Affidavit #1 of Robert McCullough
Affirmed February___, 2016

No. S159064
Vancouver Registry

IN THE SUPREME COURT OF BRITISH COLUMBIA

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

PLAINTIFF

AND:

KEN BOON, ARLENE BOON, VERENA HOFMANN, ESTHER PEDERSEN also known as Rachel Blatt, HELEN KNOTT, YVONNE TUPPER, JANE DOE, JOHN DOE and all other persons unknown to the Plaintiff occupying, obstructing, blocking, physically impeding or delaying access, at or in the vicinity of the area in and around the south bank of the Peace River upstream (west) of the Moberly River, including the area in and around the heritage site known as Rocky Mountain Fort

DEFENDANTS

AFFIDAVIT #1 OF ROBERT McCULLOUGH

I, Robert McCullough, principal of McCullough Research, 6123 S.E. Reed College Place, Portland, Oregon 97202, AFFIRM THAT:

1. I am the principal of an energy consulting firm named "McCullough Research" and have been active in the industry since 1979, and as such, I have personal knowledge of the facts and matters hereinafter deposed to, save and except for information imparted to me by other people, in which case I believe the source of the information to be reliable and I believe the information to be true.

2. I have worked on issues related to Site C and British Columbia Hydro on many occasions including as an employee or consultant to utilities and industries doing business with them, appearing as an expert witness on issues involving them, and advising parties affected by their decisions.

3. From 1979 through 1991, I held positions of increasing responsibility at Portland General Electric, a large hydro-electric and thermal utility. In 1991, I resigned my position as special assistant to the chairman of the board in order to found McCullough Research. Since 1991, I have advised governments, utilities, regulatory authorities, and aboriginal groups from Nova Scotia to California. I have been asked to testify before the U.S. Congress on issues ranging from electric markets to oil speculation, appeared in national and international journals and electronic media, testified before state and federal courts, arbitrations, and regulatory authorities, and participated in federal and state prosecutions for market manipulations in Washington, Montana, Illinois, Texas, and California. I am also an adjunct professor at Portland State University. A copy of my curriculum vitae is attached to this affidavit as **Exhibit "A"**.

4. My mandate in this proceeding is to impartially review the affidavits of Mr. Andrew Watson and Mr. Michael Savidant on the economic and energy supply issues attendant with a one to five year delay of the Site C project. Attached to this affidavit as **Exhibit "B"** is a copy of the report that I have prepared. My report sets out the rationale for my conclusion that a delay in the construction of Site C, amounting to a delay in the in-service date of Site C, would amount to a net savings to British Columbia Hydro and its ratepayers, not a net cost. The net savings of a one year delay, in present value terms, is $267.68 million; for a two year delay it is $519.44 million; for a five year delay, the net savings is $1,187.47 million.

5. I certify that I am aware of my duty as an expert witness under the British Columbia Supreme Court Civil Rules to assist the court and not to be an advocate for any party. The attached report has been made in conformity with

that duty. If I am called on to give testimony, I will do so in conformity with that duty.

NOTARIZED BEFORE ME at Multnomah County, in the State of Oregon, in the United States of America, this 10 day of February, 2016

ROBERT McCULLOUGH

OFFICIAL STAMP
RICK DEAN PHILLIPS
NOTARY PUBLIC-OREGON
COMMISSION NO. 945894
MY COMMISSION EXPIRES DECEMBER 30, 2019

Robert McCullough – *Curriculum Vitae*
Principal
McCullough Research, 3816 S.E. Woodstock Place, Portland, OR 97202 USA

Professional Experience

1985-present	Principal, McCullough Research: provide strategic planning assistance, litigation support, and planning for a variety of customers in energy, regulation, and primary metals
1996-present	Adjunct Professor, Economics, Portland State University
1990-1991	Director of Special Projects and Assistant to the Chairman of the Board, Portland General Corporation: conducted special assignments for the Chairman in the areas of power supply, regulation, and strategic planning
1988-1990	Vice President in Portland General Corporation's bulk power marketing utility subsidiary, Portland General Exchange: primary negotiator on the purchase of 550 MW transmission and capacity package from Bonneville Power Administration; primary negotiator of PGX/M, PGC's joint venture to establish a bulk power marketing entity in the Midwest; negotiated power contracts for both supply and sales; coordinated research function
1987-1988	Manager of Financial Analysis, Portland General Corporation: responsible for M&A analysis, restructuring planning, and research support for the financial function; reported directly to the CEO on the establishment of Portland General Exchange; team member of PGC's acquisitions task force; coordinated PGC's strategic planning process; transferred to the officer's merit program as a critical corporate manager
1981-1987	Manager of Regulatory Finance, Portland General Electric: responsible for a broad range of regulatory and planning areas, including preparation and presentation of PGE's financial testimony in rate cases in 1980, 1981, 1982, 1983, 1985, and 1987 before the Oregon Public Utilities Commission; responsible for preparation and presentation of PGE's wholesale rate case with Bonneville Power Administration in 1980, 1981, 1982, 1983, 1985, and 1987; coordinated activities at BPA and FERC on wholesale matters for the InterCompany Pool (the association of investor-owned utilities in the Pacific Northwest) since 1983; created BPA's innovative aluminum tariffs (adopted by BPA in 1986); led PGC activities, reporting directly to the CEO and CFO on a number of special activities,

	including litigation and negotiations concerning WPPSS, the Northwest Regional Planning Council, various electoral initiatives, and the development of specific tariffs for major industrial customers; member of the Washington Governor's Task Force on the Vancouver Smelter (1987) and the Washington Governor's Task Force on WPPSS Refinancing (1985); member of the Oregon Governor's Work Group On Extra-Regional Sales (1983); member of the Advisory Committee to the Northwest Regional Planning Council (1981)
1979-1980	Economist, Rates and Revenues Department, Portland General Electric: responsible for financial and economic testimony in the 1980 general case; coordinated testimony in support of the creation of the DRPA (Domestic and Rural Power Authority) and was a witness in opposition to the creation of the Columbia Public Utility District in state court; member of the Scientific and Advisory Committee to the Northwest Regional Power Planning Council

Economic Consulting

2015-present	Analysis and expert testimony for Illinois Attorney General in official FERC complaint against MISO
2015-present	Advisor to Oregon Department of Justice in the investigation of taxes owed the state by Powerex Corp.
2015-present	Advisor to Huu-ay-aht on Sarita Bay LNG project in British Columbia
2015-present	Advisor to Calbag Metals on generation project
2015	Economic analysis of the proposed 1100 MW hydro project, Site C, for the Peace Valley Landowner Association
2014-2015	Market analysis of the NYISO for the New York State Assembly
2014	Advisor to the Grand Council of the Cree on uranium mining in Quebec
2014-present	Support for the investigation of Barclays Bank
2013-present	Retained to do a business case analysis of the Columbia Generating Station by the Physicians for Social Responsibility

2013	Advisor to Environmental Defense Fund on gasoline and oil issues in California
2013	Advisor to Energy Foundation on Ohio competitive issues
2013	Export market review in the Maritime Link proceeding
2011	Consultant to Citizens Action Coalition of Indiana on Indiana Gasification LLC project
2010	Analysis and expert witness testimony for Block Island Intervenors concerning Deepwater offshore wind project
2010	Analysis for Eastern Environmental Law Center of 25 closed cycle plants in New York State
2010	Advisor on BPA transmission line right of way issues
2009-2010	Advisor to Gamesa USA on a marketing plan to promote a wind farm in the Pacific Northwest
2009-2010	Expert witness in City of Alexandria vs. Cleco
2009	Expert witness in City of Beaumont v. Entergy
2008-2009	Consultant to AARP Connecticut and Texas chapters on the need for a state power authority (Connecticut) and balancing energy services (Texas)
2008	Expert witness on trading and derivative issues in Barrick Gold litigation
2008-2014	Advisor to Jackson family in Pelton/Round Butte dispute
2007-2014	Advisor to the American Public Power Association on administered markets
2006-present	Advisor to the Illinois Attorney General on electric restructuring issues
2006-2007	Advisor to the City of Portland in the investigation of Portland General Electric
2006	Expert witness for Lloyd's of London in SECLP insurance litigation
2005-2007	Expert witness for Federated Rural Electric Insurance Company and TIG Insurance in Cowlitz insurance litigation

2005-2007	Advisor to Grays Harbor PUD on market manipulation
2005-2007	Advisor to the Montana Attorney General on market manipulation
2005-2006	Expert witness for Antara Resources in Enron litigation
2005-2006	Advisor to Utility Choice Electric
2004-2005	Expert witness for Factory Mutual in Northwest Aluminum litigation
2004	Advisor to the Oregon Department of Justice on market manipulation
2003-2006	Expert witness for Texas Commercial Energy
2003-2004	Advisor to The Energy Authority
2002-2005	Advisor to the U.S. Department of Justice on market manipulation issues
2002-2004	Expert witness for Alcan in Powerex arbitration
2002-2003	Expert witness for Overton Power in IdaCorp Energy litigation
2002-2003	Expert witness for Stanislaus Food Products
2002	Advisor to VHA Pennsylvania on power purchasing
2002	Expert witness for Sierra Pacific in Enron litigation
2002-2004	Advisor to U.S. Department of Justice
2002-2007	Expert witness for Snohomish PUD in Enron litigation
2002-2010	Expert witness for Snohomish in Morgan Stanley investigation
2001-present	Expert witness for City of Seattle, Seattle City Light and City of Tacoma in FERC's EL01-10 refund proceeding
2001-2008	Advisor to VHA Southwest on power purchasing
2001-2005	Advisor to Nordstrom

2001-2005	Advisor to Steelscape Steel on power issues in Washington and California
2001	Advisor to California Steel on power purchasing
2001	Advisor to the California Attorney General on market manipulations in the Western Systems Coordinating Council power markets
2000-present	Expert witness for Wah Chang in PacifiCorp litigation
2000-2001	Expert witness for Southern California Edison in Bonneville Power Administration litigation
2000-2001	Advisor to Blue Heron Paper on West Coast price spikes
2000	Expert witness for Georgia Pacific and Bellingham Cold Storage in the Washington Utilities and Transportation Commission's proceeding on power costs
1999-2002	Advisor to Bayou Steel on alternative energy resources
1999-2000	Expert witness for the Large Customer Group in PacifiCorp's general rate case
1999-2000	Expert witness for Tacoma Utilities in WAPA litigation
1999-2000	Advisor for Nucor Steel and Geneva Steel on PacifiCorp's power costs
1999-2000	Advisor to Abitibi-Consolidated on energy supply issues
1999	Expert report for the Center Helios on Freedom of Information in Québec
1999	Advisor to GTE regarding Internet access in competitive telecommunication markets
1999	Advisor to Logansport Municipal Utilities
1998-2001	Advisor to Edmonton Power on utility plant divestiture in Alberta
1998-2001	Energy advisor for Boise Cascade
1998-2000	Advisor to California Steel on power purchasing

1998-2000	Advisor to Nucor Steel on power purchasing and transmission negotiations
1998-2000	Advisor to Cominco Metals on the sale of hydroelectric dams in British Columbia
1998-2000	Advisor to the Betsiamites on the purchase of hydroelectric dams in Québec
1998-1999	Advisor to the Illinois Chamber of Commerce concerning the affiliate electric and gas program
1998	Intervention in Québec's first regulatory proceeding on behalf of the Grand Council of the Cree
1998	Market forecasts for Montana Power's restructuring proceeding
1997-2004	Expert witness for Alcan in BC Hydro litigation
1997-2003	Advisor to the Manitoba Cree on energy issues in Manitoba, Minnesota and Québec; Advisor to the Grand Council of the Cree on hydroelectric development
1997-1999	Advisor to the Columbia River Intertribal Fish Commission on Columbia fish and wildlife issues
1997-1998	Advisor to Port of Morrow regarding power marketing with respect to existing gas turbine plant
1997-1998	Expert witness for Tenaska in BPA litigation
1997	Advisor to Kansai Electric on restructuring in the electric power industry (with emphasis on the California markets)
1996-1997	Bulk power purchasing for the Association of Bay Area Cities
1996-1997	Advisor to Texas Utilities on industrial issues
1996-1997	Expert witness for March Point Cogeneration in Puget Sound Power and Light litigation
1996	Advisor to Longview Fibre on contract issues
1995-2000	Bulk power supplier for several Pacific Northwest industrials
1995-1999	Advisor to Seattle City Light on industrial contract issues

1995-1997	Advisor to Tacoma Utilities on contract issues
1995-1996	Expert witness for Tacoma Utilities in WAPA litigation
1994-1995	Advisor to Idaho Power on Southwest Intertie Project marketing
1993-2001	Northwest representative for Edmonton Power
1993-1997	Expert witness for MagCorp in PacifiCorp litigation
1992-1995	Advisor to Citizens Energy Corporation
1992-1994	Negotiator on proposed Bonneville Power Administration aluminum contracts
1992	Bulk power marketing advisor to Public Service of Indiana
1991-2000	Strategic advisor to the Chairman of the Board, Portland General Corporation
1991-1993	Chairman of the Investor Owned Utilities' (ICP) committee on BPA financial reform
1991-1992	Financial advisor on the Trojan owners' negotiation team
1991	Advisor to Shasta Dam PUD on the California Oregon Transmission Project and related issues
1990-1991	Advised the Chairman of the Illinois Commerce Commission on issues pertaining to the 1990 General Commonwealth Rate Proceeding; prepared an extensive analysis of the bulk power marketing prospects for Commonwealth in ECAR and MAIN
1988	Facilitated the settlement of Commonwealth Edison's 1987 general rate case and restructuring proposal for the Illinois Commerce Commission; reported directly to the Executive Director of the Commission; responsibilities included financial advice to the Commission and negotiations with Commonwealth and interveners
1987-1988	Created the variable aluminum tariff for Big Rivers Electric Corporation: responsibilities included testimony before the Kentucky Public Service Commission and negotiations with BREC's customers (the innovative variable tariff was adopted by the Commission in August 1987); supported negotiations with the REA in support of BREC's bailout debt restructuring

1981-1989	Consulting projects including: financial advice for the Oregon AFL-CIO; statistical analysis of equal opportunity for Oregon Bank; cost of capital for the James River dioxin review; and economic analysis of qualifying facilities for Washington Hydro Associates
1980-1986	Taught classes in senior and graduate forecasting, micro-economics, and energy at Portland State University

Education

Unfinished Ph.D.	Economics, Cornell University; Teaching Assistant in micro- and macro-economics
M.A.	Economics, Portland State University, 1975; Research Assistant
B.A.	Economics, Reed College, 1972; undergraduate thesis, "Eurodollar Credit Creation"

Areas of specialization include micro-economics, statistics, and finance

Papers and Publications

January 19, 2016	"A good time for a sensibly managed Portland gas tax", *The Portland Oregonian*
October 15, 2015	"A plan to fix Portland's roads", *The Portland Oregonian*
June 2015	"Estimating the Longevity of Commercial Nuclear Reactors", *Public Utilities Fortnightly*
December 2014	"Nuclear Winter", *Electricity Policy*
July 2013	"Mid-Columbia Spot Markets and the Renewable Portfolio Standard", *Public Utilities Fortnightly*
April 14, 2013	"Selling Low and Buying High", *The Oregonian*
December 2012	"Are Electric Vehicles Actually Cost-Effective?", *Electricity Policy*
November 30, 2012	"Portland's Energy Credits: The trouble with buying 'green'", *The Oregonian*

July 2009	"Fingerprinting the Invisible Hand", *Public Utilities Fortnightly*
February 2008	Co-author, "The High Cost of Restructuring", *Public Utilities Fortnightly*
March 27, 2006	Co-author, "A Decisive Time for LNG", *The Daily Astorian*
February 9, 2006	"Opening the Books", *The Oregonian*
August 2005	"Squeezing Scarcity from Abundance", *Public Utilities Fortnightly*
April 1, 2002	"The California Crisis: One Year Later", *Public Utilities Fortnightly*
March 13, 2002	"A Sudden Squall", *The Seattle Times*
March 1, 2002	"What the ISO Data Says About the Energy Crisis", *Energy User News*
February 1, 2001	"What Oregon Should Know About the ISO", *Public Utilities Fortnightly*
January 1, 2001	"Price Spike Tsunami: How Market Power Soaked California", *Public Utilities Fortnightly*
March 1999	"Winners & Losers in California", *Public Utilities Fortnightly*
July 15, 1998	"Are Customers Necessary?", *Public Utilities Fortnightly*
March 15, 1998	"Can Electricity Markets Work Without Capacity Prices?", *Public Utilities Fortnightly*
February 1998	"Coping With Interruptibility", *Energy Buyer*
January 1998	"Pondering the Power Exchange", *Energy Buyer*
December 1997	"Getting There Is Half the Cost: How Much Is Transmission Service?", *Energy Buyer*
November 1997	"Is Capacity Dead?", *Energy Buyer*
October 1997	"Pacific Northwest: An Overview", *Energy Buyer*
August 1997	"A Primer on Price Volatility", *Energy Buyer*
June 1997	"A Revisionist's History of the Future", *Energy Buyer*
Winter 1996	"What Are We Waiting for?" *Megawatt Markets*

October 21, 1996	"Trading on the Index: Spot Markets and Price Spreads in the Western Interconnection", *Public Utilities Fortnightly*

McCullough Research Reports

November 19, 2015	"Market Cost of the Columbia Generating Station During the FY 2014/2015 Refueling Cycle"
September 30, 2015	"Decrypting New York's "Secret" Electric Bids"
September 9, 2015	"Market Power in West Coast Gasoline Markets: September Update"
September 8, 2015	"August 10, 2015 PADD 2 Gasoline Spike at BP Whiting's Pipestill 12"
July 23, 2015	"Market Power in West Coast Gasoline Markets: July Update"
June 23, 2015	"Market Power in West Coast Gasoline Markets: June Update"
May 25, 2015	"Site C Business Case Assumptions Review"
April 7, 2015	"2015 Paducah Update"
April 6, 2015	"Market Power in West Coast Gasoline Markets: April Update"
March 23, 2015	"Market Power in West Coast Gasoline Markets"
March 20, 2015	"Daniel Poneman and the Paducah Transaction"
February 11, 2014	"Energy Northwest's Revised Analysis of the Paducah Fuels Transaction"
January 25, 2014	"Energy Northwest Losses in the 2013 Forward Purchase of Nuclear Fuel"
January 2, 2014	"Review of the November 2013 Energy Northwest Study"
January 2, 2015	"Data and Methodological Errors in the Portland Commercial Street Fee"
December 15, 2014	Report to the Bureau d'audiences publiques sur l'environment (BAPE), "Uranium Mining in Quebec: Four Conclusions"

December 11, 2013	"Economic Analysis of the Columbia Generating Station"
February 21, 2013	"McCullough Research Rebuttal to Western States Petroleum Association"
November 15, 2012	"May and October 2012 Gasoline Price Spikes on the West Coast"
June 5, 2012	"Analysis of West Coast Gasoline Prices"
October 3, 2011	"Lowering Florida's Electricity Prices"
July 14, 2011	"2011 ERCOT Blackouts and Emergencies"
March 1, 2010	"Translation" of the September 29, 2008 NY Risk Consultant's Hydraulics Report to Manitoba Hydro CEO Bob Brennan
December 2, 2009	"Review of the ICF Report on Manitoba Hydro Export Sales"
June 5, 2009	"New York State Electricity Plants' Profitability Results"
May 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas"
April 7, 2009	"A Forensic Analysis of Pickens' Peak: Speculation, Fundamentals or Market Structure"
March 30, 2009	"New Yorkers Lost $2.2 Billion Because of NYISO Practices"
March 3, 2009	"The New York Independent System Operator's Market-Clearing Price Auction is Too Expensive for New York"
February 24, 2009	"The Need for a Connecticut Power Authority"
January 7, 2009	"Review of the ERCOT December 18, 2008 Nodal Cost Benefit Study"
August 6, 2008	"Seeking the Causes of the July 3rd Spike in World Oil Prices" (updated September 16, 2008)
April 7, 2008	"Kaye Scholer's Redacted 'Analysis of Possible Complaints Relating to Maryland's SOS Auctions'"
February 1, 2008	"Some Observations on Societe Generale's Risk Controls"
June 26, 2007	"Looking for the 'Voom': A Rebuttal to Dr. Hogan's 'Acting in Time: Regulating Wholesale Electricity Markets'"

September 26, 2006	"Did Amaranth Advisors, LLC Attempt to Corner the March 2007 NYMEX at Henry Hub?"
May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio: Energy Strategies for Cities and Other Public Agencies"
April 12, 2005	"When Oil Prices Rise, Using More Ethanol Helps Save Money at the Gas Pump"
April 12, 2005	"When Farmers Outperform Sheiks: Why Adding Ethanol to the U.S. Fuel Mix Makes Sense in a $50-Plus/Barrel Oil Market"
April 12, 2005	"Enron's Per Se Anti-Trust Activities in New York"
February 15, 2005	"Employment Impacts of Shifting BPA to Market Pricing"
June 28, 2004	"Reading Enron's Scheme Accounting Materials"
June 5, 2004	"ERCOT BES Event"
August 14, 2003	"Fat Boy Report"
May 16, 2003	"CERA Decision Brief"
January 16, 2003	"California Electricity Price Spikes"
November 29, 2002	"C66 and Artificial Congestion Transmission in January 2001"
August 17, 2002	"Three Days of Crisis at the California ISO"
July 9, 2002	"Market Efficiencies"
June 26, 2002	"Senate Fact Sheet"
June 5, 2002	"Congestion Manipulation"
May 5, 2002	"Enron's Workout Plan"
March 31, 2002	"A History of LJM2"
February 2, 2002	"Understanding LJM"
January 22, 2002	"Understanding Whitewing"

Testimony and Comment

August 24, 2015	Testimony to the New York State Public Service Commission on behalf of the New York State Legislative Assembly
May 29, 2015	Testimony before the Federal Energy Regulatory Commission on behalf of Illinois Attorney General Lisa Madigan
December 15, 2014	Testimony before the Bureau d'audiences publiques sur l'environment (BAPE) in Quebec, "Uranium Mining in Quebec: Four Conclusions"
November 15, 2012	Testimony before the California State Senate Select Committee on Bay Area Transportation on West Coast gasoline price spikes in 2012
July 20, 2010	Testimony before the Rhode Island Public Utility Commission on the Deepwater offshore wind project
April 7, 2009	Testimony before the U.S. Senate Committee on Energy and Natural Resources on "Pickens' Peak"
March 5, 2009	Testimony before the New York Assembly Committee on Corporations, Authorities and Commissions, and the Assembly Committee on Energy, "New York Independent System Operators Market Clearing Price Auction is Too Expensive for New York"
February 24, 2009	Testimony before the Energy and Technology Committee, Connecticut General Assembly, "An Act Establishing a Public Power Authority" on behalf of AARP
September 16, 2008	Testimony before the U.S. Senate Committee on Energy and Natural Resources, "Depending On 19th Century Regulatory Institutions to Handle 21st Century Markets"
January 7, 2008	Supplemental Comment ("The Missing Benchmark in Electricity Deregulation") before the Federal Energy Regulatory Commission on behalf of American Public Power Association, Docket Nos. RM07-19-000 and AD07-7-000
August 7-8, 2007	Testimony before the Oregon Public Utility Commission on behalf of Wah Chang, Salem, Oregon, Docket No. UM 1002
February 23 and 26, 2007	Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180

October 2, 2006	Direct Testimony before the Régie de l'énergie, Gouvernement du Québec on behalf of the Grand Council of the Cree
August 22, 2006	Rebuttal Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
June 1, 2006	Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
May 8, 2006	Testimony before the U.S. Senate Democratic Policy Committee, "Regulation and Forward Markets: Lessons from Enron and the Western Market Crisis of 2000-2001"
December 15, 2005	Direct Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
December 14, 2005	Deposition before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, No. 04-5052RBL
December 4, 2005	Expert Report on behalf of Utility Choice Electric in Civil Action No. 4:05-CV-00573
July 27, 2005	Expert Report before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, Docket No. CV04-5052RBL
May 6, 2005	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
May 1, 2005	Rebuttal Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
March 24-25, 2005	Deposition by Enron Power Marketing, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.

February 14, 2005	Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
January 27, 2005	Supplemental Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180, et al.
April 14, 2004	Deposition by Enron Power Marketing, Inc. and Enron Energy Services before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
April 10, 2004	Rebuttal Testimony on behalf of the Office of City and County Attorneys, San Francisco, California, City and County Attorneys, San Francisco, California v. Turlock Irrigation District, Non-Binding Arbitration
February 24, 2004	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
March 20, 2003	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of the City of Seattle, Washington, Docket No. EL01-10, et al.
March 11-13, 2003	Deposition by IdaCorp Energy L.P. before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
March 3, 2003	Expert Report before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
February 27, 2003	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington and the Port of Seattle, Washington, Docket No. EL01-10-005
October 7, 2002	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
October 2002	Expert Report before the Circuit Court of the State of Oregon for the County of Multnomah on behalf of Alcan, Inc., Alcan, Inc. v. Powerex Corp., Case No. 50 198 T161 02

September 27, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8-9, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
June 28, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
May 6, 2002	Rebuttal Testimony before the Public Service Commission of Utah on behalf of Magnesium Corporation of America in the Matter of the Petition of Magnesium Corporation of America to Require PacifiCorp to Purchase Power from MagCorp and to Establish Avoided Cost Rates, Docket No. 02-035-02
April 11, 2002	Testimony before the U.S. Senate Committee on Commerce, Science and Transportation, Washington DC
February 13, 2002	Testimony before the U.S. House of Representatives Subcommittee on Energy and Air Quality, Washington DC
January 29, 2002	Testimony before the U.S. Senate Committee on Energy and Natural Resources, Washington DC
August 30, 2001	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10

August 16, 2001	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
June 12, 2001	Rebuttal Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
April 17, 2001	Before the Public Utility Commission of the State of Oregon, Direct Testimony on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
March 17, 2000	Rebuttal Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10
February 1, 2000	Direct Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10

Presentations

May 6, 2014	"Economic Analysis of the Columbia Generating Station", Energy Northwest, Boise, Idaho
April 30, 2014	"Economic Analysis of the Columbia Generating Station", Portland State University, Portland, Oregon
April 22, 2014	"Economic Analysis of the Columbia Generating Station", Clark County, Vancouver, Washington
January 9, 2014	"Economic Analysis of the Columbia Generating Station", Northwest Power & Conservation Council, Portland, Oregon
January 1, 2014	"Economic Analysis of the Columbia Generating Station", Bonneville Power Administration, Portland, Oregon
December 2, 2013	"Economic Analysis of the Columbia Generating Station", Skamania, Carson, Washington
December 1, 2013	"Peak Peddling: Has Portland Bicycling Reached the Top of the Logistic Curve?" Oregon Transportation Research and Education Consortium, Portland, Oregon

July 12, 2013	"Economic Analysis of the Columbia Generating Station", Tacoma, Washington
June 21, 2013	"Economic Analysis of the Columbia Generating Station", Seattle City Light, Seattle, Washington
January 29, 2013	"J.D. Ross (Who)", Portland Rotary Club, Portland, Oregon.
January 13, 2011	"Estimating the Consumer's Burden from Administered Markets", American Public Power Association conference, Washington, DC
October 15, 2009	"The Mysterious New York Market", EPIS, Tucson, Arizona
October 14, 2009	"Do ISO Bidding Processes Result in Just and Reasonable Rates?", legal seminar, American Public Power Association, Savannah, Georgia
June 22, 2009	"Pickens' Peak Redux: Fundamentals, Speculation, or Market Structure", International Association for Energy Economics
June 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas", Presentation at Texas Legislature
May 8, 2009	"Pickens' Peak", Economics Department, Portland State University
April 7, 2009	"Pickens' Peak: Speculators, Fundamentals, or Market Structure", 2009 EIA energy conference, Washington, DC
February 4, 2009	"Why We Need a Connecticut Power Authority", presentation to the Energy and Technology Committee, Connecticut General Assembly
October 28, 2008	"The Impact of a Volatile Economy on Energy Markets", NAESCO annual meeting, Santa Monica, California
April 1, 2008	"Connecticut Energy Policy: Critical Times…Critical Decisions", House Energy and Technology Committee, the Connecticut General Assembly
May 23, 2007	"Past Efforts and Future Prospects for Electricity Industry Restructuring: Why Is Competition So Expensive?", Portland State University
February 26, 2007	"Trust, But Verify", Take Back the Power Conference, National Press Club, Washington, DC

May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio"
February 12, 2005	"Northwest Job Impacts of BPA Market Rates"
January 5, 2005	"Why Has the Enron Crisis Taken So Long To Solve?", Public Power Council, Portland, Oregon
September 20, 2004	"Project Stanley and the Texas Market", Gulf Coast Energy Association, Austin, Texas
September 9, 2004	"Back to the New Market Basics", EPIS, White Salmon, Washington
June 8, 2004	"Caveat Emptor", ELCON West Coast Meeting, Oakland, California
June 9, 2004	"Enron Discovery in EL03-137/180"
March 31, 2004	"Governance and Performance", Public Power Council, Portland, Oregon
January 23, 2004	"Resource Choice", Law Seminars International, Seattle, Washington
January 17, 2003	"California Energy Price Spikes: The Factual Evidence", Law Seminars International Seattle, Washington
January 16, 2003	"The Purloined Agenda: Pursuing Competition in an Era of Secrecy, Guile, and Incompetence"
September 17, 2002	"Three Crisis Days", California Senate Select Committee, Sacramento, California
June 10, 2002	"Enron Schemes", California Senate Select Committee Sacramento, California
May 2, 2002	"One Hundred Years of Solitude"
March 21, 2002	"Enron's International Ventures", Oregon Bar International Law Committee, Portland, Oregon
March 19, 2002	"Coordinating West Coast Power Markets", GasMart, Reno, Nevada
March 19, 2002	"Sauron's Ring", GasMart, Reno, Nevada

January 25, 2002	"Deconstructing Enron's Collapse: Buying and Selling Electricity on The West Coast", Seattle, Washington
January 18, 2002	"Deconstructing Enron's Collapse", Economics Seminar, Portland State University
November 12, 2001	"Artifice or Reality", EPIS Energy Forecast Symposium, Skamania, Washington
October 24, 2001	"The Case of the Missing Crisis" Kennewick Rotary Club, Kennewick, Washington
August 18, 2001	"Preparing for the Next Decade"
June 26, 2001	"Examining the Outlook on Deregulation"
June 25, 2001	Presentation, Energy Purchasing Institute for International Research (IIR), Dallas, Texas
June 6, 2001	"New Horizons: Solutions for the 21st Century", Federal Energy Management-U.S. Department of Energy, Kansas City, Kansas
May 24, 2001	"Five Years"
May 10, 2001	"A Year in Purgatory", Utah Industrial Customers Symposium-Utah Association of Energy Users, Salt Lake City, Utah
May 1, 2001	"What to Expect in the Western Power Markets this Summer", Western Power Market Seminar, Denver, Colorado
April 23, 2001	"Emerging Markets for Natural Gas", West Coast Gas Conference, Portland, Oregon
April 18, 2001	"Demystifying the Influence of Regulatory Mandates on the Energy Economy" Marcus Evans Seminar, Denver, Colorado
April 4, 2001	"Perfect Storm", Regulatory Accounting Conference, Las Vegas, Nevada
March 21, 2001	"After the Storm 2001", Public Utility Seminar, Reno, Nevada
February 21, 2001	"Future Imperfect", Pacific Northwest Steel Association, Portland, Oregon
February 12, 2001	"Power Prices in 2000 through 2005", Northwest Agricultural Chillers, Bellingham, Washington

February 6, 2001	Presentation, Boise Cascade Management, Boise, Idaho
January 19, 2001	"Wholesale Pricing and Location of New Generation Buying and Selling Power in the Pacific Northwest", Seattle, Washington
October 26, 2000	"Tsunami: Market Prices since May 22nd", International Association of Refrigerated Warehouses, Los Vegas, California
October 11, 2000	"Tsunami: Market Prices since May 22nd", Price Spikes Symposium, Portland, Oregon
August 14, 2000	"Anatomy of a Corrupted Market", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 30, 2000	"Northwest Market Power", Governor Locke of Washington, Seattle, Washington
June 10, 2000	"Northwest Market Power", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 5, 2000	"Northwest Market Power", Georgia Pacific Management
May 10, 2000	"Magnesium Corporation Developments", Utah Public Utilities Commission
May 5, 2000	"Northwest Power Developments", Georgia Pacific Management
January 12, 2000	"Northwest Reliability Issues", Oregon Public Utility Commission

Volunteer Positions

2015-Present	Board member, Portland State University Master in Public Policy Advisory Committee
2013-Present	Eastmoreland Neighborhood Association, President
2013-Present	Southeast Uplift Neighborhood Coalition, President
2013-Present	City of Portland Office of Management and Finance Advisory Committee
1990-Present	Chairman, Portland State University Economics Department Advisory Committee

Robert F. McCullough, Jr.
Principal

EXPERT REPORT OF ROBERT McCULLOUGH
February 10, 2016

I am the principal of an energy consulting firm named "McCullough Research" and have been active in the industry since 1979. I have worked on issues related to Site C and British Columbia Hydro on many occasions including as an employee or consultant to utilities and industries doing business with them, appearing as an expert witness on issues involving them, and advising parties affected by their decisions.

From 1979 through 1991, I held positions of increasing responsibility at Portland General Electric, a large hydro-electric and thermal utility. In 1991, I resigned my position as special assistant to the chairman of the board in order to found McCullough Research. Since 1991, I have advised governments, utilities, regulatory authorities, and aboriginal groups from Nova Scotia to California. I have been asked to testify before the U.S. Congress on issues ranging from electric markets to oil speculation, appeared in national and international journals and electronic media, testified before state and federal courts, arbitrations, and regulatory authorities, and participated in federal and state prosecutions for market manipulations in Washington, Montana, Illinois, Texas, and California. I am also an adjunct professor at Portland State University. My curriculum vitae is attached as Exhibit A to my affidavit.

Reviewing my files, I find that I first worked on Site C issues for Portland General Electric in the early 1980s. Although the discussions are immaterial to this proceeding, we reviewed the Site C plans at that time and, in determining whether to take ownership, declined on account of its high cost.

My mandate in this proceeding is to impartially review the affidavits of Mr. Andrew Watson and Mr. Michael Savidant on the economic and energy supply issues attendant with a one to five year delay of the Site C project. The specific questions I have been asked to address are:

> 1. In your opinion, do Affidavits of Michael Savidant and/or Andrew Watson demonstrate that there would be a net cost to BC Hydro occasioned by delaying construction of the Site C Project?
>
> 2. Assuming that the in-service date is delayed by a period equivalent to a delay in construction, is it likely that there would be a net cost occasioned to BC Hydro if construction were delayed by one, two or five years?

It is my finding that a delay in the construction of Site C, amounting to a delay in the in-service date of Site C, would amount to a net savings to British Columbia Hydro and its ratepayers, not a net cost. The net savings of a one year delay, in present value terms, is $267.68 million; for a two year delay it is $519.44 million; for a five year delay, the net savings is $1,187.47 million.

I find the economic presentation of Mr. Savidant surprisingly brief for such a serious issue – so brief that I queried whether critical materials had been inadvertently omitted from the package I had reviewed.

In this case, Mr. Savidant has asked the court to take his estimates largely on faith. From materials available in other proceedings, it appears that he has had little previous experience with power plant construction or power marketing, two issues central to the conclusions in his affidavit. He has had experience with the financial model used at Site C. This model, which could answer many questions in this proceeding, was not part of his affidavit.[1]

Mr. Savidant's affidavit contains no description of his updated calculations, displays a very limited understanding of project cost estimation, and contains a number of errors of fact.

I have calculated the cost impact on British Columbia rate and tax payers, in Net Present Value (NPV). The savings from delay offset the cost impacts for the immediate future due to the dramatic fall in world energy prices since 2008:

	NPV No Delay	NPV With Delay
One Year Delay	$9,883,562,976	$9,615,887,567
Two Year Delay	$9,893,853,744	$9,374,415,189
Five Year Delay	$9,922,960,730	$8,735,487,577

Please note that the No Delay cases change with the inclusion of a longer time horizon – a five year delay requires calculations through to the end of the 105 year study period, a two year delay through 102 years, and a one year delay through 101 years.

These conclusions are discussed in much greater detail blow.

[1] Curriculum Vitae of Mr. Michael Savidant, Exhibit 1 to his August 12, 2015 affidavit.

Review of Mr. Savidant's Affidavits

Mr. Savidant's current affidavit includes two previous affidavits as Exhibits A and B. The three affidavits propound rapidly increasing costs of delay for the same one year period.

In paragraph 2 of his current affidavit, Mr. Savidant reported that the cost of a one year delay at $175 million as estimated of January 15, 2015. This value is supported briefly in Exhibit A to his affidavit as $65 million in increased construction costs, $60 million in increased financing costs, and $50 million allowance for inflation and escalation.[2]

In paragraph 72 of Exhibit B to his current affidavit, Mr. Savidant revised his estimate to $335 million as of August 12, 2015. At this time the additional direct costs increased to $100 million, $135 million in financing costs, and inflation to $100 million.

In paragraph 5 of his current affidavit, he again revises his estimate.[3] The direct costs of delay have increased to $160 million, $160 million in financing costs, and $100 million in inflation.

Paragraph 6 of his affidavit would appear to be in error since he states that "Because construction has now been ongoing for over five months, a delay at this time is expected to result in approximately $50 million of additional direct costs that did not exist in August 2015." This contradicts the values in paragraph 5 of his affidavit since he had increased the value $60 million from his previous estimate.

In a project of this size, an error of $10 million dollars is not significant. It is, however, significant in this affidavit since he has provided no details to support these values.

Placed side by side, the differences in his three estimates cast further doubt on his arithmetic:

	Affidavit of 1/15/2015	Affidavit of 8/12/2015	Affidavit of 1/28/2016
Direct Costs	$65.00 million	$100.00 million	$160.00 million
Interest	$60.00 million	$135.00 million	$160.00 million
Escalation	$50.00 million	$100.00 million	$100.00 million
Total	$175.00 million	$335.00 million	$420.00 million

In his estimation calculations, Mr. Savidant has not changed the presumed escalation since August. This would make some sense if the $50 or $60 million change in direct costs over this period has already taken place. Interest During Construction (IDC) is significant even in today's economic environment. In this case, he has assumed that interest costs are $25 million

[2] Affidavit of Michael Savidant, January 28, 2016, Exhibit A, paragraph 14.
[3] Ibid, paragraph 4.

for an increase in direct construction costs of $50 or $60 million. If the value is, in fact, $60 million, he is assuming a rather dramatic fall in interest to something in the range of 5%.[4]

Other than the lack of documentation, this is a possible value. However, it seems at odds with his similar calculation in August. When he changed his August estimate, he increased financing costs by $75 million on a direct cost change of only $35 million. This would imply an interest rate of 18%.[5] An interest rate of 18% is not a credible assumption in today's financial markets.

The sequence of rapidly increasing values is surprising since he had described exactly the same delay in each affidavit. In the absence of calculations and explanations, it is necessary to reverse engineer how he came to his numbers.

Complex engineering projects such as power plants comprise a variety of different tasks. The developer creates a schedule of tasks that must be accomplished. Contracts are signed with a variety of firms to accomplish each task. At specific milestones, progress payments are paid to contractors.

Mr. Watson's affidavit contains an excerpt from a version of the Main Civil Works Contract that references both the preliminary project schedule and the payment schedule.[6] Bearing in mind that project and payment schedules are often flexible in the early period after signing, the contract language on payments is reproduced below:

> "3 CONTRACT PRICE
> 3.1 Contract Price
> The price for the Work (the "Contract Price") will be the sum in Canadian dollars of the following:
> (a) the product of the actual quantities of the Price Items listed in Appendix 11-1 [Schedule of Prices and Estimated Quantities] which are incorporated into or related to the Work and the unit prices listed in Appendix 11-1 [Schedule of Prices and Estimated Quantities]; plus
> (b) all lump sums, if any, as listed in Appendix 11-1 [Schedule of Prices and Estimated Quantities], for Price items incorporated into or related to the Work; plus

---

[4] Interest During Construction accrues from the date of expenditure to the in-service date. I have assumed that he is assuming eight years.

[5] I have again assumed that all expenditures have been made eight years before the in-service date. This is conservative since, if so, there would have been no increase in escalation between his January 15, 2015 estimate and his August 12, 2015 estimate.

[6] Affidavit of Andrew Watson, January 28, 2016, Exhibit T, pages 3 and 4.

> (c) any payment adjustments, including any payments owing on account of Changes, approved in accordance with the provisions of the Contract Documents.
> 3.2 Entire Compensation
> The Contract Price will be the entire compensation owing to the Contractor for the complete performance of the Work and this compensation will cover and include all profit and all costs of labour, supervision, material, equipment, transportation and delivery, overhead, financing and all other costs and expenses whatsoever incurred by the Contractor in performing the Work."[7]

The sequence of tasks and progress payments comprise the basis for a financing plan that sets out the need for funds and the cost of financing at each stage. The grand total of direct construction costs paid over time and the financing costs required during construction comprise the total cost of the project. Utilities often refer to the cost calculated on the in-service date as the "Revenue Requirement." In most jurisdictions, the revenue requirement is submitted to a regulatory body who approves the expenditure and increases rates charged to customers accordingly.

The cost of delay arises frequently in large energy projects. Projects as large as Site C are often delayed for causes ranging from litigation to acts of nature. A competent project proponent like British Columbia Hydro would know to the penny what each contingency will cost since management and financing presentations generally focus on such issues.

Analysis of the cost of delay follows a well-trodden path. To the degree that contracts have been signed, the cost of delay is governed by the delay and liquidated damage provisions in the contracts.

My staff has asked British Columbia Hydro for access to contracts cited in Mr. Savidant's affidavit, but we have not yet received an answer. If Mr. Savidant had included the appropriate contracts, schedules, and financing plan, discussion of delay costs would be based on actual data – not surmise – and I would expect that his frequently changed estimates would be replaced by solid businesslike calculations.

Delays in complex projects are commonplace. If the delay is outside the control of the contractor – an act of God, civil unrest, a transportation interruption, or some other event – the cost of delay is the interest that must be paid during the course of the delay on funds already expended plus any escalation of costs that affects payments that have yet to made in future periods. If the delay is caused by factors under control of the contractor, it is common for a

[7] Ibid., Exhibit T, page 5.

calculation of liquidated damages to reimburse the developer for costs caused by the contractor.

Mr. Savidant's reasoning behind the most recent increase in direct costs is not easily compatible with the description of project economics described above. Mr. Savidant reports that British Columbia Hydro has invested $695 million as of year-end.[8] At the end of FY 2015, the Site C balance was $419 million.[9] If the cost of delay and one year's interest on the existing balance is totaled, it would come to something on the order of $200 million.[10] Since the total investment in Site C only increased $276 million over this period, we are led to believe that the disruption in schedules consumed most of the investment in Site C this year.

His narrative has some unusual delay costs. For example, he notes that the primary contract – the Main Civil Works contract – will not even begin to commence mobilization until this month.[11] Since it is unlikely that progress payments have preceded initiation of work, there should be no interest applied to the non-existent progress payments. Moreover, Mr. Savidant has not increased his provision for inflation, so he apparently does not believe that any costs under the $1.4 billion contract will be increased by delay.

He goes on to cite a second major contract for turbines that have not even been signed yet. He lists this contract as a reason why delay costs have gone up.[12] Again, there is no reason why a delay in an unsigned contract would raise costs other than inflation. However, he had no allowance for increased inflation in the new estimate.

Adding to direct costs because of a delay when no costs under the contracts have been incurred yet seems speculative at best. Delay in work under the contracts might expose the developer to inflation, but he has not increased his allowance for inflation.

In the absence of complete calculations and explanations, a reasonable person could question whether these two major contracts had been mistakenly listed as causes for the higher delay cost.

The Benefits of Delay

Several years ago a young economist in my employ questioned my decision to replace all of the light bulbs at my office with LED luminaires. While she agreed that replacement had become cost effective, she noted that economies of scale in the manufacture of LEDs would

[8] Ibid., paragraph 6.
[9] 2015 British Columbia Hydro Annual Report, page 29. See Appendix B to this report.
[10] $160 million for delay costs plus interest on the FY 2015 balance and the additional direct costs.
[11] Affidavit of Michael Savidant, paragraph 6(a)iii.
[12] Ibid., paragraph 6(a)IIII.

make them even more cost effective if I delayed. The cheaper costs in years to come would offset a decision today. She noted that delaying my decision would allow us to purchase light bulbs at a lower price later.

British Columbia Hydro faces the same problem today. In the case of Site C, the project is competing against a worldwide decrease in the cost of fossil fuels. The market implications of the global surplus are that low natural gas prices in the United States and Canada generally set the price of energy and capacity for years to come. Export of Site C, by any measure, will be at a considerable loss in the early years. This would normally encourage a profit-oriented developer to delay in order to produce energy at higher prices at a later date. Alternatively, if Site C turns out to be needed in the early years, it will be cheaper to purchase energy and capacity for some years.

The global context of lower energy prices is hardly a matter for debate. Acknowledged organizations like the National Energy Board, the U.S. Energy Information Administration, and the Pacific Northwest Regional Planning Council have all issued forecasts showing low future electric and natural gas prices.[13,14,15] I have also written and spoken extensively on the issue including an article in the industry's leading journal and a monograph on the market's impact on nuclear power.[16,17]

The Pacific Northwest Regional Planning Council, a federally funded agency that forecasts and plans for the four states of Oregon, Washington, Idaho, and Montana, have recently issued a price forecast that is less than the cost of Site C until 2051.[18] It is not my assignment here to argue the necessity or economy of Site C. It is my assignment to note that if Site C is delayed, market prices are likely to allow replacement of its energy to confer a significant benefit to British Columbia rate and tax payers.

As in the case of the LED light bulbs, a decision to delay allows years of lower price market energy and capacity to fill the gap, if needed.

[13] Canada's Energy Future 2016 at https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/index-eng.html. See Appendix C to this report.
[14] Annual Energy Outlook 2015 at http://www.eia.gov/forecasts/aeo/. See Appendix D to this report.
[15] Seventh Power Plan at https://www.nwcouncil.org/energy/powerplan/7/home/. See Appendix E to this report.
[16] "Mid-Columbia Spot Markets and the Renewable Portfolio Standard", Robert McCullough, Public Utilities Fortnightly, July 2013. See Appendix F to this report.
[17] Economic Analysis of the Columbia Generating Station, Robert McCullough, Marc Vatter, Rose Anderson, Jil Heimensen, Sean Long, Christopher May, Andrew Nisbet, & Garrett Oursland, December 2013. See Appendix G to this report.
[18] The market price forecast ends in 2015, but has been extended using the implicit escalation rate to 2130.

The dramatic shift in electric, natural gas, oil, and coal prices since 2008 have changed investment plans around the world. The Pacific Northwest Planning Council's new plan recommends against major new power plants in the Pacific Northwest.[19]

This is hardly surprising. In preparing this testimony, I reviewed many reports of delayed energy projects across the world. Similar large projects, like LNG terminals, have delayed construction in North America. On Friday, February 4, 2016, Shell announced a one year delay of the Kittimat LNG terminal.[20]

Mr. Savidant made no mention of the benefits of delay in his current affidavit. The only reference is in his August 12 affidavit, where he states:

> "In the electricity market that BC Hydro primarily trades with for imports and exports (the Mid-C market), capacity is not generally found as a firm product similar to a BC-based generation resource. The Mid-C market for capacity is an undeveloped and illiquid market, and it would not be prudent for BC Hydro to rely on this market for a substantial amount of dependable capacity required to meet customer requirements."[21]

I disagree with Mr. Savidant's opinion that the Mid-C market for capacity is undeveloped. His August 12, 2015 affidavit shows a surprising lack of knowledge concerning markets in the Northwest Power Pool.[22] He is apparently unaware that British Columbia Hydro has been a seller in Northwest Power Pool capacity markets since 1964.[23] Since 2002, almost all electric transactions in the United States have been available on the U.S. Federal Energy Regulatory Commission's web site at http://www.ferc.gov/docs-filing/eqr.asp. In 2014 and 2015, BC Hydro's power marketing subsidiary reported 4,784 capacity transactions, with a total revenue of U.S. $7,829,805.37.

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[19] Seventh Northwest Conservation and Electric Power Plan. Chapter 3, Resource Strategy. See Appendix H to this report.

[20] http://www.prnewswire.com/news-releases/royal-dutch-shell-plc-4th-quarter-and-full-year-2015-unaudited-results-567630531.html See Appendix I to this report.; see also: http://lngcanada.ca/project/news-update. See Appendix J to this report.

[21] Affidavit of Michael Savidant, January 29, 2016, Exhibit B, paragraph 82.

[22] Canadian and U.S. electric reliability areas are highly integrated. British Columbia Hydro is part of the Northwest Power Pool which includes British Columbia, Alberta, Washington, Oregon, Idaho, and Montana. This area has a vibrant power market for energy and capacity that has been in operation for many, many years.

[23] British Columbia receives capacity and energy from Columbia River dams under the 1964 Columbia River Treaty. Under the treaty, BC Hydro receives 1,320 megawatts of capacity and associated energy annually. A detailed discussion of the treaty from the Canadian perspective can be found at http://blog.gov.bc.ca/columbiarivertreaty/. See Appendix K to this report.

BC Hydro is neither the only participant in this market, nor the most important. Capacity transactions are commonplace. I, personally, have worked on such transactions in a variety of roles ranging from negotiations to litigation across my entire career.

Calculating the Total Cost of Delay

Modeling both the costs and benefits of delay is relatively simple. To analyze a one year delay, it is necessary to calculate the revenue requirement of Site C before and after the delay. The revenue requirement before delay is $8,775 million dollars. The revenue requirement after delay is higher by an amount equal to the financing cost of already-committed investments, $695 million, plus the additional price escalation on the remaining – delayed – investments.[24] If penalties under existing signed contracts exist, they would be part of the current committed funding.[25]

Delaying the in-service date from 2024 to 2025 requires purchase of energy and capacity equal to the generation lost in the delay. One further adjustment is known to industry practitioners as "end effects". The delayed plant plus replacement energy is a calculation that covers 101 years (including the 1 year of delay). Analysts include replacement energy and capacity to the calculation for the no delay period – the 101st year – to give the comparison comparable time-lines.

Calculation of the cost and benefits of delay uses a standard financial tool called Net Present Value (NPV). NPV summarizes the cost as a single number. The NPV for the No Delay case, if invested at BC Hydro's assumed cost of capital, would equal the costs of the project over 100 years, plus one year of replacement energy at the end of that period. The same procedure is used for the One Year Delay case, but with the replacement energy occurring in 2024. Both cases span the 101 years, 2024 through 2124. The difference is the benefit (or cost) of delay.

Since the turn of the last century, a standard regulatory formula has been in use to calculate the yearly cost to consumers. This formula can be found in any monograph or textbook on energy law. Dean of the Law School at the University of Cincinnati, Joseph Tolman, and the Honorable Richard Cudahy, Judge at the U.S. Court of Appeals for the Seventh Circuit, summarized the formula in his monograph on energy law as:[26]

D. THE RATE FORMULA

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[24] Affidavit of Michael Savidant, January 29, 2016, para. 6(c).

[25] Mr. Savidant has not mentioned such penalties, so it seems likely that they do not exist. However, if they do, they should be included.

[26] Energy Law, Joseph Tolman and Richard Cudahy, West Publishing, 1992.

> The traditional rate formula is intended to produce a utility's revenue requirement. The formula is simple to state:
>
> $R = O + (V — \sum D)r$
>
> The elements of the traditional rate formula are defined as:
>
> • R is the utility's total revenue requirement or rate level. This is the total amount of money a regulator allows a utility to earn.
> • O is the utility's operating expenses.[27]
> • V is the gross value of the utility's tangible and intangible property.
> • $\sum D$ is the utility's accrued depreciation. Combined $(V —\sum D)$ constitute the utility's rate base, also known as its capital investment.
> • r is the rate of return a utility is allowed to earn on its capital investment or on its rate base.[28]

While such formulas can appear daunting, the calculation is roughly the same as that for the family car. The payments to the dealership reflect both interest and principal. At the end of five years the car is completely paid off. Depreciation is comparable to repairs and upkeep. Operating expenses, or "O&M," would be similar to expenses for gasoline and oil.

We cannot know the actual values that the British Columbia Utilities Commission will use for this project when it comes into customer rates eight or nine years from now. However, it is prudent to use this industry formula and the data provided by British Columbia Hydro. As of December 2015, Site C's Construction and Development Cost, along with the Interest during Construction cost, amounts to \$8.335 billion.[29] With an additional \$440 million project reserve, this amounts to \$8.775 billion.[30] V would be \$8.775 billion. Depreciation is a science in and on itself. British Columbia Hydro has stated that the project will be in service for at

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[27] "In either case, depreciation on plant and equipment is subtracted from the rate base and carried as an operating expense. The theory behind including depreciation as an expense is that capital may be accumulated for further expansion and growth." Ibid., page 132.
[28] Ibid., page 130.
[29] BC Hydro. "Site C Capital Cost Estimate." December 2015. Accessed February 5, 2016. https://www.sitecproject.com/sites/default/files/Information-Sheet-Site-C-Capital-Cost-Estimate-December-2015.pdf. See Appendix L to this report.
[30] Ibid.

least 100 years. Straight line depreciation would be a standard choice, so the depreciation in the first year is $87.75 million.[31]

BC Hydro discusses its chosen discount rate (i.e., cost of capital) in Site C's IRP.[32]

BC Hydro uses two different values for the weighted average cost of capital in its Integrated Resource Plan. BC Hydro recommends a 5% real WACC for its own investments and 7% for IPPs and other third party developers; the 2% differential (and a sensitivity that reduces the differential to 1%) is set out in the Site C hydro project environmental assessment documentation and the IRP. The BC Hydro rate of 5% is reasonable, as its borrowing is guaranteed by the government, and BC Hydro may also borrow directly from the Province. The British Columbia Utilities Commission recognizes this, stating that "With respect to the cost of capital, BC Hydro projects will clearly have an advantage as a result of…access to the Province's high credit rating."[33]

BC Hydro does not disclose the projected O&M costs of Site C, once in operation. However, industry estimates exist for large hydroelectric projects. The International Energy Agency (IEA) estimates that hydro projects of this magnitude tend to incur O&M costs of US$40/kW-year.[34]

Page 284 of the Environmental Impact Statement attached to Mr. Watson's affidavit as Exhibit J states that Site C is expected to produce 5,100 GWh annually and 1,100 MW of capacity.[35]

To see the economic cost of delay, we would assume the existing costs identified in Mr. Savidant's most recent affidavit, $695 million dollars, and assume the financing costs of this $695 million until the in-service date. Mr. Savidant's presentation has not identified the interest rate that should be used, so I have assumed the 7% assumed in British Columbia Hydro's studies. This would indicate that $1,277 million dollars of the total $8,775 million estimated cost will have been "sunk" costs by 2025.

[31] On page 50 of its 2015 Annual Report, BC Hydro remarks that straight-line depreciation is used in its own analyses. See: BC Hydro. "2015 Annual Report." Accessed February 5, 2016. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-2015.pdf. See Appendix M to this report.
[32] https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html. See Appendix N to this report.
[33] Rachel Wilson et al. Review of BC Hydro's Alternatives Assessment Methodology. Synapse Energy Economics, September 23, 2014. See Appendix O to this report.
[34] International Energy Agency (2010), Energy Technology Perspectives 2010, OECD/IEA, Paris. https://www.iea.org/publications/freepublications/publication/etp2010.pdf. See Appendix P to this report.
[35] Affidavit #1 of Andrew Watson, January 29, 2016, Exhibit J, page 284.

The remaining $7,498 million can be delayed one, two, or five years. The following figures represent the NPV, or the discounted present value, of the total cost of Site C in the case of a one year, two year, and five year delay:

	NPV No Delay	NPV With Delay
One Year Delay	$9,883,562,976	$9,615,887,567
Two Year Delay	$9,893,853,744	$9,374,415,189
Five Year Delay	$9,922,960,730	$8,735,487,577

A delay in the construction of Site C, amounting to a delay in the in-service date of Site C, would amount to a net savings to British Columbia Hydro and its ratepayers, not a net cost. The net savings of a one year delay, in present value terms, is $267.68 million; for a two year delay it is $519.44 million; for a five year delay, the net savings is $1,187.47 million.

There is nothing mysterious about this result. Energy prices have plunged since 2008 and now reflect a very competitive alternative to Site C.

The calculation simply reflects the significant costs of delay for construction steps that have already been completed. Incurred costs would require interest until the project comes into service. On the other hand, delay for expenses that have not yet been incurred is less expensive, since the only incremental cost would be that of inflation. Since Site C has just begun, delay is an attractive option. In 2023, when most of the costs would have already been committed, delay would be significantly more expensive.[36]

Appendix Q contains the detailed results from 2024 through 2129.

Appendix A includes a list of citations.

This completes my report.

[36] NPV With Delay does not include ongoing costs of project management, such as renegotiation of contracts, or payments for security guards to monitor the site. Neither Mr. Watson nor Mr. Savidant presents documentation of these continuing costs. However, given the magnitude of the net savings by delaying, inclusion of these costs would almost certainly result in the same conclusion.

Appendix A – List of all cited Appendices

Appendix B – 2015 British Columbia Hydro Annual Report (excerpt), page 29.

Appendix C – Canada's Energy Future 2016 (excerpt) at https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/index-eng.html

Appendix D – Annual Energy Outlook 2015 (excerpt) at http://www.eia.gov/forecasts/aeo/

Appendix E – Seventh Northwest Conservation and Electric Power Plan (excerpt) at https://www.nwcouncil.org/energy/powerplan/7/home/

Appendix F – "Mid-Columbia Spot Markets and the Renewable Portfolio Standard", Robert McCullough, Public Utilities Fortnightly, July 2013.

Appendix G – Economic Analysis of the Columbia Generating Station (excerpt), Robert McCullough, Marc Vatter, Rose Anderson, Jil Heimensen, Sean Long, Christopher May, Andrew Nisbet, and Garrett Oursland, December 2013.

Appendix H – Seventh Northwest Conservation and Electric Power Plan (excerpt). Chapter 3, Resource Strategy at https://www.nwcouncil.org/energy/powerplan/7/home/

Appendix I – http://www.prnewswire.com/news-releases/royal-dutch-shell-plc-4th-quarter-and-full-year-2015-unaudited-results-567630531.html

Appendix J – http://lngcanada.ca/project/news-update

Appendix K – http://blog.gov.bc.ca/columbiarivertreaty/ (Treaty Highlights)

Appendix L – BC Hydro. "Site C Capital Cost Estimate." December 2015. Accessed February 5, 2016. https://www.sitecproject.com/sites/default/files/Information-Sheet-Site-C-Capital-Cost-Estimate-December-2015.pdf

Appendix M –2015 Annual Report, BC Hydro. “2015 Annual Report” (excerpt), pages 49-50. Accessed February 5, 2016 at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-2015.pdf

Appendix N – BC Hydro Integrated Resource Plan (excerpt), Chapter 4 at https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html

Appendix O – Rachel Wilson et al. Review of BC Hydro’s Alternatives Assessment Methodology. Synapse Energy Economics, September 23, 2014.

Appendix P – International Energy Agency (2010), Energy Technology Perspectives 2010 (excerpt), OECD/IEA, Paris.

Appendix Q – Excel output of delay calculations

British Columbia Hydro and Power Authority

2014/15
ANNUAL REPORT

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BC Hydro's Annual Report can be found online at:
http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html

Board Chair's Message and Accountability Statement

Chair's Message

The 2014/15 Annual Report outlines how BC Hydro is meeting the objectives laid out in the Government's Letter of Expectations and is aligning our organization with the Taxpayer Accountability Principles. Our Board members have all signed the addendum that is posted on bchydro.com publicly showing this support.

With prudent reinvestment, careful planning and strong, respectful relationships, BC Hydro is well positioned to deliver clean, reliable, low cost power for the long-term benefit of our growing province.

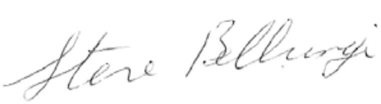
Accountability Statement

The BC Hydro 2014/15 Annual Report was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the B.C. Reporting Principles. The Board and Management are accountable for the contents of the Annual Report, including what has been included and how it has been reported.

The information presented reflects the actual performance of BC Hydro for the 12 months ended March 31, 2015 in relation to the 2014/15-2016/17 Service Plan. The Board is responsible for ensuring internal controls are in place to measure information and report accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of March 31, 2015 have been considered in preparing the report. The report contains estimates and interpretive information that represent the best judgment of management. Any changes in mandate direction, goals, strategies, measures or targets made since the 2014/15-2016/17 Service Plan was released and any significant limitations in the reliability of the information are identified in the report.

The BC Hydro 2014/15 Annual Report compares the corporation's actual results to the expected results identified in the 2014/15- 2016/17 Service Plan. I am accountable for those results as reported.



Stephen Bellringer
Board Chair

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2015**	2014
Energy Accounts		
Heritage Deferral Account	**$ 165**	$ 105
Non-Heritage Deferral Account	**524**	362
Trade Income Deferral Account	**244**	324
	933	791
Capital-Like Accounts		
Demand-Side Management (DSM)	**842**	788
Site C	**419**	338
Capital Project Investigation Costs	**30**	35
Smart Metering and Infrastructure (SMI)	**283**	277
IFRS Property, Plant and Equipment	**758**	617
	2,332	2,055
Forecast Variance Accounts		
Rate Smoothing Account	**166**	-
Non-Current Pension Cost	**564**	280
Foreign Exchange Gains and Losses	**(71)**	(89)
CIA Amortization	**87**	81
Finance Charges	**(173)**	(79)
Other Forecast Variance Accounts	**32**	56
	605	249
Non-Cash Accounts		
First Nations Costs & First Nations Provisions	**564**	589
Environmental Provisions & Costs	**382**	383
Future Removal and Site Restoration Costs	**(33)**	(56)
IFRS Pension & Other Post-Employment Benefits	**650**	688
	1,563	1,604
Total Regulatory Account Balance	**$ 5,433**	$ 4,699

BC Hydro has regulatory mechanisms in place to collect 26 of 28 regulatory accounts, which represent approximately 90 per cent of the total net regulatory account balance, in rates over various periods including six regulatory accounts which commenced amortization in fiscal 2015 and resulted in an additional $110 million of amortization expense for the year ended March 31, 2015 compared to the prior fiscal year.

COMPARISON WITH SERVICE PLAN

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan for fiscal 2014/15-2016/17 was filed in February 2014 and forecast net income for fiscal 2015 at $582 million.

Canada's Energy Future 2016

ENERGY SUPPLY AND DEMAND PROJECTIONS TO 2040

Canada

Cat. No. NE2-12/2015E-PDF
ISSN 2292-1710

This report is published separately in both official languages.
This publication is available upon request in multiple formats.

Nº de cat. NE2-12/2015F-PDF
ISSN 2292-1729

Ce rapport est publié séparément dans les deux langues officielles.
On peut obtenir cette publication sur supports multiples, sur demande.

Letter from the Chair and CEO of the National Energy Board

I am pleased to introduce the 2016 edition of the National Energy Board's *Energy Futures* series*. Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040* (EF 2016) continues a long tradition of energy outlooks which the National Energy Board has been producing regularly since 1967. The only publicly available Canadian long-term energy outlook covering all energy commodities and all provinces and territories, this series provides Canadians a key reference point for discussing the country's energy future. This Report relies on the extensive energy market expertise of the Board's technical staff. In addition, energy experts from government, industry, environmental organizations and academia across Canada provided input on the preliminary assumptions and results of this report. I would personally like to thank all those who contributed.

To use "uncertain" to characterize the past 18 months in Canadian energy would be an understatement. I doubt there is a single market observer who could have foreseen the dramatic fall in the global price of crude oil, one of Canada's largest exports, from US$110 per barrel in mid-2014 to less than US$40 per barrel by end of December 2015 and then to less than US$30 per barrel in January 2016. Among many other factors contributing to the lack of clarity on Canada's energy future were the unprecedented market volatility, the rapid deployment of advanced technologies for renewable and fossil fuel energy production, a historic climate agreement in Paris, the denial of the Keystone XL project in the U.S., the lifting of the U.S. oil export ban, as well as the lifting of sanctions on Iran.

Producing an energy supply and demand projection in this context is challenging, to say the least. Nonetheless, the projections in EF 2016 remain valid reference points for discussing Canada's long-term energy future amid the current global energy uncertainty. Our analysis is not a prediction of future outcomes but rather projections of what might occur given a certain set of assumptions and inputs. This report, which centers on a baseline projection, also outlines alternate projections for higher and lower energy prices, and alternate market access and energy infrastructure assumptions, and then goes on to explore the important long-term implications of these energy market uncertainties.

The alternative projections in EF 2016 strike me as particularly relevant in the current context. As recently noted by Bank of Canada Governor Stephen Poloz, the drop in crude oil prices, as well as in other commodities, has had an unambiguously negative impact on the Canadian economy. EF 2016 indicates that the development of future energy infrastructure directly impacts export prices, future production growth and the overall Canadian economy. While Canada has no influence on global commodity prices, it does have control over the ability to access new markets for our exports and receive the full value in the global market place, whatever future global prices may be.

Of course, building new infrastructure and reaching new markets will hinge on Canada's ability to develop its resources sustainably and transport them safely. And one thing that is clear amidst this uncertainty is that the link between energy and the environment is stronger than ever, and will continue to strengthen in the future. This stems from the fact that a majority of greenhouse gases (GHGs) emitted in Canada result from the combustion of fossil fuels and that those fossil fuels provide the vast majority of energy currently used to heat homes and businesses, transport goods and people, and power industrial equipment. In all of the EF 2016 projections, hydrocarbon energy use continues to increase, which implies increasing GHG emissions. This is important because it shows that high or low oil and natural gas prices, or the number of pipelines or LNG terminals that are built, while having a modest impact on energy use, will not lead to significant overall emission reductions by themselves. As long as there is demand for energy, markets will function to provide the supply, whether from domestic or international sources, with little consequential impact on global energy use and the associated emissions.

In recent months the federal and many provincial governments in Canada have made announcements about new climate policy initiatives and the momentum is increasing, especially following the agreement at the 21st Conference of the Parties in Paris. Many of these policies are quite bold and put Canada in the position of having some of the most advanced climate change policies in the world. EF 2016 does not include these recent announcements, as it only reports on policies and programs that are law, or near law at the time of analysis, but it does highlight their significance. The insights from the report suggest to me that these policy developments will be critical factors in Canada's energy and environmental future, and the possible addition of climate policy developments beyond those just announced will represent a considerable uncertainty for long-term energy projections.

Canada's energy future will not be determined by a single force, but rather by the interaction of many. Energy prices, economic growth, policies and regulation, market access and infrastructure development, and the development and use of new technologies will all play an important role. It is our goal to help Canadians understand these complex interactions through our analysis, reports, and statistics. The long-term projections in our *Energy Futures* series are an important part of that, along with the topical market analysis found in publications such as the *Canadian Energy Dynamics* annual review, and the weekly Market Snapshots. However, as climate policy and energy markets rapidly and continuously evolve, the type of analysis we undertake and the way by which we share that analysis with Canadians must evolve as well. In response, the Board will complete an update to EF 2016 this coming autumn to incorporate recent developments. Just as EF 2016 includes groundbreaking analysis on the long-term impacts of market access and transportation infrastructure, future work may focus on the implications of future climate policy developments.

Not only will we increase the frequency and depth of our *Energy Futures* projections, we will also implement some new and exciting ways of engaging with Canadians on energy, and look forward to hearing from them on issues that matter the most in these uncertain times.

C. Peter Watson, P. Eng. FCAE
Chair and CEO

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Executive Summary

Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040 (EF 2016) is a continuation of the National Energy Board's (NEB) Energy Futures series. The Board released the last full report, *Canada's Energy Future 2013* (EF 2013), in November 2013.

In developing EF 2016, the NEB met with various energy experts and interested stakeholders, including representatives from industry and industry associations, government, non-governmental organizations, and academia to gather input and feedback on the preliminary projections. The information obtained from these consultations helped shape the key assumptions and final projections.

It is important to note that the projections presented in EF 2016 are a baseline for discussing Canada's energy future today and **do not** represent the Board's predictions of what will take place in the future. The projections in EF 2016 are based on assumptions which allow for analysis of possible outcomes. Any assumptions made about current or future energy infrastructure or market developments are strictly theoretical and have no bearing on the regulatory proceedings that are or will be before the Board.

Key Findings

The key findings of EF 2016 are outlined below and then summarized in the following pages:

1. **Recent developments have highlighted numerous uncertainties for Canada's long-term energy outlook.**
2. **In the Reference Case, energy production grows faster than energy use and net exports of energy increase.**
3. **The levels of future oil and natural gas production are highly dependent on future prices, which are subject to considerable uncertainty.**
4. **Without development of additional oil pipeline infrastructure, crude oil production grows less quickly but continues to grow at a moderate pace over the projection period.**
5. **The volume of liquefied natural gas exports is an important driver of Canadian natural gas production growth.**
6. **Total energy use in Canada, which includes energy use in the energy production sector, grows at similar rates in all EF 2016 cases, and GHG emissions related to that energy use will follow similar trends.**

1. Recent developments have highlighted numerous uncertainties for Canada's long-term energy outlook.

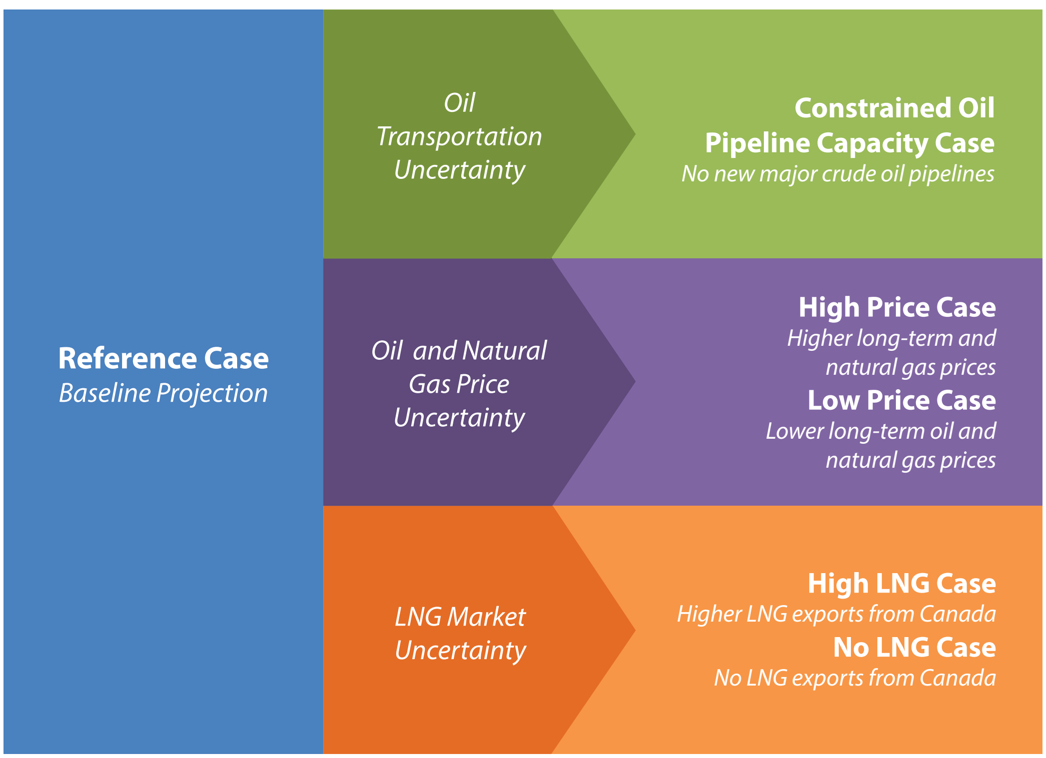
In recent years, energy prices, technology, external markets and societal factors have all undergone substantial shifts over a short period of time. As the energy system continues to adjust and new trends emerge, there are considerable uncertainties in Canada's long-term energy outlook.

The projections in EF 2016 include a Reference Case, two price sensitivity cases and three supplemental sensitivity cases:

- The Reference Case provides a baseline outlook, based on a moderate view of future energy prices and economic growth.
- Two price cases, with higher and lower oil and natural gas prices, capture some of the uncertainty related to future energy prices.
- EF 2016 also addresses uncertainties related to future oil export infrastructure by considering a case where no new major oil pipelines are built over the projection period.
- The uncertainty related to eventual volumes of liquefied natural gas (LNG) exports is explored in two additional cases.

FIGURE ES.1

Overview of Cases in EF 2016



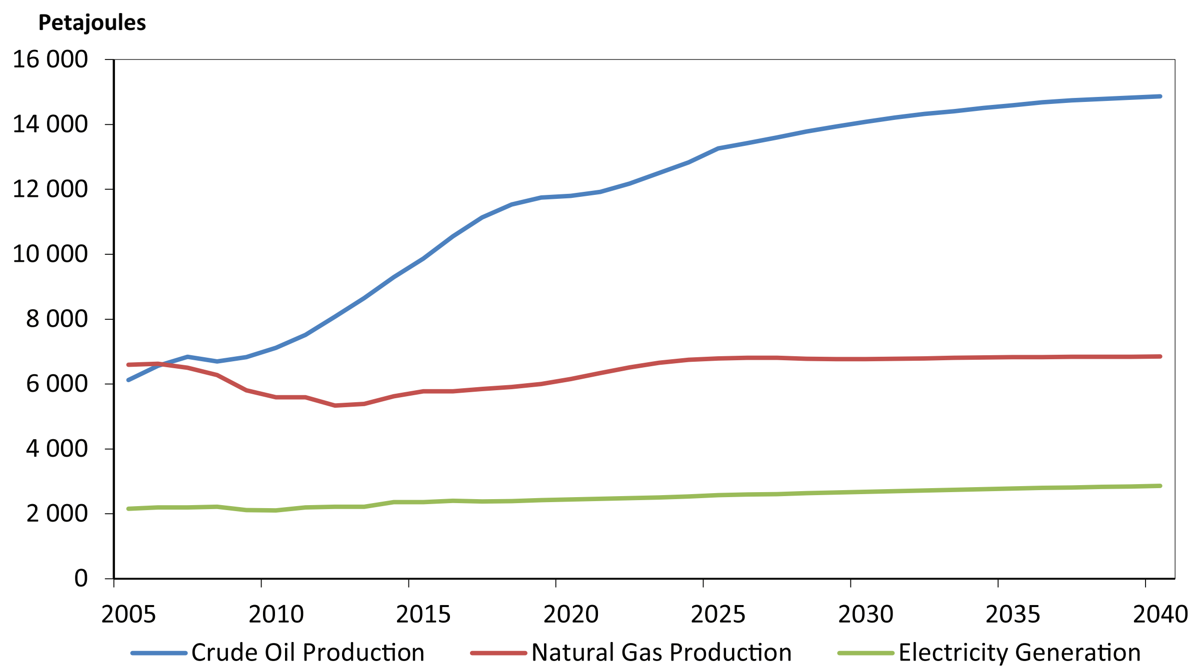
2. In the Reference Case, energy production grows faster than energy use and net exports of energy increase.

In the baseline projection of EF 2016 (the Reference Case), total Canadian energy production grows substantially over the projection period:

- Oil production leads this growth, with production reaching 963 $10^3m^3/d$ (6.1 MMb/d) by 2040, a 56 per cent increase from 2014. Much of this growth takes place in the oil sands.
- Natural gas production increases 22 per cent from 2014 levels to 506 $10^6m^3/d$ (17.9 Bcf/d), and LNG exports are a key driver of production growth.
- Electricity generation grows steadily over the projection period, with considerable additions of natural gas and renewable capacity while coal capacity declines.

FIGURE ES.2

Energy Production in Canada, on an Energy Equivalent Basis, Reference Case



While production grows steadily, energy use in Canada increases less quickly than in the past. Total end-use energy demand increases at an average annual rate of 0.7 per cent from 2014 to 2040, almost half the rate of increase from 1990 to 2013.

Combined, net exports of energy increase over the projection period, led by increasing heavy crude oil exports.

3. The levels of future oil and natural gas production are highly dependent on future prices, which are subject to considerable uncertainty.

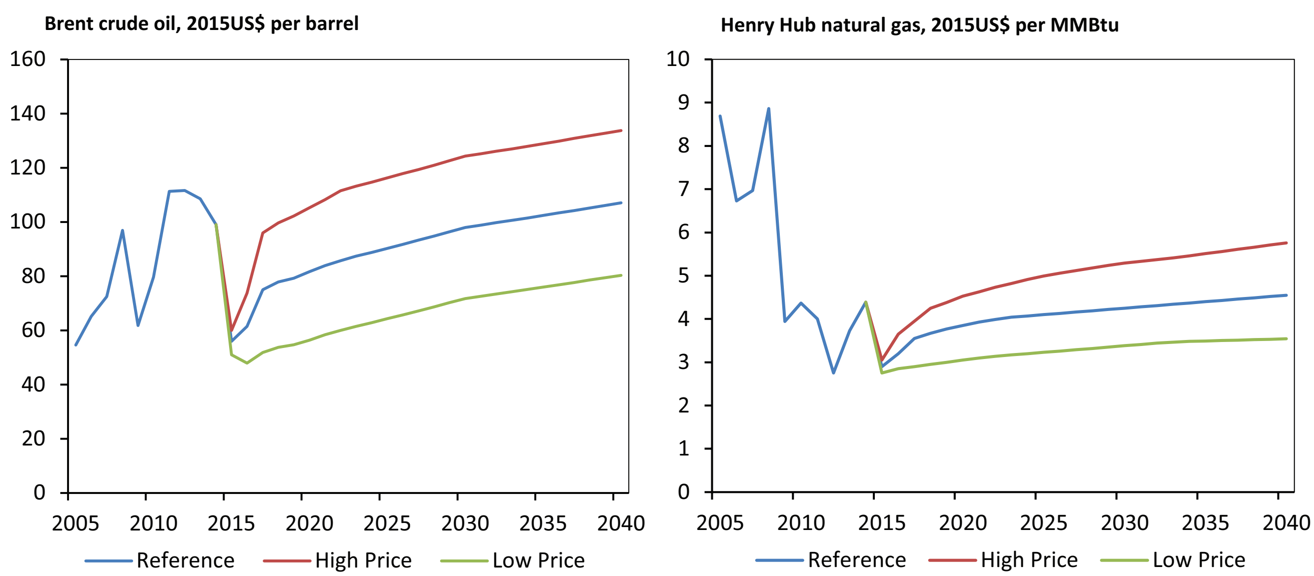
Over the last decade, both crude oil and natural gas prices have been volatile. The EF 2016 High and Low price cases consider the impacts of different price trends on Canada's energy outlook. Crude oil and natural gas prices can exhibit substantial variation in the short term, and could be outside of the ranges assumed in EF 2016 at a given point in time.

Production of crude oil in all three EF 2016 price cases is similar from 2015 to 2020, as oil sands projects already under construction are likely to be developed. In the High Price Case, total oil production continues to grow robustly, reaching 1 103 $10^3m^3/d$ (6.9 MMb/d) by 2040, 15 per cent higher than the Reference Case. In the Low Price Case, total oil production grows little after 2020, reaching 770 $10^3m^3/d$ (4.8 MMb/d) by 2040, or 20 per cent less than the Reference Case.

In the High Price Case, natural gas production grows quickly, reaching 665 $10^6m^3/d$ (24 Bcf/d) by 2040, 31 per cent higher than in the Reference Case. In the Low Price Case, total gas production is relatively flat until 2019. Production begins to increase in conjunction with assumed LNG exports and then declines gradually starting in 2026, reaching 440 $10^6m^3/d$ (16 Bcf/d) by 2040, or 13 per cent less than in the Reference Case.

FIGURE ES.3

EF 2016 Crude Oil and Natural Gas Price Assumptions



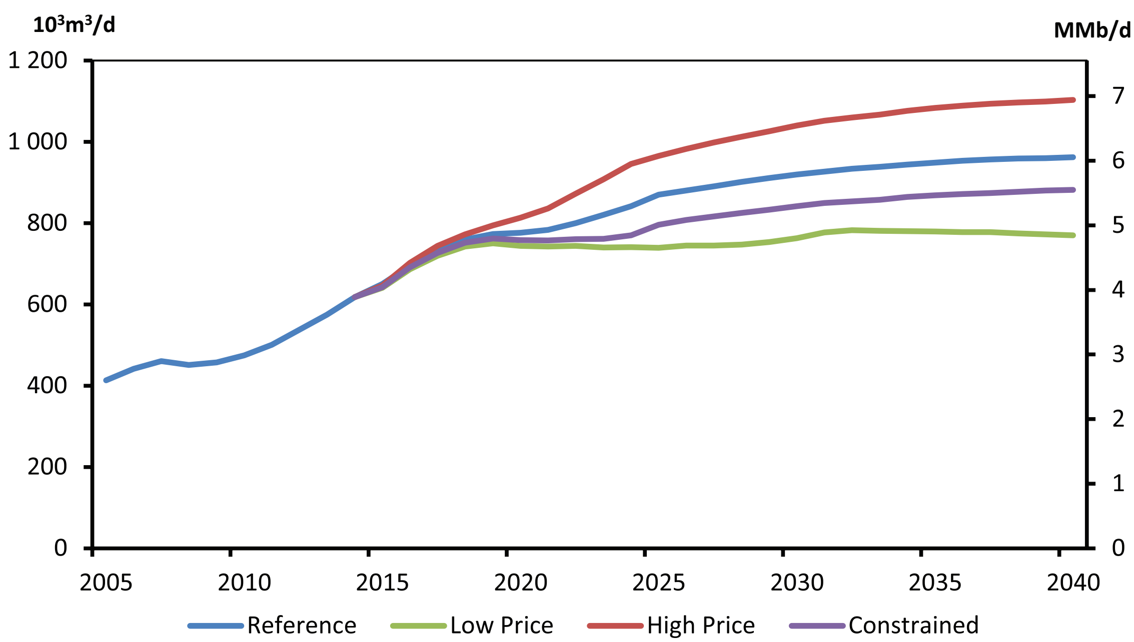
4. Without development of additional oil pipeline infrastructure, crude oil production grows less quickly but continues to grow at a moderate pace over the projection period.

The Reference Case assumes that energy infrastructure is built as needed. However, the pace of development of oil pipeline infrastructure is a notable uncertainty for the Canadian energy system. The Constrained Oil Pipeline Capacity Case (Constrained Case) considers the impact on the Canadian energy system if no new major oil export pipelines are built over the projection period, including the Keystone XL, Northern Gateway, Trans Mountain Expansion and Energy East pipeline proposals.

In this case, the increased use of rail, a more expensive shipping mode, leads to lower prices received by Canadian producers, net of transportation costs. Despite somewhat lower prices compared to the Reference Case, crude oil production continues to grow as many projects remain profitable. Oil production in the Constrained Case reaches 882 $10^3 m^3/d$ (5.6 MMb/d) by 2040, eight per cent lower than the Reference Case. Crude oil shipped by rail grows substantially over the projection, reaching 187 $10^3 m^3/d$ (1.2 MMb/d) by 2040.

FIGURE ES.4

Total Oil Production, Reference, High Price, Low Price and Constrained Cases



Total Canadian production in the Constrained Case grows quicker than in the Low Price Case, and production is 15 per cent higher than the Low Price Case by 2040. This suggests that although pipeline infrastructure may impact Canadian oil production, it is one of many factors that may do so. The High and Low Price cases suggest that crude oil prices, driven by global supply and demand dynamics, are also an important – perhaps the most important – determinant of Canadian production growth.

5. The volume of liquefied natural gas exports is an important driver of Canadian natural gas production growth.

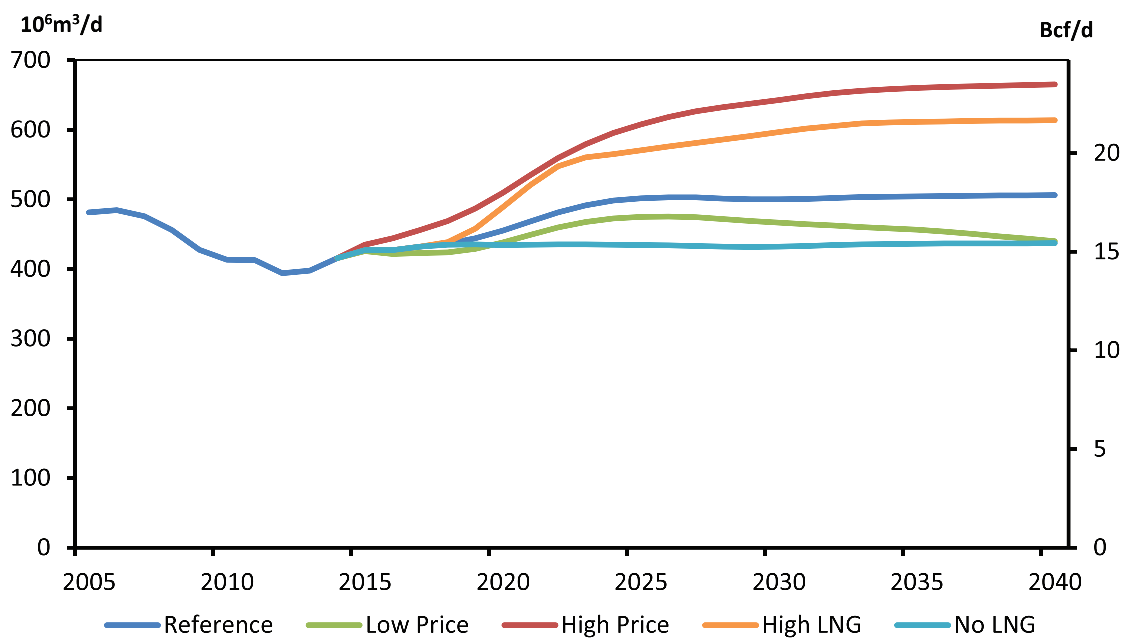
The Reference Case assumes that LNG exports begin in 2019 at 14 $10^6m^3/d$ (0.5 Bcf/d) and increase to 71 $10^6m^3/d$ (2.5 Bcf/d) by 2023. This is an assumption, as there is considerable uncertainty regarding the volume of LNG that Canada might export globally. Two EF 2016 cases, the High and No LNG cases, analyze this uncertainty.

The High LNG Case assumes higher LNG exports than the Reference Case, with exports reaching 170 $10^6m^3/d$ (6 Bcf/d) by 2030. The No LNG Case assumes that no LNG exports occur by 2040.

Exports of LNG could be a significant driver of future Canadian natural gas production growth. In the High LNG Case, total natural gas production reaches 614 $10^6m^3/d$ (22 Bcf/d) by 2040, 21 per cent higher than in the Reference Case. In the No LNG Case, total production is 437 $10^6m^3/d$ (15 Bcf/d) by 2040 or 14 per cent lower than the Reference Case.

FIGURE ES.5

Total Natural Gas Production, Reference, Price, and LNG Cases



6. Total energy use in Canada, which includes energy use in the energy production sector, grows at similar rates in all EF 2016 cases, and GHG emissions related to that energy use will follow similar trends.

The outcomes of the sensitivity cases in EF 2016 have implications for Canadian energy use. Numerous dynamics are at play but overall, the total differences in energy consumption across the cases are relatively small.

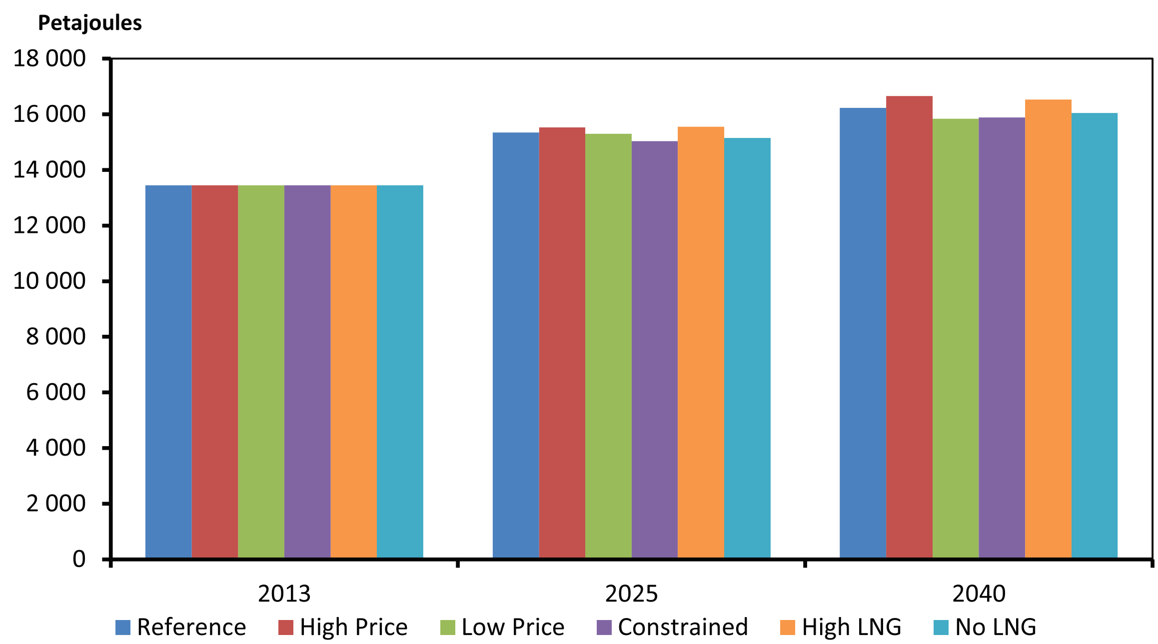
In the Reference Case, total energy use grows from 13 444 petajoules (PJ) in 2013 to 16 233 PJ in 2040. The energy intensity of the Canadian economy, measured in energy use per unit of economic activity, continues its declining trend and falls by an average of one per cent per year from 2013 to 2040.

Given the policy and technology assumptions of this analysis, fossil fuels remain the primary source of energy in Canada over the projection period. This increase in fossil fuel consumption implies that GHG emissions will increase over the projection period, consistent with the most recent GHG emission projections from Environment and Climate Change Canada.

Higher and lower energy prices impact energy use across the economy in different ways. Canada is a major producer of energy and this tends to influence its role as a consumer of energy. Energy use is highest in the High Price Case, reaching 16 659 PJ by 2040. Slightly higher economic growth and more demand in the oil and natural gas producing sector outweigh the downward impact of higher prices on consumption. The impact is reversed in the Low Price Case, which has the lowest energy use of the cases at 15 840 PJ in 2040, despite higher consumption outside of the oil and natural gas sector.

FIGURE ES.6

Canadian Energy Use, All Cases



Energy use in the Constrained Case falls between the Reference and Low Price Case projections, at 15 887 PJ by 2040. The primary reason for lower total demand is lower energy use for oil production. Slightly slower economic growth also has a minor impact.

Canadian energy use in the High LNG Case reaches 16 531 PJ by 2040, slightly above the Reference Case. The impact is reversed in the No LNG Case, with energy use reaching 16 042 PJ by 2040, just below the Reference Case.

The relatively small impact on energy use in the sensitivity cases suggests that factors other than energy prices, oil pipeline development and LNG exports could have a more significant impact on future energy use and GHG emission trends in Canada. Economic growth trends are also important and can have a very large impact on Canadian energy use and emissions. For example, the 2008-2009 global economic downturn contributed to the nearly eight per cent drop in Canadian energy use from 2007 to 2009. Similarly, technological developments beyond those considered in this report could result in markedly different outcomes. Finally, the EF 2016 cases only include existing laws, policies and programs, and future laws, policies and programs could strongly influence long term energy use and GHG emissions.

Annual Energy Outlook 2015

With Projections to 2040

April 2015

U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.gov/forecasts/aeo

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Preface

The *Annual Energy Outlook 2015* (AEO2015), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices through 2040. The projections, focused on U.S. energy markets, are based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases. The analysis in AEO2015 focuses on six cases: Reference case, Low and High Economic Growth cases, Low and High Oil Price cases, and High Oil and Gas Resource case.

For the first time, the Annual Energy Outlook (AEO) is presented as a shorter edition under a newly adopted two-year release cycle. With this approach, full editions and shorter editions of the AEO will be produced in alternating years. This approach will allow EIA to focus more resources on rapidly changing energy markets both in the United States and internationally and how they might evolve over the next few years. The shorter edition of the AEO includes a more limited number of model updates, predominantly to reflect historical data updates and changes in legislation and regulation. The AEO shorter editions will include this publication, which discusses the Reference case and five alternative cases, and an accompanying *Assumptions Report*.[1] Other documentation—including documentation for each of the NEMS models and a *Retrospective Review*—will be completed only in years when the full edition of the AEO is published.

This AEO2015 report includes the following major sections:

- **Executive summary**, highlighting key results of the projections
- **Economic growth**, discussing the economic outlooks completed for each of the AEO2015 cases
- **Energy prices**, discussing trends in the markets and prices for crude oil, petroleum and other liquids,[2] natural gas, coal, and electricity for each of the AEO2015 cases
- **Delivered energy consumption by sector**, discussing energy consumption trends in the transportation, industrial, residential, and commercial sectors
- **Energy consumption by primary fuel**, discussing trends in energy consumption by fuel, including natural gas, renewables, coal, nuclear, liquid biofuels, and oil and other liquids
- **Energy intensity**, examining trends in energy use per capita, energy use per 2009 dollar of gross domestic product (GDP), and carbon dioxide (CO_2) emissions per 2009 dollar of GDP
- **Energy production, imports, and exports**, examining production, import, and export trends for petroleum and other liquids, natural gas, and coal
- **Electricity generation,** discussing trends in electricity generation by fuel and prime mover for each of the AEO2015 cases
- **Energy-related CO_2 emissions,** examining trends in CO_2 emissions by sector and AEO2015 case.

Summary tables for the six cases are provided in Appendixes A through D. Complete tables are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser. Appendix E provides a short discussion of the major changes adopted in AEO2015 and a brief comparison of the AEO2015 and Annual Energy Outlook 2014 results. Appendix F provides a summary of the regional formats, and Appendix G provides a summary of the energy conversion factors used in AEO2015.

The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan[3]). In certain situations, however, where it is clear that a law or a regulation will take effect shortly after AEO2015 is completed, it may be considered in the projection.

AEO2015 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

[1]U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2015*, DOE/EIA-0554(2015) (Washington, DC, to be published), http://www.eia.gov/forecasts/aeo/assumptions.

[2]Liquid fuels (or petroleum and other liquids) include crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

[3]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014), https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The AEO2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. The main cases in AEO2015 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Some key uncertainties in the AEO2015 projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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Appendix F

Executive summary

Projections in the *Annual Energy Outlook 2015* (AEO2015) focus on the factors expected to shape U.S. energy markets through 2040. The projections provide a basis for examination and discussion of energy market trends and serve as a starting point for analysis of potential changes in U.S. energy policies, rules, and regulations, as well as the potential role of advanced technologies.

Key results from the AEO2015 Reference and alternative cases include the following:

- The future path of crude oil and natural gas prices can vary substantially, depending on assumptions about the size of global and domestic resources, demand for petroleum products and natural gas (particularly in non-Organization for Economic Cooperation and Development (non-OECD) countries), levels of production, and supplies of other fuels. AEO2015 considers these factors in examining alternative price and resource availability cases.
- Growth in U.S. energy production—led by crude oil and natural gas—and only modest growth in demand reduces U.S. reliance on imported energy supplies. Energy imports and exports come into balance in the United States starting in 2028 in the AEO2015 Reference case and in 2019 in the High Oil Price and High Oil and Gas Resource cases. Natural gas is the dominant U.S. energy export, while liquid fuels[4] continue to be imported.
- Through 2020, strong growth in domestic crude oil production from tight formations leads to a decline in net petroleum imports[5] and growth in net petroleum product exports in all AEO2015 cases. In the High Oil and Gas Resource case, increased crude production before 2020 results in increased processed condensate[6] exports. Slowing growth in domestic production after 2020 is offset by increased vehicle fuel economy standards that limit growth in domestic demand. The net import share of crude oil and petroleum products supplied falls from 33% of total supply in 2013 to 17% of total supply in 2040 in the Reference case. The United States becomes a net exporter of petroleum and other liquids after 2020 in the High Oil Price and High Oil and Gas Resource cases because of greater U.S. crude oil production.
- The United States transitions from being a modest net importer of natural gas to a net exporter by 2017. U.S. export growth continues after 2017, with net exports in 2040 ranging from 3.0 trillion cubic feet (Tcf) in the Low Oil Price case to 13.1 Tcf in the High Oil and Gas Resource case.
- Growth in crude oil and dry natural gas production varies significantly across oil and natural gas supply regions and cases, forcing shifts in crude oil and natural gas flows between U.S. regions, and requiring investment in or realignment of pipelines and other midstream infrastructure.
- U.S. energy consumption grows at a modest rate over the AEO2015 projection period, averaging 0.3%/year from 2013 through 2040 in the Reference case. A marginal decrease in transportation sector energy consumption contrasts with growth in most other sectors. Declines in energy consumption tend to result from the adoption of more energy-efficient technologies and existing policies that promote increased energy efficiency.
- Growth in production of dry natural gas and natural gas plant liquids (NGPL) contributes to the expansion of several manufacturing industries (such as bulk chemicals and primary metals) and the increased use of NGPL feedstocks in place of petroleum-based naphtha[7] feedstocks.
- Rising long-term natural gas prices, the high capital costs of new coal and nuclear generation capacity, state-level policies, and cost reductions for renewable generation in a market characterized by relatively slow electricity demand growth favor increased use of renewables.
- Rising costs for electric power generation, transmission, and distribution, coupled with relatively slow growth of electricity demand, produce an 18% increase in the average retail price of electricity over the period from 2013 to 2040 in the AEO2015 Reference case. The AEO2015 cases do not include the proposed Clean Power Plan.[8]
- Improved efficiency in the end-use sectors and a shift away from more carbon-intensive fuels help to stabilize U.S. energy-related carbon dioxide (CO2) emissions, which remain below the 2005 level through 2040.

The future path of crude oil prices can vary substantially, depending on assumptions about the size of the resource and growth in demand, particularly in non-OECD countries

AEO2015 considers a number of factors related to the uncertainty of future crude oil prices, including changes in worldwide demand for petroleum products, crude oil production, and supplies of other liquid fuels. In all the AEO2015 cases, the North Sea

[4]Liquid fuels (or petroleum and other liquids) includes crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).
[5]*Net product imports* includes trade in crude oil and petroleum products.
[6]The U.S. Department of Commerce, Bureau of Industry and Security has determined that condensate which has been processed through a distillate tower can be exported without licensing.
[7]Naphtha is a refined or semi-refined petroleum fraction used in chemical feedstocks and many other petroleum products. For a complete definition, see www.eia.gov/tools/glossary/index.cfm?id=naphtha.
[8]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Brent crude oil price reflects the world market price for light sweet crude, and all the cases account for market conditions in 2014, including the 10% decline in the average Brent spot price to $97/barrel (bbl) in 2013 dollars.

In the AEO2015 Reference case, continued growth in U.S. crude oil production contributes to a 43% decrease in the Brent crude oil price, to $56/bbl in 2015 (Figure ES1). Prices rise steadily after 2015 in response to growth in demand from countries outside the OECD; however, downward price pressure from continued increases in U.S. crude oil production keeps the Brent price below $80/bbl through 2020. U.S. crude oil production starts to decline after 2020, but increased production from non-OECD countries and from countries in the Organization of the Petroleum Exporting Countries (OPEC) contributes to the Brent price remaining below $100/bbl through 2028 and limits the Brent price increase through 2040, when it reaches $141/bbl.

There is significant price variation in the alternative cases using different assumptions. In the Low Oil Price case, the Brent price drops to $52/bbl in 2015, 7% lower than in the Reference case, and reaches $76/bbl in 2040, 47% lower than in the Reference case, largely as a result of lower non-OECD demand and higher upstream investment by OPEC. In the High Oil Price case, the Brent price increases to $122/bbl in 2015 and to $252/bbl in 2040, largely in response to significantly lower OPEC production and higher non-OECD demand. In the High Oil and Gas Resource case, assumptions about overseas demand and supply decisions do not vary from those in the Reference case, but U.S. crude oil production growth is significantly greater, resulting in lower U.S. net imports of crude oil, and causing the Brent spot price to average $129/bbl in 2040, which is 8% lower than in the Reference case.

Future natural gas prices will be influenced by a number of factors, including oil prices, resource availability, and demand for natural gas

Projections of natural gas prices are influenced by assumptions about oil prices, resource availability, and natural gas demand. In the Reference case, the Henry Hub natural gas spot price (in 2013 dollars) rises from $3.69/million British thermal units (Btu) in 2015 to $4.88/million Btu in 2020 and to $7.85/million Btu in 2040 (Figure ES2), as increased demand in domestic and international markets leads to the production of increasingly expensive resources.

In the AEO2015 alternative cases, the Henry Hub natural gas spot price is lowest in the High Oil and Gas Resource case, which assumes greater estimated ultimate recovery per well, closer well spacing, and greater gains in technological development. In the High Oil and Gas Resource case, the Henry Hub natural gas spot price falls from $3.14/million Btu in 2015 to $3.12/million Btu in 2020 (36% below the Reference case price) before rising to $4.38/million Btu in 2040 (44% below the Reference case price). Cumulative U.S. domestic dry natural gas production from 2015 to 2040 is 26% higher in the High Oil and Gas Resource case than in the Reference case and is sufficient to meet rising domestic consumption and exports—both pipeline gas and liquefied natural gas (LNG)—even as prices remain low.

Henry Hub natural gas spot prices are highest in the High Oil Price case, which assumes the same level of resource availability as the AEO2015 Reference case, but different Brent crude oil prices. The higher Brent crude oil prices in the High Oil Price case affect the level of overseas demand for U.S. LNG exports, because international LNG contracts are often linked to crude oil prices—although the linkage is expected to weaken with changing market conditions. When the Brent spot price rises in the High Oil Price case, world LNG contracts that are linked to oil prices become relatively more competitive, making LNG exports from the United States more desirable.

In the High Oil Price case, the Henry Hub natural gas spot price remains close to the Reference case price through 2020; however, higher overseas demand for U.S. LNG exports raises the average Henry Hub price to $10.63/million Btu in 2040, which is 35%

Figure ES1. North Sea Brent crude oil spot prices in four cases, 2005-40 (2013 dollars per barrel)

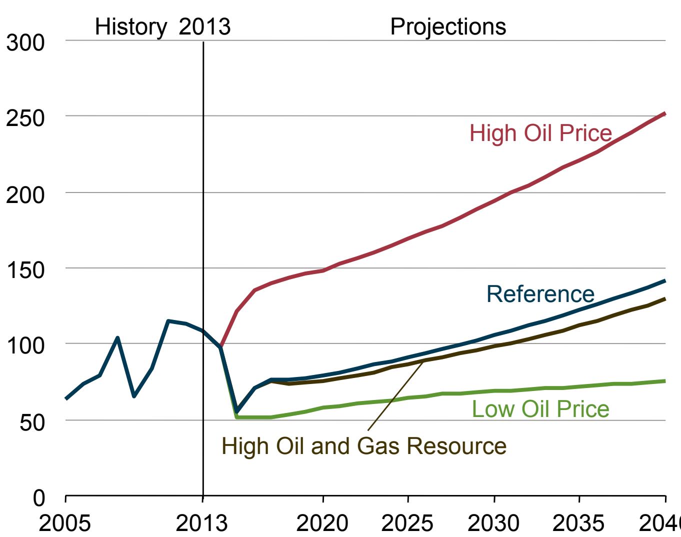
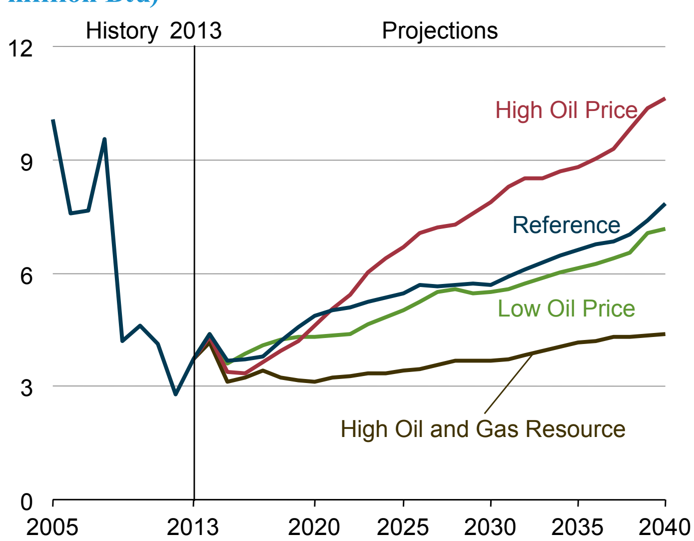


Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



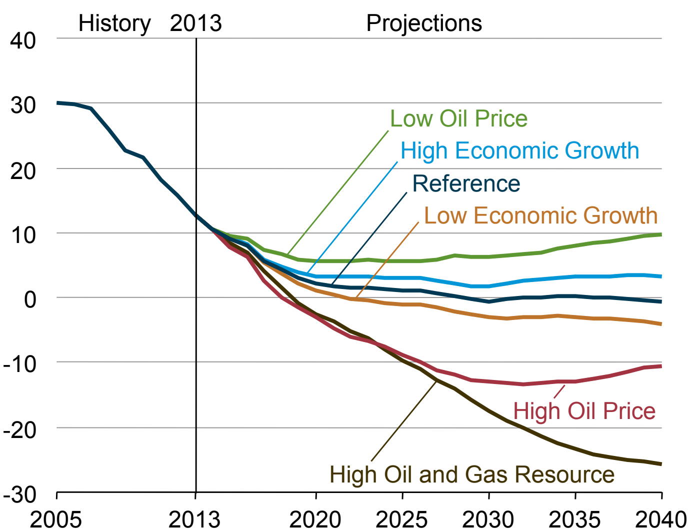
above the Reference case price. Cumulative U.S. exports of LNG from 2015 to 2040 in the High Oil Price case are more than twice those in the Reference case. The opposite occurs in the Low Oil Price case: low Brent crude oil prices cause oil-linked LNG contracts to become relatively less competitive and make U.S. LNG exports less desirable. Lower overseas demand for U.S. LNG exports causes the average Henry Hub price to reach only $7.15/million Btu in 2040, 9% lower than in the Reference case.

Global growth and trade weaken beyond 2025, creating headwinds for U.S. export-oriented industries

In the AEO2015 projections, growth in U.S. net exports contributes more to GDP growth than it has over the past 30 years (partially due to a reduction in net energy imports); however, its impact diminishes in the later years of the projection, reflecting slowing GDP growth in nations that are U.S. trading partners, along with the impacts of exchange rates and prices on trade. As economic growth in the rest of the world slows (as shown in Table ES1), so does U.S. export growth, with commensurate impacts on growth in manufacturing output, particularly in the paper, chemicals, primary metals, and other energy-intensive industries. The impact varies across industries.

Recent model revisions to the underlying industrial supply and demand relationships[9] have emphasized the importance of trade to manufacturing industries, so that the composition of trade determines the level of industrial output. Consumer goods and industrial supplies show higher levels of net export growth than other categories throughout the projection. The diminishing net export growth in all categories in the later years of the projection explains much of the leveling off of growth that occurs in some trade-sensitive industries.

Figure ES3. U.S. net energy imports in six cases, 2005-40 (quadrillion Btu)



U.S. net energy imports decline and ultimately end, largely in response to increased oil and dry natural gas production

Energy imports and exports come into balance in the United States in the AEO2015 Reference case, starting in 2028. In the High Oil Price and High Oil and Gas Resource cases, with higher U.S. crude oil and dry natural gas production and lower imports, the United States becomes a net exporter of energy in 2019. In contrast, in the Low Oil Price case, the United States remains a net energy importer through 2040 (Figure ES3).

Economic growth assumptions also affect the U.S. energy trade balance. In the Low Economic Growth case, U.S. energy imports are lower than in the Reference case, and the United States becomes a net energy exporter in 2022. In the High Economic Growth case, the United States remains a net energy importer through 2040.

The share of total U.S. energy production from crude oil and lease condensate rises from 19% in 2013 to 25% in 2040 in the High Oil and Gas Resource case, as compared with no

Table ES1. Growth of trade-related factors in the Reference case, 1983-2040 (average annual percent change)

Measure	History: 1983-2013	2013-20	2020-25	2025-30	2030-35	2035-40
U.S. GDP	2.8%	2.6%	2.5%	2.3%	2.2%	2.3%
U.S. GDP per capita	1.8%	1.8%	1.8%	1.6%	1.6%	1.8%
U.S. exports	6.1%	4.8%	6.2%	4.8%	4.5%	4.1%
U.S. imports	6.0%	4.6%	4.1%	3.7%	3.7%	3.7%
U.S. net export growth	0.1%	0.3%	2.1%	1.1%	0.8%	0.3%
Real GDP of OECD trading partners	2.4%	2.1%	1.9%	1.8%	1.7%	1.7%
Real GDP of other trading partners	4.7%	4.3%	4.2%	3.7%	3.4%	3.2%

Note: Major U.S. trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone. Other U.S. trading partners include Argentina, Brazil, Chile, Columbia, Mexico, Hong Kong, Indonesia, India, Israel, South Korea, Malaysia, Philippines, Russia, Saudi Arabia, Singapore, Thailand, Taiwan, and Venezuela.

[9]AEO2015 incorporates the U.S. Bureau of Economic Analysis (BEA) updated 2007 input-output table, released at the end of December 2013. See U.S. Department of Commerce, Bureau of Economic Analysis, "Industry Economic Accounts Information Guide (Washington, DC: December 18, 2014), http://www.bea.gov/industry/iedguide.htm#aia.

change in the Reference case. Dry natural gas production remains the largest contributor to total U.S. energy production through 2040 in all the AEO2015 cases, with a higher share in the High Oil and Gas Resource case (38%) than in the Reference case (34%) and all other cases. In 2013, dry natural gas accounted for 30% of total U.S. energy production.

Coal's share of total U.S. energy production in the High Oil and Gas Resource case falls from 26% in 2013 to 15% in 2040. In the Reference case and most of the other AEO2015 cases, the coal share remains slightly above 20% of total U.S. energy production through 2040; in the Low Oil Price case, with lower oil and gas production levels, it remains essentially flat at 23% through 2040.

Continued strong growth in domestic production of crude oil from tight formations leads to a decline in net imports of crude oil and petroleum products

U.S. crude oil production from tight formations leads the growth in total U.S. crude oil production in all the AEO2015 cases. In the Reference case, lower levels of domestic consumption of liquid fuels and higher levels of domestic production of crude oil push the net import share of crude oil and petroleum products supplied down from 33% in 2013 to 17% in 2040 (Figure ES4).

In the High Oil Price and High Oil and Gas Resource cases, growth in tight oil production results in significantly higher levels of total U.S. crude oil production than in the Reference case. Crude oil production in the High Oil and Gas Resource case increases to 16.6 million barrels per day (bbl/d) in 2040, compared with a peak of 10.6 million bbl/d in 2020 in the Reference case. In the High Oil Price case, production reaches a high of 13.0 million bbl/d in 2026, then declines to 9.9 million bbl/d in 2040 as a result of earlier resource development. In the Low Oil Price case, U.S. crude oil production totals 7.1 million bbl/d in 2040. The United States becomes a net petroleum exporter in 2021 in both the High Oil Price and High Oil and Gas Resource cases. With lower levels of domestic production and higher domestic consumption in the Low Oil Price case, the net import share of total liquid fuels supply increases to 36% of total domestic supply in 2040.

Net natural gas trade, including LNG exports, depends largely on the effects of resource levels and oil prices

In all the AEO2015 cases, the United States transitions from a net importer of 1.3 Tcf of natural gas in 2013 (5.5% of the 23.7 Tcf delivered to consumers) to a net exporter in 2017. Net exports continue to grow after 2017, to a 2040 range between 3.0 Tcf in the Low Oil Price case and 13.1 Tcf in the High Oil and Gas Resource case (Figure ES5).

In the Reference case, LNG exports reach 3.4 Tcf in 2030 and remain at that level through 2040, when they account for 46% of total U.S. natural gas exports. The growth in U.S. LNG exports is supported by differences between international and domestic natural gas prices. LNG supplied to international markets is primarily priced on the basis of world oil prices, among other factors. This results in significantly higher prices for global LNG than for domestic natural gas supply, particularly in the near term. However, the relationship between the price of international natural gas supplies and world oil prices is assumed to weaken later in the projection period, in part as a result of growth in U.S. LNG export capacity. U.S. natural gas prices are determined primarily by the availability and cost of domestic natural gas resources.

In the High Oil Price case, with higher world oil prices resulting in higher international natural gas prices, U.S. LNG exports climb to 8.1 Tcf in 2033 and account for 73% of total U.S. natural gas exports in 2040. In the High Oil and Gas Resource case, abundant U.S. dry natural gas production keeps domestic natural gas prices lower than international prices, supporting the growth of U.S. LNG exports, which total 10.3 Tcf in 2037 and account for 66% of total U.S. natural gas exports in 2040. In the Low Oil Price case,

Figure ES4. Net crude oil and petroleum product imports as a percentage of U.S. product supplied in four cases, 2005-40 (percent)

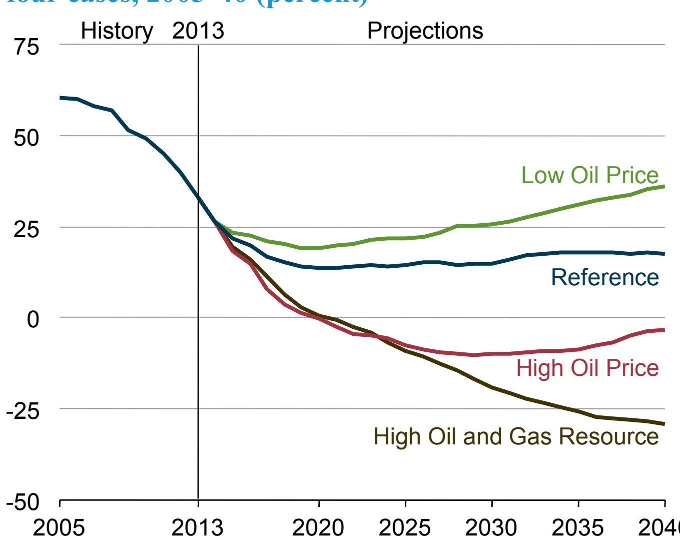
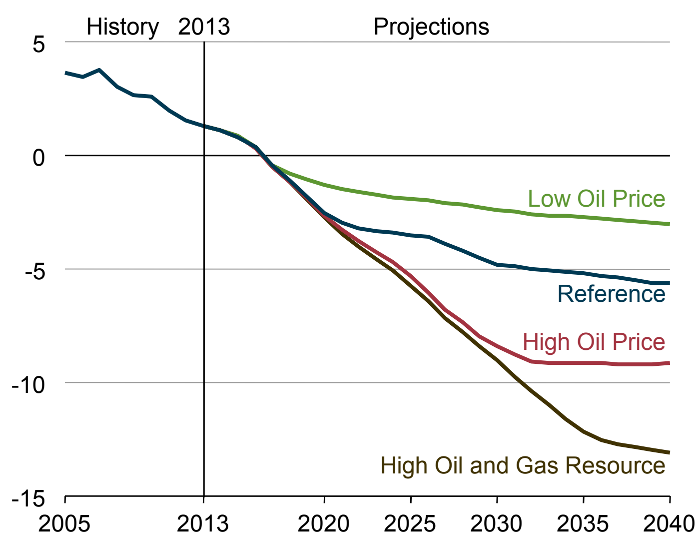


Figure ES5. U.S. total net natural gas imports in four cases, 2005-40 (trillion cubic feet)



with lower world oil prices, U.S. LNG exports are less competitive and grow more slowly, to a peak of 0.8 Tcf in 2018, and account for 13% of total U.S. natural gas exports in 2040.

Additional growth in net natural gas exports comes from growing natural gas pipeline exports to Mexico, which reach a high of 4.7 Tcf in 2040 in the High Oil and Gas Resource case (compared with 0.7 Tcf in 2013). In the High Oil Price case, U.S. natural gas pipeline exports to Mexico peak at 2.2 Tcf in 2040, as higher domestic natural gas prices resulting from increased world demand for LNG reduce the incentive to export natural gas via pipeline. Natural gas pipeline net imports from Canada remain below 2013 levels through 2040 in all the AEO2015 cases, but these imports do increase in response to higher natural gas prices in the latter part of the projection period.

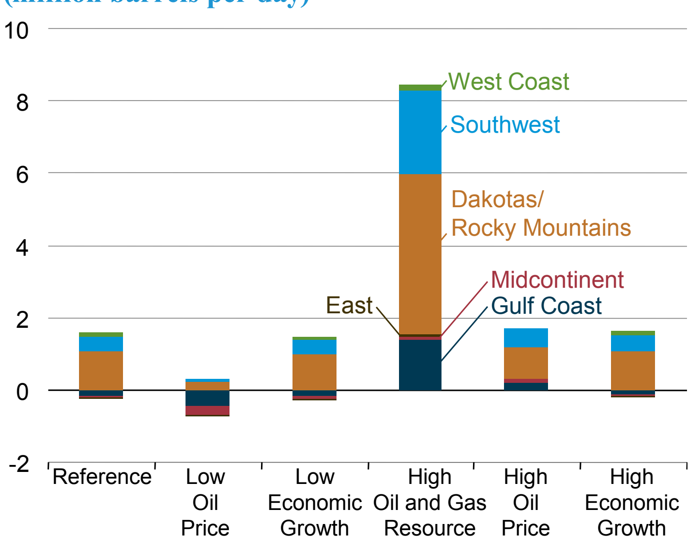
Regional variations in domestic crude oil and dry natural gas production can force significant shifts in crude oil and natural gas flows between U.S. regions, requiring investment in or realignment of pipelines and other midstream infrastructure

U.S. crude oil and dry natural gas production levels have increased rapidly in recent years. From 2008 to 2013, crude oil production grew from 5.0 million bbl/d to 7.4 million bbl/d, and annual dry natural gas production grew from 20.2 Tcf to 24.3 Tcf. All the AEO2015 cases project continued growth in U.S. dry natural gas production, whereas crude oil production continues to increase but eventually declines in all cases except the High Oil and Gas Resource case. In most of the cases, Lower 48 onshore crude oil production shows the strongest growth in the Dakotas/Rocky Mountains region (which includes the Bakken formation), followed by the Southwest region (which includes the Permian Basin) (Figure ES6). The strongest growth of dry natural gas production in the Lower 48 onshore in most of the AEO2015 cases occurs in the East region (which includes the Marcellus Shale and Utica Shale), followed by the Gulf Coast onshore region and the Dakotas/Rocky Mountains region. Interregional flows to serve downstream markets vary significantly among the different cases.

In the High Oil Price case, higher prices for crude oil and increased demand for LNG support higher levels of Lower 48 onshore crude oil and dry natural gas production than in the Reference case. Production in the High Oil Price case is exceeded only in the High Oil and Gas Resource case, where greater availability of oil and natural gas resources leads to more rapid production growth. The higher production levels in the High Oil Price and High Oil and Gas Resource cases are sustained through the entire projection period. Onshore Lower 48 crude oil production in 2040 drops below its 2013 level only in the Low Oil Price case, which also shows the lowest growth of dry natural gas production.

Crude oil imports into the East Coast and Midwest Petroleum Administration for Defense Districts (PADDs) 1 and 2 grow from 2013 to 2040 in all cases except the High Oil and Gas Resource case. All cases, including the High Oil and Gas Resource case, maintain significant crude oil imports into the Gulf Coast (PADD 3) and West Coast (PADD 5) through 2040. The Dakotas/Rocky Mountains (PADD 4) has significant crude oil imports only through 2040 in the High Oil Price case. The high levels of crude oil imports in all cases except the High Oil and Gas Resource case support growing levels of gasoline, diesel, and jet fuel exports as U.S. refineries continue to have a competitive advantage over refineries in the rest of the world. The High Oil and Gas Resource case is the only case with significant crude oil exports, which occur as a result of additional crude oil exports to Canada. The High Oil and Gas Resource case also shows significantly higher amounts of natural gas flowing out of the Mid-Atlantic and Dakotas/Rocky Mountains regions than most other cases, and higher LNG exports out of the Gulf Coast than any other case.

Figure ES6. Change in U.S. Lower 48 onshore crude oil production by region in six cases, 2013-40 (million barrels per day)



U.S. energy consumption grows at a modest rate over the projection with reductions in energy intensity resulting from improved technologies and from policies in place

U.S. energy consumption grows at a relatively modest rate over the AEO2015 projection period, averaging 0.3%/year from 2013 through 2040 in the Reference case. The transportation and residential sector's decreases in energy consumption (less than 2% over the entire projection period) contrast with growth in other sectors. The strongest energy consumption growth is projected for the industrial sector, at 0.7%/year. Declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency. Increases tend to result from other factors, such as economic growth and the relatively low energy prices that result from an abundance of supplies.

Near-zero growth in energy consumption is a relatively recent phenomenon, and substantial uncertainty is associated with specific aspects of U.S. energy consumption in the AEO2015 projections. This uncertainty is especially relevant as the United States continues to recover from the latest economic recession and resumes more normal economic growth. Although demand for energy often grew with economic recoveries during the second half of the 20th century, technology and policy factors currently are acting in combination to dampen growth in energy consumption.

The AEO2015 alternative cases demonstrate these dynamics. The High and Low Economic Growth cases project higher and lower levels of travel demand, respectively, and of energy consumption growth, while holding policy and technology assumptions constant. In the High Economic Growth case and the High Oil and Gas Resource case, energy consumption growth (0.6%/year and 0.5%/year, respectively) is higher than in the Reference case. Energy consumption growth in the Low Economic Growth case is lower than in the Reference case (nearly flat). In the High Oil Price case, it is higher than in the Reference case, at 0.5%/year, mainly as a result of increased domestic energy production and more consumption of diesel fuel for freight transportation and trucking.

In the AEO2015 Reference case, as a result of increasingly stringent fuel economy standards, gasoline consumption in the transportation sector in 2040 is 21% lower than in 2013. In contrast, diesel fuel consumption, largely for freight transportation and trucking, grows at an average rate of 0.8%/year from 2013 to 2040, as economic growth results in more shipments of goods. Because the United States consumes more gasoline than diesel fuel, the pattern of gasoline consumption strongly influences the overall trend of energy consumption in the transportation sector (Figure ES7).

Industrial energy use rises with growth of shale gas supply

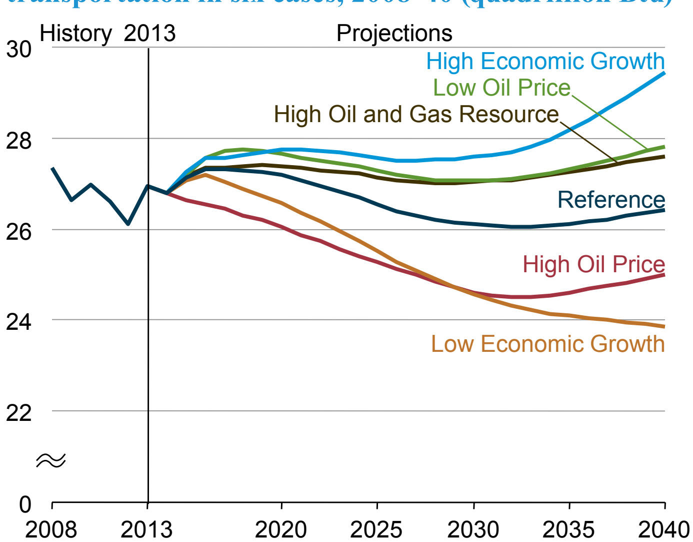
Production of dry natural gas and natural gas plant liquids (NGPL) in the United States has increased markedly over the past few years, and the upward production trend continues in the AEO2015 Reference, High Oil Price, and High Oil and Gas Resource cases, with the High Oil and Gas Resource case showing the strongest growth in production of both dry natural gas and NGPL. Sustained high levels of dry natural gas and NGPL production at prices that are attractive to industry in all three cases contribute to the growth of industrial energy consumption over the 2013-40 projection period and expand the range of fuel and feedstock choices.

Increased supply of natural gas from shale resources and the associated liquids contributes to lower prices for natural gas and hydrocarbon gas liquids (HGL), which support higher levels of industrial output. The energy-intensive bulk chemicals industry benefits from lower prices for fuel (primarily natural gas) and feedstocks (natural gas and HGL), as consumption of natural gas and HGL feedstocks increases by more than 50% from 2013 to 2040 in the Reference case, mostly as a result of growth in the total capacity of U.S. methanol, ammonia (mostly for nitrogenous fertilizers), and ethylene catalytic crackers. Increased availability of HGL leads to much slower growth in the use of heavy petroleum-based naphtha feedstocks compared to the lighter HGL feedstocks (ethane, propane, and butane). With sustained low HGL prices, the feedstock slate continues to favor HGL at unprecedented levels.

Other energy-intensive industries, such as primary metals and pulp and paper, also benefit from the availability and pricing of dry natural gas production from shale resources. However, factors other than lower natural gas and HGL prices, such as changes in nonenergy costs and export demand, also play significant roles in increasing manufacturing output.[10]

Manufacturing gross output in the High Oil and Gas Resource case is only slightly higher than in the Reference case, and most of the difference in industrial natural gas use between the two cases is attributable to the mining industry—specifically, oil and gas extraction. With increased extraction activity in the High Oil and Gas Resource case, natural gas consumption for lease and plant use in 2040 is 1.6 quadrillion Btu (68%) higher than in the Reference case.

Figure ES7. Delivered energy consumption for transportation in six cases, 2008-40 (quadrillion Btu)



Increased production of dry natural gas from shale resources (e.g., as seen in the High Oil and Gas Resource case relative to the Reference case) leads to a lower natural gas price, which leads to more natural gas use for combined heat and power (CHP) generation in the industrial sector. In 2040, natural gas use for CHP generation is 12% higher in the High Oil and Gas Resource case than in the Reference case, reflecting the higher levels of dry natural gas production. Finally, the increased supply of dry natural gas from shale resources leads to the increased use of natural gas to meet heat and power needs in the industrial sector.

Renewables meet much of the growth in electricity demand

Renewable electricity generation in the AEO2015 Reference case increases by 72% from 2013 to 2040, accounting for more than one-third of new generation capacity. The renewable share of total generation grows from 13% in 2013

[10] E. Sendich, "The Importance of Natural Gas in the Industrial Sector With a Focus on Energy-Intensive Industries," EIA Working Paper (February 28, 2014), http://www.eia.gov/workingpapers/pdf/natgas_indussector.pdf.

to 18% in 2040. Federal tax credits and state renewable portfolio standards that do not expire (sunset) continue to drive the relatively robust near-term growth of nonhydropower renewable sources, with total renewable generation increasing by 25% from 2013 to 2018. However, from 2018 through about 2030, the growth of renewable capacity moderates, as relatively slow growth of electricity demand reduces the need for new generation capacity. In addition, the combination of relatively low natural gas prices and the expiration of several key federal and state policies results in a challenging economic environment for renewables. After 2030, renewable capacity growth again accelerates, as natural gas prices increase over time and renewables become increasingly cost-competitive in some regions.

Wind and solar generation account for nearly two-thirds of the increase in total renewable generation in the AEO2015 Reference case. Solar photovoltaic (PV) technology is the fastest-growing energy source for renewable generation, at an annual average rate of 6.8%. Wind energy accounts for the largest absolute increase in renewable generation and for 40.0% of the growth in renewable generation from 2013 to 2038, displacing hydropower and becoming the largest source of renewable generation by 2040. PV capacity accounts for nearly all the growth in solar generation, split between the electric power sector and the end-use sectors (e.g., distributed or customer-sited generation). Geothermal generation grows at an average annual rate of about 5.5% over the projection period, but because geothermal resources are concentrated geographically, the growth is limited to the western United States. Biomass generation increases by an average of 3.1%/year, led by cofiring at existing coal plants through about 2030. After 2030, new dedicated biomass plants account for most of the growth in generation from biomass energy sources.

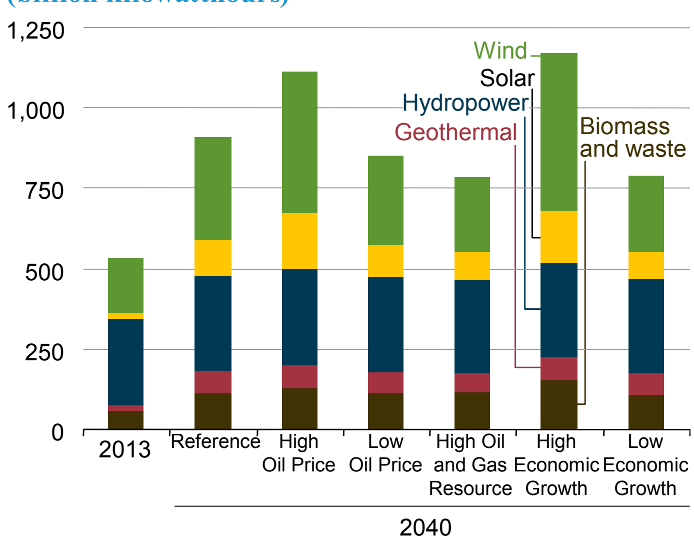
In the High Economic Growth and High Oil Price cases, renewable generation growth exceeds the levels in the Reference case—more than doubling from 2013 to 2040 in both cases (Figure ES8), primarily as a result of increased demand for new generation capacity in the High Economic Growth case and relatively more expensive competing fuel prices in the High Oil Price case. In the Low Economic Growth and Low Oil Price cases, with slower load growth and lower natural gas prices, the overall increase in renewable generation from 2013 to 2040 is somewhat smaller than in the Reference case but still grows by 49% and 61%, respectively, from 2013 to 2040. Wind and solar PV generation in the electric power sector, the sector most affected by renewable electric generation, account for most of the variation across the alternative cases in the later years of the projections.

Electricity prices increase with rising fuel costs and expenditures on electric transmission and distribution infrastructure

In the AEO2015 Reference case, increasing costs of electric power generation and transmission and distribution, coupled with relatively slow growth of electricity sales (averaging 0.7%/year), result in an 18% increase in the average retail price of electricity (in real 2013 dollars) over the projection period. In the Reference case, prices increase from 10.1 cents/kilowatthour (kWh) in 2013 to 11.8 cents/kWh in 2040. In comparison, over the same period, the largest increase in retail electricity prices (28%) is in the High Oil Price case (to 12.9 cents/kWh in 2040), and the smallest increase (2%) is in the High Oil and Gas Resource case (to 10.3 cents/kWh in 2040). Electricity prices are determined by economic conditions, efficiency of energy use, competitiveness of electricity supply, investment in new generation capacity, investment in transmission and distribution infrastructure, and the costs of operating and maintaining plants in service. Those factors vary in the alternative cases.

Fuel costs (mostly for coal and natural gas) account for the largest portion of generation costs in consumer electricity bills. In 2013, coal accounted for 44% and natural gas accounted for 42% of the total fuel costs for electricity generation. In the AEO2015 Reference case, coal accounts for 35% and natural gas for 55% of total fuel costs in 2040. Coal prices rise on average by 0.8% per year and natural gas prices by 2.4%/year in the Reference case, compared with 1.3%/year and 3.1%/year, respectively, in the High Oil Price case and 0.5%/year and 0.2%/year, respectively, in the High Oil and Gas Resource case.

Figure ES8. Total U.S. renewable generation in all sectors by fuel in six cases, 2013 and 2040 (billion kilowatthours)



There has been a fivefold increase in investment in new electricity transmission capacity in the United States since 1997, as well as large increases in spending for distribution capacity. Although investments in new transmission and distribution capacity do not continue at the same rates in AEO2015, spending continues on additional transmission and distribution capacity to connect to new renewable energy sources; improvements in the reliability and resiliency of the grid; enhancements to community aesthetics (underground lines); and smart grid construction.

The average annual rate of growth in U.S. electricity use (including sales and direct use) has slowed from 9.8% in the 1950s to 0.5% over the past decade. Factors contributing to the lower rate of growth include slower population growth, market saturation of electricity-intensive appliances, improvements in the efficiency of household appliances, and a shift in the economy toward a larger share of consumption in less energy-intensive industries. In the AEO2015 Reference case, U.S. electricity use grows by an average of 0.8%/year from 2013 to 2040.

Energy-related CO2 emissions stabilize with improvements in the energy intensity and carbon intensity of electricity generation

U.S. energy-related CO2 emissions in 2013 totaled 5,405 million metric tons (mt).[11] In the AEO2015 Reference case, CO2 emissions increase by 144 million mt (2.7%) from 2013 to 2040, to 5,549 million mt—still 444 million mt below the 2005 level of 5,993 million mt. Among the AEO2015 alternative cases, total emissions in 2040 range from a high of 5,979 million mt in the High Economic Growth case to a low of 5,160 million mt in the Low Economic Growth case.

In the Reference case:

- CO2 emissions from the electric power sector increase by an average of 0.2%/year from 2013 to 2040, as a result of relatively slow growth in electricity sales (averaging 0.7%/year) and increasing substitution of lower-carbon fuels, such as natural gas and renewable energy sources, for coal in electricity generation.
- CO2 emissions from the transportation sector decline by an average of 0.2%/year, with overall improvements in vehicle energy efficiency offsetting increased travel demand, growth in diesel consumption in freight trucks, and consumer's preference for larger, less-efficient vehicles as a result of the lower fuel prices that accompany strong growth of domestic oil and dry natural gas production.
- CO2 emissions from the industrial sector increase by an average of 0.5%/year, reflecting a resurgence of industrial activity fueled by low energy prices, particularly for natural gas and HGL feedstocks in the bulk chemical sector.
- CO2 emissions from the residential sector decline by an average of 0.2%/year, with improvements in appliance and building shell efficiencies more than offsetting growth in housing units.
- CO2 emissions from the commercial sector increase by an average of 0.3%/year even with improvements in equipment and building shell efficiency, as a result of increased electricity consumption resulting from the growing proliferation of data centers and electric devices, such as networking equipment and video displays, as well as greater use of natural gas-fueled combined heat and power distributed generation.

[11]Based on EIA, Monthly Energy Review (November 2014), and reported here for consistency with data and other calculations in the AEO2015 tables. The 2013 total was subsequently updated to 5,363 million metric tons in EIA's February 2015 Monthly Energy Review, DOE/EIA-0035(2015/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351502.pdf.

CHAPTER 1: EXECUTIVE SUMMARY

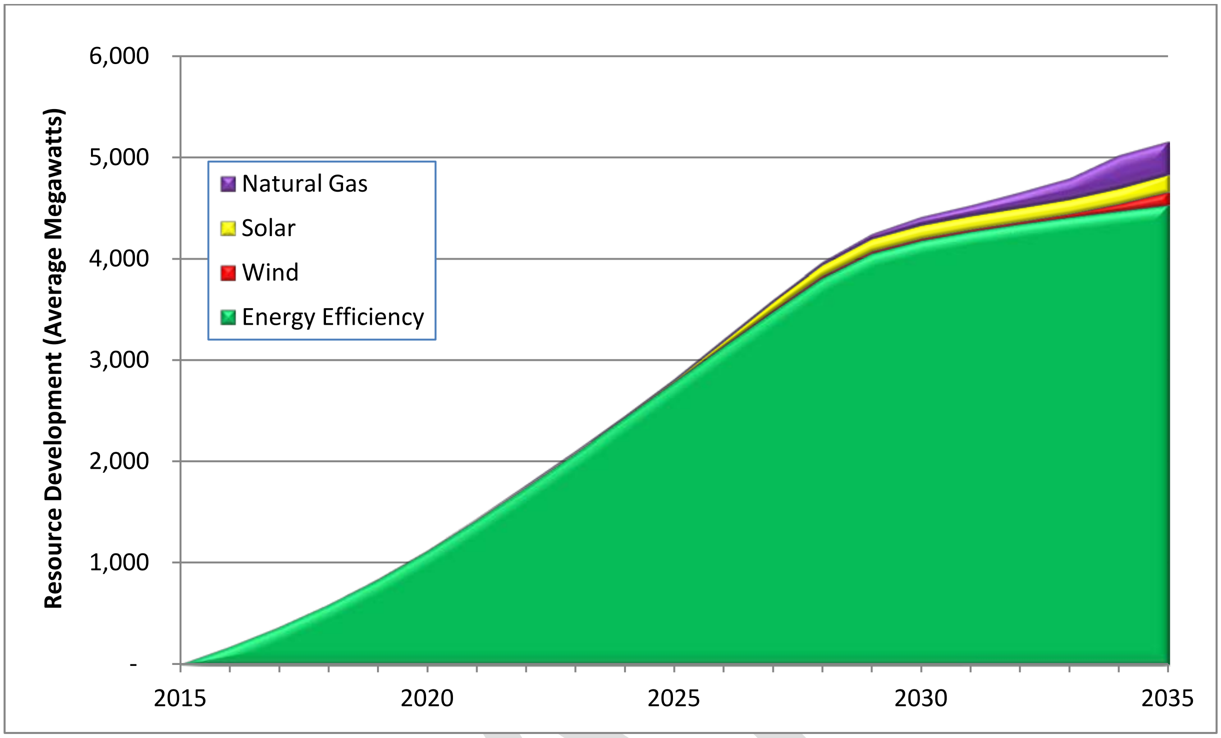
The Pacific Northwest power system faces a host of uncertainties, from compliance with federal carbon dioxide emissions regulations to future fuel prices, resource retirements, salmon recovery actions, economic growth, a growing need to meet peak demand, and how increasing renewable resources would affect the power system. The Council's Seventh Power Plan addresses these uncertainties and provides guidance on which resources can help ensure a reliable and economical regional power system over the next 20 years.

In developing its plan, the Council relies on feedback from technical and policy advisory groups and input from a broad range of interests, including utilities, state energy offices, and public interest groups.

The plan also recognizes that individual utilities, which have varying access to electricity markets and varying resource needs, may require near-term investments in resources to meet their adequacy and reliability needs. For example, some utilities face significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required in such instances, even if utilities deploy demand response resources and develop the energy efficiency called for in the plan.

Using modeling to test how well different resources would perform under a wide range of future conditions, energy efficiency consistently proved the least expensive and least economically risky resource. In more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2035. It's not only the single largest contributor to meeting the region's future electricity needs, it's also the single largest source of new winter peaking capacity. If developed aggressively, in combination with past efficiency acquisition, the energy efficiency resource could approach the size of the region's hydroelectric system's firm energy output, adding to the Northwest's heritage of clean and affordable power. Figure 1 - 1 shows the composition of the plan's resource portfolio.

Figure 1 - 1: Seventh Plan Resource Portfolio[1]



Acquiring this energy efficiency is the primary action for the next six years. The plan's second priority is to develop the capability to deploy demand response resources or rely on increased market imports to meet system capacity needs under critical water and weather conditions. While the region's hydroelectric system has long provided ample peaking capacity, it's likely that under low water and extreme weather conditions we'll need additional winter peaking capacity to maintain system adequacy. Because the probability of such events is low (but real), demand response resources, which have low development and "holding" costs are best-suited to meet this need. However, whether and to what extent the region should rely on demand response or increase its reliance on power imports to meet regional resource adequacy requirements for winter capacity depends on their comparative availability, reliability, and cost.

After energy efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Similarly, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Combined with investments in renewable generation, as required by state renewable portfolio standards, improved efficiency, demand response resources, and natural gas generation are the principal components of the plan's resource portfolio.

[1] Figure 1 - 1 shows the average resource development across all 800 futures tested in the Regional Portfolio Model. Actual development, particularly of non-energy efficiency resources, will depend on actual future conditions.

A key question for the plan was how the region could lower power system carbon dioxide emissions and at what costs. The Council's modeling found that without additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 55 million metric tons in 2015 to around 34 million metric tons in 2035,[2] the result of retiring the Centralia, Boardman, and North Valmy coal plants between 2020 and 2026; using existing natural gas-fired generation to replace them; and developing about 4,500 average megawatts of energy efficiency by 2035, which is expected to meet all forecast load growth over that time frame.

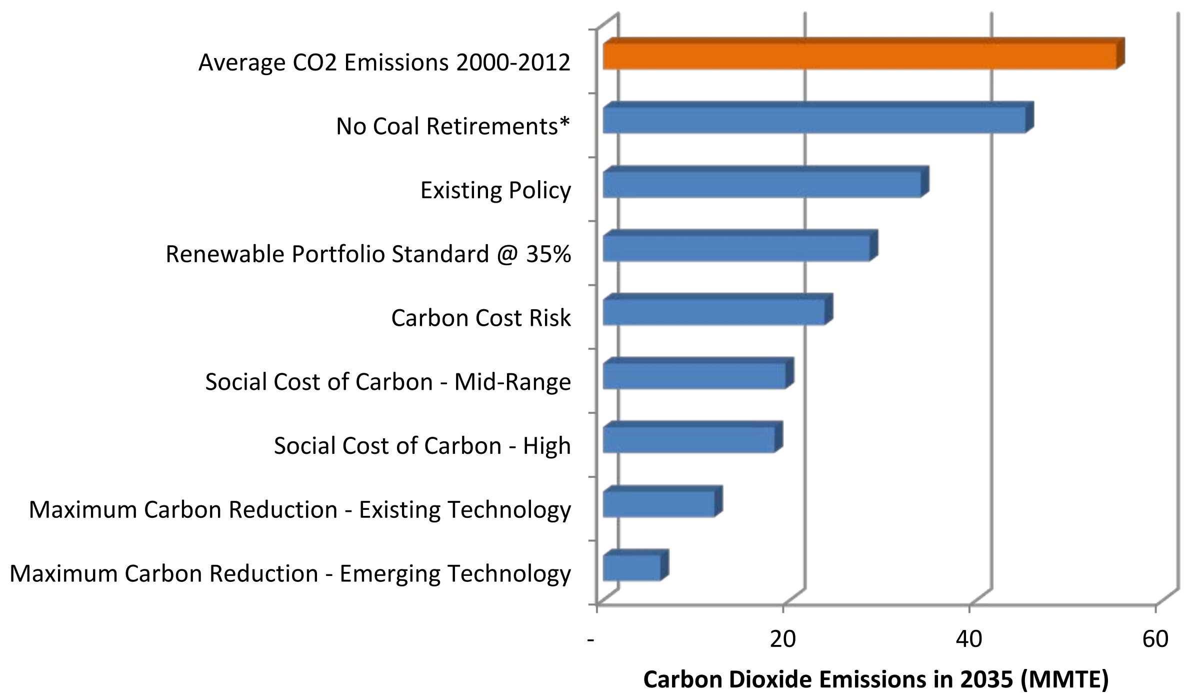
In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's carbon emissions limits, even under critical water conditions.

The Council also assessed alternative policies to further reduce emissions. With today's technology, carbon dioxide emissions could be reduced to about 12 MMTE, almost 80 percent below 2015 emissions (under average water conditions). This would require retiring all the coal generation serving the region, which is responsible for more than 85 percent of system emissions; retiring the most inefficient natural gas-fired generation; and acquiring additional energy efficiency and demand response resources. The estimated cost of doing this is nearly $20 billion over the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level. Reducing the region's power system carbon footprint below that level isn't technically feasible without developing new technologies.

Figure 1 - 2 shows the forecast average carbon dioxide emissions in 2035 under the various scenarios tested in developing the plan.

[2] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emissions could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001–2012 were 55 MMTE, but ranged from 43 MMTE to 60 MMTE.

Figure 1 - 2: Forecast Northwest Power System Carbon Dioxide Emissions in 2035 by Scenario



* Scenario assumed that the announced retirements of Boardman, Centralia and North Valmy coal plants do not occur.

Investments to add transmission capability and improve operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate low and zero-emission resources into the existing power system. The Council also expects that there are small-scale resources available at the local level in the form of cogeneration or renewable energy opportunities. The plan encourages investment in these resources when cost-effective.

The plan encourages research in advanced technologies to improve the efficiency and reliability of the power system. For example, emerging smart-grid technologies could make it possible for consumers to help balance supply and demand. Providing information and tools to consumers to adjust electricity use in response to available supplies and costs would enhance the capacity and flexibility of the power system. Smart-grid development could also help integrate electric vehicles with the power system to aid in balancing the system and reduce carbon emissions in the transportation sector. Research on how distributed solar generation with on-site storage might affect system load shape is also encouraged.

Other resources with potential, given advances in technology, include geothermal, ocean waves, advanced small modular nuclear reactors, and emerging energy efficiency technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing variable generation like wind.

Developing these technologies is a long-term process that will require many years to reach full potential. The region can make progress through investments in research, development, and demonstration projects.

FUTURE REGIONAL ELECTRICITY NEEDS AND PRICES

Pacific Northwest regional loads, measured at the generation site, are expected to increase by between 2,200 and 4,800 average megawatts between 2015 and 2035. This translates to an average increase of between 110-240 average megawatts per year, or a growth rate of between 0.5-1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from about 30,000 - 31,000 megawatts in 2015 to around 32,000 - 36,000 megawatts by 2035. This equates to an average annual growth rate of between 0.4 - 0.8 percent.

Residential and commercial sectors account for much of the growth in demand. Contributing to this growth is increasing air conditioning load, new data centers, and growth in indoor agriculture. Also, summer peak electricity use is expected to grow more rapidly than annual energy demand. All of this growth in demand must be met by a combination of existing resources, energy efficiency, and new generation.

An important finding of the plan is that future electricity needs can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour, load-following, and regulation services will also need to be considered.

Requirements for within-hour flexibility reserves have increased because of the growing amount of variable wind generation in the region. While the plan doesn't foresee renewable resource development beyond what is required to satisfy existing state renewable portfolio standards, improved regional coordination could reduce the need for resources used to integrate existing renewables. For example, establishing energy imbalance markets could enable sharing resources reserved for integrating wind resources.

Wholesale electricity prices at the Mid-Columbia hub remain relatively low, reflecting the abundance of low-variable cost generation from hydro and wind, as well as continued low natural gas prices. The average wholesale electricity price in 2014 was $32.50 per megawatt-hour. By 2035, prices are forecast to range from $33 to $60 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas-fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally sourced gas supplies from Western Canada and the U.S. Rockies.

Prices for natural gas have dropped significantly since reaching a high in 2008, and they're expected to remain relatively low going forward. Historically, natural gas prices have been volatile, so the plan uses a range of forecasts to capture most potential futures. The low price forecast range starts at

$3.50 per MMBtu in 2015 and declines in real dollars to $3.00 per MMBtu by 2035. This low-range case represents a future with slow economic growth, low gas demand, and robust supplies. The high price forecast range climbs to $10 per MMBtu by 2035. This forecast represents a future with high economic growth, high demand for natural gas, and a limited gas supply.

Recent promulgation of federal regulations that limit carbon emissions from both new and existing power generation are expected to increase the demand for natural gas. These higher natural gas prices result in higher wholesale electricity prices. Therefore, some of the futures used to develop this plan include a wide range of possible natural gas and electricity prices. Additional carbon regulations or costs could further increase electricity costs for consumers. While higher prices reduce demand, they also stimulate new sources of supply and efficiency and make more efficiency measures cost-effective.

RESOURCE STRATEGY

The plan's resource strategy provides guidance to the Bonneville Power Administration and regional utilities on resource development to minimize the costs and risks of the future power system. Timing of specific resource acquisitions will vary for each utility.

Energy Efficiency: The region should aggressively develop energy efficiency with a goal of acquiring 1,400 average megawatts by 2021; 3,100 average megawatts by 2026; and 4,500 average megawatts by 2035. Efficiency is by far the least expensive resource available to the region, avoiding the risks of volatile fuel prices and large-scale resource development, while mitigating the risk of potential carbon pricing policies. Along with its annual energy savings, it helps meet future capacity needs by reducing both winter and summer peak demand.

Demand Response: In order to satisfy regional resource adequacy standards, the region should be prepared to develop significant demand response resources by 2021 to meet additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources, the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. The Northwest's power system has historically relied on the hydrosystem to provide peaking capacity, but under critical water and weather conditions we'll need additional capacity to meet the region's adequacy standard.

Renewable Resources: Modest development of renewable generation will meet existing renewable portfolio standards. On average, renewable resources developed to fulfill state RPS mandates will contribute about 300 average megawatts of energy, or around 900 megawatts of installed capacity. While wind generation has been the dominant renewable resource developed in the region, lower costs for solar photovoltaic technology are expected to make it more competitive. As a result, compliance is expected to be met through both wind and solar PV systems. However these renewable resources lack dependable winter peak capacity and also require within-hour balancing reserves. Therefore, the plan's resource strategy encourages research and demonstration of other potential renewable resources, such as geothermal and wave energy, which have more consistent output. The resource strategy also encourages developing other renewable alternatives that may be available at the local, small-scale level and are cost-effective now.

Natural Gas: Increased use of existing natural gas generation is expected to replace retiring coal plants and meet carbon-reduction goals in the near term. Only low to modest amounts of new natural gas-fired generation is likely to be needed to supplement energy efficiency, demand response, and renewable resources, unless the region experiences prolonged periods of high load growth. Even if the region has adequate resources, individual utilities or areas may need additional supply for energy, capacity or wind integration. In these instances, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

Regional Resource Use: Continue to improve system scheduling and operating procedures across the region's balancing authorities. These cost-effective steps will help minimize reserves needed to integrate renewable resources. The region also needs to invest in its transmission grid to improve market access for utilities, reduce line losses, and help develop diverse cost-effective renewable generation. Finally, the least-cost resource strategies rely first on regional resources to satisfy the region's resource adequacy standards. Under many futures conditions, these strategies reduce regional exports.

Carbon Policies: To ensure that future carbon policies are cost-effective and maintain regional power system adequacy, the region should develop the energy efficiency resources called for in the plan and replace retiring coal plants with only those resources needed to meet regional capacity and energy adequacy requirements. As stated earlier, after energy efficiency, increasing use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Developing new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in the plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore other sources of renewable energy, especially technologies that provide both energy and winter capacity; new efficiency technologies; new energy-storage techniques; smart-grid technologies and demand-response resources; and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or where unique opportunities emerge.

Adaptive Management: The Council will annually assess the adequacy of the regional power system to guard against power shortages. Through this process, the Council will be able to identify when conditions differ significantly from planning assumptions so the region can respond appropriately. The Council will also conduct a mid-term assessment to review the plan's implementation and ensure the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

Energy Efficiency

The dominant new resource in the Seventh Power Plan's resource strategy is improved energy efficiency. Figure 1 - 3 shows that under scenarios that consider carbon risk and those that do not, and even when natural gas and wholesale electricity prices are lower than expected, the region's net load after developing all cost-effective efficiency is basically the same over the next 20 years. In more than 90 percent of the 800 futures evaluated by the Council, across more than 20 different scenarios, the least cost resource strategy developed sufficient energy efficiency resource to meet all regional load growth through 2035. Indeed, even in the scenario (Lower Energy Efficiency) that assumed only energy efficiency costing less than short-term wholesale market prices would be acquired, all regional load growth through 2030 was met with energy efficiency. However, it should be noted that developing this lower level of efficiency increased regional power system cost by $14 billion or 16 percent higher compared to resource strategies that developed sufficient energy efficiency to meet all load growth through 2035 .

This is because improved efficiency is relatively cheap, it provides both energy and capacity savings, and it has no major risks. It's half what other resources cost, without the risk of volatile fuel prices or costs of carbon reduction policies. It also has a short lead time and is available in small increments, both of which reduce risk. Therefore, improved efficiency reduces the cost of, and risks to, the power system.

Figure 1 - 3: Average Net Regional Load After Accounting for Cost-Effective Energy Efficiency Resource Development

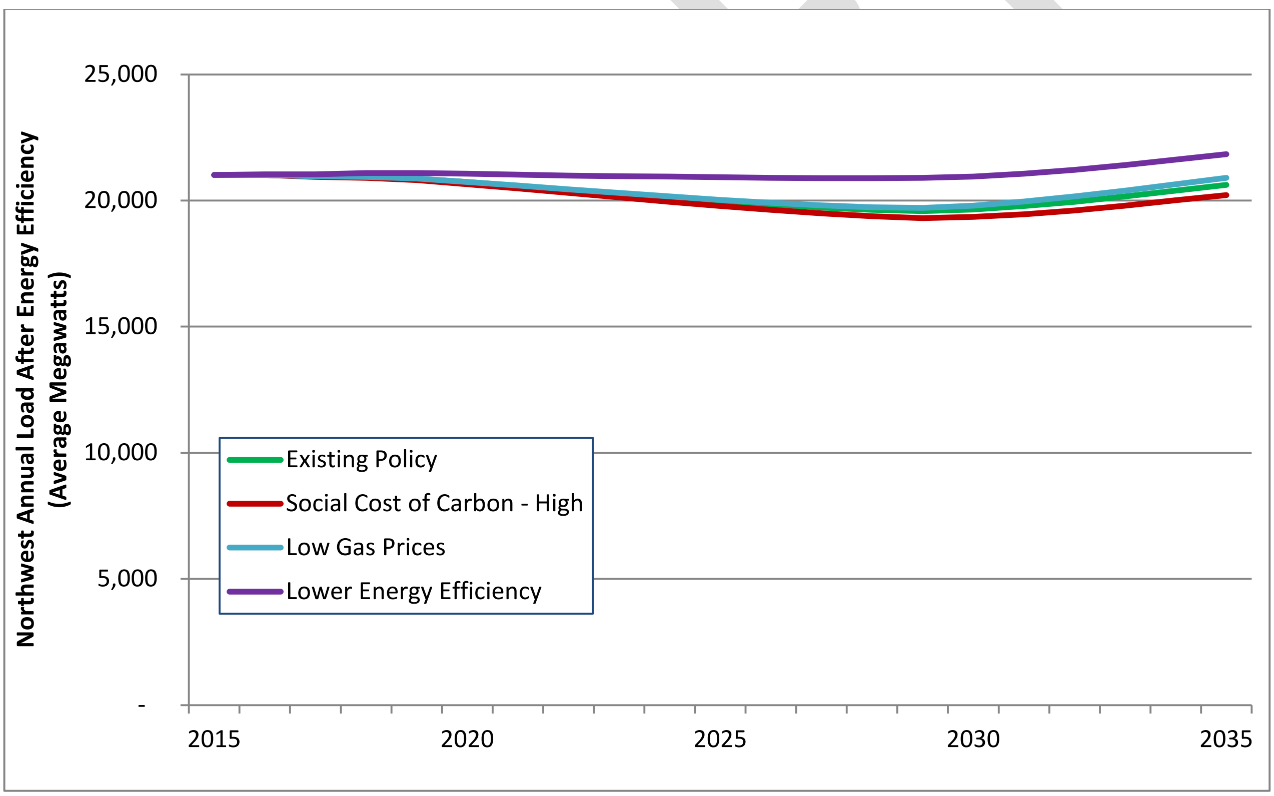


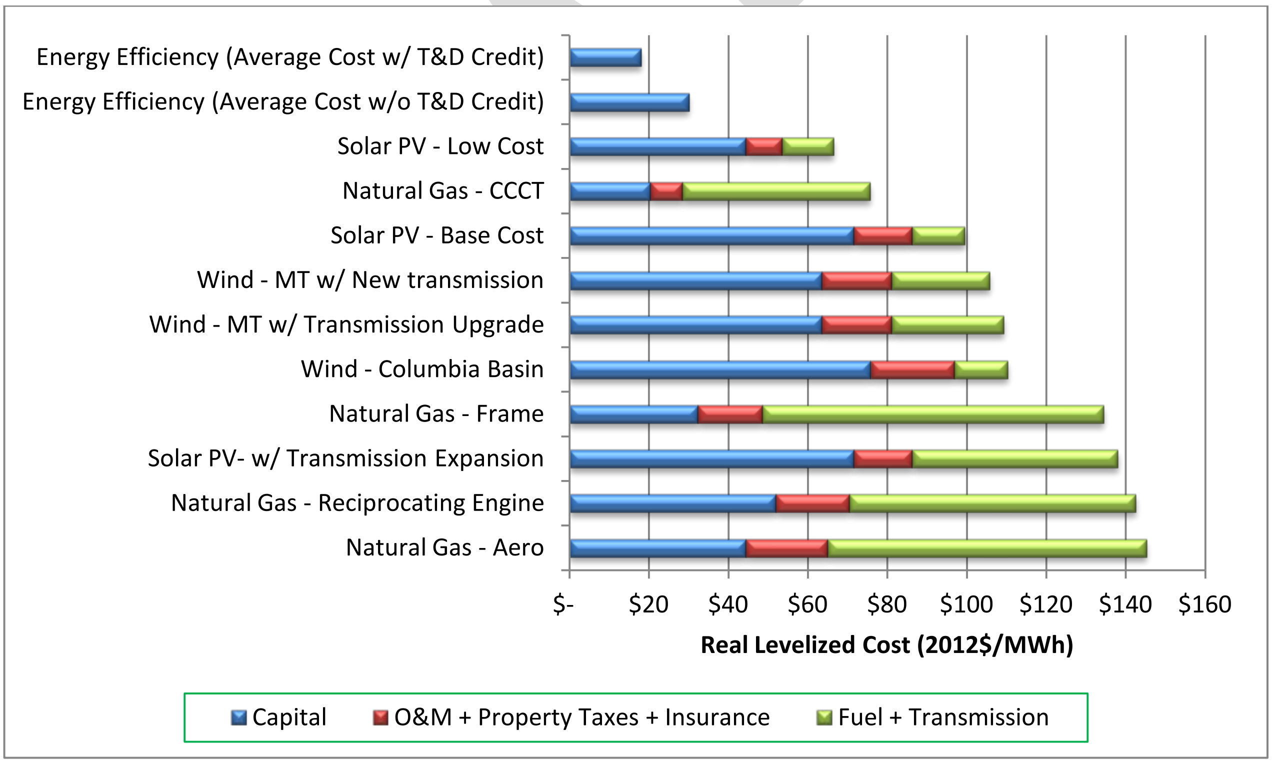
Figure 1 - 4 compares the average cost of the energy efficiency resources and the cost of generating resources considered in the plan's development. Two estimates of the cost of energy efficiency are shown. The lower average cost ($18 per megawatt-hour) reflects energy efficiency's impact on the need to expand distribution and transmission systems. The higher cost ($30 per megawatt-hour) does not include these power system benefits.

The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $75 per megawatt-hour. The current cost of utility-scale solar photovoltaic systems is approximately $100 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour. Over time, the cost of utility-scale solar photovoltaic systems is forecast to drop to around $65 per megawatt-hour. Significant amounts of improved efficiency also cost less than the forecast market price of electricity, since nearly 2,300 average megawatts energy efficiency savings are available below the average cost of $30 per megawatt-hour.

In the Council's analysis, additional resources provide insurance against an uncertain future. Efficiency improvements are particularly attractive as insurance because of their low cost and modular size. When the resources aren't needed, the energy savings from low cost energy efficiency resources can be sold in the market, paying for itself and then some.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency are found to be cost-effective even without carbon costs. If carbon reduction policies are enacted, efficiency improvements can help the region meet those goals. In all scenarios tested by the Council, the amount of cost-effective efficiency developed averaged between 1,300 and 1,450 average megawatts by 2021 and between 3,900 and 4,600 average megawatts by 2035.

Figure 1 - 4: Energy Efficiency and Generating Resource Cost Comparison



Demand Response

Demand response resources are voluntary reductions in customer electricity use during periods of high demand and limited resource availability. The plan's resource strategy uses demand response to meet winter and summer peak demands, primarily under critical water and extreme weather conditions. The strategy doesn't consider other possible applications of demand response--to integrate variable resources like wind for example.

The Council's assessment identified more than 4,300 megawatts of regional demand response potential. A significant amount of this potential, nearly 1,500 megawatts, is available at relatively low cost; less than $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response can be deployed sooner, in quantities better matched to the peak capacity need, deferring the need for transmission upgrades or expansions.

In particular, demand response is the least expensive means to maintain peak reserves for system adequacy. Its low cost is especially valuable because the need for peaking capacity in the region largely depends on water and weather conditions. Under most scenarios, there was about a 20 percent probability that as much as 600 megawatts of demand response would be cost-effective to develop by 2021, and a 15 percent probability that as much as 1,100 megawatts would be cost-effective to develop by 2026.

Alternatively, the region could rely on external power markets to meet its winter peak capacity needs. In one scenario tested by the Council, the region relied more on external markets (Canada, California, and the Southwest) which greatly reduced the need to develop demand response. That scenario relaxed the Council's current assumptions about the availability of imports from out-of-region sources and from in-region market resources. Since that scenario's system cost and economic risk were lower than scenarios in which cost-effective demand response was acquired, the plan's resource strategy recommends that the Council's Resource Adequacy Advisory Committee reexamine all potential sources of imported energy and capacity to minimize cost and avoid the risk of overbuilding.[3]

Generation Resources

The Council analyzed a large number of alternative generating technologies. Each was evaluated in terms of risk characteristics, cost, and potential for improvements in its efficiency over time. In addition, resources were considered in terms of their energy, capacity, and flexibility characteristics, such as their ability to ramp up and down to accommodate variations in the output of wind and solar PV resources.

In the near term, generating technology options that are technologically mature, meet the emission requirements for new plants, and are cost-effective are limited in number. Improvements in the

[3] See Council Action Item 10.

efficiency and operation of natural gas-fired generation make it the most cost-effective option for now. While wind continues to be the primary large-scale, cost-effective renewable resource, decreasing costs for utility-scale and distributed-scale photovoltaic systems have made them cost-competitive sources of energy supply.

Other resource alternatives may become available over time, and the plan recommends actions to encourage their development, especially those that don't produce greenhouse gas emissions.

Since the adoption of the Sixth Power Plan, renewable resource development in the Northwest has increased significantly, particularly wind. By the end of 2014, wind capacity in the region totaled just more than 8,700 megawatts. However, only about 5,550 megawatts of that capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind capacity is presently contracted to utilities outside the region, primarily California. Wind now constitutes about 8 percent of the region's electricity supply, although expiring incentives and low load growth are expected to slow development over the next five years.

Current wind generation is estimated to provide about 2,400 average megawatts per year in the region. Wind resources with access to transmission are cost competitive with other generation. However, given current technology, wind can reliably provide about 5 percent of its nameplate capacity to meet peak loads. On a firm capacity basis, wind provides about 1 percent of the total system peaking capability.

The amount of additional renewable energy acquired *on average* in the least-cost resource strategies across scenarios didn't vary significantly, even in scenarios with high carbon cost risk. This is because the two economically competitive renewable resources available in the region, wind and solar PV, provide little or no winter peaking capacity. Partly because of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water conditions the region faces the probability of a peak capacity shortfall–again, because wind provides little winter capacity.

Renewable generation development in the plan is driven by state renewable portfolio standards. In the absence of higher standards, little additional renewable development is needed, even under scenarios where the highest social cost of carbon was assumed. The Council recognizes that additional small-scale renewable resources are available and cost-effective, and the plan encourages their development as an important element of the resource strategy. For example, Snohomish PUD recently completed the Youngs Creek hydroelectric project and Surprise Valley Electric Cooperative is developing the Paisley Geothermal Project, a low-temp geothermal power project in rural Oregon. There are many other potential renewable resources that may, with additional research and demonstration, prove to be cost-effective and valuable for the region to develop.

Natural gas is the fourth major element in the plan's resource strategy. It's clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near term. After energy efficiency, increased use of *existing* natural gas generation is the lowest cost option to reduce regional carbon dioxide emissions. It plays a major role in the least-cost resource strategies to reduce carbon dioxide emissions. Existing natural gas generation increases immediately in scenarios where carbon costs are imposed.

Across the scenarios evaluated, the optioning and completion of new gas-fired generating resources varied widely. New gas-fired plants are optioned (sited and licensed) so that they are available to develop if needed in each future. The plan's resource strategy includes optioning new gas-fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and only slightly higher in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are brought to construction in only a relatively small number of futures.

Across most scenarios, the probability of gas development is less than 10 percent by 2021. By 2026, the probability of constructing a new gas-fired thermal plant increases to almost 50 percent in scenarios where utilities are unable to develop demand response, and to over 80 percent in scenarios where existing coal plants and less efficient gas-fired generation are retired to lower carbon emissions.

While efficiency, demand response, and renewable resource development were fairly consistent across most scenarios, the future role of natural gas-fired generation varied depending on the specific scenario studied. The average build-out of new natural-gas fired generation over the 800 futures in most scenarios was less than 50 average megawatts of generation by 2026. Since the average nameplate capacity of a new combined-cycle combustion turbine assumed the analysis is 370 megawatts, this implies that "on average" only a single plant, operating less than 15 percent of the time is needed. By 2035, the average build out across all 800 futures was 300 to 400 average megawatts of annual output from new gas-fired generation--one or two additional plants. In the carbon-risk scenario, the amount of energy actually generated from new combined-cycle combustion turbines, when averaged across all 800 futures, is just 10 average megawatts, but close to 100 average megawatts in scenarios that assume no demand response resources are developed.

On the other hand, some utilities may need to develop new natural gas-fired generation, even if they deploy demand response and develop the plan's recommended efficiency. The regional transmission system hasn't evolved as rapidly as the electricity market, resulting in limited access to market power. Individual utilities may need within-hour balancing reserves or have near-term resource challenges.

The varying needs of individual utilities limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources or for the types of natural gas-fired generation. But it also underscores the value of a regional approach to resource development where resources are part of an interconnected system.

Regional Resource Use

The existing Northwest power system is a significant asset for the region. The Federal Columbia River Power System provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council doesn't directly model the sub-hourly operation of the region's power system, its models presume resources located anywhere in the region can provide balancing reserve services to any other location in the region, within the limits of existing transmission. This assumption minimizes the need for new resources to integrate renewable resources.

As envisioned in the Northwest Power Act, the benefits of the federal power system would be shared by all of the region's consumers. But achieving that vision has proved elusive; its desirability even questioned by some.

Several of the scenario analyses conducted for the plan highlight the benefit of using surplus generation for in-region energy and capacity needs; it avoids the need to build new resources and lowers total system cost. Under a wide range of future conditions, the least-cost resource strategy depends on the Bonneville Power Administration selling surplus generation in-region.

While by law regional utilities have first claim to Bonneville's surplus generation, the region's investor-owned utilities ultimately compete with out-of-region buyers for that generation. And for IOUs, investing in power plants offers the opportunity to increase shareholder value compared to buying power from Bonneville because they can earn a rate of return on capital investments and not on power purchases.

Under the current law, IOU access to Bonneville's surplus peaking capacity is limited to seven-year contracts.[4] If the IOUs and Bonneville do not enter into contracts for energy or capacity, it's likely that new generation will need to be built, despite the availability of energy and capacity resources from Bonneville to serve in-region demand. This will likely continue the trend that shows the electricity rates of IOUs increasing while public utility rates have remained flat over the past several years.[5]

CLIMATE CHANGE POLICY

Evolving climate change policies to lower carbon emissions from power plants was identified by stakeholders as one of the most important issues for the plan to address. Most recently, with the promulgation by the Environmental Protection Agency's final rules limiting carbon dioxide emissions from both new and existing power generating facilities, the goal of those policies became clearer. However, since states are charged with developing and implementing plans to comply with EPA's regulations, uncertainty still exists about specific approaches Northwest states will follow to satisfy the regulation.

Reduced carbon dioxide emissions can be encouraged through various policy approaches, including regulatory mandates (renewable portfolio standards, energy efficiency resource standards, emission standards) or carbon pricing policies, such as emissions cap-and-trade systems and emissions taxes. To date, state policy responses within the region have focused on renewable portfolio

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[4] Energy and Water Appropriations Act of 1996, Pub. L. No. 104-46, §508(b), (Supp. 1 1995) and Preference Act, Pub. L. 88-552, §3(c) (1994 & Supp. 1 1995).
[5] Between 2007 and 2013, the average revenue per kilowatt-hour sold by IOUs increased from 7.4 cents to 8.6 cents, while the average revenue per kilowatt-hour sold for public utilities remained unchanged at 6.1 cents.

standards and new generation emission limits. Oregon and Washington also have carbon reduction targets adopted by statute. While there have been both regulatory and carbon pricing policies discussed at the national level, the EPA's recently promulgated emissions limits are the most concrete policy option adopted.

The plan doesn't address whether carbon dioxide emissions should be reduced, by when or to what level. For now, these questions have been settled by EPA's regulations.[6] The questions for the plan are: What are the least-cost resource strategies to reduce carbon dioxide emissions and satisfy the federal emissions limits? And, what state (or regional) policies are likely to result in those least-cost resource strategies? The Council analyzed multiple carbon reduction scenarios, including three alternative carbon pricing policies and three regulatory policies.

The key findings from the Council's analysis of climate change policies include the following:

- Without any additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 55 million metric tons in 2015 to around 34 million metric tons in 2035.[7] This reduction is driven by: 1) The retirement of three coal-fired power plants (Centralia, Boardman, and North Valmy) by 2026. These plants currently serve the region, but their retirement has already been announced; 2) Increased use of existing natural gas-fired generation to replace these retiring resources; and 3) Developing roughly 4,500 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame. If these actions do not occur, the level of forecast emissions is likely to increase. If these actions do occur, then the region will have a very high probability (98 percent) of complying with the EPA's carbon emissions limits, even under critical water conditions.

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric tons today to about 12 million metric tons, a nearly 80 percent reduction. Implementing this resource strategy would increase the present value average power system cost by nearly $20 billion (23 percent) over resource strategies that are projected to satisfy the Environmental Protection Agency's recently established limits on carbon dioxide emissions *at the regional level*.

- By developing and deploying current emerging energy efficiency and non-carbon emitting resource technologies, it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, about 50 percent below the level achievable with existing technology. Due to the speculative nature of the cost and ultimate performance of the emerging technologies considered in this scenario the economic cost of

[6] By "settled" the Council does not mean to imply that pending litigation over the EPA's regulations may not still alter those regulations. In this context, the Council simply means that in developing the plan it used EPA's draft and final regulations as the basis for its analysis of the cost and effectiveness of alternative carbon reduction policies.
[7] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emission could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001 – 2012 were 55 MMTE, but ranged from 43 MMTE to 60 MMTE.

achieving these additional emissions reductions was not evaluated.

- At present, it's not possible to entirely eliminate carbon dioxide emissions from the power system without the use of nuclear power or emerging technology breakthroughs in both energy efficiency and non-carbon dioxide emitting generation.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges.

- Given the characteristics of wind and utility-scale solar PV and the energy and capacity needs of the region, policies designed to reduce carbon emissions by increasing state renewable portfolio standards are the most costly and produce the least emissions reductions.

- Imposing a regionwide cost of carbon, equivalent to the federal government's social cost of carbon highest estimate, results in lower forecast emissions, without significantly increasing the use of energy efficiency or renewable resources.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Columbia River Basin Fish and Wildlife Program is by statute incorporated into the Council's power plan. The fish and wildlife program guides the Bonneville Power Administration's efforts to mitigate the adverse effects of the Columbia River hydroelectric system on fish and wildlife. One of the roles of the power plan is to ensure the implementation of hydrosystem operations to benefit fish and wildlife while maintaining an adequate, efficient, economic, and reliable energy supply.

The hydroelectric operations for fish and wildlife have a sizeable impact on power generation. On average, hydroelectric generation is reduced by about 1,100 average megawatts compared to operation without constraints for fish and wildlife. Since 1980, the power plan and Bonneville have addressed this impact through changes in secondary power sales and purchases; by acquiring energy efficiency and some generating resources; by developing resource adequacy standards; and by implementing other strategies to minimize power system emergencies and events that might compromise fish operations.

In addition to operational changes, most of the direct and capital costs of the fish and wildlife program have been recovered through Bonneville revenues, and Bonneville has absorbed the financial effects of lost generation, resulting in higher electricity prices. The power system is less economical as a result of fish and wildlife program costs, but still affordable when compared to the costs of other reliable and available power supplies.

The future presents a host of uncertain changes that are sure to pose challenges to integrating power system and fish and wildlife needs: potential new fish and wildlife requirements; increasing wind generation and other renewables that require more flexibility in power system operations; conflicts between climate change policies and fish and wildlife operations; possible changes to the water supply from climate change that intensify conflict between fish and power needs; and possible revisions to Columbia River Treaty operations to match 21st century power, flood control, and fish needs.

Operations to benefit fish and wildlife have a significant biological value, and also a significant effect on the amount and patterns of generation from the hydrosystem. The Council encourages the federal action agencies to continue to monitor, evaluate, and report on the benefits and impacts to fish from flow augmentation and passage measures, including spill, and to work to revise and improve these evaluation methods as much as possible.

To address current operations and prepare for the challenges ahead, the Council will track changes and recommend actions by: annually assessing the region's power supply using its regional adequacy standard to ensure that events like the 2000-01 energy crisis, in which fish operations and power costs were affected, do not happen again; working with partners on its wind integration forum to help integrate wind generation into the power system; and completing a mid-term assessment of its power plan to measure our progress.

Mid-Columbia Spot Markets and the Renewable Portfolio Standard

Robert McCullough

In 2006 and 2007, California, Oregon, and Washington enacted Renewable Portfolio Standards (RPS) designed to mandate a high percentage of renewables over the following twenty years.[1] The three initiatives have been highly successful and have increased the number of renewable resources – primarily wind – throughout the west.

The increasing number of intermittent and non-dispatchable resources has caused a variety of unintended consequences. A conflict between Bonneville Power Administration, the federal utility whose control area contains the majority of wind developments, and wind producers has reached the Federal Energy Regulatory Commission in Washington DC and is the subject of a rate proceeding at the BPA.[2]

While thermal generation is scheduled by hour, day, and month, renewable projects are often subject to weather and climate considerations. The generation of these resources can vary wildly – often from minute to minute. Hydroelectric resources are traditionally viewed as “intermittent” since run-off from winter snows is often highly variable, but intermittency is also the case for wind and solar. Wind, the current renewable of choice, is especially intermittent, with periods of zero generation interspersed with periods of high generation. In a perfect world, the extra generation from these renewables could be stored easily against later need. The world is not perfect, however. For example, the Pacific Northwest’s “battery”, the reservoirs along the Columbia and Snake Rivers, often face environmental constraints and cannot be used to store intermittent generation.

Bonneville Power Administration currently lists 41 wind projects with a combined nameplate capacity of 4,711 megawatts.[3]

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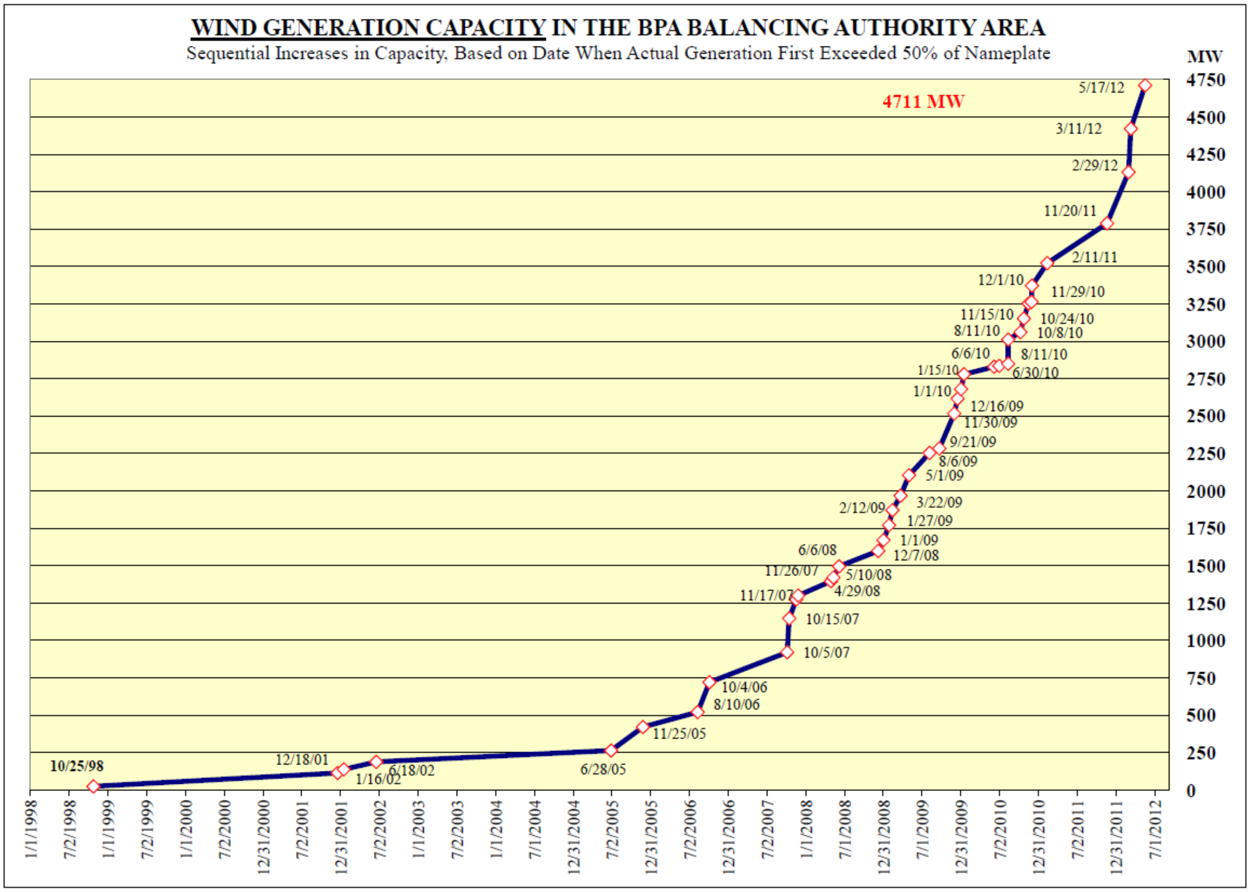
[1] The California Renewable Portfolio Standard (RPS) was enacted in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107, and expanded in 2011 under Senate Bill 2. The California RPS program requires investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of retail sales by 2020. In Oregon, Senate Bill 838 enacted in April 6, 2007, required the State Department of Energy to create an RPS under which electric utilities must derive 25 percent of annual retail electricity sales from renewable energy resources by calendar year 2025. In Washington, Initiative 937, a successful ballot initiative in November 2006, required large utilities to obtain 15 percent of their electricity from new renewable resources such as solar and wind by 2020 and undertake cost-effective energy conservation.

[2] BPA published a notice in the Federal Register on November 8, 2012 announcing the commencement of the Over Supply-14 Rate Case.

[3] http://transmission.bpa.gov/Business/Operations/Wind/WIND_InstalledCapacity_Plot.pdf



The recent Western Electricity Coordinating Council (WECC) plan indicates massive increases in wind and other renewables in the current decade (18,000 megawatts in wind alone) in the western interconnect.[4] The majority of the region's wind resources are forecasted for Oregon and Washington.

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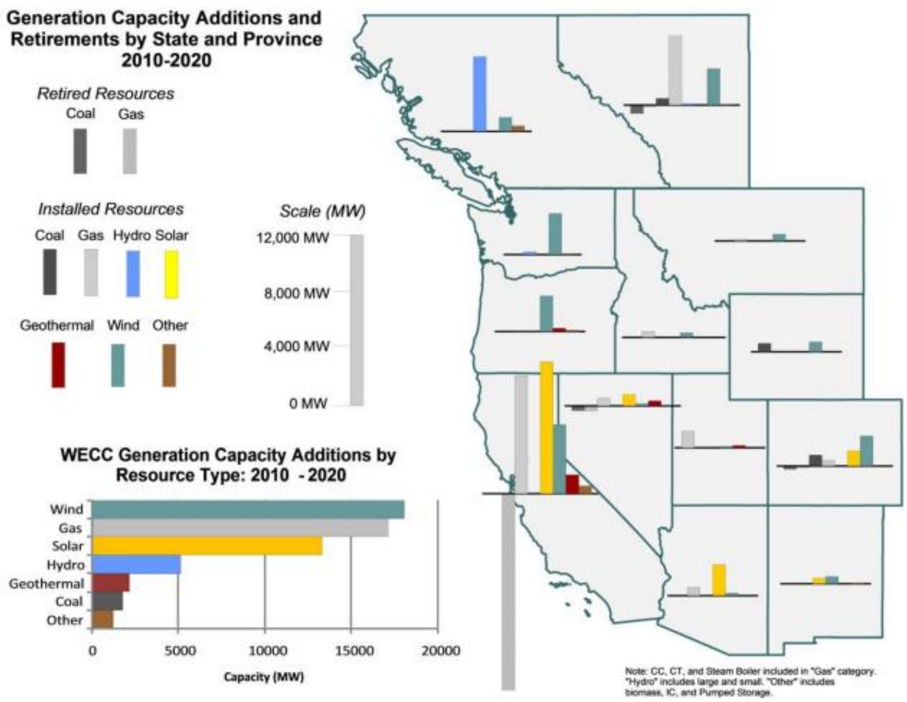
[4] 10-Year Regional Transmission Plan Summary, WECC, September 2011, page 19.

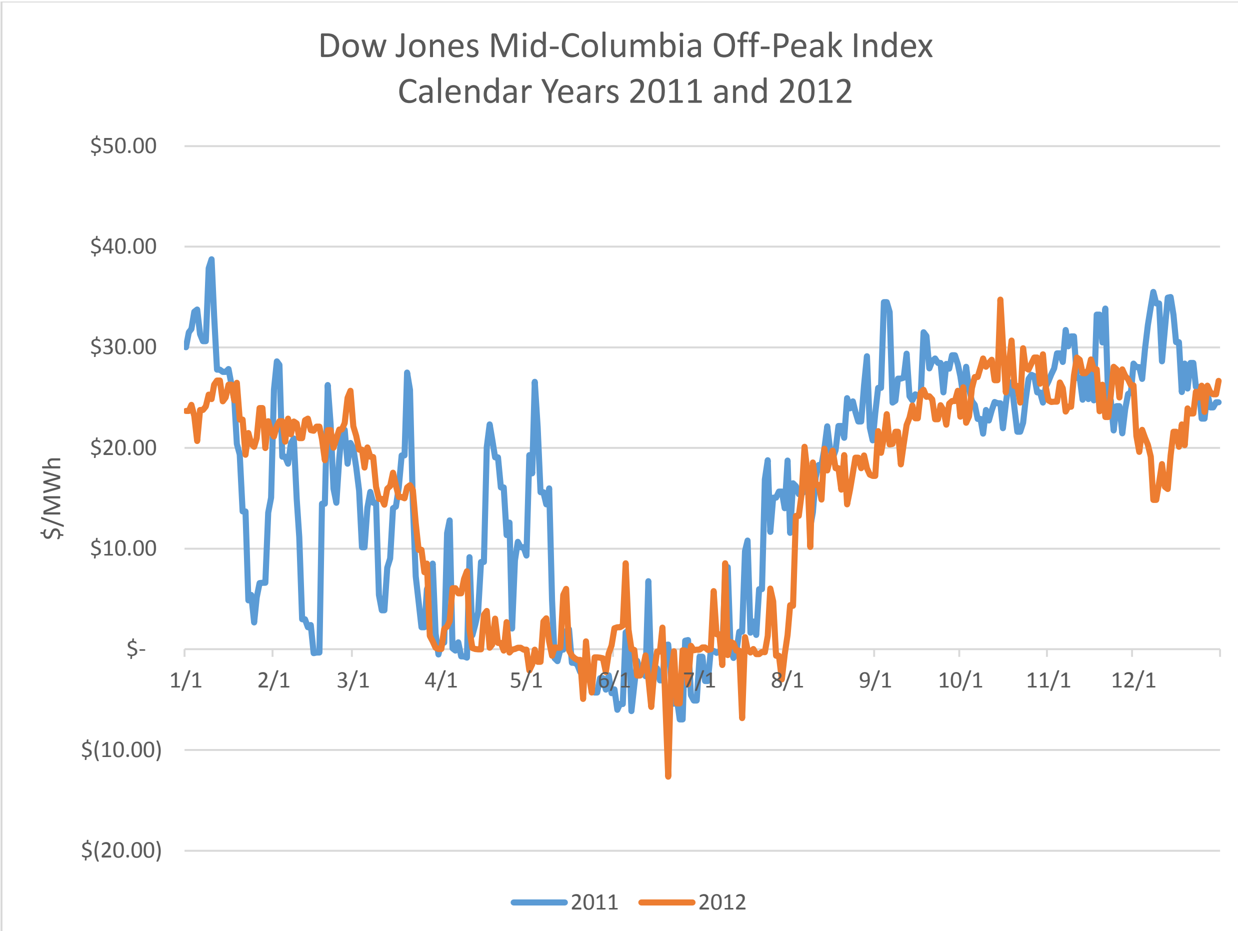


The eastern desert counties of Oregon and Washington have seen an enormous growth in wind generation. There are a number of reasons why this is such a good location. The wind resources are plentiful and NIMBY (Not In My Back Yard) concerns are rare given the area's low population.

One of the unforeseen consequences is that off-peak prices in the large and liquid Mid-Columbia wholesale market went negative for almost one sixth of the time in 2011 and 2012.[5]

---

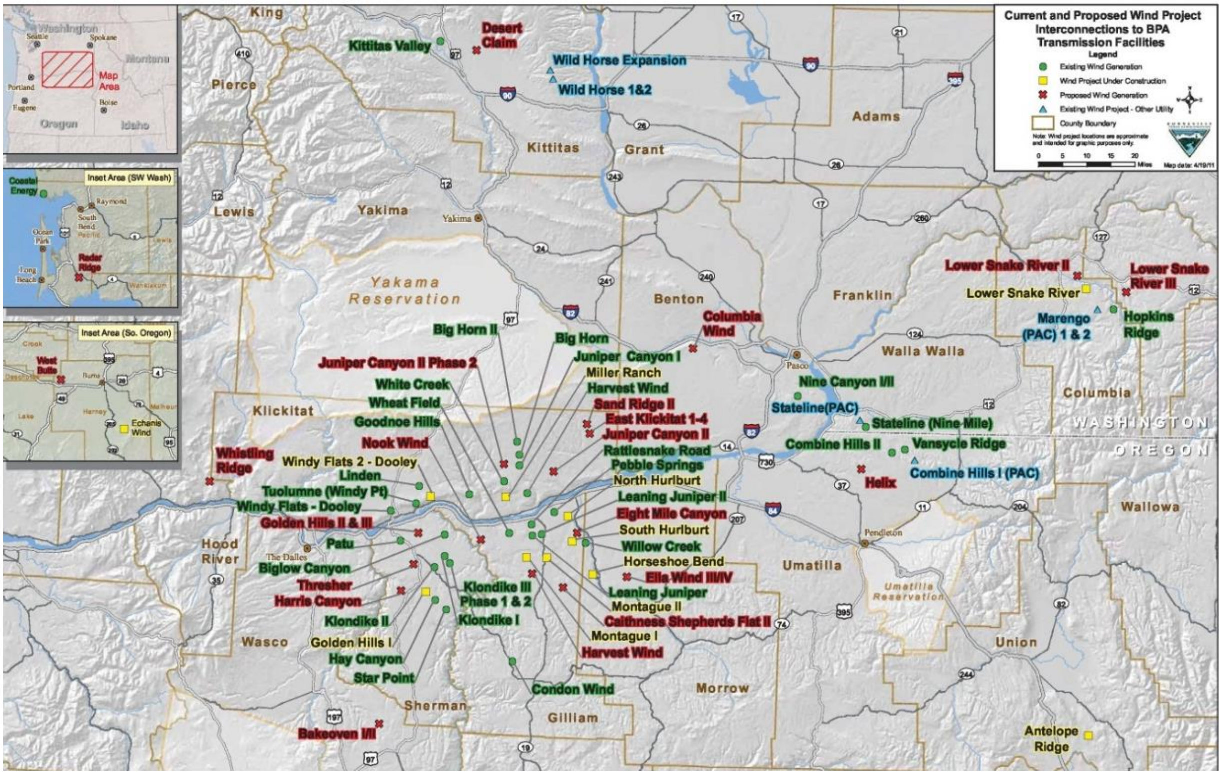
[5] In 2012 a good water year and the rapidly increasing level of renewables – primarily wind – contributed to an unusual situation: off-peak energy prices in the Mid-Columbia market fell below zero on 65 days. This is the second year when negative prices were so significant. The first year, 2011, had negative off-peak prices on 62 days.



The location of the wind farms in eastern Oregon and Washington generally surrounds the massive hydroelectric resources along the Columbia River. The Mid-Columbia Bus surrounding the major dams has created one of the largest electric markets in the world. Prices at Mid-Columbia are reported in the energy media, at FERC, and at the Energy Information Administration and are the basis of industrial and resource contracts throughout the Pacific Northwest.

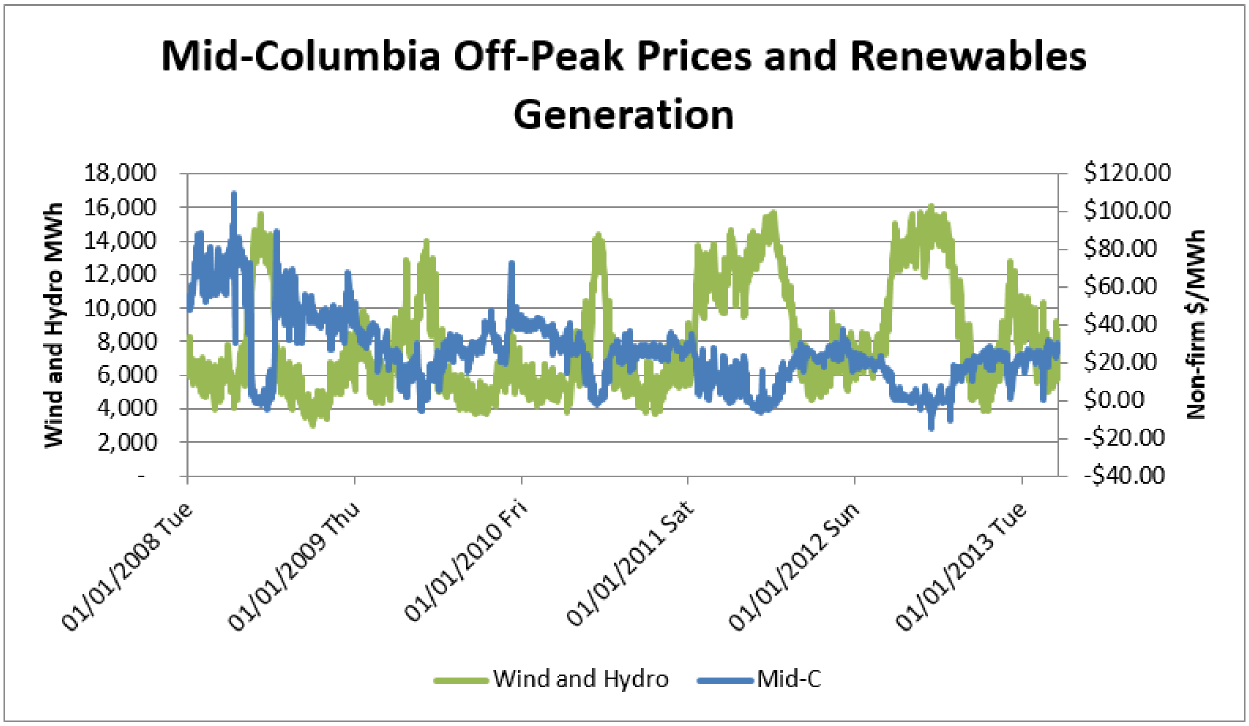
The market is also highly transparent since there is no third party administrative agency that can restrict market information. To recapitulate Paul Samuelson's classic definition of a free market, there are many buyers, many sellers, and exit and entry are free.[6] Unlike the administered markets in California, the market is a traditional open outcry market where any market participant can make a bilateral contract with any other.

[6] Economics, Paul A. Samuelson, 1948, page 592.



The presence of a large open outcry market adjacent to the wind farm areas in eastern Oregon and Washington makes it an excellent test bed for the changes we can expect in other areas as renewables became a larger and larger force in market pricing.

Dow Jones publishes an index for on-peak and off-peak prices at the Mid-Columbia market. Not surprisingly, the correlation between price and quantity is very high. The following chart shows the prices and quantities during off-peak hours in this market from 2008 through the present.



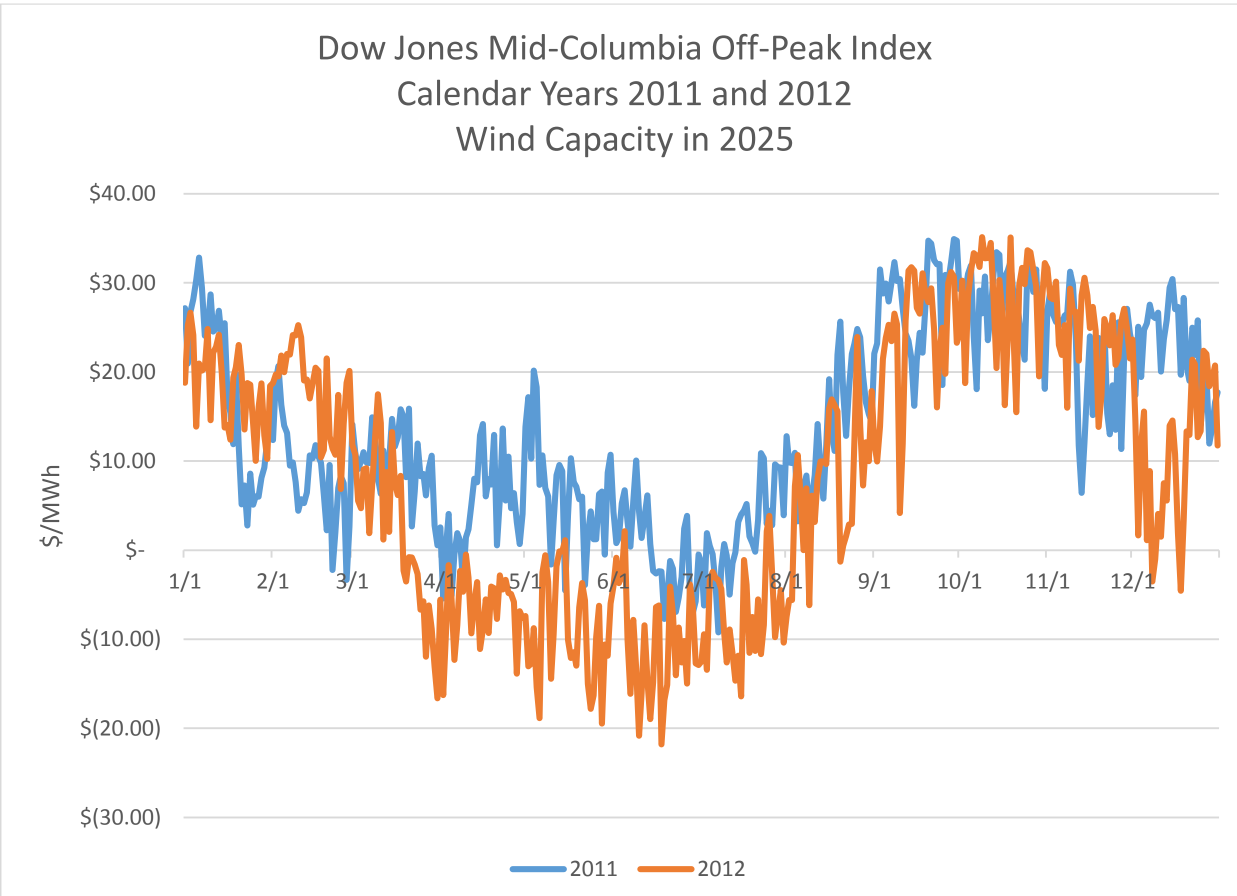
The statistical relationship between renewables and prices at Mid-Columbia is excellent:[7]

```
Cochrane-Orcutt AR(1) regression -- iterated estimates

      Source |       SS       df       MS              Number of obs =    2274
-------------+------------------------------           F(  3,  2270) =  590.55
       Model |  261835.564     3  87278.5213           Prob > F      =  0.0000
    Residual |  335489.816  2270  147.792871           R-squared     =  0.4383
-------------+------------------------------           Adj R-squared =  0.4376
       Total |   597325.38  2273  262.791632           Root MSE      =  12.157

------------------------------------------------------------------------------
  midcoffpeak |      Coef.   Std. Err.      t    P>|t|     [99% Conf. Interval]
-------------+----------------------------------------------------------------
      windmw |  -.0029674    .000421    -7.05   0.000    -.0040527   -.0018821
     hydromw |  -.0035909   .0001264   -28.41   0.000    -.0039167    -.003265
    henryhub |   4.251078   .1695291    25.08   0.000     3.814032    4.688123
       _cons |   35.76578   1.381826    25.88   0.000     32.20343    39.32812
-------------+----------------------------------------------------------------
         rho |   .3307844
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    1.341173
Durbin-Watson statistic (transformed) 2.265924
```

[7] The statistical relationship using ordinary least squares indicates a degree of heteroskedasticity. The use of Cochrane-Orcutt corrects for the inefficiency of ordinary least squares in the presence of heteroskedasticity. The use of just three explanatory variables – hydro generation, wind generation, and gas prices – is meant only to illustrate the relationship of these variables to spot prices. This is hardly a complete model of the Mid-Columbia market.

Although we expect hydroelectric generation to stay roughly constant in years to come, our expectation is that wind generation in the Pacific Northwest will expand sharply. If the hydro flows experienced in 2012 were to occur in 2025, we could expect a markedly greater number of days when off-peak prices would be negative.

The wind additions roughly doubling current capacity are largely mandated in the RPS adopted in Oregon and Washington. Even without comparable investments in California, we would expect the increasing numbers of intermittent renewable resources to significantly lower market prices and increase volatility in the wholesale spot markets.



The modeling of prices requires more sophistication than simply holding hydroelectric generation constant and doubling wind generation. Scaling wind resources from previous years up to their 2013 levels indicates that negative off-peak prices would also have occurred in 2009. The significance of 2009 is that while 2011 and 2012 were "wet" years, 2009 was relatively "dry", with January through July runoff at The Dalles at less than 90% of the eighty-year average.

To gain a better sense of prices under the California, Oregon, and Washington RPS, we used the base assumptions from the well-respected AURORA^{xmp}® model with two major changes.[8] First, we updated

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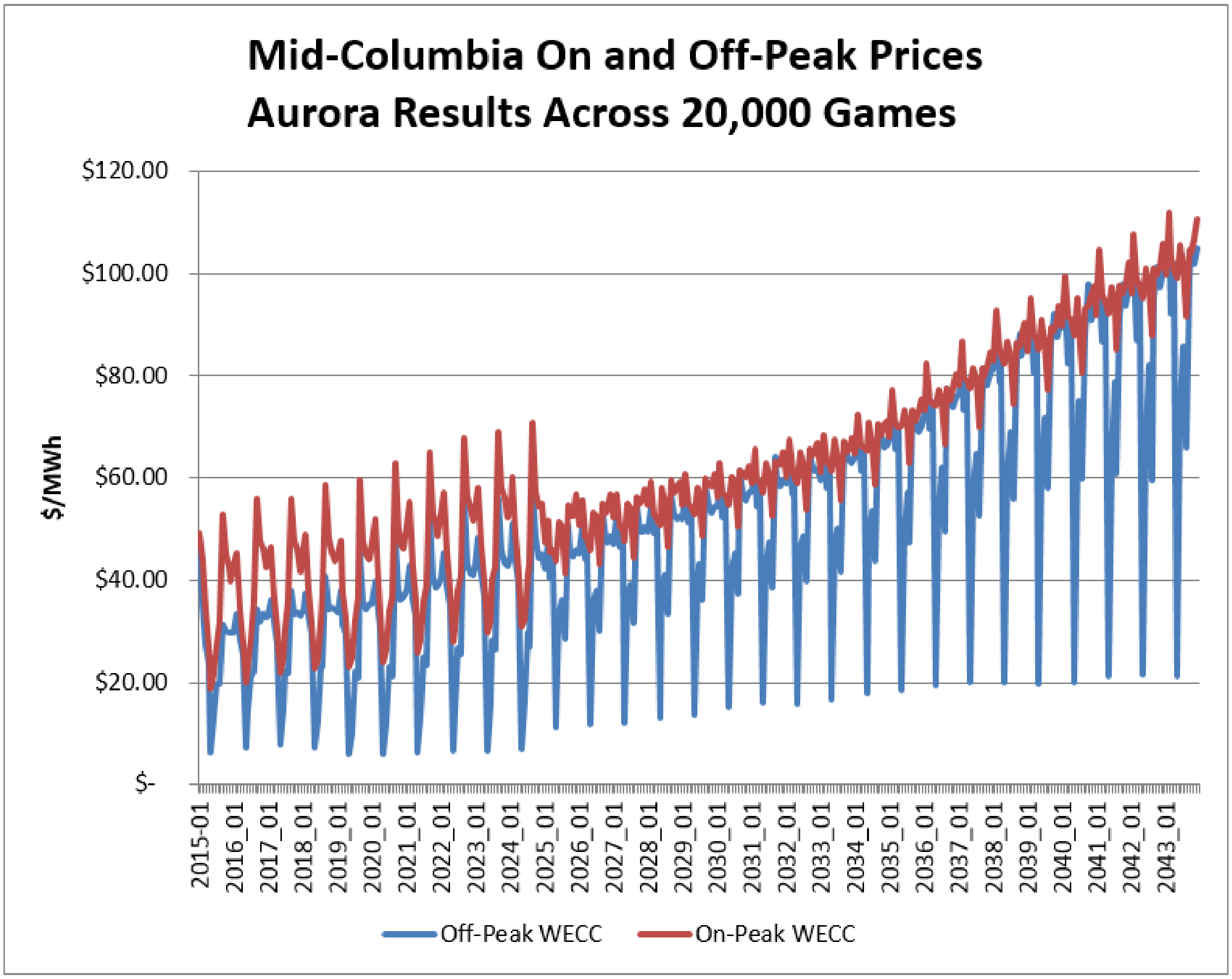
[8] http://epis.com/aurora_xmp/power_forecasting.php

the natural gas forecast using the Energy Information Administration's 2013 Early Release Annual Energy Outlook.[9] We also rebuilt the WECC to meet the requirements of the Washington, Oregon, and California renewable mandates. Since both wind and hydro are stochastic variables, we ran 20,000 "games" in a Monte Carlo model based on RPS resources.[10] Our results indicate that the current instability in off-peak prices is not simply an outlier:



Even assuming an optimal build-out of resources subject to the three RPS, the additional resources mandated by RPS schedules will increase price volatility and lower expected price across the next thirty years.

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[9] http://www.eia.gov/forecasts/aeo/er/index.cfm

[10] Monte Carlo modeling is an approach to forecasting where the model is run once for each pick of a set of random variables. The name references testing roulette strategies by spinning the roulette wheel many times to see what the expected outcome is. Each spin of the wheel is referred to as one "game." In this case, we ran the WECC 20,000 times to get expected values across hydro and wind picks. We used the normal distribution for hydroelectric generation. We derived a uniform distribution for wind based on BPA's experience over the past five years.

As always in a long run forecast, changes in technology, e.g., electric vehicles and advanced energy storage technologies, will change the result considerably. In fact, the frequent availability of low-cost off -peak power – and even negative energy prices – and the associated large differences with on-peak prices, will provide an incentive for these changes. The low prices will also change power purchasing strategies for industries and utilities. While the risk of energy purchasing is likely to increase, the advantages of taking the risk will also increase dramatically.

The present RPS standards will accentuate price instability in the Mid-Columbia market. Negative spot prices will be a feature of our market in the years ahead as oversupply conditions expand with additional mandated renewable resources. It is likely to make non-dispatchable base load resources less competitive. It is also likely to make contractual resources where third parties take the volatility risk very competitive for industry and traditional utilities.

Economic Analysis of the Columbia Generating Station

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RE: Economic Analysis of Columbia Generating Station (CGS)

The report on Columbia Generating Station's economics is attached below. I would like to thank you for the opportunity to return to a project I worked on in the 1980s. Energy Northwest (then the Washington Public Power Supply System) is a fascinating study with complex economics and a long and tangled history.

While I respect your concerns about nuclear power, you will find little on the risks of nuclear generation in this report. Our mandate was quite narrow – to carefully consider the economics of CGS and its possible replacement with other supplies. Our conclusion, bolstered by many interviews with the project's owners and operators, as well as with industry representatives throughout the region, is that CGS can be replaced at a significant cost savings to the region's ratepayers and utilities – approximately a $1.7 billion dollar saving. Our recommendation is that BPA issue a Request For Proposals (RFP) for alternatives and displace the unit within the current institutional framework.

The study has been unnecessarily complicated by a lack of transparency at Energy Northwest. Even the simplest requests have been delayed by months. In a number of cases, our request for materials already provided to the press has experienced a lengthy delay before response. We would like to thank Timothy Ford, the Washington State Assistant Attorney General for Government Accountability, and our liaison at BPA, Steven Weiss, for their help in working through these issues.

Sincerely,

Robert McCullough

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2 EXECUTIVE SUMMARY

In the mid-1990s, decreasing market prices – similar to the situation today – led to a sweeping evaluation of the role of Bonneville Power in the regional energy supply system. The governors of Oregon, Washington, Idaho, and Montana convened a blue ribbon panel to examine the facts and make recommendations. The Comprehensive Review conducted a year's worth of hearings and recommended significant changes. Among the results was a "Market Test" for the Columbia Generating Station (CGS) nuclear power plant that recommended closure if the plant cost more than market prices. The Market Test was adopted by the CEO of Energy Northwest (EN) and the Administrator of the Bonneville Power Administration (BPA), as well as endorsed by major elected officials like U.S. Senator Ron Wyden.

Carrying forward the Market Test from fifteen years ago, our study of the present day economics of CGS finds that it has failed the Market Test since 2009. We project that CGS will continue to cost more than market rates in years to come. It also poses physical and financial risks, has an antiquated ownership structure, and is ill-suited to Mid-Columbia area generation operations.

Nevertheless, we are not proposing CGS's immediate termination simply on the basis of price forecasts. Instead, we are recommending the issuance of a Request For Proposals (RFP) to see if the unit can be replaced with long-term options that are less costly, less risky, and better fitted to regional needs. If the RFP provides cost savings for BPA and its customers, CGS would commence decommissioning at the end of its current refueling cycle in 2015.

The plant's original name, "WNP-2," referenced that it was the second nuclear station constructed and operated by the Washington Public Power Supply System (WPPSS). The first, the Hanford N-Reactor, was a multi-purpose reactor that was used both for producing plutonium for nuclear weapons and steam for electric generation.

After WNP-2's construction commenced, WPPSS decided to treat the N-Reactor as a separate category. The follow on nuclear stations, WNP-1, WNP-3, WNP-4, and WNP-5, were named in numerical order to make a consistent set of unit names.[1] The N-Reactor was shut down for safety upgrades in 1987, and never resumed operation, reflecting concerns about the Chernobyl incident.[2] In 1999, WPPSS changed its name to Energy Northwest, and in 2000 WNP-2 was renamed the Columbia Generating Station, although many industry insiders today still refer to it as "WPPSS 2" or "WNP-2." [3]

[1] Miller, Gary K. *Energy Northwest: A History of the Washington Public Power Supply System*. Xlibris, 2001. Print. Page 181.
[2] Geranios, Nicholas K. *N Reactor Closure Is Permanent, Energy Secretary Says. Seattletimes.com*. The Seattle Times, 15 Aug. 1991. Web. 04 Nov. 2013. <http://community.seattletimes.nwsource.com/archive/?date=19910815>.
[3] BPA, for example, uses both WNP-2 and CGS interchangeably in many cases.

Different names have been used for the WNP-2 plant in different contexts, and we have chosen to use the name "CGS" throughout this report as a compromise between the current name "Columbia Generating Station" and the more adversarial "WNP-2".

In the Pacific Northwest, wholesale electric prices have been low over the past few years – so low in fact, that off-peak prices have actually fallen below zero on approximately 15% of days over the last two years. Adjusted for inflation, wholesale electric prices last year were at their lowest point in history.

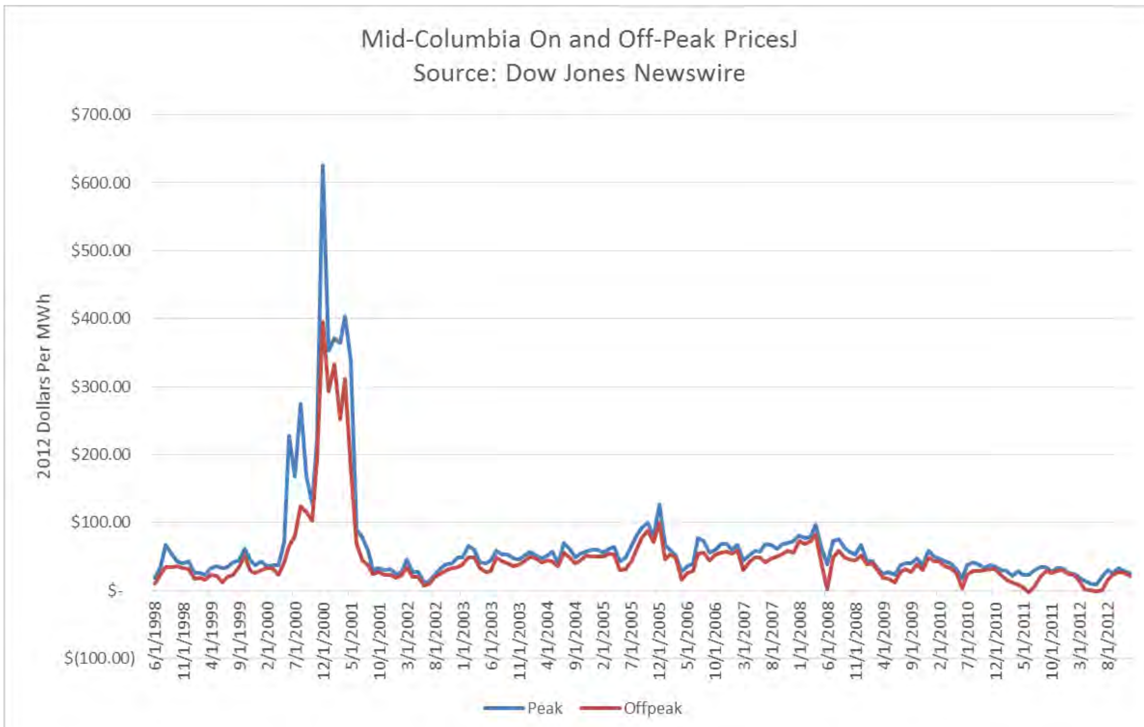


Figure 1

While wholesale power costs have fallen over the past five years, the operating costs of the Columbia Generating Station have continued to increase:

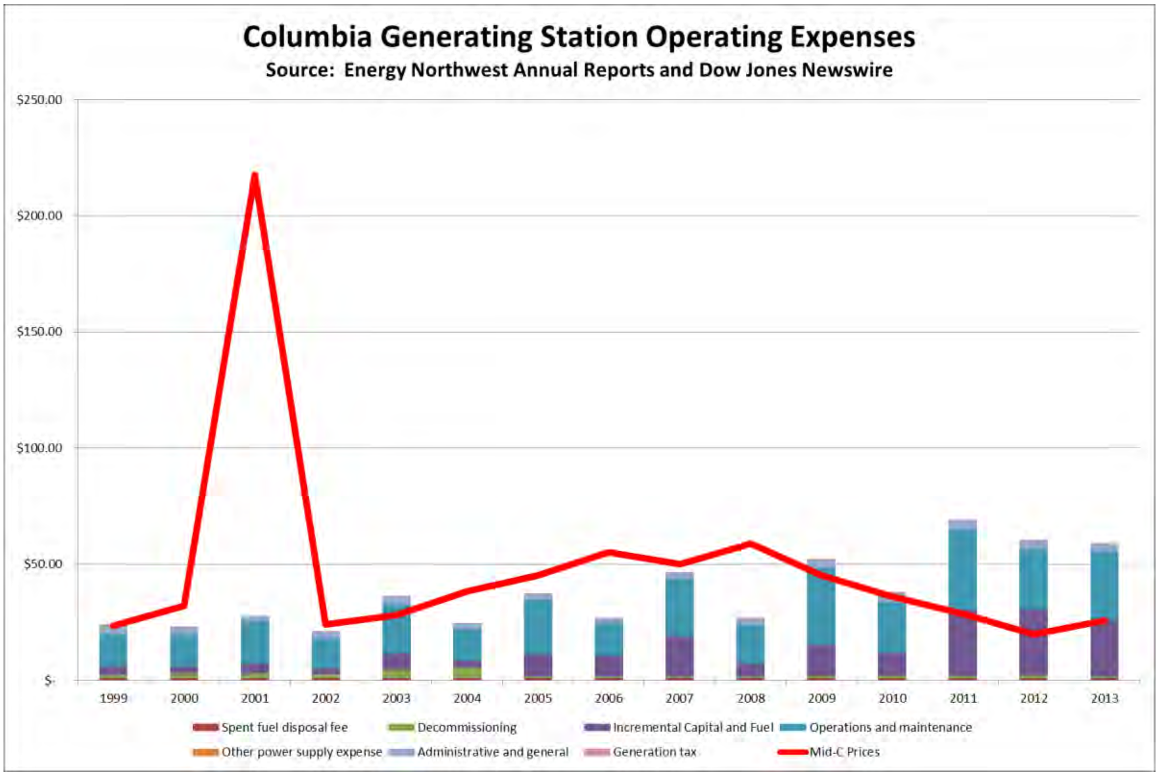


Figure 2

Several energy companies have indicated that competitive pressures have contributed to early closure and decommissioning of nuclear plants. Dominion Resources' Kewaunee Power Station (Kewaunee), Southern California Edison's San Onofre Nuclear Generating Stations, Units 2 and 3, and Duke Energy's Crystal River Unit 3 Nuclear Power Plant (Crystal River) have prematurely closed, and Entergy's Vermont Yankee nuclear plant announced it would close in 2014, turning these plants into long term decommissioning liabilities. Exelon, the largest owner of nuclear plants in the country, has said that "[Exelon] Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license."[4]

[4] Exelon. *United States Securities and Exchange Commission Form 10-K.* Washington, D.C.: United States Securities and Exchange Commission, 6 Feb. 2009. PDF. Page 46.

This sentiment was repeatedly recently when the CEO of Exelon was quoted as saying:

> "We think the nuclear assets are very valuable," Mr. Crane said. "We know how to run them better than anybody else. But at the end of the day, if we're not compensated for them we'll just have to shut them down."[5]

Recent reports indicate that decommissioning costs are rising by 8-9% per year, driven by the cost of burying lightly contaminated steel and concrete.[6] Moreover, the formula used by the Nuclear Regulatory Commission (NRC) to estimate decommissioning costs is considered to be the minimum cost of decommissioning. Actual decommissioning costs from plants undergoing closure are much higher. According to Energy Northwest, the decommissioning cost estimate for CGS is $454.6 million. Dominion estimates that decommissioning will cost nearly $1 billion for the recently closed, and much smaller, Kewaunee boiling water reactor.[7]

CGS is significantly more expensive than other nuclear plants because it is an older, stand-alone plant with an overly complex management structure. An obsolete financing structure from the 1960s called "net billing" – an arrangement discussed in more detail in Section 3.2 – bears much of the blame for high costs and a poor reliability history at the plant.

Section 4.3 summarizes a detailed review of CGS's historical and forecasted costs. Sources on comparative costs include industry surveys like that from the Nuclear Energy Institute (NEI), data from the Federal Energy Regulatory Commission (FERC), and other sources.

The following table summarizes operating costs filed at FERC for plants from 2006 through 2012. CGS has the highest cost, followed closely by the thirteen year older unit in Minnesota, Monticello.

[5] Daniels, Steve. *What's Stronger than Nuclear Power? Falling Electricity Prices.* Crain's Chicago Business. 18 Nov. 2013.Web. 3 Dec. 2013.
[6] UBS Investment Research. *Nuclear Decommissioning Discussion with the NRC Staff: Conference Call Transcript.* Nrc.gov. 9 Apr. 2013. Web. 20 Sept. 2013. Page 6. <http://pbadupws.nrc.gov/docs/ML1312/ML13128A305.pdf>
[7] Dominion Energy. *2012 Decommissioning Cost Analysis of the Document Kewaunee Nuclear Power Plant SAFSTOR Methodology*. 26 Feb. 2013. Page 6.

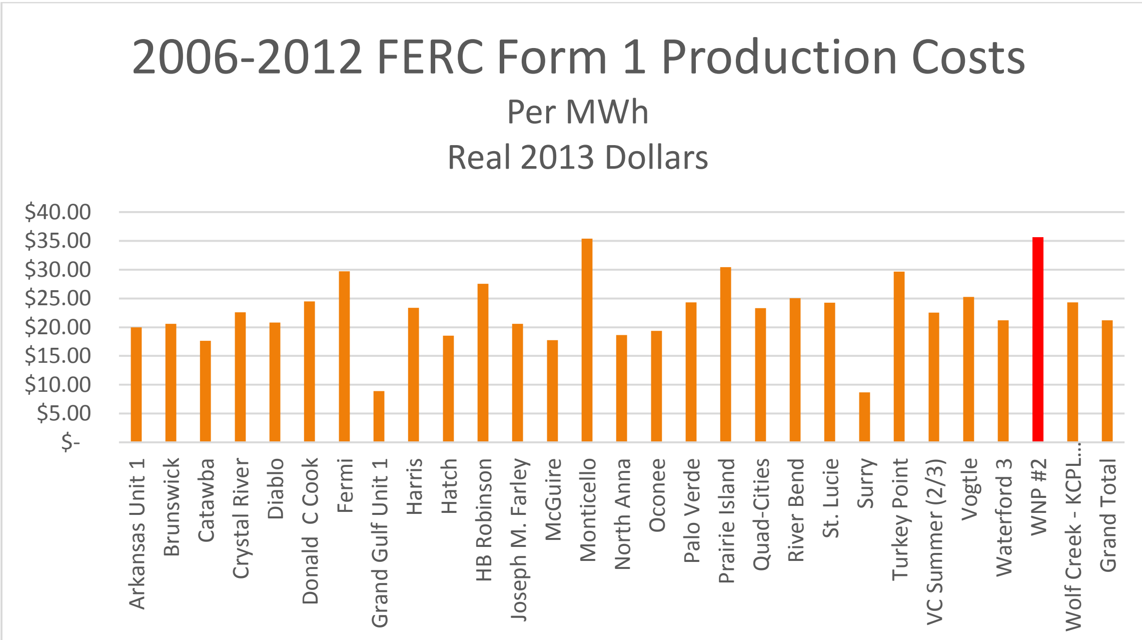


Figure 3

Simply put, CGS's costs are the responsibility of BPA, and in return, BPA receives the output of CGS.[8] Day to day management is in the hands of Energy Northwest. The history of this arrangement is rife with miscommunication and conflict between the two parties.

The cash out of pocket costs of CGS are now roughly twice the wholesale price on the Mid-Columbia market in 2012. The most recent budget estimates from Energy Northwest indicate that out of pocket costs for fiscal year 2014 will be $39.48/MWh.[9] Comparable forward prices at the Mid-Columbia market hub are $32.09/MWh.[10]

Our forecast of future CGS and market costs gives us an estimate of the possible future benefits of replacing CGS. Seattle City Light's Energy 1990 report put the role of a forecast very well:

> A forecast is not the same thing as a prediction. A prediction implies that we think we know what will happen at some time in the future. People who make forecasts do not regard themselves as prophets, nor are they necessarily

[8] CGS's costs were originally paid directly by the participating utilities who then "netted" the cost from their payments to BPA – hence the word "net" in "net billing". This was simplified in 2006 to allow direct billing of the participating utilities CGS's costs to Bonneville.

[9] Energy Northwest. *Fiscal Year 2014 Columbia Generating Station Annual Operating Budget.* 16 May 2013. Pdf. Page 5.

[10] Argus Media. *Argus US Electricity*. 28 Oct. 2013. Page 9. <https://www.argusmedia.com/Power/Argus-US-Electricity>

> pleased with the prospects they are forecasting. In essence, they are telling us the probable consequences of present assumptions and present trends. If we do not like the consequences, we can work to change the assumptions and trends.[11]

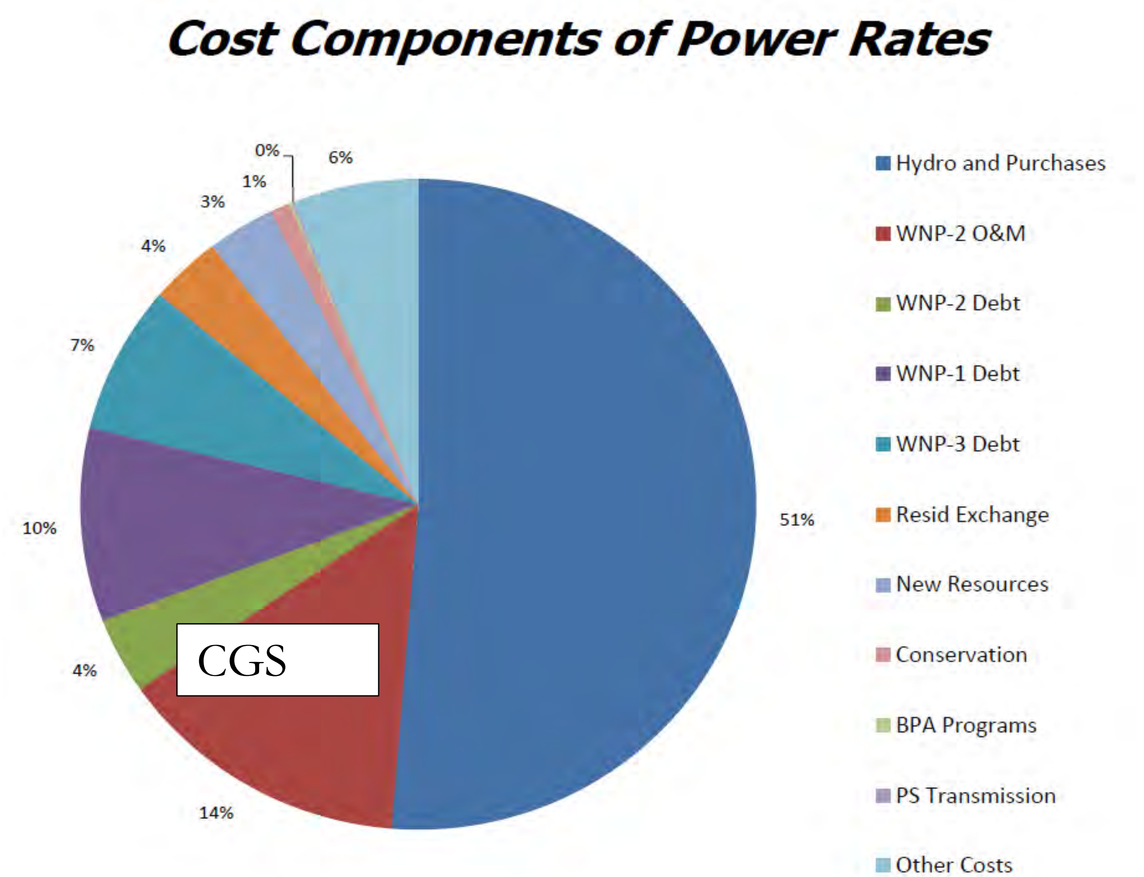
Our forecast of the regional benefits of displacing CGS at the end of its current refueling cycle until the end of its expected lifetime is $1,724,141,555 in today's dollars. The calculation of the benefits is explained in Section 5.11.

Problems and Opportunities:

- CGS institutional structure is a continuing challenge for BPA.
  - Management without ownership
  - Unmanageable "Project Consultant" arbitration
- Stand-alone plant
- Located in the center of over-generation and far from load
- For the past five years Mid-Columbia prices have been lower than "avoided costs" at CGS; this appears to be the case for many years to come.

Energy Northwest's nuclear projects have created a sizable cost burden for the region, consisting of 35% of the cost component for power rates: 17% consists of debt service for unfinished nuclear plants and 18% consists of CGS debt and O&M costs.[12]

[11] Seattle City Light. *Energy 1990 Initial Report Volume 1*. 27 Feb. 2976. Page 3-1.
[12] O&M stands for Operations and Maintenance.



[13]

Figure 4

In a perfect world, the 18% of costs attributable to CGS could be avoided. In the real world this is not the case. Existing debt costs are "sunk" and must be borne by BPA whether the plant operates or not. A variety of other costs are avoidable, however. O&M costs are largely avoidable, as are the increasing capital requirements of an aging plant. In addition, early closure of CGS will avoid the rapid escalation of decommissioning costs and exposure for future spent fuel storage.

[13] Bliven, Ray. *July 2013 Quarterly Business Review*. BPA. 30 Jul. 2013. Web. 27 Sept. 2013. Page 44. <http://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/FY2013FinancialOverviewDocuments/2013 3rd Qtr Package.pdf>.

2.1 Recommendations

- ***Aside from the inherent dangers embedded in nuclear power, the economics of CGS no longer makes sense. The plant should be "displaced."***

Displacement is a term of art in electricity operations in which a more expensive plant is "displaced" by less expensive market opportunities. CGS is already displaced, on occasion, by wind and hydroelectric generation by changing the timing of refueling. At current prices, CGS can be displaced by market purchases in the long term.

Displacement also provides an opportunity to reduce carbon exposure. Although CGS is often described as being "carbon free," CGS's fuel has been supplied by, and will continue to be supplied by for some years to come, one of the least environmentally friendly enrichment facilities in the industry. The phrase "carbon free" unfortunately has actually meant "carbon elsewhere" for CGS operations.[14]

- ***The Bonneville Power Administration should ask suppliers for firm bids to displace CGS.***

CGS's location is disadvantageous due to the ready supplies of renewable resources in its immediate vicinity. This is an opportunity to contract for an alternative supply that is less costly, more dependable, less risky, and poses fewer environmental hazards.

The Mid-Columbia market is both deep and liquid. Many suppliers are available, and a variety of transactions occurs every day. The displacement transaction or transactions would use modern power contracts that would avoid the problems in the existing antiquated 1971 Project Agreement, and would favor counterparties with substantial credit support.

- ***The displacement power should be purchased by Energy Northwest and supplied to BPA under the existing contract.***

Pacific Northwest cost allocation issues are often settled in contentious proceedings with complex dueling mathematical models. While this report does, in fact, model West Coast prices for the next thirty years as part of its review of CGS displacement, it does not attempt to model the Bonneville rate case.

Displacement and supply under the existing contract focuses squarely on the least cost solution for upcoming years. The reduction in costs from displacement would not require reworking of existing cost allocations in the BPA rate case since a similar quantity of energy would be delivered by the same entity, Energy Northwest, to the same customer. The only difference

[14] Section 4.6.7 of this report goes into detail on the operations of the now defunct 1950s facility that has been supplying CGS's fuel with substantial carbon impacts. The facility also contributed the majority of CFC-114 (Freon) release for the United States.

would be a reduction in the cost of the energy, along with a reduction in financial and operating risk.

- ***Energy Northwest should handle employment transitions by a combination of training and employing workers in plant decommissioning and a variety of additional strategies***

A solid local economy in the Tri-Cities and plans for additional industrial development, combined with educational institutions capable of retraining workers, make the adjustment of closing the CGS more manageable than it would be in some other communities. We would recommend Energy Northwest adopt DECON, rather than SAFSTOR, in order to maximize local employment during the decommissioning transition.[15] In addition, we recommend that decommissioning be handled directly by Energy Northwest and not turned over to an outside contractor. This mirrors the successful decommissioning record at Trojan and Rancho Seco.

As TransAlta has pledged to do in transitioning workers at the Centralia coal plant, it may make sense for Energy Northwest to set aside additional monies for retraining and employing workers in new energy enterprises.

2.2 THE BOTTOM LINE

If the recommendations above had been in place in Fiscal Year (FY) 2013, enormous savings would have taken place in the twelve months from July 1, 2012 through June 30, 2013.

Energy Northwest's Fiscal Year 2013 Annual report indicates that BPA paid $418,939,000 for CGS during this period (not including interest on outstanding bonds which is "sunk").[16] If BPA had purchased the same energy from the Mid-Columbia market at Dow Jones daily on-peak and off-peak prices, it would have paid $218,515,000.[17]

In sum, BPA paid $418,939,000 for $218,515,000 worth of energy. The difference, $200,424,000, would have had the impact of reducing BPA's rates by 10.67%. This calculation comes from BPA's July 2013 Quarterly Business Review, page 43, which explained that the

[15] The NRC's decommissioning studies indicate that DECON will be less costly than SAFSTOR.
[16] Energy Northwest. *Energy Northwest 2013 Annual Report*. 2013. Page 50.
[17] The Dow Jones company publishes daily prices at the Mid-Columbia power market based on a detailed survey of transactions submitted by market participants. Their reports are widely used and reported in the industry. A discussion of the index and its calculation is summarized in a Dow Jones publication entitled "Dow Jones Mid-Columbia Electricity Price Indexes[SM]" at http://www.djindexes.com/mdsidx/downloads/brochure_info/Dow_Jones_Mid-Columbia_Electricity_Price_Indexes_Overview.pdf".

$169,000,000 increase in costs was leading to a 9.0% rate increase.[18] The rate reduction, applied to BPA's Preference Firm rate, would have lowered BPA's wholesale rate by $3.37/MWh.

The U.S. Energy Information Administration (EIA) reports residential loads by utility on an annual basis.[19] The following table shows the per residential customer impact for twenty utilities in Oregon and Washington:

Utility	MWh/Customer	$/Customer	Total Impact
Puget Sound Energy Inc	11.30	$38.05	$36,602,088.67
Portland General Electric Co	10.37	$34.94	$25,274,273.86
PacifiCorp (Oregon)	11.41	$38.42	$18,203,155.15
Snohomish County PUD No 1	11.95	$33.12	$9,789,707.21
PUD No 1 of Clark County - (WA)	13.61	$32.07	$5,459,180.51
PacifiCorp (Washington)	15.32	$51.58	$5,375,422.40
City of Seattle - (WA)	8.68	$12.79	$4,637,093.51
City of Tacoma - (WA)	12.56	$27.77	$4,197,921.42
Avista Corp	11.52	$38.78	$4,131,141.13
City of Eugene - (OR)	11.83	$32.14	$2,559,318.95
PUD No 1 of Cowlitz County	17.49	$52.96	$2,284,577.03
PUD No 1 of Benton County	16.44	$44.72	$1,817,519.40
PUD No 1 of Grays Harbor County	14.36	$46.20	$1,601,164.86
Central Lincoln People's Ut Dt	13.24	$44.57	$1,459,501.49
PUD No 1 of Clallam County	16.43	$51.85	$1,409,512.82
PUD No 1 of Lewis County	17.78	$53.75	$1,381,819.79
PUD No 3 of Mason County	14.20	$44.81	$1,344,425.39
Peninsula Light Company	15.54	$44.70	$1,217,177.68
PUD No 1 of Chelan County	21.14	$11.48	$413,966.53
Inland Power & Light Company	17.17	$54.62	$85,267.43

Figure 5

This estimate is approximate since the actual impact of BPA's wholesale rates is determined differently for each utility based on the percentage of dependence on BPA and the specific types of BPA purchases. It is also incomplete, since it does not consider the savings from avoiding Energy Northwest's significant plant repairs in FY 2013.

[18] Bliven, Ray. *July 2013 Quarterly Business Review*. BPA, 30-July-2013. Web. 27 Sept. 2013. Page 43. <http://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/FY2013FinancialOverviewDocuments/2013 3rd Qtr Package.pdf>.
[19] Energy Information Administration. *2012 Utility Bundled Retail Sales- Residential*. Eia.gov. EIA, Nov. 2013. Web. 02 Dec. 2013. <www.eia.gov/electricity/sales_revenue_price/pdf/table6.pdf >.

CHAPTER 3: RESOURCE STRATEGY

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List of Tables and Figures

KEY FINDINGS

The resource strategy for the Seventh Power Plan relies on conservation, demand response, and natural gas-fired generation to meet the region's needs for energy and winter peaking capacity. In addition, the region needs to better utilize, expand, and preserve its existing electric infrastructure and research and develop technologies for the long-term improvement of the region's electricity supply. This resource strategy, with its heavy emphasis on low-cost energy efficiency and demand response, provides a least-cost mix of resources that assures the region an adequate and reliable power supply that is highly adaptable and reduces risks to the power system.

The resource strategy for the Seventh Power Plan consists of eight primary actions: 1) achieve the conservation goals in the Council's plan, 2) meet short-term needs for winter peaking capacity through the use of demand response except where expanded reliance on extra-regional markets can be assured, 3) satisfy existing renewable-energy portfolio standards, 4) increase the near term use of existing natural gas fired generation, 5) increase the utilization of regional resources to serve regional energy and capacity needs, 6) ensure that future carbon policies are cost effective and maintain regional power system adequacy, 7) support the research and development of emerging energy efficiency and clean energy resources and 8) adaptively manage future resource development to match actual future conditions.

A RESOURCE STRATEGY FOR THE REGION

The Council's resource strategy for the Seventh Power Plan provides guidance for Bonneville and the region's utilities on choices of resources that will supply the region's growing electricity needs while reducing the economic risk associated with uncertain future conditions, especially those related to state and federal carbon emission reduction policies and regulations. The resource strategy minimizes the costs and economic risks of the future power system for the region as a whole. The timing of specific resource acquisitions is not the essence of the strategy. The timing of resource needs will vary for every utility. Some utilities now find themselves with power supply resources that exceed their retail customers' demands. For these utilities, low spot market prices for wholesale power reduce the revenues they generate from sales of surplus power, putting pressure on utility budgets. In contrast, the region has been a hotbed for new data center loads as companies like Google, Microsoft, and Facebook take advantage of the mild climate and low electricity prices to develop facilities in the Northwest. The addition of loads from these new data centers to service territory can dramatically change the utilities resource needs. The important message of the resource strategy is the nature and priority order of resource development.

Summary

The resource strategy is summarized below in eight elements. The first two are high-priority actions that should be pursued immediately and aggressively. The next five are longer-term actions that must be more responsive to changing conditions in order to provide an array of solutions to meet the long-term needs of the regional power system. The final element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

Energy Efficiency: The Council's found that development of between 1350 and 1450 average megawatts of energy efficiency by 2021 was cost-effective across a wide range of scenarios and future conditions. The Seventh Power Plan's resource strategy calls upon the region to aggressively develop conservation with a goal of acquiring 1,400 average megawatts by 2021, 3100 average megawatts by 2026 and 4,500 average megawatts by 2035. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon emission reduction policies to address climate-change concerns. In addition, conservation resources not only provide annual energy savings, but contribute significantly to meeting the region's future needs for capacity by reducing both winter and summer peak demands.

Demand Response: The Northwest's power system has historically relied on its large hydroelectric generators to provide peaking capacity. While the hydrosystem can typically meet the region's winter peak demands, that likelihood decreases under critical water and weather conditions, which increases the probability of not meeting the Council's resource adequacy standard without development of additional winter peaking resources.

In order to satisfy regional resource adequacy standards the region should be prepared to develop a significant quantity of demand response resources by 2021 to meet its need for additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources – voluntary and temporary reductions in consumers' use of electricity when the power system is stressed. However, the Council's analysis also found that the need for demand response resources was highly sensitive to assumptions regarding the availability and prices of importing power from outside the region to meet winter peak demands under lower water and extreme temperature conditions. Therefore, the Seventh Power Plan recommends that the annual assessment of regional resource adequacy consider the comparative cost and economic risk of increased reliance on external market purchases versus development of demand response resources to meet winter capacity needs within the region.

Natural Gas: It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. At the regional level, the probability that new natural gas-fired generation will be needed to supply winter peaking capacity prior to 2021 is quite low. If the region does not deploy the demand response resources and develop the level of energy efficiency resources called for in this plan, the need for more costly new gas-fired generation increases. In the mid-term (by 2026) there appears to be a modest probability that new gas fired generation could be needed to replace retiring coal generation or potentially to displace additional coal use to meet federal carbon-reduction goals. Nevertheless, even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration when transmission and power market access is limited. In these instances, the Seventh Power Plan's resource strategy relies on new natural gas-fired generation to provide energy, capacity, and ancillary services.

Renewable Resources: The Seventh Power Plan's resource strategy assumes that only modest development of renewable generation, approximately 300 average megawatts of energy, or around 900 megawatts of installed capacity, is necessary to fulfill existing renewable portfolio standards. While the majority of historical renewable development in the region has been wind resources, recent and forecast further cost reductions in solar photovoltaic (solar PV) technology are expected to make electricity generated from such systems increasingly cost-competitive. In addition, solar PV systems, particularly when coupled with storage, can provide summer peaking services for which regional demand is increasing faster than winter peaking needs. As a result, solar PV systems should be seriously considered when determining which resources to acquire to comply with existing renewable portfolio standards.

The Seventh Power Plan's resource strategy encourages the development of other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. Because power production from wind and solar PV projects creates little dependable winter peak capacity and increases the need for within-hour balancing reserves the strategy also encourages research on and demonstration of different sources of renewable energy for the future, especially those with a more consistent output like geothermal or wave energy.

Increasing the requirements of state renewable portfolio standards would not result in the development of the least cost resource strategy for the region. Moreover, increased renewable portfolio standards are not necessary to comply *at the regional level* with recently promulgated federal carbon dioxide emissions regulations.

Regional Resource Utilization: The region should continue to improve system scheduling and operating procedures across the region's balancing authorities to maximize cost-effectiveness and minimize the need for new resources needed for integration of variable energy resource production. In addition, the region needs to invest in its transmission grid to improve market access for utilities and to facilitate development of more diverse cost-effective renewable generation. Finally, the Council identified least cost resource strategies for the region that rely first on regional resources to satisfy the region's resource adequacy standards. Under many future conditions, these strategies reduce regional exports.

Carbon Policies: To ensure that future carbon policies are cost effective and maintain regional power system adequacy the region should develop the energy efficiency resources called for in this plan and replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions in the near term. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore additional sources of renewable energy, especially technologies that can provide both energy and winter capacity, improved regional transmission capability, new conservation technologies, new energy-storage techniques, smart-grid technologies and demand-response resources, and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities. For example, the potential for developing geothermal and wave energy in the Northwest is significantly greater than in many other areas of the country.

Adaptive Management: The Council will annually assess the adequacy of the regional power system. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions that it would require adjustments to the plan. This annual assessment will provide the region time to take actions necessary to reduce the probability of power shortages. The Council will also conduct a mid-term assessment to review plan implementation.

SCENARIO ANALYSIS – THE BASIS OF THE RESOURCE STRATEGY

The Seventh Power Plan's resource strategy is based on analysis of over 20 scenarios and sensitivity studies. Scenarios combined elements of the future that the region controls, such as the type, amount and timing of resource development, with factors the region does not control, such as natural gas and wholesale market electricity prices. Sensitivity studies alter one parameter in a scenario to test the how the least-cost resource strategy is affected by that input assumption. For example, several scenarios were run with and without future carbon cost to assess the impact of that input assumption on the various components of the least cost resource strategy.

All of the scenarios evaluated for the plan include the same range of uncertainty regarding future fuel prices, hydropower conditions, electricity market prices, capital costs, and load growth. However, several scenarios were specifically designed to provide insights into the cost and impacts of alternative carbon dioxide emissions reduction policies. These included either the federal government's estimates of the societal damage cost of carbon dioxide emissions or the economic risk associated with future carbon dioxide regulation or pricing or "non-pricing" policies. Each of these scenarios assumed differing levels of carbon dioxide damage or regulatory cost. Also, as noted above, several sensitivity studies were conducted to assess the impact of such factors as the near term pace of conservation development, lower natural gas and wholesale electricity prices, greater reliance on external markets, or the loss of major resources.

Each scenario and sensitivity analysis tested thousands of potential resource strategies against 800 alternative future conditions to identify the least cost and lowest economic risk resource portfolios. Since the discussion of the elements of the resource strategy draws on those scenarios and sensitivity studies, an introduction to the scenarios and studies and their findings is needed. Each scenario or sensitivity study was designed to explore specific components of resource strategies (e.g. strategies with and without demand response). Therefore, the following discussion of findings compares different combinations of scenarios and sensitivity studies. That is, not all scenarios or sensitivity studies "stress test" the same element of a resource strategy, so not all provide useful insight regarding that element.

The US Environmental Protection Agency (EPA) released its draft Clean Power Plan in June, 2014, and its final set of regulations in August, 2015. These regulations establish carbon dioxide emissions limits for both new and existing power plants. Five of the scenarios summarized below: the two Social Cost of Carbon (Mid-Range and High), Carbon Cost Risk, Renewable Portfolio Standards at 35 Percent, and Maximum Carbon Reduction – Existing Technology, were designed to test alternative policies that may be considered at the regional or state level to identify resource strategies that would comply with those regulations. Two other scenarios, the Planned Loss of a Major Non-Greenhouse Gas (GHG) Emitting Resource and the Unplanned Loss of a Major Non-GHG Emitting Resource were analyzed to provide insights into the effect of the loss of a major non-greenhouse gas-emitting would have on the region's ability to reduce power system carbon dioxide emissions.

The bullets below summarize the 15 principal scenarios or sensitivity studies that informed the development of the Seventh Power Plan's resource strategy.

- **Existing Policy –** The existing-policy scenario includes current policies such as renewable portfolio standards, new plant emissions standards, and renewable energy credits, but it does not assume any carbon dioxide regulatory cost risk in the future. It helps identify the effect of carbon dioxide cost risk when added to existing policies. Other major uncertainties regarding the future, such as load growth and natural gas and market electricity prices are considered.

- **Social Cost of Carbon (SCC) –** Two scenarios, the **Social Cost of Carbon – Mid-Range (SCC-Mid-Range)** and **Social Cost of Carbon – High (SCC-High)**, use the US Interagency Working Group on Social Cost of Carbon's estimates of the damage cost of forecast global climate change. According to the Working Group:

  - *The SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO2 reduction).*

  - Therefore, in theory, the cost and economic risk of the resource strategy that achieves carbon dioxide emissions reductions equivalent to the Social Cost of Carbon would offset the cost of damage. The "SCC-Mid-Range" scenario uses the Interagency Working Group's mid-range estimate of the damage cost from carbon dioxide emissions based on a three percent discount rate. The SCC-High scenario uses the Interagency Working Group's estimate of damage cost that encompasses 95 percent of the estimated range of damage costs.[1]

- **Carbon Cost Risk –** The carbon cost risk scenario is intended to explore what resources result in the lowest expected cost and economic risk given existing policy plus the economic risk that additional carbon dioxide reduction policies will be implemented. Each of the 800 futures imposes a carbon dioxide price from $0 to $110 per metric ton at a random year during the 20 year planning period. Over time, the probability of a carbon dioxide price being imposed and the level of that price both increase. By 2035, the average price of carbon dioxide rises to $47 per metric ton across all futures. It should be noted, that the use of a

[1] Chapter 15 provides the year-by-year social cost of carbon used in these scenarios.

carbon dioxide price does not presume that a "pricing policy" (e.g., carbon tax) would be used to reduce carbon dioxide emissions. The prices imposed in this scenario could also be a proxy for the cost imposed on the power system through regulation to reduce carbon dioxide emissions (e.g., caps on emissions).

This scenario was initially designed to represent the current state of uncertainty about future carbon dioxide control policies and develop a responsive resource strategy. It is identical to a scenario analyzed for the development of the Sixth Power Plan. While with the promulgation of Environmental Protection Agency's carbon dioxide emissions regulations there is less uncertainty regarding federal regulations, the specific form of state and/or regional compliance plans with EPA's regulations are unknown. Moreover, some states may choose to adopt additional policies beyond the federal regulations to limit power system emissions.

- **Renewable Portfolio Standard at 35 Percent (RPS at 35 percent) –** This scenario assumes that a region wide Renewable Portfolio Standard (RPS) is established at 35 percent of regional electricity load across all four Northwest states. Presently, three states in the region have RPS. Montana and Washington require that 15 percent of load be served by renewable resources. Montana's RPS must be satisfied in 2015 and Washington's by 2020. Oregon requires that 20 percent of load be served by renewable resources by 2020. Since this scenario was designed to test the cost and effectiveness of this policy for reducing regional power system carbon dioxide emissions, it did not include future carbon dioxide regulatory cost risk uncertainty or estimated damage cost. The cost-effectiveness of a policy that only requires use of additional renewable generation can, therefore, be compared to other scenarios that tested alternative policy options to reduce carbon dioxide emissions.

- **Maximum Carbon Reduction – Existing Technology –** This scenario was designed to explore the maximum carbon dioxide emissions reductions that are feasible with current commercially available technologies. In this scenario all of the existing coal plants serving the region were assumed to be retired by 2026. In addition, the least efficient (i.e., those with heat rates exceeding 8,500 Btu/kWh) existing natural gas-fired generating facilities were assumed to be retired by 2031. No carbon dioxide cost risk or estimated damage cost was assumed, so this scenario can be compared to the cost-effectiveness of other policy options (e.g., Carbon Cost Risk, RPS at 35 percent, the two Social Cost of Carbon scenarios) for reducing carbon dioxide emissions.

- **Maximum Carbon Reduction – Emerging Technology –** This scenario considers the role of new technologies might play in achieving carbon dioxide reduction. Due to the speculative nature of the performance and ultimate cost of technologies considered in this scenario the Council's Regional Portfolio Model (RPM) was not used to identify this scenario's least cost resource strategy. Rather, the RPM was used to define the role (e.g., capacity and energy requirements) that new and emerging technologies would need to play in order to achieve carbon dioxide reductions beyond those achievable with existing technology.

- **Resource Uncertainty –** Four scenarios explored resource uncertainties and carbon dioxide regulatory compliance cost and economic risk. Two examined the effect that the loss of a major non-greenhouse gas-emitting resource might have on the region's ability to reduce power system carbon dioxide emissions. The **Unplanned Major Resource Loss** scenario assumed that a significant (approximately 1000 average megawatt) non-greenhouse gas emitting generator was unexpectedly taken out of service. The **Planned Major Resource Loss** scenario assumed that similar magnitudes of the region's existing non-greenhouse gas emitting resources were phased out over the next 20 years. Since both of these scenarios were designed to identify resource strategies that would maintain regional compliance with federal carbon dioxide emissions limits they assumed the cost of future carbon dioxide regulatory risk used in the **Carbon Cost Risk** scenario.

Two additional scenarios tested the economic benefits or cost resulting from a faster or slower near term pace of conservation deployment. The **Faster Conservation Deployment** scenario allowed the Regional Portfolio Model to increase the pace of acquiring conservation savings by 30 percent above the baseline assumption. The **Slower Conservation Deployment** scenario restricted the RPM's option to acquire conservation savings to a pace that was 30 percent below the baseline assumption. Since both of these scenarios were designed to test resource strategies that might reduce the cost or increase the economic risk of compliance with federal carbon dioxide emissions limits, they assumed the carbon dioxide regulatory cost risk used in the **Carbon Cost Risk** scenario.

- **No Demand Response –** This sensitivity study assumed that no demand response resources were available to meet future regional peak capacity needs. It estimated the cost and risk of not using demand response to provide regional capacity reserves under both the Existing Policy scenario and with the future carbon dioxide regulatory cost assumed in the Carbon Cost Risk scenario.

- **Low Natural Gas and Wholesale Electricity Prices –** This sensitivity study assumed that the range of future natural gas and wholesale electricity prices the region would experience was systematically lower than the baseline assumptions. It was designed to test the impact of lower gas and electricity prices on the amount of cost-effective conservation and on the best future mix of generating resource development. This sensitivity study was tested under both the **Existing Policy** scenario and with the future carbon dioxide regulatory cost assumed in the **Carbon Cost Risk** scenario.

- **Increased Market Reliance –** This scenario explored the potential benefits and risk of increased reliance on out-of-region markets to meet regional resource adequacy standards. It evaluated the cost of meeting near-term peak capacity needs with demand response and other regional resources compared to reliance on Southwest markets. This sensitivity study was conducted using the **Existing Policy** scenario.

- **Lower Conservation –** This sensitivity study explored the potential costs and benefits associated with less reliance on energy efficiency. Under this scenario, the acquisition of conservation was limited to what would be cost-effective to acquire based on short-run market prices, rather than full consideration of long-term resource costs and risks. This sensitivity study was conducted using the **Existing Policy** scenario, so no carbon dioxide regulatory cost risk or damage costs were assumed.

Results of these studies are compared in the discussion of the eight elements of the resource strategy in the following section. A discussion of the specific input assumptions for each of these scenarios as well as a more comprehensive discussion of carbon dioxide emissions, rate and bill impacts, and the Regional Portfolio Model appears in Chapter 15 and Appendix L.

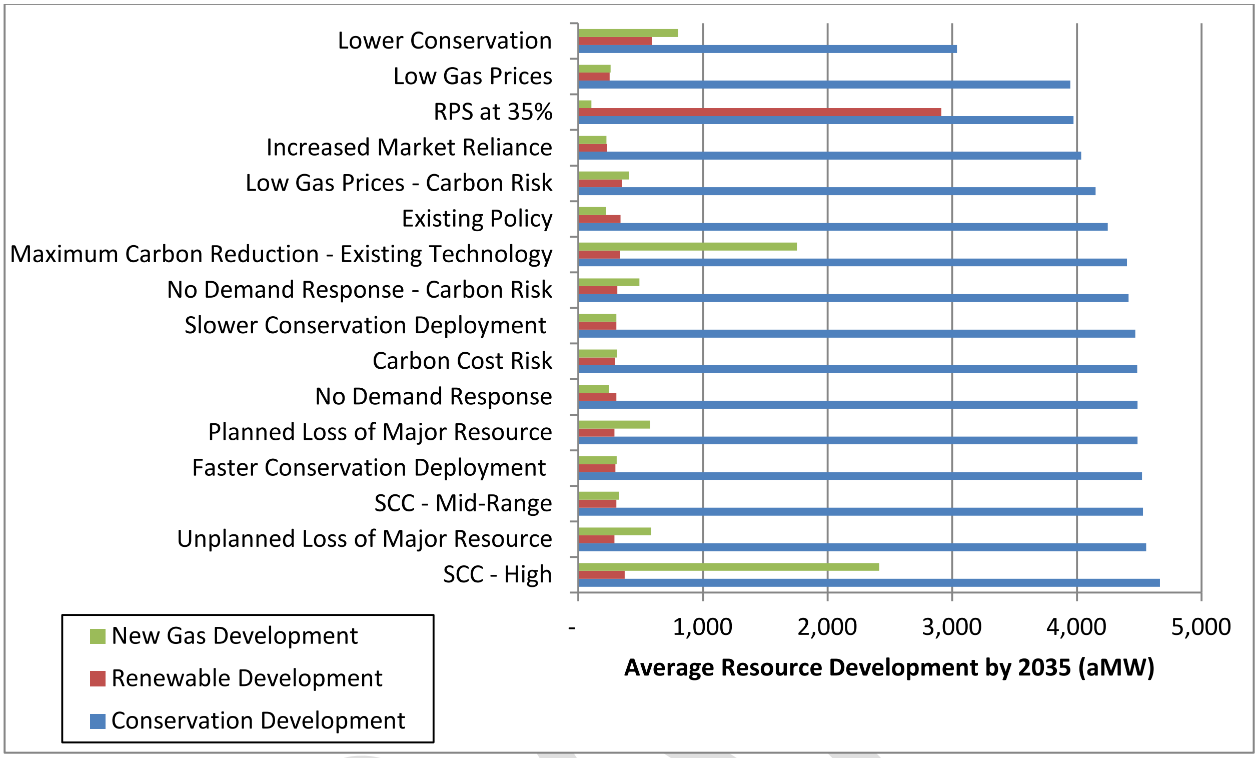
THE RESOURCE STRATEGY

The resource strategy of the Seventh Power Plan is designed to provide the region a low-cost electricity supply to meet future load growth. It is also designed to provide a low economic risk electricity future by ensuring that the region develops and controls sufficient resources to maintain resource adequacy, limiting exposure to potential market price extremes. Therefore the amount and type of resources included in the strategy are designed to meet loads, minimize costs, and help reduce the economic risks posed by uncertain future events.

Figure 3 - 1 shows the average resource development by resource type for the least cost resource strategy under the major scenarios and sensitivity studies carried out to support the development of the Seventh Power Plan. The resource development shown in Figure 3 - 1 is the *average* over all 800 futures modeled in the Regional Portfolio Model (RPM). In the RPM the specific timing and level of resource development is unique to each of the 800 potential futures modeled. The Seventh Power Plan's principal of adaptive management is based on the reality that, as in the RPM, the timing and level of resource development in the region will be determined by actual conditions as they unfold over the next 20 years. However, what should not change are the Seventh Power Plan's priorities for resource development. In that regard, Figure 3 - 1 shows the significant and consistent role of energy efficiency across all scenarios. This is because of its low cost, its contribution to regional winter capacity needs and its role in mitigating economic risk from fuel price uncertainty and volatility.

After energy efficiency, the *average* development of new natural gas generation and renewable resources by 2035 is roughly equivalent. New natural gas-fired resources are developed to meet regional capacity needs while renewable resource development is driven by state renewable resource portfolio standards. Not shown in Figure 3 - 1 is the deployment of demand response resources because these resources primarily provide capacity (megawatts) not energy (average megawatts) and the increased dispatch of existing gas generation to replace retiring coal generation. Both of these resources also play significant roles in the Seventh Power Plan's resource strategy. Each element of the resource strategy is discussed below.

Figure 3 - 1: Average Resource Development in Least Cost Resource Strategy by 2035 in Alternative Scenarios



Energy Efficiency Resources

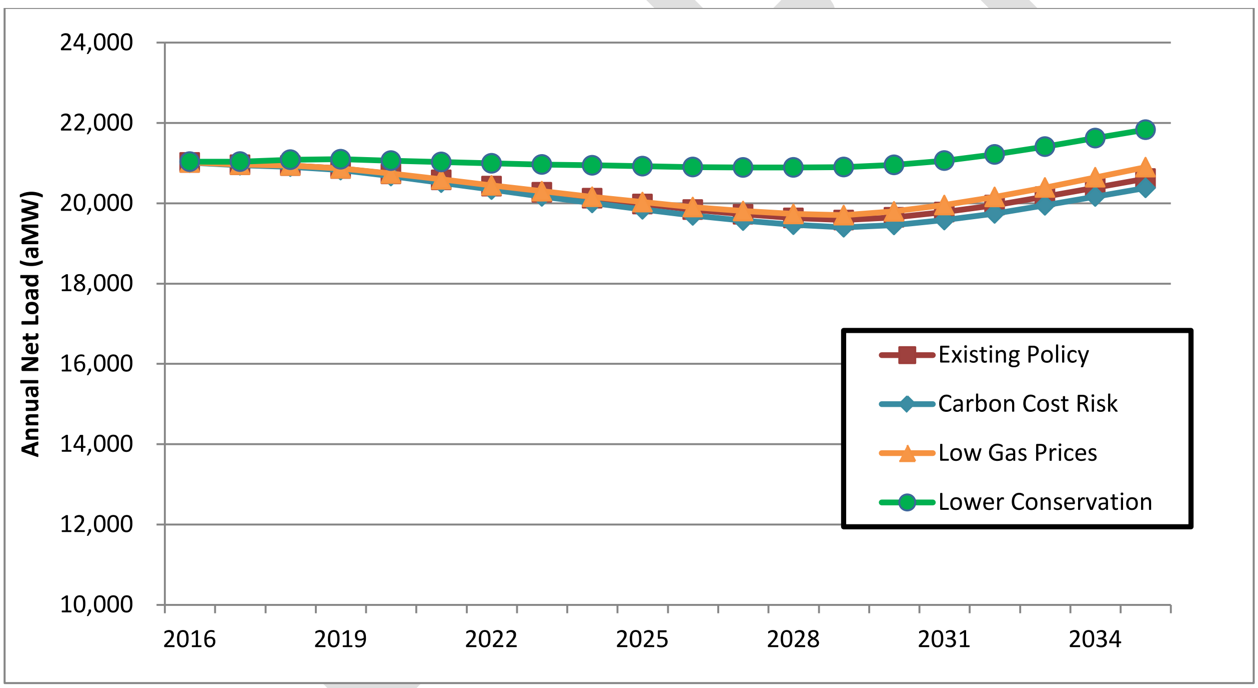
Energy efficiency has been important in all previous Council power plans. The region has a long history of experience improving the efficiency of electricity use. Since the Northwest Power Act was enacted, the region has developed nearly 5,900 average megawatts of conservation. This achievement makes efficiency the second-largest source of electricity in the region following hydroelectricity.

As in all prior plans, the highest priority new resource in the Seventh Power Plan resource strategy is improved efficiency of electricity use, or conservation. Figure 3 - 2 shows that the region's net load after development of all-cost effective energy efficiency remains essentially the same over the next 20 years. This finding holds under scenarios that both consider carbon dioxide risk or damage cost and those that do not and even when natural gas and electricity prices are lower than generally anticipated. The only scenario that developed significantly less energy efficiency was the scenario specifically designed to do so. The **Lower Conservation** scenario developed roughly 1200 average megawatts less energy efficiency by 2035 than the **Existing Policy** scenario. The **Lower Conservation** scenario had significantly higher ($14 billion) average system cost and exposed the region to much larger ($19 billion) economic risk than the **Existing Policy** scenario. However, as Figure 3 - 2 shows, even under that scenario, the development of energy efficiency offsets regional load growth through 2030.

The attractiveness of improved efficiency is due to its relatively low cost coupled with the fact that it provides both energy and capacity savings and is not subject to major sources of economic risk. The average cost of conservation developed in the least cost resource strategies across all scenarios tested was half the cost of alternative generating resources. The average levelized cost of the cost-effective efficiency developed in the Seventh Power Plan's resource strategy is $30 per megawatt-hour.[2] The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $75 per megawatt-hour. The current cost of utility scale solar photovoltaic systems is approximately $65 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour, including the cost of integrating these variable output resources into the power system. Significant amounts of improved efficiency also cost less than the forecast market price of electricity. Nearly 2,300 average megawatts of energy efficiency are available at cost below $30 per megawatt-hour.

Conservation also lacks the economic risk associated with volatile fuel prices and carbon dioxide emission reduction policies. Its short lead time and availability in small increments also reduce its economic risk. Therefore, improved efficiency reduces both the cost and economic risk of the Seventh Power Plan's resource strategy.

Figure 3 - 2: Average Net Regional Load After Accounting for Cost-Effective Conservation Resource Development



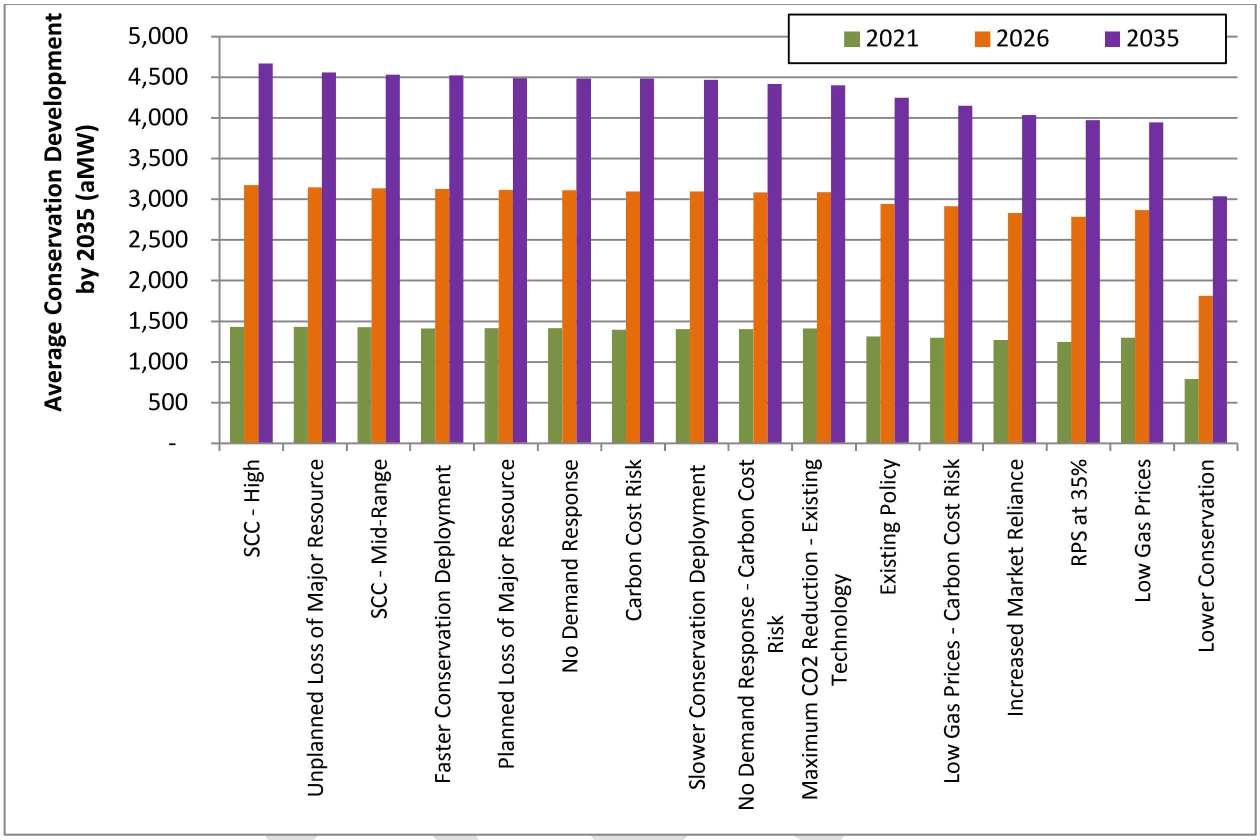
[2] This is the average real levelized cost of all conservation measures acquired in the resource strategy, excluding a cost-offset that is expected to occur as a result of lower load growth which defers the need to expand distribution and transmission systems. In evaluating conservation's cost-effectiveness in the RPM, this cost-offset was included, as well as other non-energy benefits, such as water savings from more efficient clothes washers. If the cost-offset benefits provided by energy efficiency's deferral of investments in distribution and transmission expansion are considered, the average levelized cost is $18 per megawatt-hour.

In the Council's analysis, additional resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not immediately needed, the energy and capacity can be sold in the market and all or at least a portion of their cost recovered. This is not true for generating resources, for in periods when market prices are at or below their variable operating cost; these resources cannot recover any of their capital cost. In addition, because of its low average cost to utilities, the development of energy efficiency offers the potential opportunity to extend the benefits of the Northwest's hydro-system through increased sales.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency were found to be cost-effective.[3] The selection of energy efficiency as the primary new resource does not depend significantly on whether or not carbon dioxide policies are enacted. Figure 3 - 3 shows the average amount of efficiency acquired in various scenarios considered by the Council in the power plan by 2021, 2026, and 2035. In all scenarios, the amount of cost-effective efficiency developed averages between 1,300 and 1,450 average megawatts by 2021 and 3,900 and 4,600 by 2035. The amount of conservation developed varies in each future considered in the Regional Portfolio Model. For example, in the Carbon Cost Risk scenario, the average conservation development is 4,485 average megawatts, but individual futures can vary from as low as 4,000 average megawatts to as high as just over 5,000 average megawatts.

[3] The only exception is the Lower Conservation scenario which as explicitly designed to develop less energy efficiency.

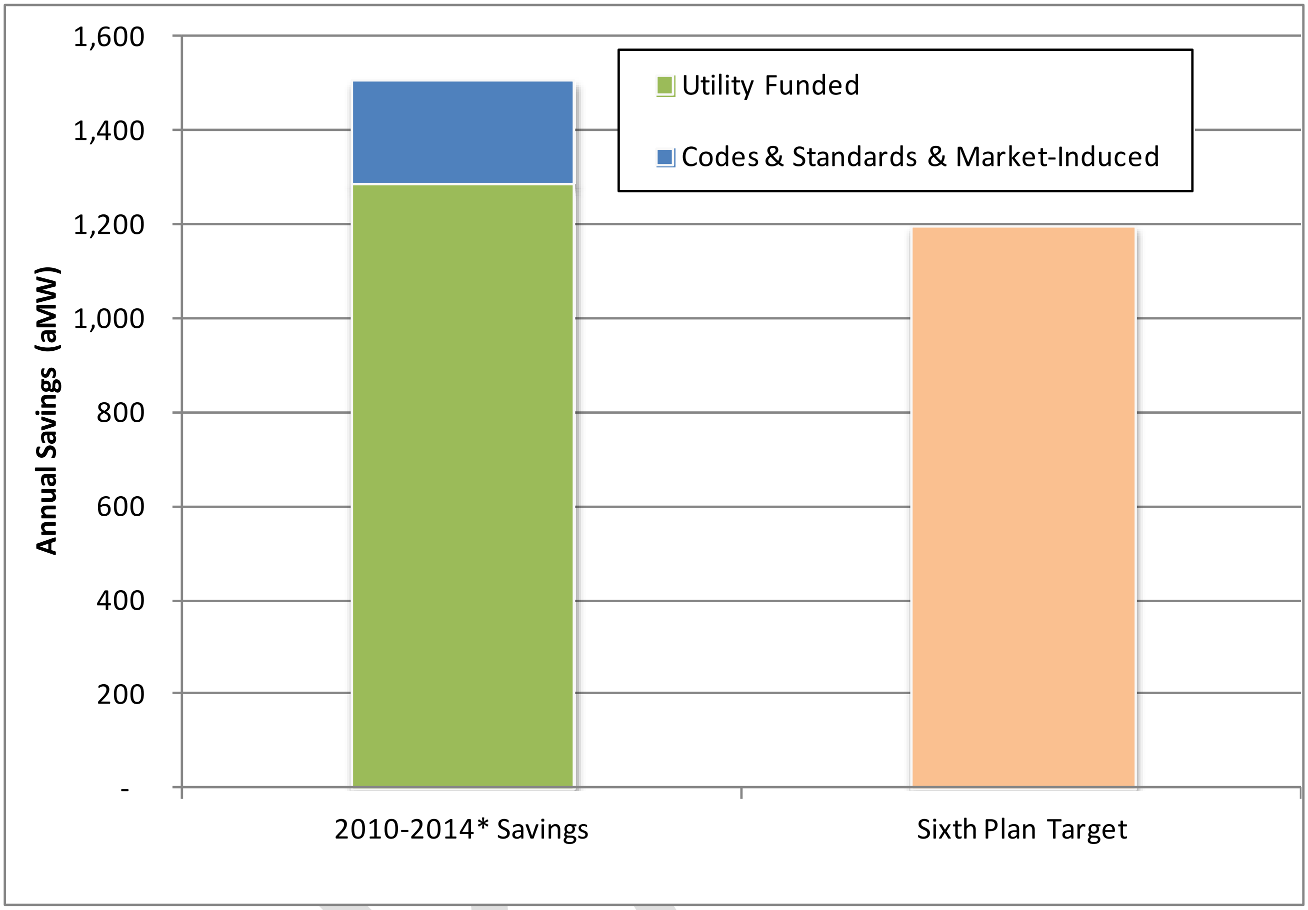
Figure 3 - 3: Amount of Cost-Effective Conservation Resources Developed Under Different Scenarios



The nature of efficiency improvement is that the total cost is recovered over a smaller number of sales. Average cost per kilowatt-hour sold will increase, but because total consumption is reduced, average consumer electricity bills will be smaller. Consumers who choose not to improve their efficiency of use could see their bills increase. However, if the region does not capture the efficiency, the higher cost of other new generating resources will increase everyone's bills. The impact on both bills and average revenue requirement per kilowatt-hour is discussed later in this chapter.

The amount of efficiency included in the Seventh Power Plan is comparable to that identified in the Council's Sixth Power Plan; even though the 20-year goal is lower (4,500 aMW vs. 5,800 aMW). To a large extent, this decrease is the result of regional conservation program achievements since the Sixth Plan was adopted in 2010 as well as significant savings that will be realized as a result of federal standards and state codes enacted since the Sixth Plan was adopted. Figure 3 - 4 shows regional utility cumulative conservation program achievements from 2010 through 2014 (projected) compared to the Sixth Plan's conservation goal for the same period. In addition, Figure 3 - 4 shows the savings achieved from the combined impact of federal and state appliance and equipment standards, state building codes, and market-induced savings. In aggregate, actual achievements from 2010 through 2014 were nearly 1500 average megawatts, exceeding the Sixth Plan's five year goal of 1200 average megawatts by 25 percent.

Figure 3 - 4: Regional Conservation Achievements Compared To Sixth Plan Goals



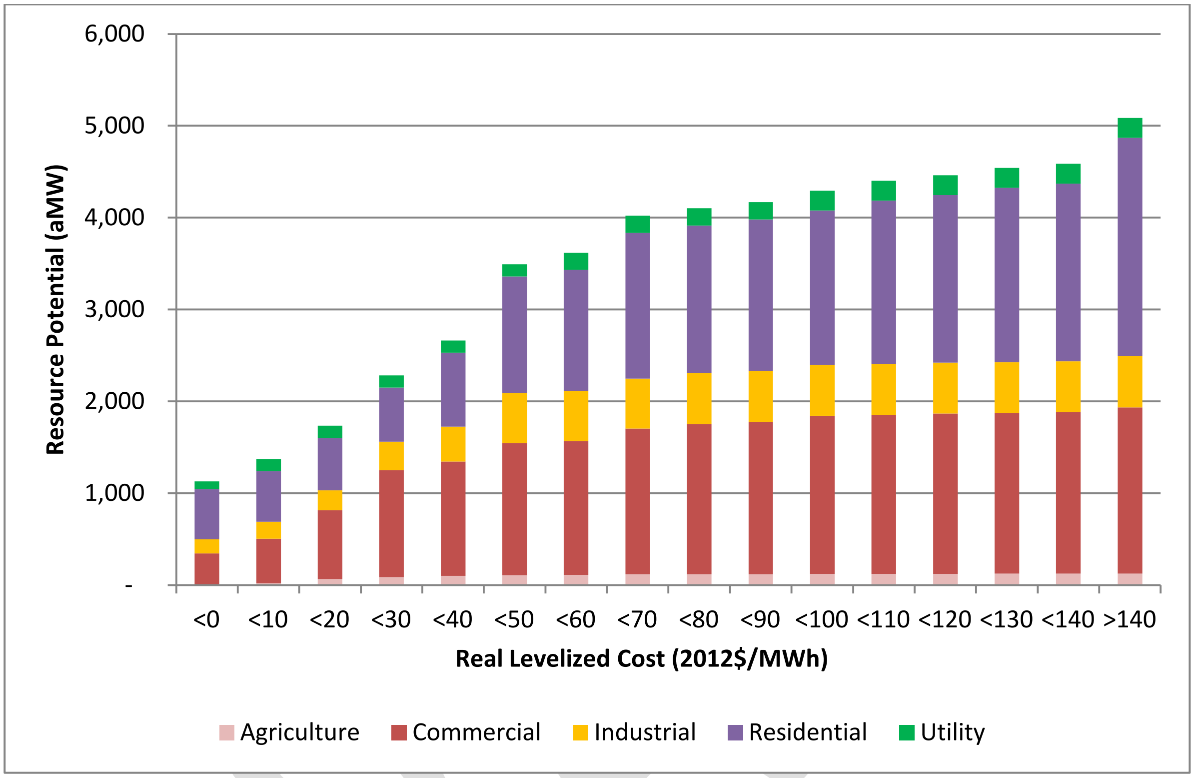
* 2014 savings are preliminary

Since the adoption of the Sixth Plan, the US Department of Energy has adopted new or revised more than 30 standards for appliances and equipment that have or will take effect over the next 10 years. These standards reduce load growth by capturing all or a portion of the conservation potential identified in the Sixth Plan. The Council estimates that collectively these standards will reduce forecast load growth by nearly 1500 average megawatts by 2035.

The Council has identified significant new efficiency opportunities in all consuming sectors. Figure 3 - 5 shows by levelized cost the sectors of efficiency improvements. Additional information on the sources and costs of efficiency improvements is provided in Chapter 12 and Appendix G.

Improved efficiency contributes not only to meeting future energy requirements, but also provides capacity during peak load periods. The savings from conservation generally follow the hourly shape of energy use, saving more energy when more is being used. As a result, efficiency contributes more to load reduction during times of peak usage. To model the impact of energy efficiency on the hourly demand for electricity, the Council aggregated the load shapes of efficiency savings from the hourly shape of individual end-uses of electricity and the cost-effective efficiency improvements in those uses. Figure 3 - 6 shows the shape of the savings for all measures during heavy and light load hours. As is shown, the energy savings are greater during the winter season than summer, in large part due to significant savings from conversion of electric resistance heating to more efficient heat pump technologies and increased use of lighting during the winter period.

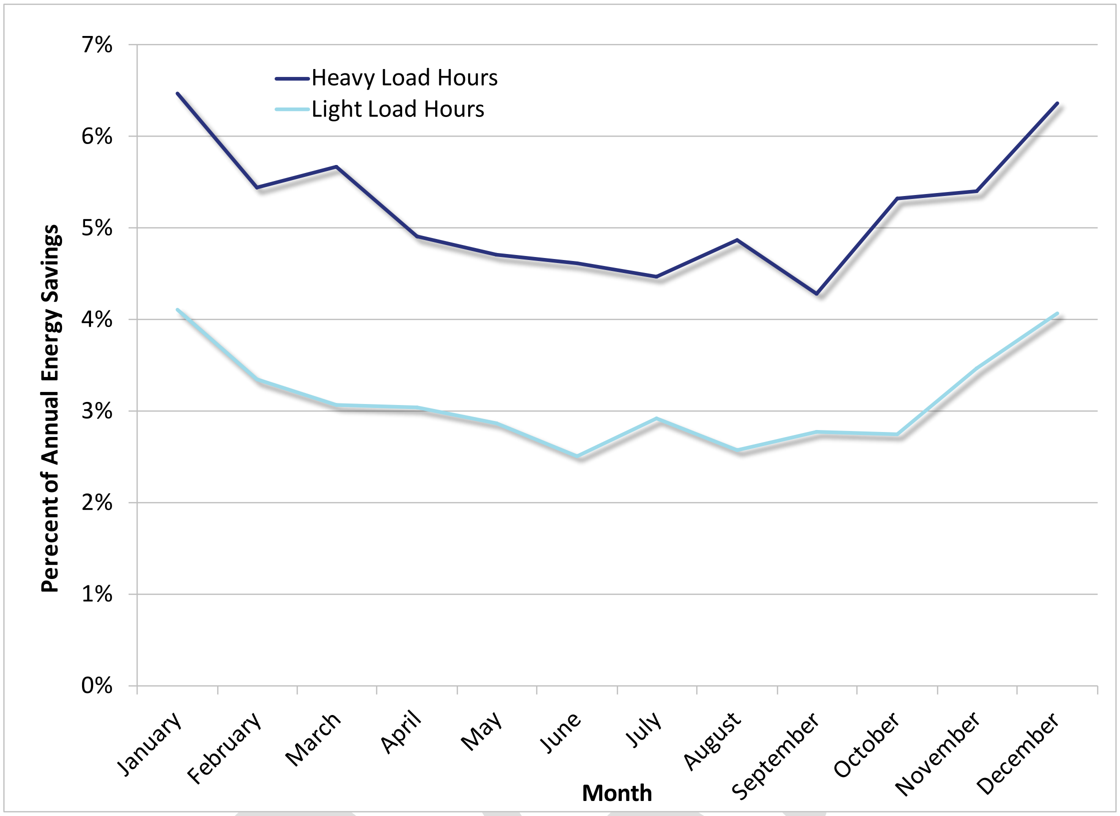
Figure 3 - 5: Efficiency Potential by Sector and Levelized Cost by 2035



For example, efficiency improvements that yield average annual savings of 4,485 average megawatts create 10,700 megawatts of peak hour savings during the winter months.[4] The capacity impact of energy efficiency is almost two times the energy contribution in winter. This reduction in both system energy and capacity needs makes energy efficiency a valuable resource relative to generation because efficiency provides winter energy and capacity resources shaped to load. Because each efficiency measure has a specific shape, or capacity impact, the Seventh Power Plan explicitly incorporates the value of deferred generation capacity in the cost-effectiveness methodology for measures and programs.[5]

[4] See Chapter 12 for a description of how the capacity savings of energy efficiency measures are estimated and Chapter 11 for a description of how the system level capacity savings, or Associated System Capacity Contributions, of conservation and generation resources are estimated.
[5] See action items RES-2 and RES-3 in Chapter 4 and Appendix G

Figure 3 - 6: Monthly Shape of 2035 Efficiency Savings



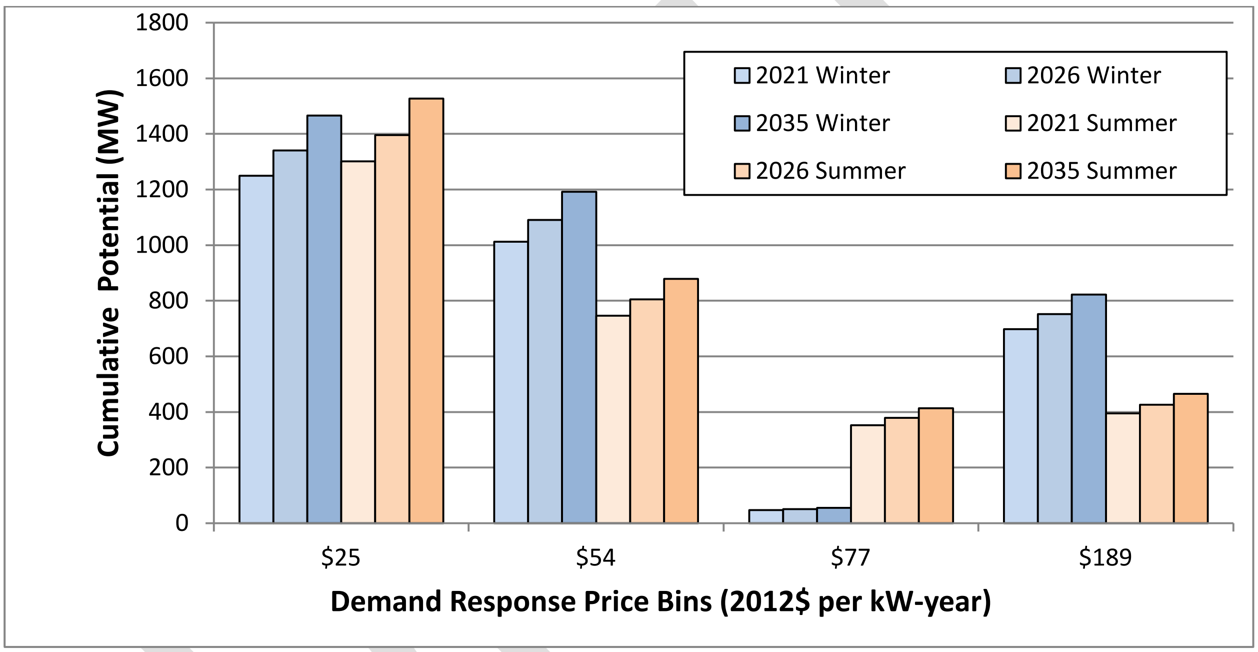
Demand Response

Demand response resources (DR) are voluntary reductions (curtailments) in customer electricity use during periods of high demand and limited resource availability. As deployed in the Seventh Power Plan, demand response resources are used to meet winter and summer single-hour peak demands primarily under critical water and extreme weather conditions. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not considered in the Seventh Power Plan.

In many areas of the US, demand response resources have long been used by utilities to offset the need to build additional peaking capacity. In the Northwest, the existing hydropower system has been able to supply adequate peaking capacity, so the region has far less experience with deployment of demand response resources. To assess the economic value of developing demand response in the Northwest, the Council conducted two sensitivity studies that assumed demand response resources were not available. The average net present value *system cost* and *economic risk* of the least cost resource strategy without demand response were $1 billion higher than in the least cost resource strategy that was able to deploy this resource. Therefore, from the Seventh Power Plan's analysis it appears that if barriers to development can be overcome and the Council's analysis of the cost of demand response are accurate; demand response resources could provide significant regional economic benefits.[6]

The Council's assessment identified more than 4300 megawatts of regional demand response potential. A significant amount of this potential, more than 1500 megawatts, is available at relatively low cost, under $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response resources can be deployed sooner and in quantities better matched to the peak capacity need. Figure 3 - 7 shows the cumulative potential for each of the four blocks (i.e., price bins) of demand response modeled in the Regional Portfolio Model. Cumulative achievable potential by the years 2021, 2026, and 2035 is shown for both winter and summer capacity demand response programs. Note that the largest single block of estimated demand response potential is also the least costly.

Figure 3 - 7: Demand Response Resource Supply Curve



The low cost of demand response resources make them the most economically attractive option for maintaining regional peak reserves to satisfy the Council's Resource Adequacy Standards. The low cost of demand response resources make them particularly valuable because the need for peaking capacity resources to meet resource adequacy in the region is a function of a combination of water and weather conditions that have low probability of occurrence. This is illustrated by Figure 3 - 8 which shows the amount of demand response resource needed by 2021 across the 800 futures tested in the RPM across multiple scenarios.

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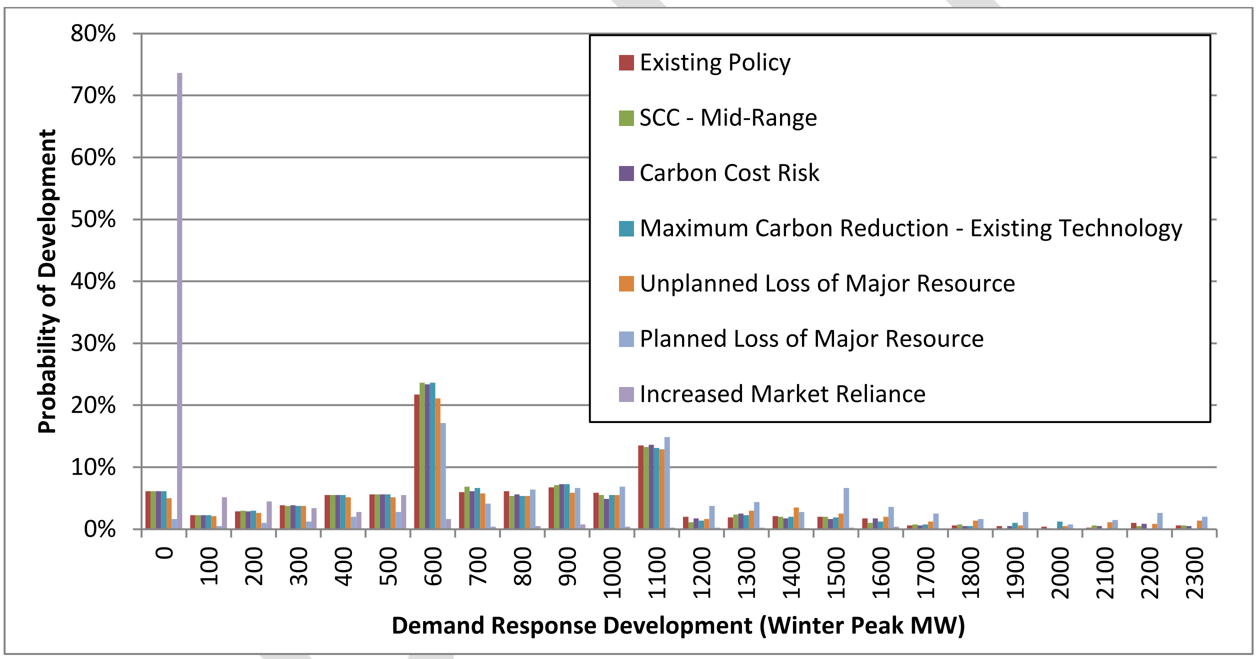
[6] See Chapter 4 for the Action Items the Seventh Power Plan recommends the region and Bonneville should engage to specifically address the barriers to development of demand response resources.

Figure 3 - 8 shows that there is a wide range of both the amount and probability of development from zero up to 2300 MW, depending on what scenario is being analyzed. In the **Increased Market Reliance** scenario**,** more than 70 percent of the futures require no demand response development. Under most other scenarios there is around a 20 percent probability that as much as 600 MW of demand response will need to be developed by 2021 and a 15 percent probability that as much as 1100 MW would need to be developed.

It is striking to note the contrast in demand response development in the **Increased Market Reliance** scenario**,** which assumed the region could place greater reliance on external power markets to meet its winter peak capacity needs, and other scenarios that used the limits on external market reliance used in the Regional Resource Adequacy Assessment. The amount of demand response developed *on average* across all futures decreased from 700 MW to less than 100 MW. In this scenario, net present value system cost and economic risk were also lower. This highlights the sensitivity of the assumed limits on external market reliance used in the Council Regional Resource Adequacy Assessment and the potential value to the region if it can rely upon additional imports.

Figure 3 - 8: Demand Response Resource Development by 2021 Under Alternative Scenarios



Renewable Generation

Since the adoption of the Sixth Plan renewable generating resources development has increased significantly. This development was prompted by Renewable Portfolio Standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region – about equivalent to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

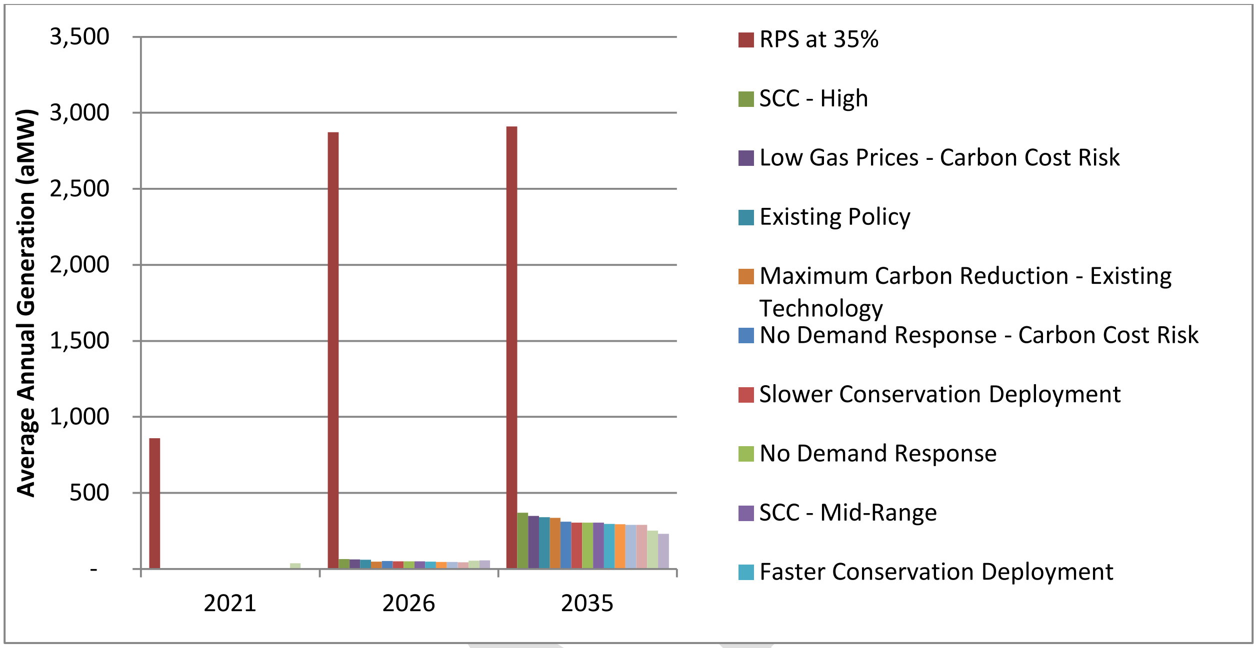
It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

Existing wind resources are estimated to provide about 2,400 average megawatts of energy generation per year in the region, or about 8 percent of the region's electricity energy supply. However, on a firm capacity basis, wind resources only provide about 1 percent of the region's total system peaking capability. The Council's current analysis of wind's ability to supply peaking capacity is based on the Resource Adequacy Assessment Advisory Committee's estimate that wind can only be relied upon to provide about 5 percent of its nameplate capacity toward meeting peak loads due to the variable nature of the resource.

Aside from hydropower, the renewable resources included in the Regional Portfolio Model (RPM) are wind and solar photovoltaic (solar PV). The Council recognizes that additional small-scale renewable resources are likely available and cost-effective. These small-scale renewables were not modeled in the RPM but the plan encourages their development as an important element of the resource strategy. In addition, there are many potential renewable resources not captured in the resource strategy that are currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable future resources.

New wind resources that have ready access to transmission produce energy at costs that are competitive on an energy basis with other generation alternatives. Recent and forecast reductions in solar PV system cost are making utility scale system's energy production cost increasingly cost-competitive. However, renewable generation development in the scenarios tested for the Seventh Power Plan is driven by state RPS and not economics. Figure 3 - 9 shows the average development of renewable resources across scenarios analyzed for the Seventh Power Plan. As can be seen from this figure, under all least cost resource strategies for all scenarios, except when the RPS were assume to increase to 35 percent, only 300 to 400 average megawatts of renewable resource development occurs later in the planning period (post-2026) after the Oregon and Washington renewable credit bank balances are forecast to be drawn down.

Figure 3 - 9: Average Renewable Resource Development by Scenarios by 2021, 2026 and 2035



The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 800 futures of demand growth in the **Carbon Cost Risk** scenario, the amount of wind and solar PV developed on average is about 300 average megawatts, with slightly more solar PV developed than wind. The only exception to this level of development is the **RPS at 35 percent** scenario that assumed regional renewable resource portfolio standards would be increased to 35 percent of annual regional load. In this scenario the least cost resource strategy develops 2,900 average megawatts of additional renewable resources, primarily wind generation by 2035.

The explanation of the outcome described above is that while the two economically competitive renewable resources available in the region, wind and solar PV, produce significant amounts of energy, they provide little or no winter peaking capacity. Partly as a result of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water and extreme weather conditions the region faces the probability of a winter peak capacity shortfall. In short, the generation characteristics of the currently economically competitive renewable resources do not align well with regional power system needs.

As stated above, the development of renewable generation is driven by state renewable portfolio standards more so than regional energy need. In the absence of higher renewable portfolio standards little additional renewable development would take place, even under scenarios where the highest social cost of carbon dioxide (**SCC-High**) might be imposed on the power system.

Natural Gas-Fired Generation

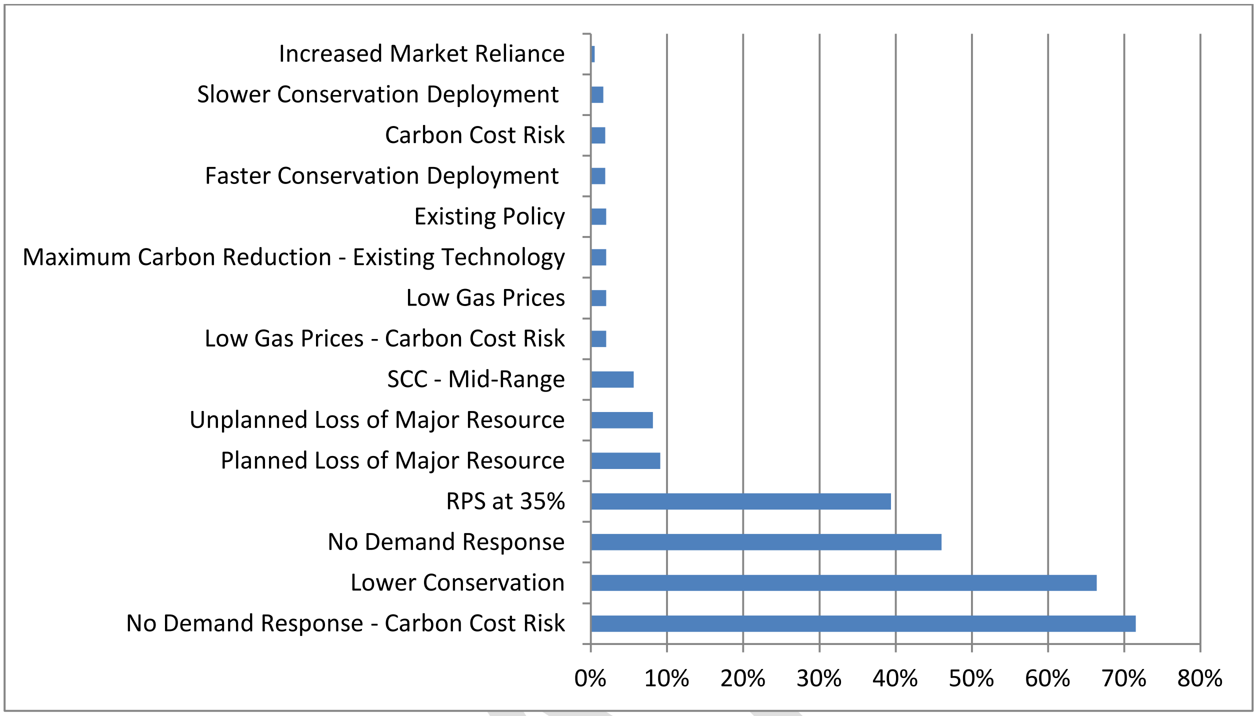
Natural gas is the fourth major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh Power Plan identified the increased use of existing natural gas generation as offering the lowest cost option for reducing regional carbon dioxide emissions. Other resource alternatives may become available over time, and the Seventh Power Plan recommends actions to encourage expansion of the diversity of resources available, especially those that do not produce greenhouse gas emissions.

Across the scenarios evaluated, there is significant variance in the amount of new gas-fired generating resources that are optioned and in the likelihood of completing the plants. New gas-fired plants are optioned (sited and licensed) in the RPM so that they are available to develop if needed in each future. The Seventh Power Plan's resource strategy includes optioning new gas fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and low in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are taken to construction in only a relatively small number of futures. Figures 3 - 10 and 3 - 11 show the probability that a thermal resource option would move to construction by 2021 and by 2026. The scenarios are rank-ordered based on the probability of any new gas resource development by 2021 and by 2026. Scenarios with the lowest probability of development are at the top of the graphs.

As can be observed from a review of Figure 3 - 10, the probability of gas development is less than 10 percent by 2021 in all but four scenarios. The only exceptions to this finding are in the **RPS at 35 percent** scenario and in scenarios where the region is unable to deploy demand response or acquires less conservation than projected. In these scenarios, the probability of moving from an option to construction on new gas-fired generation increases to 40 percent or higher.

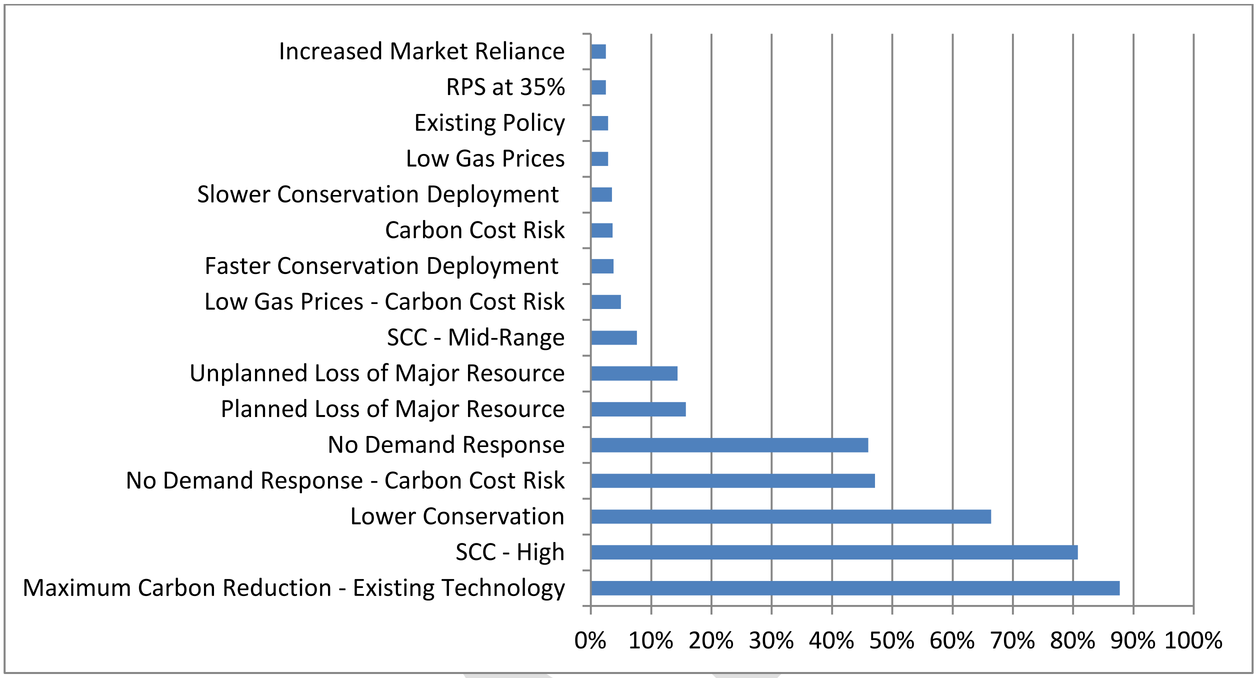
By 2026, Figure 3 - 11 shows that the probability of moving from an option to actual construction of a new gas-fired thermal plant increases to more than 80 percent in the **SCC-High** and **Maximum Carbon Reduction – Existing Technology** scenarios. This occurs because under both of these scenarios existing coal and inefficient gas-fired generation are retired or displaced by new, highly efficient natural gas generation to reduce regional carbon dioxide emissions.

Figure 3 - 10: Probability of New Natural Gas-Fired Resource Development by 2021



The development of natural gas combined cycle combustion turbines is largest when there is a need for both new capacity and energy to meet regional adequacy standards. As can be observed from the data shown in Figures 3 - 10 and 3 - 11, this occurs in scenarios that must replace energy generation lost due to the retirement of resources, such as in the two scenarios that retire or decrease the use of existing coal and inefficient existing gas plants or those that assume no demand response resources or develop significantly less amounts of energy efficiency.

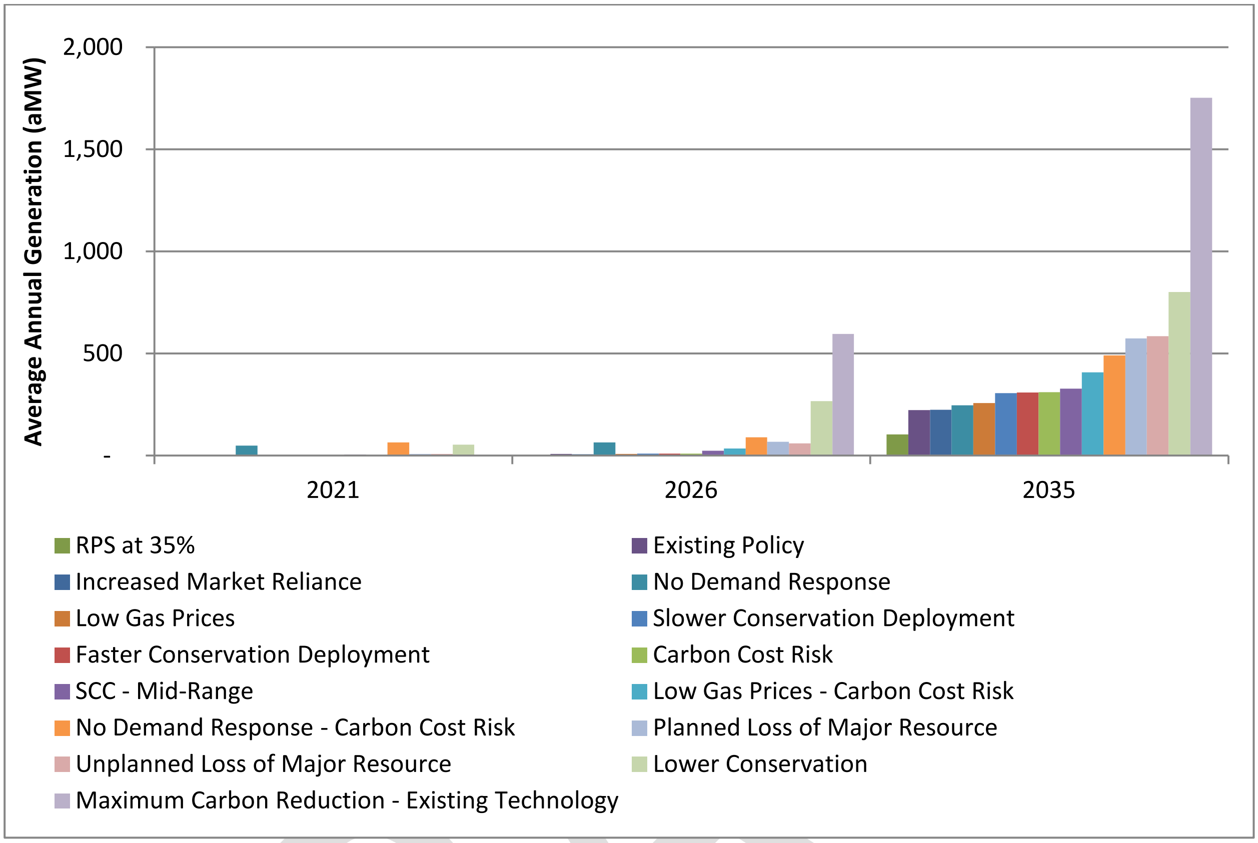
Figure 3 - 11: Probability of New Natural Gas-Fired Resource Development by 2026



As can be seen from the prior discussion, while the amounts of efficiency, demand response, and renewable resources developed were fairly consistent across most scenarios examined, the future role of new natural gas-fired generation is more variable and specific to the scenarios studied. Figure 3 - 12 shows the average amounts of gas-fired generation across 800 futures considered in each of the principal scenarios. The amount of new natural gas-fired generation constructed varies in each future. In most scenarios the average annual dispatch of new natural gas-fired generation is less than 50 average megawatts by 2026 and only between 300 to 400 average megawatts by 2035. In the **Carbon Cost Risk** scenario, the amount of energy generated from new combined cycle combustion turbines, when averaged across all 800 futures examined, is just 10 average megawatts in 2035. In contrast, the average amount generated across 800 futures is closer to 100 average megawatts in 2035 in the two scenarios that assume no demand response resources are developed.

However, the role of natural gas is larger than it appears in the Council's analysis of the regional need for new natural gas fired generation for a number of reasons. First, the regional transmission system has not evolved as rapidly as the electricity market, resulting in limited access to market power for some utilities. Second, some utilities have significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required in such instances even if the utilities deploy demand response resources and develop the conservation as called for in Seventh Power Plan.

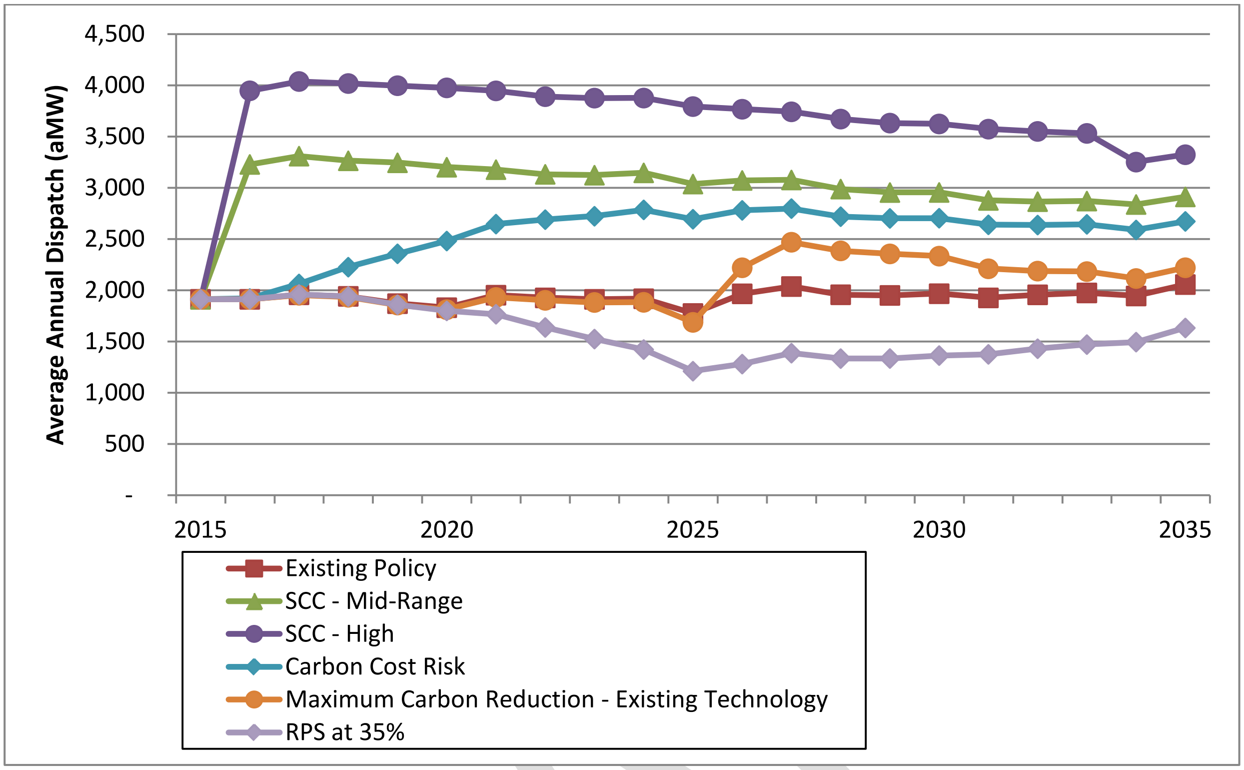
Figure 3 - 12: Average New Natural Gas-Fired Resource Development



Third, the increased use of the *existing* natural gas generation in the region plays a major role in many of scenario's least cost resource strategies, particularly those that explored alternative carbon dioxide emissions reduction policies. Figure 3 - 13 shows the average annual dispatch of the existing natural gas generation in the region through time for the five carbon dioxide reduction policy scenarios as well as the **Existing Policy** scenario. A review of Figure 3 - 13 reveals that the annual dispatch of existing natural gas generating resources increases in response to carbon dioxide emission reduction policies.

For example, under the two **Social Cost of Carbon** scenarios, existing natural gas generation increases immediately following the assumed 2016 imposition of carbon dioxide damage cost in those scenarios. In the **Carbon Cost Risk** scenario, existing natural gas generation gradually increases over time as the regulatory cost of carbon dioxide increases. In the **Maximum Carbon Reduction – Existing Technology** scenario, existing gas generation increases post-2025 when, under this scenario, the entire region's existing coal-fired generation fleet is retired. Under the **RPS at 35 percent** scenario, existing natural gas generation actually declines through time as low variable cost resources are added to the system, generally lowering market prices and diminishing the economics of gas dispatch.

Figure 3 - 13: Average Annual Dispatch of Existing Natural Gas-Fired Resources



Carbon Policies

The Northwest power system, due to its significant reliance on hydropower and its historical deployment of energy efficiency to offset the need for new thermal generation, has the lowest carbon emissions level of any area of the country. To ensure that future carbon policies are cost effective and maintain regional power system adequacy the region should develop the energy-efficiency resources called for in this plan. In addition, it should replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

The basis for the Seventh Power Plan's carbon policy recommendations are more fully described in the Carbon Dioxide Emissions section of this chapter.

Regional Resource Utilization

The existing Northwest power system is a significant asset for the region. The FCRPS (Federal Columbia River Power System) provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's Seventh Power Plan resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council does not directly model the sub-hourly operation of the region's power system, both the Regional Portfolio Model and the GENESYS models presume resources located anywhere in the region can provide energy and capacity services to any other location in the region, within the limits of existing transmission. This simplifying assumption also minimizes the need for new resources needed for integration of variable energy resource production. To the extent that actual systems can be developed that replicate the model's assumptions, fewer resources will be required. This likely means the region needs to invest in its transmission grid to improve market access for utilities, to facilitate development of more diverse cost-effective renewable generation and to provide a more liquid regional market for ancillary services.

As originally envisioned by the Northwest Power Act, the benefits of the FCRPS were to be shared by all of the region's consumers. However, since the Act was passed, implementing that vision has proved elusive at best and even questioned by some as desirable. Several of the scenario analyses conducted for the Seventh Power Plan reveal the symptoms and scope of this issue.

The least cost resource strategies identified by the RPM often reduce regional exports in order to serve in-region demands for energy and capacity. In particular, scenarios that retired or significantly reduced the dispatch of existing coal-fired generation serving the region, all of which serves investor-owned utilities, show lower regional exports. These resource strategies resulted in lower total system cost and lower system economic risk because they delayed or avoided the need for new resource development within the region. Figure 3 - 14 shows the average net (i.e., exports minus imports) exports for their least cost resource strategies across six scenarios.

Inspection of Figure 3 - 14 reveals how net exports change across time in response to the resource strategy for each scenario. For example, under the **Existing Policy** scenario exports decline slightly after 2021 and 2026 following the closure of coal plants currently serving the region. After 2030, under this same scenario, net exports continue to gradually decline as loads grow and conservation no longer offsets load growth.

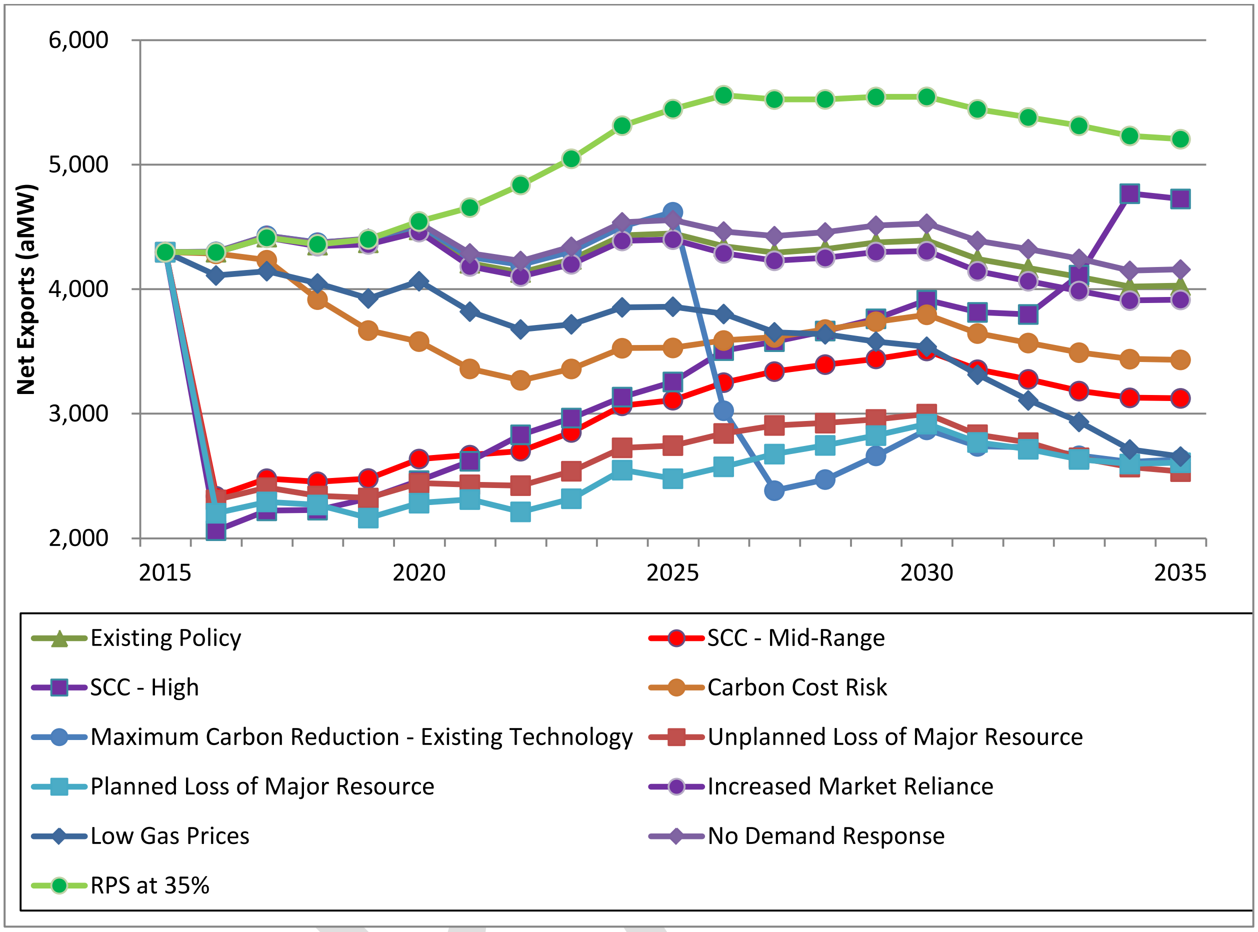
In contrast, under the two the scenarios which assume that carbon dioxide damage costs are imposed in 2016 (e.g. **SCC-Mid-Range** and **SCC-High**), net exports decline immediately. This reduction in exports offsets the reduction in regional coal plant dispatch in response to increased carbon dioxide costs. In the following years, exports gradually increase as highly efficient gas-fired generation developed in the region displaces less efficient generation outside the region. At the other extreme, under the **RPS at 35 percent** scenario, regional net exports expand significantly over time as the region develops large amounts of wind resources. These resources have very low variable cost, which makes them competitive outside the region *and* they produce energy that is surplus to regional needs during many months of the year.

What all of these scenario results reveal is that, under a wide range of future conditions, the least cost resource strategy for the region is intimately tied to decisions made regarding the disposition of "surplus" generation. But the region's utilities and Bonneville are not all in similar load/resource balance positions. The FCRPS, except under poor water conditions, produces surplus energy beyond the firm requirements of Bonneville's public utility customers. In contrast, the region's investor-owned utilities own less hydroelectric generation so they have significantly less surplus to sell on the market.

Under the current law, investor-owned utility access to Bonneville's surplus peaking capacity is limited to seven year contracts[7] which can be terminated with five year notice.[8] While all of the region's utilities must be offered the opportunity to purchase excess Federal power, as required by the NW Power Act and within the limits of existing transmission, they must ultimately compete with out-of-region buyers for access to short-term surplus generation. If the region's investor-owned utilities do not secure access to long-term contracts at competitive prices for either energy or capacity, this will result in the need to construct new generation facilities despite the potential availability of energy and capacity resources from Bonneville.

[7] Energy and Water Appropriations Act of 1996, Pub. L. No. 104-46, § 508(b), (Supp. 1 1995).
[8] Preference Act, Pub. L. 88-552, § 3(c) (1994 & Supp. 1 1995).

Figure 3 - 14: Average Annual Net Regional Exports for Least Cost Resource Strategies



Develop Long-Term Resource Alternatives

The seventh element of the Council's resource strategy recognizes that technologies will evolve significantly over the 20 years of the Seventh Power Plan. When the Council next develops a power plan, the cost-effective, available and reliable resources will most likely be different from those considered in the Seventh Power Plan. But the Seventh Power Plan identifies areas where progress is likely to be valuable and includes actions to explore and develop such resources and technologies. In many instances entities in the region can influence the development of technology and the pace of adoption.

Areas of focus in the long-term resource strategy include additional efficiency opportunities and the ability to acquire them, energy-storage technologies to provide capacity and flexibility, development of smart-grid technologies, expansion of demand response capability, and tracking and supporting the development of no-carbon dioxide or low-carbon dioxide emitting generation. The latter includes renewable technologies such as enhanced geothermal and wave energy and small modular nuclear generation.

Research, development, and demonstration of these technologies are an important part of the Council's resource strategy. Tracking these developments, as well as plan implementation and assumptions such as resource availability, cost and load growth, will identify needed changes in the power plan and near-term actions. These elements of the resource strategy are addressed primarily in the action plan.

Adaptive Management

The eighth element of the Council's resource strategy is to adaptively manage its implementation. The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. This means that during the period covered by the Seventh Power Plan's Action Plan, actual conditions must deviate significantly from the conditions tested in the 800 futures explored in the Regional Portfolio Model before the basic assumptions and action items in the Seventh Power Plan are called into question.

However, the fact that a wide range of strategies were tested against a large number of potential future conditions in developing the Plan does not mean that *all* near term actions called for in the Seventh Power Plan will be perfectly aligned with the actual future the region experiences. Therefore, the Council will annually assess the adequacy of the regional power system to identify conditions that could lead to power shortages. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions as to require adjustments to the action plan.

The Council will also conduct a mid-term assessment to review plan implementation and compare progress against specific metrics. This includes assessing how successful plan implementation has been at reducing and meeting Bonneville's obligations, both the power sales contracts and the assistance the plan's resource scheme provides in the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

CARBON DIOXIDE EMISSIONS

As in the Sixth Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon dioxide regulatory policies. In addition, the Council was asked to address what changes would need to be made to the power system to reach a specific carbon dioxide reduction goal and what those changes would cost. This section also summarizes how alternative resources strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency (EPA).

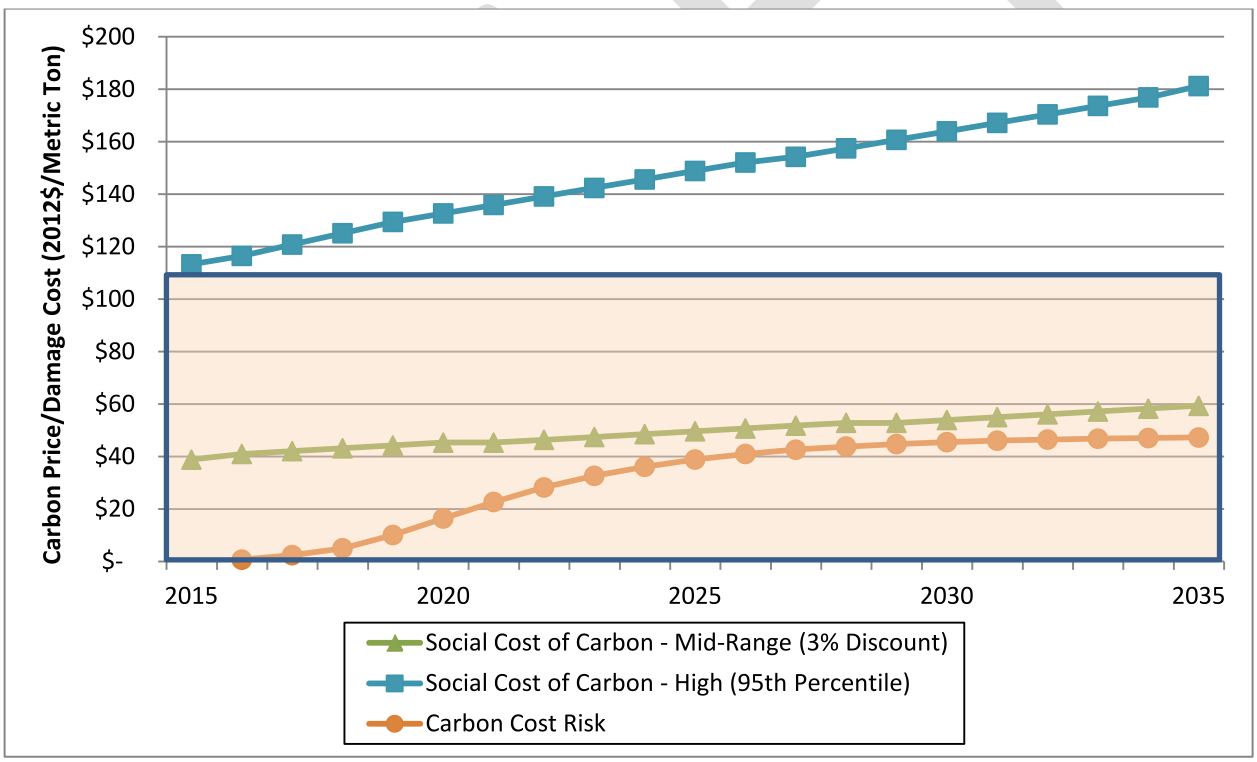
In providing analysis of carbon dioxide emissions and the specific cost of attaining carbon dioxide emissions limits, the Council is not taking a position on future climate-change policy. Nor is it taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emissions regulations. The Council's analysis is intended to provide useful information to policy-makers. Chapter 15 discusses the results of the Council's analysis of alternative carbon dioxide emissions reduction policy scenarios in more detail.

Three "carbon dioxide pricing" policy options were tested. Two scenarios assumed that alternate values of the federal government's estimates for damage caused to society by climate change due to carbon dioxide emissions, referred to as the “social cost of carbon”, are imposed beginning in 2016. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon dioxide emissions would be the maximum society should invest to avoid such damage.

The third carbon dioxide pricing policy tested, **Carbon Cost Risk** is identical to the scenario analyzed in the Sixth Plan. This scenario exposes the power system to random changes in carbon dioxide pricing each year over the 20 year planning period. This scenario was designed to reflect the uncertainty regarding future carbon dioxide regulation. In this scenario, Carbon dioxide pricing, reflecting differing levels of carbon dioxide regulatory costs, between $0 and $110 per metric ton were imposed randomly, but with increasing probability and at higher levels through time.

Figure 3 - 15 shows the two US Government Interagency Working Group’s estimates used for the **SCC - Mid-Range** and **SCC-High** scenarios and the range (shaded area) and average carbon dioxide prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Cost Risk** scenario.

Figure 3 - 15: Carbon Dioxide Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



Three other carbon dioxide emission reduction policies were tested that did not involve using carbon dioxide pricing. The first of these, the **Maximum Carbon Reduction** - **Existing Technology** scenario was designed to reduce carbon dioxide emissions by deploying all currently economically viable technology. The second, the **Maximum Carbon Reduction** - **Emerging Technology** scenario was designed to reduce carbon dioxide emissions by deploying technology that may become economically viable over the next 20 years. Under both of these scenarios all existing coal plants serving the region were retired by 2026. In addition, all existing natural gas plants with heat-rates (a measure of efficiency) above 8,500 BTU/kilowatt-hour were retired by 2030. Also, in the **Maximum Carbon Reduction – Emerging Technology** scenario, no new natural gas-fired generation was considered for development.

The **Maximum Carbon Reduction – Emerging Technology** scenario was designed assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035. As stated above, the Council created this resource strategy based on energy-efficiency resources and non-carbon dioxide emitting generating resource alternatives that might become commercially viable over the next 20 years. While the Regional Portfolio Model (RPM) was used to develop the amount, timing and mix of resources in this resource strategy, no economic constraints were taken into account. That is, the RPM was simply used create a mix of resources that could meet forecast energy and capacity needs, but it made no attempt to minimize the cost to do so. The reason the RPM's economic optimization logic was not used is that the future cost and resource characteristics of many of the emerging technologies included in this scenario are highly speculative. Therefore, in the following discussion, only the impacts on carbon dioxide emissions for this scenario are reported. A more detailed discussion of the emerging technologies considered in this scenario appears in Chapter 15.

The third "non-price" carbon dioxide emission reduction policy option tested was the **RPS at 35 percent** scenario. Under this scenario, the region's reliance on carbon dioxide-free generation was increased by assuming that the region would satisfy a Renewable Portfolio Standard requiring 35 percent of the region's electricity load to be met with such resources by 2030.

In order to compare the cost of resource strategies that reflect both "carbon-pricing" and "non-carbon pricing" policy options for reducing carbon dioxide emissions it is useful to separate their cost into two components. The first is the direct cost of the resource strategy. That is, the actual the cost of building and operating a resource strategy that reduces carbon dioxide emissions. The second component is the revenue collected through the imposition of carbon taxes or pricing carbon damage cost into resource development decisions. This second cost component, either in whole or in part, may or may not be paid directly by electricity consumers. For example, the "social cost of carbon" represents the estimated economic damage of carbon dioxide emissions worldwide. In contrast to the direct cost of a resource strategy which will directly affect the cost of electricity, these "damage costs" are borne by all of society, not just Northwest electricity consumers.

In the discussion that follows, the direct cost of resource strategies are reported separately from the carbon dioxide revenues associated with that strategy. Carbon dioxide prices or estimated damage costs are not included in the **Existing Policy**, **Maximum Carbon Reduction** - **Existing Technology** or the **RPS at 35 percent** scenarios. Therefore, only the direct cost of the least cost resource strategies for these scenarios are reported. As stated above, due to the speculative nature of the **Maximum Carbon Reduction** - **Emerging Technology** scenario no costs are reported for this scenario.

Table 3 - 1 shows the average system costs and carbon dioxide emissions for the seven scenarios and sensitivity studies conducted to specifically evaluate carbon dioxide emissions reductions policies (and economic risks) for the development of the Seventh Power Plan. This table shows the average net present value system cost for the least cost resource strategy for each scenario, both with and without carbon dioxide revenues. It also shows the average carbon dioxide emissions

projected for the generation that serves the region in 2035. For comparison purposes, the carbon dioxide emissions from the generation serving the Northwest loads averaged approximately 55 million metric tons from 2000 through 2012.

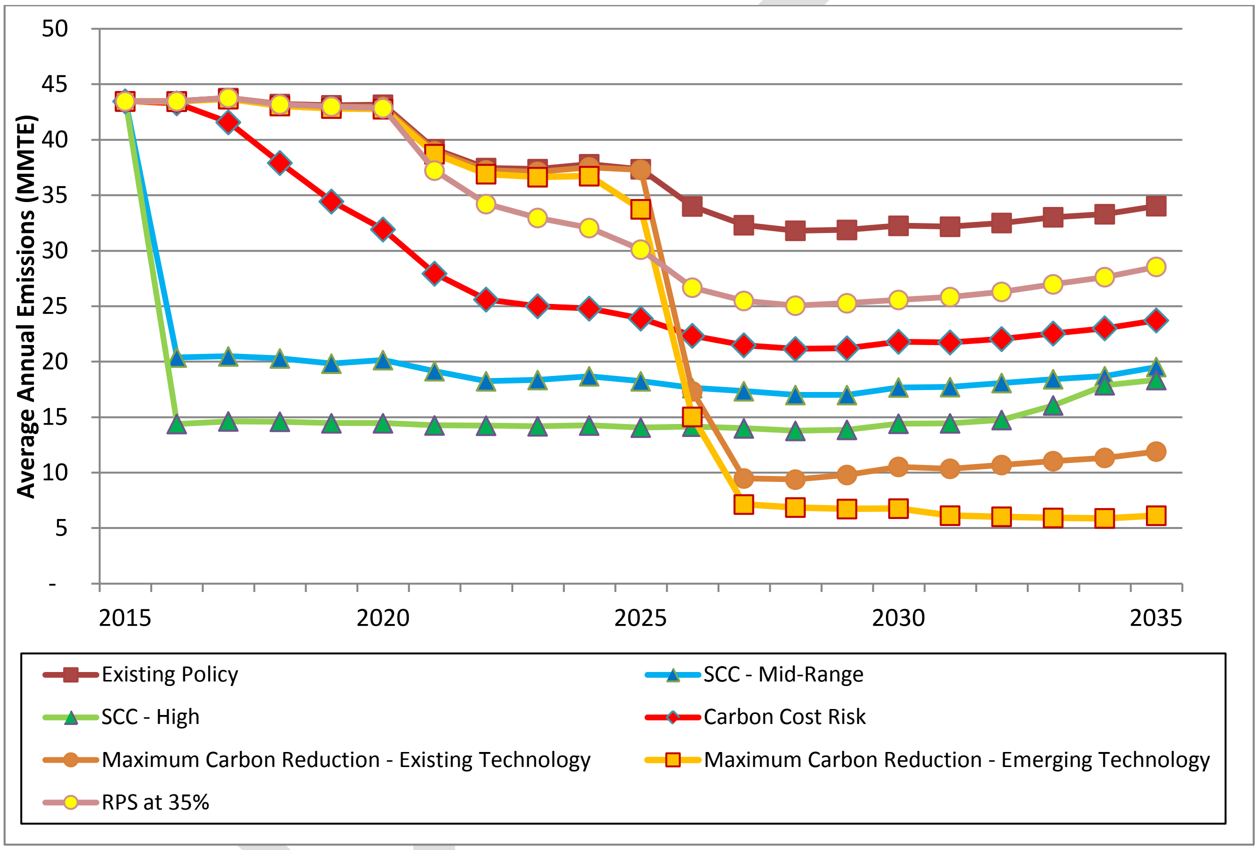
Table 3 - 1: Average System Costs and PNW Power System Carbon Dioxide Emissions by Scenario

Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$)	System Cost w/ Carbon Dioxide Revenues (billion 2012$)	2035 Carbon Dioxide Emissions (MMTE)
Existing Policy	$88	$88	34
SCC - Mid-Range	$89	$127	20
SCC - High	$90	$122	18
Carbon Cost Risk	$89	$115	24
Maximum Carbon Reduction - Existing Technology	$107	$107	12
Maximum Carbon Reduction - Emerging Technology	Not Calculated	Not Calculated	6
RPS at 35%	$122	$122	29

Table 3 - 1 shows the **Existing Policy** scenario which assumed no additional carbon dioxide emissions reductions policies beyond those in place prior to the issuance of the Environmental Protection Agency's Clean Air Act 111(b) and 111(d) regulations results in carbon dioxide emissions in 2035 of 34 million metric tons. The direct cost of this resource strategy is $88 billion (2012$). Three scenarios, the **SCC-Medium, SCC-High** and **Carbon Cost Risk** scenarios produce similar reductions in carbon dioxide emissions at similar costs. All three of these scenario result in carbon dioxide emissions of between 18 – 24 million metric tons in 2035 and have a direct cost of $1 - $2 billion more than the **Existing Policy** scenario's least cost resource strategy. The least cost resource strategy in the **Maximum Carbon Reduction - Existing Technology** scenario reduces 2035 carbon dioxide emissions to 12 million metric tons, or to about one-third that of the **Existing Policy** scenario. However, the estimated direct cost of this resource strategy is $20 billion, significantly higher than the **Existing Policy** scenario's least cost resource strategy. The **RPS at 35 percent** scenario's least cost resource strategy produces the least reduction in 2035 carbon dioxide emissions. Yet, this policy has the highest direct cost of all the options considered, at $34 billion more than the **Existing Policy** scenario's resource strategy. The **Maximum Carbon Reduction - Emerging Technology** scenario reduces 2035 carbon dioxide emissions to 6 million metric tons, roughly half the emissions of the **Maximum Carbon Reduction - Existing Technology** scenario. As stated above, no costs were calculated for this scenario, due to the speculative nature of the technologies considered.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 3 - 16 shows the annual emissions level for each scenario. A review of Figure 3 - 16 reveals that the two social cost of carbon dioxide scenarios, which assume carbon dioxide damage costs are imposed in 2016, immediately reduce carbon dioxide emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Power Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

Figure 3 - 16: Average Annual Carbon Dioxide Emissions by Carbon Reduction Policy Scenario



The **Carbon Cost Risk** and **RPS at 35 percent** scenarios gradually reduce emissions, while the **Maximum Carbon Reduction – Existing Technology** and **Maximum Carbon Reduction - Emerging Technology** scenarios dramatically reduce emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon dioxide emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of carbon dioxide emitting generation.

Table 3 - 2 shows cumulative emission reductions from 2016 through 2035 for each of the carbon dioxide reduction policy scenarios compared to the **Existing Policy** scenario. It also shows the average system cost per million metric ton of carbon dioxide reduction for these five carbon dioxide

reduction policy options, net of carbon dioxide "tax revenues." Table 3-2 reveals that three carbon dioxide pricing policies have roughly comparable cost per unit of carbon dioxide emission reduction based on cumulative emissions reductions. The **Maximum Carbon Reduction – Existing Technology** scenario, as can be seen from Figure 3 - 16, results in the lowest average annual carbon dioxide emissions from the regional power system by 2035. The average cost per ton of carbon dioxide reduction for this scenario is significantly higher than the three carbon dioxide pricing policies, but much lower than average cost per ton of carbon dioxide reduction in the **RPS at 35 percent** scenario.

Note that under the two **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario, the coal plants serving the region dispatch relatively infrequently. As a result, such plants might be viewed by their owners as uneconomic to continue operation. If this is indeed the case, and these plants are retired, then the cost of replacement resources needed to meet the energy or capacity needs supplied by the retiring plants would add to the average present value system cost of these three scenarios. As a result, the average cost of these three carbon dioxide emission reduction scenarios would likely be higher and much closer to the **Maximum Carbon Reduction - Existing Technology** scenario.

Table 3 - 2: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Dioxide Emissions Reduction Policies Compared to Existing Policies - Scenario

CO2 Emissions - PNW System 2016 - 2035 (MMTE)	Cumulative Emission Reduction Over Existing Policy - Scenario (MMTE)	Incremental Present Value Average System Cost of Cumulative Emission Reduction Over Existing Policy - Scenario (2012$/MMTE)
Carbon Cost Risk	196	$2
SCC - Medium	360	$4
SCC - High	438	$3
Maximum Carbon Reduction – Existing Technology	217	$90
Maximum Carbon Reduction – Emerging Technology	262	Not Calculated
RPS at 35%	87	$389

In the analysis shown above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon dioxide emissions will continue beyond 2035, as will their carbon dioxide emissions impacts. These "end-effects" could alter the perceived relative cost-efficiency of carbon dioxide reduction policy options shown in Table 3 - 2. For example, over a longer period of time the cumulative emissions reductions from the **Maximum Carbon Reduction –**

Existing Technology scenario could exceed those from the **SCC-Mid-Range** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 8 MMTE per year lower emissions. In this instance, if the difference in emissions rates for these two scenarios were to remain the same for an additional 20 years, then their cumulative emissions reductions over 40 years would be nearly identical. Since it is impossible to forecast these "end effects," readers should consider the scenario modeling results shown in Table 3 - 2 as directional in nature, rather than precise forecast of either emissions reductions or the cost to achieve them.

The key findings from the Council's assessment of the potential to reduce power system carbon dioxide emissions are:

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric tons today to about 12 million metric tons, or by nearly 80 percent. Achieving this level of carbon dioxide emission reduction is nearly $20 billion or more than 23 percent above the cost of the least cost resource strategies that are anticipated to comply *at the regional* level with the newly established federal emissions limits.
- With forecast development and deployment of current emerging energy efficiency and non-carbon emitting resource technologies it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, or to about 50 percent below the level achievable with existing technology. The cost of achieving this level of emissions was not estimated due to the speculative nature of the technologies considered in this scenario.
- At present, it is not possible to entirely eliminate carbon dioxide emissions from the power system without the development and deployment of nuclear power and/or emerging technology for both energy efficiency and non-carbon dioxide emitting generation that require technological or cost breakthroughs.
- Deployment of variable output renewable resources at the scale considered in the Maximum Carbon Reduction – Emerging Technology scenario presents significant power system operational challenges.

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning, development the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments the EPA issued it final Clean Power Plan (CPP) rules. The "111(d) rule," referred to by the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants, has a goal of reducing national power plant carbon dioxide emissions by 32 percent from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. EPA also issued the final rule under the Clean Air Act section 111(b) for new power plants and the proposed federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the rule requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in carbon dioxide emissions. The eight year interim compliance period is further broken down into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim goal.

Under the EPA's final rules, states may comply by reducing the average carbon dioxide emission rate (pounds of carbon dioxide/kilowatt-hour) emitted by all power generating facilities located in their state that are covered by the rule. In the alternative, states may also comply by limiting the total emissions (tons of carbon dioxide per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based" path. Under the "mass-based" compliance option EPA has set forth two alternative limits on total carbon dioxide emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under constructions as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon dioxide emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach not only better represents the total carbon dioxide footprint of the power system, but it more fully captures the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 3 - 3 shows the final rule's emission limits for the four Northwest states for the "mass-based" compliance path, including both existing and new generation.

Table 3 - 3: Pacific Northwest States Clean Power Plan Final Rule Carbon Dioxide Emissions Limits[9]

Mass Based Goal (Existing) and New Source Complement (Million Metric Tons)					
Period	Idaho	Montana	Oregon	Washington	PNW
Interim Period 2022-29	1.49	11.99	8.25	11.08	32.8
2022 to 2024	1.51	12.68	8.45	11.48	34.1
2025 to 2027	1.48	11.80	8.18	10.95	32.4
2028 to 2029	1.48	11.23	8.06	10.67	31.4
2030 and Beyond	1.49	10.85	8.00	10.49	30.8

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically

[9] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 3-2 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMTE).

located within the regional boundaries defined under the Northwest Power Act.[10] In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's carbon dioxide emissions limits to those specifically covered by the agency's regulations, it was necessary to model a sub-set of plants in the region.

Under the Clean Air Act, each state is responsible for developing and implementing compliance plans with EPA's carbon dioxide emissions regulations. However, the Council's modeling of the Northwest Power system operation is not constrained by state boundaries. That is, generation located anywhere within the system is assumed to be dispatched when needed to serve consumer demands regardless of their location. For example, the Colstrip coal plants are located in Montana, but are dispatched to meet electricity demand in other Northwest states. Consequently, the Council's analysis of compliance with EPA's regulations can only be carried out at the regional level. While this is a limitation of the modeling, it does provide useful insight into what regional resource strategies can satisfy the Clean Power Plan's emission limits.

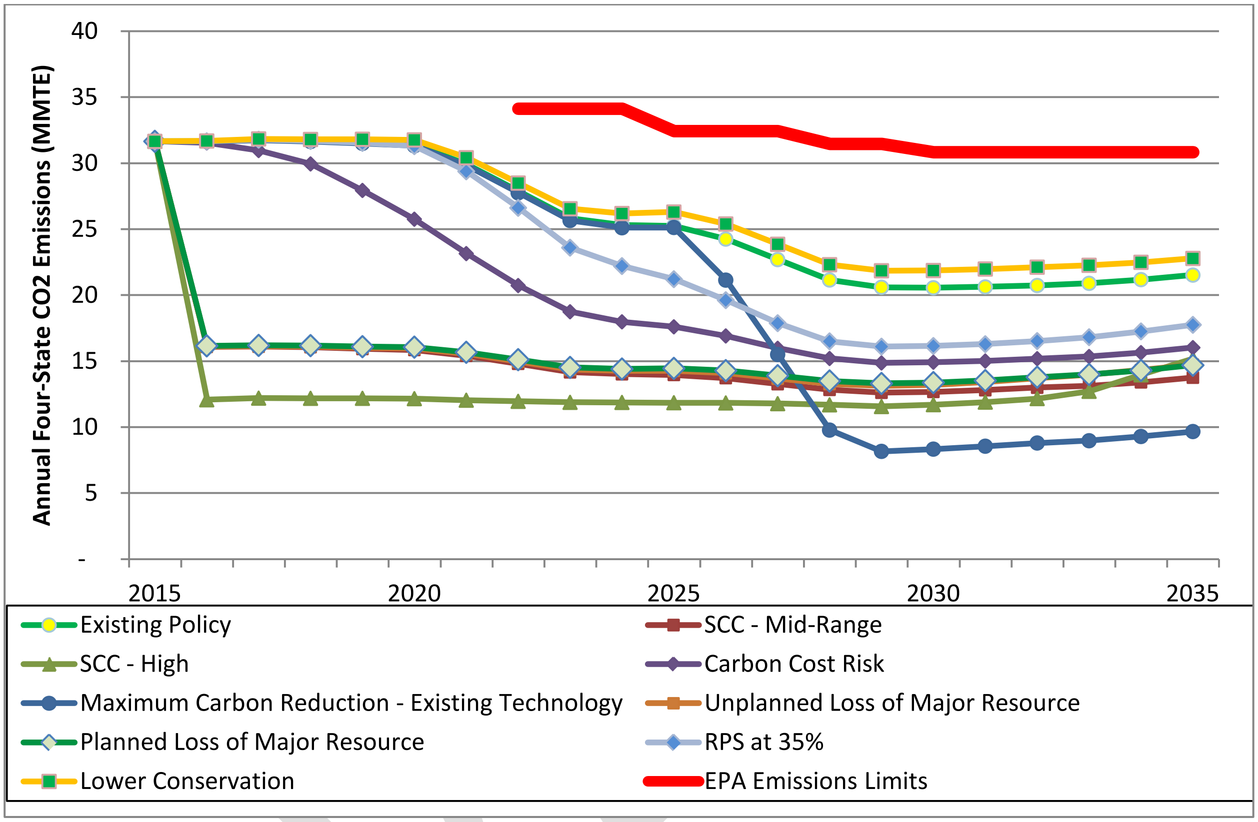
Figure 3 - 17 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final EPA carbon dioxide emissions limits aggregated from the state level to the regional level is also shown in this figure (top heavy line). Figure 3 - 17 shows all of the scenarios evaluated result in average annual carbon dioxide emissions well below the EPA limits for the region.

One of the key findings from the Council's analysis is that *from a regional perspective* compliance with EPA's carbon dioxide emissions rule should be achievable without adoption of additional carbon dioxide reduction policies in the region. This is not to say that no additional action need occur.

All of the least cost resource strategies that have their emission levels depicted in Figure 3 - 17 call for the development of between 4,000 and 4,600 average megawatts of energy efficiency by 2035. All of these resource strategies also assume that the retiring Centralia, Boardman, and North Valmy coal plants are replaced with only those resources required to meet regional capacity and energy adequacy requirements. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels included under these scenarios would increase emissions. All of the least cost resource strategies also assume that Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets.

[10] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from [those] area[s]… which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." (Northwest Power Act, §§ 3(14)(A) and (B).)

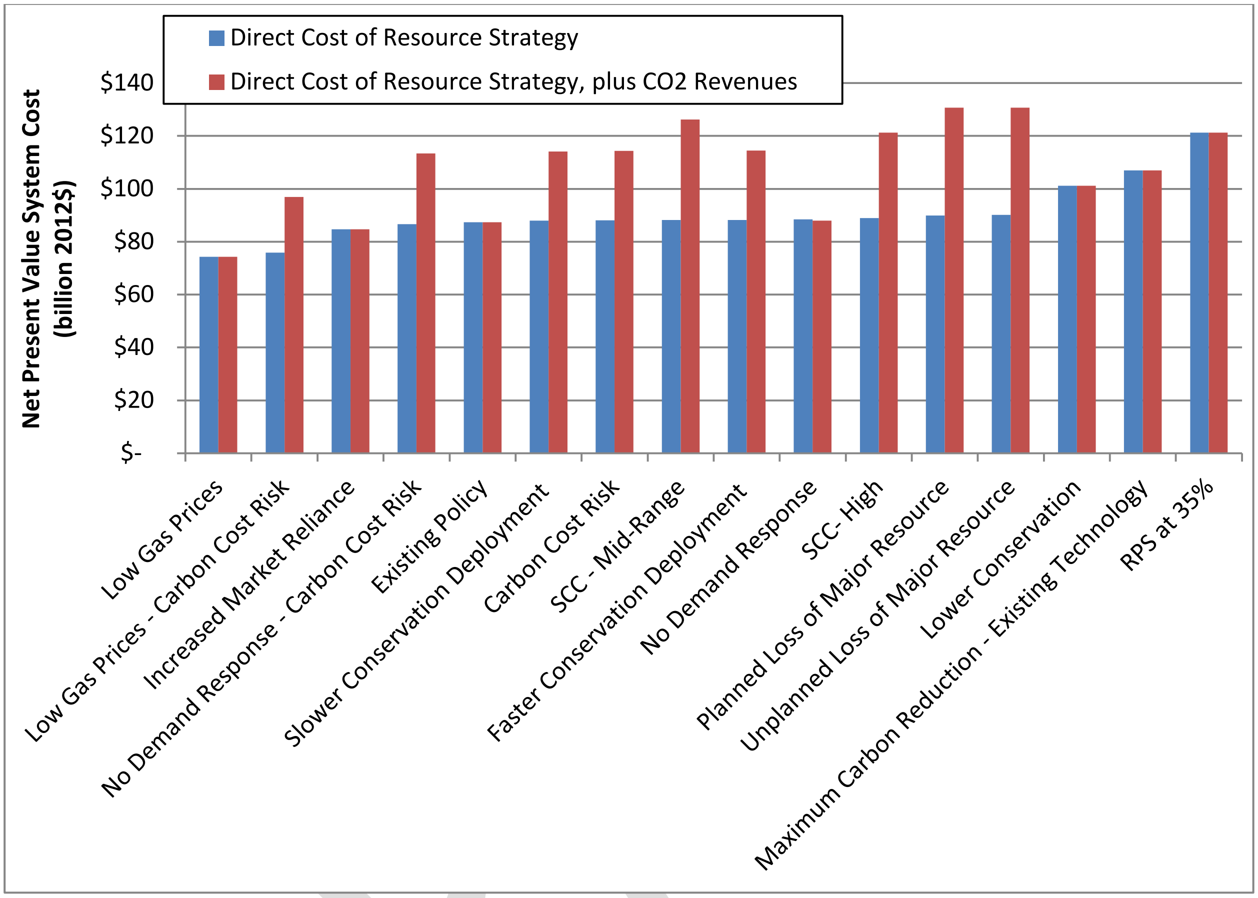
Figure 3 - 17: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States



RESOURCE STRATEGY COST AND REVENUE IMPACTS

The Council's Regional Portfolio Model (RPM) calculates the net present value cost to the region of each resource strategy it tests to identify those strategies that have both low cost and low economic risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions. Figure 3 - 19 shows the present value system cost for the principal scenarios evaluated during the development of the Seventh Power Plan. Figure 3 - 18 also shows the present value of power system costs both with and without assumed carbon dioxide emissions costs. That is, the scenarios that assumed some form of carbon dioxide price include not only the direct cost of building and operating the resource strategy, but also the costs of emitting carbon dioxide assumed in those scenarios. Therefore, in Figure 3 - 18 the present value system cost of the least cost resource strategies for the scenarios that do not assume that either carbon dioxide regulatory cost risk or damage cost are the same with and without consideration of carbon dioxide costs. For example, the average system cost for the **Low Gas Price and Existing Policy** scenarios are the same with or without considering carbon dioxide revenues.

Figure 3 - 18: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Cost



Inspection of Figure 3 - 18 shows that, exclusive of carbon dioxide costs, the average net present value system cost for the least cost resource strategies across several of the scenarios are quite similar.

Table 3 - 4 shows that only four scenarios, the **Maximum Carbon Reduction - Existing Technology**, **Increased Market Reliance, Lower Conservation**, and **RPS at 35 percent** scenarios, have average system costs that differ significantly from the **Existing Policy** scenario. This is due to the fact that with the exception of these four scenarios, the least cost resource strategies across the other scenarios are similar.

The **Maximum Carbon Reduction – Existing Technology** scenario differs from the others because it assumes that all of the coal plants that serve the region are retired as well as existing gas generation with heat rates over 8,500 Btu/kilowatt-hour. As a result, the present value system cost is significantly increased by the capital investment needed in replacement resources, largely new combined-cycle combustion turbines. The least cost resource strategy under the **Lower Conservation** scenario develops about 1200 average megawatts less energy savings and 2900 megawatts less of winter peak capacity from energy efficiency by 2035 than the **Existing Policy** scenario. As a result, its average system cost is nearly $14 billion higher because it must substitute more expensive generating resources to meet the region’s needs for both capacity and energy.

Under the **Renewable Portfolio Standard at 35 percent** scenario, the increase in average present value system cost stems from the investment needed to develop a significant quantity of additional wind and solar generation in the region to satisfy the higher standard. The average present value system cost for the least cost resource strategy under the **Increased Market Reliance** scenario is lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs.

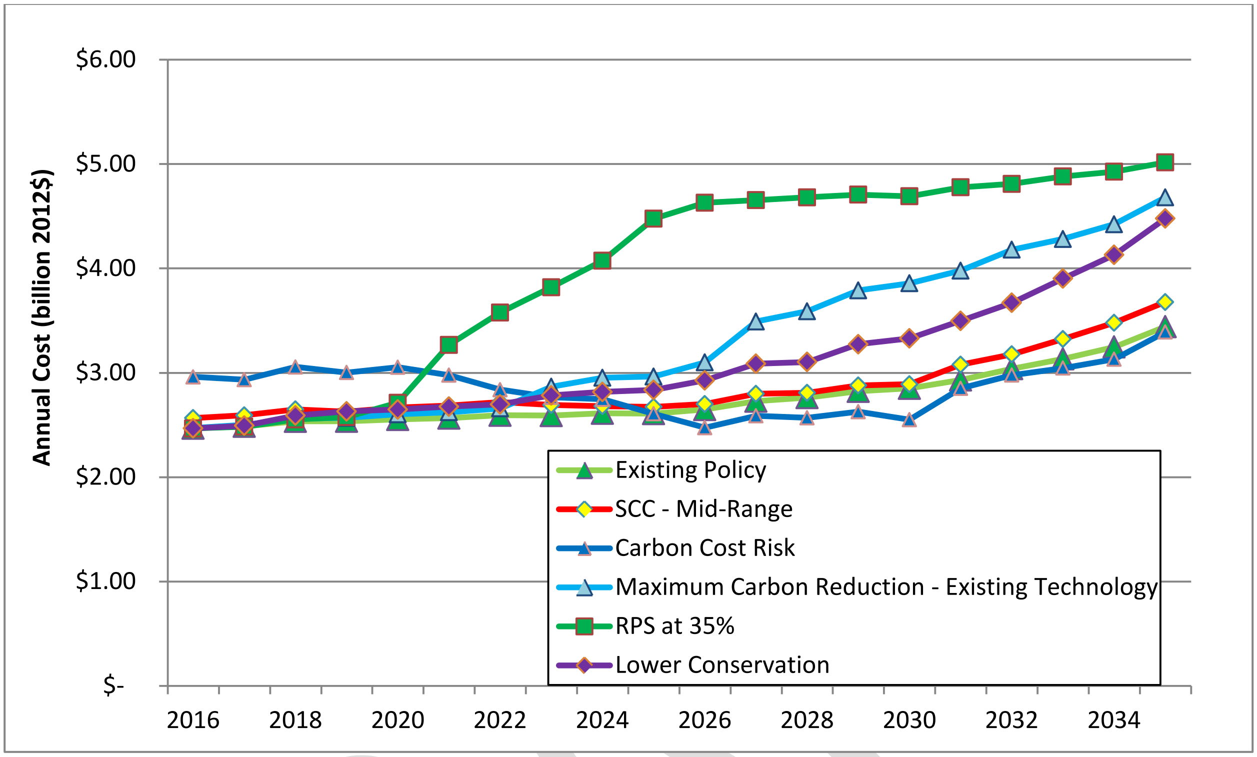
Table 3 - 4: Average Net Present Value System Cost without Carbon Dioxide Revenues and Incremental Cost Over Existing Policy Scenario

Scenario	Present Value System Cost of Resource Strategy (billion 2012$)	Incremental Present Value System Cost Over Existing Policy Scenario Resource Strategy (billion 2012$)
Existing Policy	$88	
Social Cost of Carbon - Base	$89	$0.8
Social Cost of Carbon - High	$90	$1.5
Carbon Cost Risk	$89	$0.7
Maximum Carbon Reduction – Existing Technology	$107	$19.1
Unplanned Loss of Major Resource	$91	$2.8
Planned Loss of Major Resource	$91	$2.5
Faster Conservation Deployment	$89	$0.8
Slower Conservation Deployment	$89	$0.6
Increased Market Reliance	$85	($2.7)
RPS at 35%	$122	$33.9
Lower Conservation	$102	$13.8

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Four of the scenarios assume no carbon dioxide regulatory compliance cost or damage costs**: Existing Policy, Maximum Carbon Reduction - Existing Technology, Lower Conservation** and **Renewable Portfolio Standards at 35 Percent** so their forward going costs are identical with and without carbon dioxide cost. In order to compare the direct cost of the actual resource strategies resulting from carbon dioxide pricing policies with these four scenarios it is necessary to remove the carbon dioxide cost from those other scenarios. Figure 3 - 20 shows the power system cost over the forecast period for the least cost resource strategy, excluding carbon dioxide costs.

Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2016 value in Figure 3 - 19 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions. The cost shown for the two **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario do not include the cost of carbon dioxide regulation or carbon dioxide damage.

Figure 3 - 19: Annual Forward-Going Power System Costs, Excluding Carbon Dioxide Revenues

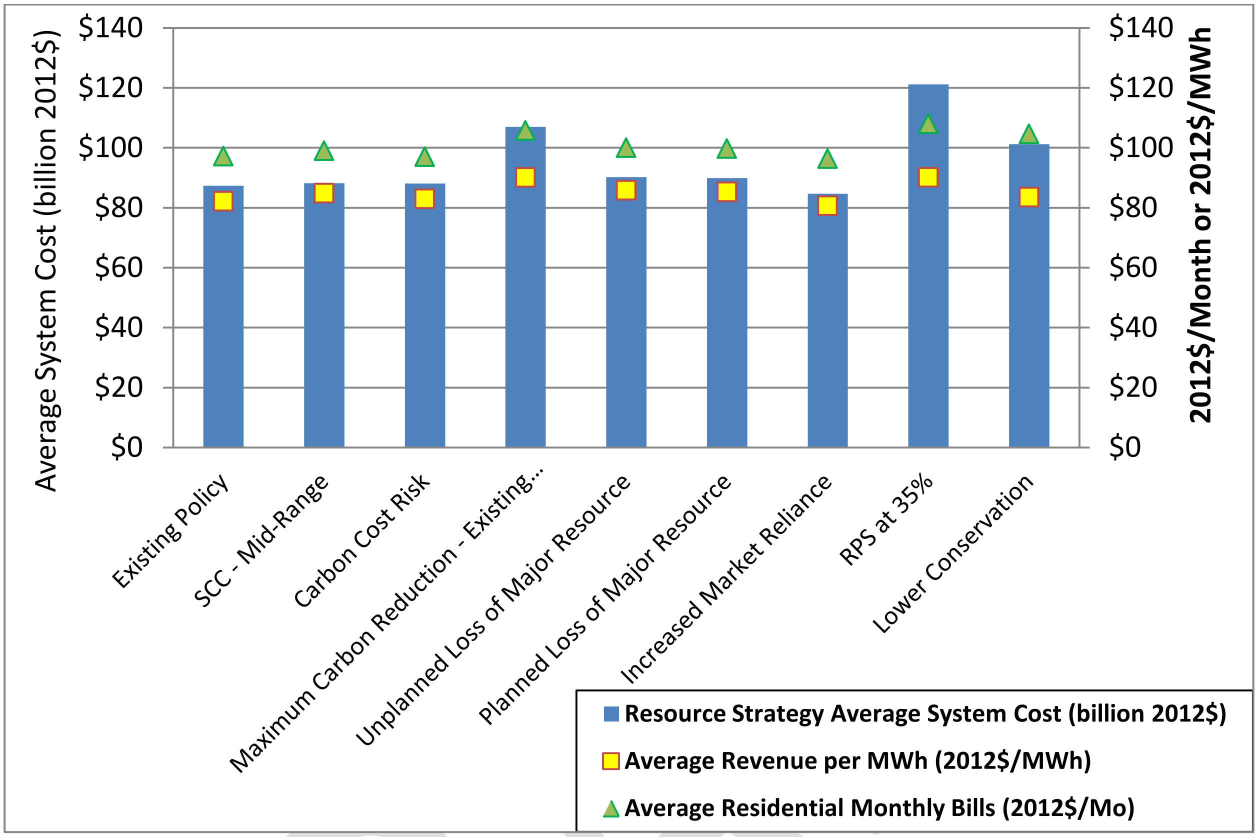


A review of Figure 3 - 19 shows that the **Carbon Cost Risk** resource strategy has a slightly lower annual cost post-2026 than the **Existing Policy** scenario. The **Lower Conservation** resource strategy shows higher annual system cost than all but two other resource strategies, the **RPS at 35 percent** and **Maximum Carbon Reduction - Existing Technology** least cost resource strategies. The highest forward going revenue requirement is the **RPS at 35 percent**. This strategy's high cost is due to not only to the high cost of renewable resources, but the cost of thermal resources that must still be added to the system to ensure winter peak needs are met.

In the following section of this chapter these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects of some of the scenarios.

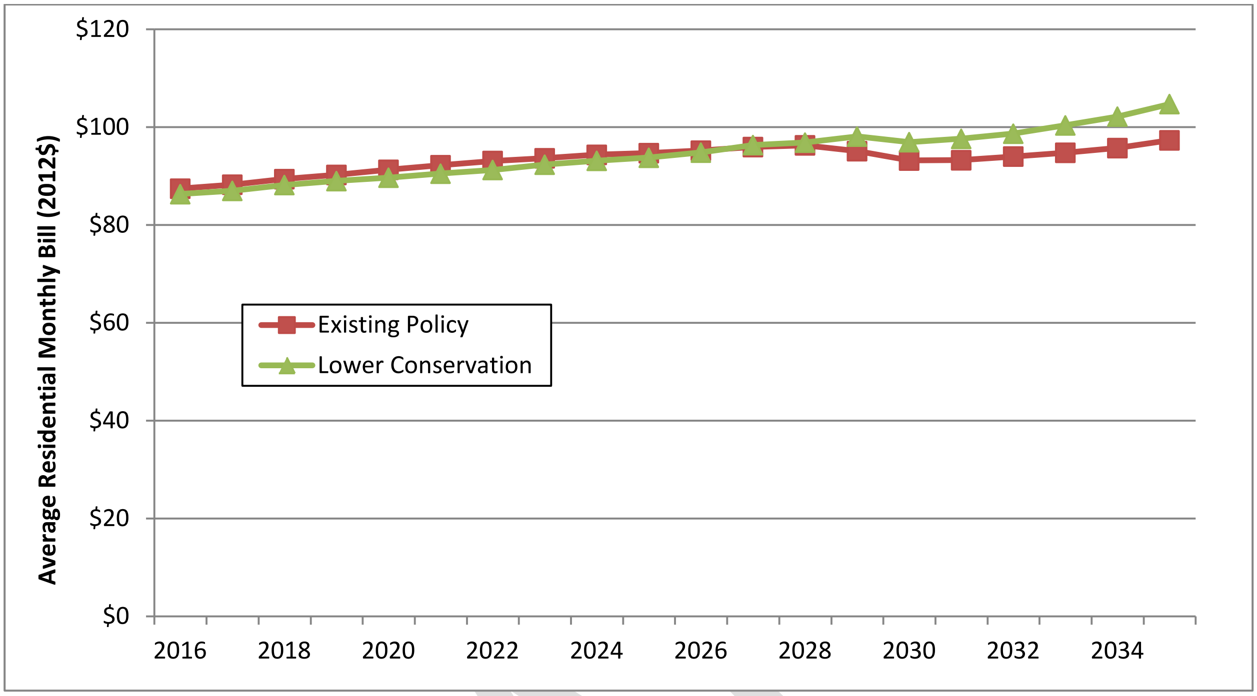
Figure 3 - 20 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 3 - 20 are average revenue requirement per megawatt-hour which include both monthly fixed charges and monthly energy consumption charges. The residential bills are typical monthly bills. In order to compare these scenarios over the period covered by the Seventh Power Plan, both the average revenue requirement per megawatt-hour and average monthly bills have been levelized over the twenty year planning period. Both are expressed in constant 2012 dollars.

Figure 3 - 20: System Costs, Rates, and Monthly Bills, Excluding Carbon Dioxide Revenues



As can be seen in Figure 3 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the lower-conservation scenario. The **Lower Conservation** scenario has an average system cost of $102 billion, compared to the **Existing Policy** resource strategy's $88 billion. Even with nearly a $14 billion higher average system cost the **Lower Conservation** resource strategy and the **Existing Policy** scenario have nearly equal average revenue requirement per megawatt-hour, with $82 per megawatt-hour for the **Existing Policy** scenario and $84 per megawatt-hour for the **Lower Conservation** scenario. However, **the Lower Conservation** scenario's average monthly bill is about $105, about $6 per month higher than **the Existing Policy** scenario's average monthly bill of $99. This illustrates how system cost can increase with lower conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 3 - 21 illustrates how the greater efficiency improvements lower average electricity bills.

Figure 3 - 21: Residential Electricity Bills With and Without Lower Conservation



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Royal Dutch Shell plc: 4th Quarter and Full Year 2015 Unaudited Results

THE HAGUE, The Netherlands, February 4, 2016 /PRNewswire/ --

- Royal Dutch Shell's (NYSE: RDS.A (http://studio-5.financialcontent.com/prnews?Page=Quote&Ticker=RDS.A))(NYSE: RDS.B (http://studio-5.financialcontent.com/prnews?Page=Quote&Ticker=RDS.B)) fourth quarter 2015 earnings, on a current cost of supplies (CCS) basis (see Note [2]), were $1.8 billion compared with $4.2 billion for the same quarter a year ago. Full year 2015 CCS earnings were $3.8 billion compared with $19.0 billion in 2014.
- Fourth quarter 2015 CCS earnings excluding identified items (see page 5) were $1.8 billion compared with $3.3 billion for the fourth quarter of 2014, a decrease of 44%. Fourth quarter 2015 earnings were positively impacted by non-cash net gains of some $0.3 billion related to currency exchange rate effects on deferred tax positions. Full year 2015 CCS earnings excluding identified items were $10.7 billion compared with $22.6 billion in 2014.
- Compared with the fourth quarter 2014, CCS earnings excluding identified items benefited from continued strong Downstream results reflecting steps taken by the company to improve financial performance. In Upstream, earnings were impacted by the significant decline in oil and gas prices, partly offset by lower costs. Contributions from integrated gas were higher mainly as a result of improved trading performance and the effect of the strengthening of the Australian dollar on deferred tax positions.
- Fourth quarter 2015 basic CCS earnings per share excluding identified items decreased by 44% versus the fourth quarter 2014. Full year 2015 basic CCS earnings per share excluding identified items decreased by 53% versus 2014.
- Total dividends distributed to Royal Dutch Shell plc shareholders in the quarter were $3.0 billion, of which $1.2 billion were settled under the Scrip Dividend Programme. No shares were bought back during the fourth quarter.
- Gearing at the end of 2015 was 14.0% compared with 12.2% at the end of 2014.
- A fourth quarter 2015 dividend has been announced of $0.47 per ordinary share and $0.94 per American Depositary Share ("ADS").
- Royal Dutch Shell is expected to announce a dividend of $0.47 per ordinary share and $0.94 per

ADS in respect of the first quarter 2016.

SUMMARY OF UNAUDITED RESULTS

Quarters				$ million	Full year		
Q4 2015	Q3 2015	Q4 2014	%[1]		2015	2014	%
939	(7,416)	595	+58	Income/(loss) attributable to Royal Dutch Shell plc shareholders	1,939	14,874	-87
901	1,296	3,568		Current cost of supplies (CCS) adjustment for Downstream	1,903	4,167	
1,840	(6,120)	4,163	-56	CCS earnings	3,842	19,041	-80
15	(7,890)	901		Identified items[2]	(6,834)	(3,521)	
1,825	1,770	3,262	-44	CCS earnings excluding identified items	10,676	22,562	-53
				Of which:			
493	(425)	1,730		Upstream	1,780	16,505	
1,524	2,617	1,550		Downstream	9,748	6,265	
(192)	(422)	(18)		Corporate and Non-controlling interest	(852)	(208)	
5,423	11,231	9,608	-44	Cash flow from operating activities	29,810	45,044	-34
0.29	(0.97)	0.66	-56	Basic CCS earnings per share ($)	0.61	3.02	-80
0.58	(1.94)	1.32		Basic CCS earnings per ADS ($)	1.22	6.04	
0.29	0.28	0.52	-44	Basic CCS earnings per share excl. identified items ($)	1.69	3.57	-53
0.58	0.56	1.04		Basic CCS earnings per ADS excl. identified items ($)	3.38	7.14	
0.47	0.47	0.47	-	Dividend per share ($)	1.88	1.88	-
0.94	0.94	0.94		Dividend per ADS ($)	3.76	3.76	

[1] Q4 on Q4 change

[2] See page 5

Royal Dutch Shell Chief Executive Officer Ben van Beurden commented: "The completion of the BG transaction, which we are expecting in a matter of weeks, marks the start of a new chapter in Shell, rejuvenating the company, and improving shareholder returns.

We are making substantial changes in the company, reorganising our Upstream, and reducing costs and capital investment, as we refocus Shell, and respond to lower oil prices. As we have previously indicated, this will include a reduction of some 10,000 staff and direct contractor positions in 2015-16 across both companies.

In 2015, we significantly curtailed spending by reducing the number of new investment decisions and designing lower-cost development solutions. For 2016, we have exited the Bab sour gas project in Abu Dhabi, and are postponing final investment decisions on LNG Canada and Bonga South West in deep water Nigeria. Operating costs and capital investment have been reduced by a total of $12.5 billion as compared to 2014, and we expect further reductions in 2016.

As a result of our actions in 2015, we have retained a strong balance sheet position, with 14% gearing. Shell will take further impactful decisions to manage through the oil price downturn, should conditions warrant that. Shell's dividends for 2015 were $1.88 per share, and are expected to be at least $1.88 per share in 2016, as previously announced."

FOURTH QUARTER 2015 PORTFOLIO DEVELOPMENTS

Upstream

During the quarter in Canada, Shell announced the start of commercial operations at the Quest carbon capture and storage project. Quest will capture one-third of the emissions from Shell's Scotford Upgrader, which turns oil sand bitumen into synthetic crude that can be refined into fuel and other products. The carbon dioxide ("CO2") is then transported through a pipeline and injected more than two kilometres underground below multiple layers of impermeable rock formations. Quest is designed to capture and safely store more than one million tonnes of CO2 each year.

In Ireland, Shell announced first production from the Corrib gas field (Shell interest 45%). At peak annual production, the Corrib gas field is expected to produce 45 thousand barrels of oil equivalent per day ("boe/d").

Shell started up the gas injection facilities at the Shell-operated Gumusut-Kakap deep-water development (Shell interest 33%) in Malaysia. This follows first oil production, achieved in the fourth quarter 2014.

In New Zealand, Shell agreed to sell its interest in the Maui natural gas pipeline (Shell interest 83.75%) to First State Investments for a consideration of NZD 335 million (around USD 200 million). The transaction, subject to regulatory approval, is expected to complete in 2016.

In Nigeria, Shell Nigeria Exploration and Production Company Ltd announced first production from the Bonga Phase 3 project (Shell interest 55%). Bonga Phase 3 is an expansion of the Bonga Main development, with peak production expected to be some 50 thousand boe/d. The oil will be transported through existing pipelines to the Bonga floating production, storage and offloading facility.

Also in Nigeria, Shell completed the sale of its 30% interest in Oil Mining Lease ("OML") 71 and OML 72 to West African Exploration and Production Company Limited, as part of its ongoing portfolio review and optimisation. Both of these blocks were non-producing.

In Shell's exploration programme there was one successful non-operated oil discovery with the Beryl K well (Shell interest 45%) in the United Kingdom.

Shell had continued success with near-field exploration discoveries in Brunei, the Netherlands, and Oman.

In January, Shell announced that after careful and thorough evaluation of technical challenges, it has decided to exit the joint development of the Bab sour gas reservoirs (Shell interest 40%) with ADNOC in the emirate of Abu Dhabi, United Arab Emirates, and to stop further joint work on the project. The evaluation concluded that for Shell, the development of the project does not fit with the company's strategy, particularly in the economic climate prevailing in the energy industry.

Upstream divestment proceeds totalled some $0.3 billion for the fourth quarter 2015.

Downstream

During the quarter, Shell announced that it reached final investment decision ("FID") on a project to increase alpha olefins production at its chemical manufacturing site in Geismar, Louisiana. Shell will construct a fourth alpha olefins unit, adding 425 thousand tonnes of capacity. This project will make the site the largest alpha olefins producer in the world.

Shell also announced FID on a project to build a major new unit at the Pernis refinery in Rotterdam, the Netherlands. The solvent deasphalter unit will remove heavier fractions from crude oil, allowing the refinery to upgrade a larger proportion of its oil intake into lighter, high-grade products. Construction work is planned to start in 2016, subject to permit approvals, with completion expected by the end of 2018.

In the United Kingdom, Shell completed the sale of 185 service stations across the United Kingdom to independent dealers. All 185 service stations will retain the Shell brand and sell Shell's fuels.

In the United States, Shell completed the sale of an additional 3.7% interest in Shell Midstream Partners, L.P. to public investors via the issuance of an additional 9,200,000 LP units for net proceeds of $297 million.

Downstream divestment proceeds totalled some $1.1 billion for the fourth quarter 2015 and included proceeds from the divestments of the Butagaz LPG business in France, Shell's 75% interest in Tongyi Lubricants in China, the retail, commercial fuels, and supply and distribution logistics businesses in Norway.

KEY FEATURES OF THE FOURTH QUARTER AND FULL YEAR 2015

- Fourth quarter 2015 CCS earnings (see Note [2]) were $1,840 million, 56% lower than for the same quarter a year ago. Full year 2015 CCS earnings were $3,842 million, 80% lower than in 2014
- Fourth quarter 2015 CCS earnings excluding identified items (see page 5) were $1,825 million compared with $3,262 million for the fourth quarter 2014, a decrease of 44%. Fourth quarter 2015 CCS earnings excluding identified items benefited from continued strong Downstream results reflecting steps taken by the company to improve financial performance. In Upstream, earnings were impacted by the significant decline in oil and gas prices, partly offset by lower costs. Contributions from integrated gas were higher mainly as a result of improved trading performance and the effect of the strengthening of the Australian dollar on deferred tax positions.
  Full year 2015 CCS earnings excluding identified items were $10,676 million compared with $22,562 million in 2014, a decrease of 53%.
- Basic CCS earnings per share for the fourth quarter 2015 decreased by 56% versus the same quarter a year ago. Full year 2015 basic CCS earnings per share decreased by 80% versus 2014.
- Basic CCS earnings per share excluding identified items for the fourth quarter 2015 decreased by 44% versus the same quarter a year ago. Full year 2015 basic CCS earnings per share excluding identified items decreased by 53% versus 2014.
- Cash flow from operating activities for the fourth quarter 2015 was $5.4 billion, compared with $9.6 billion for the same quarter last year. Excluding working capital movements, cash flow from operating activities for the fourth quarter 2015 was $3.8 billion, compared with $3.5 billion for the same quarter last year.
  Full year 2015 cash flow from operating activities was $29.8 billion, compared with $45.0 billion in 2014. Excluding working capital movements, cash flow from operating activities for the full year 2015 was $24.3 billion, compared with $38.6 billion in 2014
- Capital investment (see Note [B]) for the fourth quarter 2015 was $7.9 billion and divestments (see Note [C]) were $1.7 billion.
  Full year 2015 capital investment was $28.9 billion, $8.4 billion lower than in 2014. This was delivered by efficiency improvements and more selectivity on new investments. Capital investment for Shell and BG combined for the full year 2016 is expected to be $33 billion, down some 45% from combined spending, which peaked in 2013. Flexibility for further reductions is available and will be utilised should conditions warrant this. Full year 2015 divestments were $5.5 billion, of which proceeds from the sales of interests in Shell Midstream Partners, L.P. were $0.6 billion.
- Operating costs (see Note [F]) for the full year 2015 decreased by $4.1 billion, to $41.1 billion, and Shell's costs are expected to fall again in 2016, by a further $3 billion. This is some 15% lower than 2014 levels. Synergies from the BG combination will be in addition to that.
- Total dividends distributed to Royal Dutch Shell plc shareholders in the fourth quarter 2015 were $3.0 billion, of which $1.2 billion were settled by issuing some 49.0 million A shares under the Scrip Dividend Programme. Total dividends distributed in the full year 2015 were $12.0 billion, of which $2.6 billion were settled by issuing some 96.3 million A shares under the Scrip Dividend

Programme.

- Under our share buyback programme during the full year 2015, some 12.7 million shares were bought back for cancellation for a consideration of $0.4 billion. No shares were bought back during the fourth quarter.
- Return on average capital employed on a reported income basis (see Note [D]) was 1.9% at the end of 2015 compared with 7.1% at the end of 2014.
- Gearing (see Note [E]) was 14.0% at the end of 2015 versus 12.2% at the end of 2014.
- Oil and gas production for the fourth quarter 2015 was 3,039 thousand boe/d, a decrease of 5% compared with the fourth quarter 2014. Fourth quarter 2015 production was in line with the same period last year excluding the impact of divestments, curtailment and underground storage reinjection at NAM in the Netherlands, a Malaysia PSC expiry, PSC price effects, and security impacts in Nigeria.

  Full year 2015 oil and gas production was 2,954 thousand boe/d, a decrease of 4% compared with 2014. Full year 2015 production volumes increased by 1% compared with 2014, excluding the impact of divestments, curtailment and underground storage reinjection at NAM in the Netherlands, Abu Dhabi licence and Malaysia PSC expiries, PSC price effects, and security impacts in Nigeria.
- Equity sales of LNG of 5.68 million tonnes for the fourth quarter 2015 were 8% lower than for the same quarter a year ago.

  Full year 2015 equity sales of LNG of 22.62 million tonnes were 6% lower than in 2014.
- Oil products sales volumes for the fourth quarter 2015 were 1% lower than for the fourth quarter 2014. Chemicals sales volumes for the fourth quarter 2015 increased by 7% compared with the same quarter a year ago.

  Full year 2015 oil products sales volumes were 1% higher than in 2014. Full year 2015 chemicals sales volumes increased by 1% compared with 2014.
- When the 2015 Annual Report and Form 20-F is filed, the proved reserves reporting will update on Shell's 2015 performance, and will not include reserves from the proposed combination with BG.
- At the end of 2015, total proved reserves on an SEC basis are expected to be 11.7 billion boe, after taking into account 2015 production.

  With 2015 production of 1.1 billion boe, our proved Reserves Replacement Ratio for the year on an SEC basis is expected to be -20%, a total reduction of 1.4 billion boe to our SEC proved reserves. The 3-year average headline proved Reserves Replacement Ratio on an SEC basis is expected to be 48%.

  When final volumes are reported in the 2015 Annual Report and Form 20-F, Shell expects that SEC proved oil and gas reserves will be reduced by 0.2 billion boe, before taking into account production.

  Falling oil prices have reduced Shell’s reserves in 2015. Consistent with our past practise, the impact of changing prices is calculated by replacing the 2014 year average price with the 2015 year average price to determine the potential adjustment to SEC proved reserves at the end of 2014.

Applying this methodology, 1.7 billion of proved reserves would have been excluded from our 2014 SEC proved reserves if the 2015 year average price was used. This adjustment of 1.7 billion boe includes de-booking of 0.4 billion boe of proved reserves at Carmon Creek in Canada, and 0.95 billion boe associated with Muskeg River Mine in Canada. However, due to significant structural cost improvements at the mine in 2015 these 0.95 billion boe are retained in 2015. These barrels are not considered additions for SEC reporting purposes as they were included in our 2014 SEC proved reserves.

Further information will be provided in our 2015 Annual Report and Form 20-F, which is expected to be filed in March 2016.

- Supplementary financial and operational disclosure for the fourth quarter 2015 is available at http://www.shell.com/investor (http://www.shell.com/investor)

SUMMARY OF IDENTIFIED ITEMS

Earnings for the fourth quarter 2015 reflected the following items, which in aggregate amounted to a net gain of $15 million (compared with a net gain of $901 million for the fourth quarter 2014), as summarised in the table below:

- Upstream earnings included a net charge of $826 million, primarily reflecting asset impairments of some $640 million and a net charge on fair value accounting of certain commodity derivatives and gas contracts of some $210 million, partly offset by gains on divestments of some $100 million. Upstream earnings for the fourth quarter 2014 included a net gain of $915 million.
- Downstream earnings included a net gain of $978 million, primarily reflecting gains on divestments of some $995 million and the net positive impact of fair value accounting of commodity derivatives of some $100 million, offset by impairment charges of some $100 million. Downstream earnings for the fourth quarter 2014 included a net charge of $6 million.
- Corporate results and Non-controlling interest included a net charge of $137 million, mainly reflecting a tax provision. Earnings for the fourth quarter 2014 included a net charge of $8 million.

SUMMARY OF IDENTIFIED ITEMS

Quarters			$ million	Full year	
Q4 2015	Q3 2015	Q4 2014		2015	2014
			Segment earnings impact of identified items:		
(826)	(8,218)	915	Upstream	(7,443)	(664)
978	(136)	(6)	Downstream	495	(2,854)
(137)	464	(8)	Corporate and Non-controlling interest	114	(3)
15	(7,890)	901	Earnings impact	(6,834)	(3,521)

These identified items are shown to provide additional insight into segment earnings and income attributable to shareholders. They include the full impact on Shell's CCS earnings of the following items:

- Divestment gains and losses
- Impairments
- Fair value accounting of commodity derivatives and certain gas contracts (see Note [A])
- Redundancy and restructuring

Further items may be identified in addition to the above.

EARNINGS BY BUSINESS SEGMENT

UPSTREAM

Quarters				$ million	Full year		
Q4 2015	Q3 2015	Q4 2014	%[1]		2015	2014	%
493	(425)	1,730	-72	Upstream earnings excluding identified items	1,780	16,505	-89
(333)	(8,643)	2,645	-113	Upstream earnings	(5,663)	15,841	-136
2,916	4,044	4,991	-42	Upstream cash flow from operating activities	13,181	31,839	-59
5,820	5,848	7,511	-23	Upstream capital investment	23,527	31,293	-25
1,532	1,528	1,526	-	Liquids production available for sale (thousand b/d)	1,509	1,484	+2
8,741	7,837	9,782	-11	Natural gas production available for sale (million scf/d)	8,380	9,259	-9
3,039	2,880	3,213	-5	Total production available for sale (thousand boe/d)	2,954	3,080	-4
5.68	5.31	6.20	-8	Equity sales of LNG (million tonnes)	22.62	23.97	-6

[1] Q4 on Q4 change

Fourth quarter Upstream earnings excluding identified items were $493 million compared with $1,730 million a year ago. Identified items were a net charge of $826 million compared with a net gain of $915 million for the fourth quarter 2014 (see page 5).

Compared with the fourth quarter 2014, earnings excluding identified items were impacted by the significant decline in oil and gas prices. This was partly offset by decreased costs and lower exploration expenses, including lower well write-offs, and lower taxation.

Compared with the fourth quarter 2014, earnings benefited from the impact of the strengthening of the Australian dollar and Brazilian real on deferred tax positions, which increased earnings by $553 million and $135 million respectively. The benefit of these deferred tax movements in the fourth quarter 2015 was $257 million after tax, compared with a negative impact of some $431 million after tax in the same period a year ago.

Upstream Americas excluding identified items incurred a loss.

Global liquids realisations were 46% lower than for the fourth quarter 2014. Global natural gas realisations were 33% lower than for the same quarter a year ago, with a 44% decrease in the Americas and a 31% decrease outside the Americas.

Fourth quarter 2015 production was 3,039 thousand boe/d compared with 3,213 thousand boe/d a year ago. Liquids production was in line with the same period a year ago and natural gas production decreased by 11% compared with the fourth quarter 2014. Fourth quarter 2015 production was in line with the same period last year excluding the impact of divestments, curtailment and underground storage reinjection at NAM in the Netherlands, a Malaysia PSC expiry, PSC price effects, and security impacts in Nigeria.

The continuing ramp-up of existing fields, in particular Cardamom and Mars B in the Americas, Bonga Main in Nigeria and Gumusut-Kakap in Malaysia, contributed some 88 thousand boe/d to production compared with the fourth quarter 2014.

Equity LNG sales volumes of 5.68 million tonnes decreased by 8% compared with the same quarter a year ago, mainly reflecting the expiry of the Malaysia LNG Dua JVA.

Full year Upstream earnings excluding identified items were $1,780 million compared with $16,505 million in 2014. Identified items were a net charge of $7,443 million, compared with a net charge of $664 million in 2014 (see page 5 (http://www.prnewswire.com/news-releases/)).

Compared with 2014, Upstream earnings excluding identified items were impacted by the significant decline in oil and gas prices. Earnings benefited from lower costs including favourable exchange rate effects and divestments, and decreased depreciation.

Compared with 2014, the impact of the weakening of the Australian dollar and Brazilian real on deferred tax positions reduced earnings by $131 million and $311 million respectively. The impact of these deferred tax movements in the full year 2015 was $1,022 million after tax, compared with an impact of $580 million after tax in 2014.

Global liquids realisations were 48% lower than in 2014. Global natural gas realisations were 27% lower than in 2014, with a 47% decrease in the Americas and a 24% decrease outside the Americas.

Full year 2015 production was 2,954 thousand boe/d compared with 3,080 thousand boe/d in 2014. Liquids production increased by 2 (http://www.prnewswire.com/news-releases/DLRTAB!PCT_CYQ_VP)% and natural gas production decreased by 9% compared with 2014. Production volumes in 2015 increased by 1%, compared with 2014, excluding the impact of divestments, curtailment and underground storage reinjection at NAM in the Netherlands, Abu Dhabi license and Malaysia PSC expiries, PSC price effects, and security impacts in Nigeria.

New field start-ups and the continuing ramp-up of existing fields, in particular Cardamom and Mars B in the Americas and Bonga NW in Nigeria, contributed some 117 thousand boe/d to production in 2015, which more than offset the impact of field declines.

Equity LNG sales volumes of 22.62 million tonnes were 6% lower than in 2014, mainly reflecting the expiry of the Malaysia LNG Dua JVA, the Woodside divestment and increased maintenance activities.

DOWNSTREAM

Quarters				$ million	Full year		
Q4 2015	Q3 2015	Q4 2014	%[1]		2015	2014	%
1,524	2,617	1,550	-2	Downstream CCS earnings excluding identified items	9,748	6,265	+56
2,502	2,481	1,544	+62	Downstream CCS earnings	10,243	3,411	+200
2,101	6,605	4,698	-55	Downstream cash flow from operating activities	14,076	11,292	+25
1,974	1,211	2,098	-6	Downstream capital investment	5,119	5,910	-13
2,630	2,776	2,718	-3	Refinery processing intake (thousand b/d)	2,805	2,903	-3
6,297	6,586	6,392	-1	Oil products sales volumes (thousand b/d)	6,432	6,365	+1
4,178	4,452	3,895	+7	Chemicals sales volumes (thousand tonnes)	17,148	17,008	+1

[1] Q4 on Q4 change

Fourth quarter Downstream earnings excluding identified items were $1,524 million compared with $1,550 million for the fourth quarter 2014. Identified items were a net gain of $978 million, compared with a net charge of $6 (http://www.prnewswire.com/news-releases/PQ_US_IIDS) million for the fourth quarter 2014 (see page 5).

Compared with the fourth quarter 2014, Downstream earnings excluding identified items benefited from improved refining industry conditions. Earnings also benefited from lower costs including favourable exchange rate effects, and lower taxation. Earnings were impacted by lower results from marketing, largely as a result of negative exchange rate effects, and decreased contributions from trading and supply. Contributions from Chemicals decreased mainly as a result of weaker base chemicals and intermediates industry conditions.

Refinery intake volumes were 3% lower compared with the same quarter last year. Refinery availability was 83%, compared with 95% for the fourth quarter 2014, mainly as a result of increased maintenance.

Oil products sales volumes decreased by 1% compared with the same period a year ago, mainly reflecting lower trading volumes.

Chemicals sales volumes increased by 7% compared with the same quarter last year. Chemicals manufacturing plant availability increased to 81% from 65% for the fourth quarter 2014, reflecting recovery at the Moerdijk chemical site in the Netherlands, partly offset by increased maintenance activities.

Full year Downstream earnings excluding identified items were $9,748 million compared with $6,265 million in 2014. Identified items were a net gain of $495 million, compared with a net charge of $2,854 million in 2014 (see page 5 (http://www.prnewswire.com/news-releases/)).

Compared with 2014, Downstream earnings excluding identified items benefited from higher realised refining margins, reflecting the industry environment, lower costs including the impact of favourable exchange rate effects and divestments, and lower taxation. Contributions from marketing were impacted by negative exchange rate effects, with strong underlying performance. Contributions from Chemicals increased, reflecting improved industry conditions for intermediates and for base chemicals in Asia, partly offset by unit shut-downs at the Moerdijk chemical site in the Netherlands.

Refinery intake volumes were 3% lower compared with 2014. Excluding portfolio impacts, refinery intake volumes were 1% lower than in 2014. Refinery availability was 90%, compared with 93% in 2014.

Oil products sales volumes increased by 1% compared with 2014, mainly reflecting higher trading volumes.

Chemicals sales volumes increased by 1% compared with 2014, primarily driven by increased demand in Asia and overall improved intermediates market conditions. Chemicals manufacturing plant availability was 85%, in line with 2014.

CORPORATE AND NON-CONTROLLING INTEREST

Quarters			$ million	Full year	
Q4 2015	Q3 2015	Q4 2014		2015	2014
(192)	(422)	(18)	Corporate and Non-controlling interest excl. identified items	(852)	(208)
			Of which:		
(158)	(355)	(24)	Corporate	(536)	(153)
(34)	(67)	6	Non-controlling interest	(316)	(55)
(329)	42	(26)	Corporate and Non-controlling interest	(738)	(211)

Fourth quarter Corporate results and Non-controlling interest excluding identified items were a loss of $192 million, compared with a loss of $18 million for the same period last year. Identified items for the fourth quarter 2015 were a net charge of $137 million, whereas earnings for the fourth quarter 2014 included a net charge of $8 million (see page 5 (http://www.prnewswire.com/news-releases/)).

Compared with the fourth quarter 2014, Corporate results excluding identified items mainly reflected lower tax credits and higher net interest expense, partly offset by favourable exchange rate effects.

Compared with the fourth quarter 2014, earnings were negatively impacted by the strengthening Brazilian real on deferred tax positions related to financing of the Upstream business by $84 million. The impact of this on the fourth quarter 2015 earnings excluding identified items was a charge of $4 million after tax, compared with an $80 million gain in the same period a year ago.

Full year Corporate results and Non-controlling interest excluding identified items were a loss of $852 million compared with a loss of $208 million in 2014. Identified items for 2015 were a net gain of $114 million, whereas earnings for 2014 included a net charge of $3 million (see page 5).

Compared with 2014, Corporate results excluding identified items mainly reflected adverse currency exchange rate effects, partly offset by higher tax credits.

Compared with 2014, earnings benefited from the impact of the weakening Brazilian real on deferred tax positions related to financing of the Upstream business by $160 million. The impact of this on the full year 2015 earnings excluding identified items was a gain of $252 million after tax, compared with a gain of $92 million in 2014.

OPERATIONAL OUTLOOK FOR THE FIRST QUARTER 2016

The following information reflects Shell's asset base as of December 31, 2015.

Compared with the first quarter 2015, Upstream earnings are expected to be impacted by some 40 thousand boe/d associated with the impact of curtailment and underground storage utilisation at NAM, some 20 thousand boe/d related to a Malaysia PSC expiry, and some 15 thousand boe/d as a result of divestments. The impact of maintenance is expected to be lower by some 30 thousand boe/d. In Qatar, the Pearl GTL plant will undergo planned maintenance starting in March and continuing into the second quarter 2016.

Refinery availability is expected to decline in the first quarter 2016 as a result of higher turnaround activity and increased maintenance compared with the same period a year ago. Unit shutdowns at the Bukom chemical site in Singapore are expected to result in similar Chemicals manufacturing plant availability as in the first quarter 2015, which was heavily impacted by unit shutdowns at the Moerdijk chemical site in the Netherlands.

Upon the successful completion of the recommended combination with BG which it is expected on February 15, 2016, Shell's consolidated financial results will include BG's financial performance and the fair values of its assets and liabilities.

FORTHCOMING EVENTS

First quarter 2016 results and first quarter 2016 dividend are scheduled to be announced on May 4, 2016. Second quarter 2016 results and second quarter 2016 dividend are scheduled to be announced on July 28, 2016. Third quarter 2016 results and third quarter 2016 dividend are scheduled to be announced on October 27, 2016.

Shell's Capital Markets Day will be held on June 7, 2016 in London, United Kingdom.

PROFIT ESTIMATES

Certain statements set out in the update on fourth quarter 2015 and full year unaudited results and related supplementary prospectus published by Shell on January 20, 2016 represented profit estimates under the UK City Code on Takeovers and Mergers. The profit estimates relating to the fourth quarter ended December 31, 2015 have been confirmed by the fourth quarter results set out in this announcement and the profit estimates relating to the full year ended December 31, 2015 have been superseded by the publication of the unaudited full year results set out in this announcement.

UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF INCOME

Q4 2015	Q3 2015	Q4 2014	%[1]	$ million	2015	2014	%
Quarters					Full year		
58,146	68,706	92,374		Revenue	264,960	421,105	
793	193	818		Share of profit of joint ventures and associates	3,527	6,116	
1,237	285	974		Interest and other income	3,669	4,123	
60,176	69,184	94,166		Total revenue and other income	272,156	431,344	
43,166	51,612	73,640		Purchases	194,644	327,278	
7,515	7,419	7,465		Production and manufacturing expenses	28,095	30,038	
3,090	2,896	3,426		Selling, distribution and administrative expenses	11,956	13,965	
297	291	363		Research and development	1,093	1,222	
549	3,406	1,323		Exploration	5,719	4,224	
5,281	12,156	4,991		Depreciation, depletion and amortisation	26,714	24,499	
519	527	430		Interest expense	1,888	1,804	
(241)	(9,123)	2,528	-110	Income/(loss) before taxation	2,047	28,314	-93
(1,183)	(1,730)	2,110		Taxation	(153)	13,584	
942	(7,393)	418	+125	Income/(loss) for the period	2,200	14,730	-85
3	23	(177)		Income/(loss) attributable to non-controlling interest	261	(144)	
939	(7,416)	595	+58	Income/(loss) attributable to Royal Dutch Shell plc shareholders	1,939	14,874	-87

[1] Q4 on Q4 change

EARNINGS PER SHARE

Quarters			$	Full year	
Q4 2015	Q3 2015	Q4 2014		2015	2014
0.15	(1.17)	0.09	Basic earnings per share	0.31	2.36
0.15	(1.16)	0.09	Diluted earnings per share	0.30	2.36

SHARES[1]

Quarters			Millions	Full year	
Q4 2015	Q3 2015	Q4 2014		2015	2014
			Weighted average number of shares as the basis for:		
6,356.0	6,327.7	6,301.0	Basic earnings per share	6,320.3	6,311.5
6,416.1	6,396.9	6,301.1	Diluted earnings per share	6,393.8	6,311.6
6,397.5	6,348.4	6,295.0	Shares outstanding at the end of the period	6,397.5	6,295.0

[1] Royal Dutch Shell plc ordinary shares of EUR0.07 each

Notes 1 to 6 are an integral part of these unaudited Condensed Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Q4 2015	Q3 2015	Q4 2014	$ million	2015	2014
Quarters				Full year	
942	(7,393)	418	Income/(loss) for the period	2,200	14,730
			Other comprehensive income net of tax:		
			Items that may be reclassified to income in later periods:		
(1,249)	(3,341)	(2,398)	- Currency translation differences	(7,121)	(5,321)
(119)	(324)	(560)	- Unrealised gains/(losses) on securities	(707)	(797)
(202)	139	537	- Cash flow hedging gains/(losses)	61	528
(41)	19	(86)	- Share of other comprehensive income/(loss) of joint ventures and associates	(40)	(156)
(1,611)	(3,507)	(2,507)	Total	(7,807)	(5,746)
			Items that are not reclassified to income in later periods:		
3,140	(2,369)	(3,011)	- Retirement benefits remeasurements	4,951	(6,482)
1,529	(5,876)	(5,518)	Other comprehensive income/(loss) for the period	(2,856)	(12,228)
2,471	(13,269)	(5,100)	Comprehensive income/(loss) for the period	(656)	2,502
(16)	(53)	(163)	Comprehensive income/(loss) attributable to non-controlling interest	155	(190)
2,487	(13,216)	(4,937)	Comprehensive income/(loss) attributable to Royal Dutch Shell plc shareholders	(811)	2,692

Notes 1 to 6 are an integral part of these unaudited Condensed Consolidated Financial Statements.

CONDENSED CONSOLIDATED BALANCE SHEET

	$ million		
	Dec 31, 2015	Sep 30, 2015	Dec 31, 2014
Assets			
Non-current assets:			
Intangible assets	6,283	6,300	7,076
Property, plant and equipment	182,838	181,681	192,472
Joint ventures and associates	30,150	30,940	31,558
Investments in securities	3,416	3,573	4,115
Deferred tax[1]	11,033	10,258	8,131
Retirement benefits	4,362	2,366	1,682
Trade and other receivables	8,717	8,331	8,304
	246,799	243,449	253,338
Current assets:			
Inventories	15,822	19,276	19,701
Trade and other receivables	45,784	49,130	58,470
Cash and cash equivalents	31,752	31,846	21,607
	93,358	100,252	99,778
Total assets	340,157	343,701	353,116
Liabilities			
Non-current liabilities:			
Debt	52,849	50,438	38,332
Trade and other payables	4,528	4,510	3,582
Deferred tax[1]	8,976	9,935	12,052
Retirement benefits	12,587	14,557	16,318
Decommissioning and other provisions	26,148	25,110	23,834
	105,088	104,550	94,118
Current liabilities:			
Debt	5,530	5,149	7,208
Trade and other payables	52,770	55,230	64,864
Taxes payable	8,233	10,378	9,797
Retirement benefits	350	359	377
Decommissioning and other provisions	4,065	5,553	3,966
	70,948	76,669	86,212
Total liabilities	176,036	181,219	180,330
Equity attributable to Royal Dutch			

Shell plc shareholders	162,876	161,348	171,966
Non-controlling interest	1,245	1,134	820
Total equity	164,121	162,482	172,786
Total liabilities and equity	340,157	343,701	353,116

[1] Deferred tax assets increased and deferred tax liabilities decreased in 2015 primarily as a result of the impairments described in Note 2.

Notes 1 to 6 are an integral part of these unaudited Condensed Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

$ million	Share capital	Shares held in trust	Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
	Equity attributable to Royal Dutch Shell plc shareholders						
At January 1, 2015	540	(1,190)	(14,365)	186,981	171,966	820	172,786
Comprehensive income/(loss) for the period	-	-	(2,750)	1,939	(811)	155	(656)
Capital contributions from, and other changes in, non-controlling interest	-	-	-	501	501	387	888
Dividends paid	-	-	-	(11,972)	(11,972)	(117)	(12,089)
Scrip dividends[1]	7	-	(7)	2,602	2,602	-	2,602
Repurchases of shares[2]	(1)	-	1	1	1	-	1
Shares held in trust: net sales and dividends received	-	606	-	70	676	-	676
Share-based compensation	-	-	(65)	(22)	(87)	-	(87)
At December 31, 2015	546	(584)	(17,186)	180,100	162,876	1,245	164,121
At January 1, 2014	542	(1,932)	(2,037)	183,474	180,047	1,101	181,148
Comprehensive income/(loss) for the period	-	-	(12,182)	14,874	2,692	(190)	2,502
Capital contributions from, and other changes in,							

non-controlling interest	-	-	-	727	727	25	752
Dividends paid	-	-	-	(11,843)	(11,843)	(116)	(11,959)
Scrip dividends[1]	6	-	(6)	2,399	2,399	-	2,399
Repurchases of shares	(8)	-	8	(2,787)	(2,787)	-	(2,787)
Shares held in trust: net sales and dividends received	-	742	-	107	849	-	849
Share-based compensation	-	-	(148)	30	(118)	-	(118)
At December 31, 2014	540	(1,190)	(14,365)	186,981	171,966	820	172,786

[1] Under the Scrip Dividend Programme some 96.3 million A shares, equivalent to $2.6 billion, were issued during 2015 and some 64.6 million A shares, equivalent to $2.4 billion, were issued during 2014.

[2] Share repurchases in January 2015 were offset by repurchase commitments accrued at December 31, 2014. The share buyback programme was suspended in February 2015.

Notes 1 to 6 are an integral part of these unaudited Condensed Consolidated Financial Statements.

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

Quarters			$ million	Full year	
Q4 2015	Q3 2015	Q4 2014		2015	2014
			Cash flow from operating activities		
942	(7,393)	418	Income/(loss) for the period	2,200	14,730
			Adjustment for:		
1,212	1,146	2,330	- Current taxation	7,058	13,757
405	426	375	- Interest expense (net)	1,529	1,598
5,281	12,156	4,991	- Depreciation, depletion and amortisation	26,714	24,499
(1,108)	(493)	(972)	- Net losses/(gains) on sale of non-current assets and businesses	(3,460)	(3,212)
1,598	5,883	6,124	- Decrease/(increase) in working capital	5,521	6,405
(793)	(193)	(818)	- Share of loss/(profit) of joint ventures and associates	(3,527)	(6,116)
1,440	1,039	1,531	- Dividends received from joint ventures and associates	4,627	6,902
(1,827)	(2,407)	(1,705)	- Deferred taxation, retirement benefits, decommissioning and other provisions	(5,827)	(1,720)
(3)	2,302	1,000	- Other[1]	2,648	2,500
7,147	12,466	13,274	Net cash from operating activities (pre-tax)	37,483	59,343
(1,724)	(1,235)	(3,666)	Taxation paid	(7,673)	(14,299)
5,423	11,231	9,608	Net cash from operating activities	29,810	45,044
			Cash flow from investing activities		
(7,299)	(6,412)	(8,831)	Capital expenditure[2]	(26,131)	(31,676)
(5)	(274)	107	Investments in joint ventures and associates	(896)	(1,426)
1,398	913	2,245	Proceeds from sale of property, plant and equipment and businesses	4,720	9,873
26	81	279	Proceeds from sale of joint ventures and associates	276	4,163
91	82	56	Interest received	288	174
(397)	(108)	(536)	Other[2]	(664)	(765)
(6,186)	(5,718)	(6,680)	Net cash used in investing activities	(22,407)	(19,657)
			Cash flow from financing activities		
			Net increase/(decrease) in debt with		

(9)	(1,394)	(173)	maturity period within three months	(586)	(3,332)
5,213	5,490	4,001	Other debt: New borrowings	21,500	7,778
(1,818)	(1,387)	(571)	Repayments	(6,023)	(4,089)
(484)	(532)	(310)	Interest paid	(1,742)	(1,480)
177	2	1,002	Change in non-controlling interest	598	989
			Cash dividends paid to:		
(1,782)	(2,362)	(2,987)	- Royal Dutch Shell plc shareholders	(9,370)	(9,444)
(45)	(27)	(39)	- Non-controlling interest	(117)	(116)
-	-	(971)	Repurchases of shares	(409)	(3,328)
7	(1)	(29)	Shares held in trust: net sales/(purchases) and dividends received	(39)	232
1,259	(211)	(77)	Net cash used in financing activities	3,812	(12,790)
(590)	(437)	(271)	Currency translation differences relating to cash and cash equivalents	(1,070)	(686)
(94)	4,865	2,580	Increase/(decrease) in cash and cash equivalents	10,145	11,911
31,846	26,981	19,027	Cash and cash equivalents at beginning of period	21,607	9,696
31,752	31,846	21,607	Cash and cash equivalents at end of period	31,752	21,607

[1] In 2015, this mainly related to well write-offs.

[2] Reflects a minor change to definition with effect from 2015 which has no overall impact on net cash used in investing activities. Comparative information has been reclassified.

Notes 1 to 6 are an integral part of these unaudited Condensed Consolidated Financial Statements.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of preparation

These unaudited Condensed Consolidated Financial Statements of Royal Dutch Shell plc and its subsidiaries (collectively referred to as Shell) have been prepared in accordance with IAS 34 *Interim Financial Reporting* as adopted by the European Union and as issued by the International Accounting Standards Board and on the basis of the same accounting principles as, and should be read in conjunction with, the Annual Report and Form 20-F for the year ended December 31, 2014 (pages 111 to 116) as filed with the U.S. Securities and Exchange Commission.

The financial information presented in these Condensed Consolidated Financial Statements does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006. Statutory accounts for the year ended December 31, 2014 were published in Shell's Annual Report and a copy was delivered to the Registrar of Companies in England and Wales. The auditors' report on those accounts was unqualified, did not include a reference to any matters to which the auditors drew attention by way of emphasis without qualifying the report and did not contain a statement under sections 498(2) or 498(3) of the Companies Act 2006.

2. Segment information

Segment earnings are presented on a current cost of supplies basis (CCS earnings), which is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts.

Information by business segment:

Quarters		$ million	Full year	
Q4 2015	Q4 2014		2015	2014
		Third-party revenue		
6,712	11,251	Upstream	28,480	45,240
51,410	81,093	Downstream	236,384	375,752
24	30	Corporate	96	113
58,146	92,374	Total third-party revenue	264,960	421,105
		Inter-segment revenue		
5,512	9,429	Upstream	25,447	47,059
386	596	Downstream	1,362	2,294
-	-	Corporate	-	-
		CCS earnings		
(333)	2,645	Upstream[1]	(5,663)	15,841
2,502	1,544	Downstream[2]	10,243	3,411
(295)	(32)	Corporate	(425)	(156)
1,874	4,157	Total CCS earnings	4,155	19,096

Quarters		$ million	Full year	
Q4 2015	Q4 2014		2015	2014
1,874	4,157	Total CCS earnings	4,155	19,096
		Current cost of supplies adjustment:		
(1,122)	(4,336)	Purchases	(2,278)	(5,087)
320	1,251	Taxation	646	1,454
(130)	(654)	Share of profit/(loss) of joint ventures and associates	(323)	(733)
942	418	Income/(loss) for the period	2,200	14,730

1 Third quarter 2015 Upstream earnings include impairment charges of $3,689 million after taxation, primarily related to North America shale gas properties, and the impact of the decisions to cease Alaska drilling activities for the foreseeable future and to cease the Carmon Creek project ($2,584 million and $2,032 million after taxation respectively). Second quarter 2014 Upstream earnings included an impairment charge of $1,943 million after taxation, partly offset by divestment gains of $1,230 million after taxation.

2 First quarter 2014 Downstream earnings included an impairment charge of $2,284 million related to refineries in Asia and Europe.

3. Share capital

Issued and fully paid

Number of shares	Ordinary shares of EUR0.07 each A	B	Sterling deferred shares of GBP1 each
At January 1, 2015	3,907,302,393	2,440,410,614	50,000
Scrip dividends	96,336,688	-	-
Repurchases of shares	(12,717,512)	-	-
At December 31, 2015	3,990,921,569	2,440,410,614	50,000
At January 1, 2014	3,898,011,213	2,472,839,187	50,000
Scrip dividends	64,568,758	-	-
Repurchases of shares	(55,277,578)	(32,428,573)	-
At December 31, 2014	3,907,302,393	2,440,410,614	50,000

Nominal value

$ million	Ordinary shares of EUR0.07 each A	B	Total
At January 1, 2015	334	206	540
Scrip dividends	7	-	7
Repurchases of shares	(1)	-	(1)
At December 31, 2015	340	206	546
At January 1, 2014	333	209	542
Scrip dividends	6	-	6
Repurchases of shares	(5)	(3)	(8)
At December 31, 2014	334	206	540

The total nominal value of sterling deferred shares is less than $1 million.

At Royal Dutch Shell plc's Annual General Meeting on May 19, 2015, the Board was authorised to allot ordinary shares in Royal Dutch Shell plc, and to grant rights to subscribe for or to convert any security into ordinary shares in Royal Dutch Shell plc, up to an aggregate nominal amount of €147 million (representing 2,100 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 19, 2016, and the end of the Annual General Meeting to be held in 2016, unless previously renewed, revoked or varied by Royal Dutch Shell plc in a general meeting.

4. Other reserves

$ million	Merger reserve[1]	Share premium reserve [1]	Capital redemption reserve[2]	Share plan reserve	Accumulated other comprehensive income	Total
At January 1, 2015	3,405	154	83	1,723	(19,730)	(14,365)
Other comprehensive income/(loss) attributable to Royal Dutch Shell plc shareholders	-	-	-	-	(2,750)	(2,750)
Scrip dividends	(7)	-	-	-	-	(7)
Repurchases of shares	-	-	1	-	-	1
Share-based compensation	-	-	-	(65)	-	(65)
At December 31, 2015	3,398	154	84	1,658	(22,480)	(17,186)
At January 1, 2014	3,411	154	75	1,871	(7,548)	(2,037)
Other comprehensive income/(loss) attributable to Royal Dutch Shell plc shareholders	-	-	-	-	(12,182)	(12,182)
Scrip dividends	(6)	-	-	-	-	(6)
Repurchases of shares	-	-	8	-	-	8
Share-based compensation	-	-	-	(148)	-	(148)
At December 31, 2014	3,405	154	83	1,723	(19,730)	(14,365)

[1] The merger reserve and share premium reserve were established as a consequence of Royal Dutch Shell plc becoming the single parent company of Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited, in 2005.

[2] The capital redemption reserve was established in connection with repurchases of shares of Royal Dutch Shell plc.

5. Derivative contracts

The table below provides the carrying amounts of derivatives contracts held, disclosed in accordance with IFRS 13 *Fair Value Measurement*.

$ million	Dec 31, 2015	Sep 30, 2015	Dec 31, 2014
Included within:			
Trade and other receivables – non-current	744	885	703
Trade and other receivables – current	13,114	12,433	14,037
Trade and other payables – non-current	1,687	1,407	520
Trade and other payables – current	10,757	9,892	11,554

As disclosed in the Consolidated Financial Statements for the year ended December 31, 2014, presented in the Annual Report and Form 20-F for that year, Shell is exposed to the risks of changes in fair value of its financial assets and liabilities. The fair values of the financial assets and liabilities are defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Methods and assumptions used to estimate the fair values at December 31, 2015 are consistent with those used in the year ended December 31, 2014, and the carrying amounts of derivative contracts measured using predominantly unobservable inputs have not changed materially since that date.

The fair value of debt excluding finance lease liabilities at December 31, 2015, was $53,480 million (September 30, 2015: $50,744 million; December 31, 2014: $41,120 million). Fair value is determined from the prices quoted for those securities.

6. Recommended cash and share offer for BG Group plc by Royal Dutch Shell plc

On April 8, 2015, the Boards of Royal Dutch Shell plc and BG Group plc announced that they had reached agreement on the terms of a recommended cash and share offer to be made by Royal Dutch Shell plc for the entire issued and to be issued share capital of BG Group plc.

The shareholders of Royal Dutch Shell plc and BG Group plc voted to approve the transaction at meetings on January 27, 2016 and January 28, 2016 respectively. The transaction is expected to complete on February 15, 2016, subject to the satisfaction or waiver of certain customary conditions, including the sanction of the scheme arrangement to implement the combination by the High Court of Justice.

Under certain circumstances occurring on or prior to July 31, 2016, Royal Dutch Shell plc has agreed to pay BG Group plc £750 million by way of compensation for any loss suffered by BG Group plc in connection with the preparation and negotiation of the transaction.

ADDITIONAL NOTES FOR INFORMATION

A. Impacts of accounting for derivatives

In the ordinary course of business Shell enters into contracts to supply or purchase oil and gas products as well as power and environmental products. Derivative contracts are entered into for mitigation of resulting economic exposures (generally price exposure) and these derivative contracts are carried at period-end market price (fair value), with movements in fair value recognised in income for the period. Supply and purchase contracts entered into for operational purposes are, by contrast, recognised when the transaction occurs (see also below); furthermore, inventory is carried at historical cost or net realisable value, whichever is lower.

As a consequence, accounting mismatches occur because: (a) the supply or purchase transaction is recognised in a different period; or (b) the inventory is measured on a different basis.

In addition, certain UK gas contracts held by Upstream are, due to pricing or delivery conditions, deemed to contain embedded derivatives or written options and are also required to be carried at fair value even though they are entered into for operational purposes.

The accounting impacts of the aforementioned are reported as identified items in this Report.

B. Capital investment

Capital investment is a measure used to make decisions about allocating resources and assessing performance. It is defined as the sum of capital expenditure, exploration expense (excluding well write-offs), new investments in joint ventures and associates, new finance leases and other adjustments.

C. Divestments

Divestment proceeds comprise proceeds from sale of property, plant and equipment and businesses, joint ventures and associates, and other Upstream and Downstream investments, adjusted onto an accruals basis.

The term "Divestments" comprises both divestment proceeds as defined above and proceeds from sale of interests in Shell Midstream Partners, L.P. ("SMP"). Proceeds from sale of interests in SMP are included within "Change in non-controlling interest" in the Condensed Consolidated Statement of Cash Flows.

D. Return on average capital employed

Return on average capital employed (ROACE) measures the efficiency of Shell's utilisation of the capital that it employs and is a common measure of business performance. In this calculation, ROACE is defined as the sum of income for the current and previous three quarters, adjusted for after-tax interest expense, as a percentage of the average capital employed for the same period. The tax rate used is Shell's effective tax rate for the period. Capital employed consists of total equity, current debt and non-current debt.

E. Gearing

Gearing, calculated as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity), is a key measure of Shell's capital structure.

F. Operating costs

Operating costs comprise production and manufacturing expenses; selling, distribution and administrative expenses; and research and development expenses.

G. Liquidity and capital resources

Fourth quarter net cash from operating activities was $5.4 billion compared with $9.6 billion for the same period last year.

Total current and non-current debt increased to $58.4 billion at December 31, 2015 from $55.6 billion at September 30, 2015 while cash and cash equivalents were $31.8 billion at December 31, 2015, in line with the position at September 30, 2015. During the fourth quarter 2015, Shell issued $5.0 billion of debt under the US shelf registration. No new debt was issued under the European medium-term note programme.

Capital investment for the fourth quarter 2015 was $7.9 billion, of which $5.8 billion in Upstream, $2.0 billion in Downstream and $0.1 billion in Corporate. Capital investment for the same period last year was $9.7 billion, including $7.5 billion in Upstream and $2.1 billion in Downstream.

Dividends of $0.47 per share are announced on February 4, 2016 in respect of the fourth quarter. These dividends are payable on March 29, 2016. In the case of B shares, the dividends will be payable through the dividend access mechanism and are expected to be treated as UK-source rather than Dutch-source. See the Annual Report and Form 20-F for the year ended December 31, 2014 for additional information on the dividend access mechanism.

Under the Scrip Dividend Programme shareholders can increase their shareholding in Shell by choosing to receive new shares instead of cash dividends. Only new A shares will be issued under the Programme, including to shareholders who currently hold B shares.

Full year net cash from operating activities was $29.8 billion compared with $45.0 billion last year.

Total current and non-current debt increased to $58.4 billion at December 31, 2015 from $45.5 billion at December 31, 2014 while cash and cash equivalents increased to $31.8 billion at December 31, 2015 from $21.6 billion at December 31, 2014. During 2015 Shell issued $15.0 billion of debt under the US shelf registration, and $5.2 billion of debt under the European medium-term note programme.

Capital investment for 2015 was $28.9 billion, of which $23.6 billion in Upstream, $5.1 billion in Downstream and $0.2 billion in Corporate. Capital investment for 2014 was $37.3 billion, of which $31.3 billion in Upstream, $5.9 billion in Downstream and $0.1 billion in Corporate.

CAUTIONARY STATEMENT

The release, presentation, publication or distribution of this announcement in jurisdictions other than the United Kingdom may be restricted by law and therefore any persons who are subject to the laws of any jurisdiction other than the United Kingdom should inform themselves about and observe any applicable requirements. Any failure to comply with applicable requirements may constitute a violation of the laws and/or regulations of any such jurisdiction.

This announcement is not intended to and does not constitute or form part of any offer to sell or subscribe for or any invitation to purchase or subscribe for any securities or the solicitation of any vote or approval in any jurisdiction pursuant to the recommended combination of Royal Dutch Shell plc ("Shell") and BG Group plc ("BG") (the "Combination") or otherwise nor shall there be any sale, issuance or transfer of securities of Shell or BG pursuant to the Combination in any jurisdiction in contravention of applicable laws.

All amounts shown throughout this announcement are unaudited. All peak production figures in Portfolio Developments are quoted at 100% expected production.

The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate entities. In this announcement "Shell", "Shell group" and "Royal Dutch Shell" are sometimes used for convenience where references are made to Royal Dutch Shell plc and its subsidiaries in general. Likewise, the words "we", "us" and "our" are also used to refer to subsidiaries in general or to those who work for them. These expressions are also used where no useful purpose is served by identifying the particular company or companies. "Subsidiaries", "Shell subsidiaries" and "Shell companies" as used in this announcement refer to companies over which Royal Dutch Shell plc either directly or indirectly has control. Companies over which Shell has joint control are generally referred to as "joint ventures" and companies over which Shell has significant influence but neither control nor joint control are referred to as "associates". The term "Shell interest" is used for convenience to indicate the direct and/or indirect ownership interest held by Shell in a venture, partnership or company, after exclusion of all third-party interest.

This announcement contains forward-looking statements concerning the financial condition, results of operations and businesses of Royal Dutch Shell and of the Combination. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Royal Dutch Shell, BG and the combined group to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as "anticipate", "believe", "could", "estimate", "expect", "goals", "intend", "may", "objectives", "outlook", "plan", "probably", "project", "risks", "schedule", "seek", "should", "target", "will" and similar terms and phrases. There are a number of factors that could affect the future operations of Royal Dutch Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this announcement, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell's products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; and (m) changes in trading conditions. All forward-looking statements contained in this announcement are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Additional risk factors that may affect future results are contained in Royal Dutch Shell's Form 20-F for the year ended December 31, 2014 (available at http://www.shell.com/investor and http://www.sec.gov). These risk factors also expressly qualify all forward-looking statements contained in this announcement and should be considered by the reader. Each forward-looking statement speaks only as of the date of this announcement, February 4, 2016. Neither Royal Dutch Shell plc nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this announcement.

This Report contains references to Shell's website. These references are for the readers' convenience only. Shell is not incorporating by reference any information posted on http://www.shell.com (http://www.shell.com)

We may have used certain terms, such as resources, in this announcement that the United States Securities and Exchange Commission (SEC) strictly prohibits us from including in our filings with the SEC. U.S. investors are urged to consider closely the disclosure in our Form 20-F, File No 1-32575, available on the SEC website http://www.sec.gov (http://www.sec.gov). You can also obtain this form from the SEC by calling 1-800-SEC-0330.

February 4, 2016

The information in this Report reflects the unaudited consolidated financial position and results of Royal Dutch Shell plc. Company No. 4366849, Registered Office: Shell Centre, London, SE1 7NA, England, UK.

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SOURCE Royal Dutch Shell plc

News update

February 4, 2016 – Shell's quarterly results today included information that the LNG Canada project FID decision will occur right at the end of this year. This is not inconsistent with information LNG Canada has shared with the community.

We have always stated that our Joint Venture Participants plan to make a Final Investment Decision in 2016. We are pleased, given the current oil and gas prices, and turmoil in global energy markets, that the Joint Venture Participants in LNG Canada are still working towards a Final Investment Decision for the proposed facility late this year.

DID YOU KNOW?

A molecule of natural gas will take 12.5 days to travel from the ground to the end customer in Asia.

WHAT WE'RE UP TO

Celebrating the start of site preparation activities

In December, LNG Canada marked the beginning of specific site preparation activities that will take place in advance of a Final Investment Decision. Read more...

FAQ

What is the transportation process for natural gas?

The process of transporting natural gas from the ground in B.C. to the end user overseas takes about 12 days. Read more...


1. Gas Field
2. Pipeline
3. Liquefaction Plant
4. LNG Storage Tank
5. LNG Tanker
6. LNG Storage Tank
7. Vapourizers
8. Pipeline System

BRITISH COLUMBIA COLUMBIA RIVER TREATY REVIEW

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Public Engagement | Treaty Review Process | About the Columbia River Treaty

Columbia River Treaty Highlights

The Columbia River Treaty is a trans-boundary water management agreement between the United States and Canada signed in 1961 and ratified in 1964.

The Columbia River is approximately 2000 kilometres long and is the largest North American river emptying into the Pacific Ocean.

It begins in British Columbia at Columbia Lake and winds through British Columbia and Washington before emptying into the Pacific Ocean, near Portland, Oregon. The Kootenay River is the major uppermost tributary of the Columbia River and joins the Columbia River at Castlegar, British Columbia.

The Treaty grew out of two major challenges: devastating flooding to areas close to Columbia River in both Canada and the United States and the need for more electricity to support a growing economy and population in the Pacific Northwest.

The purpose of the Columbia River Treaty is to optimize flood management and power generation. This requires coordinated operations of reservoirs and water flows for the Columbia River and Kootenay River on both sides of the border.

Either Canada or the U.S. can unilaterally terminate most of the provisions of the Columbia River Treaty anytime after September 16, 2024, providing at least ten years' notice is given. The latest date to provide termination notice for September 2024 is September 2014.

The Canada-British Columbia Agreement (1963) transferred most Columbia River Treaty benefits, rights and obligations to British Columbia, requiring Canada to obtain B.C.'s agreement before amending or terminating the Treaty.

Under the Columbia River Treaty, Canada (British Columbia) agreed to build three dams [Duncan (1967), Arrow/Hugh Keenleyside (1968) and Mica (1973)], and in return received benefits based on the additional flood control and power generation potential. British Columbia received an upfront one-time payment of $64 million for 60 years of assured flood control.

Regardless of termination, Assured Annual Flood Control expires automatically in 2024 and converts on 16 September 2024 to a Called Upon operation of Canadian storage space as may be needed by the United States for flood risk management. "Called Upon" flood control continues for as long as the dams that provide it are in place, even if the Columbia River Treaty is terminated.

Canada's half share of the additional power that could be generated in the United States as a result of the dams, the downstream power benefits, is called the Canadian Entitlement. Under the 1963 Canada-British Columbia Agreement, these benefits are owned by the Province of British Columbia.

British Columbia sold the first 30 years of the Canadian Entitlement to a consortium of utilities in the United States for $254 million and used the money to finance the construction of the three Columbia River Treaty dams.

The Canadian Entitlement continues as long as the Columbia River Treaty is in place. If the Columbia River Treaty is terminated, the Canadian Entitlement ends.

The Columbia River Treaty also provided for the construction of the Libby dam (1973) in Montana and the resulting reservoir, Lake Koocanusa, stretches back 68 kilometres into British Columbia.

The Libby dam regulates water flow on the Kootenay River, the major uppermost tributary of the Columbia River. The obligation to regulate water flow on the Kootenay River continues indefinitely, even if the Columbia River Treaty is terminated.

Starting in the early 1990s, other agreements under the Columbia River Treaty have been put in place to serve additional values such as managing water flow for fish and for recreation.

Benefits of the Treaty

The Columbia River Treaty has brought significant flood control and power benefits to British Columbia.

Flood damage reduction	Particularly around Trail, Castlegar, Revelstoke and Creston.
Power generation	Assured winter flows for power generation. At-site electricity generation at Mica dam. Ability to develop additional generating facilities including: Kootenay Canal Plant (1974), Revelstoke Dam (1984), Arrow Lakes Generating Station (2002), Brilliant Expansion project (2007). Power generating facilities on the Columbia and Kootenay Rivers generate around 44% of electricity produced

	in British Columbia.
Jobs/Economic Stimulus	Generating facilities provide jobs, spin off industries, services from ongoing operations/periodic upgrades. Columbia Power Corporation and Columbia Basin Trust jobs and regional investment.
Canadian Entitlement (Canada's share of the downstream power benefits)	Annual delivery of 1320 megawatts capacity and 4540 gigawatt hours of energy to British Columbia border over last 10 yrs. Worth $120-300M annually.
Construction cost for the Keenleyside (Arrow), Mica, and Duncan dams	Up front cash payments of $64 million for flood control and $254 million for the first thirty years of Canadian Entitlement power.

Impacts of the Columbia River Treaty on British Columbia

Even though the four dams [Duncan, Mica, Arrow (Hugh Keenleyside), Libby] improved flood control and power production, the resulting reservoirs in Canada flooded 60,000 hectares (231 square miles) of valley land.

Flooding impacted traditional First Nations' sites, agricultural and forestry areas, displaced a dozen communities, including approximately 2,300 people, and impacted fish and wildlife habitat.

The rise and fall of reservoir levels continue to affect the surrounding ecosystems, cultural and recreation interests.

In recognition of the long-term impacts in the region as a result of the Columbia River Treaty and the Columbia River Treaty dams, Columbia Basin Trust (a Crown corporation) was created in 1995 to support social, economic and environmental well-being in the Columbia River Basin.

SITE C CAPITAL COST ESTIMATE

Large hydro projects like Site C are cost-effective because after an upfront capital cost, they have low operating costs and a long life of more than 100 years.

Site C has an estimated capital cost of $8.335 billion and would produce electricity at a cost of $58 to $61 per megawatt hour at the point of interconnection, making it the most cost-effective option to help meet B.C.'s future electricity needs.

The cost estimate for Site C is robust, and includes construction and development costs, inflation, interest during construction, mitigation costs, community benefits, First Nations accommodation and a $795 million contingency. In addition, a $440 million project reserve has been established by the provincial government to account for events outside of BC Hydro's control, such as higher than forecast inflation or interest rates. Taken together, the contingency and the project reserve amount to more than a billion dollars to address potential risks to project costs.

As the project progresses, BC Hydro is seeing a strong response from the market in relation to its procurements. The rigorous competitive selection processes undertaken to date for major contracts have confirmed the project budget in relation to the specific areas of work, and ensured BC Hydro continues to get the best value for customers.

Third-Party Reviews

External peer reviews have been completed to validate the methodologies and assumptions of the project's capital cost estimate. These reviews include KPMG and an independent panel of contractors with decades of experience in capital projects.

KPMG concluded that the level of care and diligence was consistent with an infrastructure project about to enter construction phase.

The panel of experienced independent contractors concluded that the capital cost estimate was sufficient for the proposed scope and schedule of the project.

"We have reviewed the Assumption development process and it shows a level of care and diligence consistent with an infrastructure project about to enter the construction phase."

- KPMG LLP, October 2014

"The direct cost estimate appears to be sufficiently complete and adequate to cover all anticipated costs associated with constructing the works in the planned time schedule."

- Panel of Independent Contractors, October 2014

During construction, BC Hydro will provide regular reports on project costs to the B.C. Utilities Commission.

Site C and BC Hydro Rates

Electricity in B.C. is currently among the most competitively priced in North America, largely due to BC Hydro's system of heritage hydroelectric projects that produce electricity at a very low cost to ratepayers.

Over the first 50 years of Site C's project life, ratepayers will save an average of $650 to $900 million each year compared to alternatives, amounting to average annual savings of approximately six to eight per cent for the typical household. Over the long-term, as the capital costs of the project are paid down, the annual ratepayer savings will continue to increase each year for more than 100 years.

There is no effect on today's BC Hydro rates from Site C, as costs of the project are deferred until the project begins generating electricity. This ensures that the costs for Site C are paid by the ratepayers who are benefiting from the project. Once the project is in operation, the B.C. Utilities Commission will determine the period over which costs are recovered. Typically, this would be over many decades.

-more-

Cost Estimate Breakdown

Project Cost Estimate Breakdown *	*$millions, incl. inflation & contingency ** *
Dam, Power Facilities and Associated Structures	**4,120**
Earthfill Dam, Approach Channel and RCC Buttress	
North Bank Stabilization	
Cofferdams, Dykes and Diversion Tunnels	
Access Roads	
Powerhouse	
Spillways, Intakes and Penstocks	
Turbines and Generators	
Substation and Transmission	
Offsite Works, Management and Services	**1,575**
Highway 29 Relocation	
Clearing, Land and Rights	
Worker Accommodation	
Construction Management and Services	
Total Direct Construction Costs *(nominal dollars)*	**5,695**
Indirect Costs	**1,235**
Regulatory and Development (F2007-F2015)	
Mitigation, Compensation and Benefits Agreements	
Construction Insurance	
Project Management and Engineering	
Total Construction and Development Cost *(nominal dollars)*	**6,930**
Interest During Construction	**1,405**
Total Project Cost *(nominal dollars)*	**8,335**
Project Reserve ***	**440**

Notes:

* *Categorization is as of Dec 2014; items may shift between categories depending on procurement packaging.*

** *Inflation is included in each of the categories. The $795 contingency has also been notionally allocated within each of the categories.*

*** *Access to the Project Reserve must be authorized by the provincial Treasury Board.*

Joint Review Panel Report

In its May 2014 report, the independent Joint Review Panel concluded that: *“Site C would be the least expensive of the alternatives, and its cost advantages would increase with the passing decades as inflation makes alternatives more costly.”*

The Joint Review Panel also stated: “*Site C, after an initial burst of expenditure, would lock in low rates for many decades, and would produce fewer greenhouse gas emissions per unit of energy than any source save nuclear*.”

British Columbia Hydro and Power Authority

2014/15
ANNUAL REPORT

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Board Chair's Message and Accountability Statement

Chair's Message

The 2014/15 Annual Report outlines how BC Hydro is meeting the objectives laid out in the Government's Letter of Expectations and is aligning our organization with the Taxpayer Accountability Principles. Our Board members have all signed the addendum that is posted on bchydro.com publicly showing this support.

With prudent reinvestment, careful planning and strong, respectful relationships, BC Hydro is well positioned to deliver clean, reliable, low cost power for the long-term benefit of our growing province.

Accountability Statement

The BC Hydro 2014/15 Annual Report was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the B.C. Reporting Principles. The Board and Management are accountable for the contents of the Annual Report, including what has been included and how it has been reported.

The information presented reflects the actual performance of BC Hydro for the 12 months ended March 31, 2015 in relation to the 2014/15-2016/17 Service Plan. The Board is responsible for ensuring internal controls are in place to measure information and report accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of March 31, 2015 have been considered in preparing the report. The report contains estimates and interpretive information that represent the best judgment of management. Any changes in mandate direction, goals, strategies, measures or targets made since the 2014/15-2016/17 Service Plan was released and any significant limitations in the reliability of the information are identified in the report.

The BC Hydro 2014/15 Annual Report compares the corporation's actual results to the expected results identified in the 2014/15- 2016/17 Service Plan. I am accountable for those results as reported.

Steve Bellringer

Stephen Bellringer
Board Chair

losses on monetary items is the difference between the amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in the foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

For purposes of consolidation, the assets and liabilities of Powerex, whose functional currency is the U.S. dollar, are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses of Powerex are translated to Canadian dollars at exchange rates at the date of the transactions. Foreign currency differences resulting from translation of the accounts of Powerex are recognized directly in other comprehensive income and are accumulated in the cumulative translation reserve. Foreign exchange gains or losses arising from a monetary item receivable from or payable to Powerex, the settlement of which is neither planned nor likely in the foreseeable future and which in substance is considered to form part of a net investment in Powerex by BC Hydro, are recognized directly in other comprehensive income in the cumulative translation reserve.

(e) Property, Plant and Equipment

(i) Recognition and Measurement

Property, plant and equipment in service are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour and any other costs directly attributable to bringing the asset into service. The cost of dismantling and removing an item of property, plant and equipment and restoring the site on which it is located is estimated and capitalized only when, and to the extent that, the Company has a legal or constructive obligation to dismantle and remove such asset. Property, plant and equipment in service include the cost of plant and equipment financed by contributions in aid of construction. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset are capitalized as part of the cost of the qualifying asset. Upon retirement or disposal, any gain or loss is recognized in the statement of comprehensive income.

The Company recognizes government grants when there is reasonable assurance that any conditions attached to the grant will be met and the grant will be received. Government grants related to assets are deducted from the carrying amount of the related asset and recognized in profit or loss over the life of the related asset.

Unfinished construction consists of the cost of property, plant and equipment that is under construction or not ready for service. Costs are transferred to property, plant and equipment in service when the constructed asset is capable of operation in a manner intended by management.

(ii) Subsequent Costs

The cost of replacing a component of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the component will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced component is derecognized. The costs of property, plant and equipment maintenance are recognized in the statement of comprehensive income as incurred.

(iii) Depreciation

Property, plant and equipment in service are depreciated over the expected useful lives of the assets, using the straight-line method. When major components of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

The expected useful lives, in years, of the Company's main classes of property, plant and equipment are:

Generation	15 – 100
Transmission	20 – 65
Distribution	20 – 60
Buildings	5 – 60
Equipment & Other	3 – 35

The expected useful lives and residual values of items of property, plant and equipment are reviewed annually.

Depreciation of an item of property, plant and equipment commences when the asset is available for use and ceases at the earlier of the date the asset is classified as held for sale and the date the asset is derecognized.

(f) Intangible Assets

Intangible assets are recorded at cost less accumulated amortization and accumulated impairment losses. Land rights associated with statutory rights of way acquired from the Province that have indefinite useful lives and are not subject to amortization. Other intangible assets include California carbon allowances which are not amortized because they are used to settle obligations arising from carbon emissions regulations. Intangible assets with finite useful lives are amortized over their expected useful lives on a straight line basis. These assets are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be fully recoverable. The expected useful lives, in years, are as follows:

Software	2 – 10
Other	10 – 20

Amortization of intangible assets commences when the asset is available for use and ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

BC hydro

Integrated Resource Plan

Chapter 4

Resource Planning Analysis Framework

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4.1 Introduction

BC Hydro's planning environment is dominated by three overarching uncertainties – load growth, Demand Side Management (**DSM**) deliverability and market conditions. This chapter sets out the analytical framework that BC Hydro used to compare resource alternatives, addressing multiple objectives, attributes and uncertainties. The following four criteria were adhered to in the analysis:

- Meeting BC Hydro's planning criteria (described in section 1.2.2)
- Achieving the *Clean Energy Act* (***CEA)*** subsection 6(2) requirement that BC Hydro be self-sufficient in energy and capacity by F2017 and each year after that[1]
- Meeting *CEA* subsection 2(c) 93 per cent clean or renewable energy objective
- Ensuring that at least 66 per cent of BC Hydro's expected incremental load growth is met by DSM as set out in subsection 2(b) of the *CEA*

As this chapter demonstrates, BC Hydro has sufficient resources to meet growing electricity demand over the short to mid-term[2] planning period, but will need to acquire new resources towards the middle and end of the planning horizon assuming implementation of the DSM target and Electricity Purchase Agreement (**EPA**) renewal assumptions described in this chapter, with or without Expected liquefied natural gas (**LNG**) load. This splits the analytical framework into two separate but interrelated parts, focused on shorter-term and longer-term planning issues.

The remainder of this chapter is organized as follows:

[1] Except as noted in the section 9.2.7 recommendation concerning the two-year economic bridging to Site C's in-service date (**ISD**).

[2] For the purposes of the Integrated Resource Plan (**IRP**), events occurring before F2018 are considered short-term and events occurring beyond F2023 are considered long-term. The boundaries between short, mid and long term are treated loosely as no analytic results turn on their exact definitions.

- Section 4.2 covers the short to mid-term planning period and outlines the key questions, decision objectives, uncertainties and the planning analysis framework over that period, with an emphasis on managing costs. It presents the associated analyses and recommendations, and concludes with recommended short-term actions and options to manage costs
- Sections 4.3 and 4.4 focus on the long-term planning horizon and outline the key questions, decision objectives, uncertainties, and planning analysis framework to address resource planning questions over that period

Building on this chapter, Chapter 6 takes the short-term cost management conclusions and describes the analysis undertaken to determine what actions and resources should be considered to meet the identified need for energy and capacity over the longer term. The framework described in this chapter, and the corresponding results presented in Chapter 6, led BC Hydro to select the Recommended Actions that are found in Chapter 9.

4.2 Short-Term Energy Supply Management

The Load-Resource Balances (**LRBs**) shown in Chapter 2 establish that a gap exists for energy and for capacity from the start of the planning period in F2017 and onward before accounting for DSM and the other incremental resources outlined in Table 4-1. The incremental resources listed in Table 4-1 have volumes that are generated for illustrative purposes, but that correspond to the quantity of cost-effective resources available at or below the Long Run Marginal Cost (**LRMC**) price of $135/MWh that was used by BC Hydro in the past based on the Clean Power Call results. As such, they form a baseline of “typical” resource planning volumes against which alternative short-term expenditures can be compared.

Table 4-1 Detailed Assumptions Regarding Incremental Resources in F2017

Resources	Contracted Energy[3] (GWh/year)	Firm Energy (post-attrition, GWh/year)	Effective Load Carrying Capability (ELCC) (post-attrition, MW)	Notes
Supply-Side Resources				
New EPAs: Standing Offer Program (**SOP**)	1,000	520	29	Incremental EPAs awarded under BC Hydro's SOP
New EPAs: Impact Benefit Agreements (**IBAs**)[4]	0	0	0	
Independent Power Producer (**IPP**) EPA Renewals	1,243	1,205	137	
Demand-Side Resources				
Smart Metering and Infrastructure (**SMI**) Program	n/a	65	9	Commencing in F2017, forecast theft detection benefits are expected as a result of the SMI program.
Voltage and Var Optimization (**VVO**)	n/a	359	1	Reduced energy consumption by optimizing the distribution-supply voltage for distribution customers.
DSM	n/a	5,127	781	Iincremental savings that are targeted as part of pursuing the 2008 Long Term Acquisition Plan (**LTAP**) DSM target

3 Estimated total energy (firm plus non-firm).
4 Approximately 170 GWh/year of firm energy and 25 MW of ELCC beginning in F2020.

4.2.1 Short-Term Load Resource Balances

Figure 4-1 and Table 4-2[5] show the energy LRBs, and Figure 4-2 and Table 4-3 show the capacity LRBs, after implementation of the Table 4-1 resources, including the 2008 LTAP DSM target:

- The Table 4-1 incremental resources address the energy and capacity gap without Expected LNG until F2025 and F2019 respectively, with temporary planning surpluses in the near and mid-term
- A temporary planning surplus continues to exist with Expected LNG of 3,000 GWh/year and 360 MW – the energy and capacity gaps emerge in F2022 and F2019 respectively

As there is no need for incremental resources in the near to mid term of the planning horizon, the inclusion of these incremental resources bears scrutiny to reduce costs in the short term, regardless of the potential demand from LNG.

5 BC Hydro has summarized LRBs and surplus/deficit values in this chapter with respect to key milestone years: F2017 (self-sufficiency target year and start of the planning horizon) through F2023; F2028; and F2033 (final year of the planning horizon).

Figure 4-1 Energy Surplus/Deficit with Incremental Resources

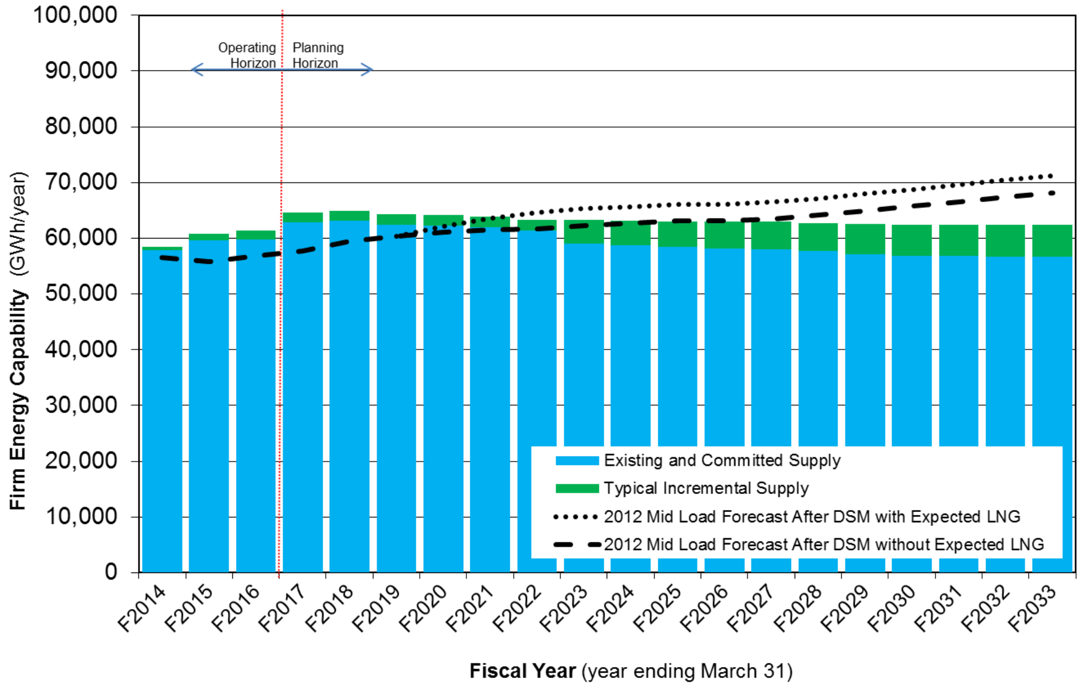


Table 4-2 Energy Surplus/Deficit with Incremental Resources, GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	6,913	5,351	3,899	2,101	406	-1,298	-2,056	-4,427	-8,706
Surplus/Deficit with Incremental Resources without Expected LNG	6,913	5,351	3,899	3,101	2,406	1,702	944	-1,427	-5,706

Figure 4-2 Capacity Surplus/Deficit with Incremental Resources

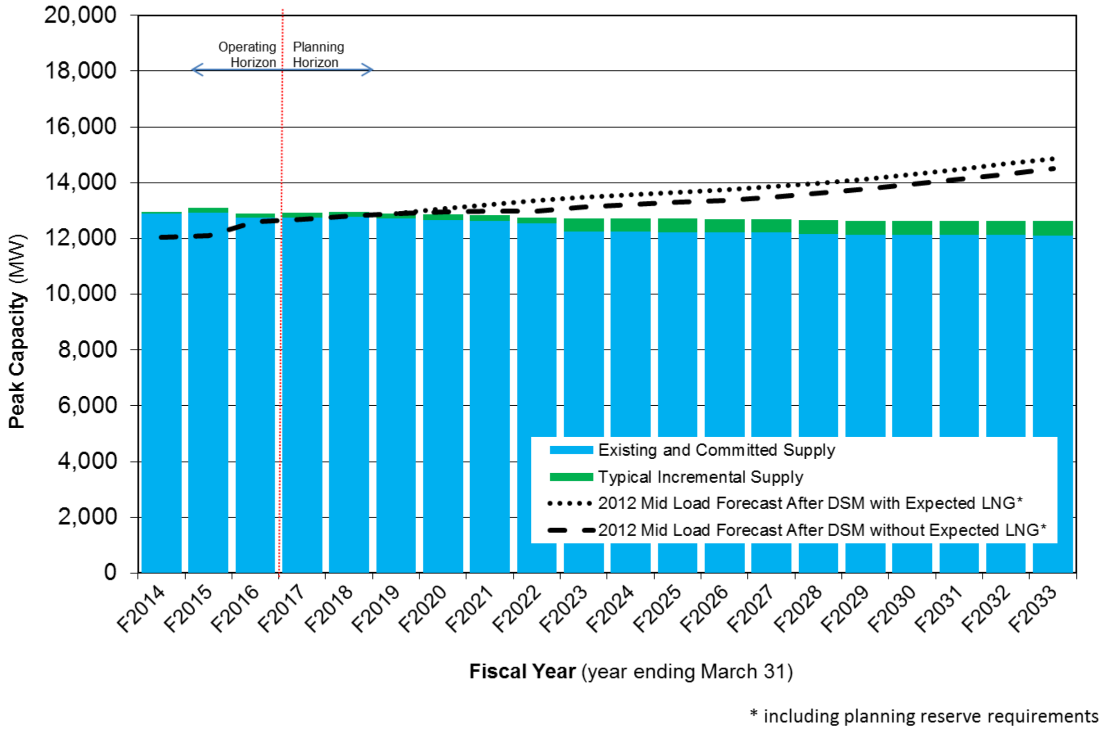


Table 4-3 Capacity Surplus/Deficit with Typical Incremental Resources, MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	240	135	-15	-213	-384	-608	-762	-1,321	-2,237
Surplus/Deficit with Incremental Resources without Expected LNG	240	135	-15	-93	-144	-248	-402	-961	-1,876

The following sections describe ways in which short-term costs can be reduced through various actions.

4.2.2 Key Questions to be Addressed Over the Short to Mid-Term Planning Horizon

BC Hydro explored four sets of actions for reducing costs over the short to mid-term planning horizon:

(a) Reduce spending on Independent Power Producer (**IPP)** resources

(b) Delay planned ramp-ups in spending on DSM initiatives

(c) Scale back implementation of BC Hydro's VVO program

(d) Create industrial customer incentive mechanisms to temporarily increase demand.

The following three sections lay out the framework for creating and comparing different options.

4.2.3 Key Decision Objectives to Design and Compare Options

Chapter 1 describes the sources and rationale for considering multiple planning objectives within this IRP, including: the *CEA* British Columbia's energy objectives and requirements; good utility practice; and statutory obligations such as the *Utilities Commission Act* (***UCA****)* service obligation. Table 4-4 presents decision objectives compiled by BC Hydro to inform either the design or the comparison of methods to reduce energy portfolio expenditures over the short to mid-term planning horizon of this IRP.

Table 4-4 *CEA* and Other Resource Planning Objectives

Decision Objective	Reason for Inclusion
Minimize Financial Impacts, including: • Cost (various measures) • Cost uncertainty	Good utility practice; First Nations, public and stakeholder interests; align with *CEA* 'ratepayer impact' objectives grouped in Table 1-1
Maximize Economic Development • Foster development of First Nations' communities • Foster development of rural communities	First Nations, public and stakeholder interests; align with *CEA* 'economic development' objectives grouped in Table 1-1
Maximize System Reliability • Minimize DSM deliverability risk	Good utility practice; First Nations, public and stakeholder interests
Maintain or Improve Relationships • Customers • IPP industry • First Nations	Good utility practice; First Nations, public and stakeholder interests
Maximize Equity of Opportunities	Good utility practice; First Nations, public and stakeholder interests

4.2.3.1 Financial Impacts

The *CEA* and good utility practice point towards the importance of tracking costs when comparing resource options. Costs are expressed on a Present Value (**PV**) basis to capture the impact of the timing of costs and trade revenues over the planning horizon. Where uncertainty is relevant, cost ranges or costs across scenarios are highlighted.

4.2.3.2 Economic Development Impacts

Consistent with subsection 2(k) and 2(l) of the *CEA*, BC Hydro considered the economic development potential of resources, and the development of First Nations and rural communities through the use of clean or renewable resources. Some future potential IPP EPAs are tied to IBAs signed with specific First Nations. The existence of these IBAs was one of several factors used to determine which IPP EPAs would be included as resources during the near to mid-term period of the planning horizon when self-sufficiency needs are met.

4.2.3.3 Maximize System Reliability

BC Hydro treats the planning criteria described in section 1.2.2 as a constraint that is not traded off against other objectives. However, some resource choices can work towards or against achieving reliability beyond the planning criteria; once the planning criteria are met, reliability can be traded off against other objectives. In this IRP, such instances might occur over the short to mid-term planning horizon, depending on the degree to which DSM is included in the portfolio.

4.2.3.4 Maintain or Improve Relationships

The ability of BC Hydro to meet future energy and capacity needs is tied to the business relationships it has developed to pursue supply-side resources and DSM initiatives. On the supply-side, maintaining BC Hydro's business reputation (including relationships with IPPs) was one consideration when assessing how EPAs would be handled during the near to mid-term planning period. On the demand-side, maintaining ties to industry that would allow BC Hydro to ramp up future DSM activities was a key design criterion for the short-term period over which DSM expenditures are to be moderated.

4.2.3.5 Maximize Equity of Opportunities

Equity was an important design criterion for DSM and potential customer incentive mechanisms:

- Access to DSM initiatives in general, and the inclusion of a low income DSM program in particular, were key design criteria used to ensure customers would have access to DSM opportunities to lower their bills
- Section 4.2.5.4 discusses potential incentive mechanisms for customers to access, on a temporary basis, energy in excess of BC Hydro's system needs. One design criterion for such incentive mechanisms will be that access to them does not unfairly benefit particular customers within an industrial sector.

4.2.3.6 IRP Treatment of Multiple Decision Objectives

BC Hydro used the decision objectives described in sections 4.2.3.1 to 4.2.3.5 to design and compare optional ways of reducing costs over the short term. Consistent with the British Columbia Utilities Commission's test and as highlighted in Table 1-1, the goal is not to arrive at the least cost solution, but rather the most cost-effective solution which entails among other things consideration of risk. Since the role of these objectives in the design of options and the impact of the options on these objectives have not been quantified in many cases, the appropriate balance amongst these objectives to achieve the most cost-effective solution has been a matter of professional judgment.

4.2.4 Key Uncertainties Over the Short to Mid-Term Planning Horizon

To provide a clear discussion of the uncertainties and risks that BC Hydro is managing, the following definitions are provided:

- Uncertainties are variables with unknown outcomes
- Risk is commonly defined as the effect of uncertainty on objectives.

Some key uncertainties and related risks for addressing resource needs over the short to mid term include:

(a) Cost risk, particularly the chance that activities to generate short-term cost reductions (e.g., reduction in DSM activities, temporary load additions) are more than offset by future cost increases

(b) Load growth and the chance that load growth exceeds or falls below expectations

(c) DSM initiatives and the uncertainty whether DSM savings can be ramped up quickly to higher levels of savings in response to emerging energy and capacity needs

(d) IPP attrition rates from power acquisition processes and the chance that they are lower than expected, adding to cost through additional energy purchases when the energy is not needed.

4.2.5 Methods to Reduce Costs Over the Short to Mid-Term Planning Period

This section lays out the framework used to assess potential actions and displays anticipated changes to the LRBs. It concludes with the cumulative impacts to the LRBs.

4.2.5.1 Reduce Spending on EPAs

One potential method considered to decrease energy costs during the short to mid-term period after self-sufficiency is achieved is to reduce spending on the contracted energy supply (i.e., EPAs). This section identifies three categories of potential opportunities to reduce EPA volume and/or cost and then addresses the method for identifying and selecting specific reduction opportunities. It concludes with a summary of how actions taken to date and actions recommended within this IRP will impact the LRB.

BC Hydro identified three categories of potential EPA portfolio supply reductions:

(i) Pre-COD EPAs where there is some ability to defer Commercial Operation Date (**COD**), downsize capacity or terminate the EPA

(ii) EPA renewals where contracts are expiring

(iii) New EPAs

For all three categories, EPAs were assessed based on:

- Cost - BC Hydro examined the potential PV of energy savings against two bookends to inform decisions: (a) termination of the EPA; and (b) continuing with the EPA. For cases where the continuation of the EPA is under consideration, options for downsizing project size or deferring COD were pursued.

- Implementation risk – This risk encompasses factors such as: First Nations relationship risk (e.g., loss of economic, training or employment opportunities for First Nations - in some cases a First Nations IBA has been executed with the IPP proponent); reputational risk (e.g., the perception that BC Hydro lacks integrity in managing its contractual obligations under these agreements); other stakeholder risk (e.g., loss of economic benefits for communities); and litigation risk (e.g., pay out of damages exceeds savings)
- System Benefits – These benefits could include factors such as capacity contribution to generation operations and local transmission, and capital and/or operating cost reductions. For example, bioenergy projects can provide hourly firm capacity.
- Economic Development Benefits – In some cases, local communities and First Nations strongly support the development of power generation projects due to economic benefits, such as direct and indirect employment, other economic activity, and tax revenues. For example, bioenergy EPAs typically result in broad economic benefits because they also benefit the forestry and transportation sectors, in addition to the benefits associated with construction and operation of the facility itself.

Category 1: Deferring, Downsizing or Terminating Pre-COD EPAs

In early 2013, BC Hydro reviewed the status of all EPAs that have not reached COD. A total of 52[6] EPAs were examined, representing about 8,200 GWh/year of contracted energy, or about 4,400 GWh/year of firm energy after adjustment for attrition. BC Hydro applied the following review process:

[6] By August 2, 2013 BC Hydro had only 46 pre-COD EPAs with two additional projects reaching COD and four EPAs being terminated (as described in this section).

- Stage 1 – Determine whether each pre-COD EPA project has progressed to substantial construction or if significant First Nations, stakeholder or other implementation risks exist. Projects where significant construction has taken place were deemed unlikely candidates for deferral, downsizing or termination because of the high costs that would be involved. As a result, 32 pre-COD EPAs proceeded to the next stage of review. This group consisted of 18 projects where development had stalled and termination appeared possible. The remaining 14 EPAs were identified as potential candidates for deferral or downsizing.
- Stage 2 – Assess the potential benefits of EPA deferral, downsizing or termination by examining the impact on the PV commitment and the PV of energy savings. In addition, carry out further assessment of implementation risks and other considerations. Based on an assessment of the estimated impact of potential deferral, downsizing or termination, a comparison of current contractual commitments versus expected commitments after implementation was carried out. This analysis indicated that, if successful, these EPA actions could result in an incremental rate reduction of, on average, approximately 1 per cent in the period F2014 through F2022.

To date, BC Hydro has executed mutual agreements to terminate four EPAs, representing 147 MW in nameplate capacity and 980 GWh/year of contracted energy generation. Since completion of these projects was not 100 per cent certain prior to termination, the impact on the probability-weighted supply forecast as shown in the LRBs is less.

BC Hydro is in discussions with other IPPs where development of pre-COD EPA projects has stalled. Based on an assessment of the estimated impact of potential deferral, downsizing or termination, a comparison of current contractual commitments versus expected commitments after implementation was carried out. This analysis indicated that, if successful, these EPA actions could result in:

- A reduction of contracted energy by F2021 of roughly 1,800 GWh
- A reduction in attrition-adjusted forecast firm energy supply by F2021 of 160 GWh/year
- A reduction in the PV of contractual commitments for electricity supply of more than $1 billion
- An incremental rate reduction of, on average, approximately 1 per cent in the period F2014 through F2022

BC Hydro is negotiating agreements to defer COD for projects or to downsize projects where possible; and is declining developer requests for BC Hydro's consent to plant capacity increases unless ratepayer value can be achieved.[7] For example, value can be realized through a variety of mechanisms, such as deferral of commercial operations, capping overall purchase obligations or other contractual concessions. There may also be some limited opportunity to cost-effectively negotiate agreements to terminate certain EPAs where BC Hydro does not have termination rights, but where a termination agreement may result in benefit to both parties. In these cases, BC Hydro weighs a number of factors to determine the best course of action, including but not limited to: BC Hydro's contractual rights and obligations; the PV of the purchase commitment; the value of the energy purchased over the term of the EPA; potential impacts on First Nations and stakeholders; the likelihood that the project will proceed to commercial operations; and the potential cost of a termination agreement, if any.

Table 4-5 and Table 4-6 show the impact on expected energy and dependable capacity of the proposed changes from deferring, downsizing or terminating pre-COD EPAs (Category 1). These changes reflected in the updated LRBs for energy and capacity presented in Figure 4-3 and Figure 4-4 at the end this section.

[7] BC Hydro has discretion under its EPAs to consent or not consent to various requests. In some cases, BC Hydro discretion is absolute and in other cases, BC Hydro must not unreasonably withhold or delay its consent.

Table 4-5 Expected Energy from Pre-COD EPA Terminations and Deferrals, GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Expected Terminations	-166	-181	-209	-209	-209	-209	-209	-211	-209
Expected Deferrals[8]	-331	-76	53	53	53	53	53	53	53
Total	-497	-257	-156	-156	-156	-156	-156	-157	-156

Table 4-6 Expected Capacity from Pre-COD EPA Terminations and Deferrals, MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Expected Terminations	-7	-7	-11	-11	-11	-11	-11	-11	-11
Expected Deferrals	-18	0	3	3	3	3	3	3	3
Total	-25	-7	-8	-8	-8	-8	-8	-9	-8

Category 2: EPA Renewals

As EPAs expire for projects already in operation, BC Hydro is targeting renewal of the contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that these are existing projects where the IPP's initial capital investment has been fully or largely recovered over the initital term of the EPA, BC Hydro expects to be able to negotiate a lower energy price. In its EPA renewal negotiations, BC Hydro will consider the seller's opportunity cost, the electricity spot market, the cost of service for the seller's plant and other factors such as the attributes of the energy produced and other non-energy benefits.

Previously BC Hydro assumed that no existing bioenergy EPAs would be renewed upon expiry due to pricing and fuel supply risks, and that all other existing EPAs would be renewed for the remainder of the planning horizon. For planning purposes, BC Hydro now estimates that about 50 per cent of the bioenergy EPAs will be

8 In some cases it is expected that there will be additional contracted energy and capacity as part of EPA amendments or prior commitments.

renewed, about 75 per cent of the small hydroelectric EPAs that are up for the renewal in the next five years will be renewed, and all remaining EPAs will be renewed. These changes are summed up in Table 4-7 and Table 4-8 and are reflected in the LRBs presented for energy and capacity in section 4.2.6.

The above changes for EPA renewals reflect updated planning assumptions used for this IRP. On an ongoing basis, IPP projects will continue to be individually assessed as EPAs come up for renewal. Refer to section 9.2.4 for additional detail.

The following tables show the impacts to energy and capacity of implementing the proposed changes to EPA renewals (Category 2) using the planning assumptions set out above.

Table 4-7 EPA Renewal Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous EPA Renewals[9]	1,205	1,297	1,298	1,298	1,298	1,298	3,468	4,316	5,086
Updated EPA Renewals	1,147	1,245	1,570	1,683	1,824	2,117	4,357	5,463	6,356
Difference	-58	-52	273	385	526	819	889	1,147	1,270

Table 4-8 EPA Renewal Capacity Differences (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous EPA Renewals	137	142	142	142	142	142	417	444	470
Updated EPA Renewals	133	146	177	202	214	256	539	603	640
Difference	-3	4	35	60	73	114	122	159	170

[9] For Table 4-7 to Table 4-10, the “previous” assumptions refer to the illustrative example, starting in the spring of 2013, used to generate a baseline for comparison.

Category 3: New EPAs

BC Hydro will strive to acquire additional electricity supplies in a prudent and sustainable manner. BC Hydro will also continue to honour prior agreements to negotiate EPAs:

- BC Hydro is committed to the IBAs it has signed with First Nations, with some of those agreements involving consideration of EPAs for power generation projects. The values of about 170 GWh/year of firm energy and 25 MW of ELCC beginning in F2020 are set out in footnote 4 to Table 4-1.
- BC Hydro, under the B.C. Government direction, has made prior commitments to enter into negotiations for EPAs with certain parties as part of broader economic development opportunities and First Nations initiatives. However, since these negotiations are at an early stage, no such potential new EPAs are reflected in the LRBs in this IRP.
- The SOP is an exceptional category of acquisitions as it is a legislated requirement pursuant to subsections 15(2) and 15(3) of the *CEA* which provide that BC Hydro may establish the terms and conditions of the offers under the SOP. The SOP was launched in April 2008 with original pricing of between about $75/MWh and $88/MWh depending on the region. In early 2011, BC Hydro increased the SOP pricing based on the Clean Power Call results. The price offered is roughly $100/MWh but varies depending on the region (the range is $95/MWh to $104/MWh). BC Hydro also increased the size eligibility from 10 MW to 15 MW of nameplate capacity. In March 2013, BC Hydro made changes to the SOP Rules that among other things limit multiple clustered projects from a single developer that exceeds 15 MW to enable broader participation; and create added flexibility for BC Hydro to better manage when SOP energy supply comes on-line. BC Hydro reviews the SOP every two years, with the next review slated for 2014.

- At the B.C. Minister of Energy and Mine's request and based on feedback from First Nations, BC Hydro revised its August 2, 2013 IRP to reflect additional support for the clean energy sector in B.C. and to further promote clean energy opportunities for First Nations communities. Among other things this resulted in an increase to the SOP annual target from 50 GWh/year to 150 GWh/year to enable more small-scale projects in communities throughout BC Hydro's service area and initiatives to promote First Nations participation in the clean energy sector; refer to section 9.2.10 for more detail.

The changes between the illustrative example and what is proposed in this IRP for the SOP are summarized in Table 4-9 and Table 4-10 and are reflected in the LRBs presented in section 4.2.6. As of August 2, 2013, pursuant to the SOP BC Hydro has awarded 11 EPAs with most of the resources being run-of-river, with 12 applications currently under review. The SOP has delivered a total of 407 GWh/year between 2009 and the end of July 2013 as follows: 2009 – 3 GWh/year; 2010 – 41 GWh/year; 2011 – 62 GWh/year; 2012 – 163 GWh/year; and 2013 – 105 GWh/year. For planning purposes BC Hydro, in using its professional judgment based on historical performance of the SOP to date and the 2013 changes to the SOP such as the "cluster rule" change, has included 70 per cent of the new SOP target of 150 GWh/year in its LRB estimates.

Table 4-9 New SOP EPA Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous SOP	520	520	520	520	520	520	520	520	520
Updated SOP	159	239	318	398	477	557	636	1,034	1,431
Difference	-361	-281	-202	-122	-43	37	116	514	911

Table 4-10 New SOP EPA Capacity Differences (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Previous SOP	29	29	29	29	29	29	29	29	29
Updated SOP	13	19	25	32	38	44	51	82	114
Difference	-16	-10	-4	3	9	15	21	53	85

4.2.5.2 Delay Planned Ramp-ups in Spending on DSM Activities

Chapter 6 examines three long-term DSM options, Option 1, Option 2/DSM Target and Option 3, as described in section 3.3.1. Section 6.3 addresses the question of whether DSM Option 2/DSM Target should be revised in the long-term.

This section considers alternative means (the various ways) to reduce DSM costs in the short-term while maintaining the ability to achieve the longer-term DSM savings targets examined in Chapter 6. However, as shown in Table 4-11 below, the LRB after: (1) the EPA management activities in section 4.2.5.1; (2) short-term reductions to the three DSM options discussed in section 3.3.1 and further explored in this section; and (3) the VVO reductions in section 4.2.5.3, still result in surplus in the short to mid-term.

Table 4-11 Energy Surplus/Deficit with DSM Options, GWh

	F2014	F2015	F2016	F2017	F2018	F2019	F2020
DSM Option 1	1,100	2,464	2,331	4,884	3,501	2,154	1,364
DSM Option 2/DSM Target	1,119	2,533	2,480	5,147	3,884	3,040	2,631
DSM Option 3	1,142	2,665	2,813	5,707	4,693	3,701	3,245

DSM is a flexible resource in the context of optimizing BC Hydro's activities over the short to mid-term. To some degree, DSM activity can be ramped up or down over time to better match demand. However, DSM activities are enabled by long-term, sustained relationships with customers and industry partners, and some opportunities are time-limited and may not be deferrable. It is important to understand the limits to which DSM savings can be ramped down (to achieve short-term savings) and then ramped back up to achieve long-term DSM targets.

For DSM Option 3, the ability to reduce current expenditure levels was considered but dismissed. Option 3 features increased program activities and expenditures to target the greatest level of DSM program savings currently considered deliverable. It is BC Hydro's professional judgement that to reduce near-term expenditures but continue to rely upon the longer term savings is not believable or prudent in the case of DSM Option 3.

For Option 1 and Option 2/DSM Target, assessments were also undertaken on near-term expenditure reductions and the ability to recover to the long-term savings targets. For both of these DSM options, the alternative means to achieve long-term DSM targets would reduce ramp rates. The following sets out the alternative means of achieving the Option 2/DSM Target:

- **Alternative Means 1:** continue with previously planned expenditures to implement the DSM target. This is a 'status quo' option, with no adjustments to program expenditures in the near term.
- **Alternative Means 2:** adjust program and supporting initiative expenditures in the near term and then moderately ramp up to the DSM target by F2021. By F2022, expenditures are reduced by over $330 million relative to Alternative Means 1. The reduction is focused over the near term (F2015 to F2022), where F2014 is a transition year. In F2016, planned expenditures are adjusted to a base level of $125 million.

A third path to reach the DSM target was also considered, which reduces expenditures further in the near-term (down to $100 million in expenditures in F2016, the same level of near-term DSM program activity as DSM Option 1 described in Chapter 3) and aggressively ramps up to higher levels of activity starting in F2017. However, even with the aggressive ramp-up rate, this path fails to return to DSM target levels by F2021. In addition, there are likely additional energy savings delivery risks associated with further carve out of expenditures and the aggressive ramp-up rate. For these reasons, BC Hydro does not consider this path to be a viable alternative to return to the current DSM target by F2021.

In examining the alternatives, BC Hydro considered a range of inputs and decision criteria. In working with its Energy Conservation and Efficiency Committee, BC Hydro formed these inputs and criteria into a framework and then condensed them to a reduced set of comparators:[10]

- **Rate Impact:** the rate impact relative to the DSM plan baseline over the near and long-term
- **Cost-Effectiveness:** relative to BC Hydro's avoided cost, program and portfolio cost-effectiveness is considered from both a Total Resource Cost (**TRC**) and Utility Cost (**UC**) perspective. The TRC and UC cost-effectiveness tests are described in section 3.3.4.1.
- **Bill Reductions:** the change to BC Hydro's revenue requirements (or aggregate customer bill) resulting from the different DSM options
- **Risk/Flexibility:** the risk and consequence (regret) of not being able to recover to higher levels of DSM activity by certain time periods; this is managed by maintaining the flexibility to ramp up to higher levels of DSM at points of time in the future

As the impacts considered were based on higher level estimates generated for planning purposes, the analysis will need to be further refined. However, some directional conclusions are:

[10] Other important attributes that were considered include: lost opportunities, customer fairness / equity, customer and industry relationships, market transformation, economic development and environmental impact. While these were not used as comparators, they were considered either (1) implicitly in the design of the alternative means, (2) as a sub-component of one of the comparators (e.g., lost opportunities, customer fairness / equity and customer and industry relationships affect the ability to ramp back up and therefore relate to risk / flexibility) or (3) as something to describe or report out on, but not actively used to tradeoff between means.

- Over the near term, lower level of expenditures are expected to have a reduced rate impact
- Over the long-term, a negligible difference between the average rate impacts of the different alternative means is expected
- A negligible impact on bill reductions from Alternative Means 1 to Alternative Means 2 over 20 years is expected
- Moving from Alternative Means 1 to Alternative Means 2 may introduce some additional, yet-to-be-quantified, deliverability uncertainty because the reduction in near-term activities may have some effect on the ability to ramp back up

As part of the plan to reduce portfolio costs, BC Hydro recommends Alternative Means 2 as the preferred path to reach the DSM target of 7,800 GWh by F2021 and by doing so, reduce expenditures in the near term by approximately $330 million.

The rationale for this recommendation is as follows:

- Moving from Alternative Means 1 to Alternative Means 2 provides roughly the same bill reduction benefit over 20 years
- Moving from Alternative Means 1 to Alternative Means 2 lowers rate impacts in the near-term by reducing expenditures by approximately $330 million

While Alternative Means 2 may have more deliverability uncertainty than Alternative Means 1, BC Hydro considers the trade-off between rate impact and deliverability risk to be acceptable. Moreover, the risk of energy savings delivery is mitigated in part through the construction of Alternative Means 2, which was designed to limit the risk of not being able to ramp up to the DSM target.

Table 4-12 and Table 4-13 demonstrate the impacts on energy and capacity of adopting Alternative Means 2 early in the planning horizon. As this table shows, this reduces savings in the near term but DSM savings return to the Option 2/DSM Target levels by F2021.

Table 4-12 DSM Plan Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Alternative Means 1 Option 2/ DSM Target	5,127	5,689	6,474	7,193	7,790	8,202	8,423	10,196	10,995
Alternative Means 2 Option 2/ DSM Target (recommended)	4,364	4,942	5,893	6,842	7,790	8,202	8,423	10,196	10,995
Change in DSM	-763	-747	-582	-352	0	0	0	0	0

Table 4-13 DSM Plan Capacity Differences[11] (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Alternative Means 1 Option 2/ DSM Target	781	940	1,090	1,238	1,371	1,460	1,519	1,873	2,074
Alternative Means 2 Option 2/ DSM Target (recommended)	820	932	1,078	1,224	1,371	1,460	1,519	1,873	2,074
Change in DSM	39	-8	-12	-14	0	0	0	0	0

Similarly, BC Hydro concluded that it could reduce short-term expenditures if it were to implement DSM Option 1 while maintaining the longer term *CEA* 66 per cent target in F2021. With the lower DSM Option 1 savings target, there was not as much room to move.

In conclusion, Alternative Means 2 is the recommended approach to achieving Option 2/DSM Target. Chapter 6 utilizes the preferred means of achieving the three DSM options and provides comparisons among maintaining, increasing or decreasing long-term levels of DSM savings and how these resource options compare against other supply-side resources available.

[11] The Option 2/DSM Target does not appear to have the same relative reductions for the peak capacity savings when compared to the original 2008 LTAP target because the DSM plan has had recent updates to the mix of programs, rates and codes which impacts the associated capacity savings.

4.2.5.3 Scale Back Voltage and Var Optimization Project Implementation

VVO technology helps reduce the amount of electricity that must be transmitted to ensure sufficient power quality at customer sites. BC Hydro's VVO program was developed in October 2011 based on long-term energy requirements and a LRMC of $132/MWh ($F2012) based on the Clean Power Call.

A review of the VVO program elements identified that a portion of those energy savings are no longer cost-effective. BC Hydro is recommending that work will be completed as planned for substation VVO projects that are presently being implemented. On a go-forward basis, substation VVO projects will be considered based on system growth, reliability, safety and sustainment requirements, and an updated LRMC revised through this IRP (see section 9.2.12). Table 4-14 and Table 4-15 show that this results in a reduction of estimated VVO savings of about 90 GWh/year and 1 MW in F2017, growing to about 250 GWh/year and 1 MW in F2022.

Table 4-14 VVO Energy Differences (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Original VVO Program	359	418	496	539	562	576	585	589	594
Updated VVO Program	273	288	304	314	326	328	329	338	346
Change in VVO	-86	-129	-193	-225	-235	-248	-256	-252	-248

Table 4-15 VVO Capacity Differences (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Original VVO Program	1	1	1	1	1	1	1	1	1
Updated VVO Program	0	0	0	0	0	0	0	0	0
Change in VVO	-1	-1	-1	-1	-1	-1	-1	-1	-1

4.2.5.4 Customer Incentive Mechanisms

Another method identified to temporarily increase demand is through specific, temporary and tailored incentives to BC Hydro's large customers (referred to as Customers Incentive Mechanisms). To date, BC Hydro focused on identifying potential incremental loads from existing Transmission Service Rate[12] (**TSR**) customers, which is approximately 300 GWh/year. Examples of incremental load categories for existing customers include: installing new operating lines; restarting existing operating lines or restarting shutdown plants; increased utilization of existing production capacity (load factor, shifting); shift to production of energy-intensive, higher value products. Going forward, BC Hydro will identify potential new customer loads. One example of potential new customer loads is commercial enterprises operating container and cruise ship terminals which are contemplating investments in shore-side electrical service.[13]

There are a limited number of examples of incentive mechanisms to increase demand: (1) B.C.'s Power for Jobs program launched in 1998, (2) Ontario's Industrial Electricity Incentive Program announced on June 12, 2012; (3) a Hydro Quebec rate schedule introduced in 1983 but phased out in 1988; and (3) Manitoba Hydro's Surplus Energy Program that gives customers access to surplus energy at the same price Manitoba Hydro would receive from the export market.

The B.C. Power for Jobs program was enabled by legislation – the *Power for Jobs Development Act*[14] – in 1997. This program was developed to stimulate economic development in B.C. by making a limited amount of discounted power available to new or expanding businesses, 200 MW of power was notionally allocated to the program from the Canadian Entitlement under the Columbia River Treaty. This

[12] Applying to BC Hydro's largest industrial customers.

[13] BC Hydro has an existing Shore Power Rate (Tariff Supplement No. 76) but the rate is exclusive to cruise ships at Canada Place. BC Hydro estimates that about 60 MW of shore power could be served in the next two to three years, and another 80 MW could be served in the next three to 10 years.

[14] S.B.C. 1997, c.51.

power was made available to qualifying companies on the same terms and conditions as BC Hydro's regular electric tariffs except for the price which the B.C. Government directed BC Hydro to provide at a discount. The program lasted several years and had a number of active participants but the program never achieved its objective of stimulating economic development in a material way. The principal reason for this is that the qualifying criteria were too onerous and screened out most of the potential candidates. However, the criteria were necessarily onerous to address some of the key design considerations, as set out below:

- **Eligibility:** Should be broad so that all TSR customers have an opportunity to participate, perhaps by sector due to intra-industry competition concerns. Commercial customers could also be eligible
- **Duration:** A shorter term may be appropriate because if the mechanism is extended this may advance the need for new higher-cost energy resources
- **Pricing:** For illustrative purposes, pricing could be set between spot market projections for the years F2013 – F2018 (a 'BC sell price'[15] of about $20/MWh for F2013 (in $F2013, USD) to $23/MWh for F2018 (in $F2013, USD) for light load hours) and industrial/commercial customer Tier 1 pricing (for example, about $37/MWh for F2013 (in $F2013) blended, energy portion only of Rate Schedule 1827 for TSR customers).[16] The significant market price differentials between freshet and winter pricing would be considered in the mechanism.

A final consideration would be to look at whether there is alignment with the need to conserve due to the longer-term energy and capacity LRB deficits set out in section 4.2.6.

[15] The 'BC sell price' is the Mid-C market electricity price less wheeling and losses from the B.C. border to Mid-C.

[16] The highest 'Tier 1' pricing is Residential Inclining Block rate at $69/MWh for up to 1,350 kilowatt hours bi-monthly ($F2013).

Using Customer Incentive Mechanisms to temporarily increase demand comes with risks:

- Favourable agreements that are "temporary" in nature can have a tendency to become entrenched and difficult to withdraw when they are no longer required. BC Hydro's E-Plus rates are an example
- There may be conflict between the need to conserve due to the longer-term energy and capacity LRB deficits and the financial benefits of temporarily increasing demand

While BC Hydro is recommending that the incentive mechanisms over the short to mid term be explored, no changes to forecasted demand will be made at this time.

4.2.6 Short-Term Energy Supply Management: Summary and Conclusions

The following tables show the cumulative impact of implementing all proposed changes to energy and capacity over the planning horizon discussed in section 4.2.

Table 4-16 Cumulative Changes to Incremental Resource Additions, Energy (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
EPA Terminations and Deferrals	-497	-257	-156	-156	-156	-156	-156	-157	-156
EPA Renewals	-58	-52	273	385	526	819	889	1,147	1,270
New EPAs (SOP)	-361	-281	-202	-122	-43	37	116	514	911
DSM	-763	-747	-582	-352	0	0	0	0	0
VVO	-86	-129	-193	-225	-235	-248	-256	-252	-248
Net Change	-1,766	-1,467	-860	-470	92	452	594	1,252	1,775

Table 4-17 Cumulative Changes to Incremental Resource Additions, Capacity (F2017 to F2023, F2028, F2033), MW

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
EPA Terminations and Deferrals	-25	-7	-8	-8	-8	-8	-8	-9	-8
EPA Renewals	-3	4	35	60	73	114	122	159	170
New EPAs (SOP)	-16	-10	-4	3	9	15	21	53	85
Change in Planning Reserves	6	2	-3	-8	-10	-17	-19	-28	-34
DSM	39	-8	-12	-14	0	0	0	0	0
VVO	-1	-1	-1	-1	-1	-1	-1	-1	-1
Net Change	0	-20	7	32	62	103	116	174	211

Figure 4-3 and Table 4-18, and Figure 4-4 and Table 4-19, show a need for energy and capacity emerges in F2027 and F2021 respectively with no LNG load, and in F2022 and F2020 respectively when including Expected LNG load.

Figure 4-3 Energy Surplus/Deficit with Incremental Resources

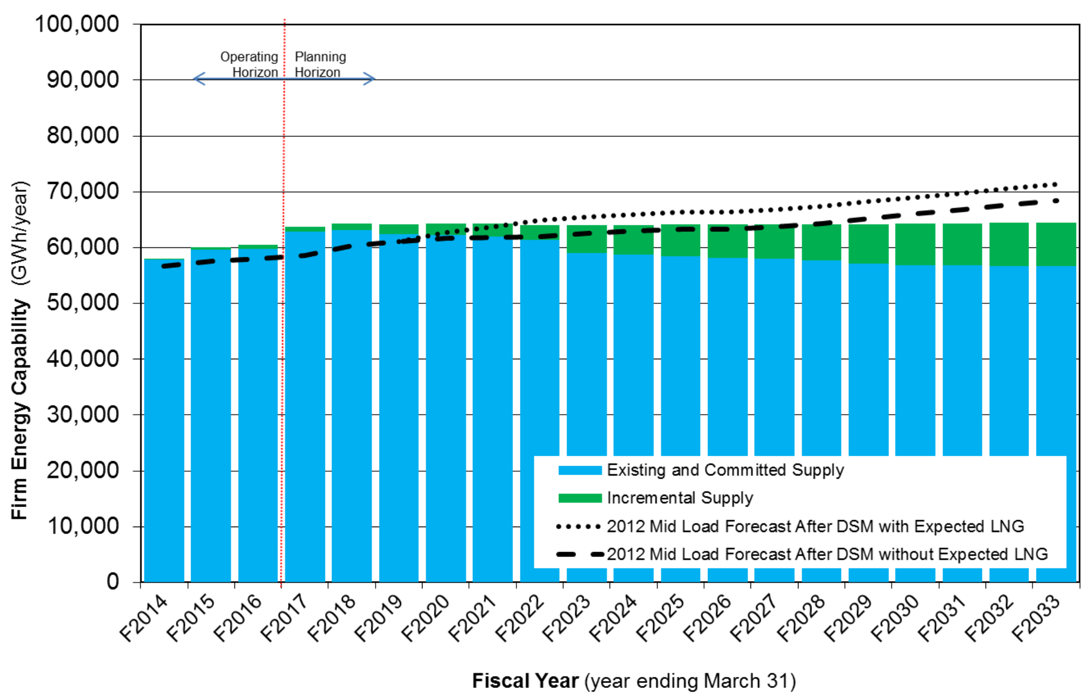


Table 4-18 Energy Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	5,147	3,884	3,040	1,631	497	-845	-1,462	-3,175	-6,932
Surplus/Deficit with Incremental Resources without Expected LNG	5,147	3,884	3,040	2,631	2,497	2,155	1,538	-175	-3,932

Figure 4-4 Capacity Surplus/Deficit with Incremental Resources

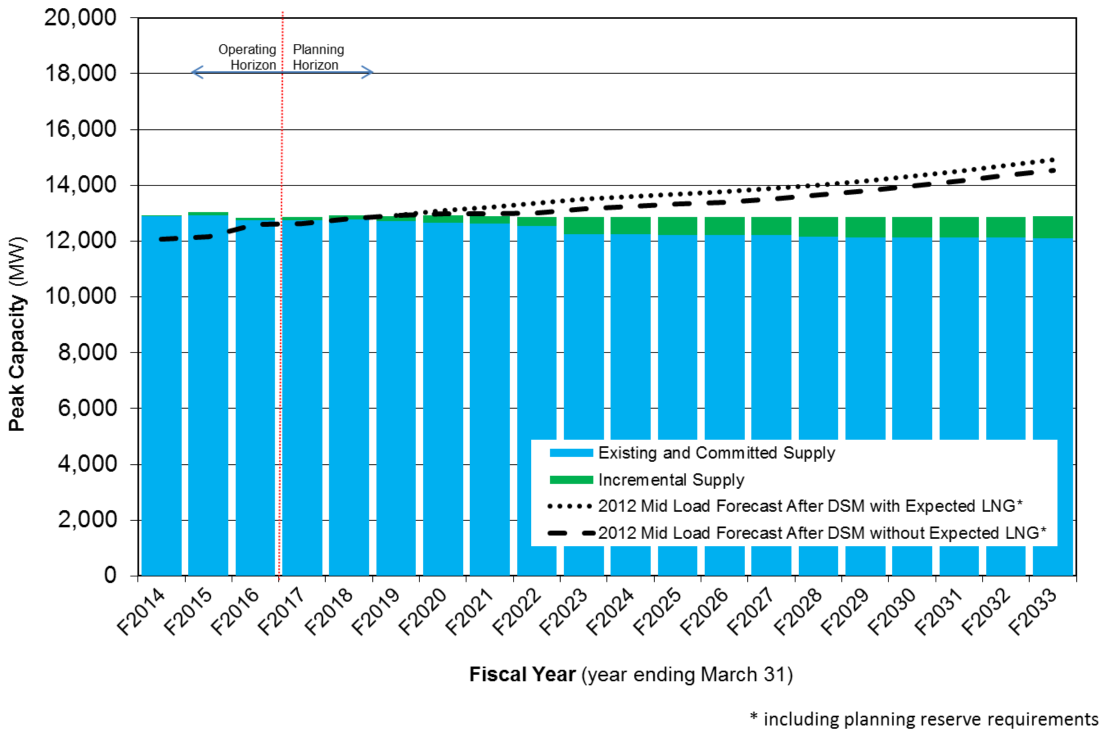


Table 4-19 Capacity Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	239	115	-8	-181	-322	-505	-647	-1,147	-2,026
Surplus/Deficit with Incremental Resources without Expected LNG	239	115	-8	-61	-82	-145	-286	-787	-1,665

Prior to the emergence of these energy and capacity gaps, BC Hydro has sufficient existing, committed and incremental resources (e.g., if the DSM target and EPA renewals are implemented) to achieve self-sufficiency and so will continue to examine ways of optimizing its portfolio of energy resources over this timeframe. Chapter 9 summarizes the Recommended Actions outlined in this section and provides more details regarding how BC Hydro will continue to act on these issues.

The remainder of Chapter 4 describes the framework for addressing these long-term resource options. Chapter 5 examines the conditions that influence prices as BC Hydro interacts with external energy markets. Chapter 6 presents analysis and conclusions regarding these long-term resourcing issues.

4.3 Long-Term Resource Planning Analysis Framework

Section 4.2.6 shows a need for energy and capacity in F2028 (the one-year move from F2027 set out in the August 2, 2013 IRP to F2028 results from the increased SOP annual target) and F2019 (based on adjustments concerning the John Hart Generating Station Replacement Project described in section 2.3.1) respectively based on BC Hydro's mid-2012 Load Forecast before Expected LNG, and a need for energy and capacity in F2022 and F2019 respectively with Expected LNG. This section explains the planning analysis used to compare long-term resource options. Analysis proceeded through the following steps:

1. Consider long-term resource planning questions

2. Define the main decision objectives used to design and compare long-term resource options
3. Assess key uncertainties regarding these resource options
4. Establish portfolio analysis methodology and assumptions

4.3.1 Key Long-Term Resource Planning Questions

The key questions to determine the best mix of supply and demand resources are as follows:

(a) **Natural Gas-Fired Generation:** What is the optimal use of natural gas-fired generation within the *CEA*'s 93 per cent clean or renewable energy objective? And how might natural gas-fired generation be used to serve LNG loads?

(b) **DSM Target:** Should BC Hydro's current long-term DSM target be adjusted?

(c) **Site C Project:** Should BC Hydro continue to advance Site C for its earliest ISD?

(d) **Serving LNG and North Coast Loads:** What actions are required and what supply options need to be maintained to ensure that BC Hydro is able to supply Expected LNG load, additional LNG load above expected and other loads in the North Coast while considering the specific planning challenges of this region?

(e) **Fort Nelson/Horn River Basin:** What is BC Hydro's strategy for meeting significant and uncertain load growth in the combined Fort Nelson and Horn River Basin regions, while ensuring load growth in Fort Nelson is met? What approach should BC Hydro take to respond to *CEA*'s subsection 2(h) energy objective to "encourage the switching from one kind of energy source or use to another that decreases [GHG] emissions in" B.C. via enabling electrification in this region?

(f) **General Electrification:** What role should BC Hydro play to support provincial climate policy? What is BC Hydro's strategy to get ready for potential load driven by general electrification, including assessing potentially significant impacts to existing ratepayers?

(g) **Transmission:** What transmission needs are foreseen over the long-term planning horizon and what actions need to be taken? And to what degree should BC Hydro take a more proactive approach to building transmission infrastructure for clusters of generation locations in advance of need?

(h) **Capacity Requirements and Contingency Considerations:** What additional capacity requirements are foreseen, and what strategies and actions are appropriate in response to these future needs? In addition to filling the most likely mid gap, what are some events that might make the gap larger or smaller, what is the magnitude and timing of these events and what actions can BC Hydro prepare as contingency plans?

4.3.2 Comparing Alternatives Using Multiple Planning Objectives

For any of the key long-term planning questions highlighted in the previous section, a number of possible solutions may be viable. Table 4-20 lays out the decision objectives by which potential solutions are compared and provides the rationale for their consideration. Many of these considerations are embodied in the *CEA* section 2 British Columbia's energy objectives, such as greenhouse gas (**GHG**) emission reduction targets, ratepayer (financial) impacts, and economic development. There is clearly an overlap between these decision objectives and the ones considered for the short-term analysis, with the exception of 'Environmental Footprint', which is more relevant as resources are being added to meet increased demand.

The following sections describe how the financial, environmental and economic development decision objectives were considered in the context of long-term resource planning; minimizing DSM deliverability risk is addressed in detail in section 4.3.4.2.

Table 4-20 *CEA* and Other Resource Planning Decision Objectives

Decision Objective	Reason for Inclusion
Minimize Financial Impacts, including: • Cost (various measures) • Cost Uncertainty • Differential Rate Impacts	Good utility practice; First Nations, public and stakeholder interests; align with *CEA* 'ratepayer impact' objectives grouped in Table 1-1
Minimize Environmental Footprint, including: • Land Footprint • Water Footprint • Criteria Air Contaminants • GHG Emissions	Good utility practice; First Nations, public and stakeholder interests; align with *CEA* 'clean/renewable/DSM/GHG impacts' objectives grouped in Table 1-1.
Maximize Economic Development	First Nations, public and stakeholder interests; align with *CEA* 'economic development' objectives grouped in Table 1-1
Maximize System Reliability • Minimize DSM Deliverability Risk	Good utility practice; First Nations, public and stakeholder interests

4.3.2.1 Financial Impacts

In the IRP, the financial implications of the resource options, or strategies, to fill the LRB gap are tracked at a portfolio level both for the cost of acquiring new resources and also for how these resources interact with the existing BC Hydro system and the external electricity market. Costs are expressed on a PV basis to capture the impact of the timing of costs and trade revenues over the planning horizon. Where uncertainty is relevant, cost ranges or costs across scenarios are highlighted.

4.3.2.2 Environmental Footprint

The environmental footprint of portfolios modelled to meet long-term energy and capacity needs are tracked with respect to potential effects on land, freshwater, marine, air (criteria air contaminants) and climate change (GHG emissions). These footprints were considered at a portfolio level as data does not exist at a regional or local level for all projects; in many cases, generation resources are represented as a "typical" project or bundle of projects. In addition, the resources selected through modelling are not necessarily the ones that would be selected through an actual power acquisition process.

The full set of environmental information for comparing portfolios with respect to the key IRP questions is presented in Appendix 6A. This information is summarized at a level appropriate for comparing portfolios of resource options in section 6.4.

4.3.2.3 Economic Development Impact

In response to the *CEA*'s subsection 2(k) energy objective "to encourage economic development and the creation and retention of jobs", BC Hydro tracks the possible footprint of each portfolio for meeting long-term energy and capacity needs with respect to effects on employment, Gross Domestic Product (**GDP**) and government revenue. These measures are generated for a provincial-level view, as the data and modelling did not exist to provide a more regional view of these potential impacts. In addition, given that the modelled resource additions might not be the same as the projects selected through an actual acquisition process, these measures are appropriate for high-level comparisons of broad impacts.

Appendix 3A-5 discusses the methodology behind these measures and provides the detailed economic development criteria, including more granular views of the source of these potential impacts (e.g., direct versus indirect/induced changes). As this additional level of analysis did not provide additional insight into the comparison of portfolios of resource options it is presented at a higher level in the body of the IRP.

BC Hydro notes that rate impacts can also be an economic development issue.

4.3.2.4 IRP Treatment of Multiple Decision Objectives

In instances where the impacts of different options are quantified with respect to how they impact decision objectives, a consequence table is a useful format in which to present these multiple effects. A consequence table is a collection of alternatives, decision objectives and their estimated attributes arranged in a matrix with the alternatives displayed as column headers (i.e., portfolios representing different strategies for addressing the LRB), and the relevant decision objectives displayed as row labels. An example similar to a consequence table from Chapter 6 is presented in Table 4-21 for illustrative purposes.

Table 4-21 Example Consequence Table

	Measure	Clean with SCGTs (within *CEA* 93% limit)	Clean Power with Transmission
Land	total hectares (**ha**)	22,300	28,200
Marine (valued ecological features)	total ha	49	56
Affected Stream Length	km	390	510
GHG Emissions	CO_2e ('000 t)	16,400	3,800
Local Air Contaminants	Oxides of Nitrogen ('000 t)	17	12
Local Air Contaminants	Carbon Monoxide ('000 t)	33	12
GDP	$ million PV	16,000	16,200
Employment	FTEs	317,000	338,100
Government Revenues	$ million PV	2,600	2,700
Cost	$ million PV	14,948	15,603

While judgment is required to reduce the full analysis to a condensed level, this view allows a reader to see the relative impacts of resource options across alternatives and decision objectives. (The unabridged versions of these tables can be found in Appendix 6A).

Consequence tables also help clarify the balance BC Hydro is seeking in developing cost-effective solutions. Given the precision of the measures and the range of their potential impacts across resource options for each IRP question, it cannot be presented as a mechanical weighting and scoring outcome. Rather the consequence tables attempt to summarize what could be gained and what might be given up across resource options. Qualitative factors not captured in the consequence tables and comparisons where impacts are not easily quantified also need to be considered; professional judgment is required to balance the quantified and non-quantified factors across these multiple options and multiple objectives when developing conclusions and recommendations.

4.3.3 Key Uncertainties and Risks

To provide a clear discussion of the uncertainties and risks that BC Hydro is managing, the following definitions are provided:

- Uncertainties are variables with unknown outcomes
- Risk is commonly defined as the effect of uncertainty on objectives

Some key uncertainties and related risks for addressing resource needs over the longer term include:

(a) Load growth and the chance that load growth exceeds or falls below expectations

(b) DSM initiatives and the chance that DSM savings exceed or fall below expectations

(c) Features of BC Hydro's existing system and its operations, including inflow water variability

(d) Natural gas and electricity spot market and long-term market price uncertainty

(e) Renewable Energy Credit (**REC**) prices and GHG emission prices

(f) Current and future regulatory and public policy developments such as: GHG regulation, Renewable Portfolio Standard targets and eligibility requirements

(g) IPP development, including type of resource and location and the risk that these resources require significant capacity and transmission support

(h) IPP attrition rates from power acquisition processes and the chance that these exceed or fall below expectations

(i) Site C timing and approval to proceed to construction

(j) Natural gas-fired generation resources and the uncertainty around the ability to permit these resources in time to respond to short-term capacity requirements

(k) New demand for electricity may develop sooner than transmission lines can be built to provide the service

(l) Non-thermal capacity resources and their ability to meet capacity requirements on short notice with high reliability

4.3.4 Quantifying Uncertainty

Section 4.3.3 laid out key uncertainties and risks that could potentially influence the comparison of resource options with respect to the IRP's key questions. Where possible, BC Hydro quantified these uncertainties to be transparent about their role in the IRP analysis, results and conclusions. This section describes the different approaches to handling uncertainty in the IRP analysis. These approaches are addressed in more detail in Appendix 4A.

Table 4-22 Approaches to Handling Uncertainty

Approach	Brief Description	Examples
Parameterization of Historical Observations	Uses sequences of past data to derive a statistical description of the range of uncertainty	Load forecast inputs, such as economic growth, housing starts, population growth
Subjective Probability Elicitation	Where good historical data does not exist, uses knowledgeable specialists to construct a description of the range of uncertainty	• Savings from DSM tools including codes and standards, rate structures and programs • IPP attrition rates for possible future calls
Monte Carlo Analysis	Mechanical way to jointly calculate the influence of several uncertain variables through simulation of thousands of combinations	• Load forecasting • DSM savings (bottom-up analysis)
Scenario Analysis	An alternative way to jointly calculate the influence of several uncertain variables, but only using a few, select combinations	• Market price scenarios • Load/resource gap (large and small gap)

Approach	Brief Description	Examples
Sensitivity Analysis	Testing one variable at a time to see whether different values within the range of uncertainty impact policy considerations	In addition to the scenarios described above, exceedance of the Site C capital cost estimate; narrowing the cost of capital differential between BC Hydro and IPPs; higher and lower wind integration cost. BC Hydro also undertook compound sensitivities such as low gap, low market
Conservative Point Estimates / Managed Costs	Incorporates uncertainty by taking a single point estimate, chosen in a "conservative" fashion	Firm energy expected from IPP hydro projects
Best Estimates	Does not take into account uncertainty in any fashion; usually reserved for variables where uncertainty is assumed to have a small or manageable impact	Energy from wind projects

The IRP analysis uses a mix of these approaches to explore how uncertainty impacts the comparison of options and the strategies to manage the residual risks of the Recommended Actions. As always, professional judgment informed by quantitative analysis and qualitative information is required when interpreting data, balancing objectives, and making decisions.

4.3.4.1 Load Forecast Uncertainty

The uncertainty around the load forecast is one of the largest uncertainties faced by BC Hydro in its long-term planning process. As outlined in section 2.2.4, BC Hydro produces both a mid-load forecast as well as a range of uncertainty around that estimate. This range of uncertainty is derived using a Monte Carlo analysis based on the impact on load of the uncertainty associated with a set of key drivers:

- The drivers for the commercial and residential sectors include economic activity, weather, electricity rates and demand elasticity
- The spread of uncertainty around the large transmission sector was approached separately. Given the large volume of transmission level demand that could increase or drop off in response to rapidly changing external market forces, the load forecast Monte Carlo model was augmented to better capture

this important influence on load uncertainty. The transmission sector was broken down into four major sub-components: Forestry, Oil and Gas, Mining, and Other. For each sector, BC Hydro produced a range of possible load levels to capture both very high load and very low load growth trajectories. For each sector, these trajectories were put into a triangular probability distribution (see Table A2.2 in Appendix 2A). To capture the notion that these sectors likely depart from their mid forecasts in response to common external shocks, these growth trajectories were modelled with a positive correlation. Finally, the Monte Carlo model also employed a slight positive correlation between these sectors and the overall GDP to capture the common movements of the resource sector and the economy in general.

The results of the Monte Carlo simulation are then split into three discrete forecasts: high forecast, mid forecast and low forecast. By construction, the high and low forecasts (shown here as the edges of the fan of uncertainty) are the mean of the upper and lower twentieth percent tails of the load forecast distribution. As the results turn out, the blue shaded area is also approximately the 80 per cent confidence interval for the load forecast.

Figure 4-5 Range of Uncertainty Regarding Energy Load Forecast

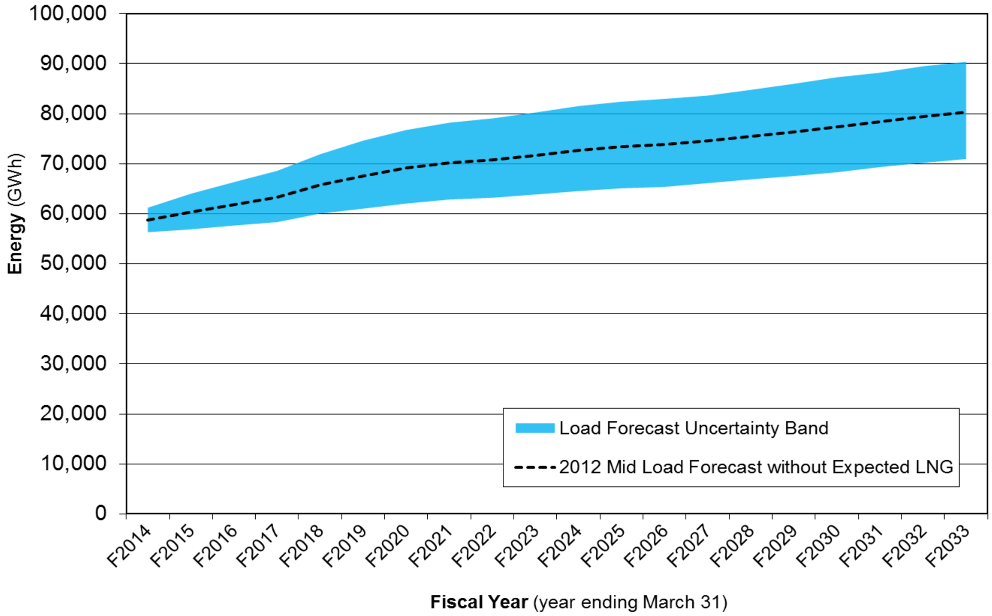
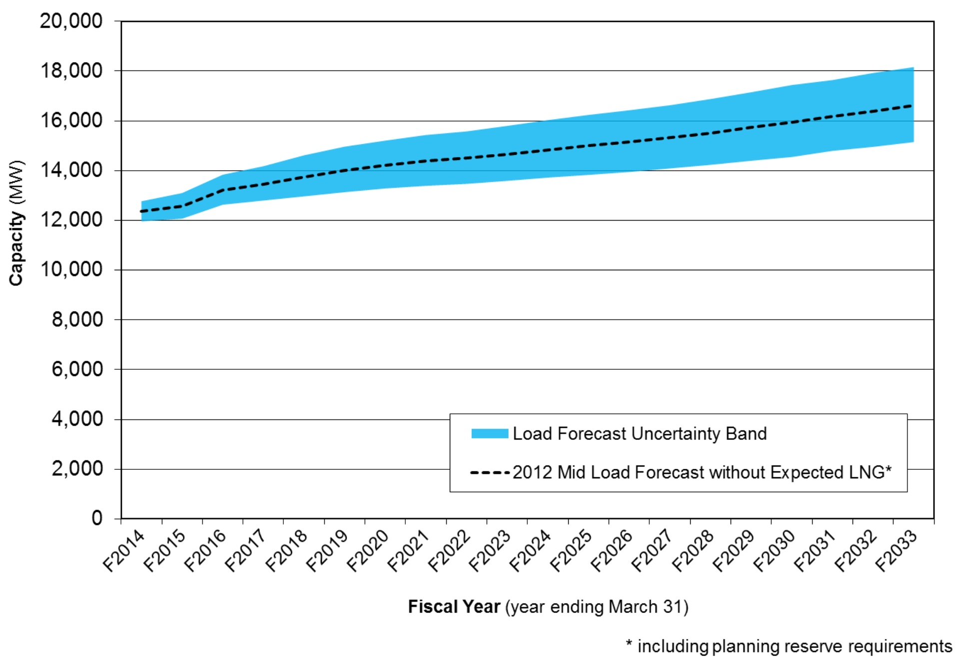


Figure 4-6 Range of Uncertainty Regarding Capacity Load Forecast



Several key uncertainties are captured through separate analyses due to their large size and uncertain timing:

- Potential North Coast LNG loads
- Potential Fort Nelson and Horn River Basin loads
- Potential general electrification loads

These potentially large, discrete additions to load are covered as separate topics of analysis within the IRP.

As discussed in section 2.2.4, and in response to the BCUC 2008 LTAP Directive 6, BC Hydro investigated the overlap and interrelationship between load growth and DSM savings (referred to as DSM/Load Forecast Integration). Details of this can be found in Appendix 2B of the IRP, however not all issues have been resolved. Some gaps still remain to be addressed, including natural conservation and natural load growth assumptions for the 2012 Load Forecast and baseline assumptions for DSM programs. These still have the potential to impact load forecasting accuracy.

4.3.4.2 DSM Savings Uncertainty

DSM continues to be BC Hydro’s first and best option for meeting load growth. However, precise forecasting of DSM savings for long-term planning purposes is challenging for several reasons, including:

- Limited experience with respect to targeting cumulative savings above current levels
- Difficulty in distinguishing between load growth and DSM effects
- Difficulty linking customer response to DSM actions, and forecasting the timing and efficacy of regulatory changes

In view of these challenges, BC Hydro continues to emphasize and build upon approaches described in the 2008 LTAP to understand DSM savings uncertainty.

Part of these approaches characterizes the range of uncertainty around DSM savings estimates to better inform decisions regarding energy and capacity planning. In addition, where possible and available, BC Hydro looked at what other jurisdictions have done on this subject and finds that it is among the leaders in the field in its efforts at assessing DSM uncertainty in the long-term planning context.

BC Hydro is filling the majority of its load/resource gap with DSM, so understanding the range of uncertainty around savings estimates is crucial. Forecasting DSM savings uncertainty is a new field that draws extensively upon unique techniques such as subjective probability judgments. As such, substantial, additional details are provided in Appendix 4B on the methodology and detailed findings. The discussion of DSM savings uncertainty is organized around the following steps:

- Jurisdictional Review Summary
- Quantified Uncertainty Regarding DSM Energy Savings
- Quantified Uncertainty Regarding DSM Energy-Related Capacity Savings
- Capacity-Focused DSM Savings Uncertainty
- Overall Conclusions

DSM Jurisdictional Review

The key driver behind the DSM uncertainty assessments was to better understand the degree to which BC Hydro could deliver on its DSM targets. While the bulk of this work was based on internal analysis, BC Hydro also looked externally to determine the extent to which other jurisdictions have been able to deliver on similar DSM goals. The resultant DSM jurisdictional assessment can be found in Appendix 4D; its application to DSM uncertainty can be found in Appendix 4B. This section highlights key findings and draws lessons for DSM uncertainty assessment.

The study looked at 26 utilities and DSM implementers in North America. To a certain extent, results are limited by reporting issues and data availability. This sample comprises a snapshot of the leading and most aggressive applications of DSM in the North American electricity sector, and is most useful for comparing changes to program spending and less useful for changes to codes and standards and rate design. At a high level, this is because few jurisdictions report energy savings from codes and standards activity and because other jurisdictions focus on peak shaving rate structures such as Critical Peak Pricing.

Using the average annual savings goals for DSM Option 2/DSM Target and comparing this to what has been claimed by other utilities, the following observations can be made:

- The study is partially based on claimed savings from other jurisdictions. However, this does not reduce the difficulty of distinguishing between DSM effects and impacts on load growth. Moreover, verification methods and reporting vary across jurisdictions. This means that those levels of savings claimed in other jurisdictions do not necessarily translate into potential to reduce BC Hydro load.
- No other jurisdiction in this survey is relying on a combination of programs, codes and standards, and rate design in a coordinated way. This makes an “apples to apples” comparison very difficult.
- If the future program targets for Option 2/DSM Target are examined alone, then there are jurisdictions that have claimed past savings in excess of BC Hydro’s planned savings from DSM programs
- At least one other jurisdiction in this sample (PacifiCorp) plans on using less than the full amount of cost-effective DSM potential due to concerns regarding reduced portfolio diversification and deliverability risk, based on professional judgment

This jurisdictional assessment was designed to assist in understanding the confidence with which BC Hydro can deliver its planned DSM savings in future years. This gives some reasons for cautious optimism about moving forward with DSM programs at the level of DSM Option 2, but it also highlights the uniqueness of BC Hydro's combination of all three DSM tools to achieve conservation targets.

Quantified Uncertainty Regarding DSM Energy Savings

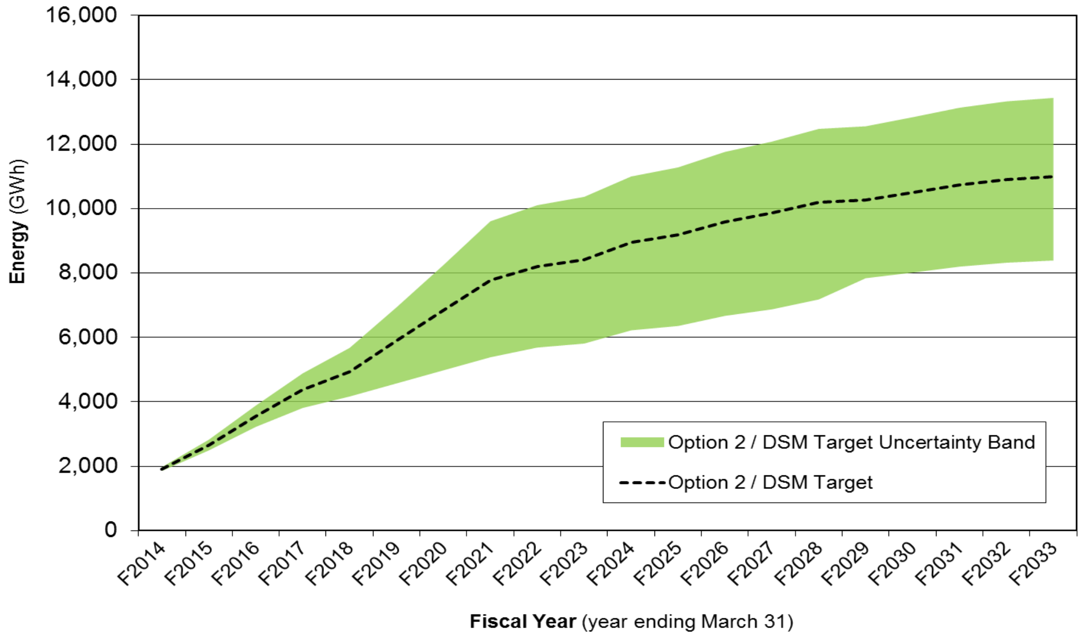
The DSM energy savings uncertainty analysis focuses on quantifying the range of possible outcomes from the following three broad categories:

- DSM programs
- Codes and standards
- Rate structures – changes considered for all major rate classes

BC Hydro undertook analysis of the range of uncertainty for each of these items. By combining all of the quantified sources of uncertainty in a Monte Carlo analysis and adjusting based on professional judgment, BC Hydro produced a quantified range of uncertainty around mid-level DSM estimates. Details of this process can be found in Appendix 4B.

Figure 4-7 puts the high and low DSM savings forecasts into a band of uncertainty around the mid DSM savings forecast for Option 2 as a way of illustrating the range of DSM savings uncertainty around the mid-point estimates. Similar to the load forecast figure, the high and low DSM savings estimates are calculated as the mean of the upper and lower twentieth percentile tails of the distributions. As the results turned out, the fan of uncertainty roughly corresponds to an 80 per cent confidence interval for DSM savings. Figure 4-7 shows uncertainty regarding DSM forecast savings in the near term is low, but this grows over time creating a broad fan of possible levels of DSM savings in the future.

Figure 4-7 Range of Potential Energy Savings for DSM Option 2



However, it must be emphasized that BC Hydro must rely on professional judgment given the uncertainty in assessing DSM deliverability. For example, the assumption made in this analysis is that uncertainty grows in a linear way. This assumption is likely not correct, as uncertainty usually grows in a non-linear way into the future, a factor not captured in this uncertainty analysis. BC Hydro is of the view that given the aggressiveness of the DSM target, there is likely more risk of under-delivery than of over-delivery. Another point of reference is a review of historic DSM savings. Table 4-23 demonstrates historic DSM savings since 2009 and shows that DSM has not either under- or over-delivered to the extent set out in Figure 4-7 above. The year 2009 is chosen because this is the year the DSM Target was introduced and the DSM Target is a significant step up from DSM targets BC Hydro set before 2009.

Table 4-23 DSM Historical Plan and Actual Cumulative Electricity Savings since F2009 (GWh)

	DSM Plan	Actual
F2009	678	1,295
F2010	1,540	1,909
F2011	2,349	2,314
F2012	3,310	3,528
F2013	4,439	4,460

Based on the experience of building several iterations of DSM options, the spread of uncertainty for DSM Options 1 and 3 would be expected to be roughly similar, albeit scaled proportionately to match their levels of savings.

Several observations can be made from this analysis. First, there is a substantial amount of uncertainty for all options when planning for the mid forecast. Second, for DSM Options 1, 2 and 3, there is no clear demarcation between “acceptable” and “unacceptable” with respect to savings uncertainty; each option shows a considerable range of potential outcomes, with the larger DSM portfolios containing both larger downside and larger upside uncertainty.

To the extent that BC Hydro can react to this potential magnitude of DSM under-performance and increase DSM electricity savings to target levels over this timeframe, then DSM savings uncertainty is manageable. However, if the size and timing of the under-performance poses concerns, then deliverability of DSM energy savings is a risk that needs to be considered, both in choosing the appropriate level of DSM and in managing the risk during the implementation of the IRP recommendations. This underscores the importance of having robust DSM performance management and a robust contingency plan to backstop BC Hydro’s energy and capacity needs. This latter topic is addressed in section 6.9.

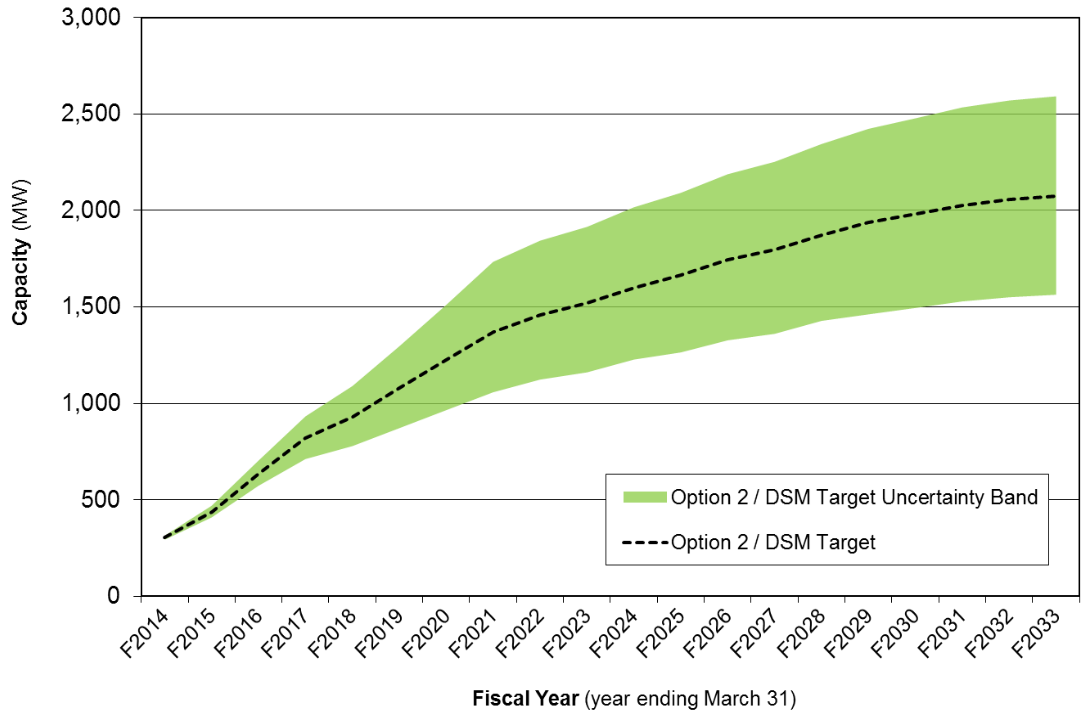
Quantified Uncertainty Regarding DSM Energy-Related Capacity Savings

Energy-focused DSM measures also bring associated capacity savings. Two sources of uncertainty were built into the IRP analysis regarding DSM energy-related capacity savings:

- The underlying uncertainty around the energy savings themselves (as discussed above)
- The capacity factors used to translate energy savings into the associated level of capacity savings

Capacity factors are used to translate general energy savings into peak savings. These parameters are treated as uncertain estimates to capture the lack of precise knowledge about how energy savings from multiple sources would reduce peak demand. Combining the uncertainty around capacity factor estimates and the uncertainty regarding the underlying savings estimates in a Monte Carlo distribution generated a spread of possible capacity savings around the estimate. Details can be found in Appendix 4B. The outcome of this can be seen in the following graph for DSM Option 2 capacity savings over time.

Figure 4-8 Range of Potential Capacity Savings for DSM Option 2



Again, the assumption made in this analysis is that uncertainty grows in a linear way. This assumption is likely not correct for the reason discussed above regarding DSM energy savings.

Similar to DSM energy savings, the range of capacity savings for Options 1 and 3 would be expected to be similar to that shown for Option 2, but proportional to the amount of savings for each option. The observations here somewhat parallel those made with regard to DSM savings uncertainty on the energy side:

- There is significant uncertainty with respect to DSM capacity savings across all options
- Moving to higher levels of DSM increases uncertainty around capacity savings

- There is no clear quantified demarcation between “acceptable” DSM options and “unacceptable” DSM options with regard to energy-related capacity savings uncertainty when comparing Options 1, 2 and 3

The significant difference that needs to be taken into account on the capacity side is that the consequences of under-delivery of capacity resources are much more severe than on the energy side, and may undermine BC Hydro’s fundamental requirement to serve load. As a result, BC Hydro draws the following conclusions:

- Choosing options with higher capacity uncertainty should only be done if the option is a cost-effective resource and if the level of deliverability risk can be adequately managed through other means
- Preparing contingency responses to prepare for the possibility of DSM under-delivery is an important part of BC Hydro’s Contingency Resource Plans, regardless of the DSM option chosen. Refer to section 6.9 and section 9.4

Capacity-Focused DSM Savings Uncertainty

While the energy-focused DSM options discussed in the previous section have associated capacity savings, additional capacity savings may be possible through capacity-focused DSM activities. These were described in section 3.3.2 and at a high level, refer to DSM activities that can reliably reduce peak demand over the long-term (also referred to as peak reduction or peak shaving). This section addresses the uncertainty around the capacity savings forecasts.

Capacity-focused DSM savings were grouped into two broad categories:

- Industrial load curtailment
- Capacity-focused programs

BC Hydro has previously entered into load curtailment agreements with industrial customers; however, it is not clear how easily this experience can be translated into agreements that can reliably reduce peak demand over the long-term when and as needed. As a result of this, a spread of possible outcomes was constructed around the estimated levels of savings to capture this uncertainty. Details outlining the method for doing this can be found in Appendix 4B.

Table 4-24 Savings from Capacity-Focused DSM and Uncertainty (MW in F2021)

	Industrial Load Curtailment	Capacity-Focused Programs
Low (P10 cutoff)	313	132
Mid (mean or expected)	383	191
High (P90 cutoff)	446	262

Capacity-focused DSM represents a potentially attractive approach to peak reduction. However, there are a number of uncertainties that have been highlighted in this analysis:

- Since BC Hydro is just starting to develop long-term capacity-focused savings options, implementation success is an important issue. In particular, customer participation rates are unknown. This makes it difficult to rely on these approaches to address near-term capacity and contingency needs.
- Once these approaches are established, operational experience will still be required to understand how participation rates and savings per participant translate into peak shaving and whether these peaks are coincident with peak load and whether peak shaving leads to other system peaks. In particular, BC Hydro will need to effectively identify and design around free-ridership to generate peak shaving behaviour change.

Overall Conclusions Regarding Long-Term DSM Savings Uncertainty

BC Hydro is expected to meet the majority of its load growth through DSM. As such, a considerable effort to better understand the uncertainty inherent in this demand-side resource and incorporate it into the decision-making framework is warranted.

Progress has been made since the 2008 LTAP on many of these questions:

- A detailed study on load forecast and DSM integration addressed some overlaps and found that other concerns were already adequately addressed by existing processes
- A more focused jurisdictional review found evidence pertaining to the experiences of other utilities
- A top-down analysis of overall DSM uncertainty tried to capture issues of uncertainty not addressed by the more mechanical, bottom-up Monte Carlo studies

In addition, newly emerging circumstances have brought to the fore some additional areas of interest that are just starting to be explored:

- Ramp-Up Rates – To what extent can DSM activities be moderated when need is not pressing, but then accelerated if and when demand growth increases?
- Capacity – Given the emergent importance of capacity issues in this IRP, and given that DSM efforts and verification to date have been energy-focused, is there additional uncertainty with associated capacity savings?

Despite the advancement in understanding some of these issues, uncertainty around the large DSM savings being targeted continues to be a key uncertainty in long-term resource planning. These are difficult issues that face the electricity industry at large and none of them can be considered “solved”. Moreover, data sets and learning continue to evolve over time, even over the course of a long-term planning cycle. As such, professional judgment will continue to play an important role in both the interpretation of data and in balancing DSM deliverability risk with other key energy planning objectives.

4.3.4.3 Net Load and Net Gap Uncertainty

Net load is the level of load after DSM savings. Forecasting net load is subject to the joint uncertainties of forecasting load growth and forecasting DSM savings.

Estimates of the range of outcomes around the forecast were developed for load growth (Chapter 2) and DSM savings (section 4.3.4.2). These were combined to yield a range of possible outcomes for net load, along with the associated relative likelihoods of achieving these outcomes. Details of this process are contained in Appendix 4A.

For most IRP questions, the uncertainty regarding future net load is expressed as a three-point, discrete distribution. Combining the net load distribution for a given DSM option with the existing, committed and incremental resource stack yields a large gap, mid gap,[17] and small gap.[18] To clarify this concept, the table below lays out how these gap levels are defined.

Table 4-25 Gap Terminology

	Small Gap	Mid Gap	Large Gap
Load Assumptions	Low load scenario	Mid-load scenario	High load scenario
DSM Assumptions	High DSM savings scenario, but with scaled back effort. Modelled as low DSM savings	Mid-DSM savings scenario	Low DSM savings

The one change to be noted for this IRP is the definition of the “small gap” scenario. As discussed in section 3.3.1, there is evidence that a reduced load forecast impacts DSM economic potential. In addition, as recent experience has highlighted, a prolonged period of low load growth would likely not be accompanied by BC Hydro continuing to pursue the same level of DSM savings. Rather, efforts would likely to

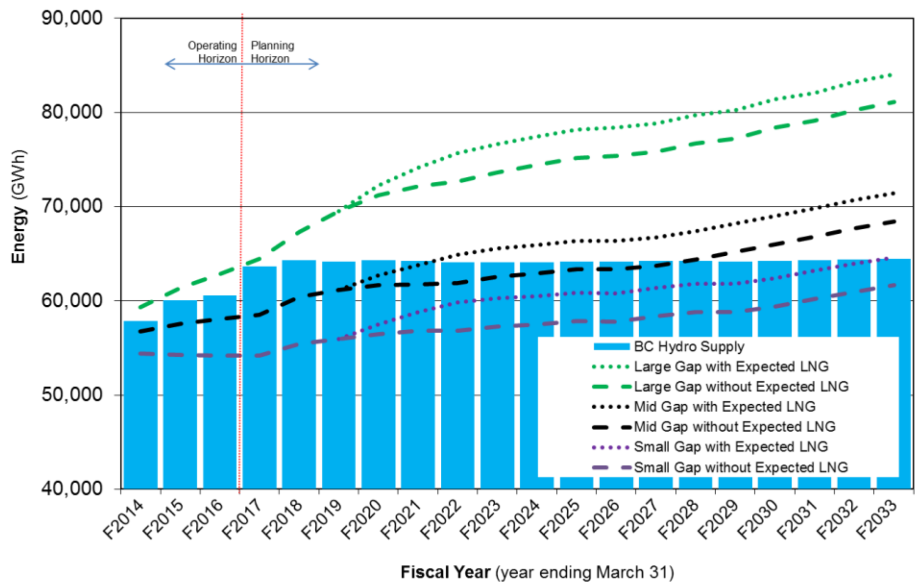
[17] The mid gap corresponds with the load-resource balance shown in section 2.4.

[18] While “gap” refers to any situation where demand does not meet supply, it is important to note that “gap” could refer to deficit (which requires additional resources to fill) or surplus (which may call for strategies to reduce). In periods of surplus, this traditional terminology can be confusing and so care must be taken in its interpretation.

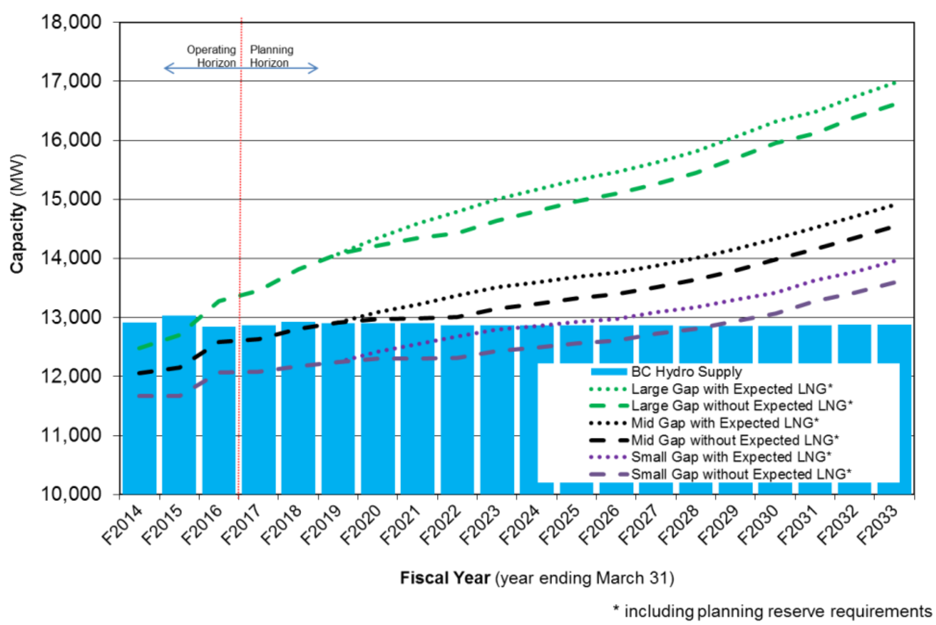
be scaled back in the face of a prolonged economic slump, even if the conditions for overachieving DSM savings (e.g., high public participation, high savings per participant, large elasticity of demand, better than expected progress on codes and standards implementation) were in place. This combination of scaled-back efforts paired with better than expected DSM savings conditions in a low load growth scenario was modelled as a low level of DSM savings. This approach is a rough approximation to capture dynamic decision-making within a static modelling framework and so some care must be taken when interpreting results involving the low gap (large surplus) scenarios.

These energy gaps (assuming DSM Option 2) are shown Figure 4-9 and Figure 4-10 for energy and capacity, respectively. The gap between load (after DSM) and resources either represents a surplus where costs need to be managed (if supply is greater than demand) or a deficit that must be filled with supply-side resources. If the comparison between load and resources results in a surplus, the IRP analysis considers the costs of selling the surplus into the market.

1 **Figure 4-9 Energy Gap**[19]



2 **Figure 4-10 Capacity Gap**



[19] The y-axis has been magnified to better demonstrate the variation between the six gap scenarios. The energy graph y-axis starts at 40,000 GWh/year and the capacity graph y-axis starts at 10,000 MW.

The conclusions to the key IRP questions addressed in Chapter 6 are collected into a Base Resource Plan (**BRP**). The primary focus of the BRP is to address the needs identified by the mid gap. As such, the majority of the analysis in Chapter 6 is based on the mid gap scenario with Option 2/DSM Target, unless otherwise noted.

BC Hydro develops additional actions for contingency plans that ensure that alternative sources of energy and capacity supply are available if the risks materialize or additional loads develop. In section 6.9, BC Hydro examines the need for additional energy supply if load differs from the mid gap scenario. The large gap scenario is a useful test of how large and how quickly load can differ from the mid gap. It provides guidance on the range of capacity resources that need to be ready, and the required timing of these resources, to respond effectively. Conversely, the small gap scenario helps explain the benefits of flexibility (for example exit ramps) in the case that need is decreased. Refer to section 6.4 for additional discussion of resource flexibility.

4.3.4.4 Market Price Forecast Uncertainty

Using costs to compare portfolios of DSM and supply-side options requires estimating not only the cost of acquisitions, but also the costs and trade revenues of each portfolio operating over the planning timeframe. The operating costs and revenues are affected by:

- Natural gas prices
- Electricity prices for import and export
- GHG allowance and offset prices
- RECs

The future price path of each of the above variables is estimated with uncertainty. These price levels vary over time; their estimated levels and departures from their estimated values are some of the main drivers of long-term planning decisions. A further complication is the inter-relationship between these variables. Chapter 5 explores each of these price forecasts in more detail. Section 5.2 outlines how these uncertainties were combined into five Market Scenarios, to create combinations of factors that:

- Represent a wide, but plausible range of input and output prices
- Avoid combinations that were internally inconsistent
- Are large enough in number to cover key combinations but small enough in number to be tractable within IRP modelling resource constraints

In most cases, the base assumption for the Chapter 6 analysis is Market Scenario 1, as BC Hydro considers this the most likely scenario. Where relevant, resource options were compared using some of the five Market Scenarios to test whether strategies were robust given possible different market price futures.

4.3.4.5 Wind Integration Cost and ELCC Uncertainty

Two main uncertainties were highlighted with respect to wind resources:

- Wind integration costs
- ELCC (discussed in section 3.2.1)

The wind integration cost is described in Appendix 3E. A value of $10/MWh is used as the base case and additional sensitivity tests were performed using $5/MWh and $15/MWh as the lower and upper bounds, respectively.

The determination of the wind ELCC value is described in Appendix 3C. The current analysis suggests an ELCC value of 26 per cent of installed capacity. This value is used as the base assumption for all portfolio modelling. The wind ELCC is modelled as a random variable with a lopsided triangular probability distribution function, using a zero per cent ELCC value as a lower bound (worst case) assumption, 26 per cent as the upper bound (best case) assumption, and 26 per cent as the most likely assumption. Changes to this variable did not make a material impact to the overall analysis.

4.3.4.6 IPP Attrition Uncertainty

IPP clean or renewable energy resources are one of the resource options BC Hydro considers to fill the load/resource gap. However, given that recent BC Hydro acquisition processes have resulted in varying rates of attrition, IPP attrition rate is flagged as an uncertainty that could affect the comparison of resource options. For this IRP, BC Hydro adopted a range of attrition rates, bracketing those evidenced in recent acquisition processes. The lower and upper bounds, as well as a best estimate, are shown in Table 4-26. A triangular distribution was developed for Monte Carlo simulation to help inform the range of uncertainty for net gap estimates.

This estimation of IPP deliverability uncertainty could play an important role in estimating risks to supply reliability. However, given the anticipated small role incremental IPP resources are expected to have in the planning horizon based on the reference load forecast and successful implementation of the DSM target, this factor was dropped from analysis in Chapter 6.

Table 4-26 IPP Attrition Rates and Uncertainty (per cent)

	Lowest Credible Bound	Mid (Best) Estimate	Highest Credible Bound
Attrition Rates	5	30	70[20]

4.3.4.7 Resource Options

Chapter 3 outlined the resource options that could be considered in filling the energy and capacity gaps. However, some of these resource options present operational and developmental challenges, as well as uncertainty around their technological

[20] The upper bound for IPP attrition is based on attrition rates from the F2006 Call for Power. The EPAs awarded during this call included two coal-fired generation projects, which were subsequently terminated due to a change in B.C. Government policy.

maturity. As described in section 3.7, only resource options that have proven development in B.C. and meet legal restrictions and B.C. Government policy objectives were included in portfolio modelling;section 4.4.6.1 provides a list of the resources considered.

4.3.5 Applying the Resource Planning Analysis Framework to Comparing Alternatives

Sections 4.3.2 to 4.3.4 outlined how the IRP's resource planning analysis framework provides a process for comparing options, using multiple objectives, given significant planning uncertainty.

Figure 4-11 is used in Chapter 6 in the discussion of modelling results to help clarify which options and uncertainties are being explored and which are fixed with respect to each of the key IRP questions. The legend is intended to clarify the background assumptions against which the resource options are examined. As an example, Figure 4-11 shows a portfolio run that has fixed the DSM target at Option 2/DSM Target, the Market Acenario at Scenario 1, etc. When the modelling choice for each row is filled in, it becomes easier to understand the key underlying variables chosen for each set of portfolios. The portfolio shown in Figure 4-11 represents the base set of assumptions, and many of the IRP questions are examined in relation to this starting point or analysis.

Figure 4-11 Modelling Map and Base Modelling Assumptions

Modelling Map					
Uncertainties/Scenarios					
Market Prices	Scenario 2 Low	Scenario 1 Mid	Scenario 3 High		
Load Forecast	Low	Mid	High		
DSM deliverability	Low	Mid	High		
LNG Load Scenarios	Prior to Expected LNG	800 GWh	3000 GWh	6600 GWh	
Resource choices					
Usage of 7% non-clean	Yes	No			
DSM Options	DSM Option 1	DSM Target/ Option 2	DSM Option 3		
Site C (all units in) timing	F2024	F2026	No Site C		
Modelling Assumptions and Parameters					
BCH/IPP Cost of Capital	5/7	5/6			
Pumped Storage as Option	Yes	No			
Site C Capital Cost	Base minus 10%	Base	Base plus 10%	Base plus 15%	Base plus 30%
Capital Cost for alternatives to Site C	Base	Base plus 30%			
Wind Integration Cost	$5/MWh	$10/MWh	$15/MWh		
	shows the modeling assumptions				

4.4 Portfolio Analysis Methodology and Assumptions

BC Hydro's primary method of analyzing resource options is portfolio analysis. Portfolio analysis develops and evaluates resource portfolios, consisting of a sequence of demand-side and supply-side resources (including transmission) to meet customers' energy and capacity needs. Portfolio analysis is part of the overall IRP resource planning analysis framework; and portfolios are compared across the resource planning objectives outlined in Table 4-20 and incorporated the key uncertainties identified in section 4.3.3.

BC Hydro has maintained the same portfolio analysis process as was used in the 2008 LTAP. In its 2006 IEP/LTAP Decision, the BCUC agreed “that a portfolio analysis is consistent with the Commission’s Guidelines”, and “is a best practice for IEP or IRP analysis”.[21] Portfolios for this IRP were created for the planning period from F2017 to F2041.[22]

This section describes the models used and the modelling assumptions made in the portfolio analysis. Figure 4-11 summarizes the range of assumptions made for the key uncertainties present in the portfolios and highlights the base set of assumptions.

4.4.1 Portfolio Analysis Models

This IRP used the same suite of models as was used in the 2008 LTAP, including:

- Hydro Simulation model (**HYSIM**)
- System Optimizer
- Multi-Attribute Portfolio Analysis (**MAPA**)

HYSIM is a system simulation and production costing model developed in-house by BC Hydro which determines a least-cost generation pattern for the large hydropower system using 60 years of historic reservoir inflow records. HYSIM provides insight into how year-to-year inflow variability may impact resource portfolio performance. It is mainly used to estimate the monthly and annual energy produced by the large hydro system under average water conditions. The resulting energy production for the large hydropower plants was input into System Optimizer.

Resource portfolios for the IRP were developed using System Optimizer which is a product of Ventyx. System Optimizer is a deterministic mixed integer programming

[21] 2006 IEP/LTAP Decision, pages 89 and 90.

[22] The four-years prior to F2017 are within the operational timeframe for which long-term planning actions have limited impact. Therefore, resources for these three years are assumed common across all portfolios and are not modelled.

optimization model that determines an optimal sequence of generation and transmission resource expansions, referred to as a portfolio, for a given set of input assumptions. It does so by minimizing the PV of net cost required to meet a given load under average water conditions. The net costs include the incremental fixed capital and operating costs for new resources, total system production costs, and electricity trade cost and revenues. System Optimizer does not value the ancillary benefits provided by future potential resources such as the ability to integrate intermittent resources and to increase the firm capability of other resources. This value could be significant for resources such as Site C, natural gas-fired generation or pumped storage.

MAPA is a tool developed within BC Hydro that takes the portfolio output from System Optimizer and tracks various attributes of each portfolio such as environmental and economic development attributes which are described in Chapter 3.

For a more detailed description of the models used, refer to Appendix 4C.

4.4.2 Modelling Constraints

The portfolios created satisfy good utility practice (e.g., they meet reliability criteria as described in section 1.2.2). Three *CEA* objectives are treated as constraints: (1) achieve self-sufficiency; [23] (2) meet the 93 per cent clean or renewable electricity target described further in section 6.2; and (3) meet the at least 66 per cent of incremental load growth by year 2020 (F2021) with DSM.

4.4.3 Financial Parameters

The IRP portfolio analysis was performed and presented in F2013 constant dollars. The PVs of the portfolios reflect the costs (or levelized costs where appropriate) for the planning period from F2017 to F2041. The key financial parameters in the IRP

[23] Except as noted in the two year proposed economic bridging to Site C's ISD described in section 9.2.7.

analysis include the following: inflation rate, cost of capital, discount rate and U.S./Canadian exchange rate.

4.4.3.1 Inflation Rate

Where conversion between nominal and real dollars is necessary, an annual rate of 2 per cent was used as the average inflation rate. This assumption is consistent with the B.C. Consumer Price Index (**CPI**) outlook which is provided in the Province of B.C. 2013 Budget and Fiscal Plan. Aside from the annual inflation rate assumption, the IRP includes no other incremental cost escalation or allowance for increasing capital costs. This assumption reflects the 2013 BC Hydro recommended project cost estimation outlook based on the following observations:

- The Bank of Canada announced that its long-term inflation target is centred around the 2 per cent level, and that it will take action if price increases stray outside of a one to three percent band around this mid-point
- While B.C. construction activities have seen a gradual recovery from 2011 to 2012:
  - Market competition for BC Hydro construction projects has remained strong in recent years
  - The continuing strength of the Canadian dollar has been helping to moderate material and equipment procurement costs in international markets
  - Having a national CPI below 2 per cent has been moderating inflationary pressure on the construction sector and contributes to a stable inflation outlook.

4.4.3.2 Cost of Capital

The cost of capital used is the weighted average cost of debt and equity. The weighted average cost of capital (**WACC**) is the rate of return that a company could expect to earn in an alternative investment of equivalent risk. As discussed in section 3.2.2, BC Hydro's WACC is 5 per cent (real), which is a reduction from 6 per cent (real) in the 2008 LTAP. The 5 per cent real rate has been consistently applied in the recent costing of resources developed by BC Hydro such as Resource Smart projects and Site C. BC Hydro used a WACC of 7 per cent (real) for IPPs for the analysis in this IRP. Sensitivity of the portfolio results to this assumption is explored by performing several System Optimizer runs using a 6 per cent (real) WACC for IPP projects, effectively reducing the cost of capital differential between BC Hydro and IPPs from 2 per cent to 1 per cent.

4.4.3.3 Discount Rate

Discount rates reflect the market demand for, or opportunity cost of, the capital associated with projects of similar risk. This IRP used 5 per cent and 7 per cent discount rates to calculate levelized resource unit costs (UECs and UCCs) for BC Hydro and IPP resources respectively. The updated discount rates reflect the change in BC Hydro's WACC and the updated assumption of IPP's WACC. In the long-term planning context, the discount rate methodology is consistent with the WACC used to calculate cost streams of installed resources.

BC Hydro's discount rate is used to calculate PVs of portfolios. This reflects that the evaluations are performed from the utility's perspective.

4.4.3.4 U.S./Canadian Exchange Rate

Assumptions about the U.S. dollar to Canadian dollar exchange rate are required to convert the market price forecasts described in Chapter 5. The assumed conversion rate was 0.9693 USD/CAD, which is similar to the exchange provided by the B.C. Treasury Board in its December 2012 Outlook.[24]

[24] The Treasury Board of the Province of B.C.'s December 2012 Outlook quoted a USD/CAD foreign exchange rate is 0.9770 for F2018 which covers most years of the planning period.

4.4.4 Load/Resource Assumptions

The LRBs shown in Figure 4-3 and Figure 4-4 form the base assumption for resource requirements in the IRP portfolio analysis. These LRBs reflect the December 2012 Load Forecast described in Chapter 2, as well as the near-term cost reduction actions on IPP acquisitions, DSM and VVO, which is described in section 4.2.5. Incremental load scenarios (i.e., large and discrete loads) as described in section 4.3.4.1 are used to create different portfolios to answer specific questions.

4.4.5 Market Price Assumptions

The costs and trade revenues of operating each portfolio over the planning time frame are one element used to compare the portfolios. These operating costs and revenues are affected by the natural gas, GHG, electricity, and REC market price assumptions. Chapter 5 describes these market prices under different market scenarios and how they are used in the IRP analysis. Portfolios were generally created for the most likely or expected Market Scenario as well as across different market scenario(s) where warranted.

4.4.6 Resource Options

Chapter 3 presents an extensive list of resource options within B.C. The resource options described in section 3.6 and 3.7 have been eliminated from consideration in the portfolio analysis. The remaining resource options, referred to as Available Resource Options, are then made available to System Optimizer for creating portfolios.

It is recognized that some of the resources that were screened or not modeled could become viable over the planning horizon. Their exclusion from the IRP portfolio analysis does not imply that they would be excluded from consideration in the IRP recommendations.

4.4.6.1 Available Resource Options

The resource options are available for portfolio analysis are listed below. Apart from pumped storage, all of these resource options have been developed in B.C.

- DSM Options 1, 2/DSM Target, and three savings, and costs attributed to various DSM options which were modelled in System Optimizer
- On-shore wind
- Run-of-river hydro
- Site C (not including sunk costs)
- Biomass – Wood-based biomass (with the exception of the standing timber portion of the potential, which has been excluded in the modeling due to cost and other uncertainty)
- Biomass – municipal solid waste
- Biomass – biogas or landfill Gas (not modeled because it only has small energy and capacity potential, and potentially double counts resources that could be acquired under existing acquisition programs)
- Cogeneration (not modeled because it only has small energy and capacity potential, and potentially double counts resources that could be acquired under the existing acquisition program)
- Resource Smart projects (GMS Units 1-5 Capacity Increase[25] and Revelstoke Unit 6[26])
- Pumped storage:

[25] The first year that these capacity upgrades were available to System Optimizer is F2021 and reflects constraints due to on-going work at GMS.

[26] The first year that the sixth unit at Revelstoke was available to System Optimizer is F2020 and reflects constraints due to on-going work at the Mica and Revelstoke powerhouses.

- ▶ There are no commercial pumped storage facilities in B.C., and only one pumped storage facility operating in Canada which was permitted in the 1950s. Siting a pumped storage facility in B.C. triggers a number of regulatory/government agency approvals resulting in timing and outcome uncertainty.
- ▶ Pumped storage resources are modeled to be dispatched in generate mode during heavy load/high price periods such as weekdays during the day, and in pump mode during light load/low price periods such as overnight and on Sundays. The sum of the energy produced and consumed by a pumped storage resource was set to yield a net efficiency of 70 per cent (a net energy consumer), which is in line with efficiencies seen at existing pumped storage facilities.

- Gas-fired generation – Section 6.2.3 describes how gas-fired generation is considered for resource planning and sets out the rationale for modelling this resource in portfolios as follows:
  - ▶ In portfolios where natural gas-fired generation is an available resource, it is limited by the requirement to comply with the *CEA* 93 per cent clean or renewable energy objective
  - ▶ Where natural gas-fired generation is built to serve non-LNG load, the type of generator built is assumed to be a SCGT with a minimum capacity factor of 18 per cent
  - ▶ Policy Action No. 18 of the 2007 BC Energy Plan provides that all new natural gas-fired generation must have zero net GHG emissions. The cost to completely offset GHG emissions is captured in the portfolio analysis. These cost assumptions are described in section 5.4.3.3.

4.4.6.2 Resource Option Attributes

The technical, financial, environmental and economic attributes of the Available Resource Options from Chapter 3 are inputs into the portfolio analysis. When evaluated as part of a resource portfolio, the following generic costs are added to the cost of these resources.

- **Soft cost adder:** This is applied to generic resource options or specific projects that do not have discrete cost estimates which specifically include costs related to mitigation, First Nations, public engagement regulatory review costs (i.e., resource options other than Site C and Revelstoke Unit 6. BC Hydro notes that it has not used a soft cost adder for GMS Units 1-5 Capacity Increase, but the addition of this adder would not materially change the results). The UECs and the UCCs described in Chapter 3 do not include mitigation measures, regulatory review, First Nation consultation and public engagement costs. To reflect the fact that developing future generic resource options would entail additional soft cost expenditures, BC Hydro has added 5 per cent to the cost of these resources. BC Hydro chose 5 per cent based on past experience. The environmental assessment, First Nations, and stakeholder engagement costs in a sample of recent representative BC Hydro capital projects ranged from 0.02 per cent to about 10 per cent.
- **Wind integration cost adder:** This is applied to future wind resources. Natural variations in wind speed make the power generated by this resource particularly challenging to both forecast in upcoming hours and days and integrate into the power system on a minute-by-minute basis. Wind power generation is highly variable in the short-term timescale of seconds to minutes resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. The natural variability in wind power generation also makes it difficult to forecast wind in the hour- to day-ahead timeframe, resulting in the need to set aside system flexibility to address the potential for wind generation to either under- or over-generate in

this time frame. Both of these challenges have cost implications that are specific to wind power generation[27] and are quantified in a wind integration cost adder that is used in this IRP analysis as well as previous acquisition processes.

BC Hydro first started to investigate wind integration costs in 2008. A wind integration cost of $10/MWh was applied in the 2008 LTAP portfolio analysis as well as in the subsequent 2010 Clean Power Call evaluation. In 2010 BC Hydro completed a second, more detailed wind integration study which is included in Appendix 3E. This study considered 12 wind integration scenarios which included: (1) two study years representing different load and system generation configurations; (2) two levels of wind location diversity; and (3) three wind power penetration levels. The wind integration costs for the 12 scenarios ranged from $5/MWh to $19/MWh. Generally speaking, wind integration cost increased as the wind penetration level increased, whereas geographic diversification significantly reduced the wind integration cost for all study years and all penetration levels. Given that $10/MWh is within the range, BC Hydro continues to use this figure for a wind integration cost adder in the IRP analysis. This value will periodically be revisited in the future with further studies on wind integration costs. BC Hydro conducted wind cost integration sensitivities, including using a low wind integration cost of $5/MWh and a high wind integration cost of $15/MWh.

- **Network upgrade cost adder:** The network upgrade (**NU**) cost adder reflects the costs borne by BC Hydro when interconnecting resource options to the bulk transmission system. This includes cost of upgrades on the transmission circuits leading from the point of interconnection to the bulk 500 kV circuits. A NU cost, estimated based on average NU costs from the Clean Power Call,

[27] Other renewable resources, such as solar and wave, are also highly variable in short-term timescales. The variability of run-of-river generation is largely contained within the monthly/seasonal timeframe, which is captured in the IRP modeling tools.

was added to all resource options except for those that have such costs explicitly included in their cost estimates or those that would interconnect directly to a 500 kV system or to a sub-station in close proximity to a 500 kV substation.

4.4.7 Transmission Analysis

The analysis of the long-term transmission requirements in this IRP was based on BC Hydro's Integrated System Planning Criteria (refer to Appendix 2D). These criteria define BC Hydro's guidelines for planning a reliable transmission network that is adequate for dispatching designated generation resources to serve forecasted demand. For system performance under normal and contingency conditions, BC Hydro's planning criteria conform to the BCUC-approved North American Electric Reliability Corporation Reliability Standards for transmission planning.

In accordance with the criteria that require the bulk transmission system to remain within its thermal and stability limits under all demand conditions, the transmission analysis in System Optimizer identifies where and when incremental transmission capacity will be required for a particular portfolio. The power flows on the bulk transmission network are calculated and, if the expected flow on a transmission cut-plane[28] exceeds its most restrictive rating, the cut-plane's total transfer capability is increased. This increase is achieved by selecting a wire or non-wire transmission improvement option (for a list of options refer to section 3.5) that will alleviate congestion along that existing transmission path. The results from System Optimizer are reviewed and, if needed, the reinforcement requirements are adjusted. The PVs of the portfolios presented in Chapter 6 reflect these adjustments.

[28] BC Hydro's critical bulk transmission paths are also referred to as transmission cut-planes. These transmission cut-planes divide the province into regions for transmission analysis (refer to Figure 3-6).

The IRP transmission analysis highlights areas of high-density power flow that may warrant upgrades to the existing bulk transmission grid. It does not compare possible transmission alternatives or recommend optimal transmission solutions. It also does not provide a detailed cost and scope for particular transmission reinforcements.

Review of BC Hydro's Alternatives Assessment Methodology

Prepared for BC Hydro

September 23, 2014

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1. Executive Summary

Synapse Energy Economics, Inc. (Synapse) was retained by BC Hydro to conduct a review of its 2013 Integrated Resource Plan (IRP) and to prepare a report detailing whether specific input assumptions and the methodology for analyzing resource alternatives align with good utility resource planning practices. Before preparing this report, we reviewed the relevant sections of BC Hydro's IRP, the various filings made as part of the 2013/2014 Site C environmental assessment process, and various other utility planning documents.

Specifically, Synapse was asked to comment on the following: 1) the differential between the weighted average cost of capital (WACC) for BC Hydro and for Independent Power Producers (IPPs); 2) the use of sensitivity analyses as a means to evaluate the direction and magnitude of risk; 3) the use of analytical methods, including the appropriateness of BC Hydro's Unit Cost Comparison, as well as the System Optimizer model; and 4) the calculation of annualized costs with respect to resource end-of-life. This report does not include validation of the remaining input assumptions or the recommended actions contained in BC Hydro's 2013 IRP. Our review is largely of the methods used for analysis in this IRP. With the exception of the WACC, Synapse was not asked to review or evaluate any of BC Hydro's input assumptions and has no comment on those assumptions at this time.

With respect to the WACC, BC Hydro has selected reasonable values and has given proper consideration and quantification of resource cost uncertainty through sensitivities. The Company's alternatives analysis methodology and tools are consistent with good utility practice and includes valuable elements. There may be areas in which BC Hydro might improve in future resource plans as changes occur in the natural world and in the resource planning environment, but those need not be considered at this time.

2. Introduction

In 2013, BC Hydro completed its most recent IRP. This plan looks out over a period of 30 years, forecasting energy and capacity needs of British Columbia and making a determination of the best portfolio of supply- and demand-side resources to meet those needs at the lowest cost to consumers.

Integrated resource planning is an extremely valuable exercise, but is nonetheless difficult and time-consuming. BC Hydro faces some additional challenges in its resource planning that are unique to the Province, which narrow the pool of resources from which it can choose. First, the British Columbia *Clean Energy Act* (CEA) mandates that BC Hydro become self-sufficient – holding the rights to enough electricity generated in the province to meet the utility's supply obligations – by the year 2016, and each year thereafter.[1] The CEA also states that at least 93% of the electricity generated in British Columbia must be from clean or renewable resources. Finally, Policy Action No. 13 of the BC Government's 2002 Energy Plan restricts BC Hydro's capacity to add new generating resources to Site C and improvements at existing plants. Other new electricity generation must be developed by the private sector. This is important, as, unlike many other utilities, BC Hydro has to go to IPPs for new capacity and energy. Financing costs and BC Hydro's WACC becomes especially important in this context, and is the only one of the BC Hydro input assumptions that Synapse was asked to review.

Given the constraints described above, and others, BC Hydro made a number of additional input assumptions (which Synapse did not review) and engaged in various types of cost and modeling analysis in order to generate various resource portfolios. These portfolios provide for the capacity and energy necessary to meet demand over a 30 year planning period at a specific cost to consumers. BC Hydro completed a levelized cost analysis that examined the unit energy and unit capacity costs of various types of resources. Those supply- and demand-side resources with the greatest potential for meeting energy and capacity needs at the lowest cost were then included in the System Optimizer model. This model generated several resource portfolios, calculating the present value of revenue requirements (PVRR), which were compared by BC Hydro. Risks and uncertainties of each of these portfolios were evaluated using a variety of sensitivity analyses. These methods of analysis that Synapse was asked to evaluate in the 2013 IRP are largely consistent with good utility practice. There may be areas in which BC Hydro might improve in the future, but there is uncertainty as to whether or not these suggestions will improve the resource planning process.

3. INPUT ASSUMPTIONS

3.1. Cost of Capital

BC Hydro utilizes two different values for weighted average cost of capital in its Integrated Resource Plan.[2] The Company recommends a 5% real WACC for its own investments and 7% for IPPs and other third party developers; the 2% differential (and a sensitivity that reduces the differential to 1%) is set out in the Site C hydro project environmental assessment documentation and the IRP. The BC Hydro rate of 5% is reasonable, as BC Hydro's borrowing is guaranteed by the government, and the Company may also borrow directly from the Province. The British Columbia Utilities Commission recognizes this, stating that "With respect to the cost of capital, BC Hydro projects will clearly have an advantage as a result

[1] S.B.C. 2010, c.22
[2] BC Hydro. 2013 Integrated Resource Plan. Page 3-8.

of…access to the Province's high credit rating."[3] Utilities similar to BC Hydro appear to be using comparable values for WACC. In its *Needs For and Alternatives To Business Case* submission, for example, Manitoba Hydro conducted its resource analysis using a WACC of 5.05% in its base case.[4]

It can logically be expected that IPP projects will have higher financing costs.[5] BC Hydro did, however, test a sensitivity case that examines a 1% differential in the WACCs . The Site C portfolio did maintain a cost advantage under this sensitivity, though the benefits were slightly reduced when compared to other portfolios.

There are two ways that project specific risks can be analyzed: 1) they can be reflected in the WACC for IPPs; and 2) they can be reflected in sensitivity analyses or project-specific contingences, as discussed in the next section. An adjustment in the WACC for different types of generating projects would depend on many factors. This is, in fact, one of the issues in using the WACC to reflect project risks. Any project may have multiple risk factors, and the use of a single WACC number that reflects all of these does not allow for an evaluation of the direction or magnitude of any individual risk factor. BC Hydro instead performed sensitivity analyses, changing one variable at a time, "to determine which variables are the most influential and which are secondary."[6]

3.2. Project Risks and Sensitivity Analyses

The set of sensitivities analyzed in the IRP include the following:

- Large and small gap conditions in the load and resource balances[7]
- BC Hydro/IPP cost of capital differential (1%)
- Market prices (high and low)
- Site C capital costs (+10%, +15% and +30%)
- Wind integration costs ($5/MWh and $15/MWh)

Fuel cost sensitivities are typically done for integrated resource plans, and BC Hydro's sensitivities around market prices also contain variation around natural gas prices, with the Company examining

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[3] British Columbia Utilities Commission. In the Matter of British Columbia Hydro and Power Authority and 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan – Decision. May 11, 2007. Page 205.
[4] Manitoba Hydro. Needs For and Alternatives To Business Case Submission. August 16, 2013. Page ES-19. Available at: http://www.hydro.mb.ca/projects/development_plan/bc_documents/nfat_business_case_complete.pdf
[5] California Energy Commission. Comparative Costs of California Central Station Electricity Generation. Draft Staff Report. August 2009. Page 15.
[6] BC Hydro. 2013 Integrated Resource Plan. Page 6-44.
[7] BC Hydro uses the mid-gap in its base case analysis.

High, Mid, and Low gas scenarios.[8] BC Hydro subsequently analyzed compound sensitivities, combining sets of variables that have the largest potential effect on cost-effectiveness: the load/resource gap, market prices, and Site C capital costs.

Sensitivity testing is a common practice among utilities engaged in resource planning, with most, if not all, utilities completing a sensitivity analysis as part of a resource plan. Best practices dictate that

> At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values…Individual utilities must determine those input assumptions that are subject to variability, and model sensitivity cases accordingly to properly account for risks and uncertainties that they face.[9]

It is essential that all important and uncertain assumptions be tested, and the BC Hydro analysis includes many that are significant. The capital cost associated with Site C is one of the most important uncertainties and deserves additional consideration here. BC Hydro evaluated sensitivity cases for Site C that increase capital costs by +10%, +15%, and +30% more than those costs in the base case. As a comparison, Nalcor Energy, in its evaluation of its Muskrat Falls hydro project, evaluated a single capital cost scenario for Muskrat Falls at +25%.[10] This estimate was categorized as Class IV, which is subject to more uncertainty than BC Hydro's Class III estimate. BC Hydro tested a comprehensive set of capital costs sensitivities and output results show that there are still benefits to Site C under some of these scenarios, but that Site C becomes more costly under others.

Water level is a variable that is important for utilities dependent on hydro generation like BC Hydro, and a sensitivity around this variable is one that may appear to be missing from the Company's analysis. In the state of Oregon, which is also largely dependent on generation from hydropower, the Public Utilities Commission *requires* that electric utilities include a consideration of the risks and uncertainties associated with hydroelectric generation in integrated resource plans.[11] Manitoba Hydro is currently pursuing two new large hydro resources: 1) the Keeyask project is 684 MW with an ISD of 2019; and 2) the Conawapa project is 1,485 MW with the earliest ISD of 2026.[12] In Manitoba's planning analysis, generating stations are planned to meet the energy demand under the lowest flow on record (as well as the highest winter peak demand),[13] but the Company also did a low water sensitivity for its proposed projects, intended to simulate severe drought conditions. It also did sensitivities on both increased and decreased river flows due to climate change.

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[8] BC Hydro. 2013 Integrated Resource Plan. Page 5-37.

[9] Wilson, Rachel and Bruce Biewald. Best Practices in Electric Utility Integrated Resource Planning. Synapse Energy Economics. Prepared for the Regulatory Assistance Project. June 2013. Pages 31-32.

[10] Navigant Consulting Ltd. Independent Supply Decision Review Prepared for Nalcor Energy. September 14, 2011. Available at: http://www.nalcorenergy.com/PDF/lcp0923.pdf

[11] Oregon Public Utility Commission. Order No. 07-002. Docket No. UM 1056. January 8, 2007. Appendix A. Page 1.

[12] Manitoba Hydro. Needs For and Alternatives To Business Case Submission. August 16, 2013. Page O-13.

[13] Manitoba Hydro. Needs For and Alternatives To Business Case Submission. August 16, 2013. Page ES-13

BC Hydro meets its energy requirements with firm energy, defined as "the ability to meet load requirements under the *most adverse* sequence of stream flows as experienced by BC Hydro's Heritage hydroelectric assets within the 60-year period between October 1940 and September 2000."[14] There is also a reliance on non-firm hydro energy backed up by market purchases. This non-firm energy is calculated based on the average water conditions experienced by the Heritage assets during the same 60-year time period. As a result, BC Hydro relies upon this non-firm energy of 4,100 GWh. The risk of stream flows that are even lower than the most adverse historic flows, does exist, though it is small. Because of the significant reliance on hydro generation in British Columbia, one might expect to see a similar type of sensitivity in BC Hydro's planning analysis. This type of sensitivity scenario might be something to consider for future IRPs.

BC Hydro did examine the implications of climate change on precipitation in the Province, and the Company's models showed that precipitation would increase under these scenarios.[15] As part of the Environmental Assessment of Site C, Environment Canada agreed with BC Hydro that these effects may be too uncertain and take place too far into the future to be included in this IRP,[16] but should continue to be studied as climate models evolve. The Site C hydro project is a long-lived asset and it is reasonable to expect that a changing climate will have an effect on its operations at some point in the future.

4. ELECTRIC GENERATION RESOURCES – CHARACTERISTICS AND INTERACTIONS

4.1. Unit Cost Comparison (Block Analysis)

BC Hydro used two different methods to evaluate the costs of new generating resources and resource portfolios. The first of those is a levelized cost analysis, which calculates the cost of a unit of energy ($/MWh) or of capacity ($/kW-year), levelized over the life of the resource. Calculation of these unit energy costs (UECs) and unit capacity costs (UCCs) allows BC Hydro to compare resource options in a way that is economically consistent, and the utility can screen out those resources with costs that are much higher. Levelized cost analysis can enable one to construct a supply stack or curve, that when matched with loads, can provide clues as to the types of resources that might be needed in a future portfolio. The Company applied this methodology to demand-side management (DSM) as well as the following supply-side resources: biogas, biomass, waste heat, municipal solid waste, non-storage hydro, pumped storage, large hydro (Site C), solar, onshore and offshore wind, tidal, wave, geothermal, natural

[14] BC Hydro. 2013 Integrated Resource Plan. Page 1-13.

[15] Site C Environmental Assessment Document – Canadian Environmental Assessment Registry #1640, Response to Joint Review Planel Information Request No. 76.

[16] Site C Environmental Assessment Document – Canadian Environmental Assessment Registry #1843 – Written Submission of Environment Canada, section 3.4.2.

gas (simple cycle gas turbines (SCGT) and combined cycle gas turbines (CCGT)), and coal with carbon capture and storage (CCS).[17,18] If all of these resources were put into an optimization model, the model could never solve within the time allotted for preparation of the IRP. Some resources must be screened out, and the levelized cost analysis is an excellent mechanism by which to do so.

One of the drawbacks of levelized cost analysis is that the resulting values are dependent upon input assumptions about unit operations. Unit capacity factors are selected by resource planners and are fixed within the calculation. In reality, some unit capacity factors can be highly variable depending on load, operating costs, and time of year. When these resources are part of a system portfolio, interactions with other resources may lead them to operate more or less than was assumed in the levelized analysis. From this perspective, levelized cost numbers may over- or underestimate resource costs. Additionally, levelized values cannot capture certain resource attributes like dispatchability or ability to provide ancillary services. These attributes are essential to the function of an integrated electric system, but are not valued from the perspective of levelized cost.

Levelized cost analysis is a valuable tool that provides decision-makers with useful information about unit energy and capacity costs; however, given the limitations of this type of analysis, the primary tool for analyzing resource porfolios should be integrated modeling (discussed in the next section). BC Hydro's analysis methodology is consistent with good resource planning practices, i.e. using levelized cost analysis for "pre-screening" and an integrated model for the optimization and plan simulations.

4.2. System Optimizer

Portfolio analysis is an essential element of integrated resource planning, and electric simulation models are necessary tools that enable utilities to create and evaluate different resource combinations under a variety of scenarios. In portfolio analysis, different individual supply- and demand-side resources are combined into portfolios in a way that meets customer energy needs and system capacity needs over time. There are two types of models that are commonly used in utility planning: optimization, or capacity expansion, models and production cost models. The primary function of optimization models is as described above – to select the best combination of resources over time, meeting the set of input constraints applied to the model while minimizing the PVRR. Optimization models do contain a production cost component; however, the dispatch of resources is often highly simplified. The present value output is thus a combination of the capital and operating costs of the resulting electric system selected by the model.

Production cost models, on the other hand, do not do any optimization and require that any resource additions during the planning period be fixed in place by the modeler. The user must identify any gaps in energy and/or capacity and select the resources necessary to close these gaps, while meeting any

[17] BC Hydro. 2013 Integrated Resource Plan. Chapter 3 – Resource Options.

[18] Note that Synapse did not review and thus had no comment on the reliability of the unit energy and capacity costs resulting from the levelized cost analysis.

renewable energy goals or emissions standards. Production cost models then simulate a detailed dispatch of an electric system or region, calculating system electric generation and operating costs over time. Capital costs of new generating resources are not included in resulting present value outputs. Because the system build-out is user defined in production cost modeling, the use of these types of models without an optimization component may result in a sub-optimal mix of generating resources and transmission over time. In conducting its resource planning study for the Railbelt System in Alaska, Black and Veatch had to use two models: Strategist for the optimization piece and PROMOD for the dispatch piece,[19] which is both time-consuming and costly.

BC Hydro states that portfolio analysis was the primary method used in the 2013 IRP to analyze various combinations of resource options.[20] BC Hydro developed its portfolios using System Optimizer, a model using either linear or mixed integer programming, which selects the optimal sequence of generation and transmission resource additions over time for a specific set of input assumptions. System Optimizer determines the optimal resource mix by minimizing the present value of revenue requirements[21] necessary to meet BC Hydro's given load under average water conditions.[22] This PVRR is the primary metric that is analyzed, and minimized, in utility IRPs.[23]

System Optimizer has the ability to add generating units, retire or refurbish existing units, and make changes to resource operations when creating long-term utility portfolios. When adding new resources, the model considers technology type, fuel, size, location, and timing to meet capacity and energy requirements. System Optimizer is not limited to new unit construction, but can also consider demand response programs, energy efficiency or demand side management, and transmission expansion.[24] There is one important drawback to this particular model. While other optimization models often output more than one, sometimes hundreds, of resource plans, System Optimizer outputs only the top plan. Being able to view a series of top plans and their PVRRs can be useful to identify patterns and quantify the magnitude of differences in revenue requirements.[25]

System Optimizer is a very useful tool for use in resource planning. It is particularly well-suited for BC Hydro and the unique policy environment in which it must conduct its resource planning, as "the primary feature of System Optimizer is its ability to analyze renewable portfolio standard and emissions

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[19] Black and Veatch. Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study. February 2010. Available at: http://www.susitna-watanahydro.org/wp-content/uploads/2012/05/Black_Veatch_2010_AlaskaRIRPFinalReport.pdf

[20] BC Hydro. 2013 Integrated Resource Plan. Page 4-59.

[21] Also referred to as Cumulative Present Worth (CPW)

[22] BC Hydro. 2013 Integrated Resource Plan. Page 4-61.

[23] Wilson, Rachel and Bruce Biewald. Best Practices in Electric Utility Integrated Resource Planning. Synapse Energy Economics. Prepared for the Regulatory Assistance Project. June 2013. Page 32.

[24] Ventyx. Product Overview: System Optimizer. Page 1.

[25] Synapse was not asked to review the results of BC Hydro's System Optimizer analysis, but merely the use of the model in resource planning applications.

regulations."[26] The model is widely-accepted within the electric industry, and PacifiCorp, Duke Energy, Tri-State, Colorado Springs Utilities, Basin Electric Power Cooperative, and Tennessee Valley Authority are some of the other utilities using System Optimizer to conduct present value analyses for use in resource planning.

4.3. Annualized Costs and End of Life Issues

When undertaking integrated resource planning, utilities examine a planning period or horizon some number of years into the future, matching annual energy and peak demands with new supply- and demand-side resources. They may evaluate the costs of a resource plan over that planning horizon, but for resources with long operating lives, that metric does not consider costs and revenue requirements after the planning period ends. For example, a utility may use a planning period of 25 years and add a long-lived resource that has high capital costs but low operating costs in one of the last years of that period. The resulting PVRR will capture the high costs of capital but not the benefits of the lower operating costs, which are incurred largely outside the utility's planning period. Annualization of costs provides a way to capture those benefits.

BC Hydro used the two different methods described above to analyze the costs of individual resources over their lifetimes, and of portfolios that contain resources with varying book lives. The first of those is the unit cost comparison, that examines the levelized cost of a unit of energy or capacity in dollars per megawatt hour ($/MWh), calculated using an annualized cost method.[27] Annualization, or levelization, is the calculation of the value that, if paid out in equal annual amounts over a specified period and discounted, would be equal to the present value.[28] In this case, annualization results in a stream of cost values that is constant over the book life of a resource, which, when discounted, yields the UECs and UCCs described above. Annualization is a useful tool because different assets have different cost profiles and book lives, and this method provides a consistent way to compare them to each other. A new hydro asset, for example, is one such resource with high upfront capital costs, but very low operating costs over a very long life. Natural gas assets, on the other hand, have much lower upfront capital costs, higher operating costs, and a book life of 25-40 years depending on turbine type. Levelization allows for a consistent comparison between these two very different asset types.

BC Hydro took these annualized values and input them into System Optimizer in order to account for these end of life issues in its analysis of portfolios of resources. In order to be accurate, these annualized values have to be independent of capacity factor in cases where resources are dispatchable, and capital must be levelized on a per kW basis. Thus, the calculation of the annualized values depends on resource type. For resources that are not dispatchable, modelers included a fixed output in the calculation of unit

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[26] Ventyx. Product Overview: System Optimizer. Page 1.

[27] BC Hydro. 2013 Integrated Resource Plan. Page 3-6.

[28] US EPA. OAQPS Economic Analysis Resource Document. Section 8.3: Discounting Benefits and Costs. Available at: http://www.epa.gov/ttnecas1/econdata/Rmanual2/8.3.html

costs. For dispatchable resources like gas, costs are annualized absent fuel price inputs (which have monthly values). At a conceptual level, this seems correct.

The longer the planning period, the less important annualization becomes, as costs further out in the future are captured by the PVRR value. In its IRP analysis, BC Hydro used a planning horizon of 30 years. Manitoba Hydro, similarly, looked at a period of 35 years, while in Alaska, a 50 year planning period was used to study the Susitna dam and other hydro projects.[29] Nalcor Energy used a period of 57 years, stating explicitly that it was looking at a longer planning period due to the long-lived nature of the hydro assets it was evaluating.[30] Hydro resources may have a book life of 70 years or more, and these longer planning periods may not need to include an annualization calculation. However, with a 30 year planning horizon and a plan that includes new hydro assets, BC Hydro is correct to include a levelization calculation in its portfolio analysis.

5. Conclusions and Recommendations

Synapse was asked to review and comment on the several elements of the BC Hydro 2013 IRP: 1) the differential between the WACC for BC Hydro and for IPPs; 2) the use of sensitivity analyses as a means to evaluate the direction and magnitude of risk; 3) the use of analytical methods, including the appropriateness of BC Hydro's Unit Cost Comparison, as well as the System Optimizer model; and 4) the calculation of annualized costs with respect to resource end-of-life. Our review is largely of the methods used for analysis in this IRP, and with the exception of the WACC, Synapse was not asked to review or evaluate any of BC Hydro's input assumptions. At this time, we cannot determine whether the Company's projections for these inputs are reasonable or reliable, nor can we comment on the conclusions arrived at by BC Hydro in its 2013 IRP.

With respect to the WACC, BC Hydro has selected reasonable values and has given proper consideration and quantification of resource cost uncertainty. The Company's alternatives analysis methodology is consistent with good utility practice and includes several valuable elements: a levelized cost analysis, integrated resource modeling using System Optimizer (both of which include annualized costs to take into account end-of-life resource considerations), and a sensitivity analysis that evaluated various risks and uncertainties. Future sensitivity analysis might include variability in water levels and/or impacts of climate change on various generating resources, particularly those long-lived resources that would be expected to operate well into the future.

Integrated resource planning processes and documents must evolve over time as the context for utility operations changes, as different types of resources become technically and economically feasible, and

[29] Black and Veatch. Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study. February 2010.
[30] Navigant Consulting Ltd. Independent Supply Decision Review Prepared for Nalcor Energy. September 14, 2011.

as new types of risks and uncertainty affect the electric system. BC Hydro's methodologies will help the Company to manage these challenges as they arise.

EXECUTIVE SUMMARY

Throughout energy circles, the threat of climate change has held the spotlight in recent years. Meanwhile, two other concerns have re-emerged from the shadows. The financial crisis of 2008/09, which some analysts link with volatile oil prices, reinforced the concern that high energy prices can cripple economic growth. Headlines announcing gas supply cuts to the Ukraine, oil tanker hijackings along the coast of Somalia, pipeline bombings in Nigeria, and hurricanes destroying oil rigs in the Gulf of Mexico showed that threats to energy security arise in many forms and unexpected places. For several years, the IEA has been presenting the case that an energy revolution, based on widespread deployment of low-carbon technologies, is needed to tackle the climate change challenge. *Energy Technology Perspectives 2010 (ETP 2010)* demonstrates that a low-carbon future is also a powerful tool for enhancing energy security and economic development.

Equally important, *ETP 2010* highlights early signs that such an energy technology revolution is under way. Investment in renewable energy, led by wind and solar, is increasing substantially. A number of countries are considering building new nuclear power stations. The rate of energy efficiency improvement in OECD countries is starting to accelerate again, after many years of modest gains. Public investment is increasing for low-carbon technology research, development and demonstration (RD&D). In transport, major car companies are adding hybrid and full-electric vehicles to their product lines and many governments have launched plans to encourage consumers to buy these vehicles. Yet these encouraging developments represent but the first small, fragmented steps on a long journey towards transforming the way we supply and use energy. The trends that drive growth in energy demand and carbon dioxide (CO_2) emissions associated with climate change continue to surge forward at an unrelenting pace.

Current energy and CO_2 trends run directly counter to the repeated warnings sent by the United Nations Intergovernmental Panel on Climate Change (IPCC), which concludes that reductions of at least 50% in global CO_2 emissions compared to 2000 levels will need to be achieved by 2050 to limit the long-term global average temperature rise to between 2.0°C and 2.4°C. Recent studies suggest that climate change is occurring even faster than previously expected and that even the "50% by 2050" goal may be inadequate to prevent dangerous climate change.

Efforts to forge a long-term policy framework for tackling climate change are continuing, but the 15th Conference of the Parties (COP 15) to the UN Framework Convention on Climate Change demonstrated the difficulty of reaching agreement on "top-down" legally binding targets. Nonetheless, COP 15 did make progress on some crucial issues. The Copenhagen Accord, while not formally adopted at COP 15, reflected a large degree of consensus on a number of vital elements, including: limiting the increase in global temperature to less than 2.0°C; achieving deep cuts in global greenhouse-gas emissions by 2050; the role of technology in meeting these goals; and the need for additional funding for developing countries. Many governments are already backing up their support for the Accord's principles through increased funding for low-carbon energy research and development, new and more effective policies, and national emissions reduction targets.

ETP 2010 feeds into this momentum by providing an IEA perspective on how low-carbon energy technologies can contribute to deep CO_2 emissions reduction targets. Using a techno-economic approach that assesses costs and benefits, the book examines least-cost pathways for meeting energy policy goals while also proposing measures to overcome technical and policy barriers. Specifically, *ETP 2010* examines the future fuel and technology options available for electricity generation and for the key end-use sectors of industry, buildings and transport. For the first time, this edition includes an analysis of OECD Europe, the United States, China and India, which together account for about 56% of today's global primary energy demand. It then sets out the technology transitions needed to move to a sustainable energy future, and provides a series of technology roadmaps to chart the path. Other new elements of *ETP 2010* include chapters on financing, behavioural change, the diffusion of technologies amongst developed and emerging economies, and a discussion of the environmental impacts of key energy technologies.

It is clear that, at present, the energy technology revolution is coming from the "bottom up". In many ways, this is a healthy sign: many energy challenges have the greatest impact on local populations – and those populations need to find solutions that work for their local contexts. Ultimately, the scale of the challenge demands a global strategy, not least because globalisation makes major economies increasingly interdependent in terms of trade, investment and the spread of technology. Another striking development is that many of these efforts already reflect stronger engagement between government, industry and civil society. *ETP 2010* highlights innovative policies and actions that warrant thoughtful consideration and broader application.

The next decade is critical. If emissions do not peak by around 2020 and decline steadily thereafter, achieving the needed 50% reduction by 2050 will become much more costly. In fact, the opportunity may be lost completely. Attempting to regain a 50% reduction path at a later point in time would require much greater CO_2 reductions, entailing much more drastic action on a shorter time scale and significantly higher costs than may be politically acceptable.

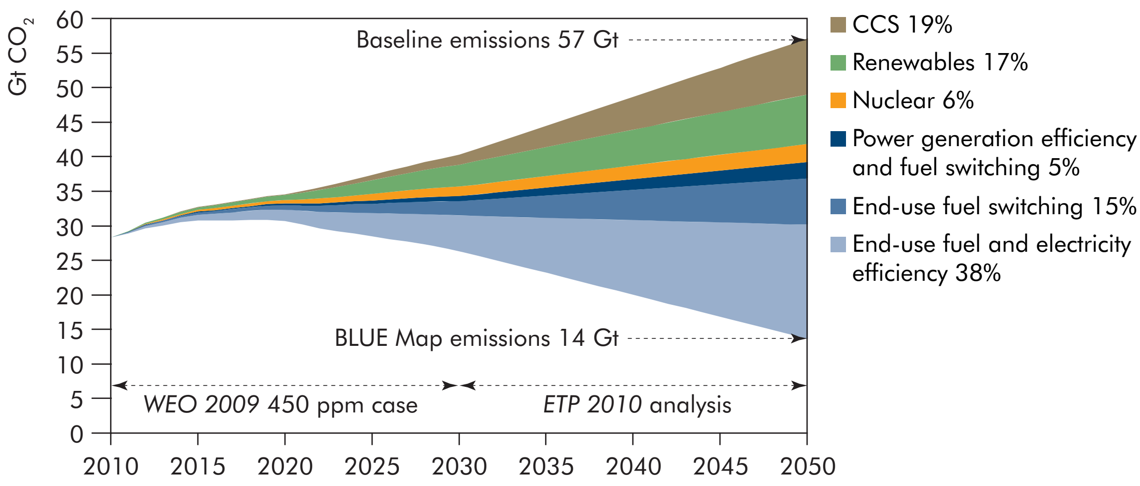
Concern about energy security, the threat of climate change and the need to meet growing energy demand (particularly in the developing world) all pose major challenges to energy decision makers. Advancing the low-carbon technology revolution will involve millions of choices by a myriad of stakeholders – all individuals acting in personal or professional spheres. Yet choice, in itself, can be a barrier: wading through the reams of information to arrive at the best choice can be quite paralysing. This book demonstrates that a portfolio of existing and new technologies will be needed to address these challenges, and lays out both the priority areas for action and the mechanisms that can help deliver change. This approach is designed to help decision makers from all spheres identify which combinations of technologies and policies will be most effective in their specific situations. By incorporating detailed roadmaps to facilitate technology deployment, *ETP 2010* hopes to prompt two aspects of the energy revolution: the necessary step change in the rate of progress and broader engagement of the full range of countries, sectors and stakeholders.

ETP scenarios present options rather than forecasts

ETP 2010 analyses and compares various scenarios. This approach does not aim to forecast what will happen, but rather to demonstrate the many opportunities to create a more secure and sustainable energy future.

The *ETP 2010* Baseline scenario follows the Reference scenario to 2030 outlined in the *World Energy Outlook 2009*, and then extends it to 2050. It assumes governments introduce no new energy and climate policies. In contrast, the BLUE Map scenario (with several variants) is target-oriented: it sets the goal of halving global energy-related CO_2 emissions by 2050 (compared to 2005 levels) and examines the least-cost means of achieving that goal through the deployment of existing and new low-carbon technologies (Figure ES.1). The BLUE scenarios also enhance energy security (*e.g.* by reducing dependence on fossil fuels) and bring other benefits that contribute to economic development (*e.g.* improved health due to lower air pollution). A quick comparison of *ETP 2010* scenario results demonstrates that low-carbon technologies can deliver a dramatically different future (Table ES.1).

Figure ES.1 ▶ Key technologies for reducing CO_2 emissions under the BLUE Map scenario



Key point

A wide range of technologies will be necessary to reduce energy-related CO_2 emissions substantially.

Table ES.1 ▶ ***Energy and emission trends under the Baseline and BLUE Map scenarios: 2050 compared to 2007***

Baseline scenario	BLUE Map scenario
• Energy-related CO_2 emissions roughly double	• Energy-related CO_2 emissions reduced by 50%
• Primary energy use rises by 84%; carbon intensity of energy use increases by 7%	• Primary energy use rises by 32%; carbon intensity of energy use falls by 64%
• Liquid fuel demand rises by 57% requiring significant use of unconventional oil and synthetic fuels; primary coal demand increases by 138%; gas demand is 85% higher	• Liquid fuel demand falls by 4% and biofuels meet 20% of total; coal demand drops by 36%; natural gas falls by 12%; renewables provide almost 40% of primary energy supply
• CO_2 emissions from power generation more than double; CO_2 intensity of power generation declines slightly to 459 g/kWh	• CO_2 emissions from power generation are cut by 76%; its CO_2 intensity falls to 67 g/kWh
• Fossil fuels supply more than two-thirds of power generation; the share of renewable energy increases slightly to 22%	• Renewables account for 48% of power generation; nuclear provides 24% and plants equipped with CCS 17%
• Carbon capture and storage (CCS) is not commercially deployed	• CCS is used to capture 9.4 Gt of CO_2 from plants in power generation (55%), industry (21%) and fuel transformation (24%)
• CO_2 emissions in the buildings sector, including those associated with electricity use, nearly double	• CO_2 emissions in buildings are reduced by two-thirds through low-carbon electricity, energy efficiency and the switch to low- and zero-carbon technologies (solar heating and cooling, heat pumps and CHP)
• Almost 80% of light-duty vehicles (LDVs) sales rely on conventional gasoline or diesel technology; petroleum products meet more than 90% of transport energy demand	• Almost 80% of LDVs sales are plug-in hybrid, electric or fuel-cell vehicles; the share of petroleum products in final transport demand falls to 50%
• CO_2 emissions in industry grow by almost half, as industrial production increases	• CO_2 emissions in industry fall by around a quarter mainly thanks to energy efficiency, fuel switching, recycling, energy recovery and CCS
• Total investment in energy supply and use totals USD 270 trillion	• Investment is USD 46 trillion (17%) more than in Baseline; cumulative fuel savings are USD 112 trillion higher than in Baseline
• Non-OECD countries are responsible for almost 90% of growth in energy demand and account for nearly three-quarters of global CO_2 emissions	• Non-OECD countries achieve CO_2 emissions reduction of around 30% compared to 2007; OECD countries account for less than one-quarter of global CO_2 emissions, having reduced emissions by 70% to 80% below 2007 levels

Box ES.1 ▶ Messages from the models

The findings of ETP 2010 reinforce conclusions from previous editions while also serving as a reminder that, since the first edition was released in 2006, the world has continued to move – and even at an accelerated pace – in the wrong direction. From 1990 to 2000, global CO_2 emissions increased by an average of 1.1% per year. Over the following seven years, the annual growth rate in emissions jumped to 3.0%. Two main factors are evident: rising energy demand in coal-based economies; and an increase in coal-fired power generation in response to higher oil and gas prices. The rate of increase in emissions from coal use rose from 0.6% per year (between 1990 and 2000) to 4.8% per year (between 2000 and 2007).

The most important message remains unchanged: current trends – as illustrated by the Baseline scenario – are patently unsustainable in relation to the environment, energy security and economic development. Ongoing dependence on fossil fuels (especially coal) continues to drive up both CO_2 emissions and the price of fossil fuels. Oil prices, for example, are assumed to reach USD 120 per barrel (in 2008 prices) by 2050.

But this carbon-intensive future is not a given. Using a combination of existing and new technologies, as envisaged in the BLUE scenarios, it is possible to halve worldwide energy-related CO_2 emissions by 2050. Achieving this will be challenging, and will require significant investment. But the benefits in terms of environmental outcomes, improved energy security and reduced energy bills will also be large. Oil prices in these scenarios are assumed to be only USD 70 per barrel (in 2008 prices) by 2050.

- *A portfolio of low-carbon technologies, with costs of up to USD 175/tCO_2 when fully commercialised, will be necessary to halve CO_2 emissions by 2050. No one technology or small group of technologies can deliver the magnitude of change required.*
- *Widespread deployment of low-carbon technologies can reduce global oil, coal and gas demand below current levels by 2050. Even so, fossil fuels will remain an important element of the world's energy supply for the foreseeable future.*
- *Increasing energy efficiency, much of which can be achieved through low-cost options, offers the greatest potential for reducing CO_2 emissions over the period to 2050. It should be the highest priority in the short term.*
- *Decarbonising the power sector, the second-largest source of emissions reductions, is crucial and must involve dramatically increasing the shares of renewables and nuclear power, and adding carbon capture and storage (CCS) to generation from fossil fuels.*
- *A decarbonised electricity supply offers substantial opportunities to reduce emissions in end-use sectors through electrification (for example, switching from internal combustion engine vehicles to electric vehicles (EVs) and plug-in hybrids (PHEVs), or from fossil fuel heating to efficient heat pumps).*
- *New low-carbon technologies will be needed to sustain emissions reductions beyond 2030, particularly in end-use sectors such as transport, industry and buildings.*

The future is inherently uncertain and always will be. Trends in economic growth (and therefore energy use and emissions) and technology development are difficult to predict. A portfolio approach to low-carbon technology development and deployment can help deal with this uncertainty.

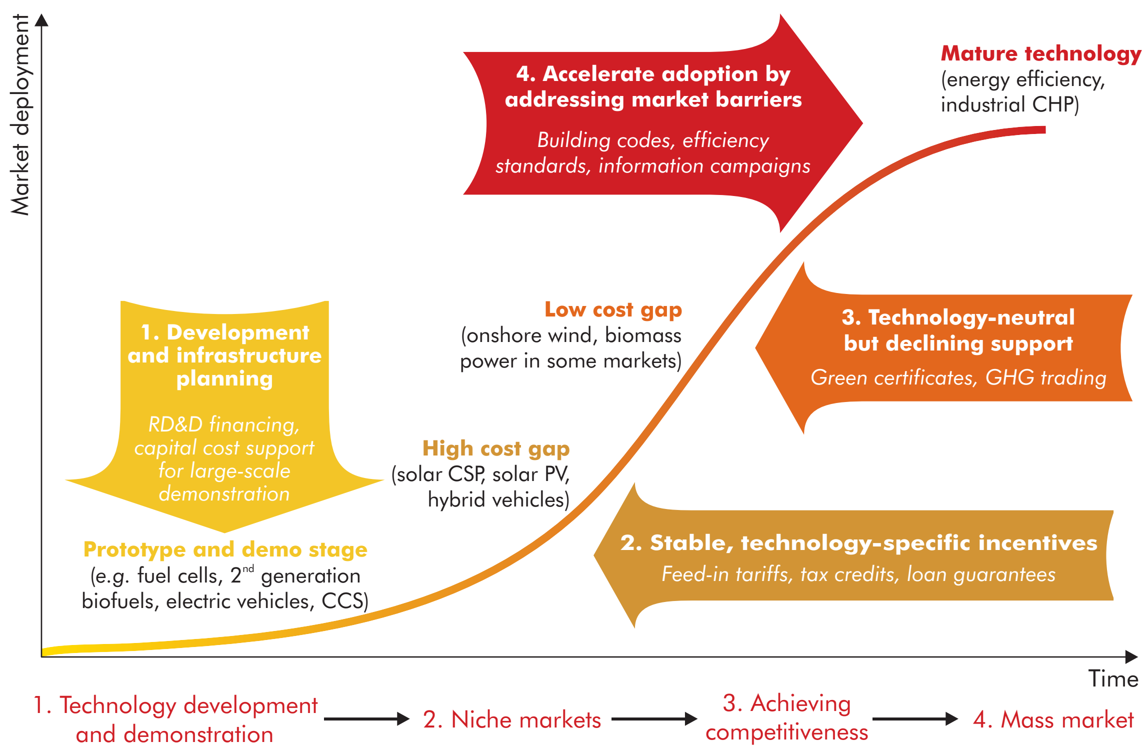
Technology policy

Many of the most promising low-carbon technologies currently have higher costs than the fossil-fuel incumbents. It is only through technology learning from research, development, demonstration and deployment (RDD&D) that these costs can be reduced and the technologies become economic. Thus, governments and industry need to pursue energy technology innovation through a number of parallel and interrelated pathways. Most new technologies will require, at some stage, both the "push" of RD&D and the "pull" of market deployment.

The role of governments in developing effective technology policy is crucial: policy establishes a solid foundation and framework on which other stakeholders, including industry, can build. Where appropriate, policies will need to span the entire spectrum of RDD&D. In this way, governments can reduce the risk for other actors in the early phases of technology development and then gradually expose the technology to greater competition, while allowing participants to realise reasonable returns on their investments as a low-carbon economy takes hold.

Governments will need to intervene on an unprecedented level in the next decade to avoid the lock-in of high-emitting, inefficient technologies. They must take

Figure ES.2 ▶ Policies for supporting low-carbon technologies



Note: The figure includes generalised technology classifications; in most cases, technologies will fall in more than one category at any given time.

Key point

Government support policies need to be appropriately tailored to the stage(s) of development of a technology.

swift action to implement a range of technology policies that target the cost-competitiveness gap while also fairly reflecting the maturity and competitiveness of individual technologies and markets (Figure ES.2). The overriding objectives should be to reduce risk, stimulate deployment and bring down costs. Evidence suggests that a large proportion of breakthrough innovations come from new firms that challenge existing business models. Thus, government steps to remove barriers to the entry and growth of new firms may have an important part to play in low-carbon energy technology development.

In recent years, much attention has been given to the importance of policies that put a price on carbon emissions as a way of stimulating the clean technology development and deployment needed to deliver an energy revolution. The Copenhagen Accord acknowledges market approaches as a means to enhance cost-effectiveness. While such policies (*e.g.* carbon trading) are likely to be an important driver of change, they are not necessarily the most effective way to deliver short-term investment in the more costly technologies that have longer-term emissions reduction benefits. Moreover, a truly global carbon market is likely to be many years away. Governments can draw upon a wide variety of other tools to help create markets for the technologies that meet national policy objectives, including regulations, tax breaks, voluntary programmes, subsidies and information campaigns. But they also need to have exit routes: the level of government support should decrease over time and be removed altogether as technologies become competitive – or indeed, if it becomes clear that they are unlikely to do so.

ETP 2010 estimates that to achieve the 50% CO_2 emissions reduction, government funding for RD&D in low-carbon technologies will need to be two to five times higher than current levels. This message is being taken seriously by many countries. Governments of both the Major Economies Forum and the IEA have agreed to dramatically increase and co-ordinate public-sector investments in low-carbon RD&D, with a view to doubling such investments by 2015. Simply increasing funding will not, however, be sufficient to deliver the necessary low-carbon technologies. Current government RD&D programmes and policies need to be improved by adopting best practices in design and implementation. This includes the design of strategic programmes to fit national policy priorities and resource availability; the rigorous evaluation of results and adjusting support if needed; and the increase of linkages between government and industry, and between the basic science and applied energy research communities to accelerate innovation.

Reducing CO_2 emissions ultimately depends on the uptake of low-carbon technologies by industry, businesses and individual consumers. To date, efforts to encourage the adoption of energy-efficient and low-carbon technologies have focused primarily on overcoming technological and economic barriers. In fact, research suggests that consumer choices are more heavily influenced by social and behavioural factors. Improved understanding of the human dimensions of energy consumption, particularly in the residential and commercial sectors and in personal transport, will help policy makers to catalyse and amplify technology-based savings. A sampling of successful programmes highlighted in *ETP 2010* indicates that policy strategies to influence consumer choices should target, inform, motivate and empower consumers.

Governments also have an important role in encouraging others to take the lead in relevant areas. Industry can demonstrate leadership through active involvement in public-private partnerships. Universities can expand training and education to develop and deploy the human capacity needed to exploit the innovative energy technologies. Non-governmental organisations can help engage the public and communicate the urgency of the need to deploy new energy technologies on a large scale, including the costs and benefits of doing so. Finally, all stakeholders must work together to strengthen international technology collaboration to accelerate RDD&D, diffusion and investment. Technology roadmaps can be an effective tool to help this process.

Box ES.2 ▶ IEA technology roadmaps

At the request of G8 Ministers, the IEA is developing roadmaps to support accelerated development and deployment of the most important low-carbon technologies. Each roadmap sets out a shared vision to 2050 and charts the actions required, at international and national levels, by relevant stakeholders. This collective approach is vital to maximising the net benefit of investment in the RDD&D of new technologies. The roadmaps also address several cross-cutting issues, on the international and regional levels, that will underpin the successful exploitation of these technologies.

Many of the IEA technology roadmaps recommend private-sector partnerships to accelerate innovation and the transition from demonstration to commercial deployment. Such partnerships may be particularly appropriate for technologies such as CCS and electric vehicles, both of which will depend on establishing new business models for industries and technologies

Increasing international technology diffusion

All of the scenarios used in *ETP 2010* confirm a somewhat startling fact: nearly all of the future growth in energy demand and in emissions comes from non-OECD countries. Accelerating the spread of low-carbon technologies to non-OECD countries is therefore a critical challenge, particularly for the largest, fast-growing economies such as Brazil, China, India, the Russian Federation and South Africa.

Non-OECD countries have traditionally been assumed to access new technologies as a result of technology transfer from industrialised countries, presupposing a general trend that technological knowledge flows from countries with higher technological capacities to those with lower capacities. The situation is, however, becoming more complex, with an increasing multi-directional flow of technologies among and between OECD and non-OECD countries, and emerging economies establishing strong manufacturing bases and becoming exporters in their own right.

To be successful, a low-carbon economy should be based on market principles in which energy technologies spread primarily through commercial transactions. The challenge is to reorient these transactions to support the transfer of low-carbon technologies while also helping emerging countries to become technology developers and market players. Careful consideration must be given to the capacity of countries to absorb new technologies. Some emerging economies, led by China, are rapidly improving their capability to develop and deploy key low-carbon technologies. Given their economic growth rates, they must advance at an even more rapid pace to decouple CO_2 emissions from economic activity.

Financing and returns on investment

ETP 2010 shows that a very considerable investment will be needed to meet the world's growing energy needs. The Baseline scenario estimates a total investment, between 2010 and 2050, of USD 270 trillion.[1] Most of this (USD 240 trillion or almost 90%) reflects demand-side investments that will be made by energy consumers for capital equipment that uses energy, including vehicles, electric appliances and plants in heavy industry.

Meeting energy demand growth in a way that supports the "50% by 2050" goal will be considerably more expensive: the BLUE Map scenario projects investment requirements of USD 316 trillion, a further increase of 17% (USD 46 trillion).

Over the past three years, annual investments in low-carbon energy technologies averaged approximately USD 165 billion. Implementing the BLUE Map scenario will require investments to reach approximately USD 750 billion per year by 2030 and rise to over USD 1.6 trillion per year from 2030 to 2050. The level of investment doubles in the latter period as a result of increased demand for cars and other consumer products, which rises alongside incomes in emerging and developing countries.

The flip side is that the energy technology revolution holds significant potential for very positive returns on investment. For example, the low-carbon economy will lead to substantial fuel savings due to efficiency improvements and as lower fuel demand drives down prices. *ETP 2010* calculates that the additional USD 46 trillion investment needs in the BLUE Map scenario will yield, over the period from 2010 to 2050, cumulative fuel savings equal to USD 112 trillion. Even if both the investments and fuel savings over the period to 2050 are discounted back to their present values using a 10% discount rate, the net savings amount to USD 8 trillion.

Moreover, the energy revolution offers substantial opportunities to business. Forward-looking companies recognise the enormous potential for developing and deploying – on a global scale – a wide range of new breakthrough and emerging technologies, as well as the possibility to make use of mechanisms that facilitate investment in non-OECD countries (*e.g.* in return for carbon credits). The role of governments in setting stable policy frameworks and providing some direct funding for RDD&D has already been stated. A second point is the need for increased dialogue between government and the investment community to improve understanding and establish appropriate boundaries to their unique but complementary spheres of activity.

ETP 2010 also examines the wider economic, social and environmental impacts (referred to as "co-impacts" because of the degree to which they are interrelated) of

1. Excluding upstream investments in the production and transportation of coal, oil and gas.

low-carbon technologies. The analysis focuses primarily on issues that, particularly in developing countries, may be more immediate political and social priorities than reducing CO_2 emissions, namely: air quality and related impacts on human health; water quality and availability; and land use. Reducing air pollution through low-carbon technologies, for example, delivers other energy-related environmental benefits and reduces negative health impacts on local populations.

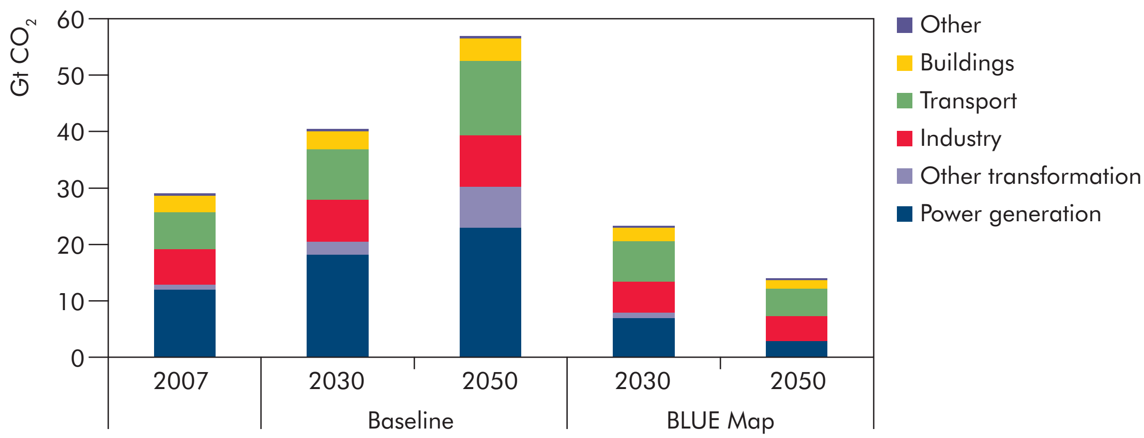
Further work is needed to refine the estimates in this assessment, including ways to leverage potential co-benefits and to ensure that any negative co-impacts are understood, quantified and, where possible, mitigated. It is equally important to assess co-benefits and potential conflicts at regional, national and local levels, as many will be setting-specific.

Sectoral findings

About 84% of current CO_2 emissions are energy-related and about 65% of all greenhouse-gas emissions can be attributed to energy supply and energy use. All sectors will need to reduce dramatically their CO_2 intensity if global CO_2 emissions are to be halved. However, this does not mean that every sector needs to cut its own emissions by 50% (Figure ES.3). Each sector has different growth prospects under the Baseline scenario and a different range of low-carbon options that can be deployed to reduce emissions. *ETP 2010* examines in detail each sector's potential to contribute to a cost-optimal low-carbon future, including the technologies and policies that will be needed.

For advancing deployment of both existing and new technologies across all sectors, a key message is the need for rapid action that takes account of long-term goals. Without a long-range perspective, there is a risk that inappropriate and costly capital investments made in the near term could undermine future emissions reduction targets or will need to be scrapped well in advance of their normal life cycles.

Figure ES.3 ▶ Global CO_2 emissions in the Baseline and BLUE Map scenarios



Key point

The BLUE Map scenario implies deep emission cuts across all sectors.

Power sector

It bears repeating that decarbonising the power sector will be at the heart of efforts to make deep cuts in global CO_2 emissions. The power sector currently accounts for 41% of energy-related CO_2 emissions. The Baseline scenario projects a doubling of these emissions over the period to 2050, because of continued reliance on fossil fuels. By contrast, the BLUE Map scenario achieves almost a 90% reduction (compared to 2007 levels) in the carbon intensity of electricity generation, with renewables accounting for almost half of global production and nuclear for slightly less than one-quarter. The other key change is that most remaining electricity production from fossil fuels has much lower CO_2 emissions thanks to widespread adoption of CCS.

Significant policy change is needed to break the current dependence on fossil fuels in the power sector, as is significant investment. The BLUE Map scenario requires investment of USD 32.8 trillion (40% more than the USD 23.5 trillion needed in the Baseline scenario), more than half directed towards new power generation plants. A key challenge is that, at present, many low-carbon alternatives are considerably more expensive than traditional fossil-based technologies. In addition to expanding RD&D support and creating market mechanisms to foster technological innovation, governments should adopt policies that encourage the earliest possible closure of the dirtiest and least efficient plants. All low-carbon generation options need to be pursued: excluding any one option could significantly increase the costs of achieving CO_2 emissions reductions from the sector.

Some low-carbon generation technologies raise unique challenges. For example, system integration will be needed to support large quantities of variable renewables (such as wind, solar PV, run-of-river hydropower, and wave and tidal power). There is also an urgent need to accelerate the demonstration of CCS in the power sector and to develop comprehensive regulatory approaches to enable its large-scale commercial deployment. Nuclear power requires further progress on building and operating disposal facilities for radioactive waste.

Achieving a near zero-carbon electricity supply creates opportunities to reduce CO_2 emissions in all end-use sectors by shifting energy consumption from fossil fuels to electricity. For example, from internal combustion engine (ICE) cars running on diesel or gasoline to EVs and PHEVs, or from fossil-fuel heating to efficient heat pumps.

There are some signs that the necessary changes in power generation are starting to happen. Investment in renewable energy, led by wind and solar, reached an all-time high in 2008 and stayed at similar levels in 2009 despite the economic downturn. In 2009, more wind power was installed in Europe than any other electricity-generating technology. Similar developments have been seen in other parts of the world; in terms of global installed renewable capacity, China now ranks second and India fifth. There is also evidence that nuclear power is undergoing a renaissance. Major expansions of nuclear capacity are planned in China, India and Russia. Several other countries with existing nuclear plants but where no new construction has been launched in recent years are also actively considering new nuclear capacity.

Electricity networks

Changing profiles for demand and generation will require modifications in the design, operation and deployment of electricity networks, with regional characteristics becoming more important in determining network configurations.

Although system-scale demonstration is still needed, the flexibility of smart grids (which integrate both electricity and thermal storage technologies) appears to support balancing of variable generation and demand, better management of peak loads and delivery of energy efficiency programmes. Smart grids can contribute to reducing CO_2 emissions from both electricity generation and use. In developing countries, smart grids will facilitate expansion of electricity services, and show significant potential to reduce transmission and distribution losses.

Industry

Over recent decades, industrial energy efficiency has improved and CO_2 intensity has declined in many sectors. However, this progress has been more than offset by growing industrial production worldwide. Direct emissions from industry account for around 20% of current CO_2 emissions. Achieving deep cuts in CO_2 emissions will require the widespread adoption of current best available technology, as well as the development and deployment of a range of new technologies (such as CCS, smelting reduction, separation membranes and black liquor gasification).

Successful application of CCS in a number of energy-intensive industrial sectors (*e.g.* iron and steel, cement, chemical and petrochemical, and pulp and paper) represents potentially the most important new technology option for reducing direct emissions in industry. To fulfil its promise, the large-scale demonstration of CO_2 capture technologies in industry should be undertaken in parallel with demonstration projects planned for the power sector. Fuel and feedstock substitution with biomass and waste represents another important option but as the resource will be fairly limited, competition could drive up prices and make industrial applications less attractive. A decarbonised power sector will offer new opportunities to reduce the CO_2 intensity through electrification of industrial processes.

Clear, stable, long-term policies that support carbon pricing will be needed to stimulate the technology transition in industry. The current situation, in which only developed countries are subject to emission constraints, gives rise to legitimate concerns about competitiveness and carbon leakage. A global system of emissions trading may eventually be most effective; in the meantime, international agreements covering specific energy-intensive sectors may be a practical first step. Government intervention will be needed to establish standards, incentives and regulatory reforms. Removing energy price subsidies should be a priority in countries where they persist.

Buildings

Direct emissions from buildings account for around 10% of global CO_2 emissions; including indirect emissions from the use of electricity in the sector increases this share to almost 30%. From an energy perspective, buildings are complex systems consisting of the building envelope and its insulation, space heating and cooling systems, water heating systems, lighting, appliances and consumer products, and business equipment.

Most buildings have long life spans, meaning that more than half of the current global building stock will still be standing in 2050. The low retirement rate of buildings in the OECD and in economies in transition, combined with relatively modest growth, means that most of the energy and CO_2 savings potential lies in retrofitting and purchasing new technologies for the existing building stock. In developing countries, where new building growth will be very rapid, opportunities exist to secure significant energy savings (rather quickly and strongly) through improved efficiency standards for new buildings.

The implementation of currently available, low-cost energy-efficient and low-carbon options is essential to achieve cost-effective CO_2 emissions reductions in the short run. This will buy time to develop and deploy less mature and currently more expensive technologies that can play an important role in the longer term. For space and water heating, these include highly efficient heat pumps, solar thermal systems, and combined heat and power (CHP) systems with hydrogen fuel cells.

In the residential sector, the main barriers to change are higher initial costs, lack of consumer awareness of technologies, split incentives and the low priority placed on energy efficiency. Overcoming these barriers will require a comprehensive policy package that may include information campaigns, fiscal and financial incentives, and other deployment policies, as well as minimum energy performance standards. Such policies must address financial constraints, develop industry capacity and boost R&D investment.

In the service sector, policies to achieve improvements in the building shell of new buildings, together with highly efficient heating, cooling and ventilation systems will be needed. Given their larger share of total use (compared to the residential sector), significant policy measures will be required to improve the efficiency of energy use in lighting and other electrical end-uses such as office equipment, information technology (IT) equipment and refrigeration.

Recent years show some encouraging signs of a shift in consumer preferences towards new technologies that can reduce CO_2 emissions. In 2007/08, sales of heat pumps showed double-digit growth in a number of major European markets. Demand has also been growing rapidly for solar thermal systems that can provide low-temperature heat for cooling and/or space and water heating.

Transport

The transport sector is currently responsible for 23% of energy-related CO_2 emissions. Given the increases in all modes of travel, especially passenger light-duty vehicles (LDVs) and aviation, the Baseline scenario shows a doubling of current transport energy use by 2050 and slightly more than a doubling of associated CO_2 emissions. Achieving deep cuts in CO_2 emissions by 2050 will depend on slowing the rise in transport fuel use through greater energy efficiency and increasing the share of low-carbon fuels. Encouraging travellers and transporters to shift from LDVs, trucks and air travel to more frequent use of bus and rail is another route for substantial savings.

While absolute reductions in transport emissions from 2007 levels are possible in OECD countries, strong population and income growth in non-OECD countries will make it extremely difficult to achieve absolute emissions reductions in the transport sector. In the BLUE Map scenario, by 2050 emissions in OECD countries are about 60% less than in 2007, but those in non-OECD countries are 60% higher on a well-to-wheel basis.

Prospects are good for cutting fuel use and CO_2 emissions from LDVs by improving the efficiency of ICEs, and through vehicle hybridisation and adoption of PHEVs, EVs and fuel-cell vehicles. Virtually all incremental efficiency improvements to gasoline and diesel vehicles seen in the BLUE Map scenario are paid for by fuel savings over the vehicle lifetime. Most OECD governments now have strong fuel economy standards and many governments worldwide have announced plans to support wider use of EVs and PHEVs. Taken together, these commitments could place more than 5 million EVs and PHEVs on the road by 2020.

In the BLUE Map scenario, biofuels, electricity and hydrogen together represent 50% of total transport fuel use in 2050, replacing gasoline and diesel. Biofuel demand for light-duty ICE vehicles begins to decline after 2030 owing to a strong shift towards electricity and hydrogen fuels. In contrast, biofuels use rises rapidly for trucks, ships and aircraft through 2050, replacing middle distillate petroleum fuels.

Despite promising signs that governments are introducing policies to reduce CO_2 emissions from transport, much more effort is needed to increase RDD&D funding and co-ordination especially to more rapidly cut the costs of advanced technologies. In addition, greater attention must be directed toward encouraging consumers to adopt the technologies and lifestyle choices that underpin the transition away from energy-intensive, fossil-fuel based transport systems.

Box ES.3 ▶ Regional differences

ETP 2010 *undertook a more detailed analysis of CO_2 trends and abatement options for four countries or regions that will have a major role in reducing global emissions: OECD Europe, the United States, China and India. Each faces unique challenges, reflecting current and future levels of economic development and diverse endowments of natural resources (represented in their energy mixes). Thus, each will have very different starting points and future trajectories in terms of their CO_2 emissions and develop in different ways in both the Baseline and the BLUE Map scenarios. Although many of the same technology options are needed to reduce emissions, the policy options associated with their application may be dramatically different.*

In the Baseline scenario, CO_2 emissions in India show the largest relative increase, rising almost fivefold by 2050. China also shows a substantial rise, with emissions almost tripling between 2007 and 2050. The United States show a much more modest rise, of 1% and emissions in OECD Europe decline by 8%. In the BLUE Map scenario, all countries show considerable reductions from the Baseline scenario: emissions in 2050 (compared to 2007) are 81% lower for the United States, 74% lower for OECD Europe and 30% lower in China, while India's emissions rise by 10%.

The BLUE Map scenario also brings significant security of supply benefits to all four countries or regions, particularly through reduced oil use. In the United States and OECD Europe, oil demand in 2050 is between 62% and 51% lower than 2007 levels (gas demand shows similar declines). In China and India, oil demand still grows in the BLUE Map scenario, but is between 51% and 56% lower by 2050 than in the Baseline scenario.

In ***OECD Europe****, the electricity sector will need to be almost completely decarbonised by 2050. More than 50% of electricity generation is from renewable energy, with most of the remainder from nuclear and fossil fuels using CCS (the precise energy mix varies widely among individual countries, reflecting local conditions and opportunities). In industry, energy efficiency and CCS offer the main measures for reducing emissions.*

In buildings, efficiency improvements in space heating can provide the most significant energy savings and more than half of the sector's emissions reductions in the BLUE Map scenario. Other mitigation measures include solar thermal heating, heat pumps, CHP/district heating and efficiency improvements for appliances. Transport volumes in OECD Europe are expected to remain relatively constant. Deep CO_2 emissions reductions in transport can be achieved through more efficient vehicles, a shift towards electricity and biofuels, and progressive adoption of natural gas followed by a transition to biogas and bio-syngas.

For the ***United States****, energy efficiency and fuel switching will be important measures in reducing CO_2 emissions across all end-use sectors. Infrastructure investments will be vital to supporting the transition to a low-carbon economy, particularly in the national electricity grid and transportation networks. Most of the existing generation assets will be replaced by 2050 and low-carbon technologies such as wind, solar, biomass and nuclear offer substantial abatement opportunities. Many energy-intensive industries have substantial scope to increase energy efficiency through technological improvements. Similarly, the average energy intensity of LDVs is relatively high; doubling the fuel efficiency of new LDVs by 2030 can help reduce emissions. Advanced vehicle technologies can also play an important role in the LDV and commercial light- and medium-duty truck sectors. In buildings, improving the efficiency of space cooling, together with more efficient appliances, offers the largest opportunity to reduce CO_2 emissions.*

Given the dominance of coal, ***China*** *must invest heavily in cleaner coal technologies (such as CCS) and improve efficiency of coal use in power generation and industry (which accounts for the largest share of China's energy use and CO_2 emissions). Priority should also be given to measures to improve energy efficiency and reduce CO_2 emissions in energy-intensive sectors such as iron and steel, cement and chemicals. The Chinese transport sector is evolving very rapidly, in terms of vehicle sales, infrastructure construction and the introduction of new technologies. The BLUE Map scenario shows that significant emissions reductions will depend on the electrification of transport modes and substantial decarbonisation of the electricity sector.*

For ***India****, the challenge will be to achieve rapid economic development — which implies a significant increase in energy demand for a growing population — with only a very small increase in CO_2 emissions. Electricity demand will grow strongly and the need for huge additional capacity creates a unique opportunity to build a low-carbon electricity system. While India has some of the most efficient industrial plants in the world, it also has a large share of small-scale and inefficient plants. Thus, improving overall industrial efficiency will be a significant challenge. Rising incomes and increased industrial production will spur greater demand for transport in India, making it imperative to promote public transport and new, low-carbon vehicle technologies. The buildings sector will also see strong growth in energy demand: efficiency improvements in space cooling and appliances will be critical to restraining growth in energy consumption and emissions.*

Conclusion

A truly global and integrated energy technology revolution is essential to address the intertwined challenges of energy security and climate change while also meeting the growing energy needs of the developing world. *ETP 2010* shows that key players, from both public and private sectors, are starting to take the steps needed to develop and deploy a very broad range of new low-carbon technologies. Action can be seen in all of the most important sectors, and across most regions of the world.

Clearly, financing remains a substantial challenge as does identifying appropriate mechanisms to accelerate the deployment of low-carbon technologies in major developing countries. A related issue is that several sources predict a severe skills shortage, which could quickly become a major barrier to deployment across all sectors and in all regions. There is an urgent need to properly assess the skills required, considering regional situations and human resource availability, and to develop recommendations on how to fulfil these needs.

As citizens of a changing world, we all live with a degree of uncertainty at all times; as energy producers and consumers entering a period of rapid change, the sense of uncertainty is likely to be amplified. The roadmaps and transition pathways presented in *ETP 2010* aim to overcome existing barriers and spur much-needed RDD&D in the very near term and throughout the period to 2050. The extensive data, projections and analysis contained in this volume will provide decision makers with the detailed information and insights they need to throw their weight behind rapid acceleration — in their own backyards or at the international level — of the switch to a more secure, low-carbon energy future.

In short, the most vital message of *ETP 2010* is that an energy technology revolution is within reach. Achieving it will stretch the capacities of all energy-sector stakeholders and entail substantial upfront costs, but over the long term these will be more than offset by the benefits. Governments, investors and consumers around the world need to take bold, decisive action to initiate and advance change in their respective spheres of influence – and increase their commitment to working together.

50% of the total cost of a geothermal project. Solar PV costs consist of the costs of modules, which are roughly 60% of the total cost with mounting structures, and inverters and cabling, which account for the rest. Costs are dependent on the price of commodities such as silicon.

Table 3.4 ► ***Cost assumptions for renewable electricity generation***

	Investment cost USD/kW		O&M cost USD/kW/yr	
	2010	**2050**	**2010**	**2050**
Biomass steam turbine	2 500	1 950	111	90
Geothermal	2 400-5 500	2 150-3 600	220	136
Large hydro	2 000	2 000	40	40
Small hydro	3 000	3 000	60	60
Solar PV	3 500-5 600	1 000-1 600	50	13
Solar CSP	4 500-7 000	1 950-3 000	30	15
Ocean	3 000-5 000	2 000-2 450	120	66
Wind onshore	1 450-2 200	1 200-1 600	51	39
Wind offshore	3 000-3 700	2 100-2 600	96	68

Note: The upper bound of the investment cost range represents the costs for enhanced geothermal systems. Estimates of costs and efficiencies in 2050 are inevitably subject to great uncertainty. These data refer to plants in the United States. Cost data in other world regions are calculated by multiplying these costs by region-specific multipliers for the investment and O&M costs. The lower investment costs in many of the non-OECD regions converge to United States levels by 2050.

Solar CSP investment costs differ considerably between plants with and without storage. But in terms of the cost of the energy they produce, they are broadly comparable because the presence of storage increases the capacity factor of plants. For ocean systems, the numbers in the table reflect the costs of existing tidal barrage systems. The costs of all other technologies are still very high.

For onshore wind, the turbine cost typically represents about 75% of the total cost, with infrastructure, grid connection and foundations accounting for the rest. Costs are linked to the price of commodities such as steel and copper. The costs of offshore turbines take account of additional factors such as the water depth and distance to the coast. In terms of the cost of the energy produced, the additional costs of offshore wind turbines are partly balanced by increased electricity production due to higher wind speeds for longer periods.

Nuclear power

Overview

Nuclear power has the capacity to provide large-scale electricity production with very low net CO_2 emissions over the plant lifecycle. The technology is already proven, although new designs hold out the prospect of better levels of performance

	NPV (no delay)	**Renenue Requirement**	2024	2025	2026
Rate base		$8,775,000,000.00	$8,731,125,000.00	$8,643,375,000.00	$8,555,625,000.00
r(V-D)			$611,178,750.00	$605,036,250.00	$598,893,750.00
O&M			$57,570,039.16	$58,721,439.95	$59,895,868.75
Depreciation			$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$9,872,963,192.39		$756,498,789.16	$751,507,689.95	$746,539,618.75
	NPV of Market Prices				
Energy			$189,011,384.26		
Capacity			$29,565,885.52		
Sum	$6,643,484,975.17		$218,577,269.78	$227,059,424.35	$235,870,739.17
	NPV (one year delay)			2025	2026
Rate base		$8,950,499,974.45		$8,905,747,474.57	$8,816,242,474.57
r(V-D)				$623,402,323.22	$617,136,973.22
O&M				$58,721,439.95	$59,895,868.75
Depreciation				$89,504,999.74	$89,504,999.74
Total	$9,615,887,567.26		$218,577,269.78	$771,628,762.91	$766,537,841.71
No Delay	$9,883,562,976.15				
	NPV (two year delay)				2026
Rate base		$9,129,509,944.77			$9,083,862,395.04
r(V-D)					$635,870,367.65
O&M					$59,895,868.75
Depreciation					$91,295,099.45
Total	$9,374,415,188.65		$218,577,269.78	$227,059,424.35	$787,061,335.85
No Delay	$9,893,853,743.59				
	NPV (five year delay)				
Rate base		$9,688,308,873.76			
r(V-D)					
O&M					
Depreciation					
Total	$8,735,487,577.22		$218,577,269.78	$227,059,424.35	$235,870,739.17
No Delay	$9,922,960,730.20				

No Delay	2027	2028	2029	2030	2031
Rate base	$8,467,875,000.00	$8,380,125,000.00	$8,292,375,000.00	$8,204,625,000.00	$8,116,875,000.00
r(V-D)	$592,751,250.00	$586,608,750.00	$580,466,250.00	$574,323,750.00	$568,181,250.00
O&M	$61,093,786.12	$62,315,661.84	$63,561,975.08	$64,833,214.58	$66,129,878.87
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$741,595,036.12	$736,674,411.84	$731,778,225.08	$726,906,964.58	$722,061,128.87

Market Prices					
Energy					
Capacity					
Sum	$245,023,987.69	$254,532,439.05	$264,409,877.34	$274,670,621.53	$285,329,546.28

One Year Delay	2027	2028	2029	2030	2031
Rate base	$8,726,737,474.57	$8,637,232,474.57	$8,547,727,474.57	$8,458,222,474.57	$8,368,717,474.57
r(V-D)	$610,871,623.22	$604,606,273.22	$598,340,923.22	$592,075,573.22	$585,810,223.22
O&M	$61,093,786.12	$62,315,661.84	$63,561,975.08	$64,833,214.58	$66,129,878.87
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$761,470,409.08	$756,426,934.81	$751,407,898.04	$746,413,787.55	$741,445,101.84

Two Year Delay	2027	2028	2029	2030	2031
Rate base	$8,992,567,295.04	$8,901,272,195.04	$8,809,977,095.04	$8,718,681,995.04	$8,627,386,895.04
r(V-D)	$629,479,710.65	$623,089,053.65	$616,698,396.65	$610,307,739.65	$603,917,082.65
O&M	$61,093,786.12	$62,315,661.84	$63,561,975.08	$64,833,214.58	$66,129,878.87
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$781,868,596.51	$776,699,815.23	$771,555,471.47	$766,436,053.97	$761,342,061.26

Five Year Delay			2029	2030	2031
Rate base			$9,639,867,329.39	$9,542,984,238.91	$9,446,101,148.43
r(V-D)			$674,790,713.06	$668,008,896.72	$661,227,080.39
O&M			$63,561,975.08	$64,833,214.58	$66,129,878.87
Depreciation			$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$245,023,987.69	$254,532,439.05	$835,235,776.87	$829,725,200.04	$824,240,048.00

No Delay	2032	2033	2034	2035	2036
Rate base	$8,029,125,000.00	$7,941,375,000.00	$7,853,625,000.00	$7,765,875,000.00	$7,678,125,000.00
r(V-D)	$562,038,750.00	$555,896,250.00	$549,753,750.00	$543,611,250.00	$537,468,750.00
O&M	$67,452,476.45	$68,801,525.98	$70,177,556.50	$71,581,107.63	$73,012,729.78
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$717,241,226.45	$712,447,775.98	$707,681,306.50	$702,942,357.63	$698,231,479.78
Market Prices					
Energy					
Capacity					
Sum	$296,402,103.45	$307,904,344.57	$319,852,944.02	$332,265,223.28	$345,159,176.01
One Year Delay	2032	2033	2034	2035	2036
Rate base	$8,279,212,474.57	$8,189,707,474.57	$8,100,202,474.57	$8,010,697,474.57	$7,921,192,474.57
r(V-D)	$579,544,873.22	$573,279,523.22	$567,014,173.22	$560,748,823.22	$554,483,473.22
O&M	$67,452,476.45	$68,801,525.98	$70,177,556.50	$71,581,107.63	$73,012,729.78
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$736,502,349.41	$731,586,048.94	$726,696,729.46	$721,834,930.59	$717,001,202.75
Two Year Delay	2032	2033	2034	2035	2036
Rate base	$8,536,091,795.04	$8,444,796,695.04	$8,353,501,595.04	$8,262,206,495.04	$8,170,911,395.04
r(V-D)	$597,526,425.65	$591,135,768.65	$584,745,111.65	$578,354,454.65	$571,963,797.65
O&M	$67,452,476.45	$68,801,525.98	$70,177,556.50	$71,581,107.63	$73,012,729.78
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$756,274,001.84	$751,232,394.37	$746,217,767.89	$741,230,662.02	$736,271,627.17
Five Year Delay	2032	2033	2034	2035	2036
Rate base	$9,349,218,057.95	$9,252,334,967.47	$9,155,451,876.99	$9,058,568,786.51	$8,961,685,696.03
r(V-D)	$654,445,264.06	$647,663,447.72	$640,881,631.39	$634,099,815.06	$627,317,998.72
O&M	$67,452,476.45	$68,801,525.98	$70,177,556.50	$71,581,107.63	$73,012,729.78
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$818,780,829.24	$813,348,062.44	$807,942,276.63	$802,564,011.42	$797,213,817.24

No Delay	2037	2038	2039	2040	2041
Rate base	$7,590,375,000.00	$7,502,625,000.00	$7,414,875,000.00	$7,327,125,000.00	$7,239,375,000.00
r(V-D)	$531,326,250.00	$525,183,750.00	$519,041,250.00	$512,898,750.00	$506,756,250.00
O&M	$74,472,984.38	$75,962,444.06	$77,481,692.95	$79,031,326.80	$80,611,953.34
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$693,549,234.38	$688,896,194.06	$684,272,942.95	$679,680,076.80	$675,118,203.34

Market Prices					
Energy					
Capacity					
Sum	$358,553,494.13	$372,467,594.92	$386,921,649.17	$401,936,610.43	$417,534,245.37

One Year Delay	2037	2038	2039	2040	2041
Rate base	$7,831,687,474.57	$7,742,182,474.57	$7,652,677,474.57	$7,563,172,474.57	$7,473,667,474.57
r(V-D)	$548,218,123.22	$541,952,773.22	$535,687,423.22	$529,422,073.22	$523,156,723.22
O&M	$74,472,984.38	$75,962,444.06	$77,481,692.95	$79,031,326.80	$80,611,953.34
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$712,196,107.34	$707,420,217.03	$702,674,115.91	$697,958,399.77	$693,273,676.31

Two Year Delay	2037	2038	2039	2040	2041
Rate base	$8,079,616,295.04	$7,988,321,195.04	$7,897,026,095.04	$7,805,730,995.04	$7,714,435,895.04
r(V-D)	$565,573,140.65	$559,182,483.65	$552,791,826.65	$546,401,169.65	$540,010,512.65
O&M	$74,472,984.38	$75,962,444.06	$77,481,692.95	$79,031,326.80	$80,611,953.34
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$731,341,224.77	$726,440,027.46	$721,568,619.34	$716,727,596.20	$711,917,565.73

Five Year Delay	2037	2038	2039	2040	2041
Rate base	$8,864,802,605.55	$8,767,919,515.07	$8,671,036,424.58	$8,574,153,334.10	$8,477,270,243.62
r(V-D)	$620,536,182.39	$613,754,366.05	$606,972,549.72	$600,190,733.39	$593,408,917.05
O&M	$74,472,984.38	$75,962,444.06	$77,481,692.95	$79,031,326.80	$80,611,953.34
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$791,892,255.50	$786,599,898.86	$781,337,331.40	$776,105,148.93	$770,903,959.13

No Delay	2042	2043	2044	2045	2046
Rate base	$7,151,625,000.00	$7,063,875,000.00	$6,976,125,000.00	$6,888,375,000.00	$6,800,625,000.00
r(V-D)	$500,613,750.00	$494,471,250.00	$488,328,750.00	$482,186,250.00	$476,043,750.00
O&M	$82,224,192.41	$83,868,676.26	$85,546,049.78	$87,256,970.78	$89,002,110.19
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$670,587,942.41	$666,089,926.26	$661,624,799.78	$657,193,220.78	$652,795,860.19
Market Prices					
Energy					
Capacity					
Sum	$433,737,165.35	$450,568,859.18	$468,053,727.18	$486,217,116.58	$505,085,358.21
One Year Delay	2042	2043	2044	2045	2046
Rate base	$7,384,162,474.57	$7,294,657,474.57	$7,205,152,474.57	$7,115,647,474.57	$7,026,142,474.57
r(V-D)	$516,891,373.22	$510,626,023.22	$504,360,673.22	$498,095,323.22	$491,829,973.22
O&M	$82,224,192.41	$83,868,676.26	$85,546,049.78	$87,256,970.78	$89,002,110.19
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$688,620,565.37	$683,999,699.22	$679,411,722.75	$674,857,293.74	$670,337,083.16
Two Year Delay	2042	2043	2044	2045	2046
Rate base	$7,623,140,795.04	$7,531,845,695.04	$7,440,550,595.04	$7,349,255,495.04	$7,257,960,395.04
r(V-D)	$533,619,855.65	$527,229,198.65	$520,838,541.65	$514,447,884.65	$508,057,227.65
O&M	$82,224,192.41	$83,868,676.26	$85,546,049.78	$87,256,970.78	$89,002,110.19
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$707,139,147.80	$702,392,974.65	$697,679,691.17	$692,999,955.17	$688,354,437.58
Five Year Delay	2042	2043	2044	2045	2046
Rate base	$8,380,387,153.14	$8,283,504,062.66	$8,186,620,972.18	$8,089,737,881.70	$7,992,854,791.22
r(V-D)	$586,627,100.72	$579,845,284.39	$573,063,468.05	$566,281,651.72	$559,499,835.39
O&M	$82,224,192.41	$83,868,676.26	$85,546,049.78	$87,256,970.78	$89,002,110.19
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$765,734,381.86	$760,597,049.38	$755,492,606.57	$750,421,711.23	$745,385,034.31

No Delay	2047	2048	2049	2050	2051
Rate base	$6,712,875,000.00	$6,625,125,000.00	$6,537,375,000.00	$6,449,625,000.00	$6,361,875,000.00
r(V-D)	$469,901,250.00	$463,758,750.00	$457,616,250.00	$451,473,750.00	$445,331,250.00
O&M	$90,782,152.40	$92,597,795.44	$94,449,751.35	$96,338,746.38	$98,265,521.31
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$648,433,402.40	$644,106,545.44	$639,816,001.35	$635,562,496.38	$631,346,771.31

Market Prices					
Energy					
Capacity					
Sum	$524,685,804.72	$545,046,870.19	$566,198,071.36	$588,170,070.41	$610,994,719.38

One Year Delay	2047	2048	2049	2050	2051
Rate base	$6,936,637,474.57	$6,847,132,474.57	$6,757,627,474.57	$6,668,122,474.57	$6,578,617,474.57
r(V-D)	$485,564,623.22	$479,299,273.22	$473,033,923.22	$466,768,573.22	$460,503,223.22
O&M	$90,782,152.40	$92,597,795.44	$94,449,751.35	$96,338,746.38	$98,265,521.31
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$665,851,775.36	$661,402,068.41	$656,988,674.32	$652,612,319.34	$648,273,744.27

Two Year Delay	2047	2048	2049	2050	2051
Rate base	$7,166,665,295.04	$7,075,370,195.04	$6,984,075,095.04	$6,892,779,995.04	$6,801,484,895.04
r(V-D)	$501,666,570.65	$495,275,913.65	$488,885,256.65	$482,494,599.65	$476,103,942.65
O&M	$90,782,152.40	$92,597,795.44	$94,449,751.35	$96,338,746.38	$98,265,521.31
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$683,743,822.79	$679,168,808.84	$674,630,107.74	$670,128,445.77	$665,664,563.70

Five Year Delay	2047	2048	2049	2050	2051
Rate base	$7,895,971,700.74	$7,799,088,610.26	$7,702,205,519.78	$7,605,322,429.30	$7,508,439,338.81
r(V-D)	$552,718,019.05	$545,936,202.72	$539,154,386.38	$532,372,570.05	$525,590,753.72
O&M	$90,782,152.40	$92,597,795.44	$94,449,751.35	$96,338,746.38	$98,265,521.31
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$740,383,260.18	$735,417,086.90	$730,487,226.47	$725,594,405.17	$720,739,363.76

No Delay	2052	2053	2054	2055	2056
Rate base	$6,274,125,000.00	$6,186,375,000.00	$6,098,625,000.00	$6,010,875,000.00	$5,923,125,000.00
r(V-D)	$439,188,750.00	$433,046,250.00	$426,903,750.00	$420,761,250.00	$414,618,750.00
O&M	$100,230,831.73	$102,235,448.37	$104,280,157.34	$106,365,760.48	$108,493,075.69
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$627,169,581.73	$623,031,698.37	$618,933,907.34	$614,877,010.48	$610,861,825.69
Market Prices					
Energy					
Capacity					
Sum	$634,705,106.38	$659,335,603.55	$684,921,916.86	$711,501,137.92	$739,111,797.72

One Year Delay	2052	2053	2054	2055	2056
Rate base	$6,489,112,474.57	$6,399,607,474.57	$6,310,102,474.57	$6,220,597,474.57	$6,131,092,474.57
r(V-D)	$454,237,873.22	$447,972,523.22	$441,707,173.22	$435,441,823.22	$429,176,473.22
O&M	$100,230,831.73	$102,235,448.37	$104,280,157.34	$106,365,760.48	$108,493,075.69
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$643,973,704.70	$639,712,971.33	$635,492,330.30	$631,312,583.45	$627,174,548.66

Two Year Delay	2052	2053	2054	2055	2056
Rate base	$6,710,189,795.04	$6,618,894,695.04	$6,527,599,595.04	$6,436,304,495.04	$6,345,009,395.04
r(V-D)	$469,713,285.65	$463,322,628.65	$456,931,971.65	$450,541,314.65	$444,150,657.65
O&M	$100,230,831.73	$102,235,448.37	$104,280,157.34	$106,365,760.48	$108,493,075.69
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$661,239,217.13	$656,853,176.76	$652,507,228.73	$648,202,174.87	$643,938,833.08

Five Year Delay	2052	2053	2054	2055	2056
Rate base	$7,411,556,248.33	$7,314,673,157.85	$7,217,790,067.37	$7,120,906,976.89	$7,024,023,886.41
r(V-D)	$518,808,937.38	$512,027,121.05	$505,245,304.72	$498,463,488.38	$491,681,672.05
O&M	$100,230,831.73	$102,235,448.37	$104,280,157.34	$106,365,760.48	$108,493,075.69
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$715,922,857.85	$711,145,658.16	$706,408,550.79	$701,712,337.60	$697,057,836.48

No Delay	2057	2058	2059	2060	2061
Rate base	$5,835,375,000.00	$5,747,625,000.00	$5,659,875,000.00	$5,572,125,000.00	$5,484,375,000.00
r(V-D)	$408,476,250.00	$402,333,750.00	$396,191,250.00	$390,048,750.00	$383,906,250.00
O&M	$110,662,937.21	$112,876,195.95	$115,133,719.87	$117,436,394.27	$119,785,122.15
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$606,889,187.21	$602,959,945.95	$599,074,969.87	$595,235,144.27	$591,441,372.15
Market Prices					
Energy					
Capacity					
Sum	$767,793,922.46	$797,589,091.65	$828,540,498.32	$860,693,011.65	$894,093,242.05
One Year Delay	2057	2058	2059	2060	2061
Rate base	$6,041,587,474.57	$5,952,082,474.57	$5,862,577,474.57	$5,773,072,474.57	$5,683,567,474.57
r(V-D)	$422,911,123.22	$416,645,773.22	$410,380,423.22	$404,115,073.22	$397,849,723.22
O&M	$110,662,937.21	$112,876,195.95	$115,133,719.87	$117,436,394.27	$119,785,122.15
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$623,079,060.17	$619,026,968.91	$615,019,142.83	$611,056,467.23	$607,139,845.12
Two Year Delay	2057	2058	2059	2060	2061
Rate base	$6,253,714,295.04	$6,162,419,195.04	$6,071,124,095.04	$5,979,828,995.04	$5,888,533,895.04
r(V-D)	$437,760,000.65	$431,369,343.65	$424,978,686.65	$418,588,029.65	$412,197,372.65
O&M	$110,662,937.21	$112,876,195.95	$115,133,719.87	$117,436,394.27	$119,785,122.15
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$639,718,037.60	$635,540,639.34	$631,407,506.26	$627,319,523.66	$623,277,594.54
Five Year Delay	2057	2058	2059	2060	2061
Rate base	$6,927,140,795.93	$6,830,257,705.45	$6,733,374,614.97	$6,636,491,524.49	$6,539,608,434.01
r(V-D)	$484,899,855.72	$478,118,039.38	$471,336,223.05	$464,554,406.71	$457,772,590.38
O&M	$110,662,937.21	$112,876,195.95	$115,133,719.87	$117,436,394.27	$119,785,122.15
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$692,445,881.66	$687,877,324.07	$683,353,031.65	$678,873,889.72	$674,440,801.27

No Delay	2062	2063	2064	2065	2066
Rate base	$5,396,625,000.00	$5,308,875,000.00	$5,221,125,000.00	$5,133,375,000.00	$5,045,625,000.00
r(V-D)	$377,763,750.00	$371,621,250.00	$365,478,750.00	$359,336,250.00	$353,193,750.00
O&M	$122,180,824.59	$124,624,441.09	$127,116,929.91	$129,659,268.51	$132,252,453.88
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$587,694,574.59	$583,995,691.09	$580,345,679.91	$576,745,518.51	$573,196,203.88
Market Prices					
Energy					
Capacity					
Sum	$928,789,608.66	$964,832,409.63	$1,002,273,894.96	$1,041,168,342.29	$1,081,572,135.56
One Year Delay	2062	2063	2064	2065	2066
Rate base	$5,594,062,474.57	$5,504,557,474.57	$5,415,052,474.57	$5,325,547,474.57	$5,236,042,474.57
r(V-D)	$391,584,373.22	$385,319,023.22	$379,053,673.22	$372,788,323.22	$366,522,973.22
O&M	$122,180,824.59	$124,624,441.09	$127,116,929.91	$129,659,268.51	$132,252,453.88
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$603,270,197.56	$599,448,464.05	$595,675,602.87	$591,952,591.47	$588,280,426.84
Two Year Delay	2062	2063	2064	2065	2066
Rate base	$5,797,238,795.04	$5,705,943,695.04	$5,614,648,595.04	$5,523,353,495.04	$5,432,058,395.04
r(V-D)	$405,806,715.65	$399,416,058.65	$393,025,401.65	$386,634,744.65	$380,244,087.65
O&M	$122,180,824.59	$124,624,441.09	$127,116,929.91	$129,659,268.51	$132,252,453.88
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$619,282,639.99	$615,335,599.48	$611,437,431.30	$607,589,112.90	$603,791,641.27
Five Year Delay	2062	2063	2064	2065	2066
Rate base	$6,442,725,343.53	$6,345,842,253.05	$6,248,959,162.56	$6,152,076,072.08	$6,055,192,981.60
r(V-D)	$450,990,774.05	$444,208,957.71	$437,427,141.38	$430,645,325.05	$423,863,508.71
O&M	$122,180,824.59	$124,624,441.09	$127,116,929.91	$129,659,268.51	$132,252,453.88
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$670,054,687.38	$665,716,487.54	$661,427,160.03	$657,187,682.29	$652,999,051.33

No Delay	2067	2068	2069	2070	2071
Rate base	$4,957,875,000.00	$4,870,125,000.00	$4,782,375,000.00	$4,694,625,000.00	$4,606,875,000.00
r(V-D)	$347,051,250.00	$340,908,750.00	$334,766,250.00	$328,623,750.00	$322,481,250.00
O&M	$134,897,502.95	$137,595,453.01	$140,347,362.07	$143,154,309.31	$146,017,395.50
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$569,698,752.95	$566,254,203.01	$562,863,612.07	$559,528,059.31	$556,248,645.50

Market Prices					
Energy					
Capacity					
Sum	$1,123,543,846.76	$1,167,144,320.83	$1,212,436,763.88	$1,259,486,834.81	$1,308,362,740.49

One Year Delay	2067	2068	2069	2070	2071
Rate base	$5,146,537,474.57	$5,057,032,474.57	$4,967,527,474.57	$4,878,022,474.57	$4,788,517,474.57
r(V-D)	$360,257,623.22	$353,992,273.22	$347,726,923.22	$341,461,573.22	$335,196,223.22
O&M	$134,897,502.95	$137,595,453.01	$140,347,362.07	$143,154,309.31	$146,017,395.50
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$584,660,125.92	$581,092,725.98	$577,579,285.04	$574,120,882.28	$570,718,618.47

Two Year Delay	2067	2068	2069	2070	2071
Rate base	$5,340,763,295.04	$5,249,468,195.04	$5,158,173,095.04	$5,066,877,995.04	$4,975,582,895.04
r(V-D)	$373,853,430.65	$367,462,773.65	$361,072,116.65	$354,681,459.65	$348,290,802.65
O&M	$134,897,502.95	$137,595,453.01	$140,347,362.07	$143,154,309.31	$146,017,395.50
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$600,046,033.35	$596,353,326.41	$592,714,578.47	$589,130,868.71	$585,603,297.89

Five Year Delay	2067	2068	2069	2070	2071
Rate base	$5,958,309,891.12	$5,861,426,800.64	$5,764,543,710.16	$5,667,660,619.68	$5,570,777,529.20
r(V-D)	$417,081,692.38	$410,299,876.04	$403,518,059.71	$396,736,243.38	$389,954,427.04
O&M	$134,897,502.95	$137,595,453.01	$140,347,362.07	$143,154,309.31	$146,017,395.50
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$648,862,284.07	$644,778,417.80	$640,748,510.52	$636,773,641.43	$632,854,911.28

No Delay	2072	2073	2074	2075	2076
Rate base	$4,519,125,000.00	$4,431,375,000.00	$4,343,625,000.00	$4,255,875,000.00	$4,168,125,000.00
r(V-D)	$316,338,750.00	$310,196,250.00	$304,053,750.00	$297,911,250.00	$291,768,750.00
O&M	$148,937,743.41	$151,916,498.28	$154,954,828.24	$158,053,924.81	$161,215,003.31
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$553,026,493.41	$549,862,748.28	$546,758,578.24	$543,715,174.81	$540,733,753.31
Market Prices					
Energy					
Capacity					
Sum	$1,359,135,334.64	$1,411,878,220.54	$1,466,667,857.75	$1,523,583,672.90	$1,582,708,174.91

One Year Delay	2072	2073	2074	2075	2076
Rate base	$4,699,012,474.57	$4,609,507,474.57	$4,520,002,474.57	$4,430,497,474.57	$4,340,992,474.57
r(V-D)	$328,930,873.22	$322,665,523.22	$316,400,173.22	$310,134,823.22	$303,869,473.22
O&M	$148,937,743.41	$151,916,498.28	$154,954,828.24	$158,053,924.81	$161,215,003.31
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$567,373,616.38	$564,087,021.24	$560,860,001.21	$557,693,747.77	$554,589,476.27

Two Year Delay	2072	2073	2074	2075	2076
Rate base	$4,884,287,795.04	$4,792,992,695.04	$4,701,697,595.04	$4,610,402,495.04	$4,519,107,395.04
r(V-D)	$341,900,145.65	$335,509,488.65	$329,118,831.65	$322,728,174.65	$316,337,517.65
O&M	$148,937,743.41	$151,916,498.28	$154,954,828.24	$158,053,924.81	$161,215,003.31
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$582,132,988.80	$578,721,086.67	$575,368,759.64	$572,077,199.20	$568,847,620.70

Five Year Delay	2072	2073	2074	2075	2076
Rate base	$5,473,894,438.72	$5,377,011,348.24	$5,280,128,257.76	$5,183,245,167.28	$5,086,362,076.79
r(V-D)	$383,172,610.71	$376,390,794.38	$369,608,978.04	$362,827,161.71	$356,045,345.38
O&M	$148,937,743.41	$151,916,498.28	$154,954,828.24	$158,053,924.81	$161,215,003.31
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$628,993,442.86	$625,190,381.39	$621,446,895.03	$617,764,175.26	$614,143,437.42

No Delay	2077	2078	2079	2080	2081
Rate base	$4,080,375,000.00	$3,992,625,000.00	$3,904,875,000.00	$3,817,125,000.00	$3,729,375,000.00
r(V-D)	$285,626,250.00	$279,483,750.00	$273,341,250.00	$267,198,750.00	$261,056,250.00
O&M	$164,439,303.37	$167,728,089.44	$171,082,651.23	$174,504,304.25	$177,994,390.34
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$537,815,553.37	$534,961,839.44	$532,173,901.23	$529,453,054.25	$526,800,640.34
Market Prices					
Energy					
Capacity					
Sum	$1,644,127,074.53	$1,707,929,408.63	$1,774,207,669.25	$1,843,057,937.71	$1,914,580,023.88
One Year Delay	2077	2078	2079	2080	2081
Rate base	$4,251,487,474.57	$4,161,982,474.57	$4,072,477,474.57	$3,982,972,474.57	$3,893,467,474.57
r(V-D)	$297,604,123.22	$291,338,773.22	$285,073,423.22	$278,808,073.22	$272,542,723.22
O&M	$164,439,303.37	$167,728,089.44	$171,082,651.23	$174,504,304.25	$177,994,390.34
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$551,548,426.34	$548,571,862.40	$545,661,074.19	$542,817,377.22	$540,042,113.30
Two Year Delay	2077	2078	2079	2080	2081
Rate base	$4,427,812,295.04	$4,336,517,195.04	$4,245,222,095.04	$4,153,926,995.04	$4,062,631,895.04
r(V-D)	$309,946,860.65	$303,556,203.65	$297,165,546.65	$290,774,889.65	$284,384,232.65
O&M	$164,439,303.37	$167,728,089.44	$171,082,651.23	$174,504,304.25	$177,994,390.34
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$565,681,263.76	$562,579,392.83	$559,543,297.62	$556,574,293.64	$553,673,722.73
Five Year Delay	2077	2078	2079	2080	2081
Rate base	$4,989,478,986.31	$4,892,595,895.83	$4,795,712,805.35	$4,698,829,714.87	$4,601,946,624.39
r(V-D)	$349,263,529.04	$342,481,712.71	$335,699,896.37	$328,918,080.04	$322,136,263.71
O&M	$164,439,303.37	$167,728,089.44	$171,082,651.23	$174,504,304.25	$177,994,390.34
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$610,585,921.15	$607,092,890.89	$603,665,636.34	$600,305,473.03	$597,013,742.78

No Delay	2082	2083	2084	2085	2086
Rate base	$3,641,625,000.00	$3,553,875,000.00	$3,466,125,000.00	$3,378,375,000.00	$3,290,625,000.00
r(V-D)	$254,913,750.00	$248,771,250.00	$242,628,750.00	$236,486,250.00	$230,343,750.00
O&M	$181,554,278.14	$185,185,363.71	$188,889,070.98	$192,666,852.40	$196,520,189.45
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$524,218,028.14	$521,706,613.71	$519,267,820.98	$516,903,102.40	$514,613,939.45

Market Prices					
Energy					
Capacity					
Sum	$1,988,877,610.87	$2,066,058,405.32	$2,146,234,293.60	$2,229,521,503.92	$2,316,040,774.88

One Year Delay	2082	2083	2084	2085	2086
Rate base	$3,803,962,474.57	$3,714,457,474.57	$3,624,952,474.57	$3,535,447,474.57	$3,445,942,474.57
r(V-D)	$266,277,373.22	$260,012,023.22	$253,746,673.22	$247,481,323.22	$241,215,973.22
O&M	$181,554,278.14	$185,185,363.71	$188,889,070.98	$192,666,852.40	$196,520,189.45
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$537,336,651.11	$534,702,386.67	$532,140,743.95	$529,653,175.37	$527,241,162.41

Two Year Delay	2082	2083	2084	2085	2086
Rate base	$3,971,336,795.04	$3,880,041,695.04	$3,788,746,595.04	$3,697,451,495.04	$3,606,156,395.04
r(V-D)	$277,993,575.65	$271,602,918.65	$265,212,261.65	$258,821,604.65	$252,430,947.65
O&M	$181,554,278.14	$185,185,363.71	$188,889,070.98	$192,666,852.40	$196,520,189.45
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$550,842,953.54	$548,083,382.10	$545,396,432.37	$542,783,556.79	$540,246,236.84

Five Year Delay	2082	2083	2084	2085	2086
Rate base	$4,505,063,533.91	$4,408,180,443.43	$4,311,297,352.95	$4,214,414,262.47	$4,117,531,171.99
r(V-D)	$315,354,447.37	$308,572,631.04	$301,790,814.71	$295,008,998.37	$288,227,182.04
O&M	$181,554,278.14	$185,185,363.71	$188,889,070.98	$192,666,852.40	$196,520,189.45
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$593,791,814.26	$590,641,083.48	$587,562,974.43	$584,558,939.51	$581,630,460.23

No Delay	2087	2088	2089	2090	2091
Rate base	$3,202,875,000.00	$3,115,125,000.00	$3,027,375,000.00	$2,939,625,000.00	$2,851,875,000.00
r(V-D)	$224,201,250.00	$218,058,750.00	$211,916,250.00	$205,773,750.00	$199,631,250.00
O&M	$200,450,593.24	$204,459,605.10	$208,548,797.20	$212,719,773.15	$216,974,168.61
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$512,401,843.24	$510,268,355.10	$508,215,047.20	$506,243,523.15	$504,355,418.61
Market Prices					
Energy					
Capacity					
Sum	$2,405,917,530.51	$2,499,282,062.04	$2,596,269,716.82	$2,697,021,094.52	$2,801,682,250.95
One Year Delay	2087	2088	2089	2090	2091
Rate base	$3,356,437,474.57	$3,266,932,474.57	$3,177,427,474.57	$3,087,922,474.57	$2,998,417,474.57
r(V-D)	$234,950,623.22	$228,685,273.22	$222,419,923.22	$216,154,573.22	$209,889,223.22
O&M	$200,450,593.24	$204,459,605.10	$208,548,797.20	$212,719,773.15	$216,974,168.61
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$524,906,216.20	$522,649,878.07	$520,473,720.17	$518,379,346.11	$516,368,391.58
Two Year Delay	2087	2088	2089	2090	2091
Rate base	$3,514,861,295.04	$3,423,566,195.04	$3,332,271,095.04	$3,240,975,995.04	$3,149,680,895.04
r(V-D)	$246,040,290.65	$239,649,633.65	$233,258,976.65	$226,868,319.65	$220,477,662.65
O&M	$200,450,593.24	$204,459,605.10	$208,548,797.20	$212,719,773.15	$216,974,168.61
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$537,785,983.63	$535,404,338.50	$533,102,873.60	$530,883,192.54	$528,746,931.00
Five Year Delay	2087	2088	2089	2090	2091
Rate base	$4,020,648,081.51	$3,923,764,991.03	$3,826,881,900.54	$3,729,998,810.06	$3,633,115,719.58
r(V-D)	$281,445,365.71	$274,663,549.37	$267,881,733.04	$261,099,916.70	$254,318,100.37
O&M	$200,450,593.24	$204,459,605.10	$208,548,797.20	$212,719,773.15	$216,974,168.61
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$578,779,047.68	$576,006,243.21	$573,313,618.98	$570,702,778.59	$568,175,357.72

No Delay	2092	2093	2094	2095	2096
Rate base	$2,764,125,000.00	$2,676,375,000.00	$2,588,625,000.00	$2,500,875,000.00	$2,413,125,000.00
r(V-D)	$193,488,750.00	$187,346,250.00	$181,203,750.00	$175,061,250.00	$168,918,750.00
O&M	$221,313,651.98	$225,739,925.02	$230,254,723.52	$234,859,817.99	$239,557,014.35
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$502,552,401.98	$500,836,175.02	$499,208,473.52	$497,671,067.99	$496,225,764.35

Market Prices					
Energy					
Capacity					
Sum	$2,910,404,909.78	$3,023,346,682.52	$3,140,671,296.97	$3,262,548,834.59	$3,389,155,977.05

One Year Delay	2092	2093	2094	2095	2096
Rate base	$2,908,912,474.57	$2,819,407,474.57	$2,729,902,474.57	$2,640,397,474.57	$2,550,892,474.57
r(V-D)	$203,623,873.22	$197,358,523.22	$191,093,173.22	$184,827,823.22	$178,562,473.22
O&M	$221,313,651.98	$225,739,925.02	$230,254,723.52	$234,859,817.99	$239,557,014.35
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$514,442,524.95	$512,603,447.99	$510,852,896.49	$509,192,640.96	$507,624,487.32

Two Year Delay	2092	2093	2094	2095	2096
Rate base	$3,058,385,795.04	$2,967,090,695.04	$2,875,795,595.04	$2,784,500,495.04	$2,693,205,395.04
r(V-D)	$214,087,005.65	$207,696,348.65	$201,305,691.65	$194,915,034.65	$188,524,377.65
O&M	$221,313,651.98	$225,739,925.02	$230,254,723.52	$234,859,817.99	$239,557,014.35
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$526,695,757.38	$524,731,373.42	$522,855,514.92	$521,069,952.39	$519,376,491.75

Five Year Delay	2092	2093	2094	2095	2096
Rate base	$3,536,232,629.10	$3,439,349,538.62	$3,342,466,448.14	$3,245,583,357.66	$3,148,700,267.18
r(V-D)	$247,536,284.04	$240,754,467.70	$233,972,651.37	$227,190,835.04	$220,409,018.70
O&M	$221,313,651.98	$225,739,925.02	$230,254,723.52	$234,859,817.99	$239,557,014.35
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$565,733,024.76	$563,377,481.46	$561,110,463.63	$558,933,741.77	$556,849,121.79

No Delay	2097	2098	2099	2100	2101
Rate base	$2,325,375,000.00	$2,237,625,000.00	$2,149,875,000.00	$2,062,125,000.00	$1,974,375,000.00
r(V-D)	$162,776,250.00	$156,633,750.00	$150,491,250.00	$144,348,750.00	$138,206,250.00
O&M	$244,348,154.64	$249,235,117.73	$254,219,820.09	$259,304,216.49	$264,490,300.82
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$494,874,404.64	$493,618,867.73	$492,461,070.09	$491,402,966.49	$490,446,550.82
Market Prices					
Energy					
Capacity					
Sum	$3,520,676,262.37	$3,657,300,350.99	$3,799,226,302.15	$3,946,659,861.02	$4,099,814,756.96
One Year Delay	2097	2098	2099	2100	2101
Rate base	$2,461,387,474.57	$2,371,882,474.57	$2,282,377,474.57	$2,192,872,474.57	$2,103,367,474.57
r(V-D)	$172,297,123.22	$166,031,773.22	$159,766,423.22	$153,501,073.22	$147,235,723.22
O&M	$244,348,154.64	$249,235,117.73	$254,219,820.09	$259,304,216.49	$264,490,300.82
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$506,150,277.61	$504,771,890.70	$503,491,243.05	$502,310,289.46	$501,231,023.79
Two Year Delay	2097	2098	2099	2100	2101
Rate base	$2,601,910,295.04	$2,510,615,195.04	$2,419,320,095.04	$2,328,024,995.04	$2,236,729,895.04
r(V-D)	$182,133,720.65	$175,743,063.65	$169,352,406.65	$162,961,749.65	$156,571,092.65
O&M	$244,348,154.64	$249,235,117.73	$254,219,820.09	$259,304,216.49	$264,490,300.82
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$517,776,975.03	$516,273,281.13	$514,867,326.48	$513,561,065.88	$512,356,493.21
Five Year Delay	2097	2098	2099	2100	2101
Rate base	$3,051,817,176.70	$2,954,934,086.22	$2,858,050,995.74	$2,761,167,905.26	$2,664,284,814.77
r(V-D)	$213,627,202.37	$206,845,386.04	$200,063,569.70	$193,281,753.37	$186,499,937.03
O&M	$244,348,154.64	$249,235,117.73	$254,219,820.09	$259,304,216.49	$264,490,300.82
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$554,858,445.75	$552,963,592.51	$551,166,478.53	$549,469,058.60	$547,873,326.59

No Delay	2102	2103	2104	2105	2106
Rate base	$1,886,625,000.00	$1,798,875,000.00	$1,711,125,000.00	$1,623,375,000.00	$1,535,625,000.00
r(V-D)	$132,063,750.00	$125,921,250.00	$119,778,750.00	$113,636,250.00	$107,493,750.00
O&M	$269,780,106.84	$275,175,708.97	$280,679,223.15	$286,292,807.62	$292,018,663.77
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$489,593,856.84	$488,846,958.97	$488,207,973.15	$487,679,057.62	$487,262,413.77

Market Prices					
Energy					
Capacity					
Sum	$4,258,913,013.36	$4,424,185,269.48	$4,595,871,114.84	$4,774,219,436.49	$4,959,488,779.87

One Year Delay	2102	2103	2104	2105	2106
Rate base	$2,013,862,474.57	$1,924,357,474.57	$1,834,852,474.57	$1,745,347,474.57	$1,655,842,474.57
r(V-D)	$140,970,373.22	$134,705,023.22	$128,439,673.22	$122,174,323.22	$115,908,973.22
O&M	$269,780,106.84	$275,175,708.97	$280,679,223.15	$286,292,807.62	$292,018,663.77
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$500,255,479.80	$499,385,731.94	$498,623,896.12	$497,972,130.58	$497,432,636.73

Two Year Delay	2102	2103	2104	2105	2106
Rate base	$2,145,434,795.04	$2,054,139,695.04	$1,962,844,595.04	$1,871,549,495.04	$1,780,254,395.04
r(V-D)	$150,180,435.65	$143,789,778.65	$137,399,121.65	$131,008,464.65	$124,617,807.65
O&M	$269,780,106.84	$275,175,708.97	$280,679,223.15	$286,292,807.62	$292,018,663.77
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$511,255,642.23	$510,260,587.37	$509,373,444.55	$508,596,372.01	$507,931,571.16

Five Year Delay	2102	2103	2104	2105	2106
Rate base	$2,567,401,724.29	$2,470,518,633.81	$2,373,635,543.33	$2,276,752,452.85	$2,179,869,362.37
r(V-D)	$179,718,120.70	$172,936,304.37	$166,154,488.03	$159,372,671.70	$152,590,855.37
O&M	$269,780,106.84	$275,175,708.97	$280,679,223.15	$286,292,807.62	$292,018,663.77
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$546,381,316.28	$544,995,102.08	$543,716,799.92	$542,548,568.05	$541,492,607.87

No Delay	2107	2108	2109	2110	2111
Rate base	$1,447,875,000.00	$1,360,125,000.00	$1,272,375,000.00	$1,184,625,000.00	$1,096,875,000.00
r(V-D)	$101,351,250.00	$95,208,750.00	$89,066,250.00	$82,923,750.00	$76,781,250.00
O&M	$297,859,037.04	$303,816,217.79	$309,892,542.14	$316,090,392.98	$322,412,200.84
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$486,960,287.04	$486,774,967.79	$486,708,792.14	$486,764,142.98	$486,943,450.84
Market Prices					
Energy					
Capacity					
Sum	$5,151,947,723.57	$5,351,875,268.70	$5,559,561,243.36	$5,775,306,722.75	$5,999,424,465.67

One Year Delay	2107	2108	2109	2110	2111
Rate base	$1,566,337,474.57	$1,476,832,474.57	$1,387,327,474.57	$1,297,822,474.57	$1,208,317,474.57
r(V-D)	$109,643,623.22	$103,378,273.22	$97,112,923.22	$90,847,573.22	$84,582,223.22
O&M	$297,859,037.04	$303,816,217.79	$309,892,542.14	$316,090,392.98	$322,412,200.84
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$497,007,660.01	$496,699,490.75	$496,510,465.11	$496,442,965.95	$496,499,423.81

Two Year Delay	2107	2108	2109	2110	2111
Rate base	$1,688,959,295.04	$1,597,664,195.04	$1,506,369,095.04	$1,415,073,995.04	$1,323,778,895.04
r(V-D)	$118,227,150.65	$111,836,493.65	$105,445,836.65	$99,055,179.65	$92,664,522.65
O&M	$297,859,037.04	$303,816,217.79	$309,892,542.14	$316,090,392.98	$322,412,200.84
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$507,381,287.44	$506,947,811.18	$506,633,478.53	$506,440,672.38	$506,371,823.24

Five Year Delay	2107	2108	2109	2110	2111
Rate base	$2,082,986,271.89	$1,986,103,181.41	$1,889,220,090.93	$1,792,337,000.45	$1,695,453,909.97
r(V-D)	$145,809,039.03	$139,027,222.70	$132,245,406.36	$125,463,590.03	$118,681,773.70
O&M	$297,859,037.04	$303,816,217.79	$309,892,542.14	$316,090,392.98	$322,412,200.84
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$540,551,164.81	$539,726,529.22	$539,021,037.24	$538,437,071.75	$537,977,063.28

No Delay	2112	2113	2114	2115	2116
Rate base	$1,009,125,000.00	$921,375,000.00	$833,625,000.00	$745,875,000.00	$658,125,000.00
r(V-D)	$70,638,750.00	$64,496,250.00	$58,353,750.00	$52,211,250.00	$46,068,750.00
O&M	$328,860,444.86	$335,437,653.76	$342,146,406.83	$348,989,334.97	$355,969,121.67
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$487,249,194.86	$487,683,903.76	$488,250,156.83	$488,950,584.97	$489,787,871.67

Market Prices					
Energy					
Capacity					
Sum	$6,232,239,367.92	$6,474,088,933.25	$6,725,323,762.65	$6,986,308,062.61	$7,257,420,173.11

One Year Delay	2112	2113	2114	2115	2116
Rate base	$1,118,812,474.57	$1,029,307,474.57	$939,802,474.57	$850,297,474.57	$760,792,474.57
r(V-D)	$78,316,873.22	$72,051,523.22	$65,786,173.22	$59,520,823.22	$53,255,473.22
O&M	$328,860,444.86	$335,437,653.76	$342,146,406.83	$348,989,334.97	$355,969,121.67
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$496,682,317.82	$496,994,176.72	$497,437,579.80	$498,015,157.93	$498,729,594.63

Two Year Delay	2112	2113	2114	2115	2116
Rate base	$1,232,483,795.04	$1,141,188,695.04	$1,049,893,595.04	$958,598,495.04	$867,303,395.04
r(V-D)	$86,273,865.65	$79,883,208.65	$73,492,551.65	$67,101,894.65	$60,711,237.65
O&M	$328,860,444.86	$335,437,653.76	$342,146,406.83	$348,989,334.97	$355,969,121.67
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$506,429,410.25	$506,615,962.15	$506,934,058.22	$507,386,329.36	$507,975,459.06

Five Year Delay	2112	2113	2114	2115	2116
Rate base	$1,598,570,819.49	$1,501,687,729.01	$1,404,804,638.52	$1,307,921,548.04	$1,211,038,457.56
r(V-D)	$111,899,957.36	$105,118,141.03	$98,336,324.70	$91,554,508.36	$84,772,692.03
O&M	$328,860,444.86	$335,437,653.76	$342,146,406.83	$348,989,334.97	$355,969,121.67
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$537,643,490.96	$537,438,883.53	$537,365,820.27	$537,426,932.07	$537,624,902.44

No Delay	2117	2118	2119	2120	2121
Rate base	$570,375,000.00	$482,625,000.00	$394,875,000.00	$307,125,000.00	$219,375,000.00
r(V-D)	$39,926,250.00	$33,783,750.00	$27,641,250.00	$21,498,750.00	$15,356,250.00
O&M	$363,088,504.10	$370,350,274.18	$377,757,279.67	$385,312,425.26	$393,018,673.77
Depreciation	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00	$87,750,000.00
Total	$490,764,754.10	$491,884,024.18	$493,148,529.67	$494,561,175.26	$496,124,923.77

Market Prices					
Energy					
Capacity					
Sum	$7,539,053,116.04	$7,831,615,165.00	$8,135,530,437.12	$8,451,239,507.93	$8,779,200,050.01

One Year Delay	2117	2118	2119	2120	2121
Rate base	$671,287,474.57	$581,782,474.57	$492,277,474.57	$402,772,474.57	$313,267,474.57
r(V-D)	$46,990,123.22	$40,724,773.22	$34,459,423.22	$28,194,073.22	$21,928,723.22
O&M	$363,088,504.10	$370,350,274.18	$377,757,279.67	$385,312,425.26	$393,018,673.77
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$499,583,627.07	$500,580,047.15	$501,721,702.63	$503,011,498.23	$504,452,396.73

Two Year Delay	2117	2118	2119	2120	2121
Rate base	$776,008,295.04	$684,713,195.04	$593,418,095.04	$502,122,995.04	$410,827,895.04
r(V-D)	$54,320,580.65	$47,929,923.65	$41,539,266.65	$35,148,609.65	$28,757,952.65
O&M	$363,088,504.10	$370,350,274.18	$377,757,279.67	$385,312,425.26	$393,018,673.77
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$508,704,184.49	$509,575,297.58	$510,591,646.06	$511,756,134.65	$513,071,726.16

Five Year Delay	2117	2118	2119	2120	2121
Rate base	$1,114,155,367.08	$1,017,272,276.60	$920,389,186.12	$823,506,095.64	$726,623,005.16
r(V-D)	$77,990,875.70	$71,209,059.36	$64,427,243.03	$57,645,426.69	$50,863,610.36
O&M	$363,088,504.10	$370,350,274.18	$377,757,279.67	$385,312,425.26	$393,018,673.77
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$537,962,468.54	$538,442,422.28	$539,067,611.43	$539,840,940.69	$540,765,372.87

No Delay	2122	2123	2124	2125	2126
Rate base	$131,625,000.00	$43,875,000.00	$0.00		
r(V-D)	$9,213,750.00	$3,071,250.00	$0.00		
O&M	$400,879,047.24	$408,896,628.19	$417,074,560.75		
Depreciation	$87,750,000.00	$87,750,000.00			
Total	$497,842,797.24	$499,717,878.19	$9,841,437,799.77	$10,223,346,663.27	$10,620,075,960.83

Market Prices					
Energy					
Capacity					
Sum	$9,119,887,496.47	$9,473,795,730.19	$9,841,437,799.77	$10,223,346,663.27	$10,620,075,960.83

One Year Delay	2122	2123	2124
Rate base	$223,762,474.57	$134,257,474.57	$44,752,474.57
r(V-D)	$15,663,373.22	$9,398,023.22	$3,132,673.22
O&M	$400,879,047.24	$408,896,628.19	$417,074,560.75
Depreciation	$89,504,999.74	$89,504,999.74	$89,504,999.74
Total	$506,047,420.21	$507,799,651.15	$509,712,233.71

Two Year Delay	2122	2123	2124	2125
Rate base	$319,532,795.04	$228,237,695.04	$136,942,595.04	$45,647,495.04
r(V-D)	$22,367,295.65	$15,976,638.65	$9,585,981.65	$3,195,324.65
O&M	$400,879,047.24	$408,896,628.19	$417,074,560.75	$425,416,051.97
Depreciation	$91,295,099.74	$91,295,099.74	$91,295,099.74	$91,295,099.74
Total	$514,541,442.63	$516,168,366.58	$517,955,642.14	$519,906,476.36

Five Year Delay	2122	2123	2124	2125	2126
Rate base	$629,739,914.68	$532,856,824.20	$435,973,733.72	$339,090,643.24	$242,207,552.75
r(V-D)	$44,081,794.03	$37,299,977.69	$30,518,161.36	$23,736,345.03	$16,954,528.69
O&M	$400,879,047.24	$408,896,628.19	$417,074,560.75	$425,416,051.97	$433,924,373.00
Depreciation	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74	$96,883,088.74
Total	$541,843,930.01	$543,079,694.62	$544,475,810.85	$546,035,485.73	$547,761,990.44

No Delay	2127	2128
Rate base		
r(V-D)		
O&M		
Depreciation		
Total	$11,032,200,817.27	$11,460,318,675.83
Market Prices		
Energy		
Capacity		
Sum	$11,032,200,817.27	$11,460,318,675.83
One Year Delay		
Rate base		
r(V-D)		
O&M		
Depreciation		
Total		
Two Year Delay		
Rate base		
r(V-D)		
O&M		
Depreciation		
Total		
Five Year Delay	2127	2128
Rate base	$145,324,462.27	$48,441,371.79
r(V-D)	$10,172,712.36	$3,390,896.03
O&M	$442,602,860.46	$451,454,917.67
Depreciation	$96,883,088.74	$96,883,088.74
Total	$549,658,661.56	$551,728,902.44