediment and scour research.

Remaining Gaps

Collecting Metocean Data Through Validated Methods

The OCS and Great Lakes regions continue to be underobserved because of the difficulty of obtaining data over such remote and expansive areas. This creates uncertainty in siting, design criteria, projected performance, and regulation—and ultimately the cost of energy. Reducing this uncertainty makes tangible progress toward achieving reduced LCOE and enhanced regulatory oversight.

Although representing a significant CapEx that may only be relevant to potential sites within the local area, offshore metocean facilities for offshore wind in U.S. waters similar to the German FINO[20] towers would generate metocean data that would be readily accepted by the community for project development, design, and other purposes. These facilities—or existing towers in Europe or elsewhere—could also serve as a reference for the validation of new, less capital-intensive technologies and methods such as lidar buoys.

If accepted by the financial community, lidar buoy data could serve as a less-expensive, portable alternative for gathering metocean observational data needed to develop offshore wind energy sites. A network of these buoys in applicable areas could collect enough data to allow for interpolation at smaller scales, as well as tuning and validation of Weather Research and Forecasting or other models in U.S.-specific metocean conditions. Collecting these data along with complementary data from existing infrastructure into a single repository or portal could facilitate development.

A significant opportunity in engineering design assessment is the acquisition of considerable hurricane metocean data. Data sets describing relevant hurricane wind profiles—speeds and directions as a function of time up to the uppermost reaches of a turbine—would help significantly reduce uncertainty and allow for more sophisticated analysis and modeling leading to more cost-effective siting, design, operation, and maintenance of a U.S. offshore wind energy fleet.

Standardizing Metocean and Geophysical and Geotechnical Data Collection Methods

Geophysical and geotechnical investigations can be conducted in a multitude of ways with a wide variety of methods and equipment. Standardizing data gathering and procedures could reduce the burden on developers, as could collecting all of the available data in a single repository or portal.

Current DOI regulations require submittal of geophysical and geotechnical survey data in the COP. Certain metocean data are required to be submitted in each project's Facility Design Report. Although DOI has published updated guidelines for geophysical and geotechnical data on its website, its existing requirements for metocean data collection are general in nature, thereby allowing for a wide variety of data collection methods. Supporting the development of standard data collection guidelines would help foster consistency in project designs as well as bestow a necessary level of certainty for developers to determine the effort required to provide the data.

Understanding Intraplant Flows

A better understanding of wind conditions inside wind plants and their effects on reliability and annual energy production (AEP) could also have a significant impact on the cost of offshore wind energy. Turbines inside wind plants interact with each other in complicated ways. The wake behind one turbine can reduce the energy captured by another and increase wear and tear on key components. Quantifying turbine-to-turbine interactions is one focus of a current major DOE initiative: Atmosphere to Electrons.[21] Greater understanding of these flows could lead to plant-level optimization of design and operation, increase AEP and reliability, and reduce uncertainty in wind resource assessment—all of which ultimately lead to lower LCOE.

Action Area 1.2: Offshore Wind Plant Technology Advancement

Problem Statement

Offshore wind technologies have matured significantly over the past 25 years as a result of extensive global research, development, and market growth. With this maturation, significant cost reductions have been realized. This research, development, and growth must continue for offshore wind to compete on an unsubsidized basis. R&D is also needed to adapt existing European technologies to the unique conditions of the U.S. market and enable cost-effective deployment.

Current Baseline

A vast majority of the global project pipeline and installed capacity are in saltwater at depths less than 40 m, distances from shore under 40 km, and at project sizes under 500 MW [5]. State-of-the-art wind turbines have reached nameplate capacities of 6 and 8 MW [5]. Prototype turbines with 10 MW could be deployed as early as 2020 [62]. At European sites, 8-MW turbines are planned to be deployed atop monopile, fixed-bottom substructures in water depths between 10 and 40 m by highly specialized, heavy-lift European vessels [5].

Though monopile, fixed-bottom substructures currently dominate the global market with 75% market share by capacity [5], this prevalent substructure technology may not be economically feasible in water depths up to and exceeding 60 m. To access sites in greater water depths, fixed foundations with wider footprints are needed, such as jacket structures or floating foundations. Currently, floating technology is significantly less prevalent, with only five operating commercial-scale prototypes worldwide as of mid-2015 [5].

With a variety of geological conditions, and more than 58% of the estimated U.S. technical resource potential capacity at depths greater than 60 m [20], the U.S. market requires a variety of fixed-bottom and floating substructure technology solutions.

Design standards for turbines and substructures are critical to ensuring the safe deployment of offshore wind projects and enabling access to financing. The varied bathymetry, metocean conditions, and geologic conditions experienced in the waters offshore the United States limit the applicability of design standards based on experience gained in European seas. Current structural design standards in Europe use safety factors that may be lower than what is needed to achieve an appropriate level of structural reliability for offshore wind turbines in the United States. In contrast, recent developments off the coast of Japan indicate that a direct application of Japanese designs [63], such as those depicted in their typhoon-class turbines, might result in overdesigned, costly turbines for the OCS.

Work to Date

Deepwater Wind's Block Island Wind Farm is scheduled to be the first offshore wind project in the United States. The project will be installed in state waters off the coast of Rhode Island and is scheduled to commence operations in the fall of 2016. This project utilizes five 6-MW direct-drive turbines designed and manufactured by GE Power in Europe that will be installed atop four-legged-jacket fixed-bottom substructures designed by domestic companies.

Other projects currently in the U.S. development pipeline include DOE's Advanced Technology Demonstration Projects. These three projects include state-of-the art turbines planned for one novel fixed-bottom jacketed substructure technology and one floating substructure technology along the Atlantic Coast, and one fixed-bottom suction bucket foundation design for deployment in freshwater conditions in the Great Lakes.

DOE's demonstration projects are planned to be highly instrumented for measuring metocean conditions, structural loads, power production, and environmental data. To benefit the U.S. offshore wind industry, data collected during the demonstrations will be made available to the public 5 years after project completion.

Since 2011, DOE has funded multiple efforts to facilitate advancements in offshore wind turbine technologies. The fiscal year (FY) 2011 U.S. Offshore Wind Technology Development FOA made federal funding available to 19 projects for the purpose of reducing the cost of offshore wind energy through technology innovation, testing, and risk reduction. Similarly, the FY11 Next Generation Drivetrain FOA awarded funding to six projects for the purpose of developing next-generation drivetrain technologies to reduce capital, O&M, and replacement costs, and increase lifetime energy production. National laboratory projects funded during those 4 years yielded major advances in offshore wind computational tools, high-resolution modeling, and rotor development. DOE concurrently funded the construction of two world-class testing facilities—the Clemson University Wind Turbine Drivetrain Test Facility and the Massachusetts Clean Energy Center's Wind Technology Testing Center—to provide unique capabilities for developing and testing offshore wind drivetrains and blades on a larger scale.

Since 2005, BOEM and the DOI's Bureau of Safety and Environmental Enforcement (BSEE) have supported research on operational safety and pollution prevention related to offshore renewable energy development through the DOI's Technology Assessment Program (TAP), formerly known as the Technology Assessment Research Program. As of the beginning of 2016, the Renewable Energy Research Program has expended over $2 million to fund 27 studies that have been completed with final reports posted on both the BOEM and BSEE websites.[22] Five new studies are expected to receive funding in 2016, with a total budget of up to $700,000. The studies have focused on five general areas: fixed-bottom turbines, floating wind turbines, standards and regulations, environment, and inspections and safety.

Remaining Gaps

Significant opportunities remain to reduce offshore wind costs in the United States. These opportunities require further investment in R&D, such as:

- Creating advanced substructure technologies to address conditions such as deep water and weak seabed soils
- Reducing the cost, risk, and need for specialized infrastructure to install offshore wind facilities
- Eliminating unscheduled maintenance through technologies such as prognostic health monitoring and management that can predict component failures and take corrective action
- Developing and validating design practices for hurricanes and other extreme conditions prevalent at U.S. sites
- Reducing energy loss caused by interactions between turbines
- Creating design tools that allow for the development of offshore wind turbines and substructures as coupled systems.

Both floating and fixed-bottom offshore wind technologies show promise for the U.S. market. Chapter 2 presents a 2016 NREL analysis that shows that although floating technologies are more expensive than fixed-bottom technologies at this time, floating technologies have the potential to achieve costs that are equal to or even lower than fixed-bottom technologies by 2030 (see Figure 2.9).[23] The advantages of floating technology include the possible reduction of site conflicts, access to higher winds in waters farther offshore, and a larger resource base. Floating technology also offers the potential for reduced marine operations during construction and installation, and in O&M. Floating technologies could allow for final turbine assembly, commissioning, and major maintenance in port at quayside, in a wide range of weather conditions and using generally available equipment. Quayside assembly and maintenance could present significant cost savings and risk reduction compared to the current practice of utilizing specialized infrastructure to conduct major construction activities offshore, particularly as developers begin to look at more challenging sites in deeper water and more extreme metocean conditions.

R&D in technology can lower offshore wind LCOE in three primary ways: by reducing upfront capital expenditures (CapEx), such as the cost of project development, turbines, substructures, and installation; increasing the potential AEP of a turbine or wind project, and reducing operational expenditures (OpEx), such as maintenance. Figure 3.1 and Figure 3.2 show potential cost reductions in each of these pathways between 2015 through 2030 for fixed-bottom and floating offshore wind technologies [24].

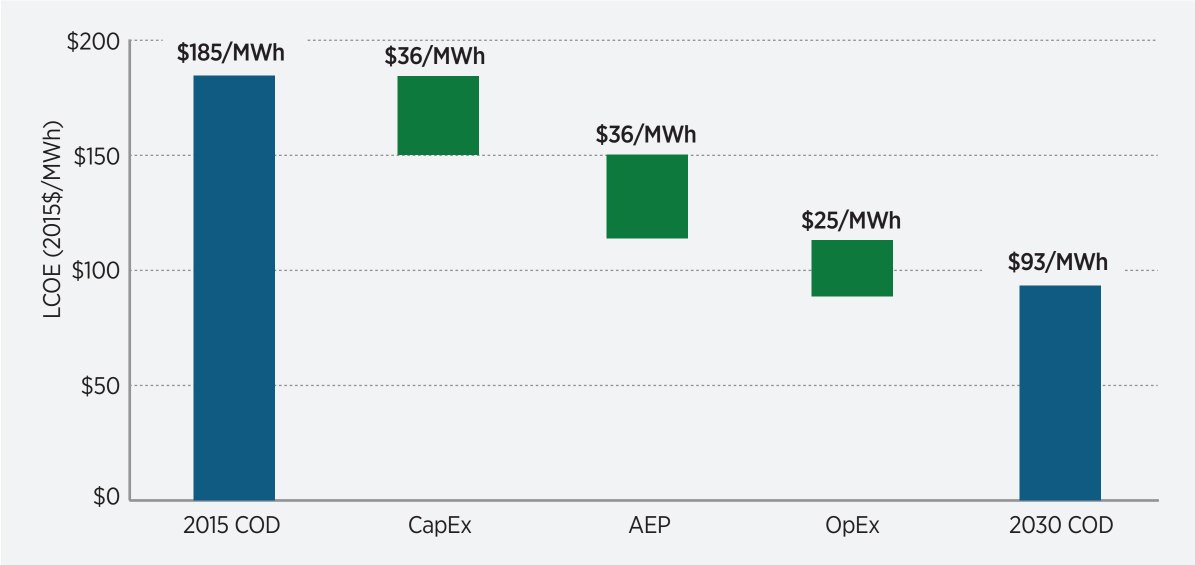


Figure 3.1. Modeled fixed-bottom offshore wind cost reduction pathways to 2030 [23]

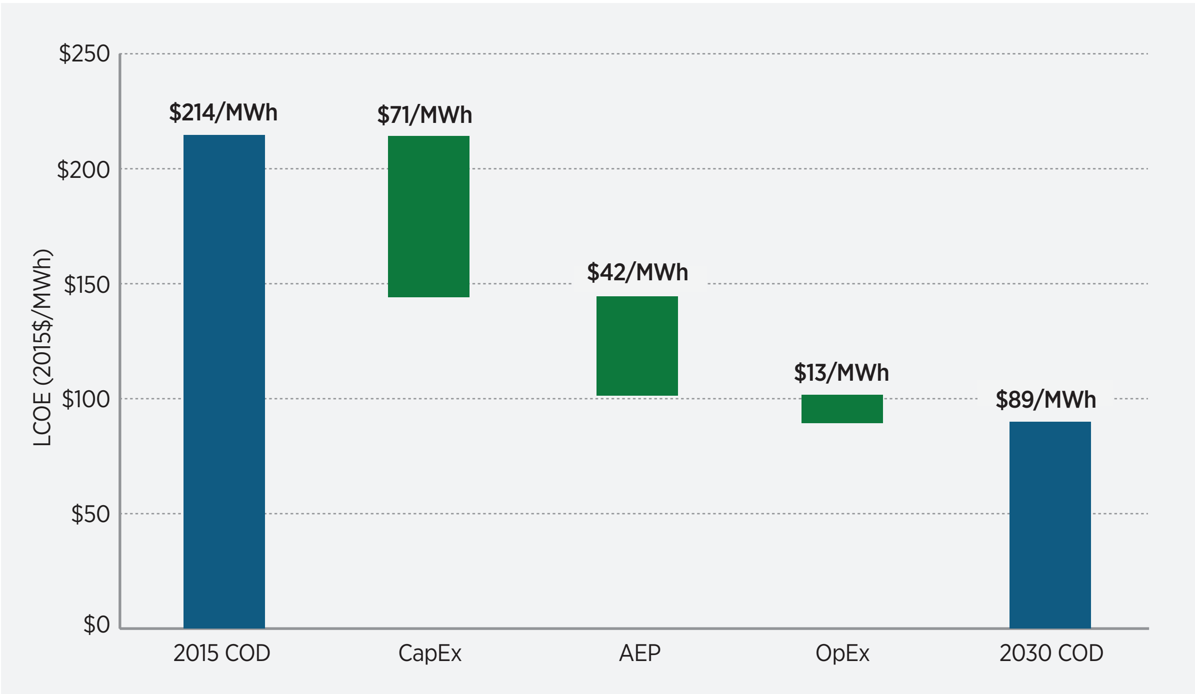


Figure 3.2. Modeled floating offshore wind cost reduction pathways to 2030 [23]

Capital Expenditure Reductions

CapEx comprises the largest component of offshore wind plant costs. Based on European market data, while average turbine ratings have risen, average CapEx has declined and is expected to continue to decline through 2020, ranging from $4,500–$5,200/kW [5]. Complex marine operations and balance-of-system costs (e.g., cabling) make installing each individual foundation and turbine expensive. Attaining plant capacity with fewer, larger turbines allows for lower installation costs and balance-of-system costs. Installation costs may be further reduced by simple, lightweight, mass-producible foundations. Balance-of-system costs may be further reduced through the optimization of a wind plant's layout. For example, balance-of-system costs could be reduced by configuring a wind plant with tighter turbine spacing without sacrificing power performance. Optimized layout configurations could be enabled by implementing advanced control strategies.

Turbines

Growth in wind turbine size and capacity can drive significant CapEx reductions. As turbines are expected to grow in size from the current 6-MW class up to 10 MW by 2030, balance-of-plant costs, including installation, substructures, and cables, among other things, will decrease on a project basis. Tools that enable technology developers to consider the turbine and substructure as a single system will enable design optimization that will drive further cost reduction, particularly in floating systems. As designers begin to develop turbines larger than 10 MW, the industry may see radical solutions that reduce nacelle and rotor weight, such as superconducting generators—particularly relevant to floating foundations—and downwind rotors with more flexible blades. Turbine technology innovations may also facilitate cost reductions associated with AEP and OpEx as described below.

Figure 3.3. Six different offshore wind substructure types. The three on the far left are fixed-bottom substructures (monopile, jacket, and inward battered guide structure [also known as a twisted jacket]), and the three on the right are floating substructures (from left: semisubmersible, tension leg platform, and spar). *Illustration by Josh Bauer, NREL*

Substructures

Fixed-bottom and floating substructure technologies can be improved to lower CapEx through fully integrated designs that optimize the turbine, controls, and substructure as a single system.

Given that the lease areas BOEM has identified to date in the mid-Atlantic region are in water less than 60 m deep, and a significant portion of economically viable sites in the United States will be in shallow water [24], continued engineering and research that focus on fixed-bottom substructures will still have a significant impact in the U.S. offshore wind market. Although the European market has expanded the design envelope of conventional monopiles to include extra-large diameter designs to accommodate state-of-the-art turbines in North Sea projects, weak soil conditions in some U.S. regions will require different and innovative substructure types, such as jackets, suction buckets, or gravity-based structures. Designing foundations for serial production and simplicity will reduce the cost and complexity of fabrication as well as significantly lower capital costs.

Cost-effective floating systems represent a significant opportunity in the United States. Fifty-eight percent (1,194 MW) of the U.S. offshore wind technical resource potential lies in waters deeper than 60 m [24], which is likely beyond the economic reach of current fixed-bottom offshore wind technologies. Floating systems could enable quayside turbine construction, commissioning, and major component maintenance and replacement, thereby eliminating specialized turbine installation vessels (TIVs) and reducing the costs of major repairs. Floating oil and gas infrastructure and fixed-bottom wind turbines offer a baseline, but differ significantly in dynamics and scale.

Similarly, design standards and practices for offshore wind substructures tailored toward U.S. site-specific conditions have the potential to decrease risks and costs in the design process. Reducing or mitigating risk through community-accepted, U.S.-specific standards[24] capable of being integrated into BOEM/BSEE regulations has the potential to significantly lower the cost of offshore wind energy.

Installation

Innovation in installation methods can also result in further cost reduction [12, 24]. Given the cost and complexity of marine operations and the need for specialized installation vessels, investment in floating systems, self-lifting turbines, float-and-flip spar systems, and other innovative installation technologies may negate the need to invest in TIVs. These technologies could also significantly reduce noisy construction activities and concerns about impacts on marine mammals and other sensitive species. This improvement could increase the length of daily and seasonal installation windows and ultimately reduce the total installation time, cost, and risk.

Increasing Annual Energy Production

The net AEP of offshore wind turbines has also been rising over time [5]. Investment in technologies to increase the efficiency of wind turbines as well as their availability, lessen unscheduled maintenance, or improve accessibility for performing maintenance in harsh marine conditions will result in cost reductions resulting from increased AEP.

Rotor Size

Through innovative rotor technology and controls, a better understanding of wind resource conditions, and design experience, turbines with larger rotors have been driving capacity factors higher and allowing for greater power production in lower wind speed regimes. These bigger rotors are able to capture more energy more efficiently, which is a trend that is expected to continue [5]. As rotor size has increased, so has the hub height, which adds incrementally to the power output by taking advantage of winds that generally get stronger higher up. Although individual turbine energy production improves, entire wind plant system losses can lead to a decrease in AEP by up to 20% [64]. However, through integrated wind plant design and optimization, total net AEP can be increased significantly.

Turbine Availability and Access

Increasing the accessibility to turbines for normal and unscheduled maintenance can improve total AEP by reducing downtime. This will be very important along the Pacific Coast, where average sea states are more severe than the Atlantic and North Sea [33, 24].

Operational Expenditure Reductions

OpEx, which covers all costs incurred between the commercial operation date and decommissioning [5], makes up approximately 20% of total LCOE [35] over the lifetime of an offshore wind project. Offshore wind turbines generally have higher maintenance costs than land-based turbines as a result of more difficult accessibility [26] and harsh operating conditions. Advances in turbine reliability and prognostic health monitoring and management that allow fewer onsite maintenance operations and turn unscheduled maintenance into scheduled maintenance will drive significant reductions in OpEx. For example, turbines with a component showing wear that could lead to premature failure could automatically reduce production to extend the life of that component until the next scheduled maintenance. Additionally, new turbine technologies that have fewer moving parts and otherwise reduce the likelihood and severity of major component failures have the potential to further reduce O&M costs and LCOE.

Action Area 1.3: Installation, Operation and Maintenance, and Supply Chain Solutions

Problem Statement

The project pipeline for offshore wind in the United States as of 2016 is not adequate to support the supply chain needed for a cost-competitive industry, or to realize associated local economic development benefits. A lack of dedicated assets and experience makes cost-effective, Jones Act-compliant (see text box below) strategies for installing, operating, and maintaining offshore wind farms challenging.

Current Baseline

The U.S. offshore wind supply chain leverages expertise and experience from around the world. It may also leverage experiences from related industries, such as offshore oil and gas, but these assets are geographically dispersed and generally far from locations planned for near-term offshore wind development. The total U.S. supply chain is not well inventoried and lacks the workforce, port facilities, and particularly the vessels needed to efficiently support a domestic industry.

Dispersed Domestic Supply Chain

Fabrication facilities in the Gulf of Mexico traditionally used by the oil and gas industry have the capacity to fabricate offshore wind substructure components; however, they are not set up for the type of serial production that is required to achieve significant cost savings [65]. Even though these facilities are currently exploring involvement in East Coast offshore wind projects (and served the Block Island Wind Farm), the availability and cost of these assets is tied closely to oil prices. Similarly, although the infrastructure and vessel requirements for floating offshore wind projects are less burdensome and specialized than for fixed-bottom offshore wind, fabrication and port facilities on the West Coast are less robust, and represent a significant supply chain gap.

Local economic development benefits are important for obtaining PPAs. In New Jersey, for example, projects have to pass a net economic benefit test to qualify for an Offshore Renewable Energy Credit (OREC). Currently, however, manufacturers of major offshore wind components, such as turbines and electrical infrastructure, are concentrated in Europe. Until several projects have been built and there is certainty in the long-term project pipeline, these manufacturers will be unlikely to invest in U.S. facilities specific for offshore wind, and the domestic workforce will remain largely inexperienced, creating a burdensome learning curve for the offshore wind domestic industry.

Installation, Operation, and Maintenance Challenges

To reduce costs, the offshore wind industry is trending toward bigger turbines and taller towers, leading to the demand for larger, purpose-built vessels and infrastructure support. Accordingly, early U.S. developers have planned creative (and potentially risky) installation strategies to use specialized European TIVs in a Jones-Act-compliant manner (see text box) [66], or adapt the existing U.S. fleet to work in the difficult wind and wave conditions of first-generation offshore wind sites.

The current U.S. fleet of heavy-lift boats and other vessels may be able to support installation of some of the first U.S. offshore wind projects, but many are likely to require purpose-built TIVs. Currently, there are a limited number of these types of vessels that are equipped to handle the weight and height requirements necessary to install the latest 6- to 8-MW turbine technology [67].

The Jones Act and Offshore Wind Energy

The Jones Act originates from the Merchant Marine Act of 1920, prohibiting the transportation of passengers or merchandise between points in the United States in any vessel other than a vessel built in, documented under the laws of, and owned and operated by citizens of the United States. In general, this means that all vessels transporting passengers or merchandise between two points in the United States, such as a port and an offshore wind installation, must be U.S.-flagged vessels with a U.S. crew and ownership. Points in the United States are defined as any point on land, such as a port, and locations within 3 nm from shore. Although the general applicability of the Jones Act to offshore wind is well-established, some aspects of how it may apply to particular projects or circumstances are unresolved [68].

Even fewer can install state-of-the-art turbines in transitional depths of 30 to 60 m, which are prevalent in the United States [5]. Engaging European vessels may require inefficient and risky installation strategies to navigate under Jones Act requirements. Typically, TIVs book years in advance and can cost between $300,000 and $850,000 per day to operate [5], and U.S. developers would have to incur additional mobilization and demobilization costs to engage these vessels. The supply chain on the West Coast of the United States is considerably less developed than the East Coast or the Gulf; however, West Coast depths will likely require floating foundations, which may not require purpose-built installation vessels.

Marine operations mean that O&M costs of offshore wind facilities are significant, and are largely driven by two factors: 1) the distance between the project and the maintenance facilities, and 2) the prevailing wind and wave conditions at the project site [5]. Purpose-built O&M vessels are being constructed in Europe to adapt to particular site conditions, and the first U.S.-flagged O&M vessel was launched in 2016 to service the Block Island Wind Farm [69]. Although the U.S. workforce has limited O&M offshore wind field experience, there are many lessons to be learned from Europe and opportunities to gain experience as the industry matures.

Safely delivering technicians, equipment, and turbine components to project sites is an additional challenge. Under current regulations, renewable energy lease holders on the OCS are required to provide a safety management system that outlines the safety measures that will be utilized during its OCS activities; however, safety requirements have not yet been well defined.

Work to Date

Since 2011, DOE has invested about $1.3 million in studies to build an understanding of the supply chain assets that will be needed in the United States to support a robust offshore wind industry. These studies address port readiness [70]; manufacturing, supply chain, and workforce [56]; and vessel needs [71], each under a variety of deployment assumptions through 2030.

DOI built on DOE's port readiness work with a more detailed study of East Coast ports on the modifications that would be needed to support offshore wind energy construction. Although many of the required capabilities are available at today's ports, the primary exception is the ability to handle the weight of the heaviest wind turbine components [72]. There are many innovative ways (e.g., logistics, equipment) to adapt a port to service offshore construction. BOEM also funded a study assessing current infrastructure requirements and identified changes to West Coast port facilities that may be necessary to support floating wind projects. The study concludes that if no modifications are made, developers of commercial-scale projects will most likely utilize a network of ports to provide fabrication and assembly support [72].

DOI has also begun taking steps to better clarify its safety requirements for offshore wind projects. DOI's TAP provides a research element that supports its OCS standards and regulations. Research associated with TAP includes a wide spectrum of topics related to offshore operations in the OCS, including renewable energy. Through TAP, DOI has conducted studies[25] that provide an example safety management system for an offshore wind facility [73–74]. These studies found that many of the same safety and environmental management system requirements DOI uses for the offshore oil and gas industry could be applied to ensure the health and safety of an offshore wind workforce. TAP studies also examined land-based and international offshore inspection practices related to wind turbine facilities and associated electrical transmission systems.

To manage safety and environmental oversight of offshore wind construction and operations, DOI will soon be transferring inspection and enforcement responsibilities from BOEM to BSEE. When DOI created BOEM and BSEE in FY12, it did not transfer the safety and environmental enforcement functions for renewable energy to BSEE as it did for oil and gas activities on the OCS. Instead, those responsibilities were to be retained by BOEM until an increase in activity justified transferring the inspection and enforcement functions to BSEE. With initial construction of OCS projects expected to commence in the near future, BOEM and BSEE are working together to plan and implement this transition. A transition team is engaged in the effort to redesignate the renewable energy regulations in 30 Code of Federal Regulations (CFR) Part 585 between the two bureaus, and is also working to develop an outreach and communication plan to clarify the roles and responsibilities of each bureau to lessees and other stakeholders.

Remaining Gaps

Establishing the supply chain for the offshore wind industry and realizing the efficiencies and cost reductions that will come with it ultimately depends on a stable and significant project pipeline. Exploring mechanisms that would reduce the costs of initial supply chain investments and maximize the use of current assets can help alleviate supply chain challenges in the interim.

Mechanisms available to support the financing and construction of TIVs need to be explored. Constructing a U.S.-flagged installation vessel would free developers from depending on European vessels, but competition between multiple vessels in the United States is likely to be needed before significant cost reductions are possible. Before that happens, it is essential to conduct an inventory of existing U.S. assets that can support installation, operation, and maintenance activities for offshore wind facilities, as well as identify ways to use these assets in the most cost-effective, least risky way.

The United States also needs a set of clear safety standards and regulations. Existing research and lessons learned from operational offshore wind facilities worldwide provide a sufficient foundation for DOI to develop safety regulations, guidelines, and procedures. Further, this information would provide DOI with the ability to establish criteria for conducting inspections of offshore renewable energy facilities to protect the safety of the structures and foundations and provide a safe environment for onsite personnel, as well as anyone working in the surrounding lease area.

3.2 Strategic Theme 2: Supporting Effective Stewardship

Effective stewardship of the nation's ocean resources will be necessary to support an offshore wind industry in the United States. DOI, through BOEM, oversees the responsible development of energy on the OCS. It is important for developers to have certainty when navigating the regulatory and environmental compliance processes. To support effective stewardship of these resources, the following action areas are needed:

- **Ensuring efficiency, consistency, and clarity in the regulatory process**. BOEM has significantly increased the efficiency of the regulatory process over the past several years. Nevertheless, further work can be done to ensure that existing requirements are not overly burdensome, such as providing more predictable review timelines.
- **Managing key environmental and human-use concerns**. To ensure that offshore wind is developed in a sustainable manner, more data need to be collected regarding the impacts of offshore wind on existing human uses of ocean space and sensitive biological resources. In addition, some issues could be retired as they are resolved to improve the efficiency of environmental reviews and allow for a greater focus on the most significant risks and impacts.

Action Area 2.1: Ensuring Efficiency, Consistency, and Clarity in the Regulatory Process

Problem Statement

Although progress has been made to improve the offshore wind planning, leasing, and approval processes, developers still face significant obstacles in the regulatory oversight process that will need to be overcome to facilitate efficient and responsible offshore wind development.

Current Baseline

The OCS Lands Act imposes a number of obligations on BOEM when conducting its offshore wind oversight processes. For example, BOEM must ensure that projects are developed in an environmentally responsible and safe manner that considers other uses of the OCS, and must coordinate with relevant federal agencies and affected state and local governments when moving forward with its offshore wind authorization process. Though BOEM is the lead federal agency, there are many other agencies that issue authorizations or are otherwise involved in or potentially affected by offshore wind projects, including the Army Corps of Engineers, U.S. Coast Guard, NOAA, the U.S. Department of Defense, and the National Park Service.

At the time *A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States* (2011) was released, the first offshore wind projects were progressing through BOEM's regulations and the considerable uncertainty regarding the process timelines and cost was regarded by stakeholders as one of the most pressing challenges to industry [8]. Since then, several developers have completed portions of the permitting process and BOEM has made strides in the planning and leasing of the OCS for offshore development, as well as identifying and remedying issues associated with its oversight processes.

For the Atlantic OCS, BOEM has conducted commercial wind planning and leasing processes for areas off the coast of six states, and is continuing with these processes for another three states. The agency has established 13 Task Forces across the country and issued 11 commercial wind leases along the Atlantic Coast—9 through the competitive lease sale process and 2 noncompetitively. BOEM is in the process of establishing an additional Task Force with the State of California. These competitive lease sales have generated $16.4 million in auction revenue for more than 1.18 million acres in federal waters. BOEM has also issued a research lease to the Commonwealth of Virginia and approved a Research Activities Plan for that project.

In the Pacific Region, BOEM has initiated the commercial leasing process for an area off the coast of Oregon. Further, BOEM has published a Call for Information and Nominations for two areas offshore Hawaii, and a Request for Interest for one area offshore California.

BOEM's Approach to Authorizing Offshore Wind Activities

BOEM's offshore wind authorization process includes four phases: 1) planning, 2) leasing, 3) site assessment, and 4) construction and operations.

Planning and Analysis

Once a state has expressed interest in the development of wind energy resources off its coast, the planning process typically begins with the establishment of an Intergovernmental Renewable Energy Task Force. The Task Force consists of relevant federal and potentially affected state, local, and tribal officials. BOEM works with each Task Force to identify an area or areas of the OCS to consider for commercial wind energy leasing and subsequent development and/or review of unsolicited applications for commercial wind leases that are submitted by specific developers. Though the Task Force is not a decision-making body, BOEM coordinates with the members of each Task Force to inform how and whether renewable energy planning and leasing should proceed. In particular, Task Force members help inform BOEM's decision-making by identifying important resources and uses that may conflict with commercial wind energy development.

After delineation of a planning area in coordination with the applicable Task Force and/or receipt of an unsolicited application identifying a particular area from a developer, BOEM will typically publish one or more Federal Register notices (e.g., a Request for Interest, Call for Information and Nominations) to determine whether there is competitive interest in the area identified and gather comments from the public.

Leasing

If there is competitive interest, BOEM will initiate a competitive planning and leasing process, including area identification. During this process, the agency considers all relevant information received to date, including public comments and nominations received

Planning and Analysis	Leasing	Site Assessment	Construction and Operations
• BOEM delineates potential area or processes unsolicited application, in coordination with Task Force • BOEM publishes one or more Federal Register notices and determines whether competitive interest exists • BOEM may further refine area, and conducts necessary environmental reviews evaluating lease issuance and site assessment	• *If Competitive Interest exists*, BOEM notifies the public and developers of its intent to lease through Sale Notices before holding a lease sale • *If Competitive Interest does not exist*, BOEM negotiates a lease (note: issuance may be combined with plan approval)	• Lessee conducts site characterization studies • Lessee submits Site Assessment Plan (SAP) • BOEM conducts environmental and technical reviews of SAP, eventually deciding to approve, approve with modification, or disapprove the SAP • If approved, Lessee assesses site (usually with meteorological tower(s) and/or buoy(s)	• Lessee may conduct additional site characterization • Lessee submits Construction and Operations Plan (COP) • BOEM conducts environmental and technical reviews of COP, eventually deciding to approve, approve with modification, or disapprove the COP • If approved, Lessee builds wind facility

Intergovernmental Task Force Engagement

Figure 3.4. The four stages of BOEM's wind authorization process [75]

in response to a Request for Interest or Call for Information and Nominations. This approach helps balance potential commercial wind development against other uses of the area and environmental concerns associated with offshore wind development. If BOEM is able to identify an area that appears suitable for offshore wind development through this process, that area is referred to as a WEA. BOEM will then conduct the necessary environmental reviews and consultations to inform a potential leasing action for the WEA. During this review, BOEM will consider the reasonably foreseeable impacts associated with lease issuance, associated site-characterization surveys, and site assessment activities (e.g., installation and operation of meteorological towers and/or buoys). BOEM may then publish sale notices detailing the proposed lease sale and hold an auction to award one or more leases to the winning bidder(s).

If BOEM determines there is no competitive interest in a requested potential lease area, then after the completion of necessary environmental reviews, BOEM may, if deemed appropriate, begin negotiating the terms of a lease with the interested developer prior to issuing a lease.

Site Assessment

After lease issuance, the lessee begins the site assessment phase, and has approximately 5 years to complete the necessary site characterization and assessment activities to gather information to support its commercial proposal. If a lessee is proposing to install a meteorological tower and/or buoy to gather wind and oceanographic resource data on the leasehold, it must submit a Site Assessment Plan (SAP) that describes these activities for BOEM's review and approval. If the proposed activities and their effects are outside the scope of BOEM's previous environmental reviews and consultations, additional review and consultation may be necessary.

Construction and Operations

The final phase of the process—construction and operations—begins with the submission of the lessee's Construction and Operations Plan (COP). The COP contains the lessee's detailed plan for the construction and operation of a wind energy project in the lease area. BOEM will conduct thorough engineering and environmental reviews of the COP, likely including an Environmental Impact Statement under NEPA. After the approval, or approval with modifications, of a COP, the lessee would develop and submit its Facility Design Report and Fabrication and Installation Report. The lessee may commence fabrication and installation of its facility once BOEM has reviewed these reports and any of its objections to them have been resolved. BOEM's offshore wind leases typically include a 25-year operations term. At the end of the operations term, the lessee will be required to decommission its project.

Once a lease is acquired, BOEM requires that a lessee pay rental and operating fees (to ensure "fair return" to the nation for use of the OCS), and that the lessee provide financial assurance to protect the government's interests.

Work to Date

BOEM has made important progress in granting access to the OCS for renewable energy development, and the agency has been incorporating lessons learned and identifying and implementing improvements to the program where appropriate. For example, BOEM has promulgated two changes to its regulations since they were published in 2009. The first change, finalized in 2010, eliminated a redundant step in BOEM's noncompetitive leasing process. In 2014, BOEM finalized a rulemaking to change certain plan submission timelines that were proving unworkable for developers.

BOEM has also developed a number of national and regional guidelines to provide its renewable energy lessees with additional information and guidance for compliance with its regulations, standards, and other requirements. For example, BOEM has developed guidance documents that provide the information recommended for inclusion in an SAP and COP, and a series of survey guidelines, including those for providing the recommended geophysical, geotechnical, and hazard information; biological data; and archaeological and historic property information.

DOE's current and former Offshore Wind Advanced Technology Demonstration Projects have helped to exercise the regulatory process on both the state and federal level. Specifically, Principle Power's WindFloat Pacific project in Oregon and Aqua Ventus in Maine have presented regulators with alternative floating foundation technologies that required analysis from a new perspective. The Commonwealth of Virginia, working with Dominion Energy's Virginia Offshore Wind Technology Advancement Project, was issued the first research lease in federal waters. Activities under these awards have also helped the community of cooperating agencies to become familiar with offshore wind energy and its siting processes.

Remaining Gaps

BOEM has received suggestions for specific changes to its regulatory process that could make it more efficient for developers. Stakeholders have recommended that BOEM reduce the burden of certain requirements, shorten and increase certainty associated with review timelines, and improve coordination among agencies and stakeholders during the regulatory process. Some suggestions are described below.

Reducing the Burden of Regulatory Requirements for Meteorological Buoys

Under BOEM's current regulations, a lessee is required to submit a SAP when proposing to install a meteorological buoy and/or meteorological tower in its lease area. Because BOEM's experience reviewing SAPs is limited, it is reasonable to anticipate that the process of reviewing and approving a SAP could take several months. In previous environmental reviews, BOEM has concluded that the environmental impacts associated with deploying a buoy are not significant under certain conditions. As such, there is an opportunity for BOEM to reconsider its requirements associated with buoy deployment.

Decommissioning Financial Assurance Requirements

BOEM's current decommissioning financial assurance regulations require a lessee to submit financial assurance covering the anticipated decommissioning costs of the proposed offshore wind project prior to installing facilities approved in a COP. Commenters have argued that this would increase the cost of energy from a project with little added public benefit. According to commenters, providing for flexibility to offer decommissioning financial assurance later in the operations term would help ensure that decommissioning requirements are met in a manner that does not disadvantage offshore wind developers relative to other forms of new power generation.

Ensuring Effective and Timely Plan Reviews

Stakeholder feedback has suggested that BOEM's plan-review process needs to be more transparent, predictable, and expeditious to reduce scheduling uncertainty and financial risk. A factor contributing to regulatory complexity is that many agencies have roles in the offshore wind project authorization process and there are challenges to aligning numerous entities at different levels of government. The number of permits and authorizations required for the realization of an offshore wind project can be daunting for developers.

Title 41 of the Fixing America's Surface Transportation Act (P.L. 114-94)[26] (FAST-41), requires the facilitating or lead agency of a major infrastructure project to establish and publicly track a concise Coordinated Project Plan for coordinating participation in, and completion of, any required federal authorizations and environmental reviews, including a permitting timetable that outlines the dates by which all reviews and authorizations must be made.[27] BOEM will track COP reviews through FAST-41, and there may be additional steps that the organization can take to create a predictable plan-review process.

Feedback from developers also suggests that it is not practical to submit a COP that includes all project specifics, and that a degree of flexibility would allow developers to make certain project-design decisions—such as which turbine to use—at the more commercially advantageous time later in the project-development process. This could potentially be accomplished by implementing the "design envelope" environmental review approach that is employed in certain European nations. With this approach, the environmental review is conducted by resource area, to include the greatest potential impact from a range of design options and parameters.

Enhancing Coordination Around Lease Area Identification

Many RFF comments from stakeholders highlighted the need for BOEM to better coordinate with other ocean users as the agency identifies potential areas for leasing (e.g., fishermen and vessel operators). One commenter also recommended that BOEM reach out to NREL during the planning process to help ensure that areas preliminarily identified are suitable for development.

Other commenters recommend that BOEM consider a more regional approach to planning than is currently provided for in BOEM's Task Force process. For instance, one RFF commenter argues that the state-by-state Task Force approach can unintentionally exclude the interests of states other than the "lead" state, resulting in issues being raised late in the process. BOEM has made adjustments to its outreach and coordination strategy for certain areas to try to better account for regional issues (e.g., realigning the planning and leasing process for the Wilmington West and East WEAs with the process for the South Carolina Call Areas, and conducting outreach in a number of states to ensure regional input into the New York WEA leasing environmental review process). However, comments indicate that as BOEM continues to identify new areas for offshore wind development, it may be able to make adjustments to its typical Task Force establishment process to ensure that planning and leasing efforts are better informed.

Action Area 2.2: Managing Key Environmental and Human-Use Concerns

Problem Statement

Much has been learned about how offshore wind facilities could impact environmental resources and human activities; however, some impact assumptions are founded in predictive information rather than in empirical research. The construction and operation of the first U.S. offshore facilities provides the opportunity to verify the analysis of previous studies, address impacts and use conflicts based on field-verified information, and promote regulatory certainty and ensure sound stewardship of the OCS.

Current Baseline

As noted in Section 2.7, offshore wind development carries with it substantial positive environmental benefits, both on land and at sea, including significant reduction in cumulative GHG emissions, air pollution, and water usage by the energy sector [2]. Still, large-scale deployment requires responsible stewardship to ensure that direct impacts to wildlife, sensitive habitat, and existing uses are properly managed. Wildlife and human-use concerns associated with offshore wind include effects on migratory birds, marine mammals, and other sensitive species, as well as impacts to human communities and competing uses such as fisheries and radar systems.

Offshore biological surveys along the East Coast, including a DOE- and DOI-sponsored effort recently conducted by the Biodiversity Research Institute, indicate that bird abundance is generally greater in nearshore areas [76–77]. Additionally, most seabirds fly below the rotor swept area [78], whereas land and shorebirds migrating offshore generally fly at heights above the rotor swept zone [76, 79]. However, concerns still persist that offshore wind could displace birds from important habitats or create barriers to migration. Under the Endangered Species Act, BOEM consults with the U.S. Fish and Wildlife Service (FWS) to address potential impacts to threatened and endangered avian species. With respect to migratory birds, BOEM consults with FWS about potential impacts to these types of birds and may impose measures to lessen such impacts consistent with BOEM's obligations under its memorandum of understanding with FWS and Executive Order 13186, thereby furthering the objectives of the Migratory Bird Treaty Act.

Offshore wind facilities can also pose risks to marine mammals, protected under the Endangered Species Act and the Marine Mammal Protection Act, through noise related to surveys and construction—particularly pile-driving associated with fixed-bottom foundations. To address these impacts, BOEM consults with the National Marine Fisheries Service under the Endangered Species Act prior to approving such activities and requires developers to comply with any resulting required mitigation measures. In addition, developers may need to apply for incidental harassment authorization under the Marine Mammal Protection Act.

Offshore wind facilities may also impact human communities and competing uses in ways that affect important aspects of coastal culture and economies. Commercial and recreational fishermen have expressed concern that access to historic fishing grounds could be impacted by offshore development. The placement of permanent structures offshore could also affect shipping routes and navigation. In addition, air traffic control, air surveillance, weather, and navigational radar systems may be impacted by offshore wind turbines through increased clutter that may inhibit target detection, increase the generation of false targets, interfere with target tracking, and hinder weather forecasting [80]. These issues may be different from those caused by land-based wind turbines, given how radar signals propagate in the ocean environment. Lastly, coastal communities are often concerned about visual impacts, particularly with respect to important historic properties [81].

Work to Date

Since 2011, there has been a significant increase in knowledge of environmental resources and human uses where offshore wind development may occur and the impact that development may have on those resources. Numerous data-collection efforts have increased information regarding marine species distribution and abundance in regions of interest for offshore wind development around the nation. Studies have improved the understanding of and certainty associated with risks to birds and bats, and the potential effects of electromagnetic fields generated by interarray and power export cables on sensitive species. Studies have also led to best practices for lighting of offshore wind turbines, and sound source verification for high-resolution geophysical equipment and pile driving associated with offshore wind development and construction activities.

The availability of reliable data is vital for responsible and informed decision-making by governmental agencies and developers alike. BOEM gathers information about existing environmental and human-use conditions along the OCS and assesses potential impacts to determine which areas are appropriate for leasing and siting offshore wind facilities. Information that improves this foundational knowledge and is applicable beyond a single lease area[28] is generally understood to be the responsibility of federal agencies.

Developers are responsible for providing BOEM with site-specific information to inform how their renewable energy plans could affect the coastal, marine, and human environment. This information, in turn, supports BOEM's environmental analysis and helps determine what measures may need to be taken to avoid, minimize, or otherwise mitigate these impacts.[29] BOEM has developed a number of national and regional guidelines for renewable energy activities on the OCS. These informal documents are intended to provide lessees, operators, and developers with additional information to clarify and supplement regulatory requirements and plan development. Existing guidance can be found on BOEM's website: *http://www.boem.gov/National-and-Regional-Guidelines-for-Renewable-Energy-Activities/*. In 2015, BOEM published guidance for providing information on the social and economic conditions of fisheries, through the development of a fisheries engagement strategy.

BOEM's approval process includes the analysis of the environmental effects from the construction, operation, and decommissioning of offshore wind facilities. Without real-time observations of these activities, estimates, and conservative scenarios based on the best available information are used to make these determinations. These analyses would benefit from empirical studies of actual impacts.

The construction and operation of the first offshore wind facilities provide an opportunity for more detailed and empirical assessments of the environmental effects of offshore wind turbines. Thus, BOEM commissioned the Real-time Opportunity for Development Environmental Observations (RODEO) study in 2015. The objective of the study is to acquire real-time observations of the construction and initial operation of wind facilities to evaluate the environmental effects of future facilities. The study also offers the opportunity to address many of the environmental questions that are of concern to the public, as well as other federal, state, and local agencies. RODEO will measure and analyze air emissions, sound produced by construction and operations activities, seafloor disturbance associated with cabling and vessel anchoring, and visual impacts from construction and early operation. In addition to actual

Mid-Atlantic Ecological Baseline Study

DOE, in collaboration with a wide range of partners, including DOI, funded the Biodiversity Research Institute to conduct the first-of-its-kind Mid-Atlantic Ecological Baseline Study between 2011 and 2015. The study provides comprehensive baseline ecological data and associated predictive models and maps to regulators, developers, and other stakeholders to inform the siting and permitting of offshore wind energy. This 4-year effort provides an extensive data set on species of concern to the wind energy community, covering over 13,000 km^2 of ocean space including the Delaware, Maryland, and Virginia WEAs, while validating novel high-definition survey technologies. The results of this study will significantly reduce the effort required by developers working in the study area and will serve as a starting point for broad-scale and site-specific environmental risk analyses and evaluating potential measures to avoid and minimize risks to wildlife from human activity in the offshore environment. For more information, visit *http://www.briloon.org/mabs*

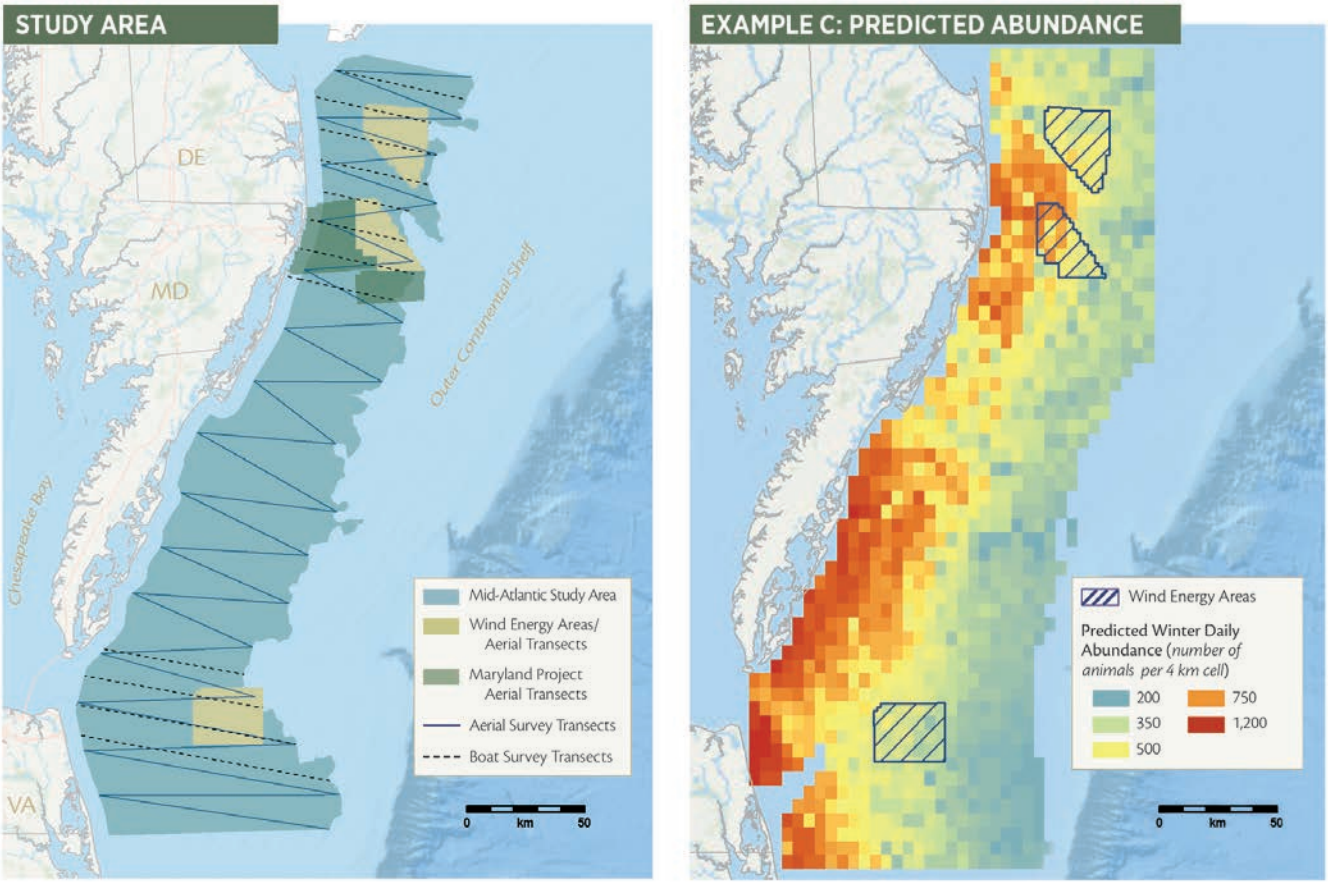


Figure 3.5. The Mid-Atlantic Ecological Baseline study area and survey transects (left), and an example study output showing predicted winter abundance of Northern Gannets in the study area

measurements, mitigation methodologies and testing of monitoring equipment are included as part of the study's obligations. BOEM contractors were in the field during the summer and fall of 2015 to take measurements at the site of the Block Island Wind Farm during and after installation of its foundations.

Additionally, in *A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States* (2011), DOE and DOI noted that although hundreds of environmental studies have been conducted in Europe at offshore wind farms, few studies have been done in U.S. waters given the lack of deployments to date. Since 2011, DOE has invested about $8 million related to these issues, and along with other federal agencies, has engaged in efforts to gather, analyze, and publicize data on environmental and competing use issues. These data will allow DOE to better inform stakeholders and policymakers on the extent of potential impacts of offshore development and begin to shed light on how those impacts might be mitigated. The largest of these efforts, the Mid-Atlantic Ecological Baseline Study, is described in the text box provided earlier.

Regarding the impacts of offshore wind on radar systems, DOE has funded a study modeling potential effects [80], and established a memorandum of understanding to mitigate wind turbine radar interference with the U.S. Department of Defense, Federal Aviation Administration, and NOAA to guide collective R&D efforts. These and other such efforts seek to avoid compelling individual developers to shoulder the high costs of more broadly applicable research and will build a common knowledge base.

Over the same period, BOEM has invested approximately $24 million in studies supporting renewable energy needs along the Atlantic Coast and more than $14 million along the Pacific Coast and Hawaii. The majority of these funds were spent on studies to better understand habitat and ecology on the OCS. Other areas of study included social science and economics, marine mammals and protected species, fates and effects,[30] as well as air quality, information management, and physical oceanography. The information obtained from these studies helps inform BOEM guidance and environmental analyses.

Remaining Gaps

The first generation of installed projects will help to establish and validate the actual effects and impacts of offshore wind development on biological communities, and narrow the range of potential effects that need to be monitored or mitigated at a given site. Collecting field data on impact-producing factors like construction noise and how these factors affect resources of concern like marine life will help to verify impact assumptions. Such information has the potential to distinguish which risks are significant or highly unpredictable—and therefore important to monitor and mitigate over the long term—from predictable and insubstantial risks that can be "retired" from consideration, monitoring, or mitigation.

From a human-use perspective, field experience also provides an opportunity to gain an understanding of the impacts of actual projects on issues such as radar interference. Although the effects of land-based wind development on various radar systems are well understood, there are unique considerations associated with how radar signals propagate over water that require closer attention. In addition, the first offshore projects will allow for the more robust development of social science that can better determine the drivers of public acceptance of and opposition to offshore wind in the United States. This knowledge can aid in the establishment of best practices for project developers and regulatory processes that better address stakeholder concerns and the development of appropriate mitigation measures.

Continued broad-scale and site-specific baseline assessment will remain valuable as the offshore wind industry develops. Given the expense associated with baseline data collection, it is likely that agencies will need to take an approach that combines site-specific, developer-collected, preconstruction surveys with surveys conducted for other broader scientific reasons (such as monitoring of North Atlantic Right Whale populations) into a coherent picture that supports offshore wind siting and plan reviews. As more developers prepare to submit COPs, additional guidance may be necessary to ensure that the data meet the needs of all the federal agencies involved.

3.3 Strategic Theme 3: Increasing Understanding of the Benefits and Costs of Offshore Wind

An increased understanding of the benefits and costs of offshore wind can help support near-term deployment. Near-term deployment will be essential to realizing the cost reduction opportunities provided by R&D and enabling the development of a supply chain. To help improve understanding of offshore wind's benefits for near-term deployment, work will be needed in two areas:

- **Offshore wind electricity delivery and grid integration.** Impacts of significant offshore wind deployment on local grids need to be better understood, and the costs and benefits associated with offshore transmission infrastructure need to be characterized.
- **Quantifying and communicating the benefits and costs of offshore wind.** Environmental and economic benefits and costs associated with offshore wind need to be rigorously quantified and communicated to policymakers and stakeholders to inform decisions on near-term PPAs and policies related to offshore wind.

Action Area 3.1: Offshore Wind Electricity Delivery and Grid Integration

Problem Statement

Significant progress has been made to understand and address the challenges of integrating large amounts of variable renewable energy into the U.S. grid, but the unique challenges of large amounts of offshore wind have not been evaluated, particularly on the scales that are relevant to local system operators and utilities. Build-out of significant offshore transmission "backbones" have been proposed as a means to support such integration and provide broader value to the electrical system, and the benefits and costs of such infrastructure need to be well defined.

Current Baseline

In Europe, more than 12 GW of offshore wind capacity had been installed at the end of 2015, enough capacity in an average wind year to provide 1.5% of the European Union's total electricity consumption [82]. The grid infrastructure supporting this generation is significant, and includes 11 offshore grids operating in the North and Baltic Seas and another 21 currently being considered by grid operators [82]. This power is interconnected to the transmission and delivery infrastructure operated by member states and commissions, and as offshore wind penetration has grown, its impacts on system reliability and operating costs have been minimal. The future outlook from a technical perspective is positive as well. A 2010 analysis by the European Wind Energy Association concluded that "the capacity of the European power systems to absorb significant amounts of wind power is determined more by economics and regulatory frameworks than by technical or practical constraints." According to recent work by the International Energy Agency, offshore wind energy could account for 5% of global electricity generation by 2050 [83].

The United States has significant experience integrating land-based wind and other variable renewables. In 2015, nearly 5% of U.S. electricity was generated by wind energy [1], with Iowa generating more than 30% of its electricity from wind [6]. Further, much has been done to investigate the impacts of incorporating significant percentages of wind and other variable renewables into the grid. Numerous studies have shown that the grid operates reliably with wind energy contributions over 10%, with minimal impacts on network operating costs and the ability to operate reliably at much higher penetrations [84–85].

Recently, the DOE-funded *National Offshore Wind Energy Grid Interconnection Study* [44] also found that the primary barriers to offshore wind interconnection and integration in the United States are not technical or practical in nature, finding that "appropriate technologies exist for interconnecting large amounts of wind energy to the U.S. grid." Instead, the report advised that R&D efforts were best focused on the reduction of initial capital investment.

Work to Date

Since 2011, DOE has funded more than $2.4 million of R&D to better understand electric system impacts. The FY 2011 U.S. Offshore Wind: Removing Market Barriers FOA made funding available to 12 research projects for the purpose of facilitating deployment and reducing technical challenges facing the offshore wind industry.

These studies investigated the impact of changes to existing practices in power system operations, the role of forecasting, and the capability of supply- and demand-side technologies in providing the needed flexibility to integrate wind power into the existing grid.

BOEM's involvement in electric systems is limited, though NREL has recently delivered data inputs to BOEM and the California Public Utilities Commission to support the expanded capability and application of the California Renewable Portfolio Standard (RPS) Calculator to offshore wind energy. The RPS Calculator creates plausible portfolios of renewable resources needed to meet RPS policy goals, from inputs describing six sites able to support offshore wind before 2030. These inputs include parameters such as project cost, O&M costs, technology capacity factors, and hourly production profiles, and have been reviewed by NREL and industry offshore wind experts.

Remaining Gaps

Although the electrical system impacts may be largely analogous to land-based wind, there remain some key differences in the interconnection and integration of offshore wind energy onto the grid that need further investigation.

Continued interconnection and integration studies conducted over state and regional areas could help quantify the broad grid integration impacts (see Action Area 3.2: Quantifying and Communicating the Benefits and Costs of Offshore Wind) of adding significant amounts of offshore wind energy to the power system, but at a level of specificity relevant to local system operators and utilities. These studies could focus on issues such as the impact of offshore wind's coincidence with system loads, how its capacity value differs from land-based wind near coastal areas, and its influence on regional electricity markets. Such information could significantly benefit the offshore wind community by informing state policies critical to supporting development.

Beyond interconnection and integration studies, R&D on reducing initial capital costs—including the development of cables and compact high-voltage direct-current converters—could lower the financial barrier to entry, increasing offshore wind energy penetration and reducing the cost of offshore wind energy. According to the *2014–2015 Offshore Wind Technologies Market Report*, an increase in array system voltage has the potential to reduce CapEx through more efficient cable layout, decrease electrical losses (up to 75%), reduce the mass and number of substations, and increase reliability [5]. Yet, progress towards higher-voltage systems in the United States has been slower than anticipated [86]. European projects are currently adopting higher-voltage export cables to reduce CapEx on projects sited further offshore. At distances greater than 90–120 km, conventional high-voltage alternating-current electrical infrastructure becomes prohibitively expensive, and transmission system operators in Europe are starting to use recently introduced high-voltage direct-current technologies [5].

Action Area 3.2: Quantifying and Communicating the Benefits and Costs of Offshore Wind

Problem Statement

The greatest challenge facing near-term offshore wind deployment is the availability of above-market PPAs or other revenue streams sufficient to finance projects. Rigorously quantifying the full electricity market and environmental benefits and costs of offshore wind (as discussed in Section 2.7) and ensuring that they are effectively communicated to policymakers and key stakeholders can aid in the evaluation of projects and policies around offshore wind and improve the basis on which decisions are made.

Current Baseline

Much of the success of the European offshore wind energy market in the face of high costs can be attributed to long-term policy support. First-generation projects have benefited from aggressive climate and renewable energy targets as well as explicit price support mechanisms, such as feed-in tariffs, that provide a sufficient revenue stream to finance projects. The resulting cost reductions and industry experience gained have led policymakers in Europe to move away from setting fixed, above-market prices for offshore wind at a national level. They are now implementing more creative price support mechanisms, such as auctions, to encourage competition between developers [5], and more indirect support, such as lower-cost financing through government-backed green investment banks and export credit agencies that have attracted commercial lenders [87].

In the United States, federal incentives such as the renewable electricity PTC and business energy ITC have helped drive significant growth in renewables, particularly in land-based wind and solar energy. Because of the capital-intensive nature of offshore wind development, the ITC is more relevant, and its continuation may be a significant driver for near-term development.

As part of the Consolidated Appropriations Act of 2016 (P.L. 114-113), Congress extended the expiration date for the ITC, with a gradual step down of the credits from 30% in 2016 to 12% for projects commencing construction in 2019 [3].

As of late 2015, 29 states and the District of Columbia have RPSs to support the development of renewable energy [88]. Many of these states have unique market characteristics wherein offshore wind energy could play an important role in meeting renewable-energy-deployment and GHG-reduction targets. For instance, New York and California each have significant energy demand in coastal cities and aim to generate 50% of their electricity from renewable energy [88]. New England states have relatively high electricity prices, renewable energy targets, and land constraints that will likely require further consideration of offshore wind development if a significant portion of their energy is to come from in-state resources. Hawaii became the first state to commit to a 100% RPS in 2015 [89], and the state's limited terrestrial resources and high energy prices create a market ripe for offshore wind.

Given the relatively high cost of offshore wind compared to other renewables, specific mechanisms have been put into place in a few states that provide special consideration. For example, New Jersey passed legislation requiring the establishment of an OREC program, though the state has not yet established regulations that provide a funding mechanism for the program. The Maryland Offshore Wind Energy Act of 2013 provides for ORECs for up to 2.5% of the state's electricity supply from offshore wind energy, requiring consideration of peak load price suppression and limiting rate impacts. [17, 90].

Other states, such as Maine, Massachusetts, and Rhode Island, have pursued, to varying degrees of success, legislation that either mandates or allows for the consideration of factors other than cost—such as net economic benefits—in evaluating offshore wind PPAs. Four offshore wind PPAs have been finalized in the United States to date (though three have since been terminated). Effective bundled prices have ranged from approximately $180 to $240/MWh, with terms extending between 15 and 25 years [5].

All of the federal and state policies that have been implemented to support renewable energy, and offshore wind in particular, are motivated at least to some extent by the notion that deploying offshore wind or other renewables provides significant benefits—decreased carbon and other air pollution, fuel diversity, energy security, and economic development. A lack of rigorous and accepted means of quantifying such benefits, and particularly the unique combination of benefits of offshore wind, has been a substantial barrier to the evaluation of policies related to offshore wind as well as project-level PPAs.

Work to Date

Through the *Wind Vision,* DOE examined the costs and benefits of the development of 22 GW of offshore capacity by 2030 and 86 GW by 2050. The study examined potential reductions in GHGs, water usage, and risk; air pollution effects; energy diversity; and workforce and economic development impacts (see Chapter 2 for a more exhaustive look at the scenario). DOE closely tracks and reports on project development and cost trends both globally and in the United States through its periodic offshore wind market reports.

As a result of local infrastructure requirements associated with the sheer size of equipment and complexity of installation, operation, and maintenance activities, offshore wind can bring significant wind-related jobs and economic activity to coastal states, as it has in some coastal areas in Europe. According to the *Wind Vision*, the offshore wind deployment envisioned in the study scenario could result in the creation of 32,000–34,000 offshore wind-related jobs in 2020, increasing to 76,000–80,000 in 2030, and 170,000–181,000 in 2050 [2]. DOE studies utilizing the offshore wind Jobs and Economic Development Impact model show that an offshore wind industry in four coastal regions of the United States has the potential to support thousands of jobs because of robust workforce requirements, even at relatively conservative levels of deployment and domestic supply chain growth [56, 91].

Through its WINDExchange program and several wind Regional Resource Centers,[31] DOE has helped communities weigh the benefits and costs of offshore wind energy, understand the deployment process, and make wind development decisions. The goal of the Regional Resource Centers project is to make it easier for stakeholders and policymakers to decide if wind project development is appropriate for their communities by producing relevant, actionable, and fact-based information; and delivering that information to communities considering their options in a clean energy portfolio.

In 2015, DOE's State Energy Program awarded almost $600,000 to state agencies in New York, Maine, Massachusetts, and Rhode Island, in addition to the Clean Energy States Alliance, to develop a roadmap to a regional market for offshore wind. Through this DOE award, the states and Clean Energy States Alliance will examine how to identify achievable cost reductions associated with a pipeline of projects.

BOEM collects revenues from lessees, or potential lessees, in the form of acquisition fees for unsolicited lease requests, bonus bids from auctions, rent for leases that have been issued, and operating fees for leases that have been developed and are in operation. In response to comments received from stakeholders, BOEM has implemented a process that considers state policies that support offtake agreements and other incentive programs in designing its offshore wind energy auctions. In its recent New Jersey lease auction, for example, BOEM employed a multiple factor auction format that included nonmonetary factors of either up to a 25% credit to any bidder able to demonstrate that they had a PPA in the amount of 250 MW, or a 25% credit to any bidder able to demonstrate they had an approved or conditionally approved OREC order from the New Jersey Board of Public Utilities. BOEM offered similar nonmonetary factors in its Maryland auction, and other nonmonetary factors in its Massachusetts and Rhode Island lease auctions. BOEM will likely continue to consider including these nonmonetary factors in future auctions in recognition of agreements that it believes would substantially contribute to the success of an offshore wind project.

Remaining Gaps

Rigorously quantifying the full costs and benefits of offshore wind development in the context of both electricity markets and broader policy issues, such as economic development and climate change, will allow for better-informed discussion between offshore wind developers, regulators, public utilities commissioners, ratepayers, and clean energy advocates surrounding policies to support offshore wind and the approval of project-specific PPAs and incentives.

For electricity markets to fully value the attributes of offshore wind energy, these attributes need to be quantified and articulated to the public. In certain markets with locational marginal pricing, offshore wind development may drive down wholesale electricity costs. The wholesale prices of these markets vary by time and region, and incorporate three cost components: energy, transmission congestion, and transmission losses. Offshore wind development can help lower transmission congestion and losses by taking advantage of relatively short interconnection distances between project sites and urban electric grids in coastal and Great Lakes states. Because of winds that peak in the late afternoon and evening—coinciding with peak loads—offshore wind in many parts of the Atlantic and Pacific regions is also likely to have a higher capacity value than land-based wind. These factors suggest that offshore wind could help depress prices in these areas, and thus lower electricity prices for utilities in the short term [2].

Environmental and economic externalities associated with offshore wind development also need to be better quantified. For example, emissions reduction and water use figures associated with offshore wind in the *Wind Vision* were estimated from the effects of all wind generation deployed in the study scenario and proportionally allocated to offshore wind based on its share of total wind generation. There is an opportunity to conduct more robust analysis that isolates the benefits of offshore wind and is conducted on a regional or state scale. This type of examination would provide a more useful picture to policymakers that can contribute to carbon reduction efforts, such as the Clean Power Plan, or other state energy or environmental planning and policy development.

Stakeholders have suggested that BOEM take further steps to align its process with state policies and available offtake mechanisms. Although significant steps have been taken to ensure effective federal and state coordination (e.g., BOEM's intergovernmental OCS Renewable Energy Task Forces), such coordination can be complicated because state policies and political landscapes change and proposed projects are often proximate to more than one state.

BOEM has received suggestions to alter the existing operating fee payment formula. Developers suggest that certain adjustments to the calculation would enhance price stability and reduce uncertainty in the high-cost offshore operating environment. There is also an opportunity to more effectively link the relative economic potential of a WEA with the BOEM WEA planning process. Adding economic metrics to the delineation of WEAs could result in site selection that is more practically developable, providing an opportunity for more informed bidding.

Significant work needs to be done to put the information developed under this action area into the hands of policymakers, key stakeholders, and the general public. Although simple dissemination of the results of research, development, and other activities undertaken in implementing this strategy is critical to ensuring industry-wide impact, it is not enough. Investment is needed to translate the technical work and other action areas of this strategy into relevant and actionable information for policymakers and stakeholders, so that they can make educated decisions about offshore wind energy development.

Notes

17. Alaska's vast offshore wind resource is not yet counted, but as a result of its extensive coastline and enormous wind-driven wave climate, it will likely have the largest gross resource capacity of any state [58–60].
18. In January 2002, the Federal Government of Germany constructed three research platforms (*FINO1*, *FINO2*, and *FINO3*) in the North Sea and the Baltic Sea, on three potentially suitable sites in the immediate vicinity of major offshore wind farms that were at the planning and application stage.
19. Visit *http://energy.gov/eere/wind/downloads/wind-forecast-improvement-project-wfip-publicprivate-partnership-improving-short* for more information.
20. In German: Forschungsplattformen in Nord und Ostsee (FINO), translates to "Research Platforms in the North and Baltic Seas." See *http://www.fino-offshore.de/en/*.
21. See *http://energy.gov/eere/wind/atmosphere-electrons*.
22. See *www.boem.gov* and *www.bsee.gov*.
23. The cost reduction model considers investments made to technology innovation to reduce cost over time, including, but not limited to, wind turbine drivetrains, rotors, and control systems; balance of system (substructure, tower); electrical infrastructure; construction; decommissioning; and innovative solutions for operation and maintenance. These cost reduction scenarios were modeled by adapting European cost models from KIC InnoEnergy and BVG Consulting [12], and represent the average physical conditions of the current U.S. offshore wind lease areas. To address U.S.-specific market needs, the cost reduction model was modified to include electrical infrastructure and floating wind turbines. For more information, see [24].
24. Such standards should include methods to estimate fatigue life of mooring systems for floating offshore wind turbines, submarine power transmission cables, electric service platforms, and geotechnical design methods for determining long-term response for the cyclical loading of wind turbine substructures, and design of turbine towers and substructures to withstand high load factors of hurricanes.
25. *http://www.boem.gov/Inspection-Safety/*
26. *https://www.congress.gov/bill/114th-congress/house-bill/22/text*
27. Fixing America's Surface Transportation Act (P.L. 114-94) Section 41003.
28. Examples include the migratory pathways of seabirds, the effect of electromagnetic fields, and the impact of chemical spills.
29. This includes biological, geophysical, geological, hazard, and archaeological survey data.
30. "Fates and effects" refer to studies of the environmental consequences associated with human activities (e.g., the effects of electromagnetic fields on marine life).
31. See *http://energy.gov/eere/wind/windexchange*.

4.0 Federal Offshore Wind Strategy

Building on past efforts and seeking opportunities to address any remaining gaps in each of the seven action areas described in Chapter 3 will help the United States responsibly develop a robust and sustainable offshore wind industry. To make progress toward this vision, DOE and DOI have implemented a set of initiatives and collaborated, where possible and appropriate, across the three strategic themes and their seven corresponding action areas. Chapter 3 identified the current baseline and gaps in each of those action areas. This chapter outlines the federal offshore wind strategy, including the specific steps DOE and DOI plan to take to fulfill their respective objectives:

- DOE aims to reduce the levelized cost of energy through technological advancement to compete with local hurdle rates, and create the conditions necessary to achieve *Wind Vision*-level deployment through market-barrier-reduction activities.
- DOI aims to enhance its regulatory program to ensure that oversight processes are well-informed and adaptable, avoid unnecessary burdens, and provide transparency and certainty for the regulated community and stakeholders.

Communication and collaboration with stakeholders will be essential to the success of this strategy. DOE and DOI will disseminate the results and deliverables of the action areas discussed here through multiple channels and across a variety of audiences, and will work with stakeholders to ensure maximum impact and check progress against these objectives at multiple points over the next 5 years.

4.1 Strategic Theme 1: Reducing Costs and Technology Risks

Improvements in offshore wind site characterization and technology advancement can drive significant cost and risk reduction in offshore wind technology. To accomplish this, DOE and DOI intend to collaborate to help establish metocean data collection guidelines (e.g., wind, wave, water current, and tidal condition measurements) that increase the comparability and usefulness of data for wind project design and inform DOI's review of data submitted by lessees. DOE can invest in R&D to advance offshore wind technology and adapt it to unique U.S. conditions. Such investments can increase AEP and reduce offshore wind capital costs, O&M costs, and the cost of financing offshore wind projects.

Action Area 1.1: Offshore Wind Power Resource and Site Characterization

Geological and metocean conditions in the United States differ from those in the established European market. To reduce the risk and uncertainty of deployment along the Atlantic Ocean, Pacific Ocean, Gulf OCS, or the Great Lakes, the full range of geological and metocean conditions in these regions must be well characterized. To accomplish this, DOE and DOI will work jointly to establish acceptable methodologies for gathering metocean data standards and guidance. DOE can further invest in extensive data gathering, as well as ensure effective dissemination of those data.

Table 4.1. DOE and DOI Actions to Address Offshore Wind Power Resources and Site Characterization

Action	Lead Agency	Deliverable	Impact
1.1.1. Support Site Characterization Data Collection Guidance	Joint DOE and DOI	Metocean characterization methodology and data collection guidance specific to offshore wind	Standardized data collection and quality that minimizes uncertainty in operating and extreme conditions, increases safety, and reduces costs for developers
1.1.2. Gather and Disseminate U.S. Metocean and Geological Data	DOE	Increased geographic and temporal coverage of U.S. offshore metocean and geological data	Increased certainty in site conditions, better understanding of lease value, and improved design, leading to increased safety and lower costs for developers
1.1.3. Validate Innovative Site Characterization Methods	DOE	Validated low-cost metocean data collection technologies	Less cost and time required for metocean site characterization, increased certainty in AEP forecasts, and reduced financing costs for developers

Action 1.1.1: Support Site Characterization Data Collection Guidance

No standards exist for metocean data collection for offshore wind site characterization. DOI and DOE will facilitate the development of these standards and associated modeling tools by assembling national and international experts to create guidance for U.S. offshore wind developers. Developing guidelines for metocean data gathering would significantly reduce project design risk and uncertainty, increase reliability in offshore renewable energy projects, reduce capital costs, and ensure human safety and the protection of the natural environment on the OCS.

Action 1.1.2: Gather and Disseminate U.S. Metocean and Geological Data

Having a thorough understanding of the meteorological, oceanographic, and geologic data related to a specific offshore project site is essential for proper design, permitting, and O&M. As a result, there is significant value in continuing and expanding ongoing work by DOE in resource assessment and site characterization for both operating and extreme conditions in BOEM WEAs, as well as more broadly across U.S. waters. Early characterization of site conditions in WEAs would help better establish the value of a particular lease area up for auction, reduce design uncertainties and development costs, and improve preconstruction power production forecasts. Ultimately, such efforts could improve the return for taxpayers on leased sites as well as reduce capital costs for offshore wind developers. DOE will explore the use of a common portal to disseminate these data and ensure they are accessible to developers, financiers, insurers, and regulators.

Action 1.1.3: Validate Innovative Site Characterization Methods

Innovative site characterization technologies that are less capital-intensive than fixed meteorological towers could make gathering metocean data easier and less expensive. Among the most promising technologies are lidar buoys. Validating this technology could yield data acquisition that is more rapid, efficient, and accurate, as well as provide the data needed to design, permit, and finance offshore wind energy plants in the United States. DOE is positioned as a credible third party to conduct this validation, and will collaborate with European government facilities if needed. Once gathered, the value of these data could be increased significantly by collecting them in a repository or portal that is easily accessible to the community. Accessing the data through a single location could allow investors, developers, engineers, regulators, and other key stakeholders to identify trends that could be leveraged for the advancement of the industry.

Action Area 1.2: Offshore Wind Plant Technology Advancement

Technology advancement has the potential to enhance safety and reduce costs of offshore wind energy in a variety of ways. The informed design and operation of wind plants in accordance with accepted standards and regulations will minimize risks to personnel and assets, whereas technology advancements targeted at the major cost drivers of offshore wind energy LCOE will drive significant cost reductions globally. In order for these advancements to benefit the domestic market, however, they must address the unique requirements of U.S. sites, including deep water; extreme conditions, such as hurricanes; and weak and unconsolidated seabed soils. Targeted investment by DOE in the following areas can help level the cost of offshore wind energy to parity with other forms of generation by 2030 in several regions of the United States.

Table 4.2. DOE and DOI Actions to Address Offshore Wind Plant Technology Advancement

Action	Lead Agency	Deliverable	Impact
1.2.1. Demonstrate Advanced Offshore Wind Technology	DOE	Full-scale offshore wind technology demonstrations; comprehensive performance, metocean, and other data sets	Reduced perception of risk, including data to provide a baseline for the U.S. offshore wind community to develop lessons learned and hone in on areas with the largest opportunities for cost reduction
1.2.2. Advance Partnerships to Address Unique U.S. Offshore Challenges	DOE	Integrated, U.S.-specific offshore wind technology advances; thriving joint industry projects	Improved industry collaboration and knowledge transfer; reduced risks and costs associated with weak soils, deeper waters, hurricanes, and other U.S.-specific challenges
1.2.3. Improve Reliability of Offshore Wind Systems	DOE	Turbines and turbine subsystems designed and tested for higher reliability using proven methods, such as prognostic health monitoring	Reduced onsite O&M, less risk to personnel and assets, and ultimately, increased availability, AEP, and reduced OpEx
1.2.4. Develop Offshore Wind Energy Design Standards	DOE	Structural design standards specific to offshore wind for U.S. conditions, particularly floating substructures and structures in hurricane-prone areas	Optimized designs; reduced project capital costs, technology risk, and financing and insurance costs

Action 1.2.1: Demonstrate Advanced Offshore Wind Technology

The Advanced Technology Demonstration Projects are currently a major focus of DOE's efforts in offshore wind and represent an opportunity to validate novel technologies that have significant potential to reduce the cost of energy both in the United States and globally. These projects, which are scheduled to be installed by 2020, will have exercised federal and state regulatory processes and the U.S. supply chain, setting a potential baseline for future offshore wind deployments. Once the projects are operational, DOE requires that each project collect a significant amount of data over the first 5 years of operations, including turbine, structure, and integrated wind plant system engineering, performance, environmental monitoring, operations, and cost data to validate the design and operation in a field environment. These data will be used to validate and de-risk the innovative technology—novel substructures, wind plant controls, O&M strategies, and so on—and its performance, confirming that implementation of these technologies on a commercial scale will lead to cost reductions. As these projects will be some of the first offshore wind projects installed in the United States, the lessons learned during project development, fabrication, construction, and operations will be documented and disseminated to benefit the broader U.S. offshore wind community.

The demonstration projects can also provide value in validating advanced design tools. Advanced design tools allow for researchers and engineers to accelerate innovative concepts from an idea to commercial-scale deployment. DOE intends to use the data collected by the Offshore Wind Advanced Technology Demonstration Projects to support model validation efforts, de-risking the tools and developing confidence in the models. This confidence reduces design uncertainty and margins, allowing for additional creativity and innovation that can lead to significant reductions in offshore wind costs.

Action 1.2.2: Advance Partnerships to Address Unique U.S. Offshore Challenges

DOE will encourage collaboration among the offshore wind community, leveraging interdisciplinary, intersector cooperation to rapidly advance U.S. offshore wind energy. A consortium that crosscuts the domestic offshore wind community operating under a joint industry project could potentially jumpstart the nation's industry through the systems approach to addressing the key U.S.-specific technological challenges. Such a consortium would leverage previous DOE and global industry investments, including the Carbon Trust's Offshore Wind Accelerator, DOE's Atmosphere to Electrons initiative, and DOE's Offshore Wind Advanced Technology Demonstration Projects. Integrated technology advancement could focus on interdependent technical areas, including advanced substructure technology, installation technology, O&M technology, development of design standards, and wake interaction technology. The consortium would oversee a portfolio of R&D projects to best address these interdependent challenges and use the experience gained to develop, de-risk, and commercially implement the most promising advancements on an accelerated timeframe.

Action 1.2.3: Improve Reliability of Offshore Wind Systems

Because of the harsh environments in which offshore wind facilities are located, the ability to perform both scheduled and unscheduled maintenance is a major challenge. As a result, availability for offshore wind plants is lower than for land-based facilities, and O&M costs can make up 20% of total LCOE for offshore wind facilities. An unplanned failure of a major component, such as a gearbox in an offshore wind turbine, can involve mobilizing an expensive heavy lift vessel (the same kind used for turbine installation) and necessitate waiting months for a safe weather window in which to conduct marine operations. To improve this situation, DOE intends to invest in technology development to reduce the cost and frequency of such unscheduled visits, leverage unscheduled maintenance for scheduled maintenance, and expand the conditions in which facilities can be safely accessed. Developing prognostic health monitoring and management of major components, for example, could allow operators to identify early signs of failure in a component and run the affected turbine at a reduced intensity to lengthen its life until the next scheduled maintenance window. These investments will increase availability and AEP, and significantly reduce O&M costs.

Action 1.2.4: Develop Offshore Wind Energy Design Standards

DOE, with support from DOI, will continue to work toward the development of structural design standards for the U.S. offshore wind industry, which provide certainty to regulators, developers, and the financial community regarding the quality and safety of turbine and substructure designs. Standards that specifically address the unique conditions of the United States, such as floating technologies and areas prone to hurricanes, will allow for optimized designs, which reduce costs for developers while increasing certainty for financiers and insurers, thus lowering the costs of financing. One potential result of this action would be an updated version of the *AWEA Large Turbine Compliance Guidelines: AWEA Offshore Compliance Recommended Practices (2012); Recommended Practices for Design, Deployment, and Operation of Offshore Wind Turbines in the United States* document adopted as a full design standard [92]. A workshop on structural modeling issues that was held in April 2016, by BOEM and NREL helped kick off this effort by soliciting feedback from industry on how the standards need to be developed. Additional workshops will be considered on a 1- or 2-year interval to continue sharing ideas with industry.

Action Area 1.3: Installation, Operation and Maintenance, and Supply Chain Solutions

The development of a U.S. supply chain dedicated to offshore wind development is inhibited by an insufficient pipeline of projects. The current U.S. offshore wind supply chain is dispersed, relying on adapted fabrication facilities in the Gulf of Mexico and international assets. Larger turbine technologies can result in reduced capital costs, increased production, and reduced OpEx, but also create unique installation challenges requiring purpose-built vessels. O&M infrastructure, especially on the West Coast, is limited in breadth and lacks operational experience. DOE can address some of these issues through the following actions.

Table 4.3. DOE and DOI Actions to Address Installation, Operation and Maintenance, and Supply Chain Solutions

Action	Lead Agency	Deliverable	Impact
1.3.1. Support a Regularly Updated U.S. Supply Chain Inventory	DOE	Open-source database of information detailing U.S. supply chain assets, such as manufacturing capabilities, vessels, and ports	Enhanced understanding of the supply chain baseline and the ability to conduct multifaceted analysis of the existing capabilities and gaps to increase domestic supply
1.3.2. Evaluate Supply Chain Bottlenecks, Costs, Risks, and Future Scenarios	DOE	Assessment of the current U.S. supply chain shortcoming and the impact on offshore wind costs with future supply chain development	Identification of supply chain investment opportunities and quantification of the supply chain infrastructure required to achieve the *Wind Vision* development scenarios and increase the domestic supply of offshore wind components and labor

Action 1.3.1: Support a Regularly Updated U.S. Supply Chain Inventory

DOE has previously supported research that establishes a supply chain baseline in manufacturing [56], vessels [72], and ports [70]. This past research can be leveraged and regularly updated to establish a baseline and capture the dynamic nature of the U.S. supply chain. To continue keeping the data relevant, the data could be put into an open-source tool that would not only catalogue the U.S. supply chain, but allow suppliers and offshore industry members to input capabilities data. The tool would need to be maintained and expanded as industry entities use it and the offshore wind industry grows in the United States. It could be organized by industry sector—manufacturing, vessels, ports, and so on—and leveraged to enable supplementary supply chain analysis. For example, DOE could sponsor a database of Jones-Act-compliant vessels in the United States that could support offshore wind installation, including technical specifications and capabilities. Using this database, further analysis could be performed to document how modifications and retrofitting could enable the vessels to support offshore wind installation activities. With access to a ports and manufacturing database, the installation vessel analysis could also be extended to identify shipyards that have the ability to modify existing vessels or construct new offshore wind installation vessels.

Action 1.3.2: Evaluate Supply Chain Bottlenecks, Costs, Risks, and Future Scenarios

To support offshore wind development in the short and long term, supply chain bottlenecks should be evaluated and assessed. In the short term, vessels that are used to install and maintain turbines are critical. Research to understand the added cost and risk of using current Jones-Act-compliant alternatives, such as European TIVs and U.S.-flagged feeder vessels, or using U.S.-based assets in creative ways, can help determine the business case for a U.S.-flagged TIV. DOE could also convene stakeholders and federal agencies such as the U.S. Department of Transportation's Maritime Administration to discuss mechanisms that could be leveraged to improve the business case for U.S.-flagged TIVs. Additionally, this work could help identify creative and effective solutions in installation sequencing.

Evaluation of the supply chain bottlenecks that inhibit significant long-term deployment is also important. DOE could sponsor research that evaluates the annual offshore wind deployment that is required to meet the *Wind Vision* scenarios from the present day to 2050, and distinguish the supply chain limits as well as where additional investment is needed. These studies could consider critical production volumes of particular components necessary to facilitate investment or LCOE reductions, the impact of various installation and O&M strategies on local content and cost, and ways to leverage the land-based wind supply chain. Research could also explore the benefits associated with more revolutionary installation solutions, such as semisubmersible floating platforms and self-erecting or "float-and-flip" turbines, that eliminate the need for specialized infrastructure by enabling offshore installation by traditional tugs and other readily available, general-purpose vessels.

4.2 Strategic Theme 2: Supporting Effective Stewardship

Stakeholders suggest that DOI optimize the regulatory process to increase certainty for offshore wind developers and stakeholders while continuing to provide effective stewardship of the OCS. To further promote good stewardship of U.S. waters in the context of offshore wind development, DOE and DOI have also acquired significant knowledge concerning the potential impacts of offshore wind development on biological resources and human communities over the past 5 years. Investment in research over the next 5 years regarding the first generation of offshore wind projects can validate that understanding and help focus regulatory efforts on the most important environmental and human-use impacts.

Action Area 2.1: Ensuring Efficiency, Consistency, and Clarity in the Regulatory Process

DOI helps facilitate safe, efficient, and environmentally responsible offshore wind development by continuing to improve consistency and clarity in the regulatory process. To advance this objective and provide more certainty to developers as they progress through the planning, siting, and plan review phases of their projects, DOI will take a number of actions, including reevaluating its SAP requirement and Intergovernmental Task Force structure, considering alternative approaches to performing its COP review and attendant NEPA analyses, and collaborating with relevant agencies to standardize and synchronize review processes where feasible. Many of these actions address postlease issues, reflecting the fact that BOEM has progressed from the planning and leasing stage to the plan-review stage for many of its offshore areas.

For a number of initiatives, DOI has been able to identify and provide reasonable timeframes for critical decision-making milestones. Other initiatives will require additional analysis prior to DOI developing a timeline for completion. However, DOI will undertake all of the following actions during the 5-year scope of this strategy and commit to informing stakeholders about its progress towards completion.

Table 4.4. DOI Actions to Ensure Efficiency, Consistency, and Clarity in the Regulatory Process

Action	Lead Agency	Deliverable	Impact
2.1.1. Reassess, and Potentially Modify, the SAP Requirements for Meteorological Buoys	DOI	In early 2017, communicate decision on path forward for initiation of potential regulatory changes and/or implementation of process changes for reviewing proposals to install meteorological buoys during the site assessment terms of commercial leases	Less costly and more efficient meteorological buoy deployment to inform commercial wind proposals in offshore wind lease areas
2.1.2. Increase Certainty in Plan-Review Processes	DOI	Decision on one or more plan-review process improvements, and external communication of decision	Greater certainty in timing and requirements for lessees during the plan-review process and reduced costs associated with unanticipated delays
2.1.3. Evaluate a "Design Envelope" Approach for Construction and Operations Plan Environmental Impact Statements	DOI	By July 1, 2017, decision on the implementation of "design envelope" approach; if adopted, revised COP guidelines and potential workshop	Greater flexibility for lessees to make final design decisions later in the process and take advantage of emerging technological improvements
2.1.4. Revisit the Structure of Intergovernmental Task Forces	DOI	Document describing Task Force evaluation and path forward for BOEM's Task Force utilization	Efficient intergovernmental coordination that considers input from any and all potentially affected states
2.1.5. Enhance Interagency Coordination Around Offshore Wind Development	DOI	Structured and recurrent federal interagency coordination on offshore wind projects; if adopted, implementation of one or more options considered to standardize agency offshore wind project review processes	Increased governmental coordination of offshore wind projects and improved project review processes
2.1.6. Provide a Regulatory Roadmap	DOI	By July 1, 2017, publish regulatory roadmap on BOEM's website that provides requirements associated with OCS offshore wind projects	Clarification of steps and approvals necessary to develop an OCS wind facility, increased understanding, and regulatory certainty for developers and stakeholders
2.1.7. Consider Modifying Decommissioning Financial Assurance Requirement	DOI	Decision on whether to allow developers to phase in required decommissioning financial assurance; if adopted, publication of proposed regulatory changes in the Federal Register	Reduced up-front financial burdens on lessees, if change adopted

Action	Lead Agency	Deliverable	Impact
2.1.8. Develop U.S. Offshore Wind Energy Safety Guidelines	DOI	Health, safety, and environmental management guidelines for offshore wind construction, installation, and operations activities	Greater certainty and guidance for developers for safe construction, installation, and operations activities
2.1.9. Assess Path Forward for Potential Next Round of Atlantic Planning and Leasing	DOI	Stakeholder meetings in summer or fall of 2017 to gather input on the next round of Atlantic planning and leasing; subsequently, decision on path forward for potential future Atlantic planning and leasing	Shared vision and coordination on the next round of planning and leasing, greater certainty for industry, and opportunity for specific feedback from stakeholder community resulting in more informed decision-making
2.1.10. Continue Work Towards Establishment of International Offshore Wind Regulators Forum	DOI	Meetings and conversations with other offshore wind regulators, in an effort to establish an offshore wind regulators forum	Facilitate sharing of best practices, which could lead to the adoption of more efficient regulatory models
2.1.11. Convene an Offshore Wind Stakeholders Group	DOI	In 2017, convene inaugural meeting of the Offshore Wind Stakeholders Group; determine appropriate meeting frequency and hold said meetings	Ensure transparent and productive dialogue about the challenges and opportunities in the regulatory realm

Action 2.1.1: Reassess, and Potentially Modify, the SAP Requirement for Meteorological Buoys

Stakeholders have expressed concern that BOEM's requirement to submit a SAP and associated data to support installation of a meteorological buoy in a specific lease area is unnecessarily onerous given the scale of these facilities. In response to these comments, BOEM will re-evaluate its current regulatory requirements and its SAP review procedures, and subsequently determine the appropriate path forward on this issue in early 2017. BOEM may, at that time, decide to initiate the rulemaking process to consider eliminating or minimizing some or all of the applicable regulatory requirements for SAPs that propose installation and operation of meteorological buoys. Alternatively, at that time, BOEM may decide to retain the current regulatory requirements, but identify and implement process changes to lessen the burden on developers. If BOEM determines that it would be appropriate to lessen any requirements, then it will implement the change(s) through the appropriate process and update its *Guidelines for Information Requirements for a Renewable Energy Site Assessment Plan (SAP)* [93], as necessary. This could result in less costly and more efficient meteorological buoy deployment to inform commercial wind proposals in offshore wind lease areas.

Action 2.1.2: Increase Certainty in Plan Review Processes

Stakeholder feedback suggests that BOEM's plan review process needs to be more transparent, predictable, and expeditious to reduce scheduling uncertainty and financial risk. As a result, BOEM will consider different approaches to improve and streamline this process. Approaches that BOEM will consider include: 1) setting timelines for BOEM's NEPA review process pursuant to 40 CFR 1501.8; 2) establishing informal agreements with lessees (e.g., developing memoranda of agreements on a project-by-project basis that include timelines for critical milestones); and 3) providing a target review period for plans once they are determined to be complete and sufficient (e.g., establish a target review period of 18 months for complete and sufficient COPs). In addition to complying with the requirements associated with FAST-41, BOEM will implement one or more methods to improve its plan review process and communicate that decision to the offshore wind stakeholder community. This effort will provide lessees with greater certainty as they move forward with their project proposals.

Action 2.1.3: Evaluate a "Design Envelope" Approach for Construction and Operations Plan Environmental Impact Statements

Industry suggests that it may not be effective for BOEM to require lessees to provide certain project details when submitting COPs, as developers may not be prepared to confirm those project design elements at that stage. In an effort to address this concern, BOEM will investigate the "design envelope" concept for conducting an Environmental Impact Statement to support its COP decision-making. This investigation will include, but not be limited to, discussions with its European regulatory counterparts, for whom this practice is more commonplace. This approach would allow a lessee to describe its project within a range of agreed-to parameters, and would permit BOEM to analyze the range of impacts associated with those parameters. BOEM will communicate its decision regarding the use of the design envelope approach by July 1, 2017. If BOEM adopts this concept, it will revise its *Guidelines for Information Requirements for a Renewable Energy Construction and Operations Plan (COP)* [94], as necessary, and may hold a workshop to explain the implementation of this approach for lessees and other stakeholders. If implemented, this methodology would provide lessees with the flexibility to defer certain project design decisions until after a COP is approved as well as take advantage of technological improvements that occur during the course of project development.

Action 2.1.4: Revisit the Structure of Intergovernmental Task Forces

In acknowledgement of comments received in response to the RFF, BOEM will re-evaluate its current approach to establishing its Intergovernmental Task Forces to ensure effective coordination with all interested and potentially affected states throughout BOEM's planning, leasing, and plan review processes. After completing its evaluation, BOEM will provide a document on its website that describes the outcome of this evaluation and its path forward. BOEM may continue to carry out the current process of setting up Task Forces on a state-by-state basis, or may implement a different methodology that it believes will be more effective. Either way, BOEM will ensure that all potentially affected states are consulted about offshore wind activities off their coasts in a manner that avoids potential delays to BOEM's planning and leasing processes.

Action 2.1.5: Enhance Interagency Coordination Around Offshore Wind Development

BOEM is not the only federal agency with a role in permitting offshore wind farms. Rather, there is a complex regulatory roadmap that each developer must traverse. The efforts under Action 2.1.6 will provide greater clarity to elucidating that path, but hurdles will still remain. Specifically, industry has highlighted the importance of governmental coordination given the multitude of agencies with a role in offshore wind permitting. BOEM will evaluate options to standardize and synchronize review processes across agencies, and will research successful examples implemented by other federal agencies, as well as its European counterparts. As a component of this effort, BOEM is leading the Offshore Wind Permitting Subgroup under the White House Interagency Working Group on Offshore Wind to identify ways to streamline and improve interagency coordination associated with the SAP review process. Lessons learned may be incorporated into the review processes for other plans. Given the multitude of agencies with a role in permitting offshore wind projects, efficient and effective governmental coordination will be critical to avoiding detrimental and costly delays in the permitting process.

Action 2.1.6: Provide a Regulatory Roadmap

Given the number of governmental permits and authorizations required for the realization of an offshore wind project, BOEM will develop a regulatory roadmap that outlines the requirements of BOEM and other agencies that industry must follow when developing offshore wind projects. BOEM will coordinate with other federal agencies to ensure that the document is thorough and informed, and make it available to the developers and the public via its website and other appropriate means by July 1, 2017. Such a roadmap will help the regulated community by clarifying the steps and approvals necessary to develop an OCS wind facility.

Action 2.1.7: Consider Modifying Decommissioning Financial Assurance Requirements

In response to the RFF, industry professionals described the potential difficulties associated with providing decommissioning financial assurance prior to receiving project income. BOEM will consider modifying its regulations to allow developers to phase in their required decommissioning financial assurance. BOEM will need to weigh the potential benefits of doing so against the financial risk that the government may incur as a result. If BOEM determines that modifying its regulations to accommodate this approach would be appropriate, the resulting regulatory amendment may alleviate a substantial financial burden that developers face prior to receiving operating income from their projects.

Action 2.1.8: Develop U.S. Offshore Wind Energy Safety Guidelines

DOI will develop health, safety, and environmental management guidelines for offshore wind construction and operation activities. These guidelines will combine applicable information from the U.S. offshore oil and gas sector, as well as lessons learned and best management practices from the international experience with offshore wind to help ensure that construction and operation activities are conducted in a safe and environmentally sound manner.

Action 2.1.9: Assess Path Forward for Potential Next Round of Atlantic Planning and Leasing

BOEM has received informal inquiries from stakeholders relating to the next steps for planning and leasing in the North and Mid-Atlantic regions, and a number of RFF comments recommended steps that BOEM could take to better inform its planning and leasing processes moving forward. In order to help BOEM determine the appropriate time for an additional round of planning and leasing offshore all or certain Atlantic states, and ensure that any such efforts are as informed as possible, BOEM will convene public meetings to gather stakeholder input on this issue in the summer or fall of 2017. After determining the appropriate path forward and the timing of next steps, BOEM will communicate that decision to the offshore wind stakeholder community via its website and any other appropriate means. This decision-making process will help to provide certainty to industry about BOEM's longer-term plans for facilitating Atlantic offshore wind development, and will help ensure that BOEM implements lessons learned from its first tranche of Atlantic planning and leasing.

Action 2.1.10: Continue Work Towards Establishment of International Offshore Wind Regulators Forum

One consistent area of informal feedback has been the importance of interfacing with regulators from other countries to learn best practices. As discussed at the White House Summit on Offshore Wind in September 2015, DOI has begun discussions with offshore wind regulators in various European countries about the best ways for the United States to learn from their experiences. BOEM recently executed a memorandum of understanding with the Embassy of Denmark to share knowledge, data, best practices, and capitalize on their decades of experience in offshore wind development. In this vein, DOI aims to establish a multilateral group to discuss ways to responsibly facilitate offshore wind development in the United States and around the globe. The group will present a unique opportunity for sharing lessons learned, discussing regulatory approaches and best practices, and exchanging scientific and environmental information.

Action 2.1.11: Convene an Offshore Wind Stakeholders Group

As referenced above, DOI's practices are and will continue to be informed by the experiences of countries that have spent years regulating offshore wind farms. For example, several of those countries, including the United Kingdom, have created opportunities for high-level conversations between government officials and industry leaders. In an effort to encourage and continue open dialogue about the challenges of and opportunities for offshore wind deployment in the United States, DOI will convene, on a regular basis, stakeholders to discuss regulatory and strategic issues to ensure clear communication between industry, other stakeholders, and regulators.

Action Area 2.2: Managing Key Environmental and Human-Use Concerns

DOE and DOI can contribute to the successful coexistence between offshore wind and other resources and users through investment in science to understand the impacts of development and identify how these impacts might be appropriately mitigated. This science is the foundation of DOI's environmental review and regulatory process. Although significant research has already been conducted on these subjects, the next 5 years present an opportunity for DOE and DOI to conduct research at first-generation offshore wind projects to better understand how offshore wind affects biological resources and human communities and uses.

Action 2.2.1: Collect Environmental Impact Data and Support Testing of Monitoring and Mitigation Technologies at First-Generation Projects

The near-term development of offshore wind facilities in the United States provides an excellent opportunity to reduce environmental uncertainty for future projects. Research at DOE's demonstration projects in addition to other first- and second-generation offshore wind developments will help reduce uncertainty regarding the environmental impacts of offshore wind. Over the next 5 years, DOE will partner with wind developers and federal agencies to conduct research at first-generation projects that will drive innovation in monitoring technologies and test the effectiveness of mitigation tools. This action will include participation in BOEM's RODEO efforts to measure environmental stressors, such as construction noise, as well as separate research efforts to measure the biological response of organisms to offshore wind energy.

Action 2.2.2: Synthesize Environmental Impact Data and Develop Predictive Models

To supplement the action to collect reliable data and develop mitigation technologies, DOE will support retrospective analyses of impact-producing factors and environmental impacts from observations and lessons learned using the demonstration projects as case studies. After multiple projects have been developed, DOE will support meta-analyses of initial data across projects, with an aim to identify environmental risks that were previously of concern, but may be retired due to lack of impacts and areas for additional research. Using data from first-generation wind projects, DOE plans to support the development of risk models that predict impacts, taking behavior, exposure, and hazard into account. The intent of this work is to replace monitoring with modeling, where feasible, by creating and validating tools that allow developers and regulators to accurately predict impacts and aid in recommending appropriate mitigation.

Action 2.2.3: Evaluate and Support Mitigation of Unique Impacts of Offshore Wind on Coastal Radar Systems and Other Federal Missions

DOE pursues approaches to mitigate wind turbine radar interference under a memorandum of understanding with the U.S. Department of Defense, Federal Aviation Administration, NOAA, and the *Federal Interagency Wind Turbine Radar Interference Mitigation Strategy* developed by these agencies [95]. Offshore wind may pose unique impacts to coastal radar systems given the differences in propagation of radar signals over the ocean versus land. One mitigation approach will be to improve modeling and simulation tools to aid in the siting and evaluation of planned offshore wind facilities. In doing so, the interagency team plans to integrate various simulation parameters into their existing tools that coincide with the offshore wind environment.

In addition, DOE plans to conduct studies to evaluate the potential impacts of currently planned offshore wind facilities on ground-based coastal air surveillance radar to evaluate the vulnerability of these air surveillance radars to offshore wind turbines. These studies will further identify which mitigation measures that are either existing or under development may be appropriate to address those vulnerabilities. For example, the interagency team is collaborating to develop concepts to improve the wind turbine interference mitigation capabilities of existing radars through signal-processing software upgrades and minor hardware modifications. DOE is partnering with the Massachusetts Institute of Technology's Lincoln Laboratory on a study that looks at the feasibility of advanced signal-processing techniques for existing National Airspace System radars, and plans to apply these techniques to coastal radars where possible. Where these initial efforts reveal a need for mitigation specific to offshore wind development, DOE will pursue further R&D with its interagency partners.

Table 4.5. DOE and DOI Actions to Manage Key Environmental and Human-Use Concerns

Action	Lead Agency	Deliverable	Impact
2.2.1. Collect Environmental Impact Data and Support Testing of Monitoring and Mitigation Technologies at First-Generation Projects	DOE	Field data of the environmental impacts from offshore wind energy in U.S. waters and field testing of monitoring and mitigation technologies	More informed understanding of the relative impact of offshore wind development in the United States to increase regulatory certainty and minimize environmental compliance costs
2.2.2. Synthesize Environmental Impact Data and Develop Predictive Models	DOE	More accurate and informed predictive models of potential impacts from offshore wind energy installations on sensitive species	Improved basis for implementation of effective and prudent monitoring and mitigation measures, and a decrease in environmental impacts
2.2.3. Evaluate and Support Mitigation of Unique Impacts of Offshore Wind on Coastal Radar Systems and Other Federal Missions	DOE	Incorporation of offshore wind-specific parameters to improve radar modeling and simulation tools and studies of potential mitigation options	Improved radar interference modeling and simulation tools, mitigation technologies, and reduced conflict between wind development and radar missions
2.2.4. Support Social Science to Understand the Drivers of Opposition and Acceptance of Offshore Wind Farms	DOE	Increased understanding of the drivers of acceptance and opposition of offshore wind facilities	Identify and encourage development practices that are most likely to create acceptance and support for offshore wind projects
2.2.5. Aggregate and Disseminate Environmental Impact Information	DOE	Greater dissemination of the results of environmental and human-use impact research	Improved understanding by regulators and stakeholders of highest priority issues; decreased impact by offshore wind, reduced uncertainty in monitoring and mitigation measures, and shorter and less-expensive project deployment timelines

Action	Lead Agency	Deliverable	Impact
2.2.6. Improve Communication of BOEM's Offshore Wind Energy Studies and Research with All Stakeholders	DOI	Implementation of appropriate outreach measures to increase stakeholder awareness of the studies' processes and results, including opportunities for industry and other stakeholder input	Increased transparency of the studies' processes, greater stakeholder accessibility and usability of BOEM's environmental studies data, and a more informed stakeholder base
2.2.7. Provide Guidance to Clarify Information Needs and Data Collection Requirements	DOI	Updated preconstruction survey guidelines, where necessary; postconstruction guidelines developed with input from industry, resource and regulatory agencies, and other stakeholders; and, if appropriate, information on how design parameters (e.g., turbine height) relate to environmental and socioeconomic resource impacts to inform future COP submission	Clearer resource agency data collection requirements and establishment of a feedback loop for guideline development, so that developers have certainty when navigating the regulatory and environmental compliance processes
2.2.8. More Comprehensive Baseline Data Collection to Support Regional Spatial Planning	**DOI**	Updated marine wildlife and habitat baseline data (collected through BOEM's environmental studies program) to support regional marine planning, NEPA processes, and predictive modeling	More comprehensive regional baseline data to better inform stakeholder knowledge as well as planning and development decisions

Action 2.2.4: Support Social Science to Understand the Drivers of Opposition and Acceptance of Offshore Wind Farms

Public acceptance of particular offshore wind facilities and development will be needed to support significant deployment in the United States. A rich collection of literature on the impacts of land-based wind facilities on communities exists throughout the world and explores the drivers of acceptance and opposition to development in those communities; however, more needs to be done both in the U.S. context as well as on offshore wind. DOE's Lawrence Berkeley National Laboratory is conducting the first national baseline assessment that looks at these factors around the nation with respect to land-based facilities. Under this action, DOE plans to conduct similar studies for the first offshore projects in development. For example, it will track community responses to these projects longitudinally, from development through operations, to determine the factors that make a project more or less acceptable to affected communities, and begin to suggest development practices that are most likely to create acceptance of and support for offshore wind in locations around the country.

Action 2.2.5: Aggregate and Disseminate Environmental Impact Information

DOE plans to work with federal agencies, the offshore wind industry, and other stakeholders to ensure that environmental and wildlife market barrier research results gathered throughout the world are aggregated, synthesized, and shared so that regulators, industry members, and other stakeholders have access to information and analysis on the state of the current scientific understanding. DOE aims to continue combining information gathering and sharing efforts, including the continued support of the Tethys[32] database, to house information on environmental research and make it easily accessible. DOE, in conjunction with DOI, will also continue to support and commit leadership to the international Working Together to Resolve Environmental Effects of Wind Energy (WREN)[33] initiative and associated activities, including a webinar series, participation in conferences, engagement with European counterparts, and biannual state-of-the-science analyses that present the current state of knowledge regarding wind-wildlife monitoring techniques, impacts, and mitigation strategies.

Action 2.2.6: Improve Communication of BOEM's Offshore Wind Energy Studies and Research with All Stakeholders

To better align BOEM efforts with project requirements and other information needs of the offshore wind industry, BOEM will create more productive opportunities for input from all stakeholders, including industry, early in the studies development process. Implementation of this action includes restructuring BOEM's outreach tools to inform and update stakeholders on the status of ongoing studies as well as the results of completed studies. Specific outreach tools that BOEM will include, but are not limited to, the following: incorporating relevant studies information on applicable web pages (e.g., individual state activities pages); producing an annual year-in-review report; conducting stakeholder webinars to share the results of completed studies and the status of ongoing studies; and holding in-person information transfer meetings with stakeholders every 2 years. BOEM will also collaborate with DOE on WREN to conduct additional outreach activities.

Action 2.2.7: Provide Guidance to Clarify Information Needs and Data Collection Requirements

As early as 2013, BOEM began publishing guidance for industry related to the collection of preconstruction or baseline data. Now that the guidance has been in use for a few years, BOEM will update it by incorporating lessons learned, new technology, and recent research/studies. In addition, BOEM will solicit industry input to determine specific topics of interest for new guidance documents (e.g., lighting requirements and assessing visual impact concerns).

Providing guidance on postconstruction monitoring will facilitate coordination between the offshore wind industry and related stakeholders. Communicating the data collection requirements of the federal resource and regulatory agencies involved will provide greater transparency and consistency in BOEM's plan-approval processes. Guideline development will focus on resources and activities that enable consistency across projects, as opposed to project- or site-specific requirements that will need to be determined through project-specific consultations.

BOEM will also conduct analyses to identify which parameters related to design envelopes (as described in Action Area 2.1: Ensuring Efficiency, Consistency, and Clarity in the Regulatory Process) are pertinent to the level of significance of resource impacts. This approach will help to clarify the information requirements for COP submission, with the overall goal of improving efficiency in the environmental review process.

Action 2.2.8: More Comprehensive Baseline Data Collection to Support Regional Spatial Planning

The preparation of NEPA documents and consultations under various regulations require information about the environment that often extends beyond the footprint of an offshore wind project. Through regional planning efforts, significant amounts of data are now available both through the compilation of existing data and the gathering of new information. These data are shared across federal, state, and tribal governments, and are available to the public through regional data portals. BOEM will help to ensure the best-available science is used in decision-making through continued collection of regional baseline data and updating of predictive models for OCS wildlife. All data collection efforts will continue to be shared and provided through existing data portals.

4.3 Strategic Theme 3: Increasing Understanding of the Benefits and Costs of Offshore Wind

To increase understanding of offshore wind and aid policymakers and stakeholders in making decisions about policies and projects, DOE can invest in rigorous assessment of grid integration challenges associated with offshore wind as well as quantify the electricity system impacts, and social and environmental benefits and costs of its development. DOI is committed to re-evaluating its operating fee mechanism to improve certainty for developers while continuing to ensure fair return to the nation from offshore wind development on the OCS. DOE can also support communication of offshore wind costs and benefits to key audiences, to enable more informed decision-making around offshore wind policies and projects, increase policymaker and public understanding and confidence of the potential effects of offshore wind in the energy system, and help improve the market outlook for offshore wind.

Action Area 3.1: Offshore Wind Electricity Delivery and Grid Integration

The interconnection and integration of offshore wind energy bear significant similarities to land-based wind, allowing the independent system operators, regional transmission operators, utilities, regulators, state legislators, and other stakeholders to more readily incorporate offshore wind energy into the energy mix. However, key challenges and advantages specific to offshore wind energy merit further study. These include examining the benefits and impacts of integrating significant quantities of offshore wind into congested load centers as well as the effects of offshore wind-specific transmission and other electrical infrastructure on the power system.

Table 4.6. DOE Actions to Address Offshore Wind Electricity Delivery and Grid Integration

Action	Lead Agency	Deliverable	Impact
3.1.1. Analyze Optimized Offshore Wind Grid Architectures	DOE	Better understanding of optimal system architectures for aggregation and delivery of electricity from U.S. offshore wind projects	Potential for reduced capital costs associated with cabling and increased potential buildout associated with access to offshore transmission infrastructure
3.1.2. Analyze State and Regional Offshore Wind Integration Strategies	DOE	Better understanding of the impacts of interconnection and integration at the state and regional levels	Electricity system plans and policies that effectively account for offshore wind integration; increased utility and policymaker confidence in the ability to integrate offshore wind

Action 3.1.1: Analyze Optimized Offshore Wind Grid Architectures

Offshore wind projects under development all currently propose individual radial connections to shore. Developing offshore transmission “backbones” and connection points could enable offshore wind development by reducing the costs of interconnection and alleviating transmission congestion on land and in transmission-constrained coastal states. The use of high-voltage direct-current transmission could also provide benefits. For example, this type of transmission can be controlled more easily than high-voltage alternating-current transmission to reduce onshore congestion. New research to evaluate the impacts of transmission expansion for offshore wind could include valuation of improved system reliability, reduced transmission congestion, and related operational effects, such as short-term reliability and flexibility from high-voltage direct-current transmission and offshore wind backbone infrastructure.

Action 3.1.2: Analyze State and Regional Offshore Wind Integration Strategies

DOE plans to conduct studies to assess state and regional interconnection and integration of offshore wind energy that would build on work started in 2011. These studies assist decision-makers, including independent system operators and utilities, to evaluate grid integration aspects for future offshore wind development scenarios and plan for the associated requirements needed including transmission expansion, resource adequacy, and other consequences for the power system. Additional studies would allow these audiences to evaluate imminent infrastructure needs as well as guide new private and public investments capable of lowering the cost of offshore wind energy through optimal siting and delivery. These studies may also become increasingly important in the context of broader renewables integration by showing offshore wind's ability to integrate with other renewables, such as solar photovoltaics and land-based wind, which present their own unique benefits and challenges. Specific information provided in these studies would also be instrumental in identifying the full suite of electricity system benefits and costs associated with offshore wind.

Action Area 3.2: Quantifying and Communicating the Benefits and Costs of Offshore Wind

As noted in Section 2.7, offshore wind offers a number of economic, environmental, and social benefits that can contribute to a long-term, low-carbon electricity future.

Table 4.7. DOE and DOI Actions to Quantify and Communicate the Benefits and Costs of Offshore Wind

Action	Lead Agency	Deliverable	Impact
3.2.1. Quantify Offshore Wind Social and Environmental Benefits and Costs	DOE	Tools that evaluate site-specific and state/regional GHGs and other environmental and economic benefits of offshore wind	Better informed consideration of offshore wind-specific policies and projects and increased policymaker, utility, and stakeholder confidence in offshore wind
3.2.2. Quantify Offshore Wind Electricity Market Benefits and Costs	DOE	Studies and tools quantifying the impacts of offshore wind on electricity system costs, including analysis on aspects such as capacity value and site-specific LCOE information	Better informed consideration of offshore wind-specific policies and projects and increased policymaker, utility, and stakeholder confidence in offshore wind
3.2.3. Communicate the Benefits and Costs of Offshore Wind	DOE	Communications products and stakeholder engagement that put offshore wind costs, benefits, and impacts in the right context for policymakers and stakeholders	Improved decision-making around offshore wind policies and projects; increased policymaker, utility, and stakeholder confidence in offshore wind
3.2.4. Reconsider Operating Fee Structure to Provide More Certainty to Developers during PPA Negotiations	DOI	Identification and evaluation of alternative operating fee structures for BOEM's consideration to implement, through rulemaking	Improved certainty around the BOEM operating fee to inform PPA negotiations, if adopted

It also carries with it impacts and costs. As a result, DOE can assist to rigorously quantify and effectively communicate these benefits and costs to support effective decision-making on offshore wind and broader energy policy issues, offshore wind PPAs, and in the project siting and regulatory process, as well as build understanding and confidence in offshore wind technology among key decision-makers to support its advancement. DOI can reassess its operating fee mechanism to give greater certainty to developers in PPA negotiations while ensuring a fair return from offshore wind development to the nation.

Action 3.2.1: Quantify Offshore Wind Social and Environmental Benefits and Costs

Offshore wind provides a number of environmental and social benefits not explicitly valued in electricity prices. These benefits include avoided emissions of greenhouse gases and other air pollutants, with associated environmental and health benefits, reductions in electricity sector water use, and significant economic development and employment impacts. DOE aims to build off the *Wind Vision* and other work to rigorously quantify these benefits for various deployment scenarios and ideally for a variety of relevant spatial and temporal scales. DOE also plans to ensure that the tools used to conduct such analyses are readily available and easily usable (where possible) by the broader offshore wind community to enable them to conduct more tailored analysis of projects and policies. These analyses and provision of the tools used to conduct them will provide a baseline to educate stakeholders, inform policymakers, and provide for more informed evaluation and decision-making around offshore wind and broader energy policy and supply questions.

Action 3.2.2: Quantify Offshore Wind Electricity Market Benefits and Costs

Offshore wind has a number of electricity system benefits and costs aside from direct LCOE effects that policymakers and utilities should consider in making decisions about the future energy system. DOE plans to develop information for coastal regions and states to provide policymakers, utilities, and system operators with vital data to inform policy and project-level decisions about offshore wind. This includes the value of offshore wind's potential contribution to resource adequacy and system reliability, as well as its capacity value. DOE also aims to provide analysis and tools for analyzing the regional energy system cost and price impacts of various offshore wind development scenarios to explore the value of potential price suppression, transmission congestion relief, and other system costs and benefits and how they flow through to ratepayers.

A key component of these analyses will include extending DOE's site-specific LCOE-LACE analysis, presented in Section 2.6. This capability allows for consideration of a wide range of variables, such as grid access points, site-specific hourly wind resource profiles, bathymetry, and turbine availability and array losses, and projected future cost curves for offshore wind. These analyses will enable policymakers, utilities, and ratepayers alike to better evaluate offshore wind development at the policy and project-specific levels in a more accurate and sophisticated context that goes beyond LCOE or a project's power purchase price.

Action 3.2.3: Communicate the Benefits and Costs of Offshore Wind

DOE will provide accurate, objective information about the costs and benefits of offshore wind that can help policymakers, stakeholders, and the public make effective decisions about the technologies that are right for their states and communities. These groups often lack detailed knowledge of the social and environmental costs and benefits of electricity generation. As a result, decisions are sometimes made regarding electricity supply without a clear understanding of the actual impacts and benefits of the various options. At the policy level, these decisions can have a significant impact on the potential project pipeline. At the level of individual projects, they can affect the siting and permitting process and the ability to obtain a PPA and financing. Even when there is little scientific information demonstrating significant impacts, negative stakeholder perceptions can ultimately lead to conflict and project abandonment.

Quantification of these costs and benefits as discussed earlier is necessary, but not enough to enable effective decision-making. The results of these analyses also need to be set into the proper context—putting local environmental impacts alongside benefits like GHG emissions reductions and job creation, and the costs and benefits of offshore wind in the light of broader energy supply choices—and translated into useful and actionable information for key audiences. This information then needs to be delivered in the right venues and media. DOE's WINDExchange program and wind Regional Resource Centers provide a useful model for this kind of communication, in which DOE and its national laboratories can serve as sources for detailed analysis and collaborate with regional and local partners to translate this information into the right forms and present it at the right forums to advance offshore wind development.

Action 3.2.4: Reconsider Operating Fee Structure to Provide More Certainty to Developers during PPA Negotiations

BOEM has received suggestions to alter its existing operating fee payment formula. Developers suggest that certain adjustments to the calculation would enhance price stability and reduce uncertainty in the high-cost offshore operating environment. For example, rather than BOEM estimating the wholesale market value of projected electric power production using the current wholesale power price, developers would prefer to use the price of electricity set forth in a PPA (i.e., contract price) or other legal contract.

Changes to current regulations would be required for any operating fee payment proposal that does not use a wholesale power price index (30 CFR 585.506). The regulations allow for minor adjustments (i.e., to reflect documented variations by state or within a region and recent market conditions), but do not address contract prices. BOEM acknowledges that its current operating fee formula has limitations, and will begin a thorough review of the operating fee payment and its individual components. If BOEM determines that revising the formula may be appropriate, then it will move forward with considering implementing the change through the rulemaking process.

Notes

32. *Tethys* is a knowledge management system that actively gathers, organizes, and disseminates information on the environmental effects of marine and wind energy development.

33. *WREN* was established by the International Energy Agency's Wind Committee in October 2012 to address environmental issues associated with commercial development of land-based and offshore wind energy projects. As the operating agent for WREN, the United States leads this effort with support from the Pacific Northwest National Laboratory, National Renewable Energy Laboratory, and the U.S. Department of Energy's Wind Energy Technologies Office.

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Facilitating the Development of the Offshore Wind Industry in the United States

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for Climate & Sustainable Energy Finance

GLOBAL TRENDS IN RENEWABLE ENERGY INVESTMENT 2017

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Cover photo courtesy of Enel. It shows Fontes dos Ventos hybrid project, Brazil.

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JOINT FOREWORD FROM ERIK SOLHEIM, PATRICIA ESPINOSA AND UDO STEFFENS

ERIK SOLHEIM

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UDO STEFFENS

The pursuit of clean energy is at the heart of world's aspirations for a better future, as reflected in the 197 countries that have signed up to the Paris Agreement on Climate Change. Moving from fossil fuels to renewable sources such as solar and wind is key to achieving social, economic and environmental development. It will change the lives of 1.2 billion people who struggle through life with no electricity. It will create new jobs and commercial opportunities. And it will slash the air pollution that claims millions of lives each year. The annual Global Trends in Renewable Energy Investment report supports that transformation by demonstrating the progress and potential of this dynamic and fast growing sector.

Successive editions of the report during the last decade show strong support from private investors. This trend continued in 2016, with investment in renewable energy capacity outstripping that in fossil fuel generation for the fifth year in a row. Excluding large hydro, some 138 gigawatts of new power capacity came online; almost 11 gigawatts more than in the previous 12 months.

The cost of achieving this was 23 per cent less than in 2015, partly due to the falling cost of clean technology. For example, the average dollar capital expenditure per megawatt dropped by over 10 per cent for solar photovoltaics and wind. Investors got more bang for their buck.

Take the Adani Group, which is just one of many companies taking advantage of the cheaper set-up costs. It has completed a massive solar plant in India, where generating energy from renewables now costs almost the same as traditional methods. The plant in Tamil Nadu covers 10 square kilometres and can power 150,000 homes. As well as making money, this will help India meet its commitment to the Paris Agreement, by generating 40 per cent of its electricity from non-fossil-fuel sources by 2030. This project created 8,500 jobs in the building phase. This is a clear example of a private company seeing and seizing the chance to do good business and build a sustainable future.

It's a story being repeated around world as public and private sectors grasp a profitable and mutually beneficial opportunity, which will help create a more equitable, stable and peaceful world. We urge investors, business leaders and policy makers to study this report, because profit does not have to be a dirty word. A rapid shift to clean renewable energy is not only slowing climate change, tackling pollution and ending the suffering of vulnerable communities, but boosting long-term economic prosperity and stability.

ERIK SOLHEIM

Head of UN Environment

PATRICIA ESPINOSA

Executive Secretary

United Nations Framework Convention on Climate Change (UNFCCC)

UDO STEFFENS

President

Frankfurt School of Finance & Management

"Ever-cheaper clean tech provides a real opportunity for investors to get more for less,"

said Erik Solheim, executive director of UN Environment.

"This is exactly the kind of situation, where the needs of profit and people meet, that will drive the shift to a better world for all."

"The investor hunger for existing wind and solar farms is a strong signal for the world to move to renewables,"

said Prof. Dr. Udo Steffens, president of Frankfurt School of Finance & Management, commenting on record acquisition activity in the clean power sector, which rose 17 per cent to $110.2 billion.

"The question always used to be 'will renewables ever be grid competitive?',"

said Michael Liebreich, chairman of the Advisory Board at BNEF.

"Well, after the dramatic cost reductions of the past few years, unsubsidised wind and solar can provide the lowest cost new electrical power in an increasing number of countries, even in the developing world – sometimes by a factor of two.

"It's a whole new world: even though investment is down, annual installations are still up; instead of having to subsidise renewables, now authorities may have to subsidise natural gas plants to help them provide grid reliability."

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METHODOLOGY AND DEFINITIONS

All figures in this report, unless otherwise credited, are based on the output of the Desktop database of Bloomberg New Energy Finance – an online portal to the world's most comprehensive database of investors, projects and transactions in clean energy.

The Bloomberg New Energy Finance Desktop collates all organisations, projects and investments according to transaction type, sector, geography and timing. It covers many tens of thousands of organisations (including start-ups, corporate entities, venture capital and private equity providers, banks and other investors), projects and transactions.

METHODOLOGY

The following renewable energy projects are included: all biomass and waste-to-energy, geothermal, and wind generation projects of more than 1MW; all hydropower projects of between 1MW and 50MW; all wave and tidal energy projects; all biofuel projects with a capacity of one million litres or more per year; and all solar projects, with those less than 1MW estimated separately and referred to as small-scale projects, or small distributed capacity, in this report.

The 2017 Global Trends report concentrates on renewable power and fuels – wind, solar, biomass and waste, biofuels, geothermal, marine and small hydro-electric projects of less than 50MW.

It does not cover larger hydro-electric dams, of more than 50MW, except briefly in the Executive Summary and Chapter 5. Energy smart technologies such as smart grid, electric vehicles and energy storage are also outside the main scope of the report, but they are discussed briefly in a section in Chapter 2.

Where deal values are not disclosed, Bloomberg New Energy Finance assigns an estimated value based on comparable transactions. Deal values are rigorously back-checked and updated when further information is released about particular companies and projects. The statistics used are historical figures, based on confirmed and disclosed investment.

Annual investment is estimated for small-scale commercial and residential projects such as rooftop solar. These figures are based on annual installation data, provided by industry associations and REN21. Bloomberg New Energy Finance continuously monitors investment in renewable energy. This is a dynamic process: as the sector's visibility grows, information flow improves. New deals come to light and existing data are refined, meaning that historical figures are constantly updated.

This 2017 report contains revisions to a number of investment figures published in the 2016 edition of Global Trends in Renewable Energy Investment. Revisions reflect improvements made by Bloomberg New Energy Finance to its data during the course of the last 12 months, and also new transactions in 2015 and before that have since come to light.

DEFINITIONS

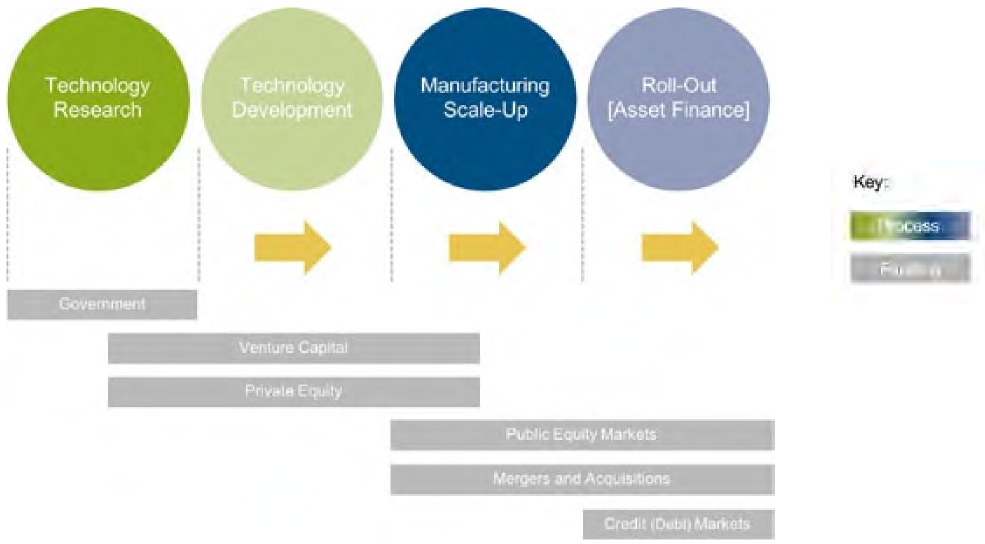
Bloomberg New Energy Finance tracks deals across the financing continuum, from R&D funding and venture capital for technology and early-stage companies, through to asset finance of utility-scale generation projects. Investment categories are defined as follows:

Venture capital and private equity (VC/PE): all money invested by venture capital and private equity funds in the equity of specialist companies developing renewable energy technology. Investment in companies setting up generating capacity through special purpose vehicles is counted in the asset financing figure.

Public markets: all money invested in the equity of specialist publicly quoted companies developing renewable energy technology and clean power generation.

Asset finance: all money invested in renewable energy generation projects (excluding large hydro), whether from internal company balance sheets, from loans, or from equity capital. This excludes refinancings.

Mergers and acquisitions (M&A): the value of existing equity and debt purchased by new corporate buyers, in companies developing renewable energy technology or operating renewable power and fuel projects.



The Renewables Global Status Report is the sister publication to Frankfurt School-UNEP Global Trends in Renewable Energy Investment. The latest edition will be released June 2017. REN21's multi-stakeholder network collectively shares its insight and knowledge to help produce the GSR each year. Today the network stands at 800 renewable energy, energy access and energy efficiency experts. These experts engage in the GSR process, giving their time, contributing data and providing comment in the peer review process. The result of this collaboration is an annual publication that has established itself as the world's most frequently referenced report on the global renewable energy market, industry and policy landscape. In 2016 it was referred to as the gold standard to which other data collection efforts can evolve.

KEY FINDINGS

- "More for less" was the story of renewable energy in 2016. Global new investment in renewables excluding large hydro fell by 23% to $241.6 billion, the lowest total since 2013, but there was record installation of renewable power capacity worldwide in 2016. Wind, solar, biomass and waste-to-energy, geothermal, small hydro and marine sources between them added 138.5GW, up from 127.5GW in the previous year.

- This 2016 gigawatt figure was equivalent to 55% of all the generating capacity added globally, the highest proportion in any year to date. Investment in 'new renewables' capacity was roughly double that in fossil fuel generation in 2016, for the fifth successive year. The proportion of global electricity coming from these renewable sources rose from 10.3% in 2015 to 11.3% in 2016, and prevented the emission of an estimated 1.7 gigatonnes of CO2.

- There were two main reasons for the fall in investment in renewables in 2016. One was lower costs, with average dollar capital expenditure per MW down by more than 10% for solar photovoltaics, onshore wind and offshore wind, improving the competitiveness of those technologies. The other was not so positive – there was a marked slowdown in financings in China, Japan and some emerging markets during the course of the year.

- Overall, renewable energy investment in developing countries fell 30% to $116.6 billion, while that in developed economies dropped 14% to $125 billion. China saw investment plunge 32% to $78.3 billion, breaking an 11-year rising trend. Mexico, Chile, Uruguay, South Africa and Morocco all saw falls in investment of 60% or more, on a mixture of scheduled pauses and delays with auction programmes and financings. Jordan was one of the few new markets to buck the trend, investment there rising 148% to $1.2 billion.

- Among developed economies, the US saw commitments slip 10% to $46.4 billion, as developers took their time to build out projects to benefit from the five-year extension of the tax credit system. Europe enjoyed a 3% increase to $59.8 billion, led by the UK on $24 billion and Germany on $13.2 billion, down 1% and 14% respectively. Japan slumped 56% to $14.4 billion.

- Europe's investment owed its resilience to record commitments to offshore wind, totalling $25.9 billion, up 53% thanks to final investment decisions on mega-arrays such as the 1.2GW Hornsea offshore wind project in the UK North Sea, estimated to cost $5.7 billion. Not all of 2016's offshore wind boom was in Europe – China invested $4.1 billion in the technology, its highest figure to date.

- The most hopeful sign last year for the future greening of the global electricity system was a succession of winning bids for solar and wind, in auctions around the world, at tariffs that would have seemed inconceivably low only a few years ago. The records set last year were $29.10 per MWh for solar in Chile and $30 per MWh for onshore wind in Morocco, but there were other eye-catchingly low outcomes to auctions from Dubai to India, and Zambia to Mexico and Peru.

- Availability of finance does not appear to be a bottleneck to investment in renewables in most countries. Indeed, investor hunger for what many regard as mature technologies helped to fuel record acquisition activity in the clean power sector worldwide last year, totalling $110.3 billion, up 17%. Purchases of assets such as wind farms and solar parks reached a highest-ever figure of $72.7 billion, while corporate takeovers reached $27.6 billion, some 58% more than in 2015.

- New investment in solar in 2016 totalled $113.7 billion, down 34% from the all-time high in 2015, due in large part to sharp cost reductions – and to real slowdowns in activity in two of the largest markets, China and Japan. India saw the construction of the Ramanathapuram solar complex in Tamil Nadu, billed as the world's largest ever PV project at some 648MW.

- Wind followed closely behind solar, at $112.5 billion of investment globally, down 9% despite the boom in offshore projects. However, while solar capacity additions rose in the year to a record 75GW, sharply up from 56GW, wind capacity additions fell back to 54GW in 2016 from the previous year's high of 63GW.

- The smaller sectors of renewable energy had mixed fortunes in terms of investment last year. Biofuels fell 37% to $2.2 billion, the lowest for at least 13 years, biomass and waste held steady at $6.8 billion and small hydro at $3.5 billion, while geothermal rallied 17% to $2.7 billion and marine edged down 7% to $194 million.[1]

- One of the up-and-coming innovations in renewable power is the siting of two different technologies in the same location, to make use of shared land, grid connections and maintenance, and to reduce intermittency. Some 5.6GW of these 'hybrid' projects have been built or are under development worldwide, including hydro-solar, wind-solar, PV-solar thermal, solar thermal-geothermal and biomass-geothermal. Hybrids are examined in this report's Focus, Chapter 4, starting on page 44.

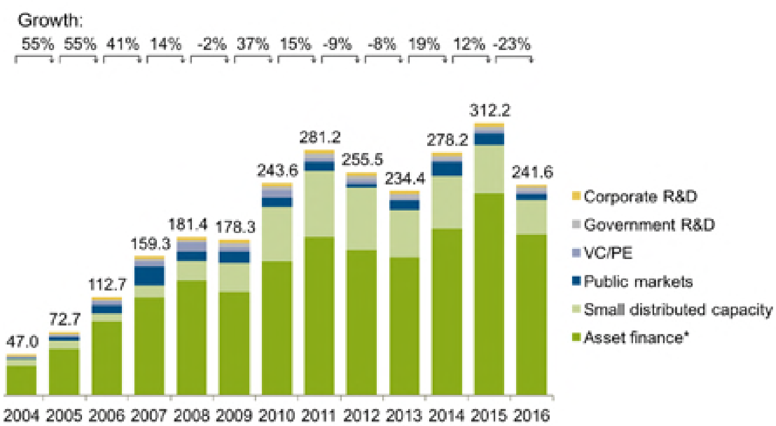
[1] Investment in large hydro-electric dams is not included in the headline figures in this report. Final investment decisions in this technology are estimated to have been worth $23.2 billion in 2016, down 48%.

EXECUTIVE SUMMARY

In 2016, the advance of renewable energy slowed in one respect, and speeded up in another. Investment in renewables excluding large hydro fell by 23% to $241.6 billion, but the amount of new capacity installed increased from 127.5GW in 2015 to a record 138.5GW in 2016. Together, the new renewable sources of wind, solar, biomass and waste, geothermal, small hydro and marine accounted for 55.3% of all the gigawatts of new power generation added worldwide last year. More solar gigawatts were added (75GW) than of any other technology for the first time. A major reason why installations increased even though dollars invested fell was a sharp reduction in capital costs for solar photovoltaics, onshore and offshore wind. On a less positive note, there were clear signs as 2016 went on of slowing activity in two key markets, China and Japan.

Figure 1 shows the trend of global new investment since 2004 in renewable energy (excluding large hydro-electric projects of more than 50MW). The dollars committed per year increased roughly fivefold from the start of the period until 2010, and have since oscillated between $234 billion and $312 billion. The 2016 investment total was once again in that range, although it was down 23% from the record established in 2015. The drop between 2015 and last year is, in fact, the sharpest seen at any time in that sequence.

FIGURE 1. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY BY ASSET CLASS, 2004-2016, $BN



*Asset finance volume adjusts for re-invested equity. Total values include estimates for undisclosed deals

Source: UN Environment, Bloomberg New Energy Finance

Why did investment fall in 2016? There were several reasons, one of the most important of which was lower dollar-denominated costs. The average capital cost for PV projects starting construction in 2016 was 13% lower than in 2015, while for onshore wind the drop was 11.5% and for offshore wind 10%.[2] A section later in this Executive Summary examines the growing cost-competitiveness of wind and solar in more detail.

A second reason was one of timing. A lot of projects in wind and solar were financed in late 2015 and only commissioned in 2016, in which case the investment dollars associated with them were recorded in the earlier year and the GW addition in the later one. Indeed, the 2015 global investment

[2] Bloomberg New Energy Finance, Levelised Cost of Electricity Market Outlooks, H1 2015, H2 2015, H1 2016 and H2 2016.

figure shown in this report represents a 9% upward revision over the one shown in last year's Global Trends report, the revision made because of new information becoming available.

A third issue was that an underlying slowdown in activity did set in, in some key markets, during the course of 2016. In particular, the Chinese solar market decelerated sharply, after a hectic first half that saw 22GW installed, to a second half with 8GW installed. Japanese solar slowed, from 11.5GW in 2015 to 9.2GW installed in 2016.

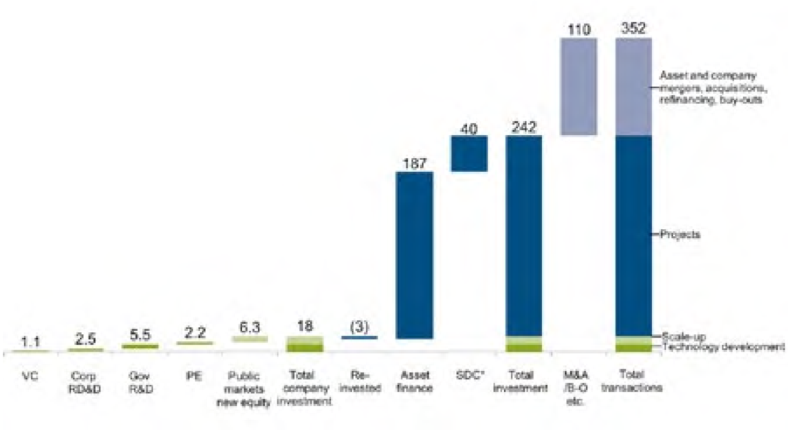
Finally, several up-and-coming renewable energy markets in the developing world produced record investment figures in 2015 but then saw sharp falls in 2016 in response to scheduled pauses, or delays, in their auction schedules. As Chapter 1 explains, South Africa, Mexico, Morocco and Chile – all $2 billion-plus investment locations in 2015 – fell into this category in 2016.

There was one important influence pushing global investment in renewables last year the other way – up – and that was an unprecedented surge in financings for offshore wind projects. These sea-based arrays typically have a much higher capital costs per MW than onshore wind farms, compensating for that to some extent by generating for a higher proportion of the year. In 2016, investment decisions in offshore wind totalled $30 billion, up 41% from the previous year, with no fewer than 14 projects each worth between $500 million and $5.7 billion getting the go-ahead in the UK, Germany, Belgium, Denmark and China.

WHERE THE MONEY WENT

Figure 2 shows the types of investment that made up the total financing for renewables in 2016. The left side of the chart shows early-stage and corporate-level investment: including venture

FIGURE 2. GLOBAL TRANSACTIONS IN RENEWABLE ENERGY, 2016, $BN



*SDC = small distributed capacity. Total values include estimates for undisclosed deals. Figures may not add up exactly to totals, due to rounding

Source: UN Environment, Bloomberg New Energy Finance

FIGURE 3. GLOBAL TRENDS IN RENEWABLE ENERGY INVESTMENT 2016 DATA TABLE, $BN

Category	Year Unit	2004 $bn	2005 $bn	2006 $bn	2007 $bn	2008 $bn	2009 $bn	2010 $bn	2011 $bn	2012 $bn	2013 $bn	2014 $bn	2015 $bn	2016 $bn	2015-16 Growth %	2004-16 CAGR %
1 Total Investment																
1.1 New investment		47.0	72.7	112.7	159.3	181.4	178.3	243.6	281.2	255.5	234.4	278.2	312.2	241.6	-23%	15%
1.2 Total transactions		56.8	99.1	146.5	217.9	240.9	242.5	302.4	354.2	322.1	300.5	364.8	406.3	351.9	-13%	16%
2 New Investment by Value Chain																
2.1 Technology development																
2.1.1 Venture capital		0.4	0.6	1.2	2.1	3.3	1.6	2.7	2.7	2.5	0.9	1.1	1.6	1.1	-30%	9%
2.1.2 Government R&D		1.9	2.0	2.2	2.7	2.8	5.4	4.9	4.8	4.7	5.2	4.5	4.4	5.5	25%	9%
2.1.3 Corporate RD&D		2.1	2.4	2.9	3.2	3.6	3.8	3.9	4.5	4.2	4.0	3.9	4.2	2.5	-40%	2%
2.2 Scale-up																
2.2.1 Private equity expansion capital		0.3	1.0	3.1	3.5	6.9	3.1	5.5	2.4	1.7	1.4	1.8	1.9	2.2	17%	17%
2.2.2 Public markets		0.3	3.6	9.3	21.4	10.8	12.7	10.8	9.9	4.0	10.3	15.9	13.3	6.3	-53%	30%
2.3 Projects																
2.3.1 Asset finance		33.7	53.0	85.5	114.9	135.6	120.5	155.1	183.5	169.4	159.3	194.4	237.4	187.1	-21%	15%
Of which re-invested equity		0.1	0.1	0.8	2.6	3.6	1.9	1.5	1.8	2.6	1.0	3.3	6.1	2.9	-53%	-
2.3.3 Small distributed capacity		8.5	10.3	9.4	14.0	22.1	33.0	62.2	75.2	71.6	54.4	60.0	55.5	39.8	-28%	14%
Total Financial Investment		34.6	58.0	98.3	139.4	153.0	136.1	172.5	196.7	174.9	170.8	209.9	248.1	193.8	-22%	15%
Gov't R&D, corporate RD&D, small projects		12.5	14.7	14.4	19.9	28.5	42.2	71.0	84.5	80.5	63.5	68.3	64.1	47.8	-25%	12%
Total New Investment		47.0	72.7	112.7	159.3	181.4	178.3	243.6	281.2	255.5	234.4	278.2	312.2	241.6	-23%	15%
3 M&A Transactions																
3.1 Private equity buy-outs		0.8	3.7	1.9	3.4	5.1	2.2	1.9	3.0	3.3	0.5	4.2	3.4	3.4	-2%	12%
3.2 Public markets investor exits		0.4	2.4	2.8	4.0	0.9	2.5	4.9	0.2	0.4	1.7	1.7	1.8	6.7	269%	28%
3.3 Corporate M&A		2.3	7.6	11.2	20.4	16.9	21.9	19.3	29.4	9.8	16.5	11.4	17.5	27.6	58%	23%
3.4 Project acquisition & refinancing		6.3	12.6	19.9	30.9	36.4	37.6	32.7	40.3	53.1	47.4	69.2	71.3	72.7	2%	23%
4 New Investment by Sector																
4.1 Wind		19.6	28.5	39.7	61.1	74.6	79.7	101.6	84.2	84.4	89.0	106.5	124.2	112.5	-9%	16%
4.2 Solar		11.2	15.9	21.9	38.9	61.3	64.0	103.6	154.9	140.6	119.1	143.9	171.7	113.7	-34%	21%
4.3 Biofuels		4.0	9.9	28.8	27.4	18.4	10.2	10.5	10.6	7.2	5.2	5.3	3.5	2.2	-37%	-5%
4.4 Biomass & w-t-e		8.3	9.8	12.8	23.0	17.5	15.0	16.6	19.9	14.9	12.4	10.8	6.7	6.8	0%	-2%
4.5 Small hydro		2.7	7.4	7.5	6.4	7.6	6.2	8.1	7.5	6.4	5.6	6.4	3.5	3.5	0%	2%
4.6 Geothermal		1.2	1.2	1.4	1.7	1.7	2.8	2.9	3.9	1.6	2.9	2.9	2.3	2.7	17%	7%
4.7 Marine		0.0	0.1	0.8	0.8	0.2	0.3	0.2	0.2	0.3	0.2	0.3	0.2	0.2	-7%	16%
Total		47.0	72.7	112.7	159.3	181.4	178.3	243.6	281.2	255.5	234.4	278.2	312.2	241.6	-23%	15%
5 New Investment by Geography																
5.1 United States		5.7	11.9	29.3	39.3	35.8	23.9	35.3	49.6	40.6	33.8	38.4	51.4	46.4	-10%	19%
5.2 Brazil		0.9	2.7	5.1	9.8	11.5	7.8	7.4	10.3	8.1	4.4	8.2	7.1	6.8	-4%	18%
5.3 AMER (excl. US & Brazil)		1.8	3.3	3.7	4.8	5.9	5.5	12.4	9.5	10.4	12.3	14.0	13.1	6.1	-54%	10%
5.4 Europe		25.0	33.1	46.8	67.4	81.3	82.5	113.9	123.8	88.9	59.4	63.0	58.1	59.8	3%	8%
5.5 Middle East & Africa		0.6	0.8	1.2	1.9	2.3	1.7	4.2	3.2	10.2	9.2	8.4	11.4	7.7	-32%	24%
5.6 China		3.0	8.7	11.1	16.6	25.3	38.1	41.4	46.0	58.3	63.3	87.3	115.4	78.3	-32%	31%
5.7 India		2.6	3.2	5.4	6.8	5.7	4.2	9.0	13.7	8.0	6.6	8.4	9.6	9.7	0%	11%
5.8 ASOC (excl. China & India)		7.2	9.0	10.1	12.8	13.6	14.5	20.0	25.1	30.9	45.3	50.5	46.1	26.8	-42%	12%
Total		47.0	72.7	112.7	159.3	181.4	178.3	243.6	281.2	255.5	234.4	278.2	312.2	241.6	-23%	15%

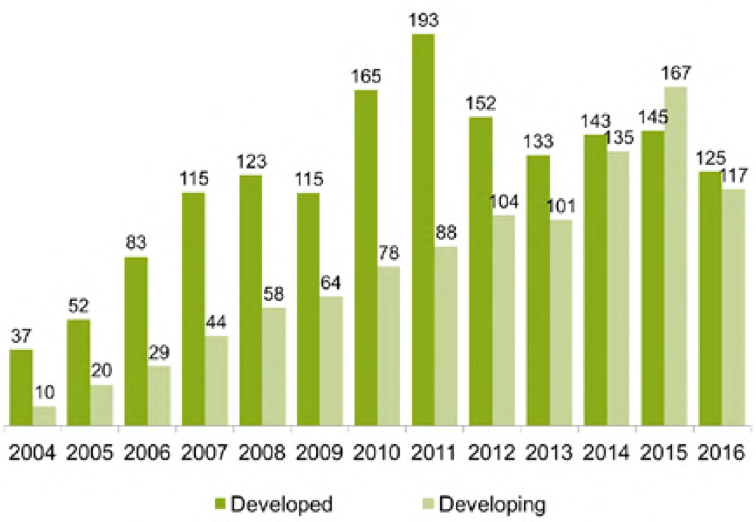
New investment volume adjusts for re-invested equity. Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

capital, private equity and public market funding of specialist renewable energy companies, and corporate and government research and development. The biggest slice of total investment was, as before, asset finance of utility-scale projects such as wind farms and solar parks, at $187.1 billion. Small distributed capacity (rooftop and other small solar projects of less than 1MW) contributed $39.8 billion, taking us to the new investment total for the year of $241.6 billion.

There was then a record $110.3 billion of acquisition deals, including purchases of renewable energy generating plants, refinancings and corporate mergers and takeovers, taking the total value of transactions in renewables to $351.9 billion. This acquisition boom is discussed in detail in Chapter 10 of this report, but the overriding message appeared to be that 'new renewables' are becoming ever more mainstream – so, for instance, wind turbine manufacturers were consolidating in a search for market share, and new owners were emerging for operating-stage wind and solar assets.

Figure 3 provides a more detailed breakdown of both new investment and acquisition activity in 2016, and in every prior year since 2004. It shows how different regions have performed over the period, Europe for example seeing a peak in new investment at $123.8 billion in 2011, at the time of the German and Italian solar booms, and a flattish trend at a lower level in recent years, with 2016 seeing a figure of $59.8 billion, up 3% on 2015.

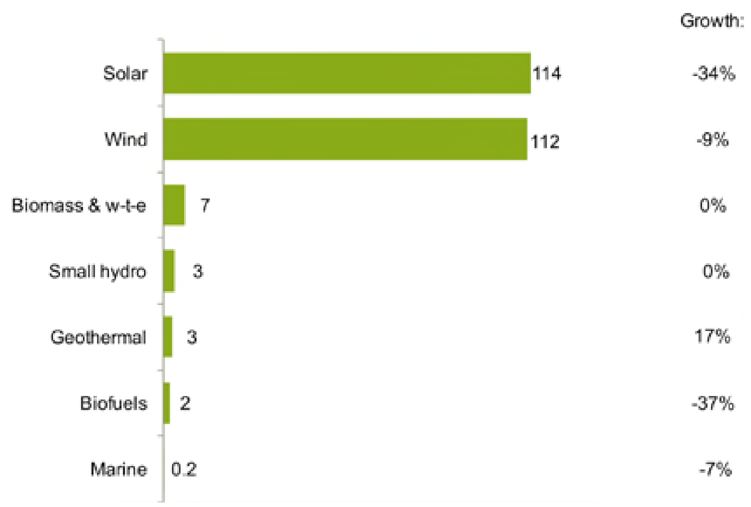
FIGURE 4. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY: DEVELOPED V DEVELOPING COUNTRIES, 2004-2016, $BN



New investment volume adjusts for re-invested equity. Total values include estimates for undisclosed deals. Developed country volumes are based on OECD countries excluding Mexico, Chile, and Turkey

Source: UN Environment, Bloomberg New Energy Finance

FIGURE 5. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2016, AND GROWTH ON 2015, $BN



New investment volume adjusts for re-invested equity. Total values include estimates for undisclosed deals

Source: UN Environment, Bloomberg New Energy Finance

It also shows the importance of China to global investment. The world's most populous country committed $78.3 billion to renewables last year, but this was down 32% on 2015's record, reflecting a combination of lower costs per MW and a dip in activity as grids concentrated on integrating capacity already built and after the previous feed-in tariff expired in mid-year. US investment fell 10% in 2016 to $46.4 billion (see Chapter 1 for detailed analysis). This was in line with its average for the previous five years.

One of the surprises of 2016 was that developed economies regained their lead over developing countries in renewables investment (see Figure 4). Both groups saw a fall in the value of financings, but the developing economy total dropped more sharply, by 30%, to $116.6 billion. Not every developing country saw investment falter – India was firm at $9.7 billion, and Jordan saw a 148% jump to $1.2 billion, but the $37.1 billion drop in China dwarfed everything else. The richer countries suffered a 14% fall in investment to $125 billion, with falling PV costs and weaker activity in Japanese solar two of the main factors.

Figure 5 highlights the way renewable energy investment continues to be dominated by just two sectors – solar and wind. Both suffered declines in dollar investment in 2016, solar down 34% to $113.7 billion and wind down 9% to $112.5 billion. The smaller sectors had mixed fortunes last year, geothermal seeing a 17% increase to $2.7 billion, while biomass and waste marked time at $6.8 billion and small hydro at $3.5 billion. Biofuels fell 37% to $2.2 billion, its lowest figure during the whole 2004-16 period and only 8% of its 2006 peak.

Looking at particular types of investment within those total figures, Figure 6 splits out the money flowing from venture capital and private equity funds into specialist renewable energy firms. This was $3.3 billion in 2016, down 4%. As usual, solar made up most of the total, at $2.3 billion, although this was down 2% year-on-year. The trends in VC/PE financing are explored in Chapter 8.

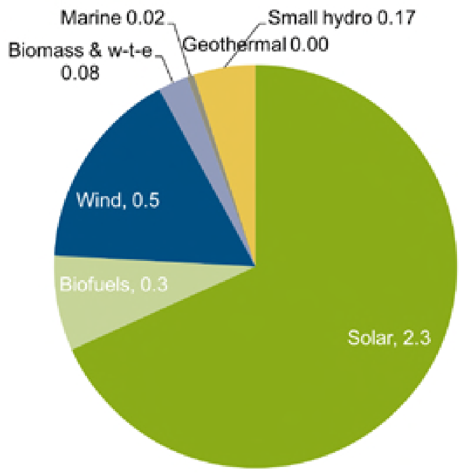
Figure 7 splits out public markets investment by sector in 2016. Overall, this fell 53% to $6.3 billion, partly due to a downturn in equity raising by 'yieldcos', or quoted funds set up to own renewable energy projects. Wind accounted for $4.3 billion of the public market activity, up 66%, while solar fell 83% to $1.7 billion. The main deals and developments of the year are explained in Chapter 7.

Renewable energy capacity investment – in other words, asset finance of utility-scale projects plus money committed to smaller systems – is shown by sector in Figure 8. Solar systems of one size or another attracted $107.6 billion, down 32% from 2015, but this total was narrowly trumped by wind, which drew $107.9 billion, down 12%. Figure 8 shows, for comparison, that estimated asset finance for large hydro-electric projects in 2016 was $23.2 billion, down 48%. This was only a fraction of the wind and solar numbers, but much larger than the remaining renewable energy sectors. Large hydro is not covered in this report, except as part of the overall power generation mix in Chapter 2 and in a separate box in Chapter 5.

DOWNWARD SPIRAL ON COSTS

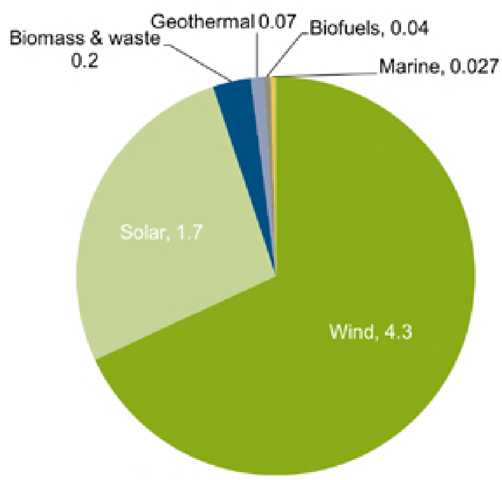
The most exciting development in renewable energy over recent years has been the rapid progress made in reducing the 'levelised', or all-in, costs of generation from solar PV and wind.[3] In the second half of 2016, levelised costs for PV without tracking varied greatly by country and project, but the central estimate was

FIGURE 6. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2016, $BN



VC/PE new investment excludes PE buy-outs. Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

FIGURE 7. PUBLIC MARKETS NEW INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2016, $BN

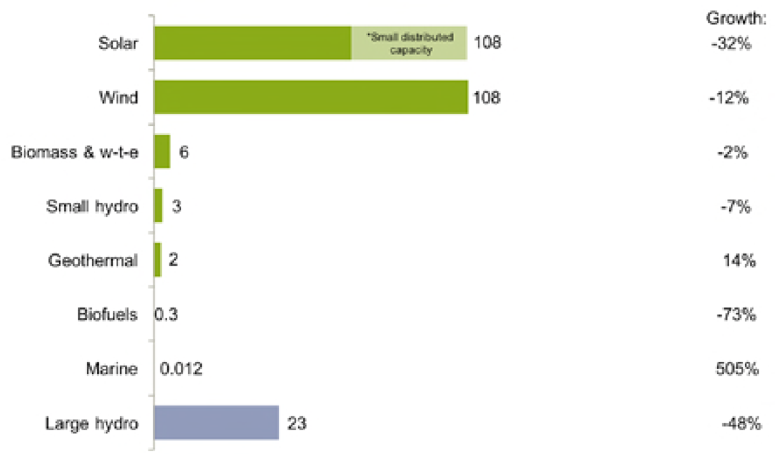


Source: UN Environment, Bloomberg New Energy Finance

[3] Levelised costs of electricity include the costs of capex, finance, operating and maintenance, development and fuel.

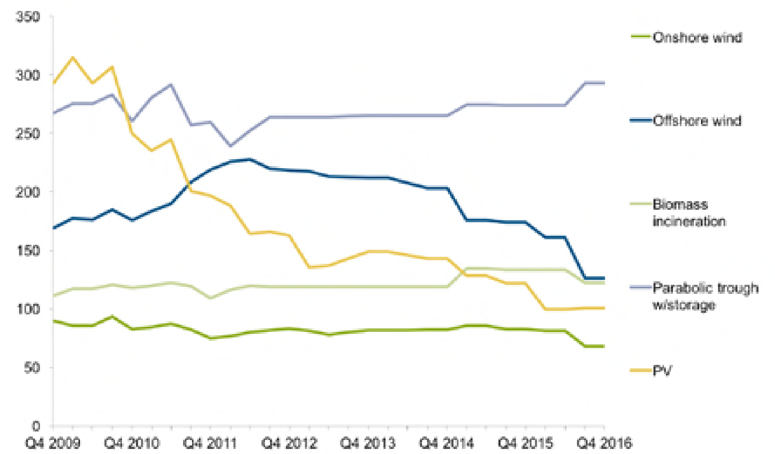
$101 per MWh, down 17% in just one year. Onshore wind's central levelised cost estimate was $68 per MWh in H2 2016, down 18% in a year, while that for offshore wind was $126, down 28%. Figure 9 shows that while electricity from PV and onshore wind have been getting cheaper and cheaper since 2009, biomass incineration and solar thermal have made little or no progress.

FIGURE 8. RENEWABLE ENERGY ASSET FINANCE AND SMALL DISTRIBUTED CAPACITY INVESTMENT BY SECTOR, 2016, AND GROWTH ON 2015, $BN



Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

FIGURE 9. LEVELISED COST OF ELECTRICITY FROM SELECTED RENEWABLE ENERGY SOURCES, Q3 2009 TO H2 2016, $ PER MWH



Solar thermal is parabolic trough with storage, PV is crystalline silicon with no tracking
Source: Bloomberg New Energy financea

How have PV and wind improved their competitiveness so much? One reason has been cheap financing in many countries (see Chapter 3) – particularly important for technologies where the overwhelming part of lifetime costs are upfront rather than in the operating phase. Another has been the improving efficiency of wind and solar equipment, and better knowhow on how to locate and to maintain it. Capacity factors (the percentage of electricity that a power plant produces during a year compared to the theoretical maximum that the device could generate under constantly perfect conditions) have increased, in the case of onshore wind from 12% on average globally in 1997 to 25% in 2015. The average efficiency for crystalline-silicon PV mono cells increased from 17.5% in 2010 to 19.8% in 2015.[4]

The most important reason, however, has been lower dollar-denominated capital expenditure, or capex, costs per megawatt. The fact that the US currency has been strong in the last two years has played a part in cutting costs in other countries when converted into dollars. But the bulk of the reduction in costs has been a real one, visible in almost any currency.

In 2016 alone, average capex for crystalline silicon PV without tracking dropped by 13%, to $1.2 million per MW, while the equivalents for onshore and offshore wind fell by 11.5% and 10% respectively, to $1.6 million and $4 million per MW. Manufacturers have played an important role in this. In offshore wind, for instance, projects used in 2009 to be built with 3MW machines, 80 metres high, now some are being constructed with 8MW devices, 220 metres high. In solar PV, over-supply along the supply chain from silicon wafers to

[4] Bloomberg New Energy Finance, Research Note, PV efficiency improvements in 2015 and forecasts, April 2016.

modules has forced manufacturers to cut prices to sell stock. Further down the supply chain, declining civil engineering and installation outlays for projects have also been important.

Lower total capex costs were responsible for part of the $70.6 billion fall in global renewable energy investment last year. Of that figure, an estimate would be that around $27 billion of that total decline reflected reduced upfront per-MW costs for PV, onshore wind and offshore wind. Breaking that down, between a third and a half of the 31% fall in PV capacity investment last year was due to lower unit costs and just over half of onshore wind's 22% drop.[5]

Both capital costs per MW and levelised costs per MWh have been squeezed down by competition, and this process has been accelerated by the spread of auctions as a prime method for countries to allocate new generating capacity. Last year brought a hectic series of milestones for declining costs, emerging from auctions around the world – to take a few, $60 per MWh for solar in Rajasthan, India, in January; $30 per MWh for wind in Morocco, in January; $37.70 per MWh for wind in Peru, in February; $40.50 for solar in Mexico, in March; $29.90 for solar in Dubai, in May; $60 for solar in Zambia, in June; $80 for offshore wind in the Netherlands, in July; $29.10 for solar in Chile, in August; $55 for offshore wind in Denmark, in November.[6]

[5] The other main factors were a sharp fall in public markets investment, lower asset finance of solar thermal, a shift in the mix between small-scale and utility-scale PV, and an underlying slowdown in financings in a number of markets since 2015.

[6] These results are not 100% comparable to each other, since auctions vary on whether the cost of transmission is included, whether tariffs are index-linked and how long they run, and when projects need to be built.

FUTURE CAVEATS

Renewables excluding large hydro have gone from being labelled as 'alternative energy' and a niche choice for wealthy countries only 10 years ago, to the majority (55.3% in 2016) of new generating capacity installed worldwide, as Chapter 2 describes. Wind and solar are undercutting coal or gas – or both – in terms of levelised costs, in an increasing number of countries.

That, however, does not mean the future will necessarily be plain sailing for renewables. Wind and solar remain vulnerable to unfriendly twists in policy, or to measures that set out directly to protect coal and gas. Their competitiveness could be eroded, for a time at least, if there was a sharp, upward turn in the international interest rate cycle, perhaps in response to a shift in US economic policy. Demand for all new generating technologies could be dampened if electricity consumption grows much less than expected.

Finally, the structure of electricity markets continues to be a challenge not just for renewable energy developers but also for energy ministries around the world. There is the issue of how to reward flexible generation and storage, so that the system is always able to respond when wind and solar generation drops.

There is also the issue of how investors in new, unsubsidised wind and solar projects can de-risk future revenues in an unsubsidised era.

INVESTMENT BY TYPE OF ECONOMY

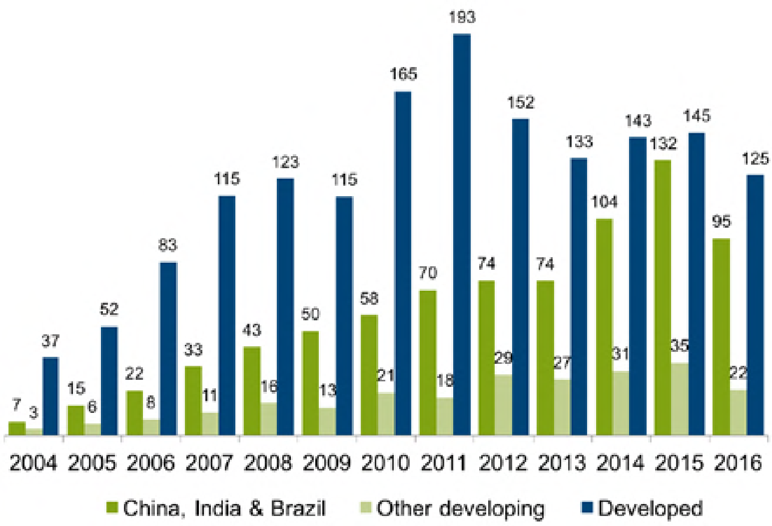
- Sharply contrasting trends were seen in renewable energy investment last year, between types of economy, regions and individual countries, although the impact of lower costs for wind and solar was felt everywhere.
- Dollar investment in developed economies fell by 14% to $125 billion in 2016, some 52% of the world total, with a 10% decline in the US, a 3% increase in Europe, and a 56% drop in Japan.
- The 'big three' developing economies of China, India and Brazil saw a combined 28% setback in dollar investment to $94.7 billion, but this disguises different trends in each. China was down by almost a third, Brazil 4% lower and India held steady.
- 'Other developing countries' saw a significant reverse (of 37% to $21.9 billion) in investment in 2016. Delays in policy support afflicted South Africa, Mexico and Brazil, while project timing issues limited dollar commitments in Morocco, Chile and Pakistan. However, there was higher investment in some other countries, with Jordan one of the star performers.
- Among the developing nations pursuing policies that could lead to increasing renewables investment in 2017 and beyond were India, Argentina, Egypt and United Arab Emirates.

DEVELOPED VERSUS DEVELOPING ECONOMIIES

If 2015 was the year that developing economies spectacularly overtook developed countries in terms of total investment in renewable energy excluding large hydro, then 2016 was the year that they unexpectedly lost that lead. As Figure 4 in the Executive Summary of this report shows, investment in developing countries dropped by 30% last year to $116.6 billion, while that in the richer nations fell 14% to $125 billion.[7]

A slightly different view of the split is presented in Figure 10. This divides developing countries into the 'big three' of China, India and Brazil on the one hand, and the remainder on the other. It highlights just how important the

FIGURE 10. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY: SPLIT BY TYPE OF ECONOMY, 2004-2016, $BN



New investment volume adjusts for re-invested equity. Total values include estimates for undisclosed deals. Developed country volumes are based on OECD countries excluding Mexico, Chile, and Turkey

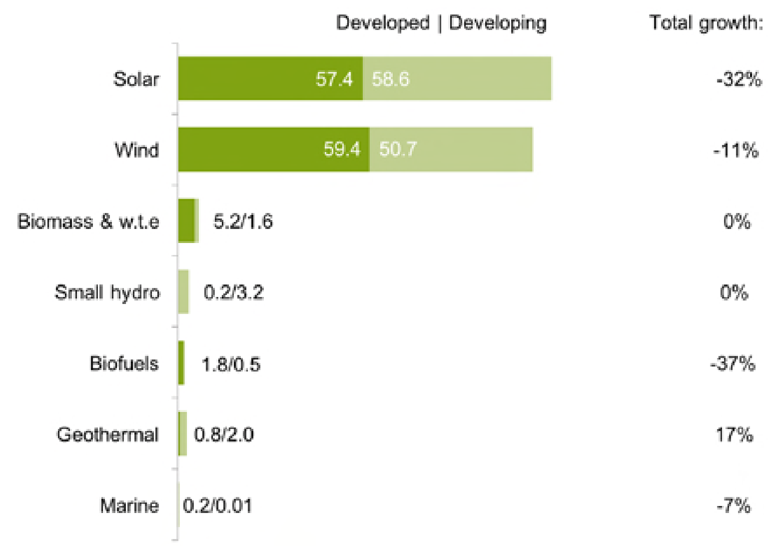
Source: UN Environment, Bloomberg New Energy Finance

[7] In this report, developing economies are defined as non-OECD countries plus Turkey, Chile and Mexico.

big three have been in investment terms in the last decade, but also reveals that both groups saw major reductions in dollar commitments in 2016. China, India and Brazil, as a group, accounted for investment of $94.7 billion, down 28%, while the 'other developing' economies managed $21.9 billion, down 37%.

The latter fall was perhaps the most surprising aspect of global renewable energy investment in 2016. 'Other developing' economies had seen their total climb fairly smoothly over the years, reaching $34.9 billion in 2015, with countries such as South Africa, Turkey, Chile, Mexico, Uruguay, the Philippines, Morocco and Pakistan becoming billion-dollar, or multi-billion-dollar, contributors. This fitted in with their rising demand for electricity, and their excellent natural resources for wind and solar deployment.

FIGURE 11. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY: DEVELOPED V DEVELOPING COUNTRIES, 2016, AND TOTAL GROWTH ON 2015, $BN



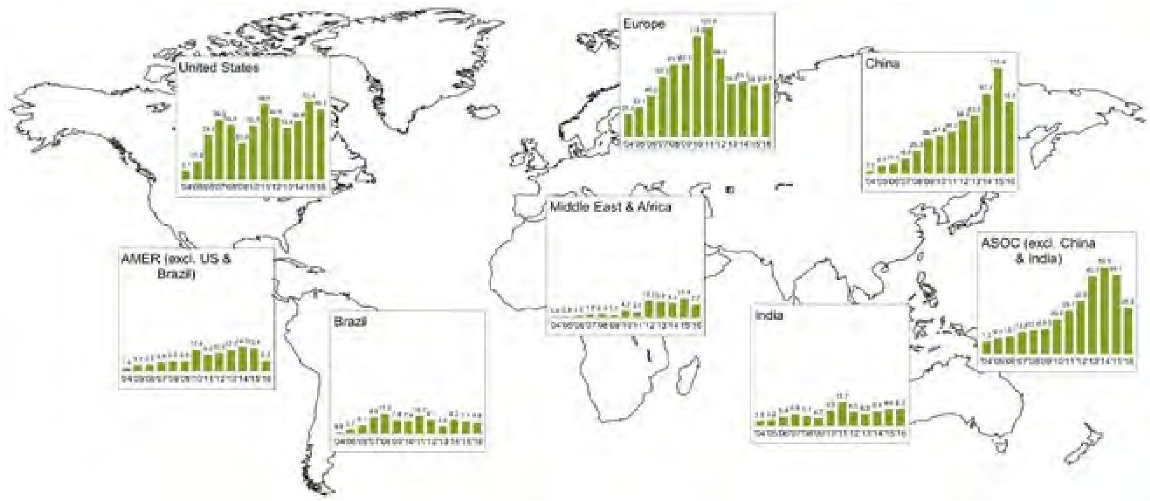
Total values include estimates for undisclosed deals. New investment volume adjusts for re-invested equity. Includes estimates for small distributed capacity, corporate and government R&D. Developed volumes are based on OECD countries excluding Mexico, Chile, and Turkey.
Source: UN Environment, Bloomberg New Energy Finance

However, there was a marked blip in that trend in 2016, with all those named countries seeing sharp falls in investment. The reasons in the case of each country are explored in detail later in this chapter, but there were some common factors, notably lower dollar costs for the projects that were financed and delays either in auction programmes or in the securing of debt and equity for projects that won capacity in auctions. Not all of the 'other developing' economies suffered falls in investment last year. Notable exceptions included Jordan, Egypt and Bolivia (see commentary later in the chapter).

Figure 11 shows the developed/developing country split on investment by sector. In 2015, developing economies including the big three accounted for more than half of global investment in both wind and solar, but in 2016 they lost the lead in wind and only narrowly maintained it in solar. Developed nations saw investment in wind of $59.4 billion, up 11% thanks in large part to their bumper year for offshore projects, against $50.7 billion for developing countries, down 28%. In solar, developed countries invested $57.4 billion, down 31%, and developing nations $58.6 billion, down 34%.

Other sectors tend to show consistent leads over the years – for developing economies in geothermal and small hydro, and developed nations in biomass and waste-to-energy. The lead in biofuels has alternated over the years, depending on whether the US or Brazil was dominant in terms of new projects in a particular period. In 2016, developed countries maintained their advantage in biomass and waste, with $5.2 billion against $1.6 billion for emerging economies, and took the lead in biofuels, with $1.8 billion against $453 million. Geothermal saw developing countries ahead as usual, $2 billion to $775 million, as did small hydro, $3.2 billion against $229 million.

FIGURE 12. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY BY REGION, 2004-2016, $BN



New investment volume adjusts for re-invested equity. Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

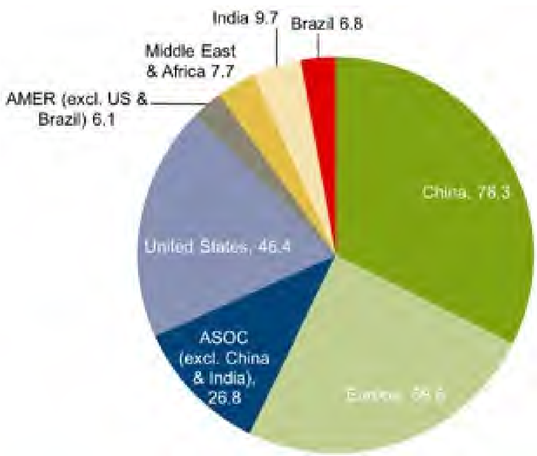
MAIN CENTRES

Renewable energy investment in 2016 showed contrasting trends between regions, and between the leading countries. Figure 12 shows the trends over the last 13 years in each of the regions. The US continued to be a strong centre for investment, its figure of $46.4 billion being roughly in line with its average since 2011, albeit 10% down on the 2015 record.

China was again the biggest location for dollar commitments, but its total of $78.3 billion was down 32% from 2015 and the lowest since 2013. This broke a 12-year sequence of rising investment year-by-year. India, arguably one of the most exciting markets for the next few years, recorded $9.7 billion in 2016, no more than on a par with 2015 and its average since 2010. Brazil bumps along from year to year in Figure 12 without much sign of an upward trend, and in fact last year's figure of $6.8 billion was down 4% and the second-lowest since 2006.

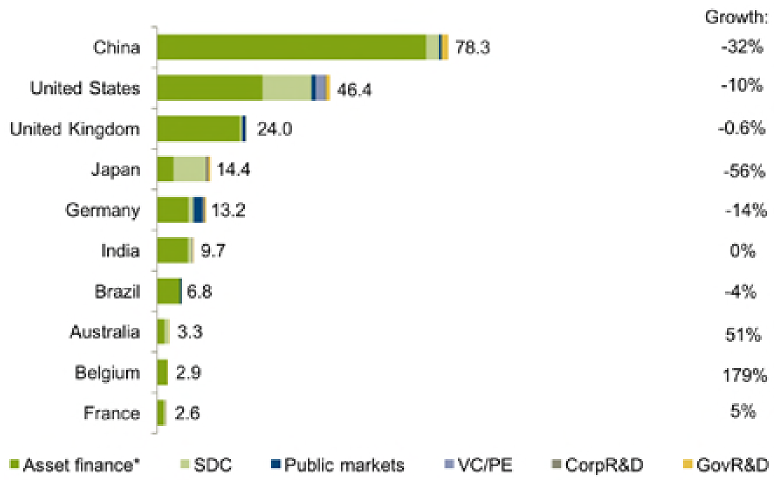
The chart shows that investment in Europe has stabilised in recent years after falling from peaks above $100 billion per year during the German and Italian solar booms of 2010-11. In 2016, it totalled $59.8 billion, up 3% on the previous year, with financing of offshore wind projects and the new equity raised by Innogy as it floated on the Frankfurt stock market two of the main features. See more on Innogy's share issue in Chapter 7.

FIGURE 13. GLOBAL NEW INVESTMENT IN RENEWABLE ENERGY BY REGION, 2016, $BN



New investment volume adjusts for re-invested equity.
Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

FIGURE 14. NEW INVESTMENT IN RENEWABLE ENERGY BY COUNTRY AND ASSET CLASS, 2016, AND GROWTH ON 2015, $BN



Top 10 countries. *Asset finance volume adjusts for re-invested equity. Includes corporate and government R&D
Source: UN Environment, Bloomberg New Energy Finance

Figure 14 breaks down the picture into the 10 leading countries for investment in 2016. The top seven are in the same order as in 2015, except that Japan's sharp fall in dollars committed pushes it from third, down below the UK into fourth place. All of those top seven saw lower investment last year than in the previous year, other than India, where it was steady. However, the size of the drops varied greatly, with the UK and Brazil down less than 5% at one extreme and China and Japan both down more than 30% at the other. The bottom three places of the top 10 changed radically in 2016, with Chile, South Africa and Canada dropping out, to be replaced by Australia, Belgium and France.

The Middle East and Africa last year had its lowest level of renewables investment since 2011, the latest figure, of $7.7 billion, being some 32% below 2015. As described below, much of this dip was due to pauses in financing in both South Africa and Morocco.

The other two regions in Figure 12 both saw sudden interruptions in 2016 to previously strong growth trends. The Americas excluding the US and Brazil suffered a 54% slump in investment to $6.1 billion, its lowest for nine years, while Asia-Oceania excluding China and India had a 42% setback to $26.8 billion, its weakest figure since 2011. As described below, several Western Hemisphere countries had fewer financings in 2016, including Canada, Mexico, Uruguay and Chile, for different reasons. A sharp drop in Japan was the dominant reason for the reduction in investment in ASOC (Asia Oceania) excluding China and India.

The relative shares of the main regions in global investment in 2016 are shown in Figure 13. China accounted for 32% of all financings of renewable energy excluding large hydro, and Europe 25%. The US was another 19% and Asia-Oceania excluding China and India was 11%. India, Other Americas, Brazil and Middle East and Africa made up 4%, 3%, 3% and 3% respectively.

DEVELOPED ECONOMIES

The US has been in the top two or three countries for renewable energy investment ever since 2004. It was the largest of all in 2011, the peak year for the Obama administration's 'green stimulus' – as programmes such as the Treasury grant scheme and the federal loan guarantee reached expiry. Last year saw no abrupt change in this trend, with US financings down 10% at $46.4 billion but above the equivalent outturns for 2013 and 2014.

Figure 15 shows the split by sector and by type of investment. US renewable energy investment tends to be more diverse than that of most other countries and regions, with strong showings by public markets, venture capital and private equity, and small-scale projects, as well as by utility-scale asset finance. In 2016, there was strong growth in small distributed capacity investment, with $13.1 billion of rooftop and other small PV projects going ahead, up 33% on 2015.

Utility-scale asset finance was down just 2% at $29.8 billion, with wind and solar each contributing $14.7 billion. The five-year extension to the Production Tax Credit for wind and the Investment Tax Credit for solar, agreed unexpectedly in

FIGURE 15. RENEWABLE ENERGY INVESTMENT IN THE US BY SECTOR AND TYPE, 2016, $BN

	Asset finance	Re-invested Equity	SDC	Public markets	VC/PE	CorpR&D	GovR&D	Total
Solar	14.7	-0.8	13.1	0.2	1.7	0.3	0.1	29.3
Wind	14.7	-0.6	-	1.1	0.2	0.0	0.1	15.5
Biofuels	0.1	-	-	0.0	0.3	0.1	0.6	1.0
Geothermal		-	-			0.0	0.1	0.1
Biomass & w.t.e	0.2	-	-		0.1	0.0	0.1	0.4
Small hydro	0.1	-	-		0.0	0.0	0.0	0.1
Marine		-	-	0.0	0.0	0.0	0.0	0.1
Total	29.8	-1.5	13.1	1.3	2.3	0.5	1.0	46.4

Source: UN Environment, Bloomberg New Energy Finance

FIGURE 16. RENEWABLE ENERGY INVESTMENT IN EUROPE BY SECTOR AND TYPE, 2016, $BN

	Asset finance	Re-invested Equity	SDC	Public markets	VC/PE	CorpR&D	GovR&D	Total
Solar	1.6	-0.1	6.7	1.0	0.4	0.2	0.5	10.2
Wind	40.6	-0.2	-	2.8	0.1	0.2	0.2	43.8
Biofuels			-	0.0		0.2	0.4	0.6
Geothermal	0.8		-			0.0	0.1	0.8
Biomass & w.t.e	3.9	0.0	-	0.0	0.0	0.1	0.1	4.2
Small hydro	0.0		-			0.0	0.0	0.1
Marine		-	-	0.0	0.0		0.1	0.1
Total	46.9	-0.3	6.7	3.8	0.5	0.8	1.4	59.8

Source: UN Environment, Bloomberg New Energy Finance

Congress in December 2015, underpinned investor interest in US renewables throughout last year – although its long duration also meant that some developers decided to take their time before pressing ahead with new projects.

However, public markets investment in the US plunged 87% to just $1.3 billion, the lowest for five years. SunEdison, the giant solar developer that raised $2 billion on its own in 2015, entered bankruptcy proceedings last year; and the 'yieldco' funds that own operating-stage renewable energy projects found it hard to raise new equity in 2016 after a share price collapse late in the prior year. There is more discussion of the yieldco rollercoaster in Chapters 3 and 7.

Venture capital and private equity investment in specialist US renewable energy firms was $2.3 billion, down 2%, while corporate and government research and development spending was down 24% and up 51% respectively, at $498 million and $1 billion.

Figure 16 shows the equivalent breakdown for Europe. More than in the case of the US, overall investment was dominated by asset finance, making up $46.9 billion out of $59.8 billion. Remarkably little ($1.6 billion, down 75%) of this asset finance was solar, while biomass and waste-to-energy made up $3.9 billion, up 14%, and wind dominated with $40.6 billion, up 10%. The onshore wind element of the latter was actually down 26% at $14.8 billion, but this drop was more than offset by offshore wind, up 53% to $25.9 billion.

Small distributed capacity in Europe attracted $6.7 billion in 2016, down 18%, with Germany, the UK and the Netherlands the three biggest contributors to that figure. Public markets investment leapt 170%, largely thanks to the $2.2 billion of new money raised by Innogy, the offshoot of German utility RWE, in its initial public offering. VC/PE investment was $516 million, almost exactly double the 2015 number, while corporate and government R&D were $780 million and $1.4 billion respectively, down 37% and up 24%.

Among individual European countries, the UK was the biggest investor in renewables for the second successive year. Asset finance contributed $22.5 billion to the UK's $24 billion total investment, with four giant offshore wind projects – Hornsea (1.2GW), Beatrice Cape (588MW), East Anglia One (714MW) and Burbo Bank Extension (258MW) – amounting to $14.2 billion of that. Each of these had clinched tariff support either through the expiring Renewable Obligation Certificate scheme or the first instalments of the new Contract-for-Difference (CfD) programme, before a hiatus in renewables policy that set in after the May 2015 general election. The Tees project, at 299MW and $841 million, heralded as the world's biggest dedicated biomass plant, also secured a CfD.[8]

Germany was the second-largest of the European markets, with investment of $13.2 billion. Within this, asset finance was $8.4 billion, down 34%, dominated by offshore and onshore wind. Three offshore arrays, the 450MW Borkum Riffgrund, 396MW Merkur and 385MW Arkona Becken Sudost all reached final investment decision, for a combined total of $5.1 billion. Outside offshore wind, one issue that may have caused some developers to hold back in 2016 was uncertainty over Germany's switch from feed-in tariff support to auctions. Auctions for PV were held last year, and the country may have 2-3 rounds for onshore wind in 2017.

In Figure 17, there is a big gulf between investment levels in the two biggest European markets, the UK and Germany, and eight other countries that recorded commitments of between $1.3 billion and $2.9 billion. However, even among that latter group, there were some sizeable projects financed in 2016, including the Norther and Rentel offshore wind farms off Belgium, at 370MW and $1.3 billion, and 309MW and $1.2 billion respectively, and the Horns Rev 3 offshore array off Denmark, at 406MW and $1.1 billion.

FIGURE 17. TOTAL RENEWABLE ENERGY INVESTMENT IN EUROPE BY COUNTRY, 2016, $BN AND CHANGE ON 2015

	2016	% growth on 2015
United Kingdom	24.0	-1%
Germany	13.2	-14%
Belgium	2.9	179%
France	2.6	5%
Denmark	2.5	128%
Norway	2.2	1419%
Italy	1.8	31%
Sweden	1.7	117%
Turkey	1.5	-51%
Netherlands	1.3	-2%

Top 10 countries. Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

[8] Tees' CfD was secured in the in the so-called FIDeR round in 2014 that preceded the first full CfD auction in early 2015.

Other technologies also produced some bumper financings. The 1GW Fosen wind portfolio in Norway, at $1.3 billion, was the biggest onshore wind deal anywhere in the world in 2016, and the Amagervaerket biomass plant in Denmark, at 150MW and $739 million the second largest biomass undertaking globally.

FIGURE 18. TOTAL RENEWABLE ENERGY INVESTMENT IN MAJOR DEVELOPED ECONOMIES, 2016, $BN, AND CHANGE ON 2015, $BN

	2016	% growth on 2015
Japan	14.4	-56%
Australia	3.3	51%
South Korea	1.4	-10%
Canada	1.7	-54%
Israel	1.2	80%

Top 10 countries. Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

Figure 18 shows renewable energy investment in five other developed economies in 2016. Australia and Israel both enjoyed increases in commitments. The latter owed much of its tally to one solar thermal project, the Ashalim II Sun Negev complex, at 110MW and $805 million. Australia financed a wider range of projects, particularly in wind, the largest two being the 270MW CWP Sapphire installation at $438 million and the 175MW White Rock plant at $326 million, both in New South Wales.

Canada experienced a 54% drop in renewable energy investment to $1.7 billion, its lowest since 2004 and far below the figures of $5-6 billion that were prevalent in the early years of this decade. The only project financed of more than 100MW was the 224MW Nicolas-Riou onshore wind farm in Quebec. Ontario, which had been the mainstay of Canadian green power investment in prior years, announced the suspension of phase two of its Large Renewable Procurement programme in 2016 in the face of an overcapacity of generating plants. Meanwhile, Alberta under a new government has shifted towards renewables and is planning to procure 5GW of clean power through auctions – but this will result in investment further down the line, and did not feature in the 2016 data.

South Korea's investment of $1.4 billion was dominated by small-scale solar, totalling $1 billion, on a par with 2015. Its $14.4 billion neighbour, Japan, has also been solar-focussed in recent years, peaking at 11.5GW of new build in 2015, making it easily the second biggest PV market in the world after China. In 2016, there was a pronounced slowdown in activity in Japan in the face of grid access difficulties and also a shift in policy from generous feed-in tariffs towards auctions. In addition, the unit price of Japanese PV fell sharply in 2016, as the lower system prices prevalent in other countries finally arrived in its market. Small-scale capacity investment fell particularly heavily, by 69% to $8.5 billion, the lowest since 2011, while asset finance – mainly of solar but to a lesser extent of wind and biomass – slipped 4% to $4.4 billion. The largest financing in Japan in 2016 was $243 million for the 81MW Karumai East PV project.

CHINA, INDIA, BRAZIL

Figure 19 shows the detail of renewable energy investment in the big three developing economies in 2016. Chinese investment, at $78.3 billion, was dominated by asset finance of $72.9 billion, down 34%, with small-scale PV project development of $3.5 billion, up 32%, and government R&D of $1.9 billion, up 7%, making up most of the rest.

Solar and wind were closely paired in terms of both overall investment, and the asset finance category, with small hydro the only other sector to break the $1 billion barrier. China had a runaway solar installation boom that extended through the final months of 2015 until the middle of last year, before a reduction in the feed-in tariff, weaker-than-expected electricity demand growth and high levels of curtailment put the brakes on deployment. The change of pace was sudden, with 22GW installed in the first half of the year (some of it financed in 2015) and only 8GW in the second half.

In wind, the issues that affected solar were also influential although there was not the same sharp change in trend during 2016. China installed some 23GW of wind capacity in 2016, the second-highest ever behind 2015's 29GW. On 7 November, the country's National Energy Administration announced a reduction in its wind

FIGURE 19. RENEWABLE ENERGY INVESTMENT IN CHINA, INDIA AND BRAZIL BY SECTOR, 2016, $BN

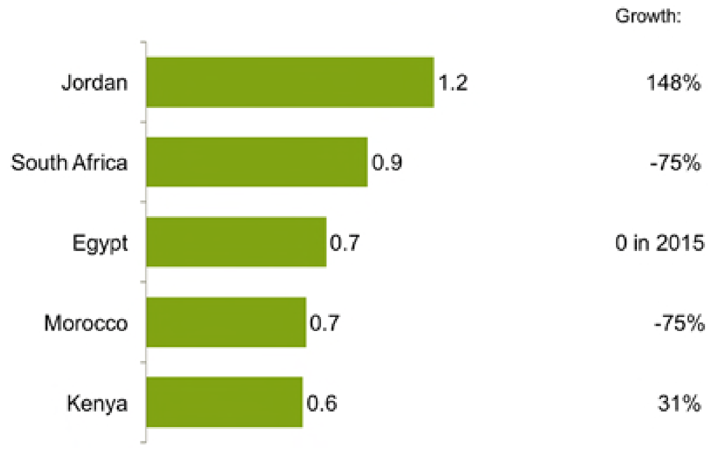
	China	India	Brazil
Solar	39.9	5.5	1.0
Wind	35.0	3.8	5.4
Biofuels	0.1	0.0	0.4
Geothermal	0.0	0.0	0.0
Biomass & w.t.e	0.7	0.1	0.0
Small hydro	2.6	0.3	0.1
Marine	0.0	0.0	0.0
Total	78.3	9.7	6.8

Source: UN Environment, Bloomberg New Energy Finance

installation target for 2020 from 250GW to 210GW, reflecting the challenges of curtailment and a persistent undershoot in electricity demand growth.

India is still a much smaller renewables market than China, but it has potential to be arguably the fastest growing over the next few years. On taking power, Prime Minister Narendra Modi set an ambitious target of 175GW gigawatts of renewables excluding large hydro by 2022, with 100GW of that being solar, up from 10GW installed at the end of 2016. Progress last year towards that target was relatively slow, with just $5.5 billion invested in new solar capacity. Most of this solar was awarded through auctions, but during 2016 the auction process took longer than hoped to roll out in some states, and even those projects that did win capacity did not necessarily achieve financial close before the end of the year. There were also delays in getting India's rooftop PV programme moving towards its own target of 40GW.

FIGURE 20. RENEWABLE ENERGY INVESTMENT IN MIDDLE EAST AND AFRICA BY DEVELOPING COUNTRY, 2016, AND CHANGE ON 2015



Source: UN Environment, Bloomberg New Energy Finance

Wind was the recipient of $3.7 billion of asset finance in India during 2016. The official target for wind is 60GW by 2022, but India already has 28GW installed, so the addition in the next five years is much less than for solar. Wind investment may speed up in early 2017 to catch the expiry of incentives at the end of the first quarter, but for most of last year activity was held back by low power prices, difficulties in agreeing power purchase deals, and the fact that many developers were more interested in solar, which often has a lower-cost advantage in India over wind.

In Brazil, a year of economic recession and political upheaval was a less than ideal backdrop for renewable energy development, and in December the energy ministry cancelled its only auction of 2016 for wind and solar, blaming weak power demand. Development bank BNDES also signalled that it would reduce its lending to the infrastructure sector, including clean energy. Given these problems, it was no surprise that asset finance of wind projects in Brazil fell by 15% to $4.9 billion in 2016. This was partially offset by a 75% rise in solar asset finance to $1 billion.

OTHER DEVELOPING ECONOMIES

Investment levels in the Middle East and Africa were disappointing in 2016, even though there were several eye-catching positive developments. One was the first-ever renewable energy auction in Zambia in June. Part of a World Bank-organised programme, this produced winning bids for 73MW of solar power at the cheapest prices yet seen in Africa. And in the United Arab Emirates in May, developers agreed to build 800MW of solar for the Dubai Electricity & Water Authority for a then-record-low price of $29.90 per MWh.

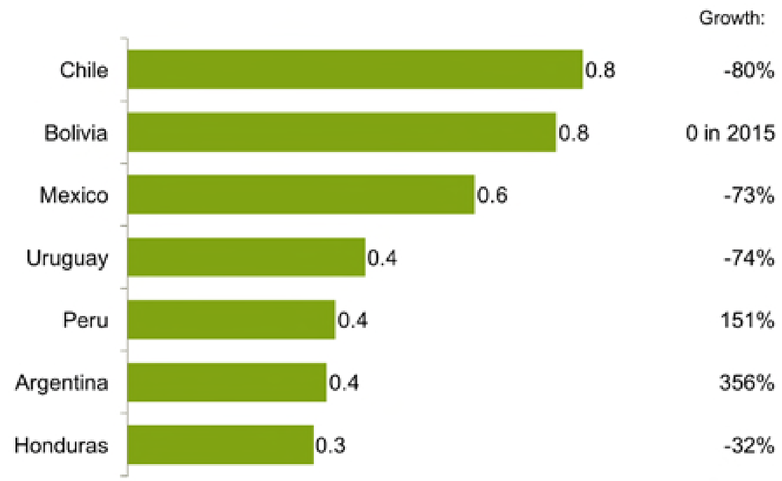
Figure 20 displays the countries where actual financings – as opposed to auction wins (which tend to pre-date the former by several months, if not longer) – took place and aggregated at more than $500 million in 2016. Jordan was the top location, attracting $1.2 billion of investment as it tried to boost power capacity to meet demand and also reduce exposure to volatile imported fossil fuel costs. This total was up 148% on 2015, and split mainly between wind at $616 million and solar at $507 million. The country has benefited from smooth access to finance from development banks such as the European Bank for Reconstruction and Development and the World Bank's International Finance Corporation. One of the main challenges remains grid access, but Jordan is trying to alleviate this with its 'Green Corridor' project to increase transmission capacity.

South Africa and Morocco were both strong performers in terms of investment in 2015, but fell back heavily last year. South Africa saw a pause in its programme of renewable energy auctions, as state utility Eskom indicated reluctance to sign fresh power purchase agreements (PPAs) until it got guidance from the government on the prices it could charge customers. Asset finance there last year was dominated by the $756 million agreed for the 100MW Kathu solar thermal plant in the Northern Cape.

Morocco hit the headlines with a world-record-low auction winning bid for onshore wind of $30 per MWh in January 2016, and the ball was set rolling on fresh PV auctions and for the development of a 400MW hybrid PV-solar thermal plant at Midelt. However, during 2016 itself, there was a lull in projects reaching the financial close milestone, save for the 202MW Aftissant wind project, at an estimated $312 million.

Egypt and Kenya both enjoyed higher investment in 2016, in the former case from a zero start in 2015. Egypt's electricity ministry announced the launch of Round 2 of its feed-in tariff programme in September last year, after a patchy response to the first round held in 2015. In November, the government agreed $662 million of PPAs for solar projects, most of which were not financed before the end of the year. Investment in 2016 was led by $362 million for the 200MW Gulf of Suez wind farm. In Kenya, the regulator began moves to switch from a feed-in tariff system to auctions. Asset finance of renewables in the country was sluggish last year, except for a $403 million package for the latest, 140MW stage of the Olkaria geothermal project.

FIGURE 21. RENEWABLE ENERGY INVESTMENT IN LATIN AMERICA BY COUNTRY (EXCLUDING BRAZIL), 2016, $BN, AND CHANGE ON 2015



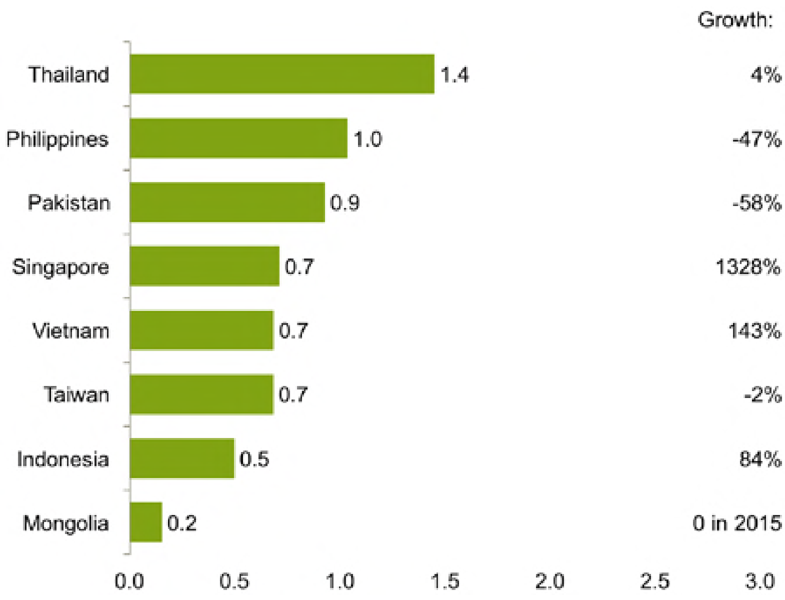
Source: UN Environment, Bloomberg New Energy Finance

Figure 21 shows similarly tepid investment totals for Latin American countries excluding Brazil. There were hopeful developments, notably in Argentina, which held two clean energy tenders during the year, contracting 2.4GW of capacity. There was only a minor hint of the coming upswing in renewable energy investment in that country during 2016, with asset finance at $362 million. Even so, that was the highest figure since 2011. Bolivia had its strongest year for renewables since at least 2004 thanks to the provision of $612 million for the 100MW ENDE Laguna Colorada geothermal installation.

Disappointments came in Chile, Mexico and Uruguay, which all recorded falls in investment of at least 70%. Chile's renewable energy drive ran into transmission bottlenecks and a sharp drop in wholesale power prices. There was also concern about whether projects winning auctions at aggressive prices would struggle to find financing. The country achieved fame in 2016 by establishing a new world record for low tariffs, of $29.10 per MWh in an auction in August, for 254GWh of solar.

Fresh auctions are set to happen in Chile in 2017, but fellow South American country Uruguay may have had the best years of its renewable energy programme after growing its wind market to near-saturation. Mexico, meanwhile, has the potential to return to the multi-billions of dollars of renewable energy investment of 2015, once projects that won capacity in the 2016 auction reach the financing stage ahead of commissioning in 2018-19. Energy reform, good for the clean power sector in the medium term, contributed to a hiatus in financings of wind and solar projects last year, although one large wind farm – the 200MW, $369 million EDP Coahuila project – did reach that milestone.

FIGURE 22. RENEWABLE ENERGY INVESTMENT IN NON-OECD ASIA (EXCLUDING CHINA AND INDIA), 2016, AND CHANGE ON 2015



Source: UN Environment, Bloomberg New Energy Finance

Finally, Figure 22 sets out the main developing countries in Asia-Oceania for renewable energy investment in 2016. Thailand took pole position once again, the solar-dominated total of $1.4 billion being its highest figure since 2013. Vietnam is emerging as a significant wind market, and saw $682 million of asset finance in that technology last year, the largest contributor to which was $247 million for the 100MW Cong Ly Ngoc Hien project. Its government said in October that it was considering increasing the feed-in tariff for wind to attract more investment, and in May last year General Electric said it planned to develop 1GW of wind power in Vietnam by 2025.

The Philippines remains an active renewable energy market, with a 5GW pipeline of wind, solar geothermal, biomass and small hydro projects under development. However, in 2016 solar made up almost all of the $1 billion capacity investment there, as developers rushed to take advantage of a feed-in tariff before it ran out of quota. Indonesia, meanwhile, announced new feed-in tariffs for solar in July 2016, with a minimum local content requirement, but then postponed the programme.

Pakistan is seeing strong interest in renewables, as the country of 230 million people seeks to meet rising electricity demand. The 58% fall in investment there in 2016 may not be more than a blip: since last year's Global Trends report, Bloomberg New Energy Finance raised sharply its estimate for Pakistan in 2015 to $2.1 billion, based on new information disclosed in the last 12 months. Both solar and wind saw significant new projects financed last year, the largest being the CWE Jhampir wind park at 99MW and $229 million. The country is also seeing activity in off-grid, with Asian Development Bank pledging $325 million in loans for small hydro and rooftop solar in Khyber Pakhtunkhwa province late last year.


CAT

PUTTING RENEWABLE ENERGY INTO PERSPECTIVE

- Renewable energy excluding large hydro accounted for 55.3% of the new electricity generating capacity added worldwide in 2016, the highest proportion in any year to date and the second successive year it has exceeded 50%.
- Last year, for the first time, there were significantly more gigawatts of solar power added than of any other generating technology. Trailing behind solar, in order of net GW installed, were wind, coal, gas, large hydro, nuclear and biomass.
- Renewable energy excluding large hydro produced an estimated 11.3% of the world's electricity in 2016, up from 10.3% in 2015 and 6.9% five years earlier, in 2011. Last year's renewables generation prevented the emission of some 1.7 gigatonnes of carbon dioxide.
- Even though investment in renewables capacity fell by 23% in 2016 in dollar terms, it was still roughly double that in new fossil fuel power stations, and more than seven times the amount committed to new nuclear plants.
- 2016 was a particularly strong year for investment in energy smart technologies. Asset finance for smart meters and energy storage, plus equity raised for specialist companies in energy efficiency, storage and electric vehicles, totalled a record $41.6 billion last year, up 29%.
- Despite the record installation of renewables, and the unprecedented activity in energy smart technologies, overall energy-related carbon dioxide emissions continue to run at more than 32 gigatonnes per year. CO2 levels in the atmosphere in January 2017 were up 3.6 parts per million from a year earlier, at 406.1ppm.

GLOBAL GENERATION MIX

Figure 23 shows the impact of the investment in renewables described in Chapter 1 on the overall mix of the world's power generation fleet. For the second year running, renewables excluding large hydro made up the majority of the new capacity added globally. The 138.5GW of new wind, solar, biomass and waste, geothermal and small hydro plants were equivalent to 55.3% of new gigawatt additions for all generating technologies, the highest proportion ever.

The other two lines on the chart give an idea of how far renewables still have to go if they are to become dominant in world electricity. Renewables excluding large hydro accounted for 16.7% of the installed GW capacity globally and, more significantly, just 11.3% of total electricity generation in 2016.

The reality of the electricity sector is that power stations have lives of 20, 40 and even 60 years or longer (in the case of hydro-electric plants), and so changing the generating mix in favour of renewables is a slow process, not a quick one. In addition, wind and solar plants have lower capacity factors – they produce electricity only when weather or daylight conditions are right – than what is possible with coal, gas, biomass, geothermal, nuclear or hydro-electric installations.[9] So gains for renewables in the share of electricity generated will tend to be slower than gains in the share of GW capacity.

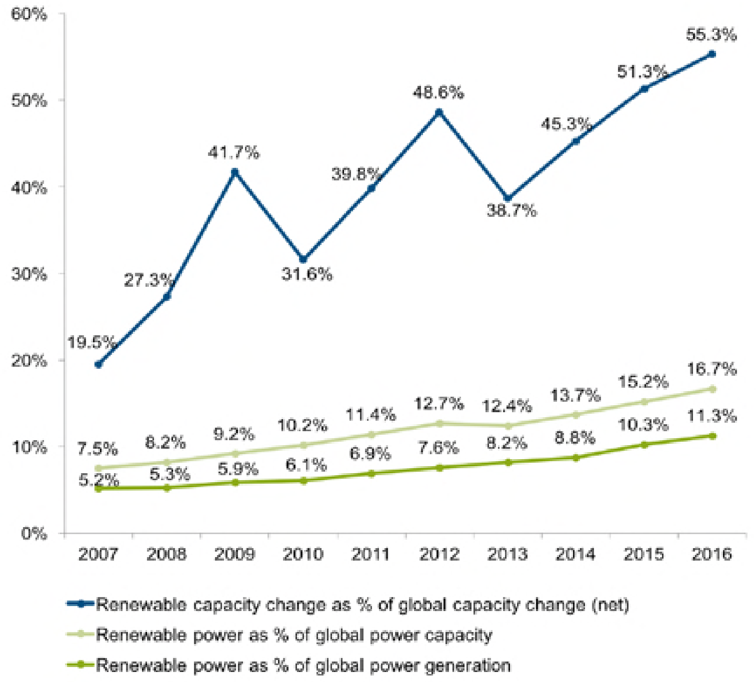
[9] Average capacity factors for a solar PV plant in a sunny country are 15-25%. Those for an onshore wind project in a good location may be 25-35%, and for an offshore wind array, 40-50%.

The 11.3% of electricity produced from wind, solar, biomass and waste-to-energy, geothermal, small hydro and marine meant that the world's power system emitted 1.7 gigatonnes of CO2 fewer than it would have done if none of that renewables capacity existed.[10] In plain speak, the world's problem with emissions would be significantly worse if these green power assets had not been built.

Figure 24, however, confirms that countries are continuing to add coal- and gas-fired capacity as well as zero-carbon plants. In 2016, as well as 138.5GW of 'new renewables', the world's fleet of large hydro-electric dams of more than 50MW increased by an estimated 15GW, and its stock of nuclear plants by 10GW – making the zero-carbon net addition 163GW.[11]

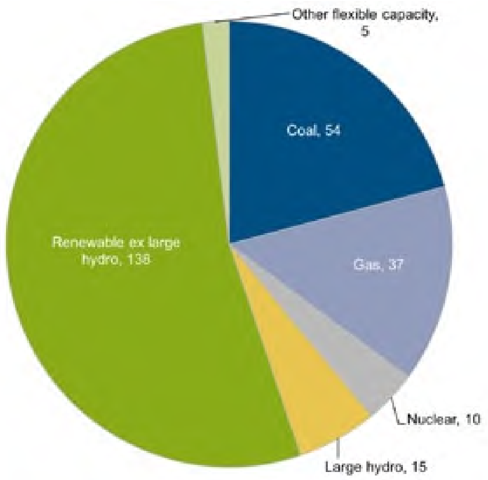
The total capacity of coal-fired power stations meanwhile went up by 54GW, and that of gas-fired generators by 37GW. In fact, both these numbers are more complicated than they look at first sight, because they are net figures, representing the difference between the new assets coming on stream in 2016 and old ones being shut down. Bloomberg New Energy Finance estimates that the world commissioned some 87GW of coal plants, and decommissioned 33GW, in 2016 – with, in general, most of the new coal assets being in developing countries and most of the closures in developed economies.

FIGURE 23. RENEWABLE POWER GENERATION AND CAPACITY AS A SHARE OF GLOBAL POWER, 2007-2016, %



Renewables figure excludes large hydro. Capacity and generation based on Bloomberg New Energy Finance totals
Source: Bloomberg New Energy Finance

FIGURE 24. NET POWER GENERATING CAPACITY ADDED IN 2016 BY MAIN TECHNOLOGY, GW



Source: Bloomberg New Energy Finance

[10] This is estimated by taking the International Energy Agency's figure for world power sector emissions in 2014, extrapolating that to 2016 using the IEA's World Energy Outlook forecast for emissions growth per year to 2020, to give a figure of 13,395Mt. Then we assume that the 11.3% of generation met by renewables last year was instead met by the same generating mix as the remaining 88.7%. If that was the case, total power sector emissions would have been 15,101Mt. Therefore, the emissions avoided through renewables excluding large hydro totalled 15,101 minus 13,395, or 1,706Mt.

[11] Note that the figures in Figure 24 do not give exactly the 55.3% number in Figure 23 for renewable energy excluding large hydro as a share of total additions. This is because included in the arithmetic for Figure 23, but not shown in Figure 24, is a 9GW reduction in oil-fired generating plant.

COMPARING INVESTMENT

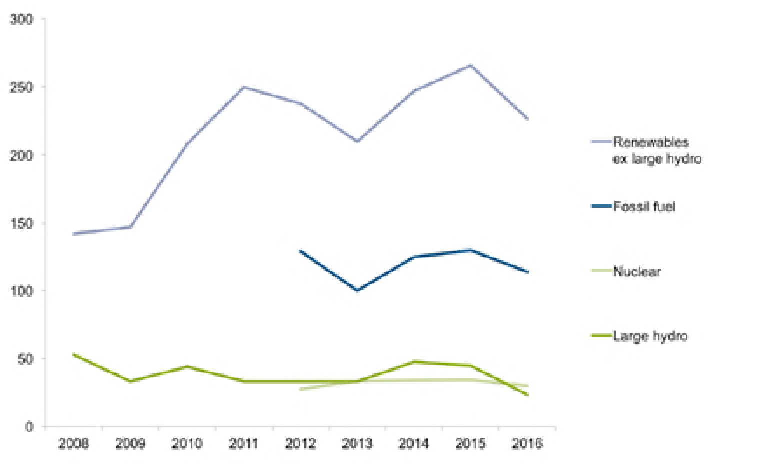
Renewables continue to attract far more dollars of investment than do fossil fuel generating plants, as Figure 25 shows. This is partly a reflection of green power's gradually growing share of world capacity and generation, and partly a reflection of the fact that almost all the cost of a project to produce power from wind, solar, geothermal and small hydro is upfront. Generally speaking, fossil fuel plants are cheaper to build but have much higher running costs, since the fuel has to be purchased on an ongoing basis.

Nevertheless, there is a persistent, large gap between the dollars committed to building renewable power plants ($226.6 billion in 2016) and those committed to constructing fossil fuel capacity (an estimated $113.8 billion).[12] The other two technologies were even further behind – large hydro attracted final investment decisions last year worth an estimated $23.2 billion, and nuclear $30 billion.[13]

Overall, renewables excluding hydro accounted for 58% of the dollars committed to new generating capacity worldwide in 2016, and large hydro-electric projects of more than 50MW another 6%.

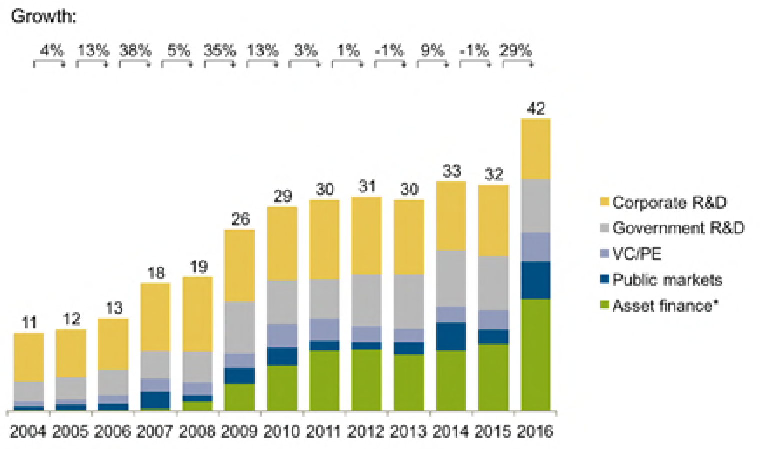
In Figure 25, the fossil fuel line is only shown for the years since 2012, because of a shortage of data using the same methodology for years before that.

FIGURE 25. INVESTMENT IN POWER CAPACITY – RENEWABLE, FOSSIL-FUEL AND NUCLEAR, 2008-2016, $BN



Source: Bloomberg New Energy Finance

FIGURE 26. GLOBAL NEW INVESTMENT IN ENERGY-SMART TECHNOLOGY BY TYPE, 2004-16



*Energy storage and smart metering asset finance only. Total values include estimatesfor undisclosed deals

Source: UN Environment, Bloomberg New Energy Finance

ENERGY SMART TECHNOLOGIES

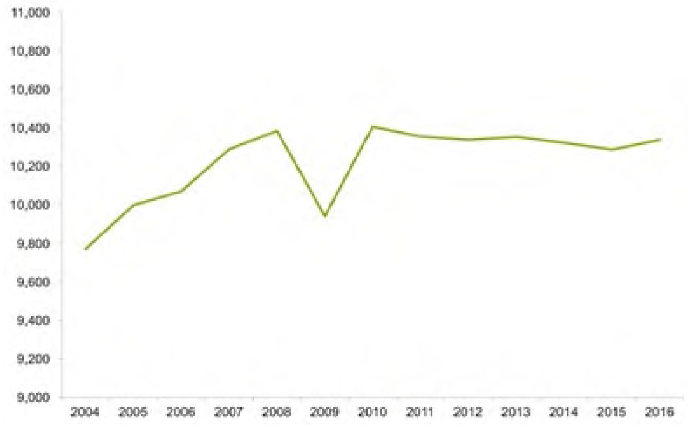
Investing in renewables is only one strand of the effort to limit global emissions. There are other steps that can be done on generation, such as coal-to-gas switching and investment in other zero-carbon sources such as nuclear. However, just as important is limiting the growth in demand for energy by investing in technologies that are more efficient in their use of electricity, heat and fuel.

Figure 26 shows that investment in energy smart technologies, or EST, jumped 29% in 2016 to a new

[12] Note that the $226.6 billion figure for renewables is power capacity investment only. The $241.6 billion total investment figure shown in the Executive Summary of this report also includes corporate-level investment, government and corporate research and development spending, and asset finance of biofuel plants.

[13] Note that, in the case of nuclear, the estimate shown is based not on final investment decisions like the other technologies, but on capex per year. This reflects the extreme length of nuclear capital spending programmes, and the high risk of cost over-runs and delays. So, for instance, the estimate spreads the $25 billion investment in the 3.2GW Hinkley Point C reactor in the UK over many years, rather than attributing it all to 2016. EDF and the UK government both gave it the go-ahead in the second half of last year.

FIGURE 27. ELECTRICITY SUPPLIED IN OECD COUNTRIES, 2004 TO 2016, TWH



Figures for full-year 2016 were not available when this report went to press, so the 2016 figure shown is the 12 months to November 2016
Source: International Energy Agency, Monthly Electricity Statistics

Last year, there was a record $14.4 billion invested in smart meters, up 63% on 2015. This dominated the $16 billion figure for asset finance in energy smart technologies.[15] There was also an all-time high for public markets investment in EST companies, of $5.3 billion, up 152%, with two electric car makers, Tesla and BYD, accounting for no less than $3.8 billion of that. VC/PE investment in energy smart technology firms was up 50% at $4.2 billion worldwide, while government R&D was down 2% at $7.5 billion and corporate R&D down 15% at $8.6 billion.

global record of $41.6 billion. This aggregate covers public markets, venture capital and private equity investment in companies active in energy efficiency, demand response, energy storage and electric vehicles; plus corporate and government R&D in all those areas; plus asset finance of smart meters and energy storage projects excluding pumped hydro.[14]

The high investor interest in electric cars came as these vehicles enjoyed a sharper increase in global sales than most commentators had expected at the start of 2016. In the end, electric vehicle sales jumped 55% last year to 695,000, equivalent to 1.1% of total new car sales in the markets tracked by Bloomberg New Energy Finance.

[14] The methodology is to include equity issues both by companies specialising in EST, and by those with a wider scope but where the specific fundraising is aimed at expanding their activities in EST.

[15] Note that there are many hard-to-quantify areas of energy efficiency investment not included in this total: for instance, industrial capital spending to reduce electricity consumption, and the insulation of buildings.

ELECTRICITY DEMAND

Electricity demand growth in developed economies has consistently fallen short of expectations since the 2008 financial crisis, and in recent years has started to do so too in a growing number of developing countries. The reasons are likely to be partly to do with shifts in the structure of economies (away from heavy industry and towards services), and partly to do with the spread of more efficient devices, from LED lighting to modern refrigerators and computers.

Figures from the IEA show that electricity supplied in OECD countries was 9,468TWh in January-November 2016, up 0.5% compared to a year earlier but only 1.3% above its level in the first 11 months of 2007 – even though those same OECD nations as a whole enjoyed GDP growth of 10.4% between 2007 and 2016.[16] Figure 27 shows the annual trend from 2004 to 2016, highlighting both the impact of the 2008-09 recession and the change of trajectory since then.

In China, electricity output growth in 2014 was 3.8%, in the following year 0.5% and last year back up to 5%.[17] However, these figures were far below the official rate of economic growth, at 7.2%, 6.8% and 6.8% in those three years. In India, estimates are that electricity demand growth was at a middling 4.3% in 2015-16 compared to the previous year, less than half the projected growth rate of 8.7%. Demand growth in the current year (2016-17) is also trailing projections, and supply of power is expected to exceed demand, though millions of people continue to remain without power.

[16] http://stats.oecd.org/

[17] http://stats.gov.cn

EMISSION AND CLIMATE TRENDS

The steady growth in deployment of renewables, the spread of energy smart technologies such as efficient lighting, and the softer-than-expected trend on electricity demand, are limiting the growth of world energy sector emissions.

UN Environment's Emission Gap Report 2016, published last November, said: "In 2015 global CO2 emissions stagnated for the first time and showed signs of a weak decline compared to 2014 (of 0.1%). This was preceded by a slowdown in the growth rate of CO2 emissions, from 2% in 2013 to 1.1% in 2014." However, the same report also warned: "The world is still heading for a temperature rise of 2.9 to 3.4 degrees Celsius this century, even with Paris pledges."

Some individual countries have performed well recently in terms of emission reduction. The Energy Information Administration said in October that carbon dioxide emissions from US energy consumption, including transport as well as power, were 2,530 megatonnes in the first six months of 2016, and on course to be 5,179 megatonnes for the whole year. This would be 14% less than in 2007, and the lowest since 1992.[18]

UK total net CO2 emissions were 383.8 megatonnes in the year to the second quarter of 2016, down 29% from 2007 and 36% from the peak year of 1991.[19] In the case of China, the International Energy Agency said in March 2016 that emissions dropped 1.5% in 2015, defying the agency's prediction from 2010 that Chinese emissions would grow 1.6% per year between 2008 and 2035.[20]

However, forecasts on global emissions are bleak. Most expect rising electricity demand in emerging economic regions such as India and South East Asia to lead to greater coal-fired generation, and to higher CO2 output. Meanwhile, energy-related emissions from transport and industry will continue to rise, they say.

The IEA, for instance, stated in November that it expects global energy-related emissions to rise from 32,175 megatonnes in 2014 and 32,795Mt in 2020, to 36,290 megatonnes in 2040, an increase of 13% over 26 years. BP's Energy Outlook 2017, published in February this year, came up with the same percentage increase but over a shorter period, 2015-35, in its base-case scenario. It added: "This is far in excess of, for example, the IEA's 450 Scenario which suggests carbon emissions need to fall by around 30% by 2035 to have a good chance of achieving the goals set out in Paris."[21]

Recent statistics have shown significant increases in CO2 in the atmosphere, and in global temperatures. The US National Oceanic & Atmospheric Administration (NOAA) says that the average CO2 content of the atmosphere at Mauna Loa, Hawaii in January 2017 was 406.1 parts per million, up 3.6ppm compared to a year earlier and up 36.8ppm, or 10%, since January 2000.[22]

Global temperatures in 2016 were also higher than for any year on record, according to preliminary analyses by NASA and the NOAA, published in January 2017. The US organisations said that average temperatures last year were 0.98 degrees Centigrade warmer than the 1951-80 mean.

This was the third year in a row to set a new record for global surface temperatures, with 2014 some 0.75 degrees and 2015 some 0.86 degrees above that benchmark. One earlier year that saw a temperature spike was 1998, at 0.63 degrees above the 1951-80 average, but that figure has been clearly exceeded in each of the last three years.[23]

[18] http://www.eia.gov/todayinenergy/detail.php?id=28312
[19] https://www.gov.uk/government/statistics/uk-greenhouse-gas-emissions-quarterly-official-statistics-q2-2016
[20] https://www.iea.org/newsroom/news/2016/march/decoupling-of-global-emissions-and-economic-growth-confirmed.html
[21] https://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2017/bp-energy-outlook-2017.pdf
[22] ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_mm_mlo.txt
[23] https://data.giss.nasa.gov/gistemp/tabledata_v3/GLB.Ts+dSST.txt

DELIVERING INVESTMENT

- Investment in renewable energy depends on mechanisms that can underpin returns and limit risks for project developers, and it depends on the availability of finance. This chapter looks at those areas.
- Auctions around the world are taking over from subsidy programmes as the main way of allocating renewables capacity. They are also delivering cost reductions, with the record-low tariff agreed in 2016 being one of $29.10 per MWh for a solar project in Chile.
- Corporate power purchasing agreements were arranged on some 4.3GW of renewable energy capacity worldwide in 2016, down 18% from 2015's record but including the highest contributions yet from both Europe and Asia.
- Institutional investors made a record $2.8 billion of direct equity commitments to European renewable energy projects last year. In the US, institutions and companies provided $13.7 billion of tax equity finance for clean power projects in 2016, up 8% on the previous year.
- Green bond issues to finance a broadly defined range of environmental projects, including renewable energy, totalled a record $95.1 billion in 2016, up 99%. These included the first ever sovereign green bond, issued by Poland.

This chapter examines what makes possible the flow of money into renewable energy projects. It starts by highlighting policy instruments, and specifically the transition from subsidies to auctions. It also looks at corporate power purchasing agreements, or PPAs, in which companies are increasingly signing deals to buy renewable electricity from projects. They are doing this either to underline to customers and investors their sustainability credentials, or to lock in a particular power price to protect themselves from the risk of higher prices in the future.

The rest of the chapter examines the flows of finance to renewable energy projects around the world in 2016, from utilities, institutional investors and debt providers. Which projects, sectors, countries and regions received those asset finance dollars is analysed in detail in Chapter 5.

FROM SUBSIDIES TO AUCTIONS

The roll-out of green power since the early years of this century has been closely associated with subsidies. Renewables are not the only sector of energy to have benefited from policy support – for instance, nuclear has often been subsidised around the world, and oil and gas exploration in the US benefits from a tax shelter called 'percentage depletion'. The International Energy Agency estimated in its World Energy Outlook 2016 that total global fossil fuel subsidies were $325 billion in 2015, down from nearly $500 billion in 2014 but still more than double the $150 billion spent on subsidies to renewable energy.

The generosity of the subsidies for renewables has been declining as technologies such as wind and solar have become more cost-competitive. The German feed-in tariff for PV installations of less than 10kW, for example, was EUR 127 per MWh between October and December 2016. This compared to a level of EUR 518 for a similarly-sized installation in 2006, and EUR 287 per MWh in the middle of 2011.

Feed-in tariffs guaranteed that renewable energy projects would receive a set price per kWh for their electricity generation, that price being well above wholesale power prices. This approach was

followed in countries such as Germany, Spain and France, and in China and parts of Canada. An alternative instrument was the green certificate, favoured in the UK and the joint Sweden-Norway market. Projects such as wind farms would qualify to receive a certificate in return for each MWh produced. The value of that certificate could go up and down depending on market forces, and it would form part of the revenue for the project, on top of wholesale electricity prices.

In the US, a third mechanism was dominant, and this was the tax credit. The Production Tax Credit for wind and Investment Tax Credit for solar would give rise to a credit that could be used by a company providing 'tax equity' finance for the project, to reduce the tax on its corporate profits. In December 2015, the US Congress voted to extend the PTC and ITC until 2020.

The last few years, however, have brought the spread of auctions as a way for governments and regulators to allocate renewable energy capacity, with developers bidding against each other for the right to develop projects. After early adoption in Brazil, and then South Africa, auctions have spread to the rest of South America, other parts of Africa, India and the Middle East, and to European countries such as the UK, Germany, Netherlands, Denmark, Spain and Italy.

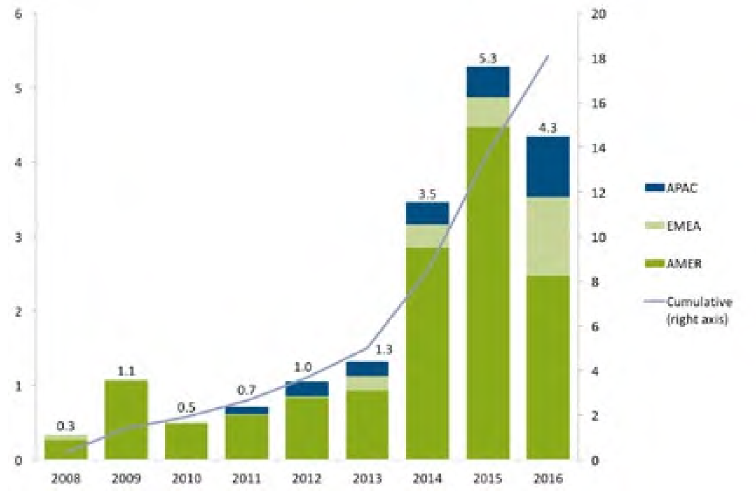
All auctions select the bidders that submitted the lowest offers in terms of tariff per MWh, but the details vary. For instance, some link that tariff to inflation and some do not, and some have an early deadline for building and commissioning the projects, while some do not. Research by Bloomberg New Energy Finance suggests that, on average, there is a 30% reduction in renewable energy project tariff when a country shifts from a feed-in tariff or green certificate programme to its first auction.[24]

Wind in Italy was a recent example of this tendency. In a December 2016 auction, the onshore wind segment was nearly 2.5 times oversubscribed and the winning bid price for the 800MW of onshore wind projects was a 40% discount on the reference price – the maximum possible discount. As such, projects will earn a tariff of just EUR 66 per MWh, some EUR 7 per MWh below BNEF's estimate of the average levelised cost of electricity for onshore wind in Italy.

As noted in the Executive Summary of this report, auctions around the world have produced some hitherto unimagined tariffs for solar and wind projects in the last year – the lowest of 2016 being Solarpack's deal last August in Chile to sell power from a 120MW PV project at $29.10 per MWh. Also last year, Morocco established a new record for wind, at $30 per MWh, in an 850MW tender.

[24] BNEF Research Note: Auctions and prices, 30 October 2015. https://www.bnef.com/core/insight/13183

FIGURE 28. VOLUME OF NEW CORPORATE POWER PURCHASING AGREEMENTS SIGNED, 2008-2016, GW



Includes government or university offtakers in addition to private sector offtakers. APAC capacity is estimated. Mexico PPAs use the off-taker maximum capacity volumes
Source: Bloomberg New Energy Finance

CORPORATE PPAs

Companies wishing to buy green electricity have various options, including installing PV panels on their warehouse roofs or, in some countries, buying renewable energy certificates on the markets, boosting the revenues for clean energy plants.

However, corporate power purchase agreements have become the focus of much attention by some of the largest global companies, including Google, Microsoft and Amazon. They come in two flavours – either 'private-wire' PPAs, in which a power cable is literally fed into a nearby corporate site, allowing the latter to buy its electricity directly; or or 'virtual' PPAs, in which the company guarantees the owner of the renewable project a certain fixed price for the electricity it sells to the grid, and can thus claim credit for bringing renewable energy onto the grid. This earns it a 'guarantee of origin', proving that its electricity came from green sources.

Last year was the second highest on record for signed PPA volume, its total of 4.3GW worldwide being 20% down on 2015's record but more than 12 times the figure in 2008. Figure 28 shows this global trend, and also the way the geographical mix has shifted from one dominated by the US and Mexico, to one also involving rising participation from Europe and Asia. AMER refers to the Americas, EMEA to Europe, Middle East and Africa, and APAC to Asia-Pacific.

The three largest deals of last year were Amazon's first PPA in Texas signed with Lincoln Clean Energy for a 228MW wind farm, Google's contract with Enel Green Power for 200MW from the Cimarron Bend wind farm in Kansas, and Amazon's arrangement with EverPower Wind Holdings for a 189MW project in Ohio. In Europe, one of the biggest was an innovative 'consumer-to-business' PPA for a 102MW onshore wind project in the Netherlands between a community co-operative and a consortium of Akzo Nobel, DSM, Google and Philips.

INVESTMENT SOURCES – UTILITIES

As Chapter 5 highlights in more detail, most utility-scale renewable power projects are financed either on-balance-sheet by a utility, energy company or large developer, or with a mixture of equity and debt provided directly to the project itself.

Utilities continued to be major providers of on-balance-sheet finance and project-level equity in 2016. Nine of the largest European utilities invested a total of $11.5 billion in renewables in 2015 according to their annual accounts, and were on track to invest $10.2 billion in 2016, judging from their interim and quarterly statements.[25] Enel was on course to be the largest investor among the nine last year, followed by Iberdrola and Dong Energy.

[25] Note that these figures reported by the utilities represent spending on projects in particular years, and are therefore calculated on a different basis from the BNEF data in this report. In BNEF data, total project capex is recorded at the time of final investment decision.

Among the many utilities backing big projects around the world in 2016 were Dong Energy financing Germany's Borkum Riffgrund II offshore wind plant, E.ON building the 228MW Bruenning's Breeze onshore wind farm in Texas, Southern Company buying a controlling stake in the 100MW Boulder Solar I solar park in Nevada, and Engie supplying the equity for the 100MW Kathu solar thermal project in South Africa. Fortum of Finland said it would spend up to $457 million on building solar plants in India.

Utilities were far from the only sort of large company to fund renewables in 2016. Oil giant Shell won a contract in December to build the 680MW Borssele III and IV offshore wind projects off the Netherlands, together with partners Eneco, Van Oord and Mitsubishi. In India, CLP Holdings, the former China Light & Power, bought a 49% stake in the 100MW SE Solar project. China Gezhouba, a large construction group, said in December it would invest $360 million to build the Tongliao PV project in Inner Mongolia.

INVESTMENT SOURCES – INSTITUTIONS

Institutional investors have become another key source of equity finance for projects, particularly in recent years. This can happen in a variety of ways, two of which are direct investment by institutions in project equity, and indirect investment through a pooled vehicle such as a 'yieldco'.[26]

Looking at the first of these, institutions such as pension funds and insurance companies committed an estimated $2.8 billion to European renewable energy projects in 2016. This was on a par with the record figure set in 2014, more than double the 2015 outturn and nearly 10 times the total in 2010.

Examples of this activity in 2016 included German insurer Talanx, plus three German and Finnish pension funds, contributing $484 million of equity to the 1GW Fosen wind portfolio in Norway, and Danish pension fund Pensionskassernes putting in 50% of the equity for the 299MW Tees biomass project in the UK. Also active once again in direct investment was German insurance company Allianz, which backed onshore wind farms in Finland and France in 2016.

Aggregate figures for other regions are not available, but direct investment deals are being done outside Europe by institutions. One big transaction was the acquisition in January 2016 by Canadian pension funds Ontario Teachers and Public Sector Pension Investment Board along with Banco Santander of 392MW of Brazilian wind parks for $494 million.

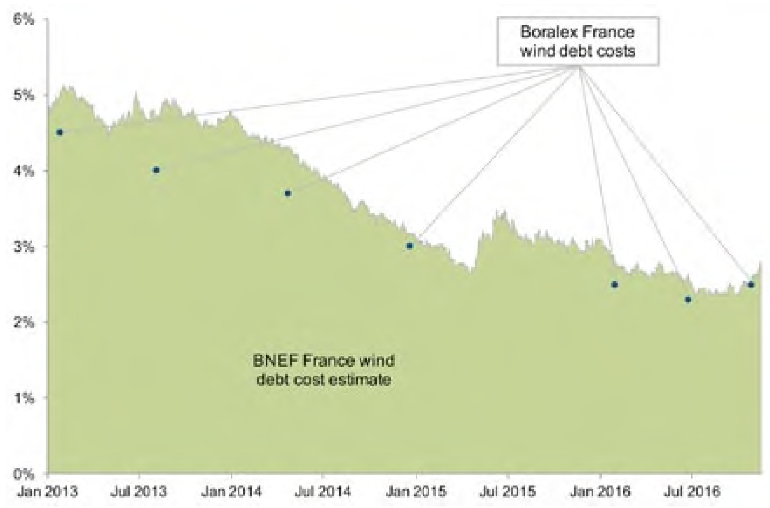
In the US, many of the institutional moves take the form of 'tax equity', as opposed to conventional equity, transactions. Tax equity is a security created to take advantage of the PTC and ITC tax credits for wind and solar mentioned in the section on policy support above. Last year, some $13.7 billion of tax equity was provided for US renewable energy by institutions, banks and corporations. This compared to $12.7 billion in 2015.

Among the tax equity transactions of note, Allianz and Mitsubishi UFJ Financial Group invested in the 225MW Great Western wind farm in Oklahoma in December, and two months earlier Bank of America and Bank of New York Mellon invested in three NextEra Energy wind projects in Kansas, totalling 415MW.

Turning to investment in projects via pooled funds, yieldcos and quoted project funds on both sides of the Atlantic raised some $1.9 billion from the stock market, down from a record $7.3 billion in 2015. That 74% plunge in fundraising followed a crisis of confidence in US yieldcos in late 2015 and early 2016 caused by investor doubts about their growth prospects and worries about the effect of the bankruptcy of SunEdison on the two yieldcos it started, TerraForm Power and TerraForm Global.

[26] Yieldcos and quoted project funds take large stakes, or 100% ownership, of renewable energy projects and hold them for the long term, distributing most of the project cash flows back to their own investors.

FIGURE 29. ESTIMATED ALL-IN COST OF DEBT FOR ONSHORE WIND PROJECTS IN FRANCE, 2013 TO 2016



Source: Bloomberg New Energy Finance, statements by Boralex

There is further discussion of yieldcos and quoted project funds in Chapter 7.

Also raising money last year for deployment in the equity of clean energy projects were a number of specialist private funds, including the Allianz Renewable Energy Fund, which had secured $374 million by the time of its final close, and the SUSI Renewable Energy Fund II, which closed with $291 million. Both will invest in wind and solar in Europe.

INVESTMENT SOURCES – DEBT

Debt makes up the majority of the capital required on most renewable energy projects that are funded using project finance structures. In developed markets, it is normal for project-level debt to meet 75% to 80% of the cost of an onshore wind installation, and equity the remainder. A solar project may get a similar debt proportion, while biomass and offshore wind projects will typically get less, at perhaps 65% to 70% debt, because of higher perceived risk.

In 2016, the cost of debt fell in some parts of the world as the markets responded to sluggish economic growth combined with low inflation and unexpected political events such as the UK's vote to leave the European Union. This low-priced financing environment helped to support demand for loans from renewable energy project developers and owners.

To take one country as an example, the all-in cost of 15-year debt on an onshore wind project in France started 2016 at 3.1% (far below the 5%-plus figures that prevailed in 2010-12) and fell to 2.4% in September last year.[27] It then started to edge back up, reaching 2.8% towards the end of the year. These figures include the bank margin, underlying market interest rate and the cost of a swap to fix borrowing costs during the term of the loan. Backing this up, Canadian infrastructure investor Boralex said it financed wind farms in France for 15 years on an all-in cost of debt as low as 2.5% in January 2016, and 2.3% in June. Similar projects were getting loans at all-in rates of 3-4% in the 2013 to 2014 period (see Figure 29).[28]

In India, the central bank's repo rate was cut by 25 basis points in the summer, helping to shave overall debt costs there, while in China central bank rates that provide a component of lending costs to projects stayed steady at 4.35% during the year. The US was one of the few major economies where official short-term rates increased (from 0.5% to 0.75% in December), and the long-term borrowing cost set by its 10-year bond yield climbed from a low of 1.4% in July to 2.4% by the end of the year.

Bank lending to renewable energy continued at high levels in 2016, contributing to the $86.4 billion of non-recourse project finance deals for new installations (see Chapter 5 on Asset Finance), as well as backing part of the $72.7 billion of asset acquisitions and refinancings (see Chapter 10 on Acquisition Activity).

One example of a big commercial bank loan for a renewable energy project in 2016 was a $1.3 billion package put together in August for the financing of the 400MW Merkur offshore wind project in the German part of the North Sea. The array of 6MW turbines attracted 10 banks from Germany, Netherlands, France, Sweden and Japan. In

[27] Bloomberg New Energy Finance estimates.

[28] http://www.boralex.com/newsfeed/press-releases

Southeast Asia, the developers of the 120MW Tuas waste-to-energy plant in Singapore secured $477 million of 27-year debt from four Malaysian and Japanese banks when the financing closed in May.

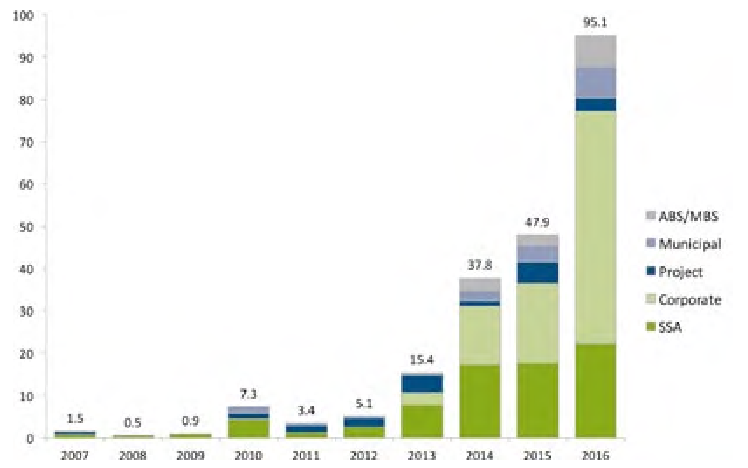
Development banks have been another important piece of the financing jigsaw for renewables throughout the last decade. Only a few of these lenders had released figures for their lending to renewables in 2016 by the time this chapter of the Global Trends report was completed.

Among the biggest players that had published data, Germany's KfW said that it provided the euro equivalent of $39 billion for "environmental and climate protection financing", including $8 billion for renewable energy and $23.5 billion for energy efficiency. The overall environmental and climate category was up 20% in euro terms compared to 2015. The Asian Development Bank approved $3.7 billion in climate finance investments in 2016, a 42% increase from the previous year, to support efforts in developing member countries.

GREEN BONDS

Green bonds are a growing asset class for investors around the world. This label includes qualifying debt securities issued by development banks, central and local governments, commercial banks, public sector agencies and corporations, and asset-backed securities and green mortgage-backed securities, and project bonds. Last year, total global green bond issuance almost doubled to $95.1 billion, as Figure 30 shows.

FIGURE 30. TOTAL GREEN BOND ISSUANCE BY CATEGORY, 2007 TO 2016, $BN



SSA stands for supranational, sovereign and agency; ABS stands for asset-backed securities; MBS stands for mortgage-backed securities
Source: Bloomberg New Energy Finance

The most eye-catching feature of this surge in 2016 was a leap in issuance in China to $27.1 billion, overtaking the US on $15.5 billion. Another headline was the world's first sovereign green bond, a $783 million issue by the Polish government in December, to finance a collection of 'climate-centred' projects.

That phrase highlights an important point about green bonds. They have a much looser scope than, for instance, renewable energy as defined in this report. Green bonds can be used to finance not just new clean energy generation but also energy efficiency, transmission, water, waste management and, sometimes, climate change adaptation. So the amount of money raised by green bonds cannot be compared to total new investment in renewable energy in 2016 of $241.6 billion.

Project bonds are usually deployed to refinance a project after a construction period that is paid for with equity and bank loans, or financed on balance sheet. Issuance of green project bonds in 2016 was $3.1 billion, down from $5.1 billion in 2015, with the largest being a $633 million issue to refinance the 100MW Kingston solar project in Canada.

FOCUS ON HYBRID PROJECTS

- Hybrid renewable energy projects put together in one location solar and wind, for instance, or solar thermal and geothermal. So far, some 5.6GW of hybrid projects, each of more than 10MW, have been built or are under development worldwide.
- The potential is for this number to grow significantly in the years ahead, as developers take advantage of synergies from co-locating two or more technologies.
- Among the attractions are the potential to share one grid connection, to produce more electricity from each hectare of land, to reduce overall intermittency, and to economise on operating and maintenance costs.
- The challenges include greater risk of curtailment if both renewable sources are generating at the same time, and a lack of familiarity with hybrid projects on the part of equity and debt providers.
- Mini-grids in developing countries and on islands provide a particular opportunity, with wind, solar or wave paired with batteries or even diesel back-up generators.

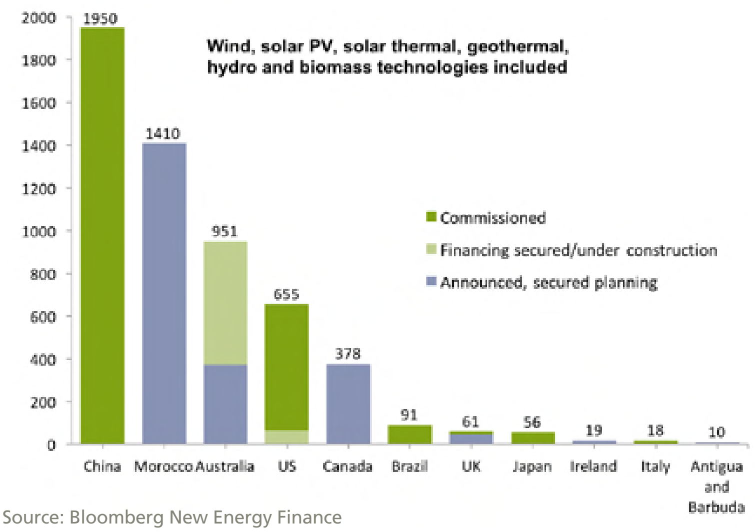
The Global Trends report has concentrated for the last 11 years on utility-scale and small-scale renewables projects in their own discrete locations. That has been by far the dominant model for siting green power projects, but things are beginning to get more complicated. In last year's report, we looked at the potential for pairing wind or solar projects with storage. This year's Focus Chapter looks at the potential for pairing renewable energy projects with each other.

As has become clear in recent years, the possibilities for hybrid projects are many. Solar could be retrofitted to a site that already has a wind farm, or floating solar could be retrofitted on a hydro-electric reservoir. Solar thermal already has been paired with geothermal, to increase the temperature of the steam driving a turbine, and so has biomass. Tidal stream just offshore could be paired with wind just onshore.

Bloomberg New Energy Finance estimates that by early 2017, some 20 renewable energy hybrid projects of a combined 10MW or more had been built or are being developed around the world. They have a total capacity of 5.6GW, with roughly half that capacity already in place, and half announced or under construction.[29]

Figure 31 shows the capacity of renewable energy hybrid projects so far built or announced worldwide,

FIGURE 31. RENEWABLE ENERGY HYBRID PROJECTS OVER 10MW BY COUNTRY, MW



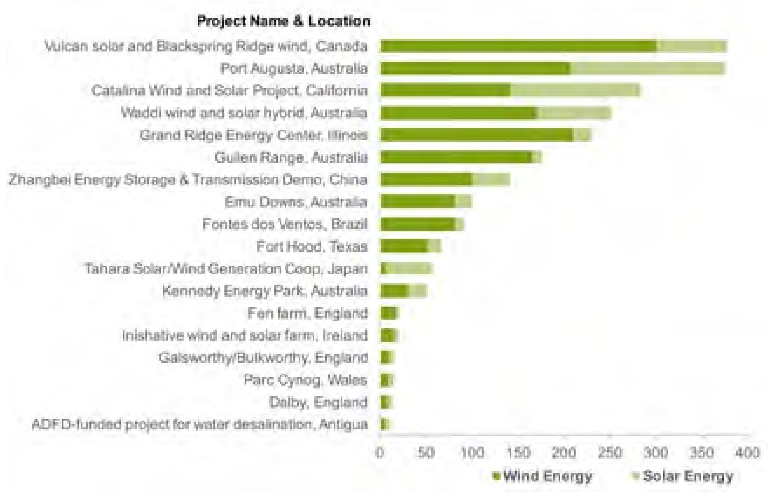
Source: Bloomberg New Energy Finance

[29] The investment value of these projects is hard to estimate since, in some cases, one of the two technologies has been in place on site for many years. Developers of new projects have often not disclosed the total capital cost. However, to build single-technology renewable energy plants totalling 5.6GW would be likely to cost somewhere either side of $10 billion, depending on the technology chosen.

and their country of location. China has the most capacity already built – including the 1.3GW Longyangxia hydropower plant on the Yellow River that stabilises the output curve of a 530MW solar PV plant.

Australia is another of the leading nations, with the 50MW Kennedy Energy Park complex (30MW of wind and 20MW of solar), the 100MW Emu Downs project (80MW of wind and 20MW of solar) and the 176MW Gullen Range configuration (166MW and 10MW) all financed and being built, and the 375MW Port Augusta project (206MW and 169MW) announced. Morocco's agency for sustainable energy, known as Masen, has plans for a combined PV and solar thermal project on 3,000 hectares near Midelt, with capacity of up to 830MW.

FIGURE 32. WIND, SOLAR POWER CO-LOCATED PROJECTS WITH OVER 10MW OF CAPACITY, MW



Source: Bloomberg New Energy Finance

Figure 32 shows a list of selected wind-solar hybrid projects, some of them already commissioned, some still under development, with the relative contribution of each technology to the overall capacity. In the majority of these cases, the dominant role is with the wind turbines, and the secondary role with the solar panels.

HYBRID ATTRACTIONS

Combining two or more power generation technologies at the same site is one way to reduce the intermittency of renewable energy and improve its competitiveness as the industry matures and becomes less dependent on subsidies.[30] The aim would be for hybrid projects to perform at a higher capacity factor than the 10-25% generally associated with PV or 20-35% with onshore wind, and to deliver a more consistent supply of power to the grid.[31]

Co-located, or hybrid, wind and solar projects are becoming more common due to the natural synergies of the sun and wind. In many temperate countries, wind speeds pick up at night and drop off in the day when solar irradiation is more plentiful. Seasonal variations can also support co-location. Winter in the northern hemisphere tends to bring stronger wind speeds, whereas summer heralds more sun. Therefore, combining wind and solar resources can strengthen a plant's overall generation profile to better match grid needs. Co-located wind and solar plants in southern Europe would generate power for more than 70% of the time, according to a study by the Massachusetts Institute of Technology.[32]

Vattenfall's Parc Cynog wind farm in Wales recorded a 10-percentage-point improvement in capacity factor after a 5MW solar PV array was added to complement the existing 8.4MW of wind turbines, according to Claus Wattendrup, director of business development at the Swedish utility. Meanwhile, Enel Green Power's 80MW Fontes dos Ventos wind park in Brazil shares a grid connection with the nearby 11MW solar park, resulting in more stable power production.

Hybrid projects may also offer the opportunity to reduce capital expenditure per MW, compared to building two separate units. Depending on the project in question, everything from the substation to the transmission line, grid connection, transformers, cabling and monitoring

[30] This chapter uses a wide definition of hybrid, to include technologies that share the same site, those that are adjacent and share grid connection and management, and those that are geographically close and are managed in tandem to increase or balance electricity generation.

[31] There are also a few hybrid renewable-fossil fuel generating plants around the world, for instance solar thermal and gas-fired generation. We have not covered these in this chapter.

[32] Characterisation of the Solar Power Resource in Europe and Assessing Benefits of Co-Location with Wind Power Installations by Cedric Bozonnat and C. Adam Schlosser.

systems can be shared between two or more technologies – reducing cost and improving project competitiveness. Developing a new-build hybrid project also allows developers to streamline development costs and environmental approvals.

Sharing the cost of operation and maintenance equipment and onsite staff could be advantageous – in some cases a single workforce can be used for cleaning, security and system monitoring. Total savings on capital expenditure for a co-located project are estimated at 3-13% and for operating expense 3-16%, according to a study completed by technical consultancy Aecom for the Australian Renewable Energy Agency (Arena).[33]

Developers of the 10MW Gullen Range solar farm near Canberra, Australia, saved an estimated AUD 6 million ($5 million) by placing solar panels adjacent to the 165MW wind farm, according to Arena. This equated to a 20% reduction for the project. In Wales, Vattenfall's Parc Cynog hybrid project achieved a cost reduction of 10% on project capex through sharing a grid connection, according to Vattenfall.

Where competitive tenders to procure power are technology-agnostic, hybrid power projects can be used as a lever to reduce costs, according to General Electric. Enel has said it intends to propose hybrid projects this year at auctions in Brazil, Mexico, the US and India. And in the Netherlands, Vattenfall intends to bid into a power auction with a proposed new solar plant integrated with an existing wind farm.

For auctions where developers bid to provide power during certain time periods, as is the case in Chile, proposing a hybrid project with a more consistent power profile could prove advantageous as it would cover more time blocks than a single technology alone. This may encourage the distribution companies that are contracting the power to look more favourably upon those particular projects.

A third benefit to aggregating power generation units at the same site is that higher overall production can be achieved. At a 13MW geothermal plant owned by Enel in Italy, commissioned in 2015, a biomass furnace increases the temperature of steam entering the power plant by more than half to as much as 380 degrees Centigrade, boosting efficiency. The 5MW biomass unit cost EUR 15 million, and it is designed to increase the geothermal plant's output by 30GWh per year.

Enel uses a similar logic at its Stillwater hybrid plant in Nevada, commissioned in 2016. There, three co-located technologies – 26MW of solar PV, 2MW of solar thermal and 33MW of geothermal – improve the efficiency of the overall plant. The heat produced by the solar thermal plant augments the input temperature of the geothermal unit, helping to deliver more production when thermal efficiency is at its lowest and during peak hours of demand.

An advantage of combining wind and solar power is being able to use the frequency converter in a wind turbine to turn direct current (DC) solar power into the alternating current (AC) needed to transport electricity on grid systems, according to wind energy developer, Mytrah Energy. This eliminates the need for additional solar inverters, which typically make up around 10% of the capex costs of a new solar plant, and also reduces the operations and maintenance costs on two sets of inverters.

At Tata Power's Whalvan hydro-electric dam near Mumbai, specially-designed solar panels float on the water surface and tap into the dam's underutilised transmission grid. They have been up and running for one year or more and have shown they can increase overall site capacity by 30%. The facility is designed so that the hydro power can run at full capacity during the monsoon season and solar can complement the rationed hydro-power when the rains dry up.

Almost all hydro-electric dams under a latitude of 40 degrees north could be suitably partnered with floating solar, and the potential scope in India alone is around 30GW, according to Sunengy, the Sydney-based floating solar developer that installed the Whalvan prototype.

[33] http://www.aecom.com/au/wp-content/uploads/2016/03/Wind-solar-Co-location-Study-Final.pdf

HYBRID CHALLENGES

In countries where policy support for larger-scale (above 5MW) onshore wind and solar PV has been withdrawn, such as the UK, it can be difficult to make the economics of a hybrid project add up. Vattenfall has identified a couple of wind projects in the UK where adding solar PV would be viable, but relying on wholesale power prices alone would not be sufficient, it says.

Another potential hurdle to overcome is arranging the appropriate land leases for a new solar farm. Many wind turbines are installed on agricultural land and have a relatively small footprint, whereas solar farms can spread more densely across the same acreage – making it a complex and expensive task to arrange permitting rights with the landowner. It is also important to ensure that wind turbines do not place solar panels in shade. Research by Reiner Lemoine Institut and Solarpraxis showed that production loss from shading is as low as 1-2% on average.

Although sharing grid connections can be a clever move in areas where these are in short supply, it can also mean that curtailment is needed at times when the technologies are generating power simultaneously. It was found that a solar farm sized at 25-50% of a wind farm's capacity would result in 5% total curtailment, in a study of 10 wind farms conducted by Arena. Advance analysis of the potential curtailment is therefore needed to determine the optimum size of the installations to be built.

Where the power assets making up a hybrid project are owned by different parties, it is also imperative to determine the dispatch priority were any curtailment to occur. It is often the preferred choice that any curtailment sits with the bottom line of the new solar project in the case of an existing wind plant.

Lack of familiarity with hybrid projects among equity and debt providers could also make it difficult to arrange non-recourse debt financing. Developers that have entered the sector so far – such as Enel and Vattenfall – have financed their projects on their balance sheets, but developers who require non-recourse debt financing could find this difficult to source, at least in the early stages of the market. "Co-located deals have different revenue streams, costs, maintenance and operating drivers. It's not always straightforward," said bank and asset manager Investec.

That said, for hybrid projects where a second technology is added to a site already hosting the first technology, environmental and meteorological studies for the location will have already been undertaken and community members approached. This may help with de-risking the project for investors.[34]

[34] An example would be adding solar PV to an existing wind farm, or to a hydro-electric reservoir. A greenfield project is where the two technologies are built together on a new site.

SOUTH ASIA

India is one step ahead in creating a policy framework to incentivise hybrid wind and solar projects. Strong monsoon winds blow from late afternoon to early morning during the summer, while the sun shines for around 300 days per year from early morning to around 6pm. The argument for wind and solar hybrid projects is therefore an appealing one, and the government aims to build 10GW of such plants by 2022.

India's Ministry for New and Renewable Energy has issued a guideline on how best to integrate wind and solar energy, and a handful of states have since produced draft policies, expected to be implemented in spring 2017.

Andhra Pradesh's policy proposes that new-build wind and solar hybrid projects either receive a feed-in tariff for all their output, or arrange a power purchase agreement, or PPA, with a private off-taker. These corporate PPAs are likely to drive the hybrid market in the near term because a commercial and industrial tariff is almost 20% higher than tariffs paid by the electricity grid.

Goldman Sachs-backed RenNew Power Ventures, together with Hero Future Energies and Greenko, are among Indian power producers interested in pursuing hybrids in the southern part of the country in order to supplement variable renewable power sources. About 70% of the 10GW of privately-owned wind generation in India would be suitable for adding solar to the mix, according to wind turbine maker Gamesa.

The company expects hybrid projects to make up 50-60% of its sales over the next three years. Suzlon Energy, an India-based turbine manufacturer, sees wind and solar hybrid plants as a "huge opportunity" due to "the complementary cycles of generation and the better utilisation of the installed infrastructure", according to a statement by Tulsi Tanti, its chairman, in the company's 2016 annual report. However, the opportunity will take one to two years to translate into commercial scale largely due to the fact that India still awaits a dedicated policy for hybrids, he said.

Pakistan, too, recognises the benefit of co-locating solar and wind projects, following the country's installation of more than 1GW of wind, solar and biomass resources in recent years. Pakistan's Alternative Energy Development Board "would encourage operators of wind power projects in Sindh to install at their site solar panels to generate additional megawatts of clean power on [a] more stable and reliable pattern", said Amjad Ali Awan, chief executive of the board in January 2017.

MICROGRIDS AND STORAGE

Complementing a hybrid renewable generation project with energy storage capacity can reduce curtailment, and allow excess power to be put aside and sold when power prices are higher. The business case for this improves when the difference between low-demand and peak power prices is substantial, because otherwise the cost to store the energy can outweigh the final payment.

Microgrids are particularly popular in remote areas like islands that are without access to a national electricity transmission network. The island of El Hierro in the Canary Islands, Spain has a 34MW microgrid, where energy is generated by wind turbines when wind resources are plentiful and otherwise by diesel. Any surplus electricity is used to pump water uphill and into an extinct volcanic crater where it is stored until finally released downhill to power hydro turbines. Wind and diesel power are also used in Antarctica on Ross Island, where the generation units are complemented by 0.5MW of flywheel energy storage. In the Portuguese Azores Islands in the Atlantic and Necker Island in the Caribbean, solar panels are added to a wind and battery storage mix.

Microgrids are also used by businesses, universities and military bases to provide reliability of power in case of grid defects, and sometimes to reduce the cost of power by replacing electricity from the grid at peak times of the day. For example, the University of Ontario in Canada has installed a 5MW microgrid, where solar PV, diesel and lithium-ion batteries work in tandem, while the US Army has a 2.6MW diesel, wind and flow battery microgrid at its military base in Hawaii.

Substantial cost reductions in solar PV and lithium-ion batteries are enabling clean energy microgrids to be built in less developed, remote regions that are otherwise devoid of electricity or dependent on expensive diesel generation. In Southeast Asia, the cost of generating electricity through a privately-owned diesel supply ranges from $0.25 to $0.90 per kWh for five to eight hours' use per day. Adding solar PV to the mix brings this cost down to $0.25-$0.45/kWh for 24/7 supply, according to microgrid developer WEnergy Global. The Singapore-based company said it secured financing in 2016 for its Sabang hybrid project in the Philippines that will consist of solar PV, diesel and batteries.

On Alaska's Kodiak Island, diesel power, energy storage and hydro stabilise the high penetration of variable wind power connected to the island's 79.2MW microgrid. And in Western Australia, plans are for the Carnegie Garden Island facility in Western Australia to combine 1MW of wave energy with 2MW of solar PV and battery storage. Developed by Carnegie Clean Energy and ABB, it is scheduled to be commissioned in 2017.

ASSET FINANCE

- Asset finance of new renewable energy projects (excluding large hydro) fell to $187.1 billion in 2016, some 21% less than the record reached in 2015, due to lower costs per MW in wind and solar, and a slowdown in two key regions, China and Latin America.
- Investments in utility-scale renewable energy are still dominated by wind and solar. The two leading sectors accounted for $175.7 billion, or 94% of the total, in 2016.
- Offshore wind was the star sub-sector in 2016, its record asset finance total of $30 billion including the go-ahead for the biggest project yet, the 1.2GW Hornsea array off the UK coast.
- China accounted for $37.6 billion of the $50.3 billion global decline, its asset finance total dropping 34% to $72.9 billion last year. The US and Europe held almost steady in 2016, at $29.8 billion and $46.9 billion respectively.
- The Americas excluding the US and Brazil saw asset finance fall by 55%, as Chile, Uruguay, Mexico and Canada all took a pause in their funding of new renewable energy capacity.

Asset finance of utility-scale renewable energy projects of more than 1MW totalled $187.1 billion in 2016, down 21% on the record figure of $237.4 billion reached in 2015.[35] These tallies exclude hydro-electric projects of more than 50MW – there is a box on large hydro at the end of this chapter.

The chart also shows a category of 'bond and other' financings, amounting to $6 billion, down 10% on 2015. This includes leasing, where the renewable energy equipment is owned by a bank and leased by the developer, and also a relatively small number of bond issues on behalf of new-build projects.

Figure 33 shows the main split within last year's $187.1 billion asset finance total. On-balance-sheet financing of projects by utilities and energy companies amounted to $94.7 billion, down 20% on the 2015 figure, while non-recourse project finance came to $86.4 billion, down 24%. The latter category consists typically of packages of equity and debt linked to the project vehicle, not to the corporate entity developing the project. In non-recourse deals, debt almost always makes up the majority of the finance for the project, and equity the minority.

FIGURE 33. ASSET FINANCE INVESTMENT IN RENEWABLE ENERGY BY TYPE OF SECURITY, 2004-2016, $BN

Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance

[35] The 2015 asset finance total has been revised up from the one shown in last year's Global Trends report, to reflect new information on projects reaching final investment decision.

More typically, bonds are used to refinance projects that started off being funded on balance sheet, rather than to provide the initial pot of money that enables them to proceed. Finally the 'bond/ other' category includes a number of deals where information is scarce and it has not been possible so far to allocate the financing either to on-balance-sheet or to non-recourse project finance.

The balance between the two main categories has varied from year to year, and there has not yet been a year in which non-recourse project finance has been larger in dollar terms than on-balance-sheet financing. Generally, though, the non-recourse element has tended to increase its share gradually: from 15% in 2004 and 26% in 2005, to a high of 48% in 2015. It slipped back to 46% of the total in 2016, but this may be a one-year blip rather than a change of trend.

The period shown in the chart has been one in which wind and solar technologies have come down sharply in price, and also established long track records of generation. That has enabled banks, in particular, to get comfortable with the risks of lending to projects, and has tended to boost the amount of non-recourse finance available.

REGIONS

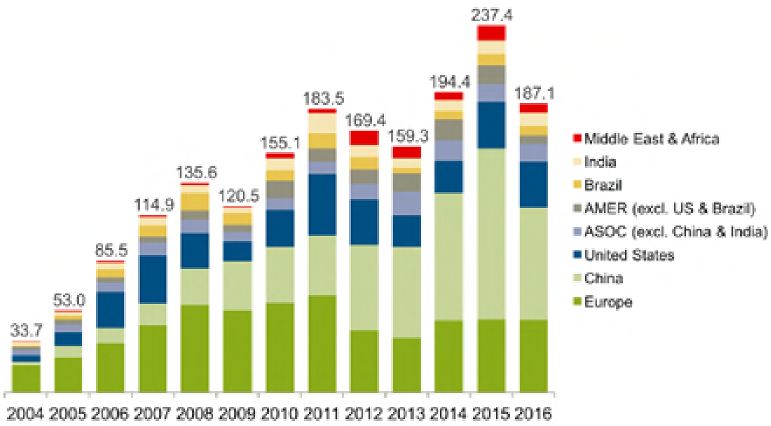
Asset finance of renewable energy projects continued in 2016 to rely heavily on China, which accounted for 39% of the global total,[36] against 25% for Europe and 16% for the US. However, the Chinese contribution was well down compared to 2015, both in money terms (at $72.9 billion, down from $110.5 billion) and as a proportion of the world total (it was 47% of the global figure in 2015).

Among the big-ticket Chinese projects financed in 2016 were four offshore wind farms, each of between 252MW and 302MW, with estimated capital costs in the $648 million to $810 million range. In solar, the 300MW Jiangsu Dison Silink Wuzhong Hongsipu Agricultural PV plant raised $506 million, and in onshore wind, the 300MW SDIC Hami Jingxia Number 5 project took an estimated $465 million.

Figure 34 shows the regional profile for asset finance over the years. Europe was the second most important region in 2016, contributing $46.9 billion, just 1% down on 2015. Ten of the largest 11 projects financed in Europe in dollar

[36] Bloomberg New Energy Finance's New Energy Outlook, or NEO, for 2016 puts all hydro at 16% of world electricity generation. Taking small hydro projects off this figure would leave large hydro at 13-14%.

FIGURE 34. ASSET FINANCE INVESTMENT IN RENEWABLE ENERGY BY REGION, 2004-2016, $BN



Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

terms in 2016 were in offshore wind, which saw a 53% surge in final investment decisions to $25.9 billion (see next section). Solar asset finance in Europe slumped 75% to $1.6 billion, while the equivalent for onshore wind retreated 26% to $14.8 billion and that for biomass and waste rose 14% to $3.9 billion.

The US came third among the regions last year, accounting for $29.8 billion, down 2% on the previous 12 months. Wind asset finance in the US rose 5% to $14.7 billion, while solar attracted the same dollar figure, but this was 6% down on 2015. Out of the top 14 projects financed in 2016, 12 were in onshore wind and two in solar. Congress' vote in December 2015 to extend the key tax credits for wind and solar for five years was a morale-booster for the two sectors rather than the trigger for a short-term boom in 2016.

Among the other regions shown in the chart, India saw a 4% slip in asset finance in 2016 to $8.4 billion, and Brazil a 17% setback to $6.1 billion. A highlight in India was the construction of the Ramanathapuram solar complex in Tamil Nadu, billed as the world's largest ever PV project at some 648MW. This is treated as several distinct projects in the investment data in this report, different stages representing anywhere between 10MW and 256MW, and financed partly in 2015 and partly in 2016. Brazil's asset finance last year was led by $486 million for the 333MW Copel Cutia wind portfolio.

The Other Americas region – excluding the US and Brazil – suffered a 55% knockback in asset finance to $5.5 billion, with sharp reductions in funding activity for projects in Mexico, Chile, Uruguay and Canada (see discussion in Chapter 1 on the impact of the timing of auction rounds). Mexico was down 80% at $443 million, Chile down 79% at $829 million, Uruguay 73% lower at $454 million and Canada down 56% at $1.3 billion. There was growth in asset finance in a few other countries, such as Bolivia, Argentina and Peru, but from a small base in the previous year. Bolivia saw the most asset finance of these three, at $777 million, up from zero in 2015, mainly thanks to the financing of the 100MW ENDE Laguna Colorado geothermal undertaking.

The Middle East and Africa region saw asset finance fall 36% to $6 billion, with South Africa accounting for most of that reduction (down 76% at $894 million, due to a gap in its auction schedule). Morocco was another to endure a slow year in 2016, its funding of renewable energy projects dropping 69% to $660 million, but there were increases elsewhere – Israel up 254% at $948 million, Kenya up 41% at $648 million, Egypt up from almost nothing to $745 million and Jordan 163% higher at $1.1 billion. Smaller renewable energy markets such as these are likely to be more volatile year-to-year because of the timing of financial close for particular, big projects.

The Asia-Oceania region excluding China and India was much steadier, its asset finance total edging up just 1% to $11.4 billion. Japan was the biggest single feature in that, accounting for $4.4 billion, down 4%. There were year-on-year increases for Australia, up 127% at $2 billion; Thailand, up 13% at $1.4 billion; Vietnam, up 144% at $682 million; and Singapore, up nearly sevenfold at $551 million.

The Philippines saw asset finance slip 47% to $1 billion, while Pakistan experienced a steep reversal, down 80% at $288 million. However, that country's 2015 asset finance figure has been revised sharply upwards since last year's Global Trends report – so the two-year total of $1.7 billion actually looks impressive compared to earlier periods.

Figure 35 lists the top 10 countries in the world for renewable energy asset finance. It shows that the global picture remained highly lopsided in 2016, with just three countries reaching double figures in terms of dollar commitments – China with $72.9 billion, down 34%, the US with $29.8 billion, down 2%, and the UK with $22.5 billion, up 2%.

There is then a group of nations in the several-billion-dollars category for 2016, led by India and Germany, with Brazil and Japan. Next is a handful of developed economies – Belgium, Denmark, Norway, Australia and France – all near to or above the $2 billion mark. Only after that did last year start to show some of the 'up-and-coming' medium-sized emerging markets for renewables, such as Turkey, Jordan, the Philippines, South Africa, Bolivia, Chile and Egypt. The reasons why asset finance paused in several of these promising markets in 2016 are explored in Chapter 1.

Some striking contrasts can be seen at the sectoral and sub-sectoral levels in Figures 36 and 37. In the first chart, the dominance of wind and solar is clear in the money invested in utility-scale renewable energy. Out of $187.1 billion total asset finance in 2016, the two leading sectors accounted for $175.7 billion, or 94%.

Wind saw $107.9 billion of asset finance committed last year, down 12% on the previous year. However, as Figure 37 highlights, there was a huge contrast at the sub-sector level. Investment in new onshore wind capacity worldwide fell 23% to $77.9 billion, its lowest since 2013. But investment in new offshore wind arrays jumped 41% to $30 billion, the highest ever and twice the figure for just two years before. Offshore wind accounted for 16% of global renewable energy asset finance in 2016, up from 9% in 2015.

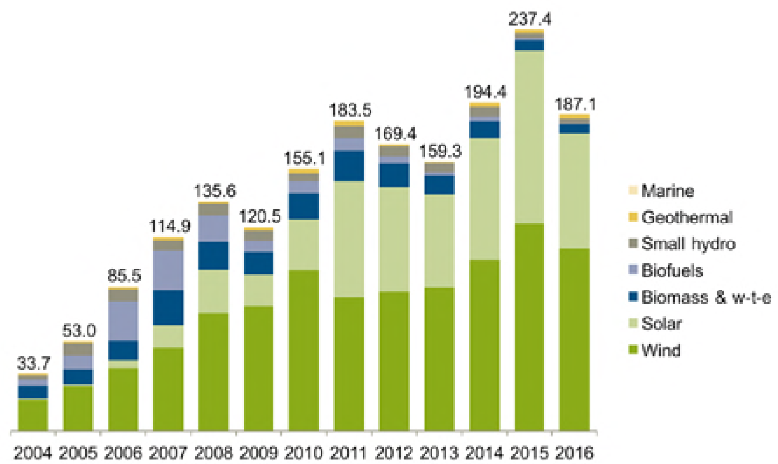
The biggest onshore wind project financed by far last year was the 1GW Fosen complex in Norway, at $1.3 billion. The equity for Fosen will be funded by developer Statkraft, utility Troenderenergi and Nordic Wind Power, a company backed by Credit Suisse, one German insurer and three German and Finnish pension funds. The debt comes from Swedish lender SEB, covered by Danish export credit house EKF.

FIGURE 35. ASSET FINANCE BY TOP 10 COUNTRY, 2016, AND CHANGE ON 2015, $BN

	2016	% growth on 2015
China	72.9	-34%
United States	29.8	-2%
United Kingdom	22.5	2%
India	8.4	-4%
Germany	8.4	-34%
Brazil	6.1	-17%
Japan	4.4	-4%
Belgium	2.7	196%
Denmark	2.4	190%
Norway	2.1	8761%

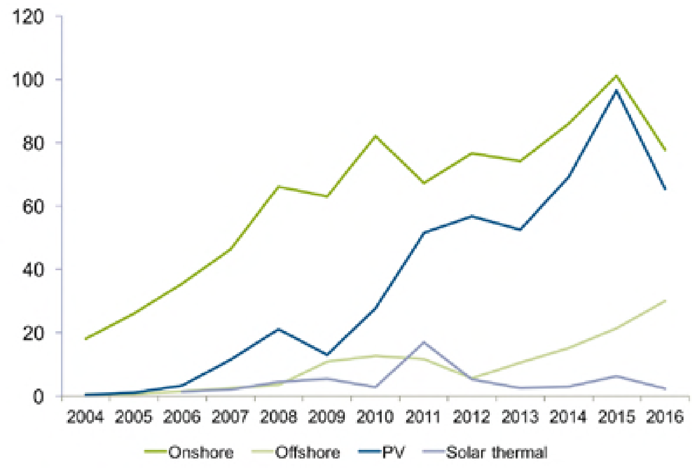
Top 10 countries. Total values include estimates for undisclosed deals
Source: UN Environment, Bloomberg New Energy Finance

FIGURE 36. ASSET FINANCE INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2004-2016, $BN



Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

FIGURE 37. ASSET FINANCE OF WIND AND SOLAR PROJECTS WORLDWIDE, BY SUB-SECTOR, 2004-2016, $BN



Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

Solar asset finance fell 34% in 2016 to $67.8 billion, its lowest figure since 2013. However, a record number of gigawatts of new PV capacity were added globally last year, so the main reason for the decline was lower unit costs in that technology, as noted in the Executive Summary of this report. Within the solar sector, funding of utility-scale PV projects slipped by 32% to $65.5 billion while financing of solar thermal, or CSP, plants fell 64% to $2.3 billion.

Solar thermal has failed to keep up with the steep cost reductions achieved in PV and, for that reason, has been pushed to the fringes in terms of global project development. There were just three significant ones getting the go-ahead last year: the 110MW Ashalim II Sun Negev complex in Israel, at $805 million, the GDF Suez Kathu plant in South Africa, at $756 million for 100MW, and the PowerChina Northwest Hami project in China, at an estimated $227 million for 50MW. The first two will use parabolic trough technology, the last is a solar tower.

Three US onshore wind financings are estimated to have broken the $500 million barrier last year – the 400MW Enel Cimarron Bend project in Kansas, the 324MW Pattern Broadview plant in New Mexico, and the 278MW E.ON Twin Forks installation in Illinois.

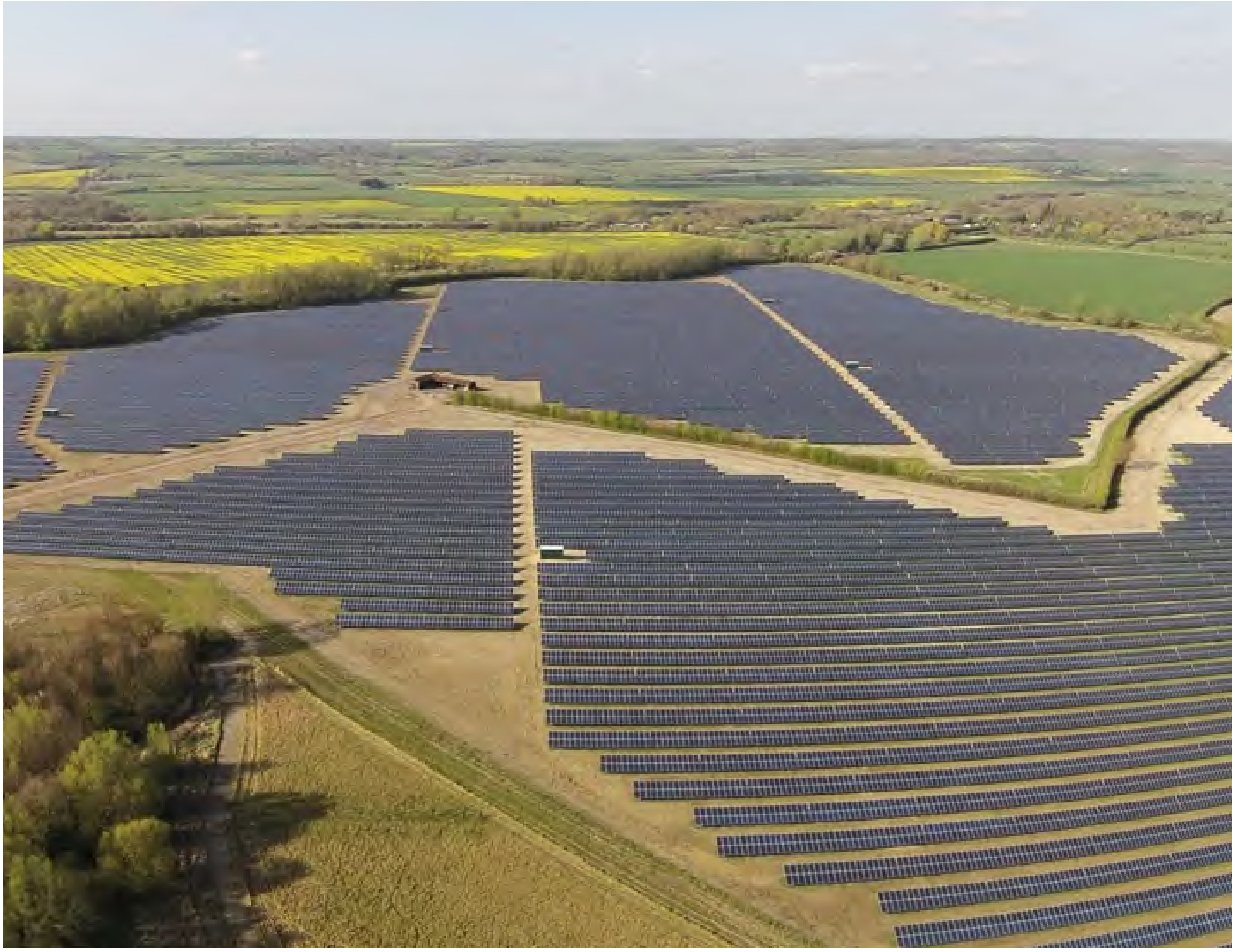
However, the offshore wind deals of 2016 were much larger. The 1.2GW Hornsea array off the coast of England, at an estimated $5.7 billion, will be the largest single project investment ever in renewable energy (outside large hydro). Financed initially on-balance-sheet by developer Dong Energy, Hornsea is due to be completed in 2020.

There were 13 other offshore wind financings in 2016 that fitted into a range between $500 million and $3.9 billion, led by two other giant UK projects (588MW Beatrice Cape and 714MW East Anglia One). Also included in the 13 were three large German arrays, two in Belgium, one more in the UK and four in China. The largest of the Chinese undertakings was the 300MW Hebei Construction Laoting plant, at an estimated $810 million. Many of the offshore wind projects will use turbines of a size hardly imagined a decade ago: East Anglia One, for instance, will use 102 machines of 7MW each, while Germany's 396MW Borkum Riffgrund will use turbines of just over 8MW each.

In PV, the average ticket size was smaller but there were far more projects reaching financial close. Among the biggest were the 31 Dominion SBL portfolio in the US, at an estimated $702 million for 580MW, and the 300MW Jiangsu Dison Silink Wuzhong Hongsipu Agricultural project, at $506 million.

The only sector to see an increase in asset finance in 2016 was geothermal, with a 14% rise to $2.5 billion. The level of investment in new geothermal capacity worldwide has been relatively consistent over the last eight years, averaging $2.2 billion, so last year's total is unlikely to mark any new trend.

The largest geothermal plants reaching financial close in 2016 were the ENDE Laguna Colorada project in Bolivia, at 100MW and $612 million, and the KenGen Olkaria V undertaking in Kenya, at 140MW and $403 million. Japan was



instrumental in the financing of both these projects, its government agreeing a credit line for the Bolivian installation and the Japan International Cooperation Agency signing a loan deal with KenGen for the latter. There were also $100 million-plus projects financed in Turkey, Iceland and Honduras.

Small hydro projects (greater than 1MW and less than 50MW) attracted $2.9 billion of asset finance in 2016, down 7% from the previous year. This sector has been on a gradual declining trend in terms of new investment since it peaked at $7.3 billion in 2005. One reason is that many of the best opportunities for building small hydro plants have now been exploited. Nevertheless, the Chinese market remains active and, elsewhere, there were significant projects reaching financing close, including the 39MW LG International Hasang dam in Indonesia, at $148 million, and the 30MW Androscoggin River plant in the US, at $62 million.

A much more dramatic shrinkage has affected the biofuels sector in recent years. It was the second-biggest sector of renewables after wind during the 2006-07 period, but asset finance of new fuel production plants has since slumped – from more than $23 billion in each of those two years, to just $272 million in 2016. Last year's figure was 73% down on 2015. The largest biofuels asset financing of 2016 was the Fiagril Lucas Do Rio Verde ethanol installation in Brazil, at $115 million.

Biofuels have retreated into insignificance as an area for new investment for three main reasons. The first is that the few countries with mandates for particular levels of biofuel use in the vehicle fuel system, such as the US and Brazil, already have sufficient capacity to meet these. Second, hopes for a boom in second-generation biofuels, using non-food plant matter, have never been realised, largely due to high costs. Third, biofuels have come to be seen in many countries as a less effective way of reducing transport emissions

than the shift to electric cars. However, there are areas of continuing interest, including biofuels for aviation.

Marine energy saw almost no asset finance in 2016, but the potential remains for it to feature in some significant projects in the future. Last year, construction continued on demonstration tidal stream projects off the north coast of Scotland, off Brittany and in the Bay of Fundy off Nova Scotia, and efforts were underway to finance larger projects in UK, Irish and French waters.

There was also political debate in the UK over the proposed 320MW lagoon at Swansea Bay, and there are a number of other tidal range projects in development in the same country. The wave sector remained well behind tidal stream and tidal range in terms of project development in 2016, after a series of company failures in the preceding years.

The biomass and waste-to-energy sector remained a firm third behind wind and solar in 2016 in terms of global asset finance, although its total of $5.7 billion was down 2% on 2015 and far below the peak figure of $20.6 billion reached in 2007.

Developed countries dominated the financing of biomass and waste installations in 2016. The largest projects to get the go-ahead were the 299MW Tees pellet and woodchip burning plant in the north of England, at $841 million, and the 150MW Amagervaerket woodchip combined-heat-and-power installation in Copenhagen, at $739 million. In waste-to-energy, the biggest financing was $548 million, for the 120MW Hyflux & Mitsubishi Tuas incinerator in Singapore.

LARGE HYDRO-ELECTRIC PROJECTS

Large hydro is an important contributor to electricity generation, making up 13-14% of the global total, thanks to projects built any time from early in the Twentieth Century through to the recent spurt in development, led by China. However, it is not included in the main figures in this report. One reason for this is that there are sustainability or geopolitical concerns over some (but certainly not all) large hydro projects. Another is that it is difficult to measure large hydro investment with the same accuracy as that in other renewable energy sectors because of the very long timescales involved – sometimes 10 years or more from start of construction to commissioning – and the risks of substantial delay.

Some organisations estimate large hydro investment by taking the amount of new capacity commissioned each year and then multiplying that by historical cost figures for those projects. This approach is adopted by, among others, the International Energy Agency in its World Energy Outlook and by the Chinese government.

That is a very different methodology from the one used by Bloomberg New Energy Finance for the figures used in this report. The BNEF database counts asset finance dollars at the moment the 'final investment decision' is made for the project, in other words just ahead of the start of main construction. This gives a forward-looking view on activity in clean energy. Doing the same for large hydro is challenging, given the tendency of many developers to begin early construction activity at the location for a dam, years before the financing package is finalised.

With that proviso, BNEF estimates that large hydro-electric projects of more than 50MW attracted $23.2 billion of final investment decisions in 2016, down 48% from the 2015 total of $44.9 billion. The lower figure last year reflected a lull in underlying activity (reported also by the big hydro-electric turbine manufacturers), and the absence of a mega-project to compete with 2015's go-ahead for the 10.2GW, $15.3 billion Wudongde dam in China.

Nevertheless, even a shrunken 2016 asset finance total of $23.2 billion would put large hydro far above the other renewable energy sectors in investment terms, other than wind and solar, as Figure 8 in the Executive Summary shows. The $23.2 billion represented the funding for 12.6GW of large hydro capacity, compared to 27.1GW financed in 2015.

Topping the list of biggest hydro projects financed last year was the 2.2GW Caculo Cabaca dam in Angola, at an estimated $4.5 billion. In December 2016, a consortium of lenders led by Industrial and Commercial Bank of China agreed to provide $4.1 billion to the country's Ministry of Energy and Water to meet the lion's share of capital costs. Also prominent was the go-ahead last April for the 1.2GW Suwalong dam on the Jinsha River in China, developed by China Huadian Corporation. And in October 2016, the 670MW Nam Theun 1 project in Laos reached a key milestone, with the award of its electromechanical equipment contract to Andritz.

The international Hydropower Association estimated in March this year that global hydro capacity, including projects of less than 50MW and pumped storage plants, reached almost 1.25TW at the end of 2016.[37]

[37] IHA: 2017 Key Trends in Hydropower.

SMALL DISTRIBUTED CAPACITY

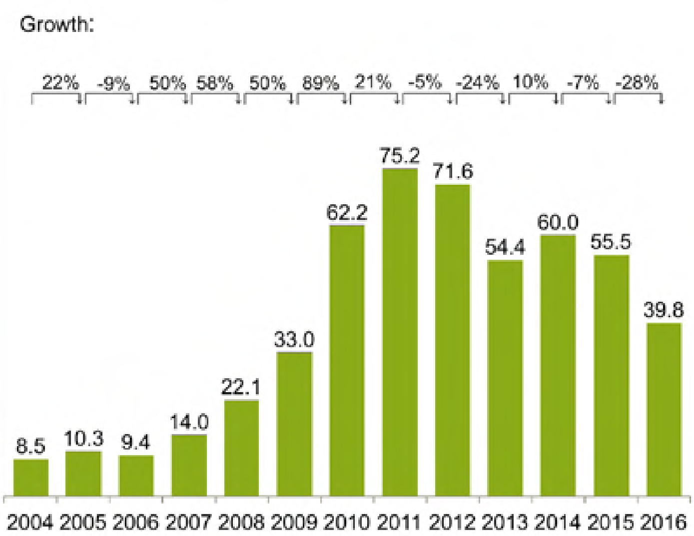
- Investment in small-scale renewable power projects of less than 1MW declined 28% in 2016. A total of $39.8 billion was channelled into predominantly solar PV systems of less than 1MW.
- The price of small-scale solar systems fell in many countries. Despite growing demand, the market will remain oversupplied in 2017, potentially leading to further price declines.
- The US took the top investment spot with $13.1 billion, followed by Japan with $8.5 billion (down from $27.1 billion in 2015) and China on $3.5 billion.
- India's small-scale solar sector looks set for lift-off, driven by the government's ambitious target to install 40GW of rooftop solar by 2022.

Investment in small-scale renewable power projects sank to its lowest level since the start of the decade. A total of $39.8 billion was channelled into predominantly rooftop and small ground-mounted solar PV systems of less than 1MW in 2016. This was a decline of 28% on the previous year's $55.5 billion and well below the totals recorded during the peak of the German and Italian PV booms in 2011 and 2012. Figure 38 sets out Bloomberg New Energy Finance annual small-scale investment data back to 2004.

Less money was available in 2016, but this did not derail the sector's development efforts. Indeed, PV installers added around 20GW of new residential and commercial capacity, about the same volume as in 2015. This was partly thanks to lower PV system costs in certain key markets, which enabled developers to build out more capacity for the same money. For instance, US PV installers SolarCity, SunRun and Vivint all dropped their prices in 2016, while in Australia and Germany they remained largely constant. For a recent history of residential PV system costs, see Figure 39.

Panel prices fell further than expected in 2016 thanks to fierce competition among component manufacturers, technological advances and a supply glut that intensified with a cooling in the Chinese solar boom in the second half of the year. By the end of November 2016, Chinese crystalline silicon PV module prices had fallen by an average of 13% since the start of the year, while those made in Germany were down 15%, according to data published by Pvxchange. A further 20%

FIGURE 38. SMALL DISTRIBUTED CAPACITY INVESTMENT, 2004-2016, $BN



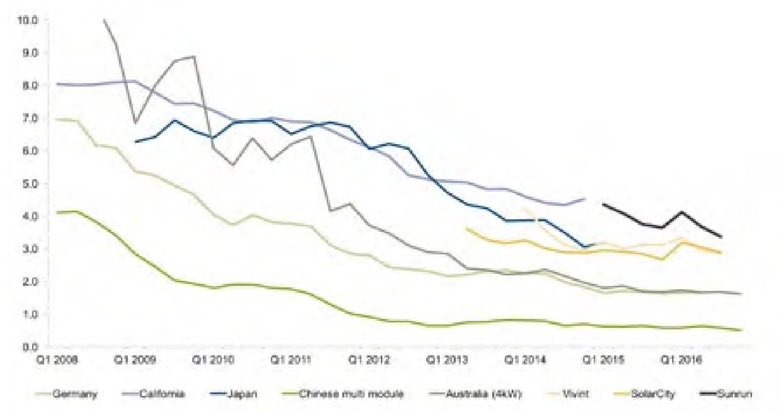
Represents investments in solar PV projects with capacity below 1MW
Source: Bloomberg New Energy Finance

decline is forecast for 2017 as the market for modules is unlikely to absorb the current 10-20% manufacturing overhang.[38]

As well as priming the pumps for PV in well-off countries such as the US and Australia, falling prices have put solar technology within reach of many more households and small businesses in developing economies. Exports of PV modules and cells from China to emerging countries and island nations reached $3 billion in the first nine months of 2016, representing a 20% increase over the same period in 2015. This is equivalent to an estimated 6.8GW of PV modules. See the next section for further discussion of recent growth of small-scale PV in emerging markets.

Harder to predict and perhaps more important than the direction of near-term PV system prices is the plethora of national and regional policies and regulations that can either set a solar boom in motion, or cause it to crumple. For instance, Japan's rampant small-scale PV sector attracted

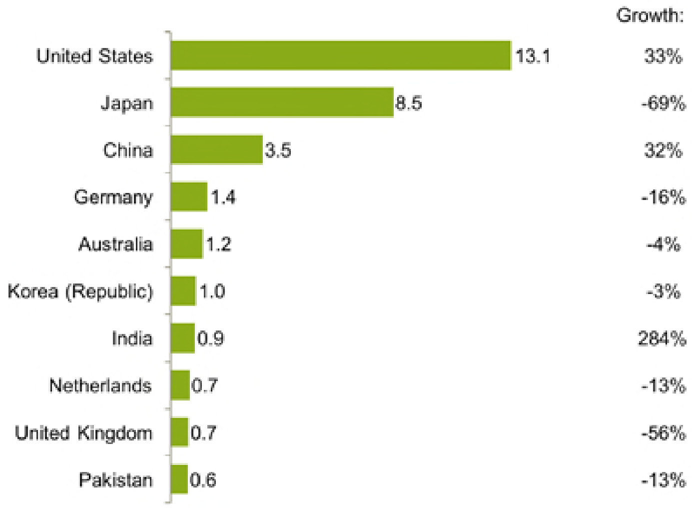
FIGURE 39. PUBLIC CAPEX BENCHMARKS FOR RESIDENTIAL PV SYSTEMS, $/W



Source: Bloomberg New Energy Finance

[38] This data is drawn from Bloomberg New Energy Finance research, December 2016 PV Supply Monthly Update, published on 9 January 2017.

FIGURE 40. SMALL DISTRIBUTED CAPACITY INVESTMENT BY COUNTRY, 2016, AND GROWTH ON 2015, $BN



Top 10 countries. Represents investments in solar PV projects with capacity below 1MW
Source: Bloomberg New Energy Finance

a very substantial $27.1 billion of investment in 2015, but has since come off the boil as lower feed-in tariffs put the brakes on growth. Investment in new small-scale capacity in that country shrank to just $8.5 billion in 2016, behind the US on $13.1 billion, but well ahead of its nearest rival, China, on $3.5 billion.

Japan's decision to slow growth by cutting subsidies is clearly working and it now seems unlikely that the market will return to the peaks seen in 2015. The rate of installation fell to 5GW in 2016 from 6.9GW in 2015, while a further tariff reduction, due to take effect in fiscal 2017, is forecast to contain growth at between 3.2GW and 3.6GW in the current year. Between July 2012, when the solar feed-in tariff was introduced, and the end of September 2016, a total of 20.5GW of small-scale PV had been commissioned, almost half of which was between 10kW and 50kW in size.

As illustrated by Figure 40, the US toppled Japan from the top investment spot in 2016. A total of $13.1 billion was spent on small-scale PV, up from $9.8 billion the previous year. The US market had a much higher mix of relatively expensive residential solar in 2016 than in Japan, where commercial installations dominated. This is a key reason why America's investment total was higher than Japan's, even though the amount of capacity added was lower, at 3.4GW.

The US solar market faces uncertainty, not least because President Donald Trump has made it plain that he is sceptical about the science behind anthropogenic climate change and intends to withdraw the US from the Paris Climate Change Agreement. It is thought that his administration is unlikely to try to repeal the ITC, which is set to run at its current 30% rate until 2020 and then decline to 10% in 2022. There is also a possibility the new government will seek to erect additional trade barriers against Asian solar companies, or tighten the current trade barriers to exclude modules made in factories set up in south-east Asia to dodge them. If so, that might raise the cost of solar systems in the US.

Development was curtailed in the southwest of the country in 2016 as net metering programmes in the states of Arizona and Nevada were scrapped (although the latter reinstated its scheme for existing solar customers in early 2017). In addition, small-scale solar in California is being constrained by a 5% net metering cap on municipal utilities. Developers are therefore seeking out and expanding into new markets elsewhere – 18 states experienced greater than 100% growth in residential PV additions over the first nine months of 2016, with growth highest across the Eastern seaboard.

Falling prices are changing the face of the US residential solar market. Smaller, local installers offering new loan products are eroding the hegemony built up by a handful of established players over the last few years. The financing services these big companies offer, such as complex third-party power purchase agreements, are no longer the necessity they once were, while proliferation of the technology and greater standardisation has broadened the pool of capable solar engineers. In the final quarter of 2016, the market share of the country's three largest installers (SolarCity, Vivint and Sunun) fell to 32%, having been 45% during the same period the previous year.

China's solar market as a whole may stand head and shoulders above the rest of the world – 34.2GW of new capacity was added to the grid in 2016, almost three times the 12.4GW added in the US – but in terms of recent investment in small-scale projects, the $3.5 billion committed to sub-1MW plants in 2016 trailed behind volumes recorded in the US and Japan. Nevertheless, this total represented an improvement on the $2.7 billion seen in 2015, and is likely to be the first of many such increases thanks to the launch of the PV for Poverty Alleviation (PVPA) campaign in October 2016.

As part of China's goal to eliminate poverty by 2020 (the closing year of the 13th Five-Year-Plan), the PVPA has approved 2.18GW of small-scale user-owned capacity in 14 provinces. It also approved almost 3GW of larger developer-owned projects, which together with the user-owned capacity will benefit 555,000 poor households. Over the next two to three years, a further 10GW are expected to be approved, a higher share of which will go to user-owned projects, according to statements from the National Energy Administration.

In another important development, the NEA said in 2016 that rooftop PV is no longer part of the quota system and can therefore qualify for subsidies once connected to the grid.

Neighbouring India's small-scale solar sector is about to take off. Investment in 2016 grew by almost 300% to $928 million, a trajectory that will need to be maintained if the country is to meet its ambitious target to install 40GW of rooftop solar by 2022. Given that sub-1MW solar capacity stood at just 500MW in April 2016, a compound annual growth rate of 108% is required over the next six years to meet the target.

Most of the growth so far has come from commercial and industrial customers, although some residential installations are also taking place. Several states have recently introduced net-metering regimes and are supporting the roll-out of projects. These measures are likely to carry the market forward in the immediate future, as will favourable economics due to high power tariffs and cash availability. However, the sector will need almost $50 billion of capital if it is to meet the 40GW goal.

India's market for small solar home systems (of less than 100W) and lanterns has also seen impressive growth. Over the last four years, sales of such items saw a compound annual growth rate of 47%, with some 2.3 million units sold in financial year 2016. Historically, this market has been supported by government subsidies and the efforts of non-government organisations. However, new business-driven distribution models are starting to look promising, and pay-as-you-go mechanisms, growth in the range of financing options and the penetration of retail banking should offer support for future growth.

Around the world in 2016, there were thousands of examples of sub-1MW PV projects going ahead that made an impression on their local communities. Here are just a very few, all well into three figures in terms of kilowatts of capacity. In December, Sacramento Kings' NBA basketball club completed the installation of a 700kW solar array on top of its Golden 1 Center arena. In the same month, Merino Panel Products installed a 550kW project in Jhajjar, India. In November, Expo Freight opened a 651kW system in Wellampitiya, Sri Lanka, that country's second largest rooftop solar plant. In October, St Scholasticas Academy-Markinia private school in the Philippines switched on a 204kW rooftop PV system.

NASCENT MARKETS

Declines in the cost of equipment, most notably solar panels, along with innovative business and financing models are transforming access to energy in some of the world's least developed nations. No less than 1.2 billion people lack sufficient access to energy, and several hundred million more are subject to frequent power outages.

Over the past five years, the market for basic solar-powered lights and small home systems with multiple lights, phone charging and basic appliances has grown rapidly, with more than 24 million units sold. This has seen the rise of pay-as-you-go solar companies such as M-Kopa, Off-Grid Electric, d.Light, Bboxx, Nova Lumos and Mobisol. Together they have raised more than $360 million in capital and serve about 700,000 customers, a small fraction of the addressable market in East and West Africa.

The world of small-scale clean energy project development in emerging economies is naturally opaque and therefore hard to quantify. However, analysis of Chinese customs data offers some useful insights. For instance, in the first nine months of 2016, PV modules and cells equivalent to 6.8GW were exported from China to emerging economies. But just 4.1GW of utility-scale capacity was installed in those same countries in 2016.

While this does not constitute evidence for the size of the small-scale market, it does allow for an indicative assessment. Bloomberg New Energy Finance estimates that the market for Chinese small-scale PV in emerging economies between January 2015 and the end of 2016 was approximately 1.4-2GW, after adjusting for anomalies such as shipments that may have transited through emerging countries or large-scale projects undergoing long construction cycles.

Countries such as Pakistan and Nigeria with their large populations and unreliable grid power supply are among the largest markets for small-scale solar in the developing world. Bangladesh, Myanmar, Ghana and the Dominican Republic imported significantly more PV modules than required by their known project pipeline. West Africa also appears to be particularly fertile ground for small-scale solar activity.

And there is activity in East Africa too. Off-grid solar start-up Bboxx sells about 200 small-scale systems per day. These come with a 50W roof-mounted solar panel and a lead-acid battery, phone chargers and LED lights. The company closed a $20 million Series C venture capital funding round in August 2016, led by French energy giant Engie. The company has 36 retail outlets in Kenya and Rwanda, but hopes to scale up to 400 retail shops in the next two years.

PUBLIC MARKETS

- A total of $6.3 billion was raised by clean energy companies on global public markets in 2016, a 53% decline compared with 2015 and 60% down on 2014.
- Funds raised via initial public offerings increased by 12% to $2.6 billion. However, this increase was entirely thanks to Innogy's $2.2 billion stock market debut.
- US yieldcos were much less active than in 2015 and no new funds were launched. Falls in yieldco share prices and the collapse of SunEdison sent shockwaves through the sector, but some US yieldcos and UK quoted project funds managed to raise new equity last year.
- Overall, solar companies and funds raised $1.7 billion, less than one-fifth of the previous year's total, while those focused on wind garnered $4.2 billion.

Fundraising by renewable energy companies on the world's public markets fell sharply in 2016. Together they notched up sale proceeds of $6.3 billion last year, which was 53% less than the $13.3 billion raised in 2015 and 60% down on the peak of $15.9 billion achieved in 2014. This was lower than at any time since 2005, except for 2012 when only $4 billion was raised. Figure 41 shows the volume of investment raised on the public markets since 2004.

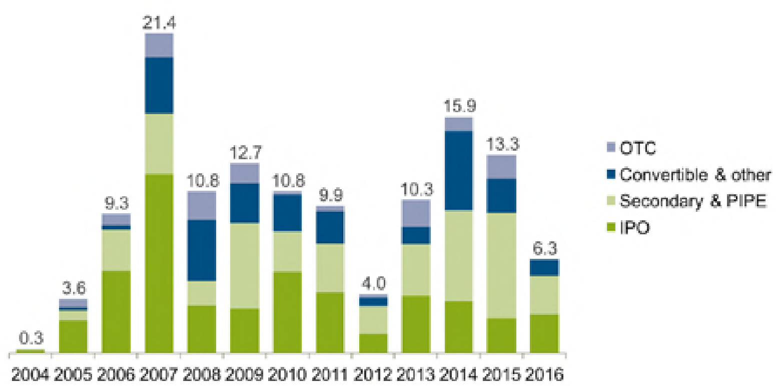
The recent decline in fundraising on the public markets chiefly reflects the bursting of the US 'yieldco' bubble in late summer 2015. In the preceding a year and a half, investors poured some $12 billion into these quoted renewable asset vehicles, and their closely related cousins, the European quoted project funds.

YIELDCO HANGOVER

Investor enthusiasm abated suddenly in the months after July 2015 when it became clear that US yieldcos' growth projections were unrealistic. Their shares fell by an average of 40% and it became almost impossible for them to issue fresh equity.

Yieldcos returned to the market in early 2016, but fundraising was more modest than previously. NextEra Energy Partners, 8Point3 Energy Partners and Pattern Energy Group raised a combined total of slightly more than $1 billion in new equity last year, while the six London-listed quoted project funds raised about $700 million. Although considerable, this level of fundraising pales in comparison with the total of $7 billion of new equity secured by these entities in 2015.

FIGURE 41. PUBLIC MARKET NEW INVESTMENT IN RENEWABLE ENERGY BY STAGE, 2004-2016, $BN



PIPE = private investment in public equity, OTC = over-the-counter
Bloomberg New Energy Finance, UN Environment

Overindulgence on yieldcos in 2015 may have given investors a hangover in 2016, but it did not completely extinguish investor appetite for the renewable energy sector. Funds raised via initial public offerings (IPOs) increased by 12% to $2.6 billion. However, this was thanks to a single very substantial debut offering – in early October, Innogy, the renewable energy arm of German utility RWE, raised $2.2 billion from the sale of a 10% stake on the Deutsche Börse. A further 15% was sold for $2.9 billion by existing investors, making it Europe's biggest IPO since Glencore in 2011.

The IPO is part of a major restructuring by RWE in response to an energy policy that favours renewables over fossil fuels and nuclear. Wind and solar are suppressing wholesale power prices and squeezing coal and natural gas out of the market. Utilities such as RWE and rival E.ON are adapting by separating traditional and renewable power generating operations – the former carved out its green business as Innogy, while E.ON placed its conventional generation assets into a new company, Uniper, which listed in Frankfurt in September last year.

Earlier in the year, investors proclaimed their enthusiasm for the sector when they snapped up shares in Dong Energy, the world's largest offshore wind farm operator. The Danish group, which also runs the country's largest utility and retains a small oil and gas business, has repositioned itself as a green energy company in recent years. The listing on the Copenhagen Stock Exchange enabled existing shareholders — including the Danish government and Goldman Sachs — to sell 20% of the company for slightly more than $3 billion. No fresh capital was raised.

The Innogy and Dong deals prove that there was investor appetite for certain blue chip clean energy companies in 2016. However, the wider picture reveals a more hesitant sector.

German wind turbine maker Senvion, for instance, dropped plans for a very substantial initial public offering early last year. The company's owners, New York-based private equity firm Centerbridge Partners, had intended to raise as much as $780 million from its listing in Frankfurt, but changed its mind, citing "a background of recent market volatility". Centerbridge bought the company from Indian wind turbine maker Suzlon Energy in 2015. Later, in March, it came back with a more modest plan, selling $278.1 million of shares in an IPO but not raising any fresh equity.

Other than Innogy, Dong and Senvion, just six companies went ahead with IPOs, raising a total of $271 million in new money between them. The next largest IPO was by China Jinjiang Environment Holding, a China-based waste-to-energy project developer, which raised $138 million on the Singapore Stock Exchange. Another Asian company, India-based Azure Power Global, raised $40.4 million when it floated on the New York Stock Exchange in October. The stock was priced below its marketed range and fell on the first day of trading.

US company TPI Composites, a manufacturer of composite wind turbine blades, also got off to a disappointing start. It raised $79.1 million in new equity on the Nasdaq Global market in July. However, immediately prior to its launch, the company lowered the price of its IPO to $11 per share from an expected range of $15 to $17, and cut the size of its offering by one million shares to 6.3 million. Despite such an inauspicious beginning, the company's shares have since risen – as of late January this year, they were up 38% on the IPO price.

CLEAN ENERGY SHARES

Uncertainty and volatility characterised the performance of clean energy share prices on global markets. The WilderHill New Energy Global Innovation Index, or NEX, which tracks around 95 quoted clean energy entities on markets across the globe, ended 2016 down 8.3%. Meanwhile, broad market indices advanced. The S&P 500 rose 9.5%, while the MSCI ACW added 5.6%. Another low-carbon energy gauge, the S&P Global Clean Energy Index ended the year 19% lower. Figures 42 and 43 show how the NEX has lagged the broader markets both in 2016 and over the longer term.

The NEX's top performer in 2016 was US smart meter manufacturer Itron – the company's shares climbed 74% over the course of the year thanks to higher-than-expected income. Next, US grid technology vendor EnerNOC rose 56% on the back of a Supreme Court decision to uphold a Federal Energy Regulatory Commission rule that puts 'demand response' on an equal footing with generation in grid procurement. Shares in Brazilian sugar and ethanol producer Sao Martinho increased by a similar percentage as domestic sugar prices hit a record high.

The index's worst performer was solar giant SunEdison (down 99%), which filed for bankruptcy protection in April 2016. The two yieldcos associated with it, TerraForm Power and TerraForm Global, were not part of the bankruptcy. Not far behind, UK fuel cell manufacturer Intelligent Energy Holdings lost 92% of its value in 2016 after failing to raise funds for a deal that would have seen it install its technology on more than 27,000 telecommunications towers in India. Shares in US solar giant SunPower lost 78% over concerns that demand for utility-scale solar

FIGURE 42. NEX VS SELECTED INDICES, 2003 TO JANUARY 2017

Index values as of 10 January 2017; Nasdaq and S&P 500 rebased
Source: Bloomberg New Energy Finance

FIGURE 43. NEX VS SELECTED INDICES, JANUARY 2016 TO 10 JANUARY 2017

Index values as of 10 January 2017; NEX, MSCI ACWI World & Emerging and S&P 500 rebased
Source: Bloomberg New Energy Finance

projects is slowing and competition is dragging panel prices lower.

Figure 44 shows the top 20 companies in the NEX by market capitalisation in early February 2017. They include companies that are not in renewable energy but are in energy smart technologies such as electric vehicles and lighting. One feature of the list is that, whereas wind developers and manufacturers are fairly well represented, there are no solar companies at all until First Solar at number 17. If the list was extended further, the next solar company would be polysilicon maker GCL-Poly at number 27. This shows that, in the biggest single sector of renewable energy, competition is fierce, making profits is hard, and investors are valuing accordingly.

FIGURE 44. LARGEST COMPANIES IN THE NEX INDEX, BY MARKET CAPITALISATION ON 7 FEBRUARY 2017

	Domicile	Sector	$m
Tesla Motors	US	Electric vehicles	41,524
BYD	China	Electric vehicles	17,888
Vestas Wind Systems	Denmark	Wind turbine maker	15,880
Dong Energy	Denmark	Offshore wind developer	15,379
Novozymes	Denmark	Biofuel enzyme maker	12,421
Acuity Brands	US	Lighting	9,120
China Longyuan	China	Wind developer	6,734
Goldwind	China	Wind turbine maker	6,287
Osram Lighting	Germany	Lighting	6,082
Gamesa Corporacion	Spain	Wind turbine maker	5,959
EDP Renovaveis	Portugal	Wind developer	5,582
Verbund	Austria	Hydro, wind operator	5,508
China Everbright Intl	Hong Kong	Environmental consultancy	5,426
Kingspan	Ireland	Energy efficiency	5,103
Nibe Industrier	Sweden	Sustainable heating	4,015
Philips Lighting	Netherlands	Lighting	3,799
First Solar	US	Thin-film PV maker	3,339
Huaneng Renewables	China	Wind developer	3,135
Mercury NZ	New Zealand	Hydro operator	3,104
NRG Yield	US	Wind, solar yieldco	3,060

NEX = WilderHill New Energy Global Innovation Index. Some of the companies in the list are in energy smart technologies rather than renewable energy

Source: Bloomberg

SECONDARY ISSUES

In line with the overall downward trend, secondary fundraising also fell in 2016 – the volume of funds accruing from follow-on sales dropped 74% to $2.6 billion. The largest offering was by Sungrow Power Supply, which raised $396 million on the Shanghai Stock Exchange. The China-based solar inverter manufacturer, together with compatriot Huawei Technologies, knocked Germany's SMA Solar Technology off the number one spot in 2015. It has begun to focus its attention on US residential rooftop solar.

The Sungrow deal stood out not simply because of its size but also because, remarkably, the remaining nine of the top 10 largest secondary offerings in 2016 were all by US yieldcos or UK quoted project funds. NYSE-listed NextEra Energy Partners, the yieldco created by power producer NextEra Energy, was the first to break the ice following the fundraising hiatus that had prevailed since August 2015. It raised $290 million in February 2016 and six months later, in September last year, it once again tapped the markets, this time raising $353 million.

Two more US yieldcos, 8Point3 Energy Partners and Pattern Energy Group, raised $118 million and $270 million, respectively. However, not all were successful: NRG Yield and TerraForm Power, funds that individually raised the largest amount of new equity in 2015, did not tap the public equity markets in 2016. The latter had hoped to conduct a follow-on offering in January 2016, but its failing parent company SunEdison put paid to those hopes. When the solar giant finally collapsed in April 2016, it was the renewable energy sector's biggest ever bankruptcy.

Quoted project funds and yieldcos raised new equity in small instalments in 2016, including by the use of at-the-market offerings. Like NextEra, some of the London-listed project funds – The Renewables Infrastructure Group, Greencoat UK Wind and NextEnergy Solar Fund – tapped the markets more than once last year. The last of these three had five separate offerings to its name by the end of 2016, raising a total of $166 million.

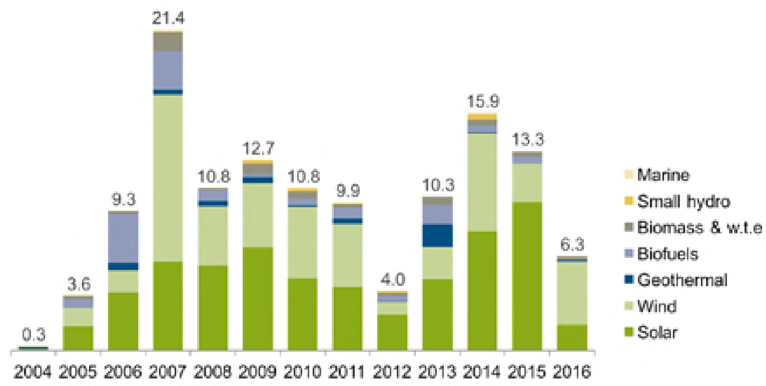
BY SECTOR AND LOCATION

A breakdown of 2016 deals shows that solar companies and funds raised $1.7 billion, less than one-fifth of the $9.9 billion they took home in 2015, and well below the solar sector's 10-year average of $5.4 billion per annum (see Figures 45 and 46). Not since 2005 has the sector reaped such meagre rewards on the public markets – back then, solar modules cost almost $4 per Watt, compared with around $0.5 per Watt for Chinese polysilicon modules in mid-2016. The largest deal in 2016 was Sungrow Power Supply's $396 million follow-on offering on the Shenzhen Stock Exchange.

It is significant that two Chinese giants of the solar sector, NYSE-listed Trina Solar and JA Solar Holdings, which is listed on Nasdaq, said they wanted to take their companies private. Their decision reflects a view that they have been undervalued by stock market investors. However, since these plans were announced, the outlook for the solar industry has darkened – PV production capacity grew faster than installations in 2016, despite surging to a record 75GW, and the cost of solar modules has fallen 30%.

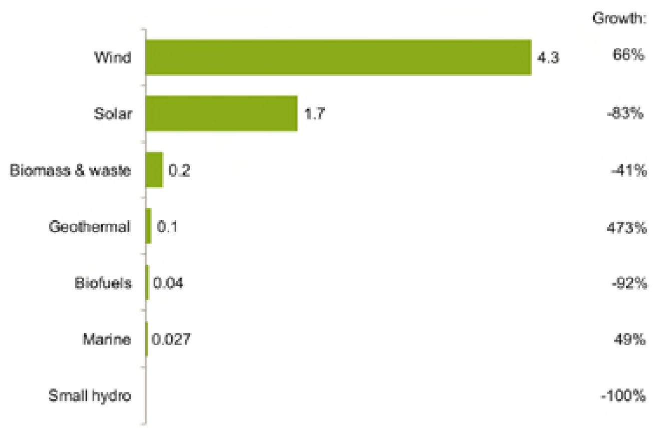
Wind companies and funds, in contrast to solar, raised more money than the previous year. Some $4.3 billion of new equity raisings were recorded, an increase of 66%, led by Innogy's issue of $2.2 billion worth of new shares in its IPO in October.

FIGURE 45. PUBLIC MARKETS INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2004-2016, $BN



Source: Bloomberg New Energy Finance, UN Environment

FIGURE 46. PUBLIC MARKETS INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2016, AND GROWTH ON 2015, $BN

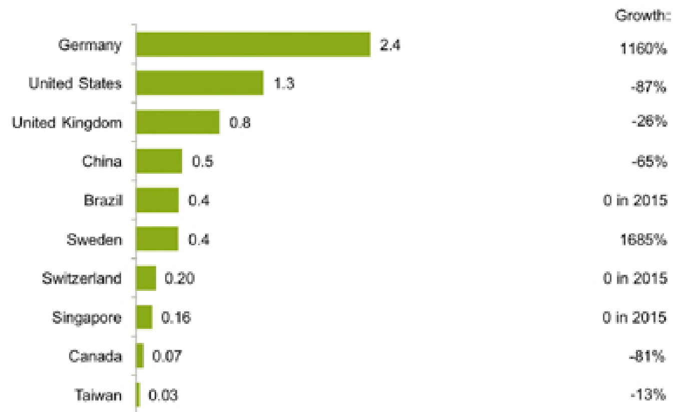


Source: Bloomberg New Energy Finance, UN Environment

Several wind-focused yieldcos and quoted project funds – namely, NextEra, Pattern Energy, Greencoat and Renewables Infrastructure Group – concluded follow-on offerings, raising a combined total of $1.4 billion. Other notable deals included TPI Composites' IPO, and Renova's $350 million from three exercise-of-rights transactions.

All other renewable sectors saw declines. In biomass and waste-to-energy, $192 million of new money was recorded, representing a 41% decline on the previous year. China Jinjiang Environment Holding's $137.6 million IPO on the Singapore Stock Exchange was the stand-out deal. Biofuel fundraising went from $437 million in 2015 to just $36 million in 2016, with only two companies raising funds on the public markets. One of these was Gevo, a US-based developer of advanced biofuel, which tapped investors for $24.4 million in three separate secondary offerings.

FIGURE 47. PUBLIC MARKETS INVESTMENT IN RENEWABLE ENERGY BY COMPANY NATIONALITY, 2016, AND GROWTH ON 2015, $BN



Top 10 countries
Source: Bloomberg New Energy Finance

Figure 47 shows the breakdown of public markets investment in 2016 by the nationality of the company concerned. Germany was by far the largest country, at $2.4 billion, mostly thanks to Innogy's IPO, while the US came in second at $1.3 billion and the UK third at $839 million – both of the latter totals boosted by share issues from yieldcos and quoted project funds.

VENTURE CAPITAL AND PRIVATE EQUITY

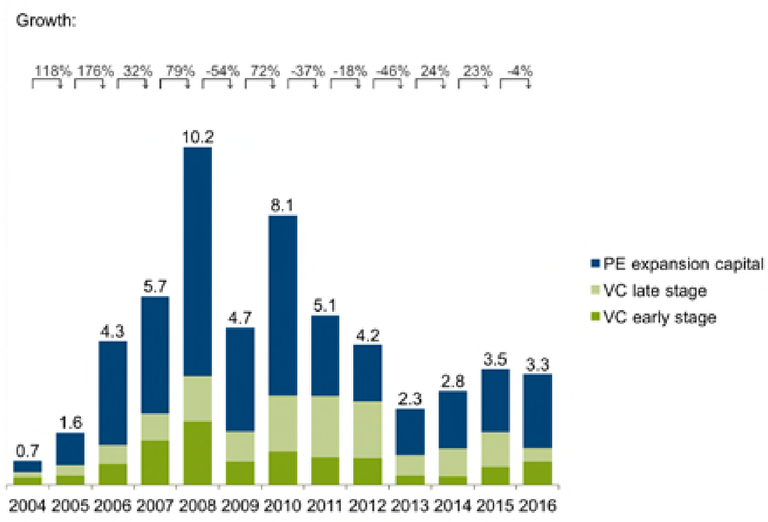
- Venture capital and private equity investment in renewable energy in 2016 fell by 4% to $3.3 billion, less than a third of its peak in 2008, but 46% above the recent low, in 2013.
- Investment in most venture capital investment stages fell sharply, but there were healthy gains in Series B and Series C, which grew 238% and 29% respectively. Private equity expansion capital gained 17% to $2.2 billion.
- As usual, solar attracted the largest investment. It captured more than two thirds of the total, although funding slipped 2% to $2.3 billion. Wind jumped 41% to $539 million, and small hydro almost quintupled to $165 million, but in each case the gain was due to a single deal. Biofuels slumped 60% to $254 million.
- The US remained the centre of worldwide VC/PE investment in renewables, at $2.3 billion, representing a fall of 2% but still more than two-thirds of the total investment. Investment in Europe doubled to $516 million, and that in the Other Asia-Pacific region jumped almost 28-fold to $55 million from a low base.

Venture capital and private equity investment in renewable energy held up well in a difficult year. Investors in the asset class confronted several challenges, including a slowdown in renewable energy investment more generally, especially in China and Japan; continuing turmoil in the solar sector; oil prices at low levels compared to recent standards; and a presidential election that has thrown the future direction of US energy policy into doubt.

In fact, global VC/PE investment in renewables fared better than total investment in renewable energy, and roughly in line with total VC/PE investment in all sectors. Renewable energy VC/PE investment fell 4% to$3.3 billion in 2016, while total renewable energy investment dropped 23% to $241.6 billion. Total VC/PE investment in all sectors of the global economy fell by around 5% to $158 billion, according to figures from Preqin, an alternative investment assets data provider.

VC/PE investment in renewable energy performed worse than equivalent investment in 'energy smart technologies', however. The latter heading

FIGURE 48. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY STAGE, 2004-2016, $BN

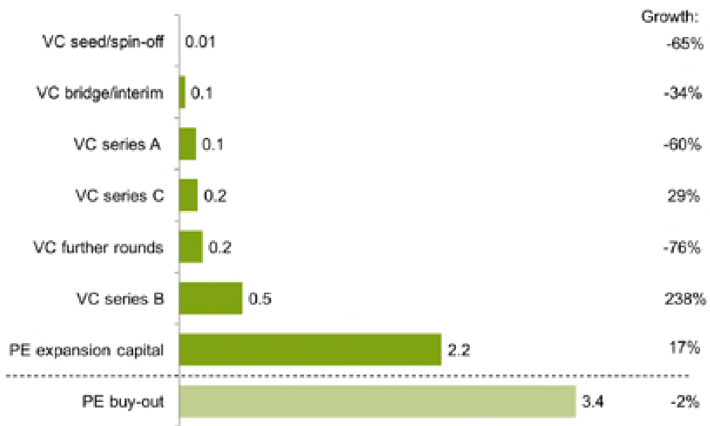


Buy-outs are not included as new investment. Total values include estimates for undisclosed deals

Source: Bloomberg New Energy Finance, UN Environment

includes electric vehicles, energy storage and smart grid technologies, areas that are discussed in a box at the end of Chapter 2 of this report. The money raised by specialist energy smart technology, or EST, companies from venture capital and private equity funds jumped 50% in 2016 to $7.5 billion, thanks in large part to two big investments in Chinese electric vehicle companies, worth $1 billion each.

FIGURE 49. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY STAGE, 2016, AND GROWTH ON 2015, $BN



Buy-outs are not included as new investment. Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

Taken together these figures may suggest a shift in VC/PE investment from renewable energy to EST, reflecting both the huge interest in electric vehicles and the increasing maturity of wind and solar. It may be that renewable energy VC/PE will never reclaim its 2008 peak of more than $10 billion.

EARLY-STAGE AND LATE-STAGE

Figure 48 shows that there was a mixed picture in 2016 in terms of the amount of funding for young renewable energy companies at different stages. Within the overall $3.3 billion total, the early-stage venture capital element rose 28% to $691 million, and there was a 17% increase in private equity expansion capital to $2.2 billion. However, late-stage venture capital slumped 60% to $413 million.

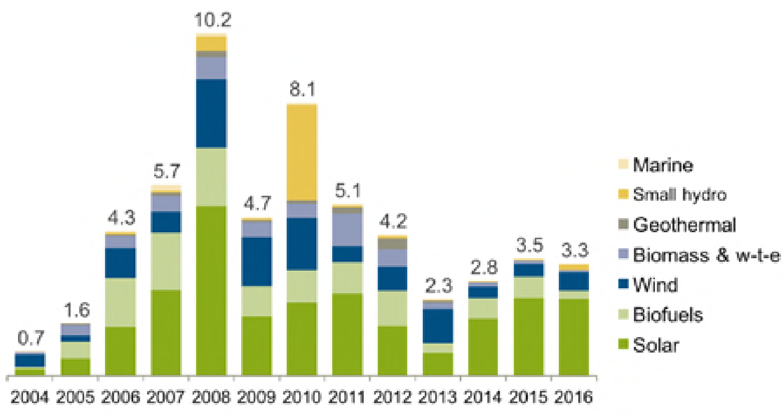
A more detailed breakdown, as presented in Figure 49, reveals that there were actually several weak spots in the VC/PE financing chain last year, with falls ranging from 34% for bridging funding to 65% for early spin-off and 76% for VC further rounds. The three risers were private equity expansion capital, which grew 17% to $2.2 billion; Series C venture capital, up 29% to $160 million; and Series B, which more than tripled to $539 million. Each of these apparent bright spots, however, was largely the result of just one or two deals. Had it not been for the funds raised by a single company, Sunnova Energy, for example, total investment in private equity would have shrunk.

SOLAR

In every investment stage that achieved growth, the decisive deals were all in solar. This should come as no surprise since the sector remains by far the largest at this stage of the financing continuum, claiming 68% of all VC/PE investment in renewable energy, as shown in Figures 50 and 51. But the type of solar company financed by VC/PE is changing. Now that solar R&D is largely carried out by global PV manufacturers, and as the price of solar panels continues to plunge, the companies that attracted VC/PE investment were in the main not technology developers, but rather those whose business models are designed to cope with changing conditions of the solar market in developed countries such as the US, or to bring off-grid power to the 1.2 billion people in developing countries who have no access to electricity.

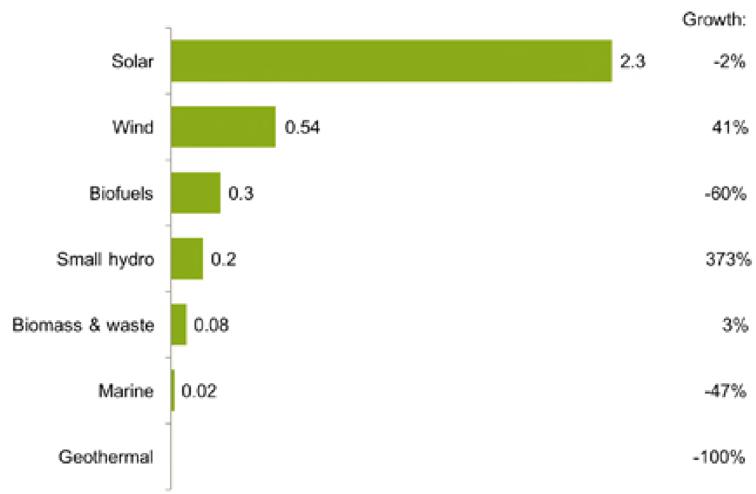
Sunnova was the biggest fundraiser by far. The residential solar installer, which is headquartered in Texas and operates in more than 20 US states, raised $428 million through three private equity rounds, including a single investment of $300 million from Energy Capital Partners. These and other deals have taken Sunnova's cumulative equity and debt funding to $1.5 billion.

FIGURE 50. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2004-2016, $BN



Buy-outs are not included as new investment. Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

FIGURE 51. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY SECTOR, 2016, AND GROWTH ON 2015, $BN



Buy-outs are not included as new investment. Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

Sunnova continued to attract investment in spite of torrid market conditions in the US, where the big incumbent installers such as SunCity, Sunrun and Vivint are experiencing slower growth, and whose share price performance has been described as the 'solarcoaster'. These companies expanded quickly by leasing solar panels to homeowners, protecting customers from high up-front costs. But because the price of panels has fallen by around 80% over the past five years – and continues to plunge – it may now be cheaper to borrow to buy the panels outright than to take on a lease. Sunnova is one of a number of companies that offer loans that allow customers to own their panels in as little as five years. The company's main investor last year, Energy Capital Partners, estimates that only 1% the US market for rooftop solar has been penetrated so far.

Solar Mosaic is another US company that was early to recognise the value of loans over leases. It secured $220 million in Series B funding organised by Warburg Pincus in August 2016. The company operates a peer-to-peer online platform that links individual and institutional investors with residential solar customers, and arranges the installations through a network of more than 20 independent dealers. Solar Mosaic offers only loan financing, and at the time of its fundraising, said it would write around $1 billion in solar loans over the following year.

Another large solar Series B deal, worth $90 million, was secured by Nova Lumos, a Dutch company operating in Nigeria, which provides pay-as-you go solar power to customers who live beyond the reach of the electricity grid. The company supplies a kit comprising a solar panel, control unit with several sockets, mobile phone charger and LED lights. The customer unlocks the system by making regular payments by SMS message. Taken together, the Solar Mosaic and Nova Lumos deals made up more than four-fifths of the growth in Series B funding in 2016.

Nova Lumos is one of many companies operating the same business model in developing countries, including M-Kopa, Off-Grid Electric, d.Light and Mobisol. By the autumn of 2016, the sector had raised more than $360 million in total and served about 700,000 customers. This is a tiny fraction of an addressable market of some 1.2 billion people without access to electricity, and the companies will need to raise billions of dollars in debt to fund their expansion.[39]

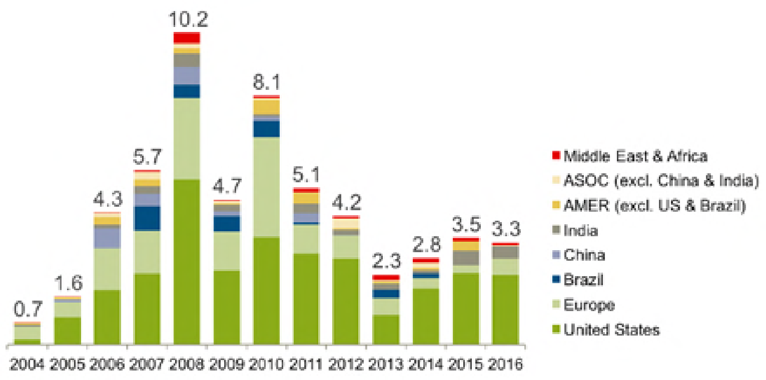
Bboxx was another pay-as-you-go off-grid solar provider to secure funding in 2016, through a Series C deal worth $20 million. The company is British and operates mostly in Kenya, Rwanda and Burundi, but plans to use the funds to expand into West Africa. The deal was noteworthy because the investor was Engie (formerly GDF Suez) through its stand-alone venture arm Rassembleur d'Energies, and was the utility's first move towards its goal of becoming a player in off-grid solar.

OTHER SECTORS

Wind secured the second largest tranche of investment, and here too there was evidence of innovative business models – or at least newly imported from the solar sector. Whereas wind development has so far been almost entirely at the utility scale, the American company United Wind installs small-scale turbines of 10kW-100kW and leases them to farms and rural businesses, which can consume the electricity or sell it back to the grid in states that allow net metering. The company secured $25 million in Series C venture capital, and then a further $142 million in private equity, and now counts both Tokyo Electric Power and oil giant Total among its investors. United Wind plans to use the new funds to expand from existing markets in New York, Colorado and Kansas to new markets in Minnesota, Iowa and Montana.

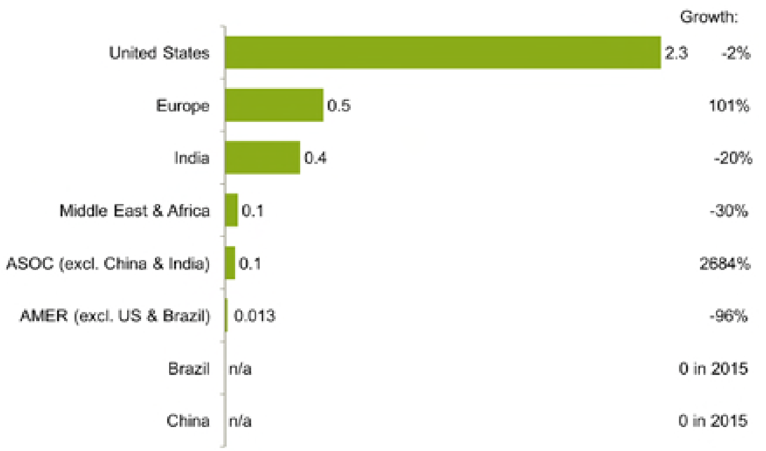
The largest wind deal was done by Greenko Energy of India, which secured $230 million in private equity from the sovereign wealth funds of Abu Dhabi and Singapore.[40] The independent power producer, based in Hyderabad, which has a generating portfolio of around 1GW of wind, small hydro and other renewables, aims to triple its capacity by 2020. The company also has around $800 million in debt.

FIGURE 52. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY REGION, 2004-2016, $BN



Buy-outs are not included as new investment. Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

FIGURE 53. VC/PE NEW INVESTMENT IN RENEWABLE ENERGY BY REGION, 2016, AND GROWTH ON 2015, $BN



Buy-outs are not included as new investment. Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance, UN Environment

[39] Bloomberg New Energy Finance, Research Note, How can pay-as-you-go solar be financed?
[40] Bloomberg New Energy Finance, H2 2016 India Market Outlook.

Biofuels slumped 60% to $254 million, with only three deals of any significance, as the sector continued to struggle with low oil prices and the tribulations of the US RFS2 biofuel regulation and the "ethanol blend wall". The blend wall results from the refusal of some manufacturers to honour warranties if their vehicles have run on a blend of more than 10% ethanol, and as a result the US Environmental Protection Agency (EPA) has slashed its 2017 targets for cellulosic ethanol – the advanced biofuel made from non-food feedstocks.

Against this backdrop, Calysta Energy, which is developing an advanced biodiesel, raised $30 million in Series C funding; Fulcrum BioEnergy, the waste gasification company, secured the same amount in a late-stage VC, or 'pre-IPO' round; and Agrivida, the crop and enzyme developer, attracted $20 million. All three of these companies are US-based.

REGIONAL MIX

The geography of VC/PE investment remained broadly unchanged in 2016, as shown in Figures 52 and 53. If anything, US dominance has increased in recent years, even though investment there slipped by 2% last year. That country's share of total VC/PE investment edged up from less than 65% in 2014 to almost 69% in 2016, well above its long-term average of 52%. By contrast, although investment in Europe doubled year-on-year to $516 million, its share of 16% was well below its long-term average of 26%.

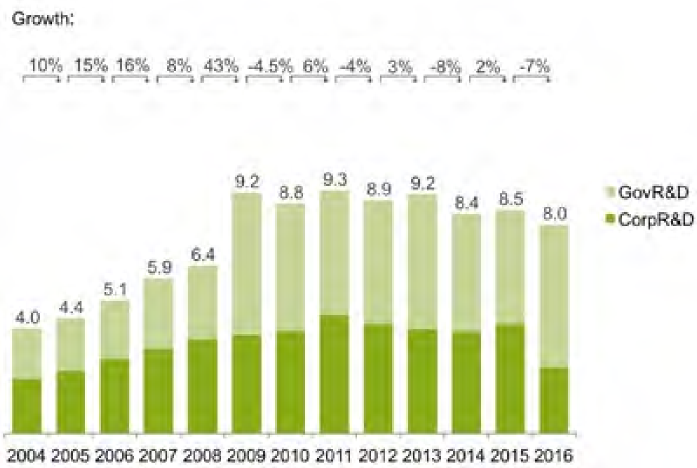
Among other regions, venture capital and private equity players played only an occasional role in 2016, as they have over the 13 years shown in Figure 52. India saw equity commitments slip 20% to $394 million, while both Asia outside China and India, and the Middle East and Africa, saw VC/PE investment of between $50 million and $100 million.

RESEARCH AND DEVELOPMENT

- Investment in research and development in renewable energy fell by 7% in 2016 to $8 billion, 14% below its peak in 2011.
- Corporate R&D slumped by almost 40% last year as wind and solar manufacturers retrenched. But estimated government spending on renewables research increased by 25% to a record $5.5 billion, breaking a three-year losing streak.
- Solar R&D investment fell by 20% to $3.6 billion and wind dropped 13% to $1.2 billion. Biofuels managed a gain of 11% to $1.7 billion in spite of low oil prices and a challenging regulatory environment.
- Europe remained the biggest regional investor in R&D, in spite of an 8% fall to $2.2 billion. China's investment slipped 2% to $2 billion but stayed well ahead of the US, where spending rose 13% to $1.5 billion.

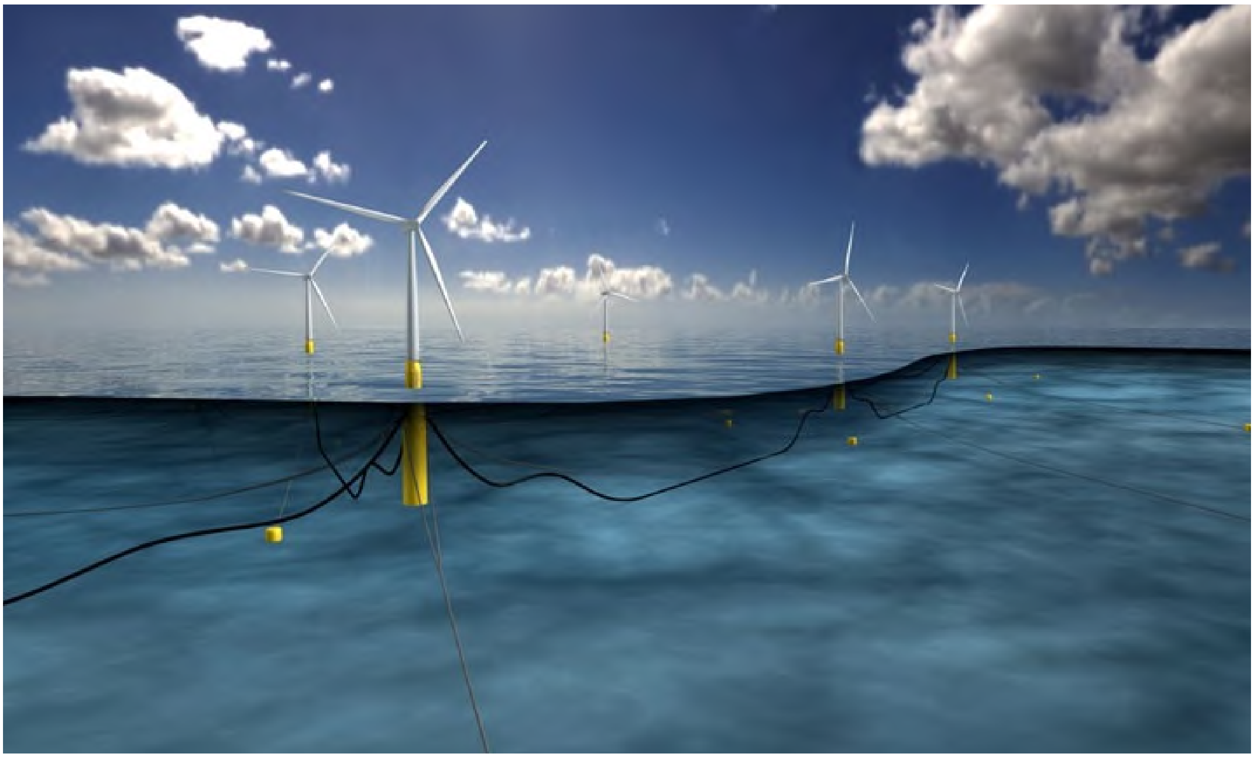
At the start of 2016, the prospects for R&D investment in renewable energy could hardly have looked better. Almost 200 countries had just signed the Paris climate accord, widely seen as a historic turning point that should assure trillions of dollars of investment in renewable energy over the coming decades. President Barack Obama had launched Mission Innovate, in which 20 of the world's richest countries committed to double their investment in clean energy R&D within five years. And Bill Gates had founded the Energy Breakthrough Coalition, a group of high-profile investors backing early-stage innovation with reported initial funding of $2 billion. The US Congress had unexpectedly extended subsidies for wind and solar until 2020, and in India, Prime Minister Narendra Modi had committed his country to install 100GW of solar by 2022.

FIGURE 54. R&D INVESTMENT IN RENEWABLE ENERGY, 2004-2016, $BN



Source: Bloomberg, Bloomberg New Energy Finance, IEA, IMF, various government agencies

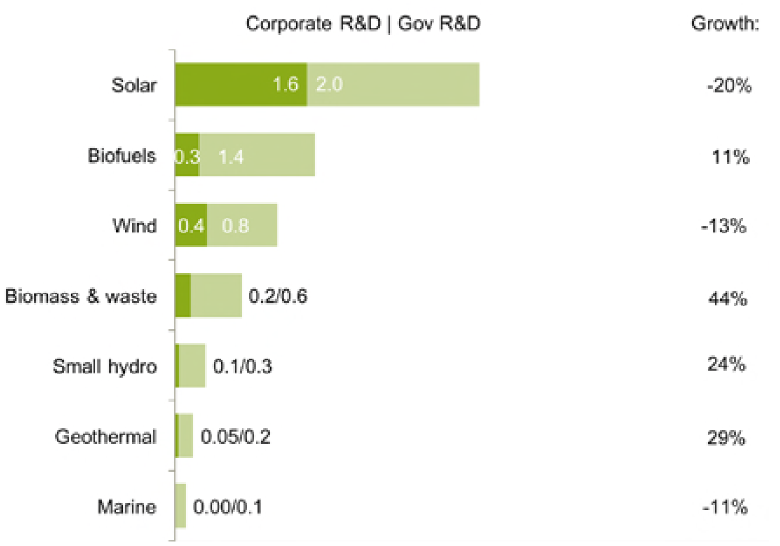
Yet in 2016, total investment in renewable energy R&D fell 7% to $8 billion, as shown in Figure 54, in what appears to be a continuing bumpy retreat from its peak of $9.3 billion in 2011. Last year's decline was caused by a 40% fall in corporate R&D spending, comprising big reductions in corporate R&D in solar (down 39%), wind (down 52%) and biomass and waste (down 50%), as shown in Figure 55.



Among the major regions, total R&D investment in the US rose 13% to $1.5 billion, while that in Europe fell 8% to $2.2 billion, and that in China slipped 2% to $2 billion, as shown in Figure 56.

The decline in renewable energy R&D would have been much larger but for a 25% increase in government spending, perhaps a sign that Mission Innovation signatories (Australia, Brazil, Canada, Chile, China, Denmark, France, Germany, India, Indonesia, Italy, Japan, Mexico, Norway, South Korea, Sweden, United Kingdom, United States, United Arab Emirates and, surprisingly, Saudi Arabia) are beginning to make good on their commitment. If they keep it up, R&D on renewable energy by governments alone could perhaps reach $10 billion by 2020. The future of US commitment to Mission Innovation is unclear, following the change of administration in Washington in January 2017.

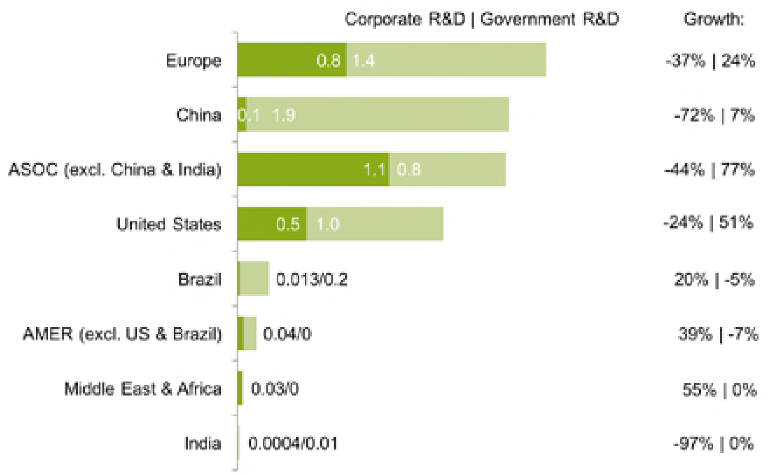
FIGURE 55. CORPORATE AND GOVERNMENT RENEWABLE ENERGY R&D BY TECHNOLOGY, 2016, AND GROWTH ON 2015, $BN



Source: Bloomberg, Bloomberg New Energy Finance, IEA, IMF, various government agencies

The slump in corporate investment came in spite of ample evidence that R&D works. In solar, this took the form of plunging power prices for new projects around the world. Records tumbled in quick succession from 64 US cents per kWh in Rajasthan, India, through Peru, Mexico, UAE, Morocco and finally Chile, where the agreed price was an astonishing 29 cents per kWh.

FIGURE 56. CORPORATE AND GOVERNMENT RENEWABLE ENERGY R&D BY REGION, 2016, AND GROWTH ON 2015, $BN



Source: Bloomberg, Bloomberg New Energy Finance, IEA, IMF, various government agencies

At these prices – and wind power was not far behind – renewable energy has started not simply to compete with fossil fuels but to undercut them without subsidy in much of the world.

This milestone has been achieved partly by years of investment to reduce the cost of renewable generation, and partly by fierce competition among developers for power deals and among manufacturers for module deals – the latter recently intensified by overcapacity. This has squeezed companies' margins, which no doubt explains much of the reduction in R&D spending in 2016. But many of the recent bids assume a couple of years' future efficiency improvements before the project gets built, so manufacturers will soon have to redouble their R&D spending to stay competitive.

SOLAR

In solar, some significant advances continue to work their way through the industry. For example, the introduction of diamond wire saws to slice multicrystalline silicon ingots into wafers can reduce the amount of silicon required for each wafer by as much as 17%. Only 2% of multicrystalline wafer production used this method in 2016, but analysts at Bloomberg New Energy Finance (BNEF) expect that by 2020 all production will have been converted. Manufacturers will also continue to shave costs by reducing the amount of silver used in electrical components, and investing in fluidised bed reactors to produce silicon more cheaply.

Manufacturers can increase the efficiency of crystalline solar cells by adopting a newer design known as passivated emitter rear contact (PERC), which increases energy output by 4% but adds only two steps to the production process. Other novel designs increase efficiency even more, but at greater expense. BNEF analysts expect PERC's share of production to rise from 6% in 2015 to more than 60% in 2018, helping to raise average crystalline silicon cell efficiency from 18.4% in 2015 to over 22% in 2025.[41]

These kinds of measures reduced the cost of an entire solar panel, or module, by 30% in 2016, and BNEF forecasts prices will fall further this year, perhaps to as little as $0.32 per Watt for standard multicrystalline silicon modules. Indeed, so successful has the industry been in reducing the cost of crystalline silicon modules that other technologies are struggling to compete. Thin-film modules, for example, once vied for dominance on the basis of lower production costs, but have now been undercut and reduced to niche applications and projects where the manufacturer is also the engineering contractor and developer. Of total photovoltaic production of 73GW in 2016, crystalline silicon captured 69GW and thin film just 4GW.

That is not to say that crystalline silicon will always have everything its own way, or that the days of fundamental breakthroughs in solar are over. Many researchers are convinced that the next major development will come from perovskites – a class of materials with the same crystal structure as calcium titanium oxide – which they believe could deliver major improvements in efficiency and cost. Named after the Nineteenth century Russian count who discovered the original mineral, perovskites can be manufactured using simple chemistry, unlike silicon, which can only

[41] https://www.bnef.com/core/insight/12330/view

be produced at extremely high temperatures in a vacuum. Experimental cells made from perovskites have increased in efficiency from less than 4% in 2010 to more than 20% in 2016, which makes this the fastest developing solar technology ever. “The rate of progress in the lab has been astounding,” according to Jenny Chase, BNEF’s head of solar research.

Perovskites also capture part of the light spectrum missed by crystalline silicon, raising the possibility of super-efficient hybrid cells. In May 2016, IMEC and Solliance reported they had produced a hybrid comprising a transparent perovskite cell stacked on top of a crystalline silicon cell, with a conversion efficiency of over 20%, and claimed this approach could eventually achieve 30% efficiency – compared to 24% for the most efficient silicon cells today. Other researchers have claimed hybrid cells might ultimately deliver 40% efficiency.

The industry is now racing to commercialise perovskite cells, pitting industry giants such as Trina Solar against thin-film producers First Solar and Solar Frontier, the Korea Research Institute of Chemical Technology, and start-ups such as Oxford Photovoltaics, which in October 2016 raised $11 million to develop perovskite cells. Though interest in the technology is intense, experts suggest that it will be commercialised in “in five years at the earliest.” It must also catch up with crystalline silicon technology, which has a ‘learning rate’ of more than 24%, or in other words, whose costs fall by almost a quarter with every doubling of capacity.

WIND

The wind sector also produced dramatic cost reductions in 2016, with a series of new record low bids for offshore projects during the year. First, Dong Energy set a new benchmark of EUR 72.7 per MWh in the Netherlands’ 700MW Borssele I & II auction. Vattenfall won the next two auctions, Denmark’s 350MW near-shore and 600MW Krieger’s Flak, with bids of EUR 63.8/MWh and EUR 49.9/MWh respectively. Finally, in December, a consortium of Shell, Eneco and Mitsubishi won the Dutch 700MW Borssele III & IV auction with a bid of EUR 54.5/MWh.

These records were set by Danish and Dutch projects in shallow waters near to shore, but huge progress was also made in the UK, the world's largest offshore market. Here the cost of offshore wind power has fallen 32% since 2012, declining to an average levelised cost of electricity of GBP 97/MWh for projects approved in 2015-16, and beating an industry-government target of GBP 100/MWh four years early. A report published by the Offshore Wind Programme Board found most of the reduction had been achieved by technological advances, particularly the installation of larger turbines of 7-8MW, and that there is scope to make further progress through measures such as enhanced control systems. Several projects would incorporate 66kV array cables and distributed lightweight transformers, for improved performance and lower cost.

One important area of development is offshore foundations. So far most turbines have been mounted on monopiles or jacket structures adopted from the oil industry, but the industry is now experimenting with newer designs such as suction buckets. These are like an upturned bucket that sticks to the sea floor when the water inside it is pumped out, and are easier and quicker to install and remove, do less damage to wildlife and the environment, and require less steel, so reducing cost.

The industry is also developing floating turbines to push into deeper waters further out. These have so far typically been mounted on spar, semi-submerged or tension leg platforms, also adopted from the oil industry. The technology has been given a boost by a recent French tender, which awarded contracts to two consortia comprising Eolfi and CGN, and Engie, GE and Principle Power. Each consortium will build 24MW of floating capacity made up of four 6MW turbines. BNEF analysts expect that by 2020, the total capacity of floating wind turbine projects in progress will reach 96MW.

Most wind R&D is carried out by big industrial players, but there are still some smaller companies pursuing interesting alternative approaches. One such is Spinetic Energy, a British start-up founded in 2013 to commercialise a radical concept in community-scale wind generation, intended to make wind as modular and cheap as solar PV. The problem, says Spinetic, is that while solar has achieved economies of scale through mass production, wind has done so by massively increasing the size of individual turbines – the world's biggest now measure more than 700 feet from blade tip to sea level. Conventional horizontal axis turbines cannot be both small and cost-effective, and this excludes them from some potential markets.

Spinetic's approach has been to develop a 'wind panel' of five 2-metre-high vertical wind turbines mounted in a lightweight aluminium frame, itself raised 5-10 metres above ground level. This is high enough to be out of reach of people and animals, and to ensure exposure to reasonable wind speeds, yet low enough to be far less obtrusive than conventional turbines. Each blade drives its own small generator, and each panel would be capable of generating 500W-1kW. The panels would be easy and quick to install and could be linked to form a long fence of generators. Spinetic says this arrangement could be incorporated into community-scale hybrid micro-grids in both developed and developing countries, meaning the world's 1.2 billion people without access to electricity could be served by wind as well as solar.

SMALLER SECTORS

Biofuels was the only large sector to increase R&D spending, up 11% to $1.7 billion, in spite of low oil prices and a dispiriting regulatory backdrop. In Europe, the EU scrapped its mandate to achieve 10% renewable energy in transport after 2020 and replaced it with a weaker set of targets. BNEF analysts believe this will lead to 28% of EU ethanol plants and 50% of biodiesel plants being decommissioned – "effectively giving up on first-generation biofuels". To fulfill the new target of 3.6% renewable energy in transport would require the construction of 170 next-generation cellulosic ethanol and diesel plants, if the necessary investment can be found.[42]

In the US, biofuels continued to struggle with the contradictions between the RFS2 biofuel mandate, with its volumetric production targets, and the "ethanol blend wall" resulting from manufacturers' refusal to honour warranties if their vehicles have run on a blend of more than

[42] Bloomberg New Energy Finance, Research Note, EU winter package: renewables, biofuels & transport.

10% ethanol. As a result, the US Environmental Protection Agency (EPA) was forced to slash its 2017 targets for cellulosic ethanol – the advanced biofuel made from non-food feedstocks.

One brighter spot was jet fuel, as FedEx, Jetblue, Alaska Airlines and Air BP signed (non-binding) agreements to buy aviation biofuels, and Air BP bought a $30 million stake in Fulcrum BioEnergy.

In marine energy, recent years have seen a series of upsets, particularly for wave technology developers. Several leading players went out of business in 2013-15, and the remaining, depleted field has found it hard to raise fresh venture capital funding. Nevertheless, in 2016 Finnish company AW-Energy raised EUR 10 million in loans from the European Investment Bank to develop further its WaveRoller technology, currently being demonstrated off the coast of Portugal. Australian companies Carnegie Wave Energy and BioPower Systems have been awarded government grants to develop demonstration projects off Western Australia and Victoria respectively.

The other fledgling, marine energy technology, tidal stream, has progressed further, with the first multi-MW demonstration projects being installed at MeyGen, off the north coast of Scotland, and at Paimpol-Brehat, off the French Brittany coast.

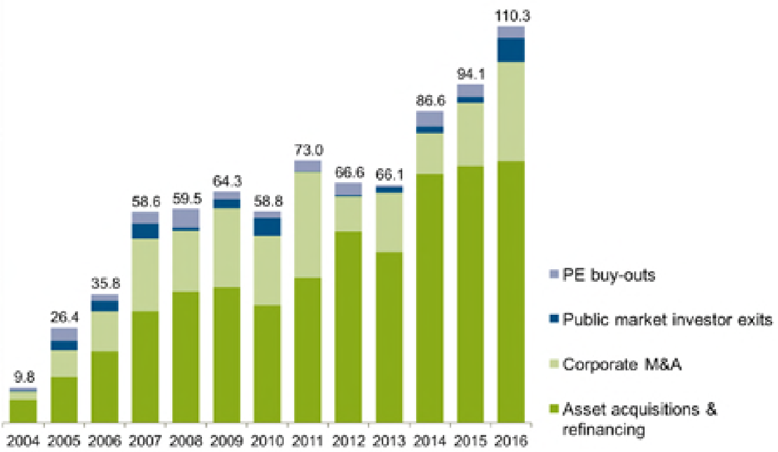
During 2016, Atlantis Resources, the company behind MeyGen, raised GBP 6.5 million via a share issue on London's Alternative Investment Market, while OpenHydro, involved at Paimpol-Brehat, raised EUR 47 million from its shareholders, led by French engineering group DCNS. Another turbine maker, Scotrenewables, was awarded a EUR 10 million grant from the European Commission's Horizon 2000 programme, in February 2016.

ACQUISITION ACTIVITY

- Acquisition transactions in renewable energy set a new record high for the third consecutive year, rising 17% to more than $110 billion.
- Growth was driven mainly by corporate mergers and acquisitions (M&A), which jumped 58% to $27.6 billion, and public market investor exits, which almost quadrupled to $6.7 billion – both new record highs.
- Asset acquisitions and refinancing remained the largest single category of acquisition activity, with deals worth $72.7 billion equating to 66% of the total, although the value of those grew by just 2% in 2016. Private equity buy-outs were also almost unchanged, down 2% at $3.4 billion.
- Wind retained its top spot in overall acquisition activity, with deals worth $62.3 billion, up 10% on 2015, but it is increasingly challenged by solar, which jumped 43% to $43.8 billion.
- In asset acquisitions and refinancings, the established regional giants were neck and neck again in 2016: US activity rose 14% to $29.2 billion, while that in Europe rose 8% to $28.6 billion. China grew 7% to $4.4 billion, but all other regions contracted.

While new investment in renewable energy shrank in 2016, acquisition activity enjoyed another bumper year. Total acquisition activity set a record high for the third year in a row, rising 17% in 2016 to $110.3 billion. The increase was driven by an upsurge in corporate M&A, which jumped 58% to $27.6 billion, as shown in Figure 57, and activity in the solar sector, which gained 43% to $43.8 billion (Figure 58). Public market investor exits were another significant feature, leaping 269% to $6.7 billion.

FIGURE 57. ACQUISITION TRANSACTIONS IN RENEWABLE ENERGY BY TYPE, 2004-2016, $BN

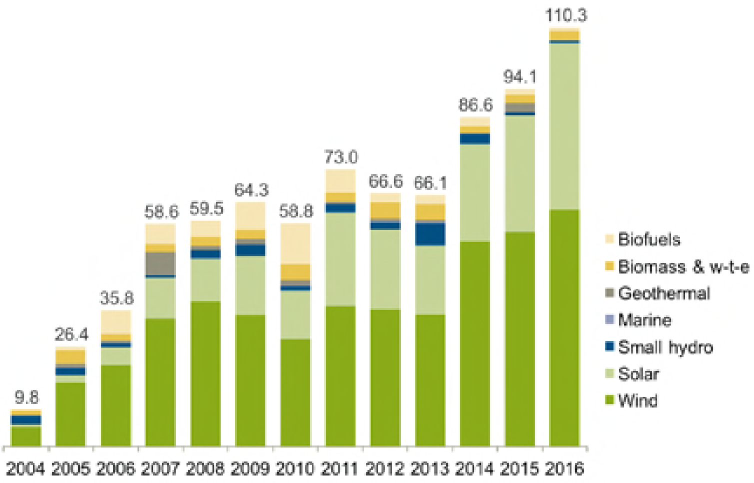


Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance

There is logic to the strength of acquisitions activity despite weaker new investment levels. As the renewable energy sector gets larger, there is simply a bigger deck of assets to shuffle. As it matures, and grapples in places with overcapacity, there is a natural tendency to consolidate. And as the rate at which new wind and solar farms are built begins to slow, but demand to own assets persists, the deal rate should rise.

Demand from investors was indeed buoyant in 2016, as they sought refuge from chronically low bond yields in the stable, long-term returns offered by renewable generating assets, and appeared

FIGURE 58. ACQUISITION TRANSACTIONS IN RENEWABLE ENERGY BY SECTOR, 2004-2016, $BN



Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance

increasingly comfortable with technology risk. There was growing interest in mature portfolios, as utilities restructured and sold out to financial investors. And it is a sign of the strength of this corner of the renewable energy markets that activity grew in spite of the almost complete withdrawal of yieldcos from the fray for much of the year.

CORPORATE M&A

The year's most prominent feature was the surge in corporate M&A, which included two major deals that could have a profound impact on the corporate architecture of renewable energy. See Figure 59.

The highest-profile transaction was Tesla's controversial acquisition of SolarCity for an enterprise value of $4.9 billion, which accounted for almost half the growth in corporate M&A in 2016.[43]

Analysts panned Elon Musk's plan to combine two companies he controlled – being both chief executive and the largest shareholder of each. But in the end investors backed Musk's vision of a 'one-stop-shop' for clean energy, with a single company to supply customers with solar panels, battery storage and an electric car. Now all he has to do is deliver it – along with his other ambitious plans. Between launching the bid in June and sealing it in November, Tesla lost almost $5 billion in market capitalisation, more than the value of the bid, though by the end of the year it had recovered all of it.

The next largest deal was done by the Italian utility Enel, which bought out the 31% minority shareholders of its subsidiary Enel Green Power for $3.5 billion. Enel said the deal was necessary because the subsidiary was expanding more quickly than it could finance itself. But it might be truer to describe the move as a reverse takeover of the utility – at least in spirit. That is certainly how Enel's chief executive Franco Starace, who led the subsidiary from 2008 to 2014, saw it – describing the deal as "effectively…turning Enel into Green Power".[44] Starace also committed Enel to increase its planned investment in renewables by 29%,

FIGURE 59. LARGEST CORPORATE M&A DEALS IN RENEWABLE ENERGY IN 2016, $BN

Acquirer	Target	Country of target	Sector	Business model	$bn
Tesla Motors	SolarCity	United States	Solar	Service Company	4.9
Enel	Enel Green Power	Italy	Wind	Developer	3.5
State Power	Pacific Hydro	Australia	Wind	Developer	2.1
Five Seasons	China High Speed Transmission	Hong Kong	Wind	Equipment Manufacturer	2.1
Beijing Enterprises	EEW Energy from Waste	Germany	Biomass & Waste	Power Generator	1.6
Tata Power	Welspun Renewables Energy	India	Solar	Developer	1.4
Endesa Generacion	Enel Green Power Espana	Spain	Wind	Developer	1.3
Nordex	Acciona Windpower	Spain	Wind	Equipment Manufacturer	0.9
Tongwei	Tongwei Solar Hefei	China	Solar	Equipment Manufacturer	0.8
China Three Gorges	BCP Meerwind Luxembourg	Luxembourg	Wind	Service Company	0.7

Source: Bloomberg New Energy Finance

[43] Where companies buy a majority stake or an entire company, as Tesla did, Bloomberg New Energy Finance values the deal by its enterprise value, which includes the target company's debt. Where a company buys a minority stake, the deal is valued on the basis of the equity stake alone.

[44] Bloomberg New Energy Finance, 7 December 2015.

and phase out its thermal generation, including 23 coal-fired power stations that will be closed or converted to biomass. "We could become a very large integrated renewable energy company – something that today does not exist."

Wind dominated the rest of the top 10 largest M&A deals. These included the acquisition of Pacific Hydro, which despite the name has marginally more wind than hydro capacity in projects across Australia, Chile and Brazil, by the State Power Investment Corporation of China, for $2.1 billion; the takeover of Spanish turbine manufacturer Acciona Windpower by its German competitor Nordex for $864 million; and Endesa Generacion's $1.3 billion purchase of a 60% stake in Enel Green Power Espana. A British Virgin Islands-registered company called Five Seasons XVI took a 65% stake in gearbox maker China High Speed Transmission for $2.1 billion. The only solar deal among the top 10 other than SolarCity was the acquisition by Tata Power Renewable Energy of Welspun Renewables for $1.4 billion.

PUBLIC MARKET EXITS

The other main change to acquisition activity in 2016, the near quadrupling of public market investor exits to $6.7 billion, was also dominated by wind, and again featured two major deals that illustrate the increasing maturity of the sector. A public market investor exit occurs when an existing investor sells some or all of its stake through a public share flotation, which may or may not also raise new money by selling additional shares.

The biggest deal was Dong Energy's long-awaited IPO, in which its joint owners, the Danish government and Goldman Sachs, sold a 17% stake in an IPO on the Copenhagen Stock Exchange for just over $3 billion. The success of the flotation, which had been proposed and pulled repeatedly since 2004, shows investors are now comfortable backing a utility that is fundamentally committed to renewable energy. Dong has transformed itself from one of the most coal-intensive utilities in Europe to the world's biggest offshore wind operator. It plans to complete a further six offshore

wind farms by 2020, more than doubling its capacity to 6.7GW, according to the company's chief executive. About 80% of its investment will go to offshore wind, and all cash generated by its oil and gas business – which it has been trying to sell – will be invested in renewables. Within days of its IPO, Dong took its final decision to invest some $2 billion in a 450MW offshore wind farm in German waters, Borkum Riffgrund 2, using the latest MHI Vestas 8MW turbines.

The other significant deal was the flotation of Innogy, a company hived off by Germany's RWE to house its cleaner energy assets, as the success of renewables upended the conventional utility business model in Europe. A similar split was performed by E.ON. Innogy's IPO raised $5.2 billion, comprising $2.9 billion for its previous owners and $2.2 billion in new equity for a company that has around 3.6GW of renewable capacity, overwhelmingly wind and hydro, along with grid and gas assets. Again, the success of the flotation showed the willingness of investors to back a major reorganisation to reflect the new reality of European markets increasingly ruled by renewables.

Senvion's launch on Germany's Xetra Stock Exchange was not quite so happy. The turbine manufacturer's owners, the private equity firms Centerbridge Partners and Arpwood Capital, raised $287 million by selling shares through a private placement, less than half the value of a planned IPO they had been forced to pull, blaming market volatility.

PRIVATE EQUITY BUY-OUTS

A total of $3.4 billion changed hands as a result of private equity buy-outs in 2016, down 2% from the 2015 figure and more or less in line with the average seen over the last 10 years.

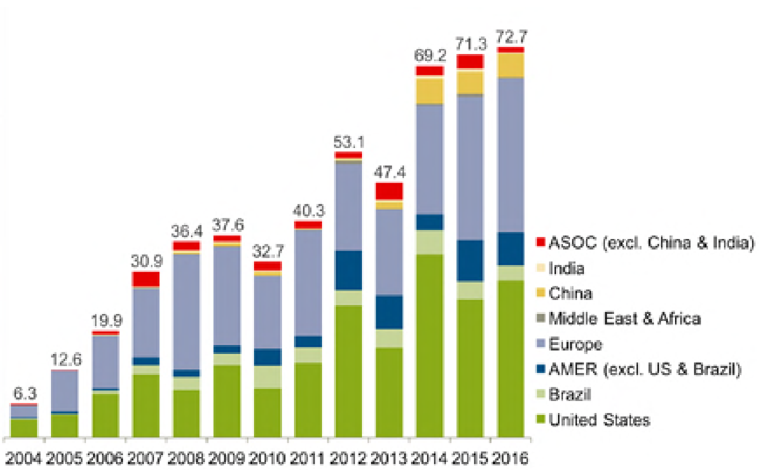
The largest deal in this category was Cerberus Capital Management's acquisition of Spanish solar, hydro and wind developer Renovalia Energy for an estimated $1.1 billion. Far behind was the second largest, Zhongshan Ruisheng Antai Investment's purchase of 67% of turbine maker China Ming Yang Wind Power for $258 million.

ASSET TRANSACTIONS

Asset acquisition and refinancing remained the largest category of acquisition activity, with deals worth $72.7 billion or two-thirds of the total, although growth was a modest 2%. Wind dominated here too, taking 13 of the top 20 deals, and almost 60% of their total value, at $41.6 billion. Analysts at Bloomberg New Energy Finance say that since the rate of onshore wind farm construction is slowing, but demand increasing, investors are scouting for older projects to buy. So between 2009 and the middle of 2016, more than a third of Europe's onshore wind capacity, around 50GW of 136GW, had changed hands. And tight competition among buyers means that new projects are increasingly being bought during the construction phase, another sign that institutional investors are now comfortable shouldering technology risk.

The biggest wind deal was the $2.2 billion refinancing of the Dudgeon East Offshore Wind Farm project in the UK. Owners Masdar, Statoil and Statkraft supplied $237 million in equity and secured $1.8 billion in senior debt. The 402MW wind farm was the first to secure financing under the UK's new Contracts for Difference scheme, and is due to start generating in late 2017.

FIGURE 60. ASSET ACQUISITIONS AND REFINANCINGS BY REGION, 2004-2016, $BN



Total values include estimates for undisclosed deals
Source: Bloomberg New Energy Finance

The next largest deal was clinched by Macquarie Capital and Macquarie Infrastructure Fund 5, which bought a 50% stake in Dong Energy's 573MW Race Bank Offshore Wind Farm, also in UK waters, for $2 billion. Under the terms of the deal, Macquarie took on half the project's remaining construction costs, including cables connecting it to the shore.

The largest deal overall, however, was the refinancing of what was briefly the world's largest solar farm for $2.7 billion. The 586MW Sun Star project in California was developed by SunPower but is now owned by BHE Solar, a subsidiary of Warren Buffett's Berkshire Hathaway Energy. Sun Star has since been overtaken in size by a 648MW plant owned by Adani Green Energy in Tamil Nadu in southern India. See Chapter 5 for discussion of this project.

Four US solar deals were funded through 'tax equity', the system by which investors with large tax liabilities can reduce them by investing in solar projects. On this basis, First Solar raised $1.2 billion from General Electric and Goldman Sachs to refinance its 294MW Moapa solar farm; sPower secured $764 million from US Bancorp and PNC Financial Services Group to refinance its 191MW Beacon PV portfolio; SolarReserve won the agreement of a banking consortium to provide $750 million to refinance its Crescent Dunes solar thermal plant; and SunEdison raised $624 million from Bank of America to refinance its 156MW Comanche PV Plant, in a deal that was arranged before SunEdison's insolvency but which closed after it.

Among the larger of the outright acquisitions registered in 2016, the Copenhagen Infrastructure Fund bought the Tri Global Texas Copenhagen Wind Portfolio, comprising two projects with a total capacity of 510MW, for just over $1 billion, and in Mexico the gas pipeline company Infraestructura Energetica Nova paid Fisterra Energy and Cemex $852 million for their 252MW Ventika wind farm project.

Figure 60 shows the breakdown of asset acquisitions and refinancings by region. Of the $72.7 billion global total in 2016, some $29.2 billion took place in the US (up 14% on the year), and $28.6 billion happened in Europe (up 8%). The only other significant centres for activity were the Americas excluding the US and Brazil, at $6.1 billion (down 21%), and China, at $4.4 billion (up 7%).

GLOSSARY[45]

ASSET FINANCE	All money invested in renewable energy generation projects, whether from internal company balance sheets, from debt finance, or from equity finance. It excludes refinancings. The project may or may not be commissioned in the same year.
CAPITAL EXPENDITURE	Funds used by a company to acquire or upgrade physical assets such as property, industrial buildings or equipment. Some investment will translate into capacity in the following year.
FEED-IN TARIFF	A premium rate paid for electricity fed back into the electricity grid from a designated renewable electricity generation source.
FINAL INVESTMENT DECISION	Moment at which the project developer, or group of investors and lenders, decide that the investment will definitely go ahead. The asset finance figures in this report are based on money committed at the moment of final investment decision.
GREEN BOND	A bond issued by a bank or company, the proceeds of which will go entirely into clean energy and other environmentally-friendly projects. The issuer will normally label it as a green bond.
INITIAL PUBLIC OFFERING (IPO)	A company's first offering of stock or shares for purchase via an exchange. Also referred to as "flotation".
INVESTMENT TAX CREDIT (ITC)	Allows investment in renewable energy in the US to be deducted from income tax.
LEVELISED COST OF ELECTRICITY (LCOE)	The all-in cost of generating each MWh of electricity from a power plant, including not just fuel used but also the cost of project development, construction, financing, operation and maintenance.
MERGERS & ACQUISITIONS (M&A)	The value of existing equity and debt purchased by new corporate buyers in companies developing renewable technology or operating renewable energy projects.
NON-RECOURSE PROJECT FINANCE	Debt and equity provided directly to projects rather than to the companies developing them.
ON-BALANCE-SHEET FINANCING	Where a renewable energy project is financed entirely by a utility or developer, using money from their internal resources.
PRODUCTION TAX CREDIT (PTC)	The support instrument for wind energy projects at federal level in the US.
PUBLIC MARKETS	All money invested in the equity of publicly quoted companies developing renewable energy technology and generation.
RENEWABLE PORTFOLIO STANDARD (RPS)	A regulation that requires that a minimum of electricity or heat sold is from renewable sources. Also called Renewable Electricity Standard (RES) at the US federal level and Renewables Obligation in the UK.
TAX EQUITY	Tax equity investors invest in renewable energy projects in exchange for federal tax credits.
VENTURE CAPITAL AND PRIVATE EQUITY (VC/PE)	All money invested by venture capital and private equity funds in the equity of companies developing renewable energy technology.

[45] Further definitions and explanations can be found in Private Financing of Renewable Energy – a Guide for Policymakers. S. Justice/K. Hamilton. Chatham House, UNEP Sustainable Energy Finance Initiative, and Bloomberg New Energy Finance, December 2009.

UN ENVIRONMENT

UN Environment is the leading global voice on the environment. It provides leadership and encourages partnership in caring for the environment by inspiring, informing, and enabling nations and peoples to improve their quality of life without compromising that of future generations. UN Environment works with governments, the private sector, the civil society and with other UN entities and international organizations across the world. To ensure its global effectiveness UN Environment supports six regional offices, a number of sub-regional and country offices and a growing network of centres of excellence.

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FRANKFURT SCHOOL – UNEP COLLABORATING CENTRE FOR CLIMATE & SUSTAINABLE ENERGY FINANCE

The Frankfurt School – UNEP Collaborating Centre for Climate & Sustainable Energy Finance is a strategic cooperation between the Frankfurt School of Finance & Management and UN Environment. The Centre is committed to facilitate the necessary structural change of energy supply and use around the globe by helping to catalyse private sector capital flow towards investments in sustainable energy and climate change mitigation and adaptation. A primary objective is to bridge the public-private sector gap through think-tank activities combining research, education and project implementation. A key part of this process is to enable the public sector to put in place policies, regulations and initiatives that overcome existing or perceived investment risks and other barriers seen by the private sector due to unfamiliarity with clean energy initiatives, particularly in developing countries. Together with partners in different institutions, the Centre is elaborating and field-testing new financial instruments and implementing cutting-edge projects that serve the growing markets for energy-efficient and clean energy production.

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