PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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June 5, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attn: Filing Center

RE: Docket No. UE-210 – PacifiCorp's Supplemental Direct Testimony

Pursuant to the Administrative Law Judge's May 14, 2009 Ruling ("Ruling") in the above-referenced matter, enclosed for filing by PacifiCorp d/b/a Pacific Power are an original and five (5) copies of supplemental direct testimony and exhibits. The following witnesses submit supplemental direct testimony on the specific requests from the Ruling:

- Dr. Samuel C. Hadaway, responds to Requests 1 and 3.
- Stefan A. Bird, responds to Request 2.
- Gregory N. Duvall, responds to Requests 9, 10, 11, 12, 13, 15, 16, 17, 18, 19 and 20.
- R. Bryce Dalley, responds to Requests 4, 6, 7, and 8.
- C. Craig Paice, responds to Request 22.
- William R. Griffith, responds to Requests 5, 14, 21, and 23.

It is respectfully requested that all data requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com.

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 300
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Very truly yours,

Andrea L. Kelly/JJ

Andrea L. Kelly
Vice President, Regulation
Enclosures

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 210, on the date indicated below by email and/or overnight delivery, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: June 5, 2009.

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Ariel Son
Coordinator, Administrative Services

Samuel C. Hadaway
Exhibit PPL/208

Docket No. UE-210
Exhibit PPL/208
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Supplemental Direct Testimony of Samuel C. Hadaway

June 2009

Q. Please state your name.

A. My name is Samuel C. Hadaway.

Q. Are you the same Samuel C. Hadaway who provided direct testimony in this case as Exhibit PPL/200?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to respond to Requests 1 and 3 in the May 14, 2009 Ruling of the Administrative Law Judges on Supplemental Testimony ("Ruling on Supplemental Testimony"), which pertain to my direct testimony.

Request 1—Request for Documents

Q. What is Request 1 in the Ruling on Supplemental Testimony?

A. Request 1 directed the Company to provide, as additional exhibits to PPL/200, copies of the documents cited in the following testimony**:**

- PPL/200, Hadaway/25, Lines 3-4, 14-15;
- PPL/200, Hadaway/28, Table 4; and
- PPL/200, Hadaway/35, Lines 1-2

Q. Did you previously provide copies of each of these documents in the workpapers filed as a part of the Company's initial filing?

A. Yes. These documents were included in whole or in part in my workpapers, which were provided with the Company's initial filing on April 2, 2009.

Q. Have you provided new exhibits to your testimony in response to this request?

A. Yes. My testimony relies upon and sponsors only the following, specific pages from these documents

- Exhibit PPL/209 – Standard & Poor's *Industry Surveys*, Electric Utilities, February 26, 2009, p. 6. (Referenced at PPL/200, Hadaway/25, Lines 3-4.)
- Exhibit PPL/210 – Value Line Investment Survey, Electric Industry, February 27, 2009, p. 148. (Referenced at PPL/200, Hadaway/25, Lines 14-15.)
- Confidential Exhibit PPL/211 – *Regulatory Focus,* Regulatory Research Associates, Inc., Major Rate Case Decisions, January 12, 2009. (Referenced at PPL/200, Hadaway/28, Table 4.)
- Exhibit PPL/212 – Morningstar, Inc., Ibbotson SBBI, 2008 Classic Yearbook, p.31. (Referenced at PPL/200, Hadaway/35, Lines 1-2.)

In compliance with the Ruling on Supplemental Testimony, I have provided a complete copy of the documents in Exhibits PPL/209 and PPL/211. Because the documents cited in Exhibits PPL/210 and PPL/212 are too voluminous to provide in full, the Company has provided only the relevant portions of these documents. By submitting these documents as exhibits, the Company does not concede the relevance of all of the information contained in the entire publication.

Request 3—Return on Equity Information from Comparable Group

Q. What is Request 3 in the Ruling on Supplemental Testimony?

A. Request 3 directs the Company to provide, as additional exhibits to PPL/200, the authorized rate of return on equity for the 19 comparable companies listed in Exhibits PPL/202 and PPL/204.

Q. Was the authorized rate of return on equity one of the factors you considered in determining the comparable group?

A. No. My review focused on companies with business risk and financial risk profiles comparable to PacifiCorp. I did not consider the current authorized rate of return on equity in selecting the companies in my analysis.

Q. Is the information requested in the Ruling on Supplemental Testimony available?

A. No. The comparable group listed in Exhibits PPL/202 and PPL/204 is comprised of publicly traded *parent* companies, which have the market data required for the comparable company DCF analysis. Because these parent companies are not regulated entities, they do not have authorized rates of return.

Q. Is there information available on the authorized rates of return on equity for the regulated utility operating subsidiaries of the comparable companies listed in Exhibits PPL/202 and PPL/204?

A. Yes. Authorized returns for the regulated *operating subsidiaries* of the comparable companies are available. To the extent that such operating companies have had cases with announced authorized returns during the past two years, those data are included in pages 5 to 7 in the Regulatory Research Associates ("RRA") publication, which was provided in my workpapers and is now being filed as Confidential Exhibit PPL/211.

Other RRA data available to the Company lists historical authorized rates of return on equity. Using these RRA data, the Company has prepared a list of authorized rates of return on equity for each operating subsidiary of my comparable companies. This listing is provided as Exhibit PPL/213.

Q. Do you have any additional observations about Exhibit PPL/213?

A. Yes. The data in Exhibit PPL/213 are, to my knowledge, the best indication of authorized returns associated with the comparable companies. However, some of the authorized returns are from cases decided several years ago and, therefore, may not be representative of the current cost of capital. Also, there is no standard weighting methodology that I am aware of for grouping the operating companies' authorized returns into a composite return for their respective parent companies. For these reasons, and because I selected the comparable group without considering such information, the Company does not believe that Exhibit PPL/213 is relevant to setting PacifiCorp's authorized return on equity in this case.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/209
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Samuel C. Hadaway

Standard & Poor's *Industry Surveys*, Electric Utilities, February 26, 2009

June 2009

Exhibit PPL/209
Hadaway/1

STANDARD
&POOR'S

Industry Surveys
Electric Utilities

Justin C. McCann, Electric Utilities Analyst

February 26, 2009

This issue updates the one dated August 14, 2008.
The next update of this Survey is scheduled for August 2009.

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Exhibit PPL/209
Hadaway/2

Topics Covered by Industry Surveys

Aerospace & Defense
Airlines
Alcoholic Beverages & Tobacco
Apparel & Footwear: Retailers & Brands
Autos & Auto Parts
Banking
Biotechnology
Broadcasting, Cable & Satellite
Chemicals
Communications Equipment
Computers: Commercial Services
Computers: Consumer Services & the Internet
Computers: Hardware
Computers: Software
Computers: Storage & Peripherals
Electric Utilities
Environmental & Waste Management
Financial Services: Diversified
Foods & Nonalcoholic Beverages
Healthcare: Facilities
Healthcare: Managed Care
Healthcare: Pharmaceuticals
Healthcare: Products & Supplies
Heavy Equipment & Trucks
Homebuilding
Household Durables
Household Nondurables
Industrial Machinery
Insurance: Life & Health
Insurance: Property-Casualty
Investment Services
Lodging & Gaming
Metals: Industrial
Movies & Home Entertainment
Natural Gas Distribution
Oil & Gas: Equipment & Services
Oil & Gas: Production & Marketing
Paper & Forest Products
Publishing
Real Estate Investment Trusts
Restaurants
Retailing: General
Retailing: Specialty
Savings & Loans
Semiconductor Equipment
Semiconductors
Supermarkets & Drugstores
Telecommunications: Wireless
Telecommunications: Wireline
Transportation: Commercial

Global Industry Surveys

Airlines
Autos & Auto Parts
Banking
Food Retail
Foods & Beverages
Healthcare: Pharmaceuticals
Media
Oil & Gas
Telecommunications
Tobacco

Standard & Poor's Industry Surveys
55 Water Street, New York, NY 10041

EXECUTIVE EDITOR: EILEEN M. BOSSONG-MARTINES ASSOCIATE EDITOR: CHARLES MACVEIGH STATISTICIAN: SALLY KATHRYN NUTTALL

CLIENT SUPPORT: 1-800-523-4534. ISSN 0196-4666. USPS NO. 517-780.

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The McGraw-Hill Companies

CURRENT ENVIRONMENT

New president appears determined to reduce greenhouse gas emissions

With the election of Barack Obama to the presidency and the Democrats gaining large majorities in both houses of Congress, it appears certain that there will be a new approach to the problem of reducing greenhouse gas (GHG) emissions.

Obama proposes target dates for GHG reductions...
The administration of former President George W. Bush had long refused to acknowledge that there even was a problem. Under its plan, the US would not have taken action to stop the growth of GHG emissions until 2025, when such emissions would then have to start declining from the levels reached at that time. President Obama, in contrast, wants to reduce GHG emissions to 1990 levels by 2020 and to 80% below 1990 levels by 2050. Unlike the traditional cap-and-trade system — whereby companies trade emission allowances or credits — President Obama's program would require all emission credits to be auctioned, with some of the revenue raised to be used for clean energy–related investments.

...and accelerated growth of renewable resources
The Obama plan would also require that renewable sources account for 30% of the federal government's energy use by 2020 and for 25% of total electric generation by 2025. His plan would provide incentives for energy conservation by allowing utilities to earn more from improving energy efficiency than from increased energy consumption. The new president has made it clear that he intends to make the US a global leader in implementing GHG reduction.

EEI STILL SEEKS MARKET-BASED SOLUTIONS FOR GREENHOUSE GAS REDUCTIONS

Given the strong public and political support that had emerged for GHG emission reductions over the past several years, industry leaders clearly wanted to position themselves so they would have some meaningful input into whatever legislation might emerge. In February 2007, the Edison Electric Institute (EEI), the association of US investor-owned electric companies, issued a statement of principles regarding GHG reductions.

In this statement of principles, the EEI emphasized the importance of developing consistent public policies and initiatives, as well as creating stable long-term public/private funding to accelerate and support the production of viable and cost-effective energy efficiency programs and technologies (*i.e.*, zero- or low-emissions generation technologies, and carbon capture and storage technologies). It also wanted to see solutions compatible with a market economy — reasonably priced GHG reductions that don't harm the industry's economic competitiveness — as well as the participation of the entire world economy (including China and India) that could lead to international partnerships and facilitate technology transfer.

Supreme Court rules EPA can regulate GHG emissions
On April 2, 2007, in a 5–4 decision, the US Supreme Court ruled that the US Environmental Protection Agency (EPA) had the authority under the Clean Air Act to regulate greenhouse gas emissions. The majority decision stated that the "harms associated with climate change are serious and well recognized" and that, under the terms of the Clean Air Act, the "EPA can avoid taking further action only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do. The EPA has refused to comply with this clear statutory command. Instead, it has offered a laundry list of reasons not to comply." The court's decision was a setback for the Bush administration, which had previously claimed that it did not have the legal authority to implement controls over GHG emissions.

President Obama's selection of Steven Chu as his Energy Secretary, Carol Browner as his Energy Czar, and Lisa Jackson as the new administrator of the EPA, makes it clear that his administration will be strongly proactive in taking on a wide variety of environmental issues, with the regulation and enforcement of standards related to GHG emissions a top priority. Steven Chu is a Nobel Prize-winning scientist committed to developing alternative sources of energy; Carol Browner is the former director of the EPA in the Clinton administration; and Lisa Jackson is the former head of the EPA in New Jersey.

Industry remains opposed to federal mandate for renewable energy

In December 2007, the Democratic-led US House of Representatives passed an ambitious energy bill that included a federal Renewable Portfolio Standard (RPS) mandate that, if it became law, would have required investor-owned utilities to obtain up to 15% of their electricity from renewable sources by 2020.

The bill had been strongly opposed by the EEI and by many utility companies. The EEI argued that the RPS mandate would undercut or preempt renewable plans that already exist in 26 states and the District of Columbia, and would financially benefit states and power generators in areas where renewable resources are abundant at the expense of those where they are not. It also argued that a mandate requiring 15% renewable generation by 2020 would require a three-fold increase above the 4.8% renewable generation that the Energy Information Administration (EIA) had projected by 2030, and that a mandate would require it 10 years earlier.

The House bill was also opposed by the Bush Administration, which promised to veto any legislation that contained the RPS mandate. Since the House bill that contained the RPS mandate failed to get a filibuster-proof vote in the Senate, the Senate's Democratic leaders decided to eliminate the proposal from their own package of energy legislation. However, with the Democrats now in control of the White House and both houses of Congress, it seems likely that there will be a renewed effort for an RPS mandate.

UTILITY ACQUISITIONS UNDERWAY

Severe liquidity crisis results in major acquisition

In September 2008, Constellation Energy Group Inc. (CEG), the largest wholesale power seller in the US and the holding company for Baltimore Gas & Electric Co., was confronted with a liquidity crisis so severe that it threatened to put the company into bankruptcy. During an extremely volatile period of eight trading days, Constellation's stock plunged more than 60% due to investors' fears that the company would be unable to access the liquidity it needed for its troubled commodities-trading business. The liquidity crisis was the result of the impact that sharply higher commodity prices had on CEG's derivative assets and liabilities, its collateral requirements, and its counterparty credit exposure.

Seeking immediate assistance, Constellation Energy agreed, on September 19, 2008, to a $4.7 billion ($26.50 a share) offer for all of the company's outstanding shares from MidAmerican Energy Holdings Co., a privately held subsidiary of Berkshire Hathaway Inc., whose chairman and CEO is Warren E. Buffet. However, nearly three months later, Constellation Energy decided to terminate this agreement for a more attractive offer from EDF Development Inc. (EDF), a wholly owned subsidiary of Électricité de France (84%-owned by the French state), which already owned about 9.5% of Constellation's common shares.

Électricité de France agrees to acquire 49.99% of Constellation Energy's nuclear business...

On December 17, 2008, Constellation Energy reached a definitive agreement with EDF under which EDF would acquire a 49.99% interest in CEG's nuclear business for $4.5 billion. The agreement with EDF included an immediate $1 billion cash investment in the form of nonconvertible preferred stock, which will be surrendered to Constellation upon the completion of the transaction and credited against the $4.5 billion purchase price.

EDF also provided Constellation with a two-year asset put option to sell to EDF non-nuclear generation assets with a value of up to $2 billion, and a $600 million interim backstop liquidity facility. This liquidity facility would remain available until either six months after the investment agreement or, if earlier, the receipt of all the regulatory approvals related to the transfer of the non-nuclear generation assets.

While the EDF transaction will require approvals from the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and the Committee on Foreign Investment in the US, it will not require the approval of state regulators in Maryland since Constellation's utility operations are not part of the transaction. Nor will it require approval by Constellation shareholders, since the transaction is considered an asset sale and not a purchase of Constellation shares. Pending required approvals, the transaction is expected to be completed during the third quarter of 2009.

...while Warren Buffet unit gets 9.9% of Constellation's stock

On the same day in December 2008 that the agreement with EDF was announced, Constellation and MidAmerican Energy Holdings Co. announced that they had jointly agreed to terminate their merger agreement of September 19, 2008.

Upon the signing of the merger agreement with MidAmerican, Constellation had received an immediate investment of $1 billion in exchange for a preferred equity yielding 8.0%. Under the provisions of the termination agreement, the preferred shares were converted into a $1 billion note at 14% interest, which will mature on December 31, 2009. MidAmerican will also receive about 20 million shares of CEG's common stock (about 9.9%), as well as a termination fee of $175 million and an additional $418 million for common stock which could not be issued due to regulatory limits.

Exelon makes hostile bid for NRG Energy

On October 19, 2008, Exelon Corp. made an unsolicited offer to acquire all of the outstanding shares of NRG Energy Inc., one of the leading competitive wholesale power generators in the US. Exelon is the largest nuclear operator in the US and the holding company for Chicago-based Commonwealth Edison and Philadelphia-based PECO Energy. The deal was a fixed exchange offer of 0.485 Exelon shares for each NRG share.

NRG management rejected the offer, claiming that it undervalued the company, and urged its shareholders to do the same. On January 6, 2009, the initial deadline for the exchange offer, Exelon announced that about 45.6% of NRG's shares had been tendered. Exelon then extended the deadline to February 25, 2009, a date that could be extended further.

Exelon has said it may seek to obtain majority control of NRG Energy's board at that company's shareholder meeting in May. It clearly hopes that it will be able to negotiate a business combination in a way that would avoid, or at least reduce the costs of, any "change of control" refinancing requirements related to roughly 90% of NRG's $8 billion in debt. Should Exelon succeed in its takeover of NRG, the combined company would have a generating capacity of about 47,000 megawatts (after expected divestitures of about 3,000 megawatts) and a greatly expanded presence in the national wholesale power market.

Spanish utility enters US market

On September 16, 2008, Iberdrola SA, a global utility headquartered in Bilbao, Spain, completed its acquisition (announced on June 25, 2007) of Energy East Corp. for around $4.5 billion in cash and the assumption of nearly $4 billion in debt. Energy East's electric and gas utility subsidiaries serve nearly three million customers in New York, Connecticut, Maine, and Massachusetts.

The acquisition had faced opposition from an administrative law judge and certain consumer groups in New York. However, Iberdrola's agreement to invest at least $2 billion in new wind power facilities in New York if the acquisition were approved had gained it the support of key members of the state's legislature, its governor, and its US Senator, Charles Schumer.

With the acquisition of Energy East, Iberdrola has created a platform for its future growth. The company, which already has operations throughout Europe and Latin America, is expected to make additional investments in energy infrastructure and to optimize its presence in the renewable energy business in the United States, which is the world's second largest market for renewable energy (the European Union being the largest.)

Regulators approve private equity buyout

On February 6, 2009, the private equity buyout of Puget Energy Inc. was completed by a consortium led by Macquarie Infrastructure Partners, an owner and manager of infrastructure assets. Puget Energy, a Washington State–based utility holding company, has about 1.06 million electric customers and 729,500 gas customers. The $7.4 billion buyout (which includes the buyer's assumption of about $3.2 billion in Puget Energy debt) had been conditionally approved by the Washington Utilities and Transportation Commission (WUTC) on December 31, 2008; the conditions were accepted by both the consortium (Puget Holdings LLC) and Puget Energy on January 16, 2009.

The state's Public Counsel and the WUTC staff had opposed the transaction, which was announced on October 26, 2006. In a filing dated June 19, 2008, they asserted that the private equity buyout went against the "public interest" and that the utility's customers "appeared to get nothing" for the "undue level of financial risk" that would result from an additional $1.6 billion in bank debt. However, on July 23, 2008, Puget Sound Energy Inc., the utility subsidiary of Puget Energy, and the parties that had opposed the transaction (with the exception of the Public Counsel) filed a settlement stipulation with the WUTC outlining the terms of the settlement agreement they had reached a day earlier.

Among the commitments that Puget Sound Energy agreed to were the securing of committed credit facilities of not less than $1.4 billion for a period of not less than three years; the maintenance of its own corporate and debt credit ratings; honoring its labor contracts; continuing to work with low-income agencies; and not seeking to recover in rates the acquisition premium or the legal and financial advisory fees related to the transaction. Two other conditions that the WUTC insisted on were the commitment of the consortium to Puget Sound Energy's five-year, $5 billion infrastructure development program, and providing the utility customers with $10 million in annual rate credits for a 10-year period.

Credit crisis defers spin-off of Entergy's nonutility nuclear assets

Due to the turmoil in the financial markets, Entergy Corp. has deferred its plan (announced on November 5, 2007) to spin off to its shareholders the company's nonutility nuclear business, which would have been called Enexus Energy Corp. Entergy is a New Orleans–based integrated energy company that is the second largest nuclear generator in the US and has retail electric distribution operations in four states.

Also deferred is Entergy's plan to form an equally owned joint venture (to be named EquaGen) with the spun-off company. Once market conditions improve, however, Entergy plans to seek the required financing and, pending required approvals, expects to complete the transactions, which should be tax-free for both the company and the shareholders. The EquaGen joint venture would be involved in the operation of Enexus Energy's nuclear assets and would offer ancillary services to third parties.

Although no other utility holding company with major nuclear assets has expressed similar plans, we believe the entire process will be closely monitored. Should the spin-off eventually take place and if both the spun-off company and the retained utilities are valued favorably by their respective markets, other companies would be likely to engage in their own transactions.

FERC INCENTIVES FOR FUEL TRANSMISSION INFRASTRUCTURE INVESTMENTS

In July 2006, the Federal Energy Regulatory Commission (FERC) issued its Final Rule promoting transmission-pricing reforms that were designed to promote needed investment in the US energy infrastructure. The Energy Policy Act of 2005 had directed the FERC to develop incentive-based rate treatments for the interstate transmission of electric power. The Final Rule was intended to implement those incentives, provide regulatory certainty, and ensure that transmission rates remain just and reasonable.

The rate incentives identified in the Final Rule are intended for both traditional utilities and stand-alone transmission companies (known as "transcos"). The incentives include providing a rate of return on equity sufficient to attract new investment; allowing the recovery in rate base of 100% of prudent transmission-related construction work in progress; accelerating the recovery of depreciation expense; allowing the recovery of deferred costs; and providing a higher rate of return on equity for utilities that join transmission organizations. In addition to enhancing the reliability of the national grid, the Final Rule aims to expedite the procedures for the approval of incentives and to facilitate the financing of transmission projects.

In its annual financial review, the Edison Electric Institute reported survey data that showed the industry had planned to invest $8.3 billion in the transmission system in 2007, 20% more than was invested in 2006. Over the four years from 2007 to 2010, the survey showed the industry was planning to invest $36.9 billion in the transmission system, which would represent an approximate 55% increase over the amount invested during the 2003–06 period. In November 2008, the EEI presented a report prepared by The Brattle Group, an economic and financial consulting firm, in which it was estimated that for the 20-year period from 2010 to 2030, the industry would invest nearly $300 billion in the transmission system.

EARNINGS DOWN IN THIRD-QUARTER 2008 DUE TO MILDER WEATHER

According to the latest available data from the EEI, net income in the third quarter of 2008 fell 2.1%, to $13.4 billion. However, if one were to exclude the two largest outliers — a $2.6 billion increase from Energy Future Holdings (formerly TXU Corp.), which went private, and a $1.8 billion decrease from Dominion Resources (reflecting its exit from the exploration and production business) — net income for the industry fell by $1.1 billion, to about $12.6 billion. The decline largely reflected the adverse impact of the milder weather, with cooling degree-days down 11% from the 2007 third quarter.

Operating revenues for the third quarter of 2008 were up 13.2%, to $121.7 billion. However, over half of the $14.2 billion increase reflected the accounting treatment of gains from commodity hedging and trading at two companies: Energy Future Holdings and PPL Corp. The increase in industry revenues also benefited from the impact of rate increases and growth in the rate base. Operating expenses for the industry were up 10.4%, to $95.2 billion, as a 1.7% decline in operation and maintenance expenses (aided by plant and business divestitures), to $21.7 billion, was more than offset by an 18.4% increase, to $52.0 billion, in power generation costs. Operating income in the third quarter grew 24.7%, to $26.5 billion. However, if one were to exclude the $5.3 billion increase at Energy Future Holdings (due to its commodity hedging and trading), industry operating income was down by about 0.3%, to $21.2 billion.

Although the yet-to-be-released earnings for 2008 and the projected earnings for 2009 will be impacted (as always) by the weather, we believe that earnings in both years will benefit from utility rate increases (including a full-year of the rate increases implemented during the prior year) and the renewal of expiring power contracts at higher prices. A prolonged economic slowdown or a recession would have a less severe impact on utilities that have a large residential customer base, but a more significant impact on those with a large industrial base.

Dividends increased

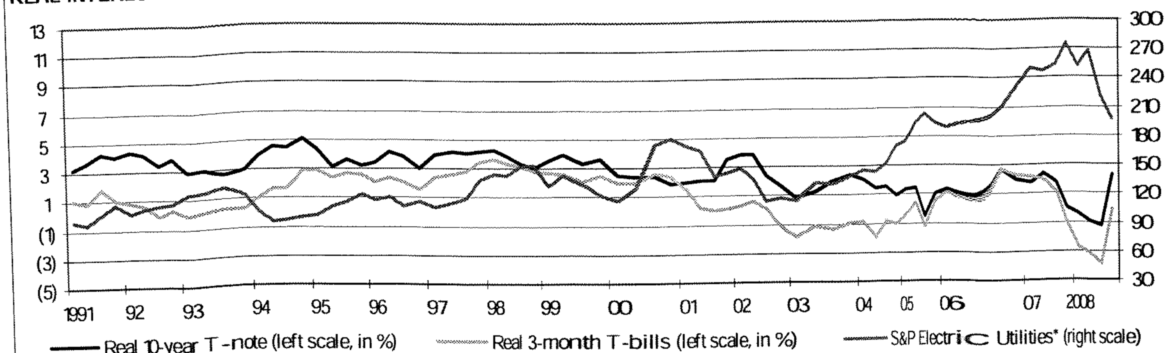
The average dividend increase for publicly traded electric utilities was 9.2% during the first nine months of 2008. As of September 30, 2008, the EEI reported that only two of the industry's 59 publicly traded companies (3.4%) were not paying a common dividend, the lowest percentage since the 2.8% at the close of 2000. We expect industry dividends to continue to rise over the next few years, as companies attempt to share with their shareholders the benefits of their reduced debt and improved balance sheets.

The cut in the federal tax rate on dividends (from the earned income rate to 15%), which occurred in 2003 and which significantly enhanced the appeal of dividends, has been extended by two years through the end of 2010. Looking ahead, we expect companies with strong earnings and balance sheets, and solid investment-grade credit ratings to increase their dividends on a regular basis. However, given the impact of the current economic downturn, we expect dividends to be increased at a lower rate in 2009 than they were during the first nine months of 2008.

Electric utility shares drop sharply in 2008—but still outperform

The S&P Electric Utilities subindex fell 28.1% in 2008, compared with declines of 38.5% for the benchmark S&P 500 Composite stock index and 38.2% for the broader S&P 1500 SuperComposite. This followed strong gains of 16.8% in 2007 and 19.2% in 2006 for the S&P Electric Utilities subindex, compared with gains of 3.5% and 13.6%, respectively, for the S&P 500, and 3.6% and 13.3% for the S&P 1500. The S&P Electric Utilities index also outperformed in both 2005 (up a solid 11.7%, compared with increases of 3.0% for the S&P 500 and 3.8% for the S&P 1500) and 2004 (up a strong 19.6%, compared with gains of 9.0% and 10.0% for the S&P 500 and 1500, respectively).

REAL INTEREST RATES VS. ELECTRIC UTILITY STOCK PRICES



*Price Index, December 30, 1994=100
Sources: Federal Reserve Board; Standard & Poor's.

The sector's outperformance in 2007 and 2006 reflected a continuation of the investor shift into the higher-yielding utility sector. The sector appears to have benefited from the volatility of the broader market, as well as its improved financial strength and earnings outlook, and the anticipation of additional interest rate cuts by the Federal Reserve. (Lower interest rates not only decrease the cost of capital for the substantial amount of debt that utilities must sell, but also increase the relative value of utility stocks' dividends.)

The electric utility sector did not appear to have benefited from the broader market's extraordinary decline in 2008, in marked contrast to what seems to have occurred in 2007 and 2006. Although the electric utility sector did not decline as severely as the broader market did last year, it was still badly hurt by the unprecedented turmoil in the stock market, which largely reflected the ongoing crisis in the housing, financial, and credit markets, which combined to set off a significant downturn in the overall economy.

We expect the performance of both the electric utility sector and the individual companies within the sector to remain relatively volatile over the next several years. However, assuming that the housing, financial, and credit markets begin to stabilize, we believe the stocks will be less volatile in 2009 than they were in 2008, or during the first few years of this decade, when the sector confronted the prospect of soaring profits in the wholesale power market on the one hand, but severe financial problems and restatements, and unprofitable nonregulated businesses on the other. Since then, the electric utility industry has improved both its financial strength and its credibility, in our view. The performance of the sector, however, will remain sensitive to the macroeconomic environment and market forces surrounding it. ■

INDUSTRY PROFILE

An industry in transition

The US electric power industry is a collection of investor-owned, cooperative, municipal, state, and federal utilities, as well as power-generating companies that are not classified as utilities. In 2007 (latest full year for which data are available), investor-owned utilities accounted for approximately three-fourths of the industry's sales in terms of volume and revenues.

According to data compiled by the Edison Electric Institute (EEI), the association of US investor-owned electric companies, the market capitalization of investor-owned utilities totaled $514.5 billion (for 61 companies) at the end of 2007, up 2.1% from $503.9 billion (64 companies) at the end of 2006. The 2006 total, in turn, represented an increase of 17.5% from $428.8 billion (65 companies) at the end of 2005, which grew 12.4% from $381.4 billion (65 companies) at the end of 2004.

Some of the larger investor-owned utilities (ranked by 2007 revenues) are Constellation Energy Group Inc. ($21.19 billion), Exelon Corp. ($18.92 billion), Southern Co. ($15.35 billion), FPL Group Inc. ($15.26 billion), American Electric Power Co. Inc. ($13.38 billion), PG&E Corp. ($13.24 billion), Consolidated Edison ($13.12 billion), Edison International ($13.11 billion), Public Service Enterprise Group Inc. ($12.85 billion), First Energy Corp. ($12.80 billion), Duke Energy ($12.72 billion), and Entergy Corp. ($11.48 billion).

INDUSTRY TRENDS

The electric power industry has been through a period of major changes. Historically, the regulated investor-owned utilities have had exclusive franchises to provide vertically integrated electric services to retail customers — usually within a given state, in contiguous areas outside the state, or both. However, the monopolistic, tightly regulated utilities created under trust-busting legislation more than 60 years ago have become increasingly exposed to competition, particularly in the generation and wholesale power markets, due to changes brought about by the National Energy Policy Act (NEPA) of 1992. (For details, see the "How the Industry Operates" section of this *Survey*.)

The turmoil between 2000 and 2002 in the nonregulated power-marketing and power-trading arena seriously set back the move toward deregulation. Nonetheless, Standard & Poor's expects that, over the long term, advances in technology and in the desire for customer choice (primarily from the large industrial and commercial customers), as well as more prudent regulatory oversight, will gradually lead to a more competitive market.

The terminations of the merger agreements between Exelon Corp. and Public Service Enterprise Group Inc. in September 2006 and between FPL Group Inc. and Constellation Energy Group Inc. (CEG) in October 2006 significantly set back consolidation activity in the industry. However, CEG's recent joint venture agreement with Électricité de France, and Exelon's unsolicited offer to acquire NRG Energy, Inc., could set in motion other merger or acquisition proposals, either agreed-to or hostile. We still believe that eventually a few dominant powerhouse companies could emerge. While this concentration conceivably could produce a market environment that is notably less competitive than regulators initially intended, it still should allow electricity buyers to choose the supplier from which they purchase power.

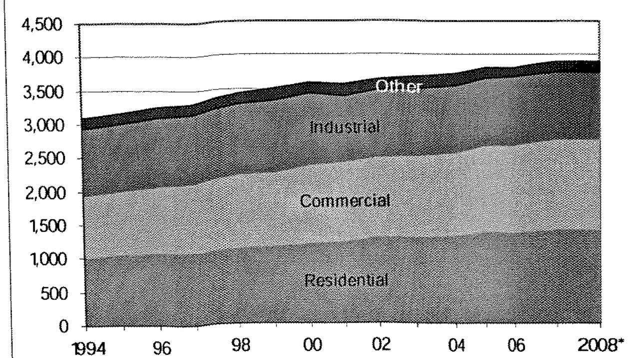
OUTLOOK VARIES BY CUSTOMER SECTOR

According to the Edison Electric Institute (EEI), the association of US investor-owned electric companies, the total volume of electricity sales for investor-owned utilities increased 2.2%, to 2,485,010 gigawatt-hours (GWh) in 2007 (latest full year for which data are available), from a revised 2,431,041 GWh in 2006. Revenues totaled $237.23 billion, up 6.3% from a revised $223.13 billion in 2006.

◆ **Residential.** The EEI's report showed that electricity sales to residential customers in 2007 were up 4.7% in volume and up 9.6% in revenues. In our view, the increase in revenue mainly reflected the impact of rate increases, as well as the home construction boom that had taken place over the previous few years, and the related growth in home computers and appliances.

According to the EEI, the number of residential electric utility customers increased 0.3% in 2007, to 86.912 million (from a revised 86.653 million in 2006), to account for approximately 87.3% of the 99.509 million customers of investor-owned utilities, which was up 0.3% from the revised 99.192 million customers in 2006). We expect this slight rate of increase in the residential customer base, as well as the slowing rate of new US household formations and the modest growth in the overall population, to restrict growth for the foreseeable future. Thus, demand growth will remain mostly weather-related, in our opinion.

ELECTRICITY SALES BY CUSTOMER CLASSIFICATION
(In billions of kilowatt-hours, total electric utility industry)



*12 months ended October.
Source: Energy Information Administration.

◆ **Industrial.** Long-term growth in investor-owned electric utility sales to industrial customers is expected to be much more modest than the residential and commercial sectors over the next five years. The EEI's report said that while electricity sales to industrial customers in 2007 were down 1.1% in volume, they were up 2.4% in revenues. We believe the decline in volume mainly reflected the ability of large industrial firms to buy power from alternative energy providers. We expect annual industrial sales growth to be relatively modest through 2010, with demand largely determined by the strength of the economy.

◆ **Commercial.** The EEI report said that electricity sales to commercial customers in 2007 were up 2.2% in volume and up 4.7% in revenues. The number of commercial customers for investor-owned electric utilities increased 0.6% in 2007, to 12.168 million, from a revised 12.094 million in 2006.

Over the next several years, we expect to see increased demand from the commercial sector, with the pace dependent on the strength of the economy. The growing number of customers should boost demand, as should the increasingly widespread use of computers and other office equipment.

ELECTRICITY LEGISLATION ENACTED

In August 2005, President George W. Bush signed into law a comprehensive energy bill called the Energy Policy Act of 2005 (EPAct 2005). The electricity portion of the new legislation—called the Electric Reliability Act of 2005 — made grid-reliability standards mandatory, repealed the Public Utility Holding Company Act of 1935 (PUHCA), and authorized federal permits for transmission lines. The main electricity provisions contained in the new law are outlined below.

Establishing electric reliability organizations

To address reliability issues highlighted by the power blackout of August 2003, the new law made several amendments to the Federal Power Act of 1935. It created a new section in the law, Section 215, which calls for the establishment of a self-regulating, electric reliability organization (ERO) under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The law also authorized the FERC to establish ERO requirements, including regulations allowing the ERO to delegate authority to a regional entity for the purpose of proposing and enforcing standards that would ensure the reliability of the bulk power system.

Although the EROs and any regional entities given enforcement authority would not be considered departments or agencies of the US government, the FERC was authorized to take whatever actions it considered necessary to ensure compliance with reliability standards or related commission orders. The law does not preclude individual states from taking actions aimed at ensuring the reliability of the bulk power systems situated in those states, as long as those actions are consistent with the reliability standards.

PUHCA repealed

The new legislation repealed the Public Utility Holding Company Act of 1935. PUHCA was enacted to eliminate the abuses committed by the holding companies of that period, such as excessive charges for "services" provided to the operating utilities that were then passed on to the consuming public. PUHCA restricted the nonutility activities of holding companies and required that the service territories of the utility operating companies be contiguous. (For more information about PUHCA, see the "How the Industry Operates" section of this *Survey*.)

The new law required that holding companies maintain and make available (to both the FERC and the appropriate state commissions) any books and records deemed relevant to the costs incurred by a utility within a holding company. In addition, both the FERC and the state commissions would maintain their authority to ensure that jurisdictional rates were just and reasonable, to prevent cross-subsidization, and to determine whether a utility would be allowed to recover, via rates, costs related to another company within the holding company.

While new mergers would still require approval by the FERC and state utility commissions, the legislation required the US Department of Energy (DOE) to review the extent to which the FERC's merger authority was duplicative of other federal and state merger authorities, and imposed statutory deadlines intended to accelerate the merger review process.

PUHCA's repeal could pave the way for the entry of new nonutility domestic players into the industry and for additional acquisition activity by foreign companies. However, the termination of two major mergers in the industry during 2006 (discussed below) has made everyone aware of the difficulties that can be encountered in obtaining merger approval from state regulators. It was not surprising, therefore, that the recent joint venture agreement between Électricité de France and Constellation Energy, and Exelon's unsolicited offer to acquire NRG Energy, were designed so that the approval of state regulators would not be required.

Modernizing transmission infrastructure

The new legislation effectively countered the "not in my backyard" attitudes that have hindered the construction of new transmission facilities. In any geographic area where consumers were adversely affected by transmission capacity constraints or congestion, the DOE was given the authority to designate a "national interest electric transmission corridor" after consulting with the appropriate states and regional reliability entities. In such areas and under specified conditions, the FERC had the authority to issue permits for the construction or modification of transmission facilities. Permit holders could acquire the rights-of-way for the project by exercising eminent domain in the federal district court with jurisdiction over the area where the property is located.

INDUSTRY CONSOLIDATION STALLED BY TERMINATION OF MAJOR MERGERS

Many investors had believed that repeal of the Public Utility Holding Company Act (PUHCA) in December 2005 would accelerate industry consolidation — and, for a while, that appeared to be the case. However, at about the same time that the move to repeal PUHCA gained steam, state regulators started to become much more assertive in their demands, in large part due, in our opinion, to what was often intense political and consumer group pressures.

We believe these factors played a major role in bringing about the termination of the agreed-to merger between Exelon Corp. and Public Service Enterprise Group Inc. in the fall of 2006. When this was followed six weeks later by the termination of the agreed-to merger between Constellation Energy Group Inc. and

FPL Group, the effect on the industry was chilling. One element that may have factored into Exelon's unsolicited offer to acquire NRG Energy is that, since NRG is in the business of power generation rather than distribution, such a deal would not need the approval of state regulators. This may also have been a reason why Électricité de France decided to pursue a 50% interest in Constellation's nuclear assets rather than renew an attempt to acquire the entire company. Since Constellation's utility distribution operations would not be involved in the proposed transaction, the deal would not require the approval of the state regulators in Maryland. We also believe that one of the reasons why Constellation initially accepted the offer from MidAmerican Energy (a subsidiary of Warren Buffet's Berkshire Hathaway) was that Mr. Buffet's reputation would ease the approval required from regulators in Maryland.

Possible alternatives to mergers

Although mergers had appeared to be one of the best ways to achieve growth in what is essentially a mature business, the enormous amount of time and money that was involved in an increasingly contentious regulatory approval process made utility holding companies much more cautious about entering into them. Assuming that a company would still want to go through with a merger proposal, it would also have to be much more thorough in its analysis of its planned partner's overall regulatory environment as well as its cultural compatibility, market outlook, and business prospects.

We may see more mergers between small and mid-sized utilities (such as the recent acquisition of Energy East Corp. by Spain-based Iberdrola SA) and, should a significant recovery take place in the credit markets, perhaps even some more private equity buyouts over the next couple of years. We believe, however, that if larger companies are faced with a difficult regulatory environment, they may start thinking in terms of limiting themselves to the acquisition of individual assets (such as power plants), rather than attempting to merge with an entire company.

We also believe it is possible that, given a return to a more favorable market environment, more utility companies will give greater consideration to spinning off some of their own nonutility operations, as Entergy Corp. has announced. Such efforts caused considerable problems a few years back, when companies such as Reliant Energy Inc. (spun-off from CenterPoint Energy Inc.), Mirant Corp. (Southern Co.), and NRG Energy Inc. (Xcel Energy Inc.) all experienced severe financial problems, with the latter two having to declare bankruptcy. However, given the current strength of many nonregulated power producers, we believe it would cause far fewer problems if attempted again.

RATE STRUCTURES THAT MOTIVATE

Critics have argued that traditional utility regulation — in which rates are based on the cost of service, plus a risk component — does not give utilities an incentive to become efficient. Hence, many states are examining the need to reform the cost-based framework.

Incentive regulation mechanisms

An alternative to cost-of-service ratemaking exists in the form of "incentive regulation mechanisms," which, at one point, were prevalent in the telecommunications industry. Through incentive mechanisms, utility managements are given performance targets. If the utility exceeds its target, it will share part of the resulting benefits through incremental increases in its allowed return on equity. Examples of incentive-based ratemaking include performance-based pricing, revenue sharing, and price-cap regulation.

◆ **Performance-based pricing.** Utilities that have settlement agreements on new nuclear plants or nuclear plants that have suffered prolonged outages use this ratemaking mechanism. It entails removing the plant from the rate base and extracting related operating expenses from those included in the utility's cost of service.

Instead of earning a rate of return based on assets specified by regulators, a utility using performance-based pricing earns a preset price per kilowatt-hour (kWh) that the plant produces, making recovery dependent on plant performance. The most notable example is Pacific Gas & Electric Co.'s Diablo Canyon nuclear plant in California.

◆ **Revenue sharing.** This method seeks to compensate a utility for greater-than-average risk when its cost of capital is estimated. The utility is assured that benefits resulting from gains in productivity or efficiency are shared between customers (in the form of lower rates) and shareholders (as higher earnings). Some electric utilities in New York and California currently use revenue sharing.

◆ **Price-cap regulation.** Common in the telecommunications industry, this regulation sets a ceiling for consumer prices. The price cap is intended to cover a reasonable cost of service, while letting utilities choose the most efficient way to provide that service. The choice of services that a utility may offer a specific customer currently is subject to state regulatory review.

POWER MARKETERS AND BROKERS

The advent of wholesale wheeling and nonutility generation created the opportunity — and the need — for companies to market and broker power. As of April 2008, 456 independent power marketers and 96 affiliated power marketers were registered with the FERC.

Power marketers and brokers, independent power producers, and unregulated subsidiaries of utility companies offer power-supply alternatives to other utilities in the wholesale market and, increasingly, to large industrial customers. Power marketers buy and sell wholesale electricity at market-determined prices. Brokers match buyers and sellers of wholesale electricity, but they do not take the title to the power. Power-marketing operations have been formed by energy companies (many with experience in marketing natural gas), utility subsidiaries, and independents.

As with the gas industry, electric power brokers and marketers hope to develop an efficient market by straddling the gulf between electricity generators and their customers, who have become "free agents" in the newly competitive environment.

In 2007, Constellation Energy was the largest power marketer, with sales of 400.5 million megawatt-hours (MWh), or 7.59% of total power-marketing sales. Exelon Generation Co. LLC was second, with 360.9 million MWh (6.84%), followed by Morgan Stanley Capital Group Inc. (232.1 million MWh; 4.40%), Sempra Energy Trading Corp. (211.8 million MWh; 4.02%), and First Energy Solutions Corp. (195.6 million MWh; 3.71%).

FINAL TASK FORCE REPORT ON BLACKOUT

On April 5, 2004, the US–Canada Power System Outage Task Force issued a study entitled Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. This report covered the August 2003 electric power blackout that affected 50 million people in nine states and in the Canadian province of Ontario, and an estimated electric load of 61,800 megawatts (MW).

Calls for mandatory compliance with reliability rules

In its final report, the task force said reliability rules must be established and made mandatory, with substantial penalties for noncompliance. The recommendations had four main themes.

First, government and regulatory bodies in the United States and Canada should make high reliability standards paramount, and, while market mechanisms were acceptable, any irreconcilable conflicts between reliability and commercial objectives must be resolved in favor of high reliability. Second, regulators must assure that investments and operational costs related to the maintenance of reliability will be recoverable through approved electric rates. Third, the North American governments and industry must work together to implement the recommended mechanisms for performance monitoring, the accountability of senior management, and the enforcement of compliance with reliability standards. Finally, a number of security-related actions were needed.

In addition to making reliability standards mandatory and enforceable, the task force made several other recommendations related to institutional, operating, security, and coordination changes. On an institutional level, the task force made recommendations in the areas of funding, recoverable costs, minimal functional requirements, and the framework of future investigations. On an operational level, the task force recommended the establishment of enforceable standards for maintaining electrical clearances in right-of-way areas, and improvements in training and certification. On security-related issues, the task force recommendations addressed physical and cyber security, system and network controls, operating and training procedures, and the installation of backup generation equipment. Finally, the task force recommended that international coordination mechanisms be developed between the governments in Canada and the United States.

Reliability performance trends not readily available to the public

In August 2007, the National Energy Board (NEB) of Canada issued a report that concluded that while substantial steps had been taken to improve the reliability of the North American bulk power system (particularly the implementation of mandatory electric reliability standards), the establishment of an independent source of reliability performance information had not progressed as quickly. It noted that the biggest problem was the lack of readily available information that tracked the trends in reliability performance in either Canada or the US. This was not because such information or data was not being reported, but rather because it was not readily displayed for public use. The NEB said this needed to be corrected in order to enable an assessment of reliability trends that would be useful to the industry, regulators, policy makers, and the public, and that doing so would require sustained attention from government agencies for several years.

HOW THE INDUSTRY OPERATES

Since electricity first was harnessed more than 100 years ago, technological advances have altered the landscape of the electric utility industry. Nevertheless, the physics of electricity generation have not changed: electricity is produced when a magnet is rotated inside a coil of wire. The spinning of the magnet may be caused by steam (as in coal, oil, and nuclear power plants), by falling water (as in hydroelectric plants), or by hot expanding gases (as in gas turbines and diesel generators).

Electrical energy cannot be stored economically, so it must be generated and instantaneously delivered based on customer demand. Consequently, an electric utility company must own production facilities capable of meeting the maximum demand on its system, as well as transmission and distribution systems that can manage the load. Each utility also must have a reserve margin of extra production capability to allow for maintenance, equipment outages, and unexpected variations in usage.

In general, the electric utility industry's peak earnings come with the warm weather in the second and third quarters, when customers are running air conditioners. By contrast, cold weather tends to have a marginal impact on earnings; most customers use electricity simply to start their heaters, while fuel (oil or gas) provides the heat. Thus, electric utilities' lowest earnings typically occur in the first and fourth quarters, although actual results may vary by region, and depend on weather conditions and other factors.

GENERATING POWER

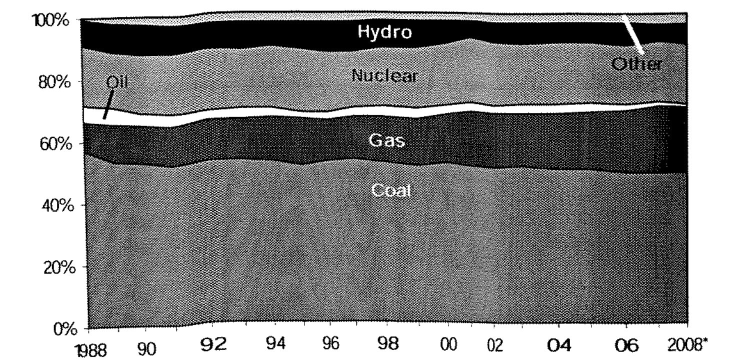
The electric utility industry relies on various fuel sources to generate electricity. Some utilities also purchase power to meet peak demand.

Fuel sources

Fuel sources used by the electric utility industry include coal, natural gas, nuclear power, renewable sources (including hydroelectric and wind), oil, and other gases.

◆ Coal. According to the latest available data from the Energy Information Administration (EIA), a statistical agency of the US Department of Energy, coal accounted for 48.6% of total US electricity production (in kilowatt-hours) in 2007. Historically, coal supplies have been abundant, and while there has been a sharp recent rise in coal prices, they are still relatively favorable when compared with prices of other energy sources, primarily natural gas. These factors help explain the industry's reliance on the mineral. The EIA expects coal to remain the dominant source of fuel for US electricity production, with its share increasing to about 51.4% by 2015.

ELECTRIC GENERATION BY ENERGY SOURCE
(Percentage of US total)



*12 months ended October.
Source: Energy Information Administration.

◆ Natural gas. The EIA forecasts that natural gas, which accounted for 21.5% of US electricity production in 2007, will decline to about 16.5% in 2015. The projected decrease largely reflects the negative impact of high gas prices in 2006 and 2007 — a problem expected to continue for the next several years. These price increases were believed to largely offset the more favorable long-term effect of environmental and technological forces, including the demand for cleaner forms of fuel, and the desire for equipment with lower capital requirements, such as gas-fired combustion turbines.

Most new nonutility generators are fueled by natural gas. If natural gas prices were attractive, gas-fired turbines would likely be popular. High gas prices, however, such as those that have occurred from the first half of 2003 through the first half of 2008, can dampen enthusiasm for gas among both investor-owned utilities and nonutility generators. Both types of operators have the capability to switch between oil and gas, which can result in rapid shifts in demand. With natural gas prices expected to remain high over the next few years, we believe natural gas will remain relatively unattractive as a fuel source during this time.

AVERAGE COST OF FOSSIL FUELS DELIVERED TO STEAM-ELECTRIC UTILITY PLANTS
(Cents per million Btu consumed)

YEAR	COAL	RESIDUAL OIL†	NATURAL GAS	ALL FOSSIL FUELS‡
2008*	205.0	1,537.0	956.0	426.0
2007	178.0	847.0	710.0	324.0
2006	169.0	785.0	694.0	302.0
2005	154.0	706.0	821.0	325.0
2004	136.0	473.0	596.0	248.0
2003	127.1	466.0	539.0	222.7
2002	125.3	372.7	356.0	183.8
2001	123.2	372.6	448.7	173.0
2000	120.0	429.4	430.2	173.5
1999	121.6	243.6	257.4	143.8
1998	125.2	207.9	238.1	143.5

Btu-British thermal unit. †Includes fuel oils No. 4, No. 5, No. 6, and topped crude fuel oil. ‡The weighted average price for all fossil fuels includes both residual fuel oil and light oil (fuel oil No.2, kerosene, and jet fuel), as well as small quantities of coke oven gas, refinery gas, and blast furnace gas.
*Through October.
Source: Energy Information Administration.

◆ Nuclear power. According to EIA projections, nuclear power, which accounted for 19.4% of total US electricity production in 2007, is expected to see its share remain steady at about 19.5% by 2015. This reflects a change from the decline that had been projected in recent years, as nuclear power remains an important source of energy that is relatively inexpensive and clean (in terms of air pollution), and because several companies are considering the possibility of building new nuclear facilities. Utilities have made concerted efforts to control nuclear operating expenses. Should any of the operational systems develop safety problems, however, the expenses related to their resolution could have a significant impact on the company's earnings.

Plant decommissioning — which involves reducing radioactivity, disposing of nuclear waste, and dismantling certain machinery — creates uncertainty. Utilities are required to prefund decommissioning costs over each plant's 40-year operating life. These costs are substantial, generally running into hundreds of millions of dollars.

◆ **Renewable sources.** The EIA forecasts that renewable sources will account for 11.3% of the country's total electric energy production in 2015, compared with 8.4% in 2007. These sources include hydroelectric, geothermal, wood, waste, landfill gas, solar, and wind power. The generation of hydroelectric power depends on the weather: when it does not rain or snow, less water is available to generate power.

◆ **Petroleum.** The EIA expects US electrical production from petroleum to decline from 1.6% of production in 2007 to 1.2% in 2015. Electric energy production using petroleum occurs chiefly in the Northeast and the Southeast.

◆ **Other gases.** Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels, which accounted for 0.5% of US electric power supply in 2007, are expected to provide an even smaller amount in 2015.

Purchased power fills the gap

Wholesale wheeling — the buying and selling of power by different utility-related companies — has significantly increased utilities' use of purchased power. Urban utilities in particular, with their high daytime peak loads, have found that purchased power contracts let them meet peak demand and boost their load factors without building additional capacity.

A purchased power contract generally has two components: a capacity charge and an energy charge. The capacity charge usually is considered a rate base item; in other words, it is incorporated into the end-customer's base rates, whether or not the power is used. Energy charges are regarded as fuel costs and are passed along to the end-customer on a dollar-for-dollar basis, according to usage.

GETTING POWER TO THE USER

A utility uses a combination of generators to accommodate different levels of demand. Baseload generating units can supply large amounts of power; they ordinarily operate at or near full capacity for long periods. While baseload generating units are the most expensive units to build in terms of capital investment, they are also the most efficient — and thus the most economical, in terms of operating expenses.

In contrast, peaking units are designed to operate exclusively during periods of high demand, and may run for as little as a few hours at a time. These generators — usually oil or gas combustion turbines — are the least costly in terms of capital investment, but they are usually the most expensive to run.

The cycling unit, an intermediate class of generator, runs when demand is above the capacity of the baseload generators but below the level necessary to use the peaking units. In terms of capital investment and operating costs, cycling units normally fall between baseload generators and peaking units.

Transmission and distribution facilities are the arteries through which power is delivered to customers. To transmit electricity effectively over long distances while minimizing power losses, utility companies use high-voltage transmission lines. Although such lines commonly cost considerably more to build than low-voltage wires, they can carry much more power.

Transformers reduce the voltage of electricity as it moves from transmission lines to distribution lines. At a customer's site, meters attached to the distribution lines measure the amount of electricity used during a particular period so that the utility may charge the appropriate sum to each account.

Some electricity-generating plants are members of regional power "pools," which generally are made up of several investor-owned utilities in a geographic area. The participating power plants dispatch electricity to all member utilities from a central control point.

Peak load and energy rates

A utility's customer profile (the proportion of its sales that go to large industrial and wholesale customers versus smaller retail customers) can have a big influence on both its expenditures and its rates. Utilities forecast their peak loads — the average amount of energy required to serve customers at times of greatest usage — based on the average total demand from all customers at peak periods.

Peak loads can differ significantly from utility to utility. Some companies' loads are relatively uniform throughout the day, whereas others' are heavily concentrated during particular hours.

Capacity and load factors

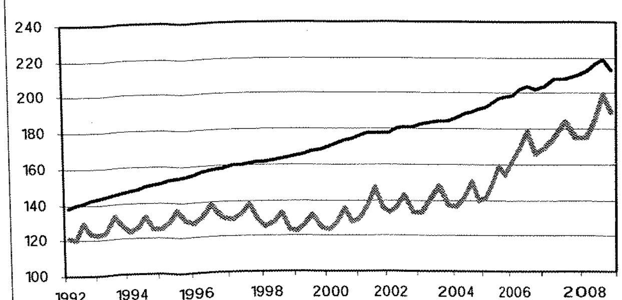
The relationship between demand and capacity is called a utility's capacity factor. It is the measure of actual output versus a generator's rated capacity.

Load factor is a related but somewhat different concept: the ratio of actual electric energy consumption during a given time period relative to the consumption that would have occurred if usage had been fully sustained at the peak capacity level. Thus, it measures the variability of load (or demand) over a given time period. A high load factor means that a utility operates near capacity most of the time.

HOW RATES ARE SET

State commissions are responsible for determining utilities' proper rate bases and allowable operating expenses. Individual states' rulings often differ with regard to these determinations. They also differ in allowed accounting treatments for depreciation accruals and investment tax credits. Although rulings are often presumed to be based solely on the public interest, commissions actually seek to provide a balance between investor and consumer interests.

COST OF ELECTRICITY VS. CONSUMER PRICES
(Index, 1982-84 = 100; quarterly data)



Source: US Bureau of Labor Statistics

Shareholder risk is a component of a utility's allowed rate of return. To determine risk levels, state utility commissions consider the percentage of common equity versus debt in a utility's capitalization. The higher the equity component, the lower the assumed risk; a lower assumed risk generally results in a lower allowed rate of return. In contrast, shareholders that assume higher risk usually will be allowed a higher potential return.

Utilities that engage in significant cost-cutting tactics, such as work force downsizing and refinancing (both prevalent in recent years), often attempt to delay the next rate review for as long as possible. This strategy lets its investors benefit from the savings until the next rate case.

Consumer safeguards

To protect consumers against potential pricing abuses while allowing utilities to attract capital and provide adequate service, utility companies are required to charge what the regulatory bodies deem "just and reasonable rates."

Establishing a utility's rates on an individual cost-of-service basis typically involves two steps. The first is to determine the rate level that will cover the utility's operating costs and give it an opportunity to earn a reasonable return on its investment. The utility's required revenue often is referred to as the "revenue requirement" or "cost of service." The second step designs specific rates that will eliminate discrimination against, and unfairness toward, affected classes of customers.

Government guides rates, construction

Regulators once encouraged utilities to construct ample generating plants to satisfy vigorously growing electric demand. During the late 1970s, however, electric demand slowed significantly as that decade's energy crises sparked large increases in electric rates. Meanwhile, the cost of nuclear plant construction skyrocketed because of the Three Mile Island nuclear accident in Pennsylvania in 1979.

In response to those developments, regulators often disallowed or delayed cost recovery for plant investments deemed imprudent or unnecessary. In the wake of those disallowances, utilities became hesitant to undertake major capacity-related construction projects, and many chose to rely on power purchased from other generators.

When generating capacity appears unable to meet the levels of power required during periods of great demand (such as during "above-normal" heat waves), resulting in significant power shortages, utilities or independent power generators have found themselves compelled to increase their generating capacity. This was the case with the California power crisis in 2000, which resulted from the state's insufficient power supplies; it led to an accelerated approval process for new plants. A nationwide expansion of power plants ensued, resulting in an excess of power-generating capacity. Meanwhile, demand was greatly reduced due to a longer-than-expected weakness in the economy.

THE LAWS THAT SHAPE THE INDUSTRY

Over time, several pieces of federal legislation have shaped the US electric utility industry. Below are brief descriptions of some of these laws and their immediate and ongoing impact.

◆ **The Public Utility Holding Company Act (PUHCA) of 1935.** This trust-busting legislation was aimed at the large and powerful companies that controlled US electric and gas distribution networks until 1935. Before PUHCA, nearly half of all electricity generated in the United States was controlled by three massive holding companies, whose size and complexity made regulating them virtually impossible.

Under PUHCA, the Securities and Exchange Commission (SEC) was authorized to break up the trusts and to regulate the reorganized industry. By design, the utility industry that PUHCA reorganized contained barriers to entry. In essence, "outsiders" were prevented from participating in the construction and operation of new electricity-generating facilities. PUHCA was repealed by the Energy Policy Act of 2005.

◆ **The Federal Power Act.** Also enacted in 1935, this law created the Federal Power Commission (later renamed the Federal Energy Regulatory Commission, or FERC) to regulate the interstate transmission and sale of electric power, and to license hydroelectric plants.

◆ **The Public Utility Regulatory Policies Act (PURPA) of 1978.** By the 1970s, the regulatory framework that had been in place for some 40 years was in need of change. That decade's energy crises generated widespread support for reducing US dependence on nonrenewable sources of energy in general and on foreign oil in particular.

To promote national self-sufficiency in energy consumption, Congress enacted PURPA in 1978. As part of this legislation, the FERC was ordered to develop rules to encourage alternative energy sources and cogeneration by creating qualifying facilities (QFs), a special class of independent power producers.

The small generators that QFs owned were exempt from PUHCA's restrictions. Utilities were required to purchase the firms' electricity at prices mandated by state regulators, typically set at the utility's "avoided cost," or the cost that an electric utility would incur to produce or otherwise procure electric power. Although PURPA did not exempt the larger independent power producers from PUHCA, it nonetheless had a significant impact on the growth of nonutility generation.

◆ **The National Energy Policy Act (NEPA) of 1992.** By reforming PUHCA, this law greatly increased competition within the electric utility industry at the level of both production and sale of wholesale power; the latter having become the industry's most lucrative business when demand is high. Under NEPA, the FERC was empowered to direct an electric utility to provide wholesale wheeling, or transmission service, at cost from any electricity-generating entity to another utility, regardless of whether the transmitting entity is another utility or an independent power producer (IPP).

Under NEPA's terms, transmitting utilities must receive compensation for providing wholesale wheeling services. The FERC sets rates for transmission service at a level that lets a company fully recover the "legitimate and verifiable" costs of providing the service.

NEPA created an additional class of independent power producers — the exempt wholesale generator (EWG) — that was free from regulation under PUHCA provisions. Unlike IPPs of the past, however, EWG projects could have investor-owned utilities as majority interests. Affiliated EWGs can produce and sell electric power at the wholesale level; state commissions regulate these transactions. NEPA also allowed EWGs to operate outside the US and to compete in foreign markets at the retail level.

THE REGULATOR'S ROLE

The Federal Energy Regulatory Commission (FERC), a division of the US Department of Energy, exercises jurisdiction over wholesale utility sales and certain transactions between affiliated companies. It also oversees utilities' issuance of certain stock and debt securities, the assumption of obligations and liabilities, and mergers.

State public utility commissions regulate electricity sales to end-use customers, such as homeowners and businesses. Regulation seeks to ensure that consumers receive reliable service at a fair price. It gives each utility the opportunity — not a guarantee — to earn an adequate return so that it can attract new capital to develop and expand plants to meet customer demand. Regulation also aims to ensure public safety and to prevent unreasonable prices, excessive earnings, and discrimination against customers.

Regulated monopolies move toward competition

Historically, individual companies have operated as natural monopolies. In theory, a natural monopoly should provide economies of scale, efficient service, and lower prices. Owners of a monopoly can profit excessively, however, if they control an essential resource. The federal government regards the supply of electricity as a necessity; thus, federal and state governments have long supervised the industry through close regulation.

Under "regulatory compacts," states have granted investor-owned utilities exclusive service territories in exchange for the utility's "obligation to serve" all consumers in that territory on demand. This obligation requires utilities to build, operate, and maintain generating plants, and transmission and distribution systems that would service all present and future customers. Such franchise agreements allow the highly capital-intensive utility companies to raise the necessary financing, recover their fixed costs over time from a stable customer base, and enjoy increased efficiency through economies of scale.

The most significant difference between regulated utilities and competitive enterprises is in the pricing process. Whereas market forces and competition determine how much an unregulated company can charge for its products or services, a state regulatory commission establishes a utility's rates in a rate-case proceeding. Once set, rates generally do not change without another rate case.

While the wholesale power market has been opened up to competition in many states, the scandals related to Enron and other power marketing operations have made some state regulatory commissions much more cautious about opening up their own states to competition. We also expect energy transmission to remain somewhat regulated in the United States, and distribution to remain completely regulated, which would maintain a degree of monopoly in those areas.

FERC rulings pulled the plug on monopolies

In March 1995, the FERC released a watershed Notice of Proposed Rulemaking (NOPR), alerting the industry that it had targeted the wholesale power market for deregulation and was about to issue new rulings on open-access transmission. (A NOPR is a notice to the industry that the FERC is revising its regulations and will release an official ruling later.) In the industry, this particular ruling is referred to as the Mega-NOPR.

On April 24, 1996, the FERC issued the expected rulings, which consisted of two separate orders. The first, Order 888, addressed both open-access and stranded-cost issues. The second, Order 889, required electric utilities to establish electronic systems to share information about available transmission capacity.

The FERC rulings initially targeted the wholesale power market, where electric power is provided to the utilities, which then distributes it to the retail market. The agency believed that, in the long term, the rulings would reduce the need to regulate bulk power sales. It expected the opening of the transmission system to increase competition and lower prices by eliminating the power-generation monopoly at the electric plant level.

◆ **Order 888.** This order addressed two principal issues: transmission service and "stranded costs."

Transmission. Order 888 required public utilities that own, control, or operate transmission lines to provide transmission service for wholesale transactions on an open, nondiscriminatory basis. The order set guidelines for efficient operation of the transmission system, and for terms and conditions of service. It required utilities to file open-access transmission tariffs (OATTs) stating the minimum conditions under which they can provide both network and point-to-point service. (Network service involves sales to a third-party bulk power marketer; point-to-point service is a wholesale transaction to a specific utility.) Order 888 did not mandate either corporate unbundling or divestiture of assets, but it did establish standards of conduct to ensure this functional unbundling.

In issuing this order, the FERC supported the concept of independent system operators (ISOs), although it did not require utility companies to join them. An ISO is an entity formed to control and to operate a regional transmission system; the individual parts of the system have different owners.

Commissions in each state determine the rules for ISOs. Each ISO controls the operation of interconnected transmission facilities within a certain region. It also is responsible for ensuring nondiscriminatory, open-access transmission, as well as the planning and security of the utilities' combined bulk transmission systems.

Stranded costs. The term stranded costs refers to the money a utility could lose if it were unable to recover its investment in generating plants, and/or other deferred costs, such as those incurred when a wholesale customer switches providers or types of service.

In Order 888, the FERC endorsed the principle of full recovery of prudently incurred wholesale stranded costs. The FERC thus reaffirmed its view that utilities should be able to recover these costs from departing customers by negotiating remedies before the end of the contract.

State regulatory commissions remain the primary forums for handling stranded costs and other issues related to retail transmission service. Also known as "retail wheeling," this service involves one entity — whether an independent power producer, cooperative, or electricity-generating utility — selling its transmission services to another, which then sells the electricity at retail to the ultimate customer.

◆ **Order 889.** Also known as the Open Access Same-time Information System rule (OASIS), Order 889 required electric utilities to do two things. First, each utility must make available electronically, to other utilities and electricity providers, certain information about its transmission systems — the information that it would use for its own wholesale power transactions. The electronic availability of this information, which should be similar in content for all published competitors, should prevent any one utility from having any special advantage over others that want to use its transmission system.

Second, each utility's wholesale power marketing must be administered and accounted for separately from its transmission operation functions. This requirement enabled customers to compare prices for these services — a change from past practices, when the services were bundled.

◆ **Order 2000.** Orders 888 and 889 established the foundation necessary to develop competitive bulk power markets in the United States. Although they encouraged the formation of ISOs, they still left management of the transmission grid to the vertically integrated electric utilities. The FERC eventually concluded that this structure was not efficient or reliable enough to support the development of genuinely competitive electricity markets.

To promote efficiency in wholesale electricity markets and to ensure that consumers pay the lowest possible price for reliable service, the FERC issued Order 2000 in December 1999. Its objective was to encourage all public and nonpublic electric utilities to place their transmission facilities under the independent control of a regional transmission organization (RTO). The function of an RTO is to control the transmission grid in a given regional territory, thus assuring nondiscriminatory access while increasing efficiency and reliability. Although similar in concept to the ISO, the RTO would have more authority to eliminate discrimination.

Order 2000 established the minimum characteristics and functions for an RTO: independence from market participants, a sufficient geographical scope and regional configuration, a clear operational responsibility and authority, and the ability to assure short-term reliability. The order encouraged a collaborative process whereby all utilities that own, operate, or control interstate transmission facilities could consider and develop RTOs in consultation with state officials.

◆ **Proposal for standard market design.** Disappointed with the slow industry response to Order 2000, the FERC issued its NOPR for a standard market design (SMD) for the interstate transmission system on July 31, 2002. The proposed rule would have established a single flexible transmission system called Network Access Service. The service would have established a single open-access transmission tariff (a public schedule detailing rates, rules, and terms of service) that would apply to all customers, as well as an SMD for wholesale electric markets.

Although the FERC proposal saw a formal role for the state regulators as members of a regional state advisory committee, there was strong regional opposition to the SMD proposal, mainly from state regulators in the Southeast and the West. Given the strength and political power of this opposition, the FERC issued a white paper on April 28, 2003, which refined its SMD proposal and eliminated the requirement for public utilities to create or join an independent transmission provider, although they would have to join an RTO or ISO.

The refined version, though, did not succeed in lessening the opposition to the proposal, and the FERC subsequently decided not to press for mandatory membership in an RTO. This became official policy with the signing into law of EPAct2005 in August 2005. The new law specifically stated that, while the FERC could encourage transmission-owning entities to join RTOs, it did not have the authority to order them to do so.

◆ **Order 890.** The EPAct2005 authorized the FERC to prescribe rules to provide for the dissemination of information about the availability and price of wholesale electric power and transmission service, with due regard for the integrity of these markets, fair competition, and the protection of consumers.

The FERC strongly believed that, more than 10 years after Order 888, the open access transmission tariffs (OATTs) contained flaws that had undermined its core objective of preventing undue discrimination by transmission owners. To change this, the FERC issued Order 890 on February 16, 2007. This order authorized several reforms.

First, it eliminated the wide discretion that transmission providers have in calculating available transfer capacity. Second, it required an open, transparent, and coordinated transmission-planning process. Third, it increased the efficient utilization of transmission by eliminating artificial barriers (such as denying a request for long-term, point-to-point service if the request cannot be granted in an hour). Fourth, it facilitated the use of clean energy resources, such as wind power, through reforming generator imbalance charges (since these resources have limited ability to control their output). Last, Order 890 increased the clarity of OATT requirements and strengthened compliance and enforcement efforts by adopting penalties for clear violations of an OATT. The new order was applicable to all regulated transmission providers, including regional transmission organizations and independent system operators.

FERC Order 592 addressed market power in mergers

In December 1996, the FERC adopted Order 592, a new policy setting forth the criteria and procedures for approving mergers. The order stated that the agency would consider a proposed merger's impact on competition, costs, and rates, and the ability of the commission and the states to regulate the new entity effectively.

With regard to competition, the FERC considers whether one utility or a few large utilities could gain excessive market power by controlling all the capacity of a specific transmission system. Such a setup would enable those controlling the capacity to charge more for their electricity — an undesirable result, from the perspectives of both consumers and regulators.

The deregulation of the industry was intended to increase competition and to loosen electric utilities' monopoly on power generation. Because the process could not be completed overnight, however, the FERC made it clear that it would use its authority to prevent any one company — or a small number of them — from gaining too much market power.

INDUSTRY ACCOUNTING QUIRKS

The industry's regulated nature has given rise to unique accounting practices. In particular, several significant "noncash" items can dramatically alter a utility's earnings. Historically, the most notable noncash component in accounting has been the allowance for funds used during construction (AFUDC). If state regulators do not include a utility's construction work in progress (CWIP) in the calculation of its rate base (upon which the utility is allowed to earn an actual return), the utility records an AFUDC on its income statement. This is an income credit representing construction financing costs. Once the facility is placed into operation, a return will be earned on the portion of those costs included in the rate base. The costs not included in the rate base will be recovered over the life of the facility through depreciation charges.

AFUDC amounts are added to a plant's costs. Like other construction expenditures, they are depreciated over time. During periods of heavy construction, AFUDC could represent a substantial portion of utility earnings. AFUDC, of course, would be of much less significance during periods of limited construction spending.

Another source of noncash earnings is multiyear phase-ins of rate hikes given to utilities to cover costs for new generating plants. This practice generates noncash earnings in that the reported "earnings" do not include the related expense that has been recorded as an asset on the balance sheet under deferred charges. By phasing in these large rate increases, regulators lessen the "rate shock" to customers.

To avoid the negative earnings impact from enormously expensive projects, utilities can defer the recording of these costs while new rates are phased in. Such deferred amounts then are amortized and recovered over time.

Many state commissions require or allow utilities to create "regulatory assets" by deferring the recording of some costs — such as those related to damages from severe storms, clean air expenditures, and demand-side management energy-efficiency programs — until the next general rate increase. For some utilities, the next expected general rate increase might be years away, so reported earnings would be affected only in the long term. However, the deferred costs hurt the quality of near-term earnings, because the earnings do not fully reflect the costs of that period. Suppose, for example, that a company incurs a $100 million expense for repairing storm damage. The company's current reported earnings would not be affected because the expense has been deferred, but this compromises the quality of those earnings. Regulatory assets are only appropriate if it is probable that they will be amortized and recovered once the next rate increase becomes effective.

KEY INDUSTRY RATIOS AND STATISTICS

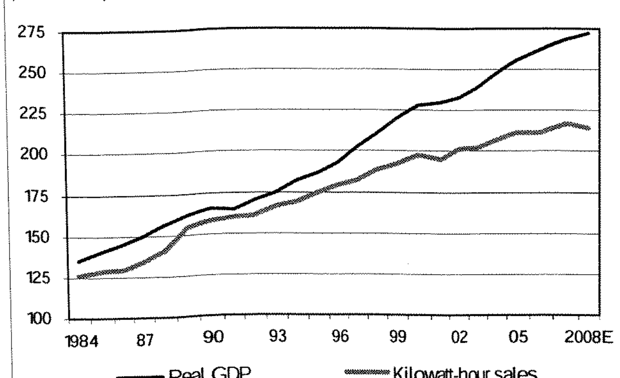
◆ **Interest rates.** The regulated and capital-intensive nature of the electric utility industry makes the financial performance of these companies very sensitive to the level of interest rates and available returns. Utility rates are based on operating costs, capital investments, and the cost of capital. Changes in overall market rates affect utility rates via the cost of debt and the allowed return on equity (ROE). When market rates drop substantially, utility rates are likely to be lowered as financing cost savings are passed on to customers.

In addition, income-oriented investors are sensitive to interest rates when evaluating a utility company's shares. If interest rates are rising, these investors may be able to receive comparable returns elsewhere and, consequently, would be less likely to purchase a utility stock that did not provide a comparable yield.

In 2008, the S&P Electric Utilities index was down 28.1%, compared with a 38.5% decline for the S&P 500 Composite Stock index. This followed a gain of 16.8% in 2007, versus a 3.5% increase for the S&P 500. In contrast to the past few years, utility stocks did not benefit from the dramatic decline in the broader market in 2008. Instead, the sector was also badly hurt by the extraordinary turmoil in the stock market that reflected, we believe, the crisis in the housing, credit, and financial markets, which combined to bring about a significant downturn in the overall economy. The strong outperformance in 2007 continued the pattern established in the prior three years, when gains for the S&P Electric Utilities index (19.2% in 2006, 11.7% in 2005, and 19.6% in 2004) clearly outperformed the respective increases of 13.6%, 3.0%, and 9.0% for the S&P 500.

The gains in 2007 and 2006 were a continuation of the investor shift into the higher-yielding utility sector, with utility stocks apparently having benefited from the volatility of the broader market, the anticipation of interest rate cuts, and their improved financial strength and earnings outlook. In 2004 and 2005, the sector was considered a safer alternative to the broader market, due to the uncertainties that had been created by the sharp rise in oil prices and the adverse impact that the increase could have on the economy and corporate earnings.

REAL GDP AND TOTAL KILOWATT-HOUR SALES
(1975=100)



E-Estimated.
Sources: US Department of Commerce; US Department of Energy.

Despite the recent record-low interest rates, many electric utilities are still paying higher rates on their debt issues due to the credit crisis, which brought on a shortage of available credit.

◆ **US gross domestic product** (GDP). Reported quarterly by the US Department of Commerce, GDP is a broad measure of aggregate economic activity. It is the market value of goods and services produced by labor and capital in the United States. Growth in the economy is measured by changes in inflation-adjusted (or real) GDP.

Changes in demand for electricity closely mirror the rate of economic growth. However, weather patterns can cause swings in electric consumption. In addition, demand growth for an individual utility company depends heavily on economic trends within its geographic region.

Real GDP grew 2.0% in 2007, following a 2.9% increase in 2006. As of January 2009, Standard & Poor's was projecting that real GDP would grow by 1.1% in 2008, but then decline by 2.0% in 2009.

◆ **Cooling and heating degree-days.** Cooling and heating degree-days are measures of the average temperature for a given period. Mean temperatures below a reference temperature, usually 65 degrees Fahrenheit, result in heating degree-days; those above the reference temperature result in cooling degree-days. Reported quarterly by the Edison Electric Institute (EEI), these statistics have an important bearing on utility earnings, in that usage increases when it is hotter than normal in the summer or, to a much lesser extent, when it is colder than normal in the winter.

In the third quarter of 2008 (latest available), the EEI reported that the number of cooling degree-days was down 11% from the year-earlier period, but up 3% from the historical average. In 2007, the number of cooling degree-days was up 4% from 2006, and 14% above the historical average; while in 2006, the number of cooling degree-days was 2% less than in 2005, but 16% higher than the historical average.

The number of heating degree-days in the third quarter of 2008 was 8% higher than the comparable year-earlier period, but 24% below the historical average. The number of heating degree-days in 2007 was up 7% from 2006, but 6% below the historical average, while in 2006, the number of heating degree-days was 8% less than in 2005 and 13% less than the historical average.

◆ **Key demographic and housing statistics.** Demographic trends can influence an electric utility's customer base. New household formations and the rate of new housing construction are the key sources of residential customer growth. Household formations are reported by the US Census Bureau, while housing starts are reported monthly by the US Department of Commerce.

Following a 12.6% decline in 2006, housing starts fell 26.0% in 2007. As of January 2009, Standard & Poor's was estimating that housing starts would decline by 32.4% in 2008 and by 28.3% in 2009.

HOW TO ANALYZE AN ELECTRIC UTILITY

With the industry moving toward a deregulated, competitive marketplace, the job of analyzing an electric utility company is becoming increasingly complex. A fair assessment now requires much more than a look at the dividend yield (the annual dividend divided by the stock price). When evaluating a utility, it is as important to assess the utility's underlying business position as it is to determine its current financial health.

QUALITATIVE FACTORS

Below are some important factors that affect a utility company's business position.

Location

The ideal environment for a utility is one in which a robust economy attracts new businesses that, in turn, contribute to above-average population growth. Is economic activity in the utility's service region healthy and growing? What is the area's outlook for population growth and new housing starts? What are the forecasts for future regional demand?

Customer mix

A utility's customer base has an important bearing on its profitability level. A utility with a large industrial and commercial load should be viewed with caution, because these customer classes expose the utility to competition. A large residential customer base, in contrast, provides a more stable and predictable earnings stream. (The introduction of residential competition is not likely to affect this situation any time soon; most residential customers are expected to remain with their current utility.)

If any single wholesale or retail customer accounts for a significant portion of a utility's sales, the analysis must focus on the stability of that customer and on the utility's competitive position — its prospects for retaining that company's business.

Competitive position

A company's rates and its ability to lower production costs generally determine its position relative to competitors. A high-volume customer could choose to relocate to a different service area with lower rates or to buy power from an independent producer. A large industrial customer could turn to self-generation or nontraditional energy sources.

How do the utility's production costs and rates compare with those of other utilities in the same region and with the national average? Examine the utility's plans for capital additions. How much is it expecting to spend? How will its plans be funded? As competition increases, utilities must become even more careful about capital additions, questioning whether the future customer base will support the additional costs.

Fuel mix and supply

A utility company's ability to alter its generating sources (such as coal, nuclear power, hydroelectric power, gas, and oil) defends it against supply disruptions or price spikes in a particular commodity. It also lets the company take advantage of changes in fuel costs. Conversely, a lack of flexibility in fuel supply restricts a company's options if the environment changes.

Plant operations

Areas for analysts to consider include the various costs to run the plants, the reliability of the operations, and the quality of the service. Have there been any unscheduled outages? What are the current estimates of remaining plant life and decommissioning costs? Will it be profitable to run the plant(s) in a competitive market? Does the company have idled or excess capacity? If so, what are its plans?

In addition, look at the utility's transmission access. Is it adequate for current demand? Is the company locked into any long-term purchase power contracts with high-price nonutility generators? If competition drives down the industry's production costs and market prices, the utility would suffer from contractual obligations to purchase power at above-market rates.

Business strategy

Given its maturity, the electric utility industry offers little in the way of domestic growth prospects. For that reason, many utilities had attempted to achieve growth through investments in wholesale energy marketing and trading operations, and/or other energy-related businesses, as well as in utilities in foreign countries. Such ventures, however, added a significant risk component to their operations, and often resulted in serious economic losses and even bankrupt businesses. One must determine whether the utility's business strategy and management are conservative or aggressive, and whether they are appropriate in light of the company's strengths and culture, and the opportunities available to it.

The regulatory environment

Despite the eventual arrival of retail competition, electric utilities' activities remain subject to extensive state and federal regulation. Regulated areas include consumer rates, allowed rates of return, the safety and adequacy of service, the purchase and sale of assets, accounting systems, and the issuance of securities.

Therefore, it is important to study the trends at the regulatory commissions that have jurisdiction over a utility. Compare the recent average return on equity (ROE) that the commission authorized for the utility with the amount the utility requested. Was the ruling favorable? If not, why? Is there a possibility of a rate decrease? When will the next rate increase or decrease be filed, and what other major issues will be addressed?

What are the local commission's views on retail competition and regulatory reform? On stranded-cost recovery, demand-side management programs, and clean air compliance? All of these factors can affect a utility's ultimate revenues.

EVALUATING THE INCOME STATEMENT

At this point, one should have a good idea of how well the utility being analyzed is positioned to compete in the current changing environment and its own particular markets. Now it is time to look at the financial statements, beginning with the income statement.

Revenue growth

For utilities, revenue growth is somewhat predictable because of regulatory constraints on price increases. Nevertheless, it is still important to study past sales trends and expectations for the future. Did growth come from a rate hike or from increased weather-related demand? Is the economy improving and is the population growing in the utility's service area?

STATEMENT OF INCOME — INVESTOR-OWNED UTILITIES
(In millions of dollars, except as noted)

ITEM	DEC. 31 2006	DEC. 31 2007	% CHG.
Total electric operating revenues*	382,382	405,938	6.2
Electric operating expenses			
Energy expenses	173,480	184,505	6.4
Operations & maintenance	79,636	86,609	8.8
Depreciation & amortization	32,092	33,219	3.5
Taxes (other than income)	14,797	15,469	4.5
Other operation & maintenance	20,842	22,580	8.3
Total operating expenses	320,846	342,381	6.7
Total utility operating income	61,536	63,557	3.3
Total other recurring revenue	5,302	5,589	5.4
Nonrecurring revenue	1,233	5,388	336.9
Net interest expense	20,666	21,118	2.2
Other expenses	727	675	(7.2)
Non-recurring expenses	2,833	1,635	(42.3)
Net income before taxes	43,845	51,105	16.6
Net income bef. extraordinary items	28,955	33,666	16.3
Total extraordinary items	2,208	267	(87.9)
Net income	31,163	33,933	8.9

NM-Not meaningful. *Note: Revenues are adjusted for intra-industry sales for the resale of electricity.
Source: Edison Electric Institute.

Operating expenses

Fuel is the largest and most variable item on a utility's list of operating expenses, and it is often the least controllable. Note whether the company has been able to pass along higher fuel costs to customers. Pay close attention to nonfuel expenses, and particularly to how they compare with revenues. An improving trend in operating and maintenance costs usually indicates that a company is focusing on streamlining its operations and controlling costs.

Noncash items

Unique to the analysis of utility companies are certain noncash items that can make a big difference in the quality of reported earnings. These items include the treatment of deferred income taxes, deferred expenses, phase-ins, depreciation and amortization, and the allowance for funds used during construction (AFUDC). If any of these items constitutes a significant portion of reported earnings, the results may be overstated or unsustainable.

Study the trends in depreciation and amortization charges. Given the current competitive environment and the possibility of stranded investments, many utilities are accelerating the write-down of assets that are at risk. Although a higher depreciation rate will depress a utility's current net earnings, analysts view the tactic as a positive step, because accelerated depreciation helps a utility recover the costs of its investments more quickly.

Nonoperating expenses

Because the utility industry is extremely capital-intensive, interest payments are its most significant nonoperating expense. Since the mid-1980s, however, interest costs have trended downward, largely because industry overcapacity has resulted in reduced capital expenditures and construction. If interest expenses are increasing, find out why.

BALANCE SHEET, CASH FLOW, AND VALUATION MEASURES

The first four of the following categories — the capitalization ratio, debt ratings, cash flow, and ROE — are measures of a company's financial strength and performance. The others, in which the stock price figures as a variable, indicate the market's valuation of a company's current and potential future performance.

Capitalization ratios

When analyzing a utility's balance sheet, pay close attention to the capitalization ratio, which measures long-term debt as a percentage of capital.

Historically, utilities have been highly leveraged. Following adjustments due to methodology changes (such as recognizing as debt certain preferred security issues previously recognized as equity), the average long-term debt-to-capital ratio for the industry declined during the five-year period from 2002 to 2006 (latest available), from a revised 62.2% in 2002, to 58.1% in 2004, to 54.2% in 2006.

BALANCE SHEET DATA — INVESTOR-OWNED UTILITIES
(In millions of dollars)

ITEM	YEAR END, DEC. 31 2006	2007	% CHG.
ASSETS			
Utility plant			
Gross property & equipment	853,907	874,832	2.5
Accumulated depreciation	306,210	314,030	2.6
Net property in service	547,698	560,802	2.4
Construction work in progress	33,841	43,852	29.6
Net nuclear fuel	5,876	6,885	17.2
Other property	1,400	2,232	59.4
Net property & equipment	588,816	613,771	4.2
Current assets	146,836	139,424	(5.0)
Investments	68,466	67,736	(1.1)
Other assets	180,167	172,271	(4.4)
Total assets	984,284	993,202	0.9
CAPITALIZATION & LIABILITIES			
Common equity	257,073	264,462	2.9
Nonredeemable preferred equity	596	566	(5.0)
Total shareholders' equity	257,669	265,029	2.9
Short-term debt	21,509	25,050	16.5
Current portion of long-term debt	27,333	26,386	(3.5)
Short-term and current long-term debt	48,843	51,436	5.3
Accounts payable and accrued expenses	62,838	62,608	(0.4)
Other current liabilities	51,158	43,861	(14.3)
Current liabilities	162,839	157,905	(3.0)
Deferred taxes	101,294	99,026	(2.2)
Noncurrent portion of long-term debt	295,772	297,582	0.6
Other liabilities	160,039	167,204	4.5
Total liabilities	719,944	721,717	0.2

Source: Edison Electric Institute.

The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt compared with the value of the company's common stock. (A company will not issue new shares if its stock price is relatively low.) Companies with strong balance sheets will have more flexibility to further reduce their debt, invest in their nonregulated businesses, and/or increase their dividends.

Debt ratings

A debt rating measures a company's financial position and its ability to repay debt. The Standard & Poor's ratings for a utility's debt securities are a good indication of a company's financial security. Look for any trends in these ratings over time. Have they changed for the better or the worse?

Although a high debt rating is usually desirable, it is not always the best news for shareholders. For example, a company that focuses on using earnings (cash) to pay off debt may do so at the expense of common stock dividend payments.

As a rule, however, low debt ratings are not desirable. Companies with low ratings often find it hard to raise capital; they also incur high interest payments to finance capital improvements. If the stock price is low enough, however, the utility's shares may be attractive to investors.

Cash flow

A review of cash flow trends helps to reveal a utility's health. Over the last several years, capital expenditures for new generation plants has grown significantly as utilities and independent power producers prepared for an anticipated rise in power demand. However, if a much longer-than-expected slowdown in the economy develops, and wholesale prices are significantly depressed, cash flows could decline dramatically. In the most extreme cases (as occurred during 2003 and 2004), companies could suffer a severe liquidity crisis.

For an equity analyst, it is more important to look at free cash flow — what is left after interest and dividend payments have been made. A company struggling with cash flow problems may have to consider a dividend cut to preserve its funds.

Return on equity

If a utility's return on equity (ROE) is too low, the analyst must determine if it was caused by mild weather or the absence of a needed rate hike — or if the utility is poorly operated. Conversely, too high a return on equity could cause regulators to seek a rate cut. For firms in the S&P Electric Utilities index, ROE generally ranges between 10% and 13%.

CASH FLOW STATEMENT — INVESTOR-OWNED UTILITIES
(In millions of dollars)

ITEM	YEAR END, DEC. 31 2006	2007	% CHG.
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	31,163	33,933	8.9
Depreciation and amortization	35,050	35,577	1.5
Deferred taxes and investment credits	3,573	2,848	(20.3)
Operating changes in AFUDC	(191)	(325)	NM
Change in working capital	844	(5,767)	NM
Other operating changes in cash	(1,008)	(4,600)	NM
Net cash provided by operating activities	69,432	61,666	(11.2)
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(59,859)	(69,146)	NM
Change in nuclear decommissioning trust	(1,039)	(288)	NM
Investing changes in AFUDC	90	144	59.6
Other investing changes in cash	(222)	(3,007)	NM
Net cash used in (provided by) investing activities	(59,234)	(50,378)	NM
CASH FLOWS FROM FINANCING ACTIVITIES			
Net change in short-term debt	3,153	3,318	5.2
Net change in long-term debt	383	7,549	1,871.3
Proceeds from issuance of preferred equity	664	490	(26.3)
Preferred share repurchases	(556)	(314)	NM
Net change in preferred issues	108	176	62.7
Cash flow: proceeds from issuance of common equity	10,008	4,813	(51.9)
Cash flow: common share repurchases	(6,261)	(11,902)	NM
Net change in common issues	3,746	(7,090)	NM
Dividends paid to shareholders	(16,397)	(16,981)	NM
Other financing changes in cash	233	379	62.4
Cash flows from financing activities	(8,773)	(12,648)	NM
Other changes in cash	114	49	(56.8)
Net increase (decrease) in cash and cash equivalents	1,540	(1,311)	NM
Cash and cash equivalents at beginning of period	11,060	12,600	13.9
Cash and cash equivalents at end of period	12,600	11,289	(10.4)

NM-Not meaningful. AFUDC-Allowance for funds used during construction.
Source: Edison Electric Institute.

Market-to-book ratio

The market-to-book (or price-to-book) ratio is used to measure shareholder confidence in a company's prospects. It is calculated by dividing the company's current market price per share by the company's book value per share. A low market-to-book ratio could mean that a company has assets, such as nuclear generation facilities, that are no longer economically viable.

For firms in the S&P Electric Utilities index, shares normally trade between one and two times the company's book value per share.

Price/earnings ratio and dividend yield

To evaluate the current market price of the utility's shares, look at the price/earnings (P/E) ratio and the dividend yield. Is the P/E ratio greater or less than the expected sustainable growth rate of the company's earnings? How does the P/E compare with the industry average? Investors tend to pay a higher P/E and to accept a lower dividend yield from the shares of a company with earnings that are expected to rise rapidly.

For firms in the S&P Electric Utilities index, shares normally trade between nine and 15 times the company's projected earnings per share. These shares tend to trade at a discount to the market multiple because of the slow-growth nature of utilities' regulated operations. Dividend yields normally fall within a range of 3% to 7%. Because of these higher-than-average dividend yields, dividend income is an important component of investors' total return on electric utility stocks. The importance of the dividend was significantly increased in May 2003, when President Bush signed legislation that cut the tax rate on dividend income from the earned income rate to a 15% rate.

Despite the importance of the dividend (especially for income-oriented investors), electric utility stocks are much less interest rate-sensitive than they were in the past. In fact, the value of electric utility stocks declined in both 2001 and 2002, despite a significant decline in interest rates. This primarily reflects the perception of investors that other sectors may benefit more from a drop in rates.

Although there was a coincidence in 2007 between the decline in interest rates and the rise in utility stocks, we believe the latter was more affected by the weakness of the overall market. Utility stocks appear to benefit the most — as they did in 2004, 2005, and 2007 — when the broader market is in a state of decline or uncertainty and investors are looking for a "safe haven" for their investments. However, this haven is not as safe as it once was: utility stocks have become much more volatile in recent years, sometimes experiencing sharp swings within a short period of time — often in the opposite direction of the broader market. ■

INDUSTRY REFERENCES

PERIODICALS

Megawatt Daily
http://www.platts.com
Daily newsletter; covers industry news.

Platts Electric Utility Week
http://www.platts.com
Weekly; covers electric utility industry news.

Public Utilities Fortnightly
http://www.pur.com
Monthly; covers the electric and gas utility industry.

BOOKS

America's Electric Utilities: Past, Present and Future, 8th ed.
Leonard S., Andrew S. and Robert C. Hyman
Vienna, VA: Public Utilities Reports Inc., 2005
http://www.pur.com

TRADE ASSOCIATIONS

Edison Electric Institute (EEI)
http://www.eei.org
Supplies industry statistics and information on electric power industry issues.

National Association of Regulatory and Utility Commissioners (NARUC)
http://www.naruc.org
Represents individual states' viewpoints on regulation.

North American Electric Reliability Council (NERC)
http://www.nerc.com
A not-for-profit organization formed in 1968 by the electric utility industry to promote the reliability and adequacy of North America's bulk power supply.

GOVERNMENTAL AND REGULATORY BODIES

Energy Information Administration (EIA)
http://www.eia.doe.gov
An agency within the US Department of Energy; supplies publications and statistics on the electricity industry.

Federal Energy Regulatory Commission (FERC)
http://www.ferc.gov
An independent five-member commission within the US Department of Energy; regulates interstate and wholesale electric power rates (tariffs) and transactions, hydroelectric licensing, and interstate natural gas pipeline companies.

US Department of Energy (DOE)
http://www.energy.gov
A position in the US Cabinet comprising the Office of the Secretary of Energy and the FERC.

US Environmental Protection Agency (EPA)
http://www.epa.gov
An independent federal agency that formulates and enforces policies and regulations aimed at the protection of human health and the environment.

US Nuclear Regulatory Commission (NRC)
http://www.nrc.gov
An independent federal agency that regulates the civilian uses of nuclear materials in the United States. The NRC's main functions include inspecting plant operations, reviewing and issuing construction and operating licenses, and researching regulatory and standards development.

INDUSTRY CONSULTANTS

Platts/The McGraw-Hill Cos. Inc.
http://www.platts.com
Consulting and publishing firm that collects strategic energy information. Purchased Financial Times Energy, an energy information and consulting firm with consolidated Boulder-based businesses, including Research Data International (RDI), which provides wholesale suppliers with market information; and E Source, a retail consultant for utilities and consumers. (The McGraw-Hill Cos. is the parent company of Standard & Poor's.)

COMPARATIVE COMPANY ANALYSIS — ELECTRIC UTILITIES

Operating Revenues

Ticker	Company	Yr. End	Million $ 2007	2006	2005	2004	2003	2002	1997	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (1997 = 100) 2007	2006	2005	2004	2003
	ELECTRIC UTILITIES‡																
AYE	[] ALLEGHENY ENERGY INC	DEC	3,307.0 F	3,121.5 D,F	3,037.9 C,D	2,756.1 D,F	2,472.4 C,F	2,988.5 C,F	2,369.5	3.4	2.0	5.9	140	132	128	116	104
ALE	§ ALLETE INC	DEC	841.7 F	767.1 D,F	737.4 D	751.4 C,D	1,581.9 D,F	1,474.4 D,F	892.9 A,F	(0.6)	(10.6)	9.7	94	86	83	84	177
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	13,380.0 A,C	12,622.0 D,F	12,111.0 C,D	14,057.0 D,F	14,545.0 C,D	14,536.0 C,D	6,161.4	8.1	(1.6)	6.0	217	205	197	228	236
CV	§ CENTRAL VERMONT PUB SERV	DEC	329.1	325.7 A,C	311.4 D	302.2 D	306.0 D	303.4	304.7	0.8	1.6	1.0	108	107	102	99	100
CNL	§ CLECO CORP	DEC	1,030.6 F	1,000.7 D,F	920.2 D,F	745.8 D,F	874.6 F	721.2 F	456.2	8.5	7.4	3.0	226	219	202	163	192
DPL	† DPL INC	DEC	1,515.7 D,F	1,393.5 D,F	1,284.9 C,D	1,199.9 F	1,191.0 C,F	1,186.4 F	1,332.9 F	1.3	5.0	8.8	114	105	96	90	89
DUK	[] DUKE ENERGY CORP	DEC	12,720.0 D,F	15,184.0 A,C	16,746.0 C,D	22,503.0 D,F	22,154.0 C,D	15,663.0 A,F	16,308.9 A,F	(2.5)	(4.1)	(16.2)	78	93	103	138	136
EIX	[] EDISON INTERNATIONAL	DEC	13,113.0 D,F	12,622.0 C,D	11,852.0 C,D	10,199.0 A,C	12,135.0 D,F	11,488.0 D,F	9,045.5 F	3.8	2.7	3.9	145	140	131	113	134
EE	§ EL PASO ELECTRIC CO	DEC	877.4 F	816.5 F	803.9 C,F	708.6 F	664.4 C,F	690.1 F	594.0	4.0	4.9	7.5	148	137	135	119	112
ETR	[] ENTERGY CORP	DEC	11,484.4 F	10,932.2 D,F	10,106.2 D,F	10,123.7 F	9,194.9 C,F	8,305.0 F	9,561.7 A,F	1.8	6.7	5.1	120	114	106	106	96
EXC	[] EXELON CORP	DEC	18,716.0 D,F	15,655.0 D,F	15,357.0 C,D	14,515.0 C,F	15,812.0 C,F	14,955.0 F	4,617.9	15.0	4.6	19.6	405	339	333	314	342
FE	[] FIRSTENERGY CORP	DEC	12,781.0 F	11,501.0 D,F	11,989.0 C,D	12,453.0 D,F	12,307.0 C,D	12,247.4 F	2,821.4 B	16.3	0.9	11.1	453	408	425	441	436
FPL	[] FPL GROUP INC	DEC	15,263.0 F	15,710.0 F	11,846.0 F	10,522.0 F	9,630.0 C,F	8,311.0 C,F	6,369.0 F	9.1	12.9	(2.8)	240	247	186	165	151
GXP	† GREAT PLAINS ENERGY INC	DEC	3,267.1 F	2,675.3 F	2,604.9 D,F	2,464.0 D,F	2,149.5 D,F	1,861.9 C,F	895.9	13.8	11.9	22.1	365	299	291	275	240
HE	† HAWAIIAN ELECTRIC INDS	DEC	2,536.4 F	2,460.9 F	2,215.6 D,F	1,924.1 D,F	1,781.3 D,F	1,653.7 F	1,464.0 A,F	5.6	8.9	3.1	173	168	151	131	122
IDA	† IDACORP INC	DEC	879.4 D,F	926.3 D,F	859.5 F	844.5 F	823.0 F	928.8 F	748.5	1.6	(1.1)	(5.1)	117	124	115	113	110
NU	† NORTHEAST UTILITIES	DEC	5,822.2 D,F	6,884.4 D,F	7,397.4 C,D	6,686.7 F	6,069.2 C,F	5,216.3	3,834.8	4.3	2.2	(15.4)	152	180	193	174	158
NVE	† NV ENERGY INC	DEC	3,601.0 F	3,355.9 F	3,030.2 D,F	2,823.8 D,F	2,789.2 D,F	2,991.7 C,F	799.1	16.2	3.8	7.3	451	420	379	353	349
POM	[] PEPCO HOLDINGS INC	DEC	9,366.4 F	8,362.9 F	8,065.5 F	7,221.8 F	7,271.3 F	4,324.5 A,F	1,863.5	17.5	16.7	12.0	503	449	433	388	390
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	3,523.6 D,F	3,401.7 D,F	2,988.0 D,F	2,899.7 D,F	2,817.9 D,F	2,637.3 C,F	1,995.0 F	5.9	6.0	3.6	177	171	150	145	141
PPL	[] PPL CORP	DEC	6,498.0 D,F	6,899.0 D,F	6,219.0 C,D	5,812.0 D,F	5,587.0 D,F	5,429.0 C,F	3,049.0 F	7.9	3.7	(5.8)	213	226	204	191	183
PGN	[] PROGRESS ENERGY INC	DEC	9,153.0 D,F	9,570.0 C,D	10,108.0 C,D	9,772.0 D,F	8,743.0 C,D	7,945.1 A,C	3,024.1	11.7	2.9	(4.4)	303	316	334	323	289
SO	[] SOUTHERN CO	DEC	15,353.0 F	14,356.0 D,F	13,554.0 F	11,902.0 F	11,107.0 F	10,549.0 F	12,611.0 A,F	2.0	7.8	6.9	122	114	107	94	88
UIL	§ UIL HOLDINGS CORP	DEC	982.0 D,F	846.0 D,F	1,213.1 D,F	1,101.3 D,F	963.7 D,F	1,131.0 F	710.3	3.3	(2.8)	16.1	138	119	171	155	136
UNS	§ UNISOURCE ENERGY CORP	DEC	1,381.4 F	1,316.9 D,F	1,229.5 C,F	1,169.0 F	972.8 C,F	856.2 F	729.9	6.6	10.0	4.9	189	180	168	160	133
WR	† WESTAR ENERGY INC	DEC	1,726.8	1,605.7	1,583.3 D	1,464.5 D	1,461.1 D	1,771.1 C,D	2,151.8 A,F	(2.2)	(0.5)	7.5	80	75	74	68	68
	MULTI-UTILITIES‡																
LNT	† ALLIANT ENERGY CORP	DEC	3,437.6 D,F	3,359.4 D,F	3,279.6 D,F	2,958.7 D,F	3,128.2 C,D	2,608.8 D,F	919.3 F	14.1	5.7	2.3	374	365	357	322	340
AEE	[] AMEREN CORP	DEC	7,546.0	6,880.0 A	6,780.0 C,F	5,160.0 A,F	4,593.0 A,C	3,841.0 F	3,326.5 B,F	8.5	14.5	9.7	227	207	204	155	138
AVA	§ AVISTA CORP	DEC	1,417.8 F	1,506.3 F	1,359.6 F	1,151.6 C,F	1,123.4 C,D	980.4 D,F	1,302.2 F	0.9	7.7	(5.9)	109	116	104	88	86
BKH	† BLACK HILLS CORP	DEC	695.9 D,F	656.9 A,C	1,391.6 A,C	1,121.7 D,F	1,136.1 C,D	423.9 C,D	313.7 A,F	8.3	10.4	5.9	222	209	444	358	362
CNP	[] CENTERPOINT ENERGY INC	DEC	9,623.0 F	9,319.0 F	9,722.0 D,F	8,510.4 D,F	9,760.1 C,D	7,922.5 D,F	6,873.4 A,F	3.4	4.0	3.3	140	136	141	124	142
CHG	§ CH ENERGY GROUP INC	DEC	1,196.8 F	993.4 F	972.5 F	791.5 F	806.7 F	695.5 D,F	520.3	8.7	11.5	20.5	230	191	187	152	155
CMS	[] CMS ENERGY CORP	DEC	6,464.0 D,F	6,810.0 D,F	6,288.0 D,F	5,472.0 C,D	5,513.0 C,D	8,687.0 C,D	4,787.0 F	3.0	(5.7)	(5.1)	135	142	131	114	115
ED	[] CONSOLIDATED EDISON INC	DEC	13,120.0 D,F	12,137.0 D,F	11,690.0 D,F	9,882.0 D,F	9,827.0 C,F	8,481.9 C,F	7,121.3	6.3	9.1	8.1	184	170	164	139	138
D	[] DOMINION RESOURCES INC	DEC	15,674.0 D,F	16,482.0 D,F	18,041.0 D,F	13,972.0 D,F	12,078.0 C,D	10,218.0 A,F	7,677.6 A,F	7.4	8.9	(4.9)	204	215	235	182	157
DTE	[] DTE ENERGY CO	DEC	8,506.0 D,F	9,022.0 C,D	9,022.0 D,F	7,114.0 D,F	7,041.0 C,D	6,749.0 F	3,764.0 F	8.5	4.7	(5.7)	226	240	240	189	187
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	10,292.4 A,C	6,890.7 D,F	6,962.7 C,F	4,890.6 D,F	4,321.3 C,D	2,674.9 A,F	878.3 F	27.9	30.9	49.4	1,172	785	793	557	492
MDU	† MDU RESOURCES GROUP INC	DEC	4,247.9 D,F	4,070.7 D,F	3,455.4 F	2,719.3 F	2,352.2 C,F	2,004.1 A,F	607.7 F	21.5	16.2	4.4	699	670	569	447	387
NI	[] NISOURCE INC	DEC	7,973.3 D,F	7,490.0 D,F	7,899.1 D,F	6,666.2 D,F	6,246.6 D,F	6,492.3 D,F	2,586.5 A,F	11.9	4.2	6.5	308	290	305	258	242
NST	† NSTAR	DEC	3,261.8 F	3,577.7 F	3,243.1 F	2,954.3 F	2,914.1 F	2,719.1 F	1,776.2	6.3	3.7	(8.8)	184	201	183	166	164
OGE	† OGE ENERGY CORP	DEC	3,797.6 F	4,005.6 D,F	5,948.2 D,F	4,926.6 D,F	3,779.0 D,F	3,023.9 D,F	1,472.3 F	9.9	4.7	(5.2)	258	272	404	335	257
PCG	[] PG&E CORP	DEC	13,237.0	12,539.0	11,703.0 D	11,080.0 D	10,435.0 C,D	12,495.0 C,D	15,400.0 A,F	(1.5)	1.2	5.6	86	81	76	72	68
PNM	† PNM RESOURCES INC	DEC	1,914.0 D,F	2,471.7 A,F	2,076.8 C,F	1,604.8 F	1,455.7 C,F	1,169.0 F	1,135.3 F	5.4	10.4	(22.6)	169	218	183	141	128
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	12,853.0 D,F	12,164.0 D,F	12,430.0 D,F	10,996.0 D,F	11,116.0 D,F	8,390.0 A,C	6,370.0 F	7.3	8.9	5.7	202	191	195	173	175
PSD	† PUGET ENERGY INC	DEC	3,220.1 D,F	2,905.7 C,D	2,573.2 C,D	2,568.8 F	2,491.5 C,F	2,392.3 F	1,676.9 A,F	6.7	6.1	10.8	192	173	153	153	149
SCG	[] SCANA CORP	DEC	4,621.0 F	4,563.0 C,F	4,777.0 F	3,885.0 F	3,416.0 F	2,954.0 C,F	1,523.0	11.7	9.4	1.3	303	300	314	255	224
SRE	[] SEMPRA ENERGY	DEC	11,438.0 D,F	11,761.0 D,F	11,737.0 D,F	9,410.0 D,F	7,887.0 C,F	6,020.0 F	2,738.0 F	15.4	13.7	(2.7)	418	430	429	344	288

Data by Standard & Poor's Compustat — A Division of The McGraw-Hill Companies

Operating Revenues

Ticker	Company	Yr. End	2007 (Million $)	2006	2005	2004	2003	2002	1997	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (1997 = 100) 2007	2006	2005	2004	2003
TE	[] TECO ENERGY INC	DEC	3,536.1 D,F	3,448.1 D,F	3,010.1 D,F	2,669.1 D,F	2,740.0 C,D	2,675.8 D,F	1,862.3 A,F	6.6	5.7	2.6	190	185	162	143	147
VVC	† VECTREN CORP	DEC	2,281.9 F	2,041.6 A,F	2,028.0 F	1,689.8 F	1,587.7 F	1,804.3 C,F	530.4 C	15.7	4.8	11.8	430	385	382	319	299
WEC	[] WISCONSIN ENERGY CORP	DEC	4,237.8 D,F	3,996.4 D,F	3,815.5 D,F	3,431.1 D,F	4,054.3 F	3,736.2 F	1,789.6	9.0	2.6	6.0	237	223	213	192	227
XEL	[] XCEL ENERGY INC	DEC	10,034.2 D,F	9,840.3 D,F	9,625.5 D,F	8,345.3 D,F	7,937.5 D,F	9,452.8 D,F	2,733.7 A	13.9	1.2	2.0	367	360	352	305	290
INDEPENDENT POWER PRODUCERS & ENERGY TRADERS‡																	
AES	[] AES CORP. (THE)	DEC	13,588.0 D	11,564.0 D	11,086.0	9,463.0	8,415.0 D	8,632.0 D	1,411.0 A	25.4	9.5	17.5	963	820	786	671	596
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	21,193.2 A,C	19,284.9 D,F	17,132.0 C,D	12,549.7 A,C	9,703.0 C,F	4,703.0 A,F	3,307.6 F	20.4	35.1	9.9	641	583	518	379	293
DYN	[] DYNEGY INC	DEC	3,072.0 A,C	2,017.0 A	2,313.0 A,C	6,153.0	5,817.0 D	5,516.0 C,D	13,378.4 A	(13.7)	(11.0)	52.3	23	15	17	46	43
OTHER ELECTRIC UTILITY COMPANIES																	
POR	PORTLAND GENERAL ELECTRIC CO	DEC	1,743.0	1,520.0	1,446.0	1,454.0	1,752.0 C	1,855.0	1,416.0	2.1	(1.2)	14.7	123	107	102	103	124

Note: Data as originally reported. CAGR-Compound annual growth rate. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
**Not calculated; data for base year or end year not available. A - This year's data reflect an acquisition or merger. B - This year's data reflect a major merger resulting in the formation of a new company. C - This year's data reflect an accounting change.
D - Data exclude discontinued operations. E - Includes excise taxes. F - Includes other (nonoperating) income. G - Includes sale of leased depts. H - Some or all data are not available, due to a fiscal year change.

Net Income

Ticker	Company	Yr. End	Million $ 2007	2006	2005	2004	2003	2002	1997	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (1997 = 100) 2007	2006	2005	2004	2003
ELECTRIC UTILITIES‡																	
AYE	[] ALLEGHENY ENERGY INC	DEC	412.9	319.9	79.2	134.8	(329.2)	(497.1)	290.6	3.6	NM	29.1	142	110	27	46	(113)
ALE	§ ALLETE INC	DEC	87.6	77.3	17.6	39.1	143.1	119.0	77.6	1.2	(5.9)	13.3	113	100	23	50	184
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	1,147.0	995.0	1,036.0	1,133.0	531.0	32.0	638.2	6.0	104.6	15.3	180	156	162	178	83
CV	§ CENTRAL VERMONT PUB SERV	DEC	15.8	18.1	1.4	11.4	18.4	19.8	17.2	(0.8)	(4.4)	(12.7)	92	106	8	67	107
CNL	§ CLECO CORP	DEC	151.8	74.7	183.0	66.1	(34.9)	71.9	52.5	11.2	16.1	103.3	289	142	348	126	(67)
DPL	† DPL INC	DEC	211.8	125.6	124.7	217.3	131.5	87.3	182.3	1.5	19.4	68.6	116	69	68	119	72
DUK	[] DUKE ENERGY CORP	DEC	1,522.0	2,019.0	2,533.0	1,232.0	(1,009.0)	1,034.0	974.4	4.6	8.0	(24.6)	156	207	260	126	(104)
EIX	[] EDISON INTERNATIONAL	DEC	1,151.0	1,134.0	1,132.0	232.0	789.0	1,154.0	742.5	4.5	(0.1)	1.5	155	153	152	31	106
EE	§ EL PASO ELECTRIC CO	DEC	74.8	61.4	36.6	33.4	20.3	31.1	54.6	3.2	19.2	21.8	137	112	67	61	37
ETR	[] ENTERGY CORP	DEC	1,160.0	1,160.9	968.6	933.0	813.4	623.1	300.9	14.4	13.2	(0.1)	385	386	322	310	270
EXC	[] EXELON CORP	DEC	2,726.0	1,590.0	955.0	1,844.0	793.0	1,670.0	336.6	23.3	10.3	71.4	810	472	284	548	236
FE	[] FIRSTENERGY CORP	DEC	1,309.0	1,265.0	888.0	895.2	464.4	708.2	333.6	14.6	13.1	3.5	392	379	266	268	139
FPL	[] FPL GROUP INC	DEC	1,312.0	1,281.0	885.0	887.0	906.0	710.0	637.0	7.5	13.1	2.4	206	201	139	139	142
GXP	† GREAT PLAINS ENERGY INC	DEC	159.2	127.6	164.2	173.5	153.6	129.2	76.6	7.6	4.3	24.7	208	167	214	227	201
HE	† HAWAIIAN ELECTRIC INDS	DEC	86.7	109.9	129.3	109.6	120.1	120.2	92.7	(0.7)	(6.3)	(21.1)	93	119	140	118	130
IDA	† IDACORP INC	DEC	82.3	100.1	63.7	77.8	50.0	66.3	92.3	(1.1)	4.4	(17.8)	89	108	69	84	54
NU	† NORTHEAST UTILITIES	DEC	251.5	131.7	(223.7)	122.1	126.7	157.7	(99.7)	NM	9.8	90.9	NM	NM	NM	NM	NM
NVE	† NV ENERGY INC	DEC	197.3	279.8	86.2	35.6	(129.4)	(302.1)	83.2	9.0	NM	(29.5)	237	336	104	43	(155)
POM	[] PEPCO HOLDINGS INC	DEC	334.5	249.5	364.7	261.5	107.6	210.5	181.8	6.3	9.7	34.1	184	137	201	144	59
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	298.8	317.1	223.2	235.2	230.6	215.2	248.7	1.9	6.8	(5.8)	120	128	90	95	93
PPL	[] PPL CORP	DEC	1,031.0	899.0	739.0	702.0	748.0	425.0	320.0	12.4	19.4	14.7	322	281	231	219	234
PGN	[] PROGRESS ENERGY INC	DEC	693.0	514.0	727.0	753.0	811.0	552.2	388.3	6.0	4.6	34.8	178	132	187	194	209
SO	[] SOUTHERN CO	DEC	1,782.0	1,608.0	1,621.0	1,562.0	1,495.0	1,335.0	1,015.0	5.8	5.9	10.8	176	158	160	154	147
UIL	§ UIL HOLDINGS CORP	DEC	46.7	58.6	31.4	36.9	29.5	43.9	45.8	0.2	1.2	(20.3)	102	128	68	81	65
UNS	§ UNISOURCE ENERGY CORP	DEC	58.4	69.2	46.8	45.9	46.5	33.3	83.6	(3.5)	11.9	(15.7)	70	83	56	55	56
WR	† WESTAR ENERGY INC	DEC	168.4	165.3	134.9	100.1	162.9	(166.0)	494.1	(10.2)	NM	1.8	34	33	27	20	33
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	443.4	357.0	75.1	229.5	176.6	82.4	64.6	21.2	40.0	24.2	687	553	116	355	274
AEE	[] AMEREN CORP	DEC	629.0	558.0	641.0	541.0	517.0	393.0	399.1	4.7	9.9	12.7	158	140	161	136	130
AVA	§ AVISTA CORP	DEC	38.5	73.1	45.2	35.6	50.6	34.3	114.8	(10.4)	2.3	(47.4)	34	64	39	31	44
BKH	† BLACK HILLS CORP	DEC	100.1	74.0	35.8	57.2	57.0	63.2	32.4	12.0	9.6	35.2	309	229	111	177	176
CNP	[] CENTERPOINT ENERGY INC	DEC	399.0	432.0	225.0	205.7	419.7	386.3	423.4	(0.6)	0.6	(7.6)	94	102	53	49	99
CHG	§ CH ENERGY GROUP INC	DEC	43.6	44.1	45.3	43.4	45.4	38.6	55.1	(2.3)	2.5	(1.0)	79	80	82	79	82
CMS	[] CMS ENERGY CORP	DEC	(124.0)	(80.0)	(93.0)	132.0	(40.0)	(414.0)	293.0	NM	NM	NM	(42)	(27)	(32)	45	(14)
ED	[] CONSOLIDATED EDISON INC	DEC	936.0	749.0	743.0	560.0	536.0	680.6	712.8	2.8	6.6	25.0	131	105	104	79	75
D	[] DOMINION RESOURCES INC	DEC	2,721.0	1,579.0	1,050.0	1,280.0	964.0	1,362.0	435.0	20.1	14.8	72.3	626	363	241	294	222
DTE	[] DTE ENERGY CO	DEC	787.0	437.0	576.0	443.0	480.0	632.0	429.0	6.3	4.5	80.1	183	102	134	103	112
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	181.1	151.6	162.1	156.2	110.6	112.5	56.9	12.3	10.0	19.5	319	267	285	275	195
MDU	† MDU RESOURCES GROUP INC	DEC	322.8	317.9	275.1	207.1	182.9	148.4	54.6	19.4	16.8	1.5	591	582	504	379	335
NI	[] NISOURCE INC	DEC	312.0	314.6	287.8	434.6	430.2	432.5	199.5	4.6	(6.3)	(0.8)	156	158	144	218	216
NST	† NSTAR	DEC	223.5	208.7	198.1	190.4	183.5	163.7	144.6	4.4	6.4	7.1	155	144	137	132	127
OGE	† OGE ENERGY CORP	DEC	244.2	226.1	166.1	153.0	135.6	81.0	132.6	6.3	24.7	8.0	184	171	125	115	102
PCG	[] PG&E CORP	DEC	1,006.0	991.0	904.0	3,820.0	791.0	(32.0)	749.0	3.0	NM	1.5	134	132	121	510	106
PNM	† PNM RESOURCES INC	DEC	59.9	121.3	71.0	88.3	59.1	64.3	81.0	(3.0)	(1.4)	(50.6)	74	150	88	109	73
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1,323.0	756.0	862.0	725.0	856.0	416.0	575.0	8.7	26.0	75.0	230	131	150	126	149
PSD	† PUGET ENERGY INC	DEC	184.7	167.2	146.3	55.0	121.5	117.9	125.7	3.9	9.4	10.4	147	133	116	44	97
SCG	[] SCANA CORP	DEC	327.0	311.0	327.0	264.0	289.0	95.0	230.0	3.6	28.0	5.1	142	135	142	115	126
SRE	[] SEMPRA ENERGY	DEC	1,135.0	1,101.0	939.0	930.0	705.0	586.0	191.0	19.5	14.1	3.1	594	576	492	487	369
TE	[] TECO ENERGY INC	DEC	398.9	244.4	211.0	(404.4)	(14.7)	298.2	211.9	6.5	6.0	63.2	188	115	100	(191)	(7)
VVC	† VECTREN CORP	DEC	143.1	108.8	136.8	107.9	111.2	114.0	20.5	21.4	4.7	31.5	698	531	667	526	542
WEC	[] WISCONSIN ENERGY CORP	DEC	336.5	312.5	303.6	122.2	245.5	168.2	61.9	18.4	14.9	7.7	543	505	490	197	396

Net Income

Ticker	Company	Yr. End	Million $ 2007	2006	2005	2004	2003	2002	1997	CAGR (%) 10-Yr.	5-Yr.	1-Yr.	Index Basis (1997 = 100) 2007	2006	2005	2004	2003
TE	[] TECO ENERGY INC	DEC	398.9	244.4	211.0	(404.4)	(14.7)	298.2	211.9	6.5	6.0	63.2	188	115	100	(191)	(7)
VVC	† VECTREN CORP	DEC	143.1	108.8	136.8	107.9	111.2	114.0	20.5	21.4	4.7	31.5	698	531	667	526	542
WEC	[] WISCONSIN ENERGY CORP	DEC	336.5	312.5	303.6	122.2	245.5	168.2	61.9	18.4	14.9	7.7	543	505	490	197	396
XEL	[] XCEL ENERGY INC	DEC	575.9	568.7	499.0	526.9	510.0	(1,661.4)	237.3	9.3	NM	1.3	243	240	210	222	215
INDEPENDENT POWER PRODUCERS & ENERGY TRADERS‡																	
AES	[] AES CORP. (THE)	DEC	495.0	135.0	632.0	258.0	336.0	(2,590.0)	188.0	10.2	NM	266.7	263	72	336	137	179
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	835.6	761.8	619.9	602.0	488.9	538.8	282.8	11.4	9.2	9.7	295	269	219	213	173
DYN	[] DYNEGY INC	DEC	116.0	(358.0)	(804.0)	(10.0)	(688.0)	(1,349.0)	(87.7)	NM	NM	NM	NM	NM	NM	NM	NM
OTHER ELECTRIC UTILITY COMPANIES																	
POR	PORTLAND GENERAL ELECTRIC CO	DEC	145.0	71.0	64.0	92.0	56.0	66.0	126.0	1.4	17.0	104.2	115	56	51	73	44

Note: Data as originally reported. CAGR-Compound annual growth rate. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600.
#Of the following calendar year. **Not calculated; data for base year or end year not available.

Ticker	Company	Yr. End	Return on Revenues (%) 2007	2006	2005	2004	2003	Return on Assets (%) 2007	2006	2005	2004	2003	Return on Equity (%) 2007	2006	2005	2004	2003
ELECTRIC UTILITIES‡																	
AYE	[] ALLEGHENY ENERGY INC	DEC	12.5	10.2	2.6	4.9	NM	4.5	3.7	0.9	1.4	NM	17.8	16.9	4.9	9.0	NM
ALE	§ ALLETE INC	DEC	10.4	10.1	2.4	5.2	9.0	5.5	5.3	1.2	1.7	4.6	12.4	12.2	2.9	3.7	10.6
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	8.6	7.9	8.6	8.1	3.7	2.9	2.7	2.9	3.2	1.5	11.7	10.7	11.7	13.8	7.0
CV	§ CENTRAL VERMONT PUB SERV	DEC	4.8	5.6	0.5	3.8	6.0	3.0	3.4	0.2	2.0	3.2	8.4	8.9	0.5	5.1	8.4
CNL	§ CLECO CORP	DEC	14.7	7.5	19.9	8.9	NM	5.9	3.2	9.1	3.1	NM	16.0	9.3	29.5	12.3	NM
DPL	† DPL INC	DEC	14.0	9.0	9.7	18.1	11.0	5.9	3.4	3.1	5.0	3.1	26.7	14.4	12.0	22.3	15.2
DUK	[] DUKE ENERGY CORP	DEC	12.0	13.3	15.1	5.5	NM	2.6	3.3	4.6	2.2	NM	6.4	9.5	15.3	8.1	NM
EIX	[] EDISON INTERNATIONAL	DEC	8.8	9.0	9.6	2.3	6.5	3.0	3.0	3.3	0.7	2.3	13.6	15.1	17.5	4.0	15.9
EE	§ EL PASO ELECTRIC CO	DEC	8.5	7.5	4.6	4.7	3.1	4.2	3.6	2.3	2.1	1.3	12.0	10.8	6.7	6.5	4.3
ETR	[] ENTERGY CORP	DEC	10.1	10.6	9.6	9.2	8.8	3.5	3.7	3.2	3.2	2.8	14.1	14.2	11.8	10.7	9.5
EXC	[] EXELON CORP	DEC	14.6	10.2	6.2	12.7	5.0	6.0	3.7	2.2	4.3	2.0	27.1	16.7	10.3	20.5	9.8
FE	[] FIRSTENERGY CORP	DEC	10.2	11.0	7.4	7.2	3.8	4.1	4.0	2.8	2.7	1.3	14.5	13.8	9.8	10.4	5.5
FPL	[] FPL GROUP INC	DEC	8.6	8.2	7.5	8.4	9.4	3.4	3.7	2.9	3.2	3.8	12.7	13.9	11.0	12.2	13.4
GXP	† GREAT PLAINS ENERGY INC	DEC	4.9	4.8	6.3	7.0	7.1	3.4	3.1	4.3	4.6	4.2	10.8	9.8	13.7	16.4	16.0
HE	† HAWAIIAN ELECTRIC INDS	DEC	3.4	4.5	5.8	5.7	6.7	0.9	1.1	1.3	1.2	1.3	7.2	9.3	10.5	9.4	11.1
IDA	† IDACORP INC	DEC	9.4	10.8	7.4	9.2	6.1	2.3	2.9	1.9	2.3	1.5	7.1	9.3	6.3	7.8	5.4
NU	† NORTHEAST UTILITIES	DEC	4.3	1.9	NM	1.8	2.1	2.1	1.1	NM	1.0	1.1	8.6	4.8	NM	5.1	5.4
NVE	† NV ENERGY INC	DEC	5.5	8.3	2.8	1.3	NM	2.2	3.3	1.1	0.4	NM	7.0	11.9	4.6	2.2	NM
POM	[] PEPCO HOLDINGS INC	DEC	3.6	3.0	4.5	3.6	1.5	2.3	1.8	2.6	1.9	0.8	8.8	6.9	10.4	8.1	3.6
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	8.5	9.3	7.5	8.1	8.2	2.6	2.8	2.1	2.4	2.6	8.6	9.2	7.0	8.1	8.4
PPL	[] PPL CORP	DEC	15.9	13.0	11.9	12.1	13.4	5.1	4.7	4.1	4.0	4.4	19.0	18.6	17.0	18.7	26.2
PGN	[] PROGRESS ENERGY INC	DEC	7.6	5.4	7.2	7.7	9.3	2.7	1.9	2.7	2.9	3.4	8.3	6.3	9.3	10.0	11.5
SO	[] SOUTHERN CO	DEC	11.6	11.2	12.0	13.1	13.5	3.9	3.8	4.1	4.3	4.4	14.6	14.3	15.2	15.4	16.1
UIL	§ UIL HOLDINGS CORP	DEC	4.8	6.9	2.6	3.4	3.1	2.7	3.4	1.7	2.0	1.6	10.1	11.7	5.7	7.1	6.1
UNS	§ UNISOURCE ENERGY CORP	DEC	4.2	5.3	3.8	3.9	4.8	1.8	2.2	1.5	1.5	1.6	8.7	10.9	7.8	8.1	9.3
WR	† WESTAR ENERGY INC	DEC	9.7	10.3	8.5	6.8	11.1	2.8	3.1	2.6	1.8	2.7	9.9	11.1	9.6	8.2	16.4
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	12.9	10.6	2.3	7.8	5.6	6.0	4.6	0.7	2.6	2.2	15.9	13.3	2.3	8.5	7.6
AEE	[] AMEREN CORP	DEC	8.3	8.1	9.5	10.5	11.3	3.1	2.9	3.5	3.3	3.9	9.3	8.4	10.3	10.4	12.3
AVA	§ AVISTA CORP	DEC	2.7	4.9	3.3	3.1	4.5	1.1	1.6	1.0	1.0	1.4	4.2	8.7	5.9	4.7	6.8
BKH	† BLACK HILLS CORP	DEC	14.4	11.3	2.6	5.1	5.0	4.2	3.4	1.7	2.8	2.8	11.4	9.7	4.9	8.0	9.2
CNP	[] CENTERPOINT ENERGY INC	DEC	4.1	4.6	2.3	2.4	4.3	2.2	2.5	1.3	1.0	2.0	23.7	30.3	18.7	14.4	26.4
CHG	§ CH ENERGY GROUP INC	DEC	3.6	4.4	4.7	5.5	5.6	2.9	3.0	3.3	3.3	3.5	8.2	8.5	8.9	8.7	9.0
CMS	[] CMS ENERGY CORP	DEC	NM	NM	NM	2.4	NM	NM	NM	NM	0.8	NM	NM	NM	NM	6.3	NM
ED	[] CONSOLIDATED EDISON INC	DEC	7.1	6.2	6.4	5.7	5.5	3.4	2.9	3.1	2.5	2.6	10.8	9.6	10.2	8.1	8.5
D	[] DOMINION RESOURCES INC	DEC	17.4	9.6	5.8	9.2	8.0	6.1	3.1	2.1	2.8	2.3	24.2	13.4	9.5	11.5	9.1
DTE	[] DTE ENERGY CO	DEC	9.3	4.8	6.4	6.2	6.8	3.3	1.9	2.6	2.1	2.4	13.5	7.5	10.2	8.2	9.7
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	1.8	2.2	2.3	3.2	2.6	2.0	2.4	3.2	3.5	2.9	7.5	10.5	13.3	14.6	12.0
MDU	† MDU RESOURCES GROUP INC	DEC	7.6	7.8	8.0	7.6	7.8	6.1	6.8	6.7	5.8	5.8	13.8	15.8	15.5	13.3	13.4
NI	[] NISOURCE INC	DEC	3.9	4.2	3.6	6.5	6.9	1.7	1.7	1.6	2.6	2.5	6.2	6.3	5.8	9.3	9.9
NST	† NSTAR	DEC	6.9	5.8	6.1	6.4	6.3	2.9	2.7	2.7	2.8	2.9	13.5	13.3	13.2	13.5	13.6
OGE	† OGE ENERGY CORP	DEC	6.4	5.6	2.8	3.1	3.6	4.8	4.6	3.4	3.2	3.1	14.9	15.2	12.5	12.3	12.4
PCG	[] PG&E CORP	DEC	7.6	7.9	7.7	34.5	7.6	2.8	2.9	2.6	11.8	2.5	12.3	13.2	11.4	59.5	20.2
PNM	† PNM RESOURCES INC	DEC	3.1	4.9	3.4	5.5	4.1	1.0	2.1	1.6	2.6	1.8	3.5	8.1	5.7	8.1	5.7
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	10.3	6.2	6.9	6.6	7.7	4.6	2.6	2.9	2.5	3.2	18.8	11.8	14.6	12.8	17.9
PSD	† PUGET ENERGY INC	DEC	5.7	5.8	5.7	2.1	4.9	2.5	2.4	2.4	1.0	2.1	8.0	8.1	8.0	3.4	7.3
SCG	[] SCANA CORP	DEC	7.1	6.8	6.8	6.8	8.5	3.2	3.1	3.5	2.9	3.5	11.0	11.0	12.5	10.8	12.6
SRE	[] SEMPRA ENERGY	DEC	9.9	9.4	8.0	9.9	8.9	3.8	3.8	3.5	4.0	3.5	14.2	16.0	16.9	21.0	20.7
TE	[] TECO ENERGY INC	DEC	11.3	7.1	7.0	NM	NM	5.6	3.4	2.5	NM	NM	21.3	14.7	14.7	NM	NM
VVC	† VECTREN CORP	DEC	6.3	5.3	6.7	6.4	7.0	3.4	2.7	3.7	3.1	3.5	11.9	9.4	12.2	10.0	11.5

Ticker	Company	Yr. End	Return on Revenues (%) 2007	2006	2005	2004	2003	Return on Assets (%) 2007	2006	2005	2004	2003	Return on Equity (%) 2007	2006	2005	2004	2003
WEC	[] WISCONSIN ENERGY CORP	DEC	7.9	7.8	8.0	3.6	6.1	2.9	2.9	3.0	1.2	2.7	11.2	11.2	11.7	5.0	10.9
XEL	[] XCEL ENERGY INC	DEC	5.7	5.8	5.2	6.3	6.4	2.5	2.6	2.4	2.6	2.1	9.4	10.1	9.3	10.1	10.3
INDEPENDENT POWER PRODUCERS & ENERGY TRADERS‡																	
AES	[] AES CORP. (THE)	DEC	3.6	1.2	5.7	2.7	4.0	1.5	0.4	2.2	0.9	1.1	16.2	5.9	48.2	31.9	221.1
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	3.9	4.0	3.6	4.8	5.0	3.8	3.5	3.1	3.6	3.2	16.5	15.7	12.6	13.3	11.9
DYN	[] DYNEGY INC	DEC	3.8	NM	NM	NM	NM	1.1	NM	NM	NM	2.0	3.4	NM	NM	NM	16.1
OTHER ELECTRIC UTILITY COMPANIES																	
POR	PORTLAND GENERAL ELECTRIC CO	DEC	8.3	4.7	4.4	6.3	3.2	3.7	1.9	1.8	2.7	1.7	11.4	5.9	5.2	7.5	4.8

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Ticker	Company	Yr. End	Current Ratio 2007	2006	2005	2004	2003	Debt / Capital Ratio (%) 2007	2006	2005	2004	2003	Net Inc. as % of Oper. Revs. 2007	2006	2005	2004	2003
ELECTRIC UTILITIES‡																	
AYE	[] ALLEGHENY ENERGY INC	DEC	1.7	1.1	0.9	1.3	1.2	50.1	52.2	59.2	67.8	66.9	12.5	10.2	2.6	4.9	-13.3
ALE	§ ALLETE INC	DEC	1.6	2.0	3.1	3.4	1.3	35.3	34.8	38.9	38.2	33.9	10.4	10.1	2.4	5.2	9.0
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	0.6	0.7	0.7	0.8	0.8	48.8	46.6	44.0	44.8	50.4	8.6	7.9	8.6	8.1	3.7
CV	§ CENTRAL VERMONT PUB SERV	DEC	0.6	1.3	2.4	2.5	2.3	33.5	35.1	31.8	32.6	33.7	4.8	5.6	0.5	3.8	6.0
CNL	§ CLECO CORP	DEC	1.1	1.4	1.5	0.9	0.7	35.6	31.5	34.2	32.2	51.8	14.7	7.5	19.9	8.9	-4.0
DPL	† DPL INC	DEC	1.4	1.1	2.9	1.6	0.7	54.0	57.8	53.9	58.5	59.1	14.0	9.0	9.7	18.1	11.0
DUK	[] DUKE ENERGY CORP	DEC	0.9	1.0	0.9	1.1	1.0	26.5	34.7	39.2	41.9	50.9	12.0	13.3	15.1	5.5	-4.6
EIX	[] EDISON INTERNATIONAL	DEC	1.0	1.3	1.2	1.3	0.8	37.6	38.9	40.4	45.3	49.9	8.8	9.0	9.6	2.3	6.5
EE	§ EL PASO ELECTRIC CO	DEC	1.6	1.9	1.9	0.6	2.0	43.5	45.8	47.3	37.1	48.7	8.5	7.5	4.6	4.7	3.1
ETR	[] ENTERGY CORP	DEC	1.2	1.3	1.3	1.3	1.3	40.0	37.9	39.4	33.7	34.5	10.1	10.6	9.6	9.2	8.8
EXC	[] EXELON CORP	DEC	0.8	0.9	0.7	0.8	0.8	43.9	54.2	45.1	45.9	50.5	14.6	10.2	6.2	12.7	5.0
FE	[] FIRSTENERGY CORP	DEC	0.4	0.4	0.4	0.6	0.5	49.7	48.6	46.5	52.9	53.2	10.2	11.0	7.4	7.2	3.8
FPL	[] FPL GROUP INC	DEC	0.7	0.8	0.7	0.6	0.7	51.2	49.1	48.6	51.6	55.6	8.6	8.2	7.5	8.4	9.4
GXP	† GREAT PLAINS ENERGY INC	DEC	0.7	0.5	1.2	0.7	0.8	32.8	23.0	37.4	34.1	41.5	4.9	4.8	6.3	7.0	7.1
HE	† HAWAIIAN ELECTRIC INDS	DEC	NA	NA	NA	NA	NA	69.6	70.4	58.5	59.6	65.7	3.4	4.5	5.8	5.7	6.7
IDA	† IDACORP INC	DEC	0.7	0.6	1.0	0.8	0.8	48.9	45.2	50.0	49.3	50.8	9.4	10.8	7.4	9.2	6.1
NU	† NORTHEAST UTILITIES	DEC	1.1	1.3	1.2	1.1	1.2	51.6	50.6	52.6	52.4	52.8	4.3	1.9	-3.0	1.8	2.1
NVE	† NV ENERGY INC	DEC	1.2	1.6	1.5	1.4	1.0	51.6	53.7	59.5	66.0	66.5	5.5	8.3	2.8	1.3	-4.6
POM	[] PEPCO HOLDINGS INC	DEC	1.0	0.8	0.9	0.9	0.8	43.4	43.1	46.3	48.2	52.3	3.6	3.0	4.5	3.6	1.5
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	0.7	1.0	0.8	0.7	0.8	47.0	48.4	43.2	46.7	50.6	8.5	9.3	7.5	8.1	8.2
PPL	[] PPL CORP	DEC	1.1	1.1	0.9	1.0	1.2	54.0	55.1	57.2	61.3	70.8	15.9	13.0	11.9	12.1	13.4
PGN	[] PROGRESS ENERGY INC	DEC	0.9	1.3	1.3	0.9	1.1	49.7	50.0	54.8	52.7	54.0	7.6	5.4	7.2	7.7	9.3
SO	[] SOUTHERN CO	DEC	0.8	0.6	0.8	0.9	0.8	41.7	40.2	42.3	42.8	44.2	11.6	11.2	12.0	13.1	13.5
UIL	§ UIL HOLDINGS CORP	DEC	0.9	1.3	1.4	1.3	1.0	38.0	34.0	35.4	35.3	37.6	4.8	6.9	2.6	3.4	3.1
UNS	§ UNISOURCE ENERGY CORP	DEC	0.8	1.2	1.3	1.4	1.4	64.5	69.3	72.5	74.2	75.8	4.2	5.3	3.8	3.9	4.8
WR	† WESTAR ENERGY INC	DEC	0.9	0.8	0.9	1.0	1.1	41.8	38.2	39.3	40.5	66.6	9.7	10.3	8.5	6.8	11.1
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	1.6	1.1	1.1	1.2	1.0	32.4	31.3	37.0	38.5	38.3	12.9	10.6	2.3	7.8	5.6
AEE	[] AMEREN CORP	DEC	0.9	0.9	1.2	0.9	0.9	38.5	36.9	38.3	38.6	38.4	8.3	8.1	9.5	10.5	11.3
AVA	§ AVISTA CORP	DEC	0.4	1.1	1.0	1.0	1.0	41.0	53.7	59.4	58.1	58.7	2.7	4.9	3.3	3.1	4.5
BKH	† BLACK HILLS CORP	DEC	0.9	0.9	1.2	1.3	1.7	36.7	44.1	47.4	49.8	54.9	14.4	11.3	2.6	5.1	5.0
CNP	[] CENTERPOINT ENERGY INC	DEC	0.7	0.7	1.0	0.5	0.9	67.2	66.6	69.2	66.8	67.6	4.1	4.6	2.3	2.4	4.3
CHG	§ CH ENERGY GROUP INC	DEC	1.5	1.4	2.2	2.6	2.1	42.5	38.7	39.6	38.3	35.5	3.6	4.4	4.7	5.5	5.6
CMS	[] CMS ENERGY CORP	DEC	1.2	1.5	1.8	1.7	1.5	69.5	69.5	68.7	65.3	71.7	-1.9	-1.2	-1.5	2.4	-0.7
ED	[] CONSOLIDATED EDISON INC	DEC	0.7	1.0	0.9	0.8	0.8	35.6	40.3	39.7	37.4	40.7	7.1	6.2	6.4	5.7	5.5
D	[] DOMINION RESOURCES INC	DEC	0.9	0.7	0.7	0.9	0.8	57.7	43.7	48.4	47.4	50.7	17.4	9.6	5.8	9.2	8.0
DTE	[] DTE ENERGY CO	DEC	0.9	1.0	1.0	1.0	0.9	47.1	50.0	48.9	52.3	53.8	9.3	4.8	6.4	6.2	6.8
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	1.1	1.0	1.1	1.1	1.2	37.2	43.1	37.8	41.4	43.1	1.8	2.2	2.3	3.2	2.6
MDU	† MDU RESOURCES GROUP INC	DEC	1.4	1.5	1.5	1.6	2.0	31.2	35.1	36.9	34.2	39.3	7.6	7.8	8.0	7.6	7.8
NI	[] NISOURCE INC	DEC	0.7	0.7	0.8	0.6	0.8	45.5	43.7	44.1	42.2	49.2	3.9	4.2	3.6	6.5	6.9
NST	† NSTAR	DEC	0.9	0.8	0.9	0.8	0.5	46.5	45.2	60.4	58.6	58.5	6.9	5.8	6.1	6.4	6.3
OGE	† OGE ENERGY CORP	DEC	0.6	1.0	1.1	1.0	1.2	34.5	35.1	37.9	40.1	41.9	6.4	5.6	2.8	3.1	3.6
PCG	[] PG&E CORP	DEC	0.8	0.7	0.9	0.9	2.3	44.9	44.0	47.2	39.0	44.1	7.6	7.9	7.7	34.5	7.6
PNM	† PNM RESOURCES INC	DEC	0.4	0.5	0.8	1.0	0.9	34.6	43.1	49.5	40.8	41.7	3.1	4.9	3.4	5.5	4.1
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	1.1	1.1	1.0	1.0	1.1	54.0	60.3	64.9	69.0	69.8	10.3	6.2	6.9	6.6	7.7
PSD	† PUGET ENERGY INC	DEC	0.8	0.8	1.2	1.1	0.7	51.5	55.5	54.4	60.5	57.4	5.7	5.8	5.7	2.1	4.9
SCG	[] SCANA CORP	DEC	0.8	1.0	1.0	1.0	0.9	41.1	43.2	43.4	47.2	49.2	7.1	6.8	6.8	6.8	8.5
SRE	[] SEMPRA ENERGY	DEC	1.1	1.2	1.1	1.0	0.9	33.5	36.5	42.8	44.0	46.8	9.9	9.4	8.0	9.9	8.9
TE	[] TECO ENERGY INC	DEC	1.3	1.0	1.4	0.3	0.4	61.0	65.0	70.0	68.2	66.6	11.3	7.1	7.0	-15.2	-0.5

Ticker	Company	Yr. End	Current Ratio 2007	2006	2005	2004	2003	Debt / Capital Ratio (%) 2007	2006	2005	2004	2003	Net Inc. as % of Oper. Revs. 2007	2006	2005	2004	2003
VVC	† VECTREN CORP	DEC	0.7	0.7	0.9	0.7	0.9	44.4	45.5	51.2	48.1	50.0	6.3	5.3	6.7	6.4	7.0
WEC	[] WISCONSIN ENERGY CORP	DEC	0.7	0.7	0.8	1.2	1.0	46.0	46.4	47.4	51.0	53.5	7.9	7.8	8.0	3.6	6.1
XEL	[] XCEL ENERGY INC	DEC	0.8	0.9	0.9	1.1	1.2	41.1	43.7	43.0	46.3	46.7	5.7	5.8	5.2	6.3	6.4
INDEPENDENT POWER PRODUCERS & ENERGY TRADERS‡																	
AES	[] AES CORP. (THE)	DEC	1.5	1.3	1.0	1.0	0.8	68.7	68.5	80.0	85.2	87.0	3.6	1.2	5.7	2.7	4.0
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	1.3	1.3	1.3	1.2	1.3	39.3	39.8	40.7	43.0	46.0	3.9	4.0	3.6	4.8	5.0
DYN	[] DYNEGY INC	DEC	1.7	1.7	1.8	1.5	1.2	50.7	53.8	57.7	59.3	66.4	3.8	-17.7	-34.8	-0.2	-11.8
OTHER ELECTRIC UTILITY COMPANIES																	
POR	PORTLAND GENERAL ELECTRIC CO	DEC	1.4	0.9	1.3	2.0	1.5	49.9	38.7	38.2	35.9	37.4	8.3	4.7	4.4	6.3	3.2

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Exhibit PPL/209
Hadaway/39

Ticker	Company	Yr. End	P/E 2007	P/E 2006	P/E 2005	P/E 2004	P/E 2003	Payout 2007	Payout 2006	Payout 2005	Payout 2004	Payout 2003	Yield 2007	Yield 2006	Yield 2005	Yield 2004	Yield 2003
			Price / Earnings Ratio (High-Low)					Dividend Payout Ratio (%)					Dividend Yield (High-Low, %)				
Ticker	Company	Yr. End	2007	2006	2005	2004	2003	2007	2006	2005	2004	2003	2007	2006	2005	2004	2003
ELECTRIC UTILITIES‡																	
AYE	[] ALLEGHENY ENERGY INC	DEC	26 - 18	24 - 16	67 - 38	20 - 12	NM - NM	6	0	0	0	NM	0.3 - 0.2	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
ALE	§ ALLETE INC	DEC	17 - 12	18 - 15	80 - 55	79 - 22	18 - 11	53	52	192	204	66	4.3 - 3.2	3.4 - 2.9	3.5 - 2.4	9.2 - 2.6	6.0 - 3.6
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	18 - 15	17 - 13	15 - 12	12 - 10	23 - 14	55	60	54	49	122	3.8 - 3.1	4.6 - 3.5	4.4 - 3.5	4.9 - 3.9	8.7 - 5.2
CV	§ CENTRAL VERMONT PUB SERV	DEC	27 - 15	14 - 10	NM - NM	26 - 20	17 - 11	61	56	NM	101	61	4.1 - 2.2	5.7 - 3.8	6.0 - 3.9	5.0 - 3.8	5.3 - 3.6
CNL	§ CLECO CORP	DEC	12 - 9	19 - 15	7 - 5	16 - 12	NM - NM	35	66	25	68	NM	4.1 - 3.0	4.3 - 3.4	4.8 - 3.7	5.6 - 4.3	8.2 - 4.9
DPL	† DPL INC	DEC	17 - 13	26 - 22	28 - 23	14 - 9	19 - 10	53	89	93	53	85	4.1 - 3.2	4.0 - 3.5	4.0 - 3.4	5.8 - 3.8	8.4 - 4.4
DUK	[] DUKE ENERGY CORP	DEC	18 - 14	20 - 16	11 - 9	20 - 14	NM - NM	71	73	43	84	NM	5.1 - 4.0	4.7 - 3.7	4.8 - 3.8	5.8 - 4.2	9.0 - 5.1
EIX	[] EDISON INTERNATIONAL	DEC	18 - 13	14 - 11	15 - 9	47 - 31	9 - 4	35	33	30	152	0	2.7 - 1.9	2.9 - 2.3	3.4 - 2.1	4.9 - 3.2	0.0 - 0.0
EE	§ EL PASO ELECTRIC CO	DEC	17 - 13	19 - 14	29 - 23	27 - 19	32 - 24	0	0	0	0	0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
ETR	[] ENTERGY CORP	DEC	22 - 16	17 - 12	18 - 14	17 - 13	16 - 12	45	40	48	47	46	2.9 - 2.1	3.2 - 2.3	3.3 - 2.7	3.7 - 2.8	3.8 - 2.8
EXC	[] EXELON CORP	DEC	21 - 14	27 - 22	40 - 29	16 - 11	27 - 19	43	68	113	45	79	3.0 - 2.0	3.1 - 2.5	3.8 - 2.8	4.1 - 2.8	4.2 - 2.9
FE	[] FIRSTENERGY CORP	DEC	18 - 14	16 - 12	20 - 14	16 - 13	28 - 19	47	47	63	56	108	3.5 - 2.7	3.8 - 2.9	4.4 - 3.1	4.3 - 3.5	5.8 - 3.9
FPL	[] FPL GROUP INC	DEC	22 - 16	17 - 12	21 - 15	15 - 12	14 - 11	50	46	61	53	48	3.1 - 2.3	4.0 - 2.7	4.0 - 3.0	4.3 - 3.4	4.5 - 3.5
GXP	† GREAT PLAINS ENERGY INC	DEC	18 - 14	20 - 17	15 - 12	15 - 12	15 - 10	89	102	76	69	75	6.2 - 5.0	6.1 - 5.1	6.1 - 5.1	6.0 - 4.7	7.8 - 5.1
HE	† HAWAIIAN ELECTRIC INDS	DEC	27 - 20	22 - 19	19 - 16	22 - 17	15 - 12	120	93	78	91	78	6.1 - 4.5	4.8 - 4.3	5.0 - 4.2	5.4 - 4.2	6.5 - 5.2
IDA	† IDACORP INC	DEC	21 - 16	17 - 12	21 - 17	17 - 13	25 - 17	65	51	79	63	139	4.0 - 3.1	4.1 - 3.0	4.6 - 3.7	4.7 - 3.6	8.2 - 5.6
NU	† NORTHEAST UTILITIES	DEC	21 - 16	35 - 23	NM - NM	22 - 19	21 - 14	49	88	NM	69	61	3.0 - 2.3	3.8 - 2.5	3.9 - 3.1	3.6 - 3.1	4.4 - 2.8
NVE	† NV ENERGY INC	DEC	22 - 16	13 - 10	35 - 20	62 - 38	NM - NM	18	0	0	0	NM	1.1 - 0.8	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
POM	[] PEPCO HOLDINGS INC	DEC	18 - 14	21 - 17	13 - 11	15 - 12	33 - 26	60	80	52	68	159	4.3 - 3.4	4.8 - 3.9	4.9 - 4.1	5.9 - 4.6	6.2 - 4.9
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	17 - 12	16 - 12	20 - 17	18 - 14	16 - 11	70	63	83	71	68	5.7 - 4.1	5.3 - 4.0	4.8 - 4.1	5.0 - 4.0	6.1 - 4.3
PPL	[] PPL CORP	DEC	21 - 13	16 - 12	17 - 13	14 - 10	11 - 8	46	47	49	43	37	3.5 - 2.2	4.0 - 2.9	3.8 - 2.9	4.1 - 3.0	4.9 - 3.5
PGN	[] PROGRESS ENERGY INC	DEC	19 - 16	24 - 20	16 - 14	15 - 13	14 - 11	90	118	80	74	65	5.7 - 4.6	6.0 - 4.9	5.9 - 5.1	5.7 - 4.8	6.0 - 4.7
SO	[] SOUTHERN CO	DEC	17 - 14	18 - 14	17 - 15	16 - 13	16 - 13	70	72	69	68	68	4.8 - 4.1	5.0 - 4.1	4.7 - 4.0	5.2 - 4.2	5.1 - 4.3
UIL	§ UIL HOLDINGS CORP	DEC	23 - 14	18 - 11	26 - 21	21 - 16	22 - 15	92	72	133	112	139	6.4 - 4.0	6.3 - 3.9	6.3 - 5.1	6.9 - 5.3	9.4 - 6.3
UNS	§ UNISOURCE ENERGY CORP	DEC	24 - 17	19 - 15	26 - 18	19 - 17	18 - 12	55	43	56	48	43	3.3 - 2.2	2.9 - 2.2	3.1 - 2.2	2.8 - 2.6	3.8 - 2.4
WR	† WESTAR ENERGY INC	DEC	15 - 12	14 - 11	16 - 14	19 - 15	9 - 4	58	53	60	67	34	4.7 - 3.8	5.0 - 3.7	4.4 - 3.7	4.4 - 3.5	7.8 - 3.7
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	12 - 9	14 - 10	64 - 53	15 - 13	16 - 10	34	40	219	54	64	3.6 - 2.7	4.1 - 2.9	4.1 - 3.4	4.3 - 3.5	6.7 - 4.0
AEE	[] AMEREN CORP	DEC	18 - 16	21 - 18	18 - 15	18 - 14	15 - 12	85	95	81	89	81	5.4 - 4.6	5.3 - 4.6	5.3 - 4.5	6.3 - 5.0	6.8 - 5.5
AVA	§ AVISTA CORP	DEC	35 - 25	18 - 12	22 - 18	26 - 21	18 - 10	82	38	59	70	48	3.3 - 2.3	3.2 - 2.1	3.3 - 2.7	3.4 - 2.7	5.0 - 2.6
BKH	† BLACK HILLS CORP	DEC	17 - 13	17 - 15	41 - 27	18 - 15	18 - 12	51	59	117	70	65	3.9 - 3.0	4.1 - 3.5	4.4 - 2.9	4.7 - 3.8	5.5 - 3.6
CNP	[] CENTERPOINT ENERGY INC	DEC	16 - 12	12 - 8	21 - 15	18 - 14	8 - 3	54	43	56	60	29	4.6 - 3.4	5.2 - 3.6	3.8 - 2.6	4.1 - 3.2	9.2 - 3.8
CHG	§ CH ENERGY GROUP INC	DEC	20 - 15	20 - 16	18 - 15	18 - 16	18 - 14	80	79	77	80	78	5.2 - 4.0	4.8 - 3.9	5.1 - 4.3	5.0 - 4.4	5.4 - 4.3
CMS	[] CMS ENERGY CORP	DEC	NM - NM	NM - NM	NM - NM	16 - 11	NM - NM	NM	NM	NM	0	NM	1.3 - 1.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
ED	[] CONSOLIDATED EDISON INC	DEC	15 - 12	17 - 14	16 - 14	20 - 16	19 - 15	67	78	76	97	95	5.4 - 4.4	5.6 - 4.7	5.5 - 4.6	6.1 - 5.0	6.1 - 4.9
D	[] DOMINION RESOURCES INC	DEC	12 - 10	19 - 15	29 - 22	18 - 16	22 - 17	35	62	89	68	86	3.7 - 3.0	4.0 - 3.3	4.0 - 3.1	4.3 - 3.8	5.0 - 3.9
DTE	[] DTE ENERGY CO	DEC	12 - 9	20 - 16	15 - 13	18 - 15	17 - 12	46	84	63	80	72	4.8 - 3.9	5.4 - 4.2	5.0 - 4.3	5.4 - 4.5	6.1 - 4.2
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	24 - 19	16 - 14	14 - 11	12 - 11	14 - 11	101	65	54	54	66	5.2 - 4.1	4.8 - 3.9	4.7 - 3.7	5.1 - 4.4	5.9 - 4.6
MDU	† MDU RESOURCES GROUP INC	DEC	18 - 14	15 - 12	16 - 11	16 - 12	15 - 10	32	30	32	40	40	2.3 - 1.8	2.4 - 1.9	2.9 - 2.0	3.2 - 2.5	4.0 - 2.7
NI	[] NISOURCE INC	DEC	22 - 15	22 - 17	24 - 19	14 - 12	13 - 10	81	80	88	56	67	5.3 - 3.6	4.7 - 3.7	4.5 - 3.6	4.7 - 4.0	6.7 - 5.0
NST	† NSTAR	DEC	18 - 15	19 - 14	17 - 14	15 - 13	14 - 11	63	62	63	63	63	4.2 - 3.5	4.6 - 3.4	4.7 - 3.7	4.9 - 4.1	5.6 - 4.4
OGE	† OGE ENERGY CORP	DEC	16 - 11	16 - 11	17 - 13	16 - 13	15 - 10	51	54	72	77	80	4.7 - 3.3	5.0 - 3.3	5.4 - 4.3	5.8 - 4.9	8.3 - 5.5
PCG	[] PG&E CORP	DEC	18 - 15	17 - 13	17 - 13	4 - 3	14 - 6	50	46	51	0	0	3.4 - 2.8	3.6 - 2.7	3.9 - 3.1	0.0 - 0.0	0.0 - 0.0
PNM	† PNM RESOURCES INC	DEC	45 - 27	19 - 13	30 - 23	18 - 13	20 - 13	118	50	75	44	62	4.3 - 2.7	3.8 - 2.7	3.2 - 2.5	3.4 - 2.4	4.8 - 3.1
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	19 - 12	24 - 20	19 - 14	17 - 13	12 - 9	45	76	63	72	58	3.6 - 2.3	3.9 - 3.1	4.5 - 3.3	5.8 - 4.2	6.7 - 4.9
PSD	† PUGET ENERGY INC	DEC	18 - 14	18 - 14	17 - 14	45 - 37	20 - 15	64	69	70	182	81	4.5 - 3.5	5.0 - 3.9	4.9 - 4.1	4.9 - 4.0	5.5 - 4.1
SCG	[] SCANA CORP	DEC	17 - 12	16 - 14	16 - 13	17 - 14	14 - 11	64	64	56	63	54	5.3 - 3.9	4.6 - 4.0	4.3 - 3.6	4.4 - 3.7	4.9 - 3.9
SRE	[] SEMPRA ENERGY	DEC	15 - 12	13 - 10	13 - 9	9 - 7	9 - 7	29	28	31	25	30	2.4 - 1.9	2.8 - 2.1	3.3 - 2.4	3.4 - 2.6	4.5 - 3.2
TE	[] TECO ENERGY INC	DEC	10 - 8	15 - 12	19 - 15	NM - NM	NM - NM	41	64	75	NM	NM	5.2 - 4.2	5.3 - 4.3	5.1 - 3.9	6.7 - 4.9	9.8 - 5.4
VVC	† VECTREN CORP	DEC	16 - 13	20 - 18	16 - 14	19 - 16	17 - 12	67	85	66	80	70	5.1 - 4.2	4.9 - 4.2	4.8 - 4.0	5.0 - 4.2	5.6 - 4.2

Ticker	Company	Yr. End	Price / Earnings Ratio (High-Low) 2007	2006	2005	2004	2003	Dividend Payout Ratio (%) 2007	2006	2005	2004	2003	Dividend Yield (High-Low, %) 2007	2006	2005	2004	2003
WEC	[] WISCONSIN ENERGY CORP	DEC	18 - 14	18 - 14	16 - 13	33 - 28	16 - 11	35	34	34	80	38	2.4 - 2.0	2.4 - 1.9	2.6 - 2.2	2.8 - 2.4	3.5 - 2.4
XEL	[] XCEL ENERGY INC	DEC	18 - 14	17 - 13	16 - 13	14 - 12	14 - 8	66	63	69	62	59	4.7 - 3.6	5.0 - 3.7	5.2 - 4.2	5.2 - 4.3	7.2 - 4.3
INDEPENDENT POWER PRODUCERS & ENERGY TRADERS‡																	
AES	[] AES CORP. (THE)	DEC	33 - 23	NM - 74	19 - 13	34 - 19	17 - 5	0	0	0	0	0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	23 - 15	17 - 12	18 - 13	13 - 10	14 - 9	38	36	39	33	36	2.5 - 1.7	3.0 - 2.2	3.1 - 2.1	3.2 - 2.5	4.1 - 2.6
DYN	[] DYNEGY INC	DEC	73 - 43	NM - NM	NM - NM	NM - NM	6 - 1	0	NM	NM	NM	0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
OTHER ELECTRIC UTILITY COMPANIES																	
POR	PORTLAND GENERAL ELECTRIC CO	DEC	13 - 11	27 - 21	NA - NA	NA - NA	NA - NA	40	59	NA	NA	NA	3.6 - 3.0	2.8 - 2.2	NA - NA	NA - NA	NA - NA

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.

Ticker	Company	Yr. End	Earnings per Share ($) 2007	2006	2005	2004	2003	Tangible Book Value per Share ($) 2007	2006	2005	2004	2003	Share Price (High-Low, $) 2007	2006	2005	2004	2003
ELECTRIC UTILITIES‡																	
AYE	[] ALLEGHENY ENERGY INC	DEC	2.48	1.94	0.48	1.00	(2.64)	12.97	10.36	7.98	6.94	8.72	65.48 - 44.28	46.25 - 31.33	32.32 - 18.25	20.20 - 11.75	13.09 - 4.70
ALE	§ ALLETE INC	DEC	3.09	2.78	0.65	1.39	5.16	24.11	21.90	20.03	21.23	31.47	51.30 - 38.17	49.30 - 42.55	51.70 - 35.65	110.13 - 30.76	93.00 - 56.25
AEP	[] AMERICAN ELECTRIC POWER CO	DEC	2.87	2.52	2.64	2.85	1.35	24.94	23.49	22.89	21.32	19.74	51.24 - 41.67	43.13 - 32.27	40.80 - 32.25	35.53 - 28.50	31.51 - 19.01
CV	§ CENTRAL VERMONT PUB SERV	DEC	1.52	1.65	0.09	0.91	1.45	18.43	17.70	17.70	18.49	17.57	41.05 - 22.53	23.92 - 16.11	23.69 - 15.27	24.08 - 18.45	24.50 - 16.52
CNL	§ CLECO CORP	DEC	2.55	1.36	3.54	1.33	(0.79)	16.85	15.22	13.73	10.92	10.23	29.84 - 22.14	26.20 - 20.81	24.36 - 18.93	20.75 - 16.19	18.36 - 10.95
DPL	† DPL INC	DEC	1.97	1.12	1.03	1.81	1.10	7.69 J	6.69 J	8.58	8.72	7.54	32.72 - 25.41	28.83 - 25.03	28.34 - 23.87	25.39 - 16.44	21.42 - 11.20
DUK	[] DUKE ENERGY CORP	DEC	1.21	1.73	2.69	1.31	(1.13)	12.55	13.54	13.65	12.85	10.74	21.30 - 16.91	34.50 - 26.94	30.55 - 24.37	26.16 - 18.85	21.57 - 12.21
EIX	[] EDISON INTERNATIONAL	DEC	3.37	3.32	3.38	0.69	2.39	25.92 J	23.66	20.29	18.55	13.86	60.26 - 42.76	47.15 - 37.90	49.16 - 30.43	32.52 - 21.24	22.07 - 10.57
EE	§ EL PASO ELECTRIC CO	DEC	1.64	1.29	0.77	0.70	0.42	14.80	12.63	11.59	11.25	10.46	28.19 - 20.76	25.05 - 18.15	22.42 - 17.80	19.12 - 13.07	13.63 - 10.10
ETR	[] ENTERGY CORP	DEC	5.77	5.46	4.49	4.01	3.48	38.76	38.59	35.49	36.52	36.38	125.00 - 89.60	94.03 - 66.78	79.22 - 64.48	68.67 - 50.64	57.24 - 42.26
EXC	[] EXELON CORP	DEC	4.06	2.37	1.42	2.79	1.22	11.36	10.87	8.21	7.10	5.77	86.83 - 58.74	63.62 - 51.13	57.46 - 41.77	44.90 - 30.92	33.31 - 23.04
FE	[] FIRSTENERGY CORP	DEC	4.27	3.85	2.66	2.67	1.39	11.06	9.83	9.64	7.70	6.55	74.98 - 57.77	61.70 - 47.75	53.36 - 37.70	43.41 - 35.24	38.90 - 25.82
FPL	[] FPL GROUP INC	DEC	3.30	3.23	2.33	2.47	2.52	26.35	24.49	21.52	20.24	18.90	72.77 - 53.72	55.57 - 37.81	48.11 - 35.90	38.05 - 30.10	34.04 - 26.77
GXP	† GREAT PLAINS ENERGY INC	DEC	1.86	1.62	2.18	2.39	2.20	17.16	15.60	15.20	14.18	13.46	33.36 - 26.89	32.85 - 27.08	32.78 - 27.09	35.69 - 27.86	32.78 - 21.36
HE	† HAWAIIAN ELECTRIC INDS	DEC	1.03	1.33	1.58	1.36	1.58	14.29	12.38	13.92	13.88	13.12	27.49 - 20.25	28.94 - 25.69	29.79 - 24.60	29.55 - 22.97	24.00 - 19.10
IDA	† IDACORP INC	DEC	1.86	2.34	1.51	1.90	1.22	26.14	24.95	23.35	23.14	21.79	39.19 - 30.07	40.17 - 28.97	32.05 - 26.22	32.95 - 25.30	30.19 - 20.60
NU	† NORTHEAST UTILITIES	DEC	1.59	0.82	(1.74)	0.91	0.95	16.93	16.28	13.98	15.17	15.04	33.62 - 26.21	28.90 - 19.07	21.95 - 17.30	20.27 - 17.17	20.32 - 13.13
NVE	† NV ENERGY INC	DEC	0.89	1.33	0.44	0.17	(1.15)	12.82	11.86	10.15	12.56	9.60	19.60 - 14.06	17.50 - 12.68	15.36 - 9.00	10.60 - 6.38	7.53 - 2.85
POM	[] PEPCO HOLDINGS INC	DEC	1.72	1.30	1.91	1.47	0.63	13.01	11.48	11.34	10.28	9.13	30.71 - 24.20	26.99 - 21.79	24.46 - 20.26	21.71 - 16.94	20.56 - 16.10
PNW	[] PINNACLE WEST CAPITAL CORP	DEC	2.98	3.19	2.31	2.57	2.53	34.09	33.51	33.66	30.99	29.81	51.67 - 36.79	51.00 - 38.31	46.68 - 39.81	45.84 - 36.30	40.48 - 28.34
PPL	[] PPL CORP	DEC	2.66	2.32	1.94	1.90	2.08	11.33	9.35	7.72	7.50	5.53	54.58 - 34.43	37.34 - 27.83	33.68 - 25.52	27.08 - 19.92	22.17 - 15.82
PGN	[] PROGRESS ENERGY INC	DEC	2.71	2.05	2.95	3.11	3.42	18.33	18.09	15.94	14.48	13.78	52.75 - 43.12	49.55 - 40.27	46.00 - 40.19	47.95 - 40.09	48.00 - 37.45
SO	[] SOUTHERN CO	DEC	2.29	2.12	2.14	2.07	2.03	16.22 J	15.23 J	14.41 J	13.86 J	13.13 J	39.35 - 33.16	37.40 - 30.48	36.47 - 31.14	33.96 - 27.44	32.00 - 27.00
UIL	§ UIL HOLDINGS CORP	DEC	1.87	2.40	1.30	1.54	1.24	18.55	18.53	18.90	19.77	17.78	42.99 - 27.02	43.76 - 27.44	33.67 - 27.36	32.79 - 25.06	27.65 - 18.48
UNS	§ UNISOURCE ENERGY CORP	DEC	1.64	1.96	1.35	1.34	1.38	19.54	18.59	17.68	16.95	16.47	40.01 - 27.63	37.46 - 29.47	34.80 - 24.30	24.94 - 22.90	24.90 - 16.00
WR	† WESTAR ENERGY INC	DEC	1.85	1.88	1.54	1.19	2.24	19.14 J	17.61 J	16.10	15.94	13.98	28.57 - 22.84	27.24 - 20.09	24.97 - 21.07	22.92 - 18.06	20.49 - 9.76
MULTI-UTILITIES‡																	
LNT	† ALLIANT ENERGY CORP	DEC	3.78	2.90	0.48	1.86	1.57	24.27	22.81	20.85	22.18	21.42	46.53 - 34.95	39.96 - 27.79	30.58 - 25.56	28.80 - 23.50	25.09 - 14.98
AEE	[] AMEREN CORP	DEC	2.98	2.66	3.13	2.84	3.14	27.47	26.80	25.12	24.90	23.20	55.00 - 47.10	55.24 - 47.96	56.77 - 47.51	50.36 - 40.55	46.50 - 37.43
AVA	§ AVISTA CORP	DEC	0.73	1.49	0.93	0.74	1.03	17.18	17.46	15.87	15.54	15.54	25.81 - 18.19	27.52 - 17.61	20.20 - 16.31	19.43 - 15.35	18.70 - 9.80
BKH	† BLACK HILLS CORP	DEC	2.70	2.23	1.09	1.76	1.86	24.32	22.03	20.49	20.37	19.55	45.41 - 35.40	37.95 - 32.46	44.63 - 29.19	32.49 - 26.52	33.54 - 21.85
CNP	[] CENTERPOINT ENERGY INC	DEC	1.25	1.39	0.72	0.67	1.38	0.35	(0.49)	(1.51)	(2.25)	(0.20)	20.20 - 14.70	16.87 - 11.62	15.14 - 10.55	12.32 - 9.66	10.49 - 4.35
CHG	§ CH ENERGY GROUP INC	DEC	2.70	2.73	2.81	2.69	2.78	26.90	27.44	25.63	24.87	24.04	53.79 - 41.37	54.92 - 44.63	50.23 - 42.07	49.58 - 43.14	49.69 - 40.21
CMS	[] CMS ENERGY CORP	DEC	(0.62)	(0.44)	(0.51)	0.68	(0.30)	9.46	9.91	10.41	10.51	9.68	19.55 - 14.98	17.00 - 12.09	16.80 - 9.70	10.65 - 7.81	10.74 - 3.41
ED	[] CONSOLIDATED EDISON INC	DEC	3.48	2.96	3.00	2.33	2.37	31.86	29.20	27.78	27.00	26.15	52.90 - 43.10	49.28 - 41.17	49.29 - 41.10	45.59 - 37.23	46.02 - 36.55
D	[] DOMINION RESOURCES INC	DEC	4.15	2.23	1.51	1.92	1.50	9.21	11.44	8.79	10.48	9.60	49.38 - 39.83	42.22 - 34.36	43.49 - 33.26	34.42 - 30.39	32.97 - 25.87
DTE	[] DTE ENERGY CO	DEC	4.64	2.46	3.29	2.56	2.87	23.22	21.00	20.88	19.98	19.10	54.74 - 43.96	49.24 - 38.77	48.31 - 41.39	45.49 - 37.88	49.50 - 34.00
TEG	[] INTEGRYS ENERGY GROUP INC	DEC	2.49	3.51	4.15	4.09	3.26	29.97	28.35	31.55	27.92	26.20	60.63 - 48.10	57.75 - 47.39	60.00 - 47.67	50.53 - 43.50	46.80 - 36.80
MDU	† MDU RESOURCES GROUP INC	DEC	1.77	1.76	1.54	1.18	1.09	11.31	10.49	9.04	8.14	6.13	31.79 - 24.39	27.04 - 21.85	24.75 - 16.99	18.47 - 14.57	16.23 - 10.94
NI	[] NISOURCE INC	DEC	1.14	1.15	1.05	1.63	1.64	3.56	3.29	2.79	2.14	0.70	25.43 - 17.49	24.80 - 19.51	25.50 - 20.44	22.82 - 19.65	21.97 - 16.39
NST	† NSTAR	DEC	2.07	1.94	1.84	1.77	1.71	9.98	14.82 J	8.21	9.52	8.70	37.37 - 30.75	35.90 - 26.50	31.46 - 24.90	27.23 - 22.65	24.48 - 19.33
OGE	† OGE ENERGY CORP	DEC	2.66	2.48	1.84	1.73	1.66	18.31	17.59	14.82	13.86	13.29	41.30 - 29.12	40.58 - 26.34	30.60 - 24.41	26.95 - 22.85	24.34 - 15.99
PCG	[] PG&E CORP	DEC	2.87	2.86	2.43	9.60	2.05	24.00	22.31	21.09	22.00	10.78	52.17 - 42.58	48.17 - 36.25	40.10 - 31.83	34.46 - 25.90	27.98 - 11.69
PNM	† PNM RESOURCES INC	DEC	0.77	1.73	1.03	1.45	0.98	14.59	14.44	10.30	18.19	17.84	34.28 - 21.05	32.07 - 22.49	30.45 - 23.83	26.11 - 18.70	19.65 - 12.63
PEG	[] PUBLIC SERVICE ENTRP GRP INC	DEC	2.60	1.50	1.78	1.52	1.87	14.23	12.19	10.78	10.70	10.42	49.88 - 32.16	36.31 - 29.50	34.24 - 24.66	26.32 - 19.05	22.25 - 16.05
PSD	† PUGET ENERGY INC	DEC	1.57	1.44	1.43	0.55	1.23	19.45 J	18.15 J	17.52 J	15.64	15.17	28.60 - 22.47	25.91 - 20.13	24.60 - 20.21	24.81 - 20.51	24.40 - 18.10
SCG	[] SCANA CORP	DEC	2.74	2.63	2.81	2.30	2.54	25.30	24.32	23.28	21.71	20.82	45.49 - 32.93	42.43 - 36.92	43.65 - 36.56	39.71 - 32.82	35.70 - 28.10
SRE	[] SEMPRA ENERGY	DEC	4.34	4.25	3.78	4.03	3.29	31.27	28.02	23.97 J	20.77 J	17.17 J	66.38 - 50.95	57.35 - 42.90	47.86 - 35.53	37.93 - 29.51	30.90 - 22.25
TE	[] TECO ENERGY INC	DEC	1.91	1.18	1.02	(2.10)	(0.08)	9.28	7.97	7.36	6.13	8.55	18.58 - 14.84	17.73 - 14.40	19.30 - 14.87	15.49 - 11.30	17.00 - 9.47
VVC	† VECTREN CORP	DEC	1.89	1.44	1.81	1.43	1.58	13.05	12.30	12.32	11.70	11.46	30.50 - 24.85	29.25 - 25.24	29.46 - 25.00	27.09 - 22.86	26.13 - 19.70
WEC	[] WISCONSIN ENERGY CORP	DEC	2.88	2.67	2.59	1.04	2.09	22.72	20.92	19.13	17.53	12.86	50.48 - 41.06	48.70 - 38.16	40.83 - 33.35	34.60 - 29.50	33.68 - 22.56
XEL	[] XCEL ENERGY INC	DEC	1.38	1.39	1.23	1.31	1.27	14.70 J	14.28 J	13.37 J	12.99 J	12.95 J	25.03 - 19.59	23.63 - 17.80	20.19 - 16.50	18.78 - 15.48	17.40 - 10.40

Ticker	Company	Yr. End	Earnings per Share ($)					Tangible Book Value per Share ($)					Share Price (High-Low, $)									
			2007	2006	2005	2004	2003	2007	2006	2005	2004	2003	2007		2006		2005		2004		2003	
INDEPENDENT POWER PRODUCERS & ENERGY TRADERS‡																						
AES	[] AES CORP. (THE)	DEC	0.74	0.21	0.96	0.40	0.56	1.91	1.93	(0.17)	(1.11)	(1.60)	24.24 -	16.69	23.85 -	15.63	18.13 -	12.53	13.71 -	7.56	9.50 -	2.63
CEG	[] CONSTELLATION ENERGY GRP INC	DEC	4.56	4.17	3.42	3.42	2.86	28.46	24.66	26.74	25.99	23.81	104.29 -	68.78	70.20 -	50.55	62.60 -	43.01	44.90 -	35.89	39.61 -	25.17
DYN	[] DYNEGY INC	DEC	0.15	(0.80)	(2.13)	(0.09)	0.87	4.25	3.85	4.37	4.87	5.14	10.95 -	6.47	7.32 -	4.50	5.70 -	3.21	6.09 -	3.40	5.43 -	1.13
OTHER ELECTRIC UTILITY COMPANIES																						
POR	PORTLAND GENERAL ELECTRIC CO	DEC	2.33	1.14	NA	NA	NA	21.05	19.58	27.99	29.75	27.69	31.25 -	25.50	31.11 -	24.17	NA -	NA	NA -	NA	NA -	NA

Note: Data as originally reported. ‡S&P 1500 index group. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
J-This amount includes intangibles that cannot be identified.

Docket No. UE-210
Exhibit PPL/210
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Samuel C. Hadaway

Value Line Investment Survey, Electric Industry, February 27, 2009

June 2009

All of the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western providers are covered in Issue 11.

Since our last review, electric utility stocks have continued to feel the burden of the slumping global economy. Consumers tend to be more cost-conscious during these times, and businesses' demand for power declines. As a result, energy consumption in many major service areas is on a downward slope. Many in the group finished off 2008 on a sour note. For instance, *Allegheny Energy's* fourth-quarter earnings plummeted a hefty 85% from those of a year ago, due in part to bad bets on commodity prices.

Capital Expenditures

Declining energy sales, coupled with higher financing costs, have led several utilities in the group to cut back on spending. Many projects are being postponed for future years or canceled altogether. However, despite the tough times, other utilities are moving forward with major infrastructure upgrades. *Con Edison* announced it plans to spend about $2.6 billion in 2009 on various projects poised to improve reliability and technology. Too, *UIL Holdings* indicated it also plans to invest about $1.1 billion on plant upgrades and enhancements geared towards its transmission and distribution segments. Although increased spending during these rocky economic times might not seem prudent, it may well lead to more consistent earnings growth over the next 3-5 years, provided that the utilities receive reasonable regulatory treatment

Dividends

Income-oriented investors generally find utility stocks to be most appealing due to their reliable income streams provided in quarterly dividends. In 2008, despite economic turmoil, over 60% of utilities raised their dividends, proving this still remains a primary focus in the industry. Currently, the average dividend yield for the industry is 5.3%, almost two full percentage points higher than the *Value Line Investment Survey* average of 3.5%. Leading the pack in this issue is Florida-based *TECO Energy*, yielding a hefty 7.6%, Connecticut-based *UIL Holdings* (7.1%), and North Carolina-based *Duke Energy* (6.7%). Those trailing the pack include *Allegheny Energy* (2.2%), Wisconsin Energy (3.2%), and *Central Vermont* (3.8%).

INDUSTRY TIMELINESS: 26 (of 99)

Coal

Due to its abundance and low cost, coal has been a staple in energy portfolios. In fact, it is currently responsible for almost 50% of domestic power. However, coal plants have been pressured of late due to stricter curbs on C02 emissions. In response, developments are being made to improve coal plants and allow emissions to be captured, transported and stored.

Smart Grid

Many electric companies have been upgrading old equipment by means of *Smart Grid Technology*. *Smart Grid* stands to revolutionize the industry by greatly improving communication capabilities. By installing a digital electric meter in a consumer's home, *Smart Grid* will enable utilities to read meters remotely, detect outages faster, hook customers up quicker, and allow users to better manage their monthly bills. Not only will this technology better the environment, but it will also save many electric utilities money.

Conclusion

Due to the uncertainty surrounding the current economy, we recommend that investors proceed here with a little bit of caution. We believe earnings growth for electric utilities may be slowed in 2009 based mainly on the chance of more modest base rates. Moreover, declining energy consumption in areas such as Florida and volatile prices for power are also a concern as we move forward. On the other hand, the broad market selloff has resulted in higher, more attractive yields, as well as increased recovery potential for discounted stocks. All told, investors could do a lot worse than beef-up their depressed portfolios with choice selections from this relatively recession-resistant industry.

Michael Ratty

Composite Statistics: Electric Utility Industry

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	***375***	***390***	***405***	Revenues ($bill)	***460***
21.4	25.3	27.7	***29.5***	***32.0***	***34.0***	Net Profit ($bill)	***39.0***
29.1%	31.4%	33.2%	***34.5%***	***34.5%***	***34.5%***	Income Tax Rate	***34.5%***
4.6%	4.8%	6.1%	***7.0%***	***7.0%***	***7.0%***	AFUDC % to Net Profit	***4.0%***
54.8%	51.8%	51.0%	***51.0%***	***51.0%***	***51.0%***	Long-Term Debt Ratio	***49.0%***
44.0%	47.1%	47.9%	***48.0%***	***48.0%***	***48.0%***	Common Equity Ratio	***50.0%***
405.6	468.3	471.7	***490***	***515***	***540***	Total Capital ($bill)	***585***
426.0	491.9	509.6	***520***	***540***	***560***	Net Plant ($bill)	***600***
7.1%	7.0%	7.5%	***7.0%***	***7.5%***	***7.5%***	Return on Total Cap'l	***8.0%***
11.7%	11.2%	12.0%	***11.0%***	***11.5%***	***11.5%***	Return on Shr. Equity	***13.0%***
11.9%	11.4%	12.1%	***11.5%***	***11.5%***	***11.5%***	Return on Com Equity	***13.0%***
5.1%	5.6%	5.6%	***5.5%***	***5.5%***	***5.5%***	Retained to Com Eq	***5.0%***
57%	52%	54%	***55%***	***55%***	***55%***	All Div'ds to Net Prof	***60%***
16.1	14.8	17.0		*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***14.5***
.86	.80	.90				Relative P/E Ratio	***.95***
3.5%	3.5%	3.2%				Avg Ann'l Div'd Yield	***3.9%***

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.7
Fixed Charge Coverage (%)	253	265	289

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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Docket No. UE-210
Exhibit PPL/211
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Supplemental Direct Testimony of Samuel C. Hadaway

***Regulatory Focus*, Regulatory Research Associates, Inc., Major Rate Case Decisions, January 12, 2009**

June 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Samuel C. Hadaway
Exhibit PPL/212

Docket No. UE-210
Exhibit PPL/212
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

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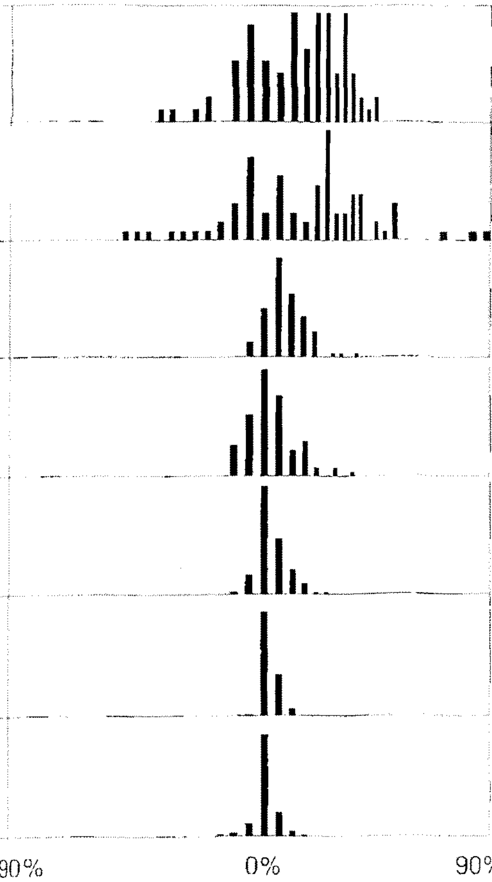
Morningstar, Inc. The Long-Run Perspective, p. 31

June 2009

Exhibit PPL/212
Hadaway/1

Table 2-1
Basic Series: Summary Statistics of Annual Total Returns

from 1926 to 2007

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.4%	12.3%	20.0%	
Small Company Stocks	12.5	17.1	32.6	*
Long-Term Corporate Bonds	10.4 5.9 4.5	12.3 ~~6.2~~ 6.1	8.4	
Long-Term Government	~~5.5~~	5.8	9.2	
Intermediate-Term Government	5.3	5.5	5.7	
U.S. Treasury Bills	3.7	3.8	3.1	
Inflation	3.0	3.1	4.2	

*The 1933 Small Company Stocks Total Return was 142.9 percent.

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Summary of Operating Companies in Proxy Group

June 2009

Summary of Operating Companies in Dr. Hadaway's Proxy Group

No	Holding Company	Operating Company Name	State	Allowed ROE	Date Allowed
1	ALLETE	Minnesota Power, Inc.	MN	10.74%	5/4/2009
2	Alliant Energy Corp.	Interstate Power & Light Co.	IA	10.97%	12/14/2004
	Alliant Energy Corp.	Interstate Power & Light Co.	MN	10.39%	3/3/2006
	Alliant Energy Corp.	Wisconsin Power & Light Co.	WI	10.80%	1/19/2007
3	Consolidated Edison, Inc.	Consolidated Edison Co. Of New York Inc.	NY	10.00%	4/24/2009
	Consolidated Edison, Inc.	Orange & Rockland Utilities, Inc.	NY	9.40%	7/16/2008
	Consolidated Edison, Inc.	Rockland Electric Co.	NJ	9.75%	3/22/2007
4	DPL	Dayton Power & Light	OH	13.00%	1/22/1992
5	DTE Energy Co.	Detroit Edison Co.	MI	11.00%	12/23/2008
6	Duke Energy	Duke Energy Ohio	OH	10.29%	12/21/2005
	Duke Energy	Duke Energy Carolinas	NC	11.00%	12/20/2007
	Duke Energy	Duke Energy Carolinas	SC	12.25%	11/5/1991
	Duke Energy	Duke Energy Kentucky	KY	11.50%	5/5/1992
	Duke Energy	Duke Energy Indiana	IN	10.50%	5/18/2004
7	Edison International	Southern California Edison Co.	CA	11.50%	12/21/2007
8	Entergy	Entrgy Arkansas	AR	9.90%	6/15/2007
	Entergy	Entergy Gulf States	LA	11.10%	1/8/2003
	Entergy	Entergy Lousiiana	LA	10.25%	5/18/2005
	Entergy	Entergy Mississppi	MS	11.75%	12/31/2002
	Entergy	Entergy New Orleans	LA	11.10%	4/2/2009
	Entergy	Energy Texas	TX	11.40%	7/10/1998
9	FPL Group, Inc.	Florida Power & Light Co.	FL	12.80%	1/9/1990
10	IDACORP, Inc.	Idaho Power Co.	ID	10.50%	1/30/2009
11	NSTAR	NSTAR Electric Co.	MA	11.75%	10/30/1992
12	PG&E Corp	Pacific Gas and Electric Co.	CA	11.35%	12/21/2007
13	Portland General Electric Co.	Portland General Electric Co.	OR	10.10%	12/29/2008
14	Progress Energy, Inc.	Progress Energy Carolinas	NC	12.75%	8/5/1988
	Progress Energy, Inc.	Progress Energy Carolinas	SC	12.75%	8/29/1988
	Progress Energy, Inc.	Progress Energy Florida	FL	12.00%	9/22/1992
15	Sempra	San Diego Gas & Electric	CA	11.10%	12/21/2007
16	Southern Co.	Alabama Power Co.	AL	13.75%	3/5/1990
	Southern Co.	Georgia Power Co.	GA	11.25%	12/31/2007
	Southern Co.	Gulf Power Co.	FL	12.00%	6/10/2002
	Southern Co.	Mississippi Power Co.	MS	12.88%	12/3/2001
17	Vectren Corp.	Southern Indiana Gas & Electric Co.	IN	10.40%	8/15/2007
18	Wisconsin Energy Corp.	Wisconsin Electric Power Co.	WI	10.75%	1/17/2008
19	Xcel Energy, Inc.	Northern States Power Co.	MN	10.54%	9/1/2006
	Xcel Energy, Inc.	Northern States Power Co.	ND	10.75%	12/31/2008
	Xcel Energy, Inc.	Northern States Power Co.	SD	12.00%	12/19/1990
	Xcel Energy, Inc.	Northern States Power Co. Wisconsin	WI	10.75%	1/8/2008
	Xcel Energy, Inc.	PSC of Colorado	CO	10.50%	12/1/2006
	Xcel Energy, Inc.	Southwestern Public Service Co.	NM	10.18%	8/26/2008
	Xcel Energy, Inc.	Southwestern Public Service Co.	TX	16.17%	6/23/1982

Stefan A. Bird
Exhibit PPL/504

Docket No. UE-210
Exhibit PPL/504
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Supplemental Direct Testimony of Stefan A. Bird

June 2009

Q. Please state your name.

A. My name is Stefan A. Bird.

Q. Are you the same Stefan A. Bird who provided direct testimony in this case as Exhibit PPL/500?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to respond to Request 2 in the May 14, 2009 Ruling of the Administrative Law Judges on Supplemental Testimony ("Ruling on Supplemental Testimony"), which pertains to my direct testimony.

Request 2—Request for Documents

Q. What is Request 2 in the Ruling on Supplemental Testimony?

A. Request 2 directs the Company to provide, as additional exhibits to PPL/500, copies of the documents cited in PPL/500, Bird/9, n 1-3.

Q. Did you previously provide copies of each of these documents in the workpapers filed as a part of the Company's initial filing?

A. Yes. These documents were included in my workpapers, which were provided with the Company's initial filing on April 2, 2009.

Q. Have you provided these documents as new exhibits to your testimony in response to this request?

A. Yes. While I am including complete copies of these documents as exhibits in compliance with the Ruling on Supplemental Testimony, my testimony relies upon and sponsors only the following, specific pages from these documents:

- Exhibit PPL/505 – Prabhu, Aneesh and Pratt, Terry A., “Increasing Construction Costs Could Hamper U.S. Utilities Plans to Build New Power Generation,” Ratings Direct, Standard & Poor’s (June 12, 2007), page 2. (Referenced at PPL/500, Bird/9, n 1.)

- Exhibit PPL/506 – Chupka, Marc W. and Basheda, Gregory, Rising Utility Construction Costs: Sources and Impacts, The Brattle Group for The Edison Foundation (September 2007), page 8. (Referenced at PPL/500, Bird/9, n 2.)

- Exhibit PPL/507 – Chupka, Marc. W and Earle, Robert, Transforming America’s Power Industry: the Investment Challenge 2010-2030, The Brattle Group for The Edison Foundation (November 2008), page 6-7. (Referenced at PPL/500, Bird/9, n 3.)

By submitting these complete documents as exhibits, the Company does not concede the relevance of all of the information they contain.

Q. Does this conclude your Supplemental Direct Testimony?

A. Yes.

Stefan A. Bird
Exhibit PPL/505

Docket No. UE-210
Exhibit PPL/505
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Stefan A. Bird

Prabhu, Aneesh and Pratt, Terry A., "Increasing Construction Costs Could Hamper U.S. Utilities Plans to Build New Power Generation," Ratings Direct, Standard & Poor's

June 2009

Exhibit PPL/505
Bird/1

STANDARD
&POOR'S

RATINGSDIRECT®

June 12, 2007

Increasing Construction Costs Could Hamper U.S. Utilities' Plans To Build New Power Generation

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Table Of Contents

Increasing Construction Costs Could Hamper U.S. Utilities' Plans To Build New Power Generation

As a result of declining reserve margins in some U.S. regions the U.S. brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation.

While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poor's Ratings Services broadly classifies under the following categories:

- Global demand for commodities,
- Material and equipment supply,
- Relative inexperience of new labor force, and
- Contractor availability.

The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement, and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT) (1). In a separate yet key point, as capital costs rise, energy efficiency and demand side management, already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirement for new capacity.

Increasing capital costs will affect market participants to varying degrees. For regulated utilities, regulation remains the dominant credit driver. The key credit consideration for utilities with plants under development will be the preapproval of costs in rate base and timeliness of allowed returns as construction progresses. For utilities that choose to accept additional risks posed by nontraditional EPC contracts, agreements for recovery of potential cost increases or self-insurance against contingencies through reserve funds will also be important.

Construction risks of large projects undertaken by unregulated generation affiliates of diversified energy companies may affect the consolidated business risk profile, especially if costs aren't locked in and overages must be recovered from competitive market revenues. Project-financed, single-asset constructions that rely on nonstandard EPC contracts could be challenged to reach investment-grade ratings even if they are fully contracted post-construction.

The Resource Challenge

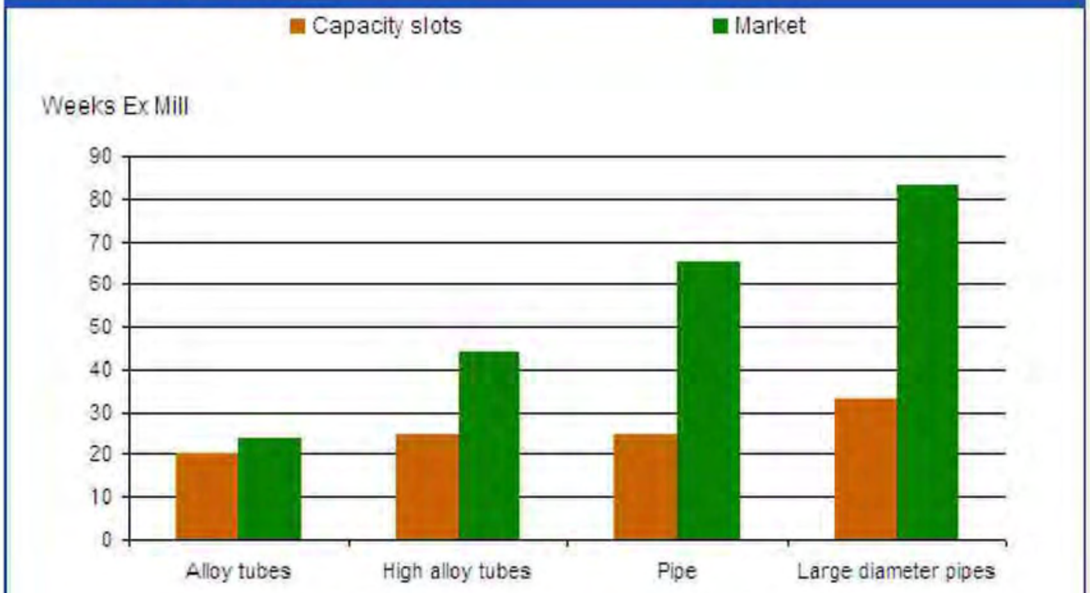
Global demand for commodities

A rapid increase in global demand, predominantly from Asia, has resulted in a sharp increase in prices for commodities important in the power sector. Some industry sources estimate that China's consumption accounted for about 40% of world cement supply and 25% of world steel supply in 2005 (2). A number of construction materials have seen a dramatic price increase in each of the years since the first quarter of 2004, and still remain at elevated levels. Prices of steel--up 50% in first half of 2004 alone--leveled off in 2005 but were on the rise again in 2007, up 20% over December 2005 (3). Copper products (up 60% since December 2005) and cement (up 15% since 2005) are the current drivers for continuing upward price pressures.

Material and equipment supply

In recent years, price competitiveness has encouraged (read: forced) original equipment manufacturers to employ global sourcing for raw material and fabrication needs. But here too the rapid growth in Asia, which is drawing on global supply for raw materials, is resulting in longer lead times and price increases. An example of this rapid growth is China: It went from an exporter of iron ore to being the world's largest importer by 2004 (4). Lead times for materials have increased (see chart) as raw material suppliers and fabrication facilities are taking reservation fees in order to secure availability of material and fabrication slots.

Tube And Pipe Leadtimes*



*As of March 2007. Source: Burns & Roe. Market implies no reservation.
© Standard & Poor's 2007.

Relative inexperience of new labor

While an extreme materials price escalation may have run its course, labor costs are becoming the new driver for industry inflation. The Construction Cost Index (CCI) (4) and the Building Cost Index (BCI) have increased at a compound annual growth rate of 5% and 5.5%, respectively, over the past three years. We learned in discussions with EPC contractors that the cost of labor has nearly doubled since the last round of construction in 2001. This labor cost and supply situation is due to a significant amount of construction experience that has retired and replaced by a new, less experienced work force resulting in reductions in labor productivity. And it could get worse: In the engineering sector, over 45% of labor will be eligible for retirement over the next five years. At the same time, strong global labor construction demand is leading to shortages of skilled labor, especially in the energy sector, which threatens the schedule and in-service dates of projects.

Contractor availability

Only a few contractors can absorb the risk of major construction projects. Sponsors are seeing more single bidder projects and an overall reduction in the number of bidders for projects.

Contract provisions are changing

The supply-side issues are causing a change in contract provisions offered by the construction industry. EPC contracts with guaranteed prices that shield utilities from cost overruns are now either very expensive, contain clauses that one can drive a truck through, or simply aren't offered. Simultaneously, we have seen the advent of risk-sharing mechanisms such as multi-prime contracting (EPCM), which distributes construction risk between contractor and sponsor but lowers installed cost.

To be clear though, the record of construction over the past few years when contractors got hit with performance penalties is another reason that contract provisions have changed. Still, the supply issues have allowed contractors the upper hand. We have increasingly seen the use of adjustment clauses as contractors respond to material price escalations, including:

- Material escalation clauses that track the actual variation of prices from bid amounts,
- The use of indices to adjust prices, commonly CCI (which assigns a higher weighting to labor costs) and also the Materials Cost Index,
- An escalation allowance line item in contracts that serves as a cap for the contractor to recover unanticipated cost increases,
- The use of surcharges typically to limit fuel-only escalations, and
- The re-emergence of cost-based plus contracting.

Extent Of Cost Increase

We assessed the magnitude of cost increases by comparing coal projects under construction during 2003 to 2006. Table 1 lists some coal-fired generation projects currently under development:

Table 1

Coal Plants Under Construction

Power plant	Location	Primary owner	Size (MW)	Type of unit	EPC contract	Year EPC contracted	Broke ground	Expected completion	Project cost ($ per kW)
Council Bluffs Unit 4	Iowa	MidAmerican Energy Co.	790	Super-critical	Fixed	2002	2003	2007	1,816
Elm Road	Wisconsin	Wisconsin Energy Corp.	1,230	Super-critical	Fixed	2002/2003	2004	2009/2010	1,781
Weston 4	Wisconsin	WPS Resources Corp.	500	Super-critical	Multi-prime	2002/2003	2004	2008	1,560

Table 1

Coal Plants Under Construction (cont.)

Nebraska City 2	Nebraska	Omaha Public Power District	653	Sub critical	Fixed	2004	2005	2009	1,600
Iatan Unit 2	Missouri	Kansas City Power & Light Co.	850	Super-critical	Multi-prime	December 2005	2006	2010	1,965
Plum Point	Arkansas	Plum Point Energy Associates	663	Sub-critical	Fixed	2005	2006	2010	2,150
LongView	Pennsylvania	LongView Power LLC	695	Super-critical	Multi	2006	2007	2010	2,600

Sub and supercritical technologies result in minor differences to capital cost. Adjustments were made to AFUDC/funded interest to make the comparison relevant. Some projects also have modest other costs such as coal cars or transmission connects. AFUDC--Allowance for funds used during construction. EPC--Engineering, procurement, and construction.

The sample is small but the trend is evident. Broadly, capital costs have risen, from about $1,700 per kW in 2003-2004 to about $2,500 per kW by year-end 2006. The increase was sharp from 2005 to 2006. A key comparison is between Nebraska City #2 (NC#2) and the Plum Point Project as these two allow us to control all other cost variables--they are of similar size and have a fixed priced EPC that is contracted with the same construction consortium (we recognize that the existing site gives NC#2 some advantages). The important distinction is that the construction contracting was a year apart. Capital costs for Plum Point were almost 35% higher. The fixed price EPC component for Plum Point was almost 40% higher, increasing to nearly $1,325 per kW compared with $960 per kW for NC#2. For the Longview project, which completed construction contract negotiations a year after Plum Point, the EPC contract price is a further 30% higher at about $1,700 per kW.

New combined-cycle plants have similar issues

We had informal discussions with some EPC contractors to determine the effect on new combined-cycle plants (see table 2). The theme is similar. Labor costs have nearly doubled since the last construction cycle, from about 25% to nearly 40% of total project cost. Other factors included higher costs of commodities like copper, steel, and cement, somewhat offset by reductions in turbine costs. The range of about $745 to $785 per kW is about 20% to 25% higher than costs in 2002. The high range is about 60% higher than price in 2002.

Table 2

Combined-Cycle Plant Cost Comparison*

($ per kW)	EPC 1	EPC 2 low range	EPC 3	Average	EPC 1 high range	EPC 2 High Range
EPC cost	630	615	650	632	870	760
Soft cost¶	160	125	195	160	220	225
Total	790	740	845	792	1090	985

*Costs estimated by three different EPC contractors. Estimates are identified as EPC 1, EPC 2, and EPC 3. ¶Soft costs include water supply, finance, legal, IDC, and natural gas pipe connects. EPC--Engineering, procurement, and construction.

Still, these units have shorter construction lead times and can be carried on utilities' balance sheets without significant credit impact. Together with potential future costs relating to climate change, we could see the cancellation of some coal-fired construction projects and a shift in favor of natural gas fired units. However, supply, longer-term prices, and volatility of natural gas will remain concerns.

Credit Implications For Industry Participants

Because the electric industry is entering a period of sustained building after a prolonged absence, companies are again highly dependent on regulatory decisions for full recovery of these growing costs. There has also been a shift in this round of heavy construction to predominantly rate-based recovery as regulated utilities undertake many large projects. However, regulators are dealing with cost pressures from a variety of other factors, such as expiring frozen/capped periods, fuel cost recovery, distribution related base rate requests, and extensive spending related to environmental emissions control. After the relatively calm period of transition/rate freeze agreements between 1996 and 2005, the sheer volume of rate cases facing regulators will pose a challenge. Balancing competing priorities of maintaining reliability and avoiding rate shocks will be an unenviable job, and some rate-case orders may result in regulatory deferrals or even pressure the full recoverability of rate-based plants, which could weaken some utilities' credit quality.

Recognizing the need for new power, some states are enacting laws that allow utilities to seek regulatory decisions that effectively preapprove the costs of new generation facilities. Rulemaking clarity is also being provided by specifying the rate-making principles that commissions will apply when that new generation can be placed in the utility's rate base. House Bill 577 in Iowa, Senate Bill 79 in Wisconsin, Senate Bill 1416 in Virginia, and House Bill 1910 in Oklahoma are examples of such efforts. While the laws in Wisconsin, Oklahoma, and Virginia remain untested, MidAmerican Energy Co. used Iowa's HF 577 to seek preapproval of its 60.67% ownership interest in the Council Bluffs facility. Pursuant to rate settlements in Iowa, MidAmerican Energy will be permitted to include in its rate base the Iowa portion of up to $682.5 million in construction costs and earn a 12.29% return on equity once the 790 MW plant is completed. Costs exceeding this cap would be recoverable if determined to have been prudently incurred.

Credit implications for regulated utilities should be fairly straight forward. As long as the utility in the process of building a large project has access to protective safeguards like regulatory preapproval for construction, timely recovery on capital work in progress, and other cost-recovery mechanisms, it can meaningfully mitigate the large risks posed by construction projects. Still, these utilities will have to manage overall risks during the construction process to avoid cost overruns. For example, despite their approved fixed-price EPC construction for the Elm Road project, Wisconsin Energy Corp. and Madison Gas & Electric Co. will have to absorb cost escalations from more stringent environmental requirements if overall cost overruns exceed 5% of the approved capital cost.

Regulated utilities that forego the protection of a fixed EPC will increase their exposure to construction risk from material cost increases, scheduling delays, and performance issues. In such cases, we look for regulatory pre-agreements that lessen the risk of disallowance or restricted reserves that mitigate the risk of overruns. Some utilities also address risk by partaking in large projects through joint ownership interest. Utilities have also used a combination of these strategies. The Iaton 2 project is a good example of a EPCM approach that is structured to protect its owners' credit quality. The project has five owners, but two owners, Kansas City Power & Light Co. and Empire District Electric Co., are allowed to accelerate plant-related amortization expense in rate proceedings occurring before the in-service date, and the project has nearly 12.5% of project costs in contingency reserves.

Unregulated generation companies can't recover any of their capital investment through regulated means and must rely on market prices to recover these investments. The current environment of increasing prices has pressured the economics of merchant generation. While capacity markets can provide visibility into market-based revenues in some areas, they have not developed enough to provide the certainty needed to support generation projects with long lead times. However, the capacity clearing price of PJM's first reliability pricing model auction for the eastern Mid-Atlantic Area Council subregion is close to the price that can support new CCGT capital costs. However, it's too early to tell whether this will drive significant unregulated construction activity. We do expect some unregulated generation affiliates of diversified utilities to consider self-build options for CCGTs to lower installed cost. Implications for credit quality will depend on the relative magnitude of construction risk and the presence of mitigating factors like contingency reserves.

Regions with strong demand and depleting reserve margins will see some project finance-based debt issuances. The 695 MW Longview project is a good example of a recently rated merchant project finance transaction. However, in that case, merchant risks dominated the credit–quality considerations. Plum Point is an example of a fully contracted coal-fired plant with a fixed-price EPC currently under construction. The project has investment-grade characteristics supported by 16.5% of the EPC contract price in contingency reserve and contingent equity during construction.

Notes

(1) We exclude nuclear from this discussion as investments in nuclear units may only be in the medium to long term, and potentially at over $4,000 per kW.

(2) John Gallagher and Frank Briggs, Construction Briefings, December 2006, Thomas West.

(3) U.S. Bureau of Labor Statistics.

(4) The Financial Times, Jan. 27, 2004.

(5) Engineering News-Record, a unit of McGraw-Hill Companies. Both the CCI and BCI indexes have labor as the major component at 80% and 64%, respectively.

Other Sources

- "Construction Contract Provisions: Credit Considerations For Utilities That Are Building Owned Generation" published on RatingsDirect on March 30, 2005.
- "Regulatory Support Is Key For U.S. Utilities Building New Coal-Fired Power Plants" published on RatingsDirect on Nov. 3, 2006.

Docket No. UE-210
Exhibit PPL/506
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

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Chupka, Marc W. and Basheda, Gregory, Rising Utility Construction Costs: Sources and Impacts, The Brattle Group for The Edison Foundation

June 2009

Exhibit PPL/506
Bird/1

Transforming America's Power Industry:

The Investment Challenge 2010-2030

Prepared by:

Marc W. Chupka
Robert Earle
Peter Fox-Penner
Ryan Hledik

The Brattle Group

Prepared for:

The EDISON FOUNDATION

NOVEMBER 2008

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people.

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The Brattle Group has offices in Cambridge, Massachusetts; San Francisco; Washington, D.C.; Brussels; and London.

Detailed information about *The Brattle Group* is available at www.brattle.com.

Exhibit PPL/506
Bird/3

Transforming America's Power Industry:

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NOVEMBER 2008

Published by:
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701 Pennsylvania Avenue, N.W.
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Executive Summary

The U.S. electric utility industry faces the greatest challenge in its history. The demand for electric services to meet the needs of our growing population and to power our increasingly digital and connected economy continues to rise. At the same time, high demand for commodities such as steel and cement is causing cost increases for building all electric infrastructure systems, including every type of new power plant, whether it's fueled by coal, nuclear power, natural gas, or renewable sources of energy. Concerns about global climate change and other environmental issues have created a new industry emphasis on more energy-efficient products and services and low-emission generation sources. New distribution end-use technologies, such as advanced automation and communications and plug-in hybrid electric vehicles (PHEVs), will dramatically change how utilities deliver electricity and how customers use it, allowing new efficiencies and greater customization of electric service.

To chart the magnitude of this challenge, The Edison Foundation asked *The Brattle Group* to examine the total investment that would be required to maintain today's high levels of reliable electric service across the United States through 2030, net of the investment that could be avoided through the implementation of more aggressive energy efficiency and demand response (EE/DR) programs.[1] In addition, the Foundation wanted *The Brattle Group* to determine the investment cost of one projected generation mix, known as the "Prism Analysis," which the Electric Power Research Institute (EPRI) developed to reduce the growth in carbon emissions.

For our research, we developed four scenarios:

1. **Reference Scenario**: This is similar to the Annual Energy Outlook (AEO) forecast published by the U.S. Department of Energy's Energy Information Administration (EIA), but is adjusted for higher fuel and construction costs. The Reference Scenario is a modeling benchmark and the starting point for our analysis. It does not include the impact of any new federal policy to limit carbon emissions, nor does it include the possible impacts of new industry EE/DR program efforts. The Reference Scenario should not be viewed as our "base" or "most likely" scenario, but rather is a starting point for our analysis.

2. **RAP Efficiency Base Case Scenario**: This scenario adds the impact of realistically achievable potential (RAP) for EE/DR programs, but does not include any new federal carbon policy. This scenario includes a forecast of likely customer behavior and takes into account existing market, financial, political, and regulatory barriers that are likely to limit the amount of savings that might be achievable through EE/DR programs. It is important to note that the RAP Efficiency Base Case

[1] For ease of exposition, we refer throughout this report to *The Brattle Group*; however, the analysis and views contained in this report are solely those of the authors and do not necessarily reflect the views of *The Brattle Group, Inc.* or its clients.

Scenario is our most likely case in the absence of a new federal carbon policy, while the Reference Scenario is simply a benchmark.

3. **MAP Efficiency Scenario**: This scenario captures the higher-end or maximum achievable potential (MAP) for EE/DR programs and assumes a more aggressive customer participation rate in EE/DR programs. It still does not include the effects of a new federal carbon policy.

4. **Prism RAP Scenario**: The final scenario assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP EE/DR programs.

Study Findings

- **By 2030, the electric utility industry will need to make a total infrastructure investment of $1.5 trillion to $2.0 trillion.**[2] The entire U.S. electric utility industry will require investment on the order of $1.5 trillion under the RAP Efficiency Base Case Scenario. The cost could increase to $2.0 trillion under the Prism RAP Scenario.

- **Under the Reference Scenario, 214 gigawatts (GW) of new generation capacity would be required by 2030, at an investment cost of $697 billion.**[3] For the Reference Scenario, we determined that the entire U.S. electric utility industry would require an investment of $697 billion to build 214 GW of new generation capacity under existing EE/DR programs and state-level renewable programs and carbon policies. Figure 1 shows the breakdown of required new generation capacity by geographic region and generation capacity type.

- **EE/DR programs could significantly reduce, but not eliminate, the need for new generation capacity.** As shown in Figure 2, the implementation of realistically achievable EE/DR programs by electric utilities would reduce the need for new generation capacity significantly; dropping the Reference Scenario's forecast from 214 GW to an estimated 133 GW, or by 38 percent.

  In Figure 2, we also calculated the potential results for the MAP Efficiency Scenario, which represents the higher-end of the range of potential impacts of EE/DR programs. Under the MAP Efficiency Scenario, the need for new generation capacity would be reduced from 214 GW to 111 GW, or by 48 percent.

[2] Dollar amounts have been rounded to the nearest billion or trillion dollars, and generation capacity has been rounded to the nearest gigawatt (GW) throughout the text of this report for readability.

[3] Our estimates of generation cost apply to the entire U.S. electric utility industry, including shareholder-owned electric utilities, electric cooperatives, and government-owned utilities. We assume that all segments of the industry have approximately the same capital costs and plan their systems to supply at the lowest regional cost.

Figure 1
Required New Regional Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)

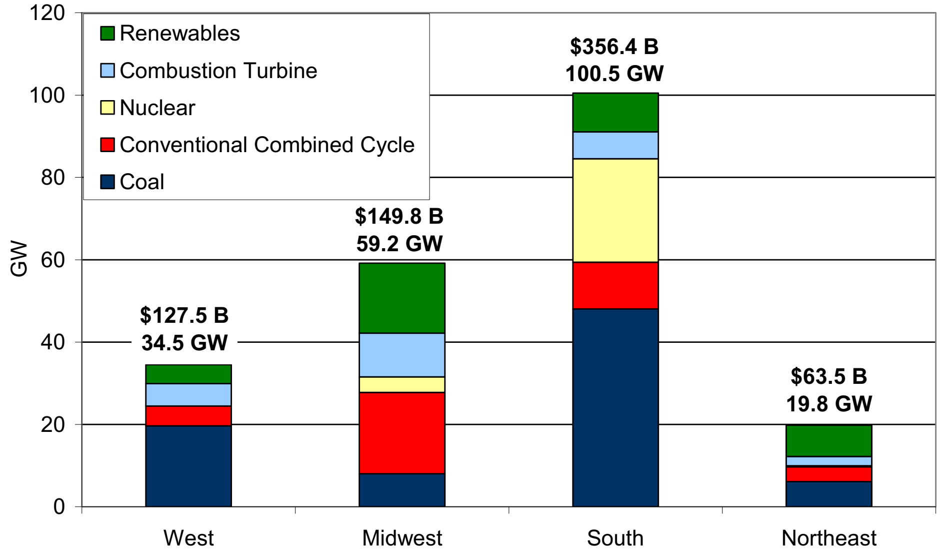
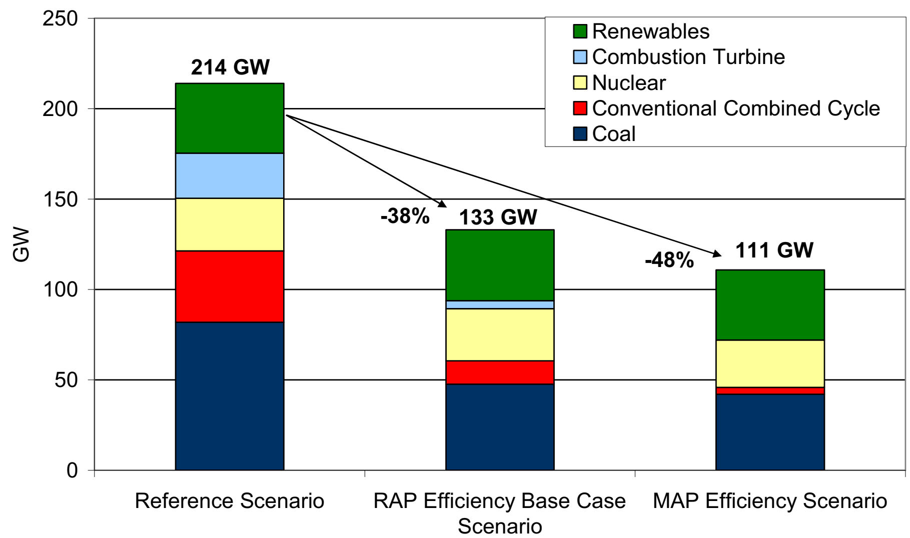


Figure 2
Impact of RAP and MAP EE/DR Programs on Reference Scenario Required Generation Capacity
No Carbon Policy (2010-2030)



Our projected demand and sales reductions from utility EE/DR programs used in this study are based on a study of energy efficiency potentials conducted by EPRI.[4] The EPRI study incorporates extensive analysis of demand response and dynamic pricing programs, as well as energy-saving technologies.

- **Reductions in generation capacity requirements do not mean an equal reduction in total investment, due in part to offsetting the cost of utility EE/DR programs.** As shown in Figure 3, the implementation of the RAP Efficiency Base Case Scenario would reduce required generation investment by $192 billion (28 percent), from $697 billion to $505 billion. Generation investment costs are not reduced in proportion to the GW reduction. This is because the bulk of capacity avoided due to the RAP Efficiency Base Case Scenario programs is comprised of lower capital cost natural gas technologies. This generation investment reduction notwithstanding, the implementation of the RAP Efficiency Base Case Scenario would require an additional investment of at least $85 billion through 2030 in both advanced metering infrastructure (AMI) and EE/DR programs. Thus, the net reduction in total investment needs between the Reference Scenario and the RAP Efficiency Base Case Scenario is $107 billion, or 15 percent.

Figure 3
Potential Avoided Investment from RAP and MAP EE/DR and AMI Programs
No Carbon Policy (2010-2030)

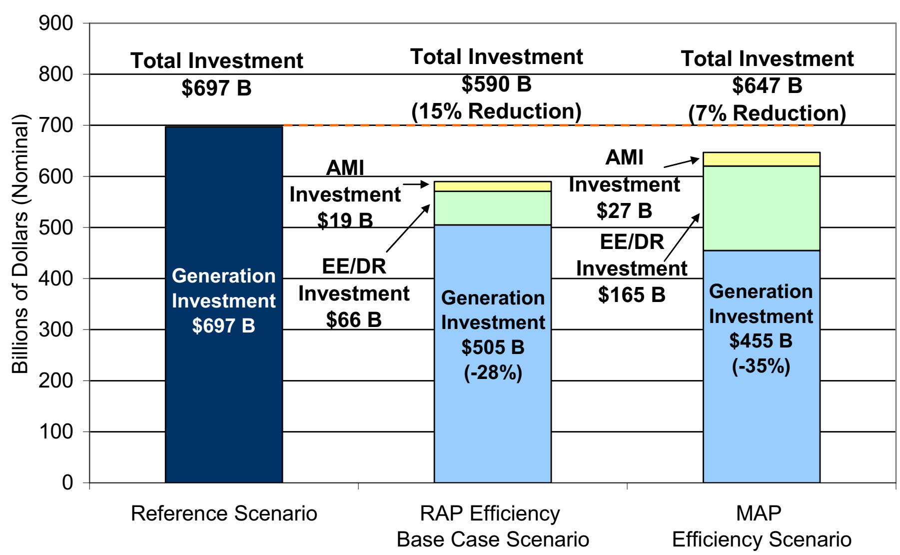


Figure 3 also shows that the more aggressive MAP Efficiency Scenario would lead to a $242-billion (35-percent) drop in the generation investment requirement, from $697 billion to $455 billion. However, this would require AMI and EE/DR program outlays of about $192 billion and, therefore, would decrease total investment needs by only $50 billion to $647 billion, which is a savings of 7 percent.

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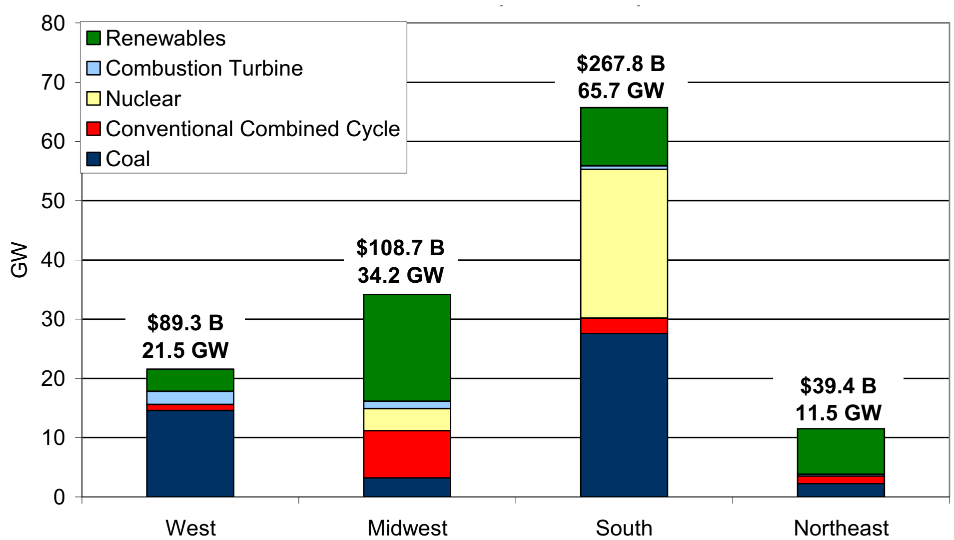
[4] A report on the results of the study, entitled *Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030)*, by the Electric Power Research Institute will be published soon.

- **All types of generation capacity are needed.** As Figure 4 illustrates, in projections through 2030, new generation investment will vary significantly in different regions of the United States, with the highest investment and load growth occurring in the South.

  For the country as a whole, every type of power plant, including those fueled by natural gas, coal, nuclear, and renewable sources will play a significant role in the projected expansion plan. Of the total new 133 GW built under the RAP Efficiency Base Case Scenario, natural gas would fuel 17 GW (13 percent), of which about 13 GW represents combined cycle and 4 GW represents combustion turbines. Coal would comprise an additional 48 GW (36 percent); nuclear would provide 29 GW (22 percent); and renewable sources (primarily wind and biomass) would provide 39 GW (29 percent). This level of renewable investment assumes the full implementation of state-level requirements in place as of August 2008.

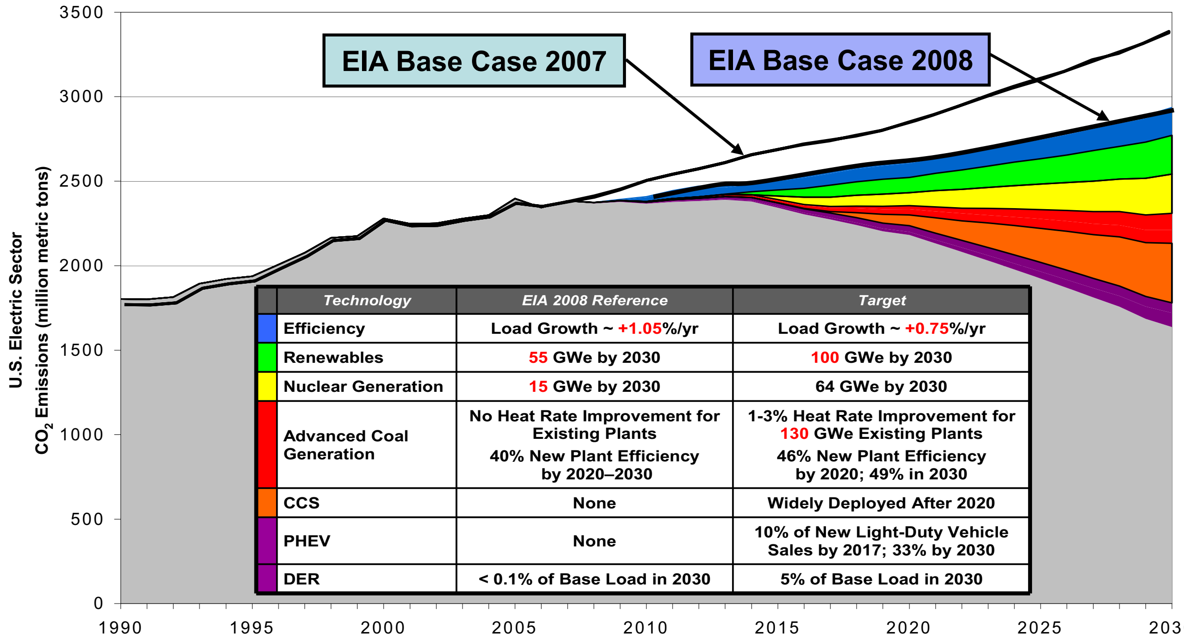
Figure 4
Required New Regional Generation Capacity for RAP Efficiency Base Case Scenario No Carbon Policy (2010-2030)



- **Implementation of a new federal carbon policy would significantly increase the cost and change the mix of new generation capacity.** For this study, we created a simplified model of one scenario for industry adjustment to a new carbon policy. It is based on EPRI's Prism Analysis, shown in Figure 5, which incorporates both energy efficiency and generation-related technologies to reduce the growth in carbon emissions.[5] In the scenario that we developed based on EPRI's Prism Analysis (i.e., the Prism RAP Scenario), plants with advanced coal technology and full carbon capture and storage (CCS) would be the only coal-based plants deployed after 2020; some fossil-based plants would be retired prematurely; and the electric industry would increase investments in renewable energy and nuclear plants. The results of this scenario should be viewed as an illustrative example of a possible outcome rather than a definitive picture of the impacts of a U.S. carbon policy (Figure 6).

[5] Figure 5 uses "GWe" as an acronym for Gigawatt-electric. GWe is equivalent to GW.

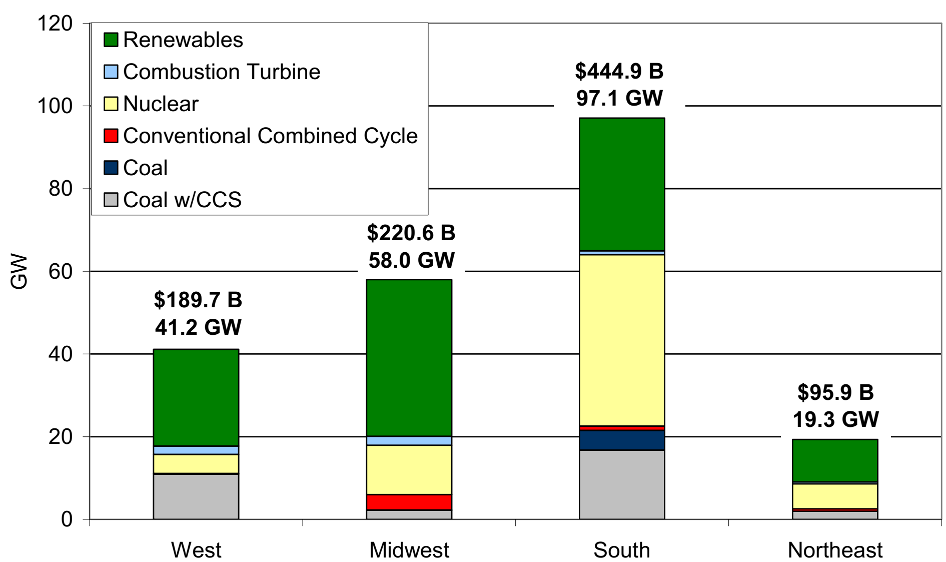
Figure 5
EPRI Prism Analysis for U.S. Carbon Policy Outcomes



Technology	EIA 2008 Reference	Target
Efficiency	Load Growth ~ +1.05%/yr	Load Growth ~ +0.75%/yr
Renewables	55 GWe by 2030	100 GWe by 2030
Nuclear Generation	15 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Heat Rate Improvement for Existing Plants 40% New Plant Efficiency by 2020–2030	1-3% Heat Rate Improvement for 130 GWe Existing Plants 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Light-Duty Vehicle Sales by 2017; 33% by 2030
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

Source: Based on data compiled by Electric Power Research Institute (EPRI), found at:
http://www.iea.org/Textbase/work/2008/roadmap/2a_Tyran_EPRI%20Roadmaps.pdf

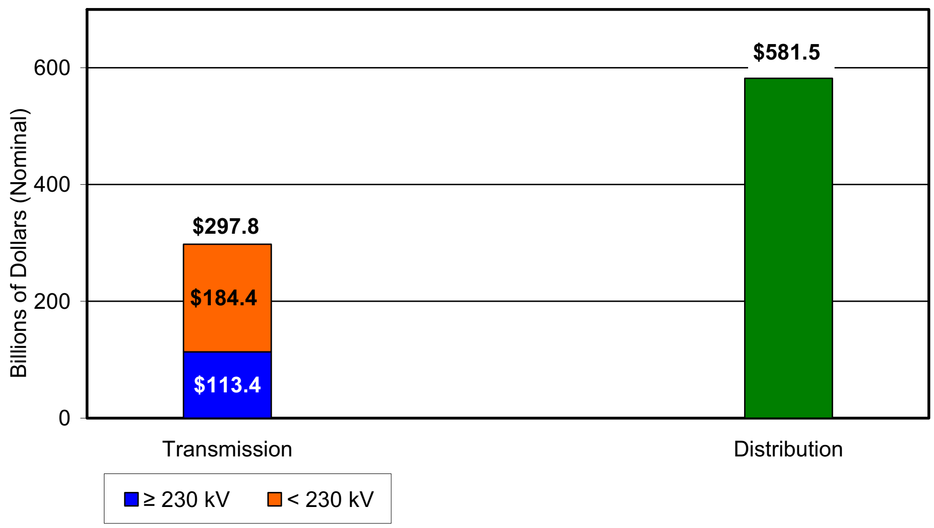
Figure 6
Regional Capacity Additions and Generation Capital Costs
In Prism RAP Scenario with Carbon Policy (2010-2030)



In the EPRI Prism Analysis, energy efficiency programs produce approximately the same reduction in demand growth as under our RAP Efficiency Base Case Scenario. However, in our Prism RAP Scenario, the generation capacity requirements will increase to 216 GW from 133 GW, which will increase the total investment cost to $951 billion from $505 billion. This capacity increase is due to several factors: the greater use of renewables; 21 GW of premature retirements of carbon-intensive generation; and a larger nuclear construction program of 64 GW.

- **Required transmission and distribution (T&D) investment could be as large as, or larger than, generation investment.** The combined investment in new T&D during this period will total about $880 billion, including $298 billion for transmission and $582 billion for distribution (Figure 7).[6] In comparison, generation investment will cost $505 billion for the RAP Efficiency Base Case Scenario. These investments will enable the industry to integrate the approximately 39 GW of renewable energy already mandated under state renewable portfolio standards (RPS) and continue the installation of a "Smart Grid."[7] These investments also will bring new efficiencies and service options to electricity customers and accommodate new end-use technologies, such as PHEVs.

Figure 7
Transmission and Distribution Investment Including Smart Grid
(2010-2030)



[6] These estimates are derived primarily from shareholder-owned electric utility expenditure data. To the extent that the data excludes T&D expenditures undertaken by electric cooperatives or government-owned utilities, these estimates are conservative.

[7] There is currently no standard definition of "Smart Grid" within the electric utility industry. It commonly refers to an array of advanced technologies for the telecommunication network and electric grid that possess two-way communication and monitoring to link all functional areas of the electric power system, including customers. The "Smart Grid" vision is that the technologies will: 1) provide customers with information and tools that allow them to be responsive to system conditions; 2) ensure more efficient use of the electric grid; and 3) enhance system reliability.

Study Methodology

This study's findings are based on EIA's AEO 2008. We modified EIA's data to reflect more recent, higher prices for electric fuels and the costs of new power plants. This resulted in an average price increase of 53 percent for natural gas (Figure 8) and 18 percent for coal (Figure 9) over the 2010 to 2020 period. The cost of constructing new power plants was based on EPRI's Technical Assessment Guide (TAG), published in July 2008 (Figure 10).

Figure 8
Comparison of U.S. Average Delivered Natural Gas Price Projections (2006 Dollars)

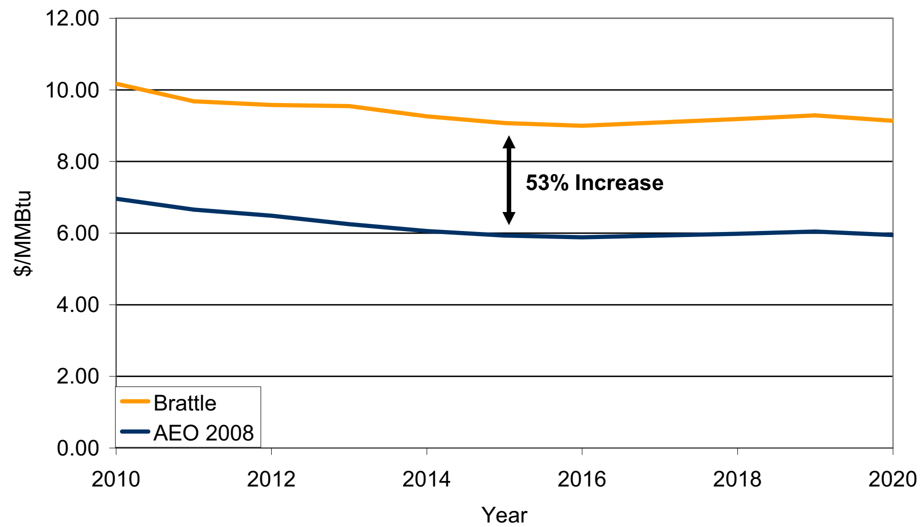


Figure 9
Comparison of U.S. Average Delivered Coal Price Projections (2006 Dollars)

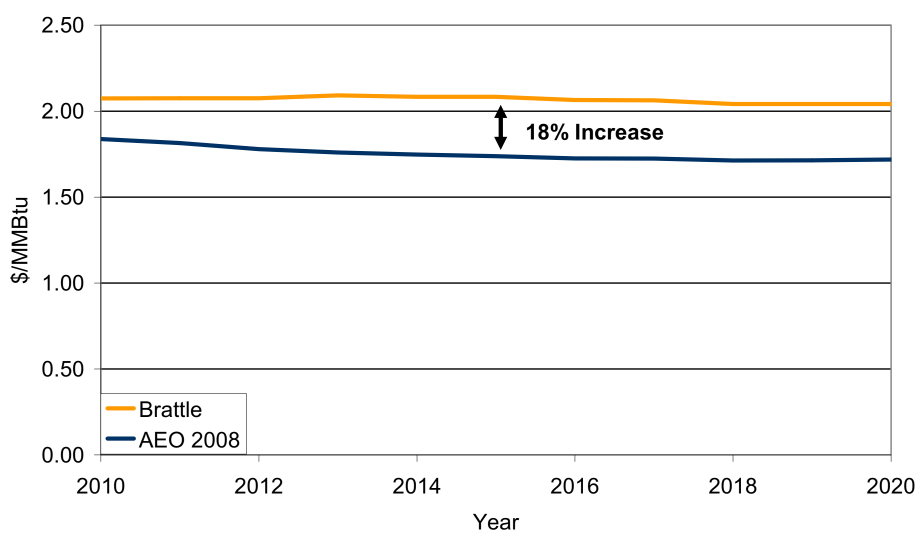
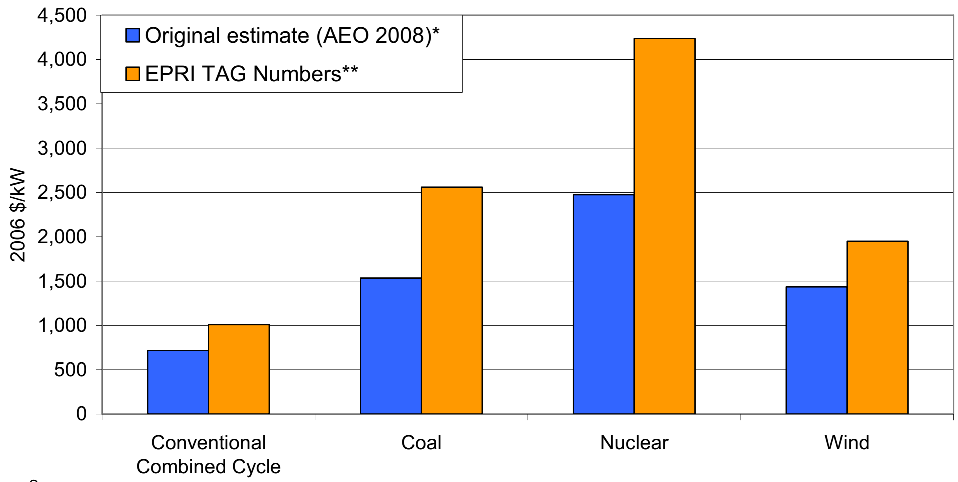


Figure 10
Updated Plant Construction Cost Estimates
(Including Construction Interest)



Sources:
* Annual Energy Outlook 2008, U.S. Department of Energy, Energy Information Administration, June 2008.
** Program on Technology Innovation: Power Generation (Central Station) Technology Options - Executive Summary, Electric Power Research Institute, July 2008.

We inserted these updated cost figures into a generation expansion planning model that *The Brattle Group* developed, the Regional Capacity Model (RECAP). This allowed us to estimate regional least-cost build-out plans through 2030.[8] RECAP uses traditional least-cost planning criteria to choose the mix of generation additions that can most economically supply the energy needs of each region that remain after energy efficiency programs reduce peak demand and energy sales. Using the readjusted EIA data in RECAP, we developed the four scenarios outlined on pages v and vi.

Summary of Results and Conclusion

The results of our study, in terms of capacity and investment costs, are summarized in Table 1.

As our starting point under the Reference Scenario, we determined that the electric industry would have to build 214 GW of new generation capacity and make a total infrastructure investment of $1.577 trillion by 2030. In the RAP Efficiency Base Case Scenario, which depicts the most likely impact of EE/DR programs under existing real-world constraints (and is therefore highlighted in Table 1), the industry still would have to build 133 GW of new generation capacity and make a total infrastructure investment of $1.470 trillion. In the MAP Efficiency Scenario, which depicts the impact of more aggressive EE/DR programs, the required new generation build still would be 111 GW, with a total infrastructure investment cost of $1.527 trillion. Finally, in the Prism RAP Scenario, which depicts the impact of a new carbon policy, the industry would have to build 216 GW of new generation capacity and make a total infrastructure investment of $2.023 trillion.

[8] It is important to note that we did not model customer response to the increased retail rates that would accompany the higher fuel and construction costs used in RECAP. Depending on the price elasticity of demand, the reductions in future load growth could be significant.

Table 1: Model Results Overview

	Reference Scenario No Carbon Policy	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy	Prism RAP Scenario Carbon Policy
Average Peak Load Growth Rate		0.70%	0.30%	0.70%
New Capacity Through 2030 (in GW)				
Renewables	38.6	39.2	38.8	103.7
Combustion Turbine	25.0	4.3	0.0	5.5
Nuclear	29.1	28.9	26.2	64.0
Conventional Combined Cycle	39.5	12.9	3.8	5.4
Coal	81.8	47.6	42.1	36.9*
Total New Capacity (GW)	**214.0**	**132.9**	**110.9**	**215.5**
Capital Investment Through 2030 (rounded to nearest billion)				
Generation	$697	$505	$455	$951
Transmission	$298	$298	$298	$298
AMI and EE/DR	$0	$85	$192	$192
Distribution	$582	$582	$582	$582
Total Capital Investment ($ Billions)	**$1,577**	**$1,470**	**$1,527**	**$2,023**

*32 GW of EPRI Prism coal generation incorporates carbon capture and storage.

No matter which scenario is implemented, total utility industry investment needs will range from approximately $1.5 trillion to $2.0 trillion by 2030.

It is important to recognize that total investment amounts are not the same as revenue requirements, rate levels, or societal costs. As a result, one cannot directly link higher investment costs with specific rate changes until fuel costs and other operating expenses are considered. For example, the implementation of RAP and MAP EE/DR programs could lead to reduced fuel expenditures or the Prism RAP Scenario could reduce the costs of complying with carbon policy mandates.

Affordable, reliable electricity is as essential to the global economy of the 21st century as it was to the American economy of the 20th century. The U.S. electric utility industry is capable of rising to this enormous investment challenge, but implementation of appropriate policies will be an essential ingredient for success.

Chapter 1: Reference Projections for New Generation Capacity 2010-2030

The electric utility industry currently faces its greatest challenge in decades as it endeavors to meet rising demand while contending with the impact of higher fuel prices and construction costs. To assist the industry in addressing this challenge, The Edison Foundation commissioned a study by *The Brattle Group* to analyze the impact of higher fuel prices and construction costs on the projected capacity mix through 2030, as well as the overall capital costs associated with this new capacity.[9] Further, *The Brattle Group* was asked to examine the impact on new generation capacity and projected overall capital costs of both an aggressive expansion of energy efficiency and demand response (EE/DR) programs and investments (see Chapter 2) and a federal climate change policy that emphasizes low-carbon investments [such as nuclear, renewables, and coal with carbon capture and storage (CCS)] in the generation sector (see Chapter 3). *The Brattle Group* used analysis for both the EE/DR and climate scenarios from the Electric Power Research Institute (EPRI).

Long-run projections of the cost of building new generation capacity are based on projections of electricity demand growth, generation fuel costs, state-level renewable energy requirements, construction costs, and retail rates. Our analysis used the U.S. Department of Energy's Energy Information Administration's (EIA's) widely used Annual Energy Outlook (AEO) forecast of U.S. electricity market growth as a starting point, but we adopt different assumptions regarding several key elements, such as generation fuel and construction costs, to reflect sustained and substantial price increases that are not reflected in the data used by EIA.

The Annual Energy Outlook

EIA's AEO is a well-known reference for a long-term national generation investment outlook that presents projections of energy supply, demand, and prices for the energy sector (not just electricity) over a 25-year horizon. The projections are based on results from the National Energy Modeling System (NEMS) and assume no changes in energy policy, such as enactment of a federal policy that limits carbon emissions. The AEO is a reliable starting point for analyzing the need for new generation capacity because of its high visibility and credibility among policy makers.

[9] For ease of exposition, we refer throughout this report to *The Brattle Group*; however, the analysis and views contained in this report are solely those of the authors and do not necessarily reflect the views of *The Brattle Group, Inc.* or its clients.

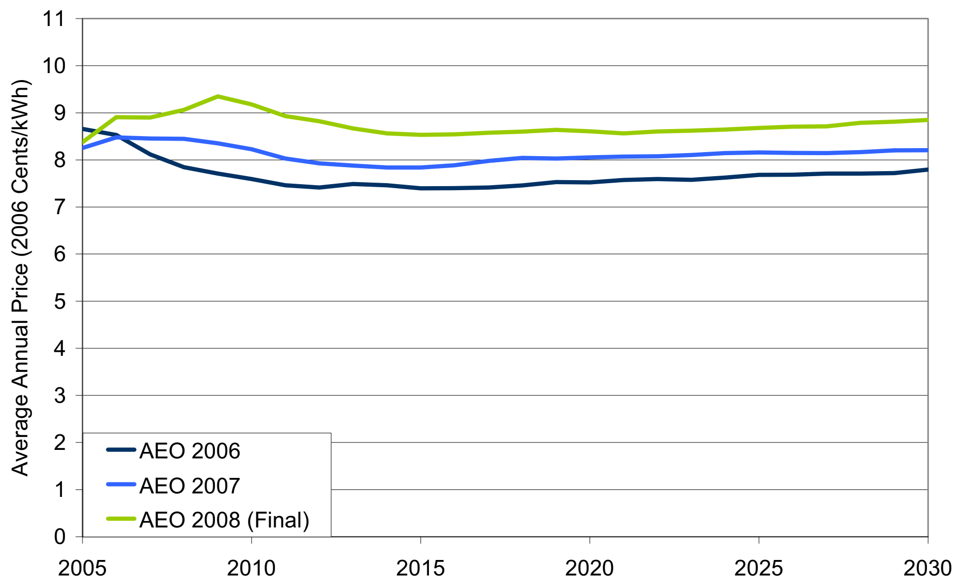
The AEO 2008 was published in June 2008.[10] As part of the AEO release, EIA makes underlying data and detailed NEMS modeling results available, which the authors of this study used to construct alternative projections of capacity builds.

AEO 2008 Load Growth

EIA projects regional and national growth in the demand for electricity through 2030, accounting for assumed economic growth and projected future energy prices. The AEO 2008 forecast projects that electricity demand growth will average about 1.1 percent per year between 2008 and 2030.

In recent versions of the AEO, EIA has projected higher retail electricity prices and lower load growth as a result of those prices (and as a result of policy changes). As the cost of the fuels used to generate electricity has risen over the past several years, customer rates have risen as well. These price increases will tend to dampen load growth.[11] Figure 1-1 shows the increased retail price projections since the AEO 2006, and Figure 1-2 shows the resulting EIA electricity growth projections.

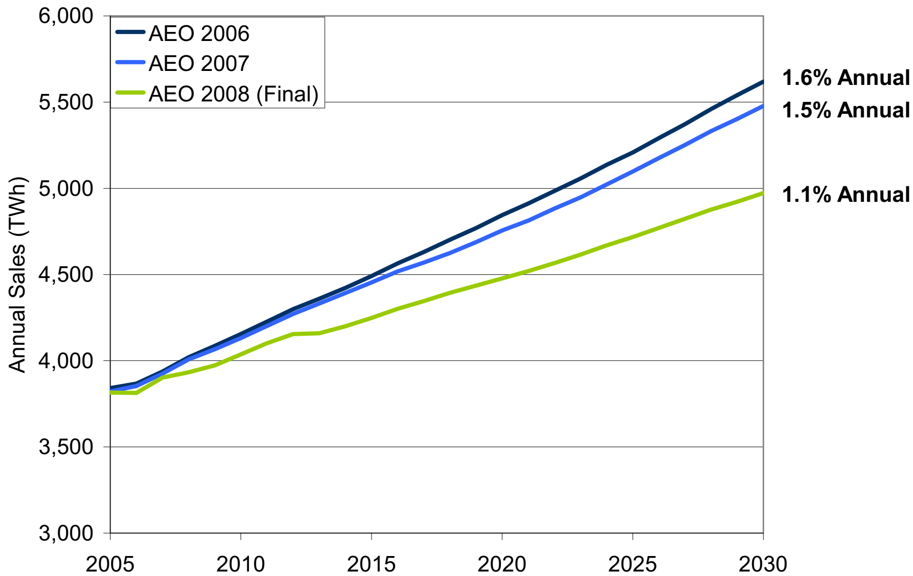
Figure 1-1
Comparison of AEO U.S. End-Use Electricity Price Forecasts



[10] Normally, the AEO is published in January, but EIA elected to postpone the release of the full document until the impacts of the Energy Independence and Security Act of 2007 (EISA) could be incorporated into the long-term projections.

[11] See *Why Are Electricity Prices Increasing? An Industry-Wide Perspective,* prepared by *The Brattle Group* for The Edison Foundation, June 2006, pages 30-31 and Appendix B.

Figure 1-2
Comparison of AEO U.S. Annual Electricity Sales Forecasts



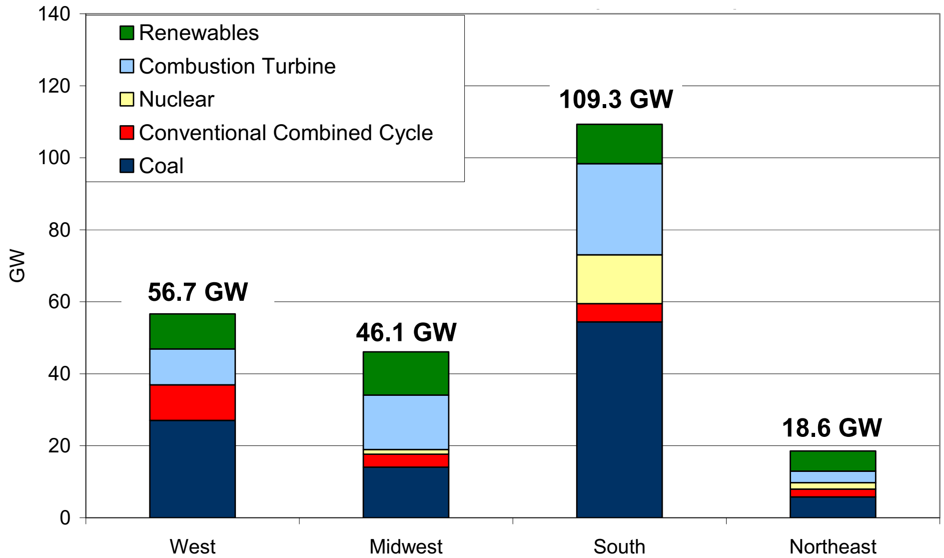
AEO 2008 Generation Investment Projections

<u>New Generation Capacity</u>

According to the AEO 2008, overall electricity consumption will be about five million gigawatt-hours (GWh) by 2030, which will require the addition of 231 GW of new generation capacity during the 2010 to 2030 period. EIA projects that about 101 GW, or 44 percent, of new capacity will be coal-based. Combustion turbines (CTs), which primarily are fueled by natural gas, represent the next largest category of plant, with 54 GW (23 percent) of new CTs built. EIA estimates that the nation will add 38 GW (16 percent of the total) of renewable generation capacity, primarily to comply with existing state-level renewable portfolio standard (RPS) requirements.[12] Natural gas-based combined-cycle plants (21 GW) and nuclear generation (17 GW) make up the remaining capacity additions. Figure 1-3 shows the capacity builds from 2010 to 2030 by technology type in the four main U.S. census regions.

[12] An RPS also can be referred to as a Renewable Electricity Standard (RES).

Figure 1-3
Required New Regional Generation Capacity
AEO 2008 Forecast (2010-2030)



Almost half, or 109 GW, of the cumulative new generation capacity in the AEO 2008 forecast would be located in the South census region, with about half of that as coal-based capacity. The South also accounts for the majority of nuclear capacity additions (15 GW out of a total of 17 GW) nationwide.[13] The West census region would build 57 GW of the new capacity, and the remainder will be built in the Midwest (46 GW) and the Northeast (19 GW). Coal-based capacity additions also comprise about half of the generation capacity added in the West, while capacity additions in the Midwest and the Northeast reflect a more even composition of coal, renewables, combined-cycle, and combustion turbine plants.

The regional differences in cumulative generation capacity additions appear to be largely explained by assumed growth in electricity consumption, relative fuel costs, and the assumed generation capacity retirements. In the South census region, there is significant growth expected in population, economic activity, and electricity demand. According to the AEO 2008 load forecast, roughly half of the expected increase in U.S. electricity demand between 2010 and 2030 will occur in the South.

Renewable capacity builds are primarily a function of state-level RPS requirements that will grow rapidly over the next two decades. One of the significant differences between the AEO 2007 and AEO 2008 capacity projections is the amount of renewables (particularly wind) that is expected to come online. The AEO 2007 projection showed a very small magnitude of renewable capacity additions (only 9 GW through 2030, primarily in early years) while the AEO 2008 projects 38 GW of renewable capacity between 2010 and 2030. This significant increase appears to arise from EIA's increased recognition of the impact of state-

[13] The AEO 2008 provides new generation capacity data by region through the NEMS Electricity Market Module (EMM). Projections of capacity builds in the NEMS EMM regions were mapped to census regions.

level RPS requirements, which require a rising percentage of electricity to be provided by renewable electric generation.[14]

It is important to emphasize that the AEO does not account for the likelihood of a new federal policy to constrain carbon emissions.[15] The emergence of state and regional carbon-reduction efforts and the prospects for a federal carbon policy already have affected utility capacity planning in ways that the AEO projections do not reflect. While the long-term form and intensity of such regulations are very difficult to predict, these regulations likely will have a significant impact on the cost and composition of new generation development, as well as the value of demand-side energy efficiency investments. A detailed examination of these impacts is beyond the scope of this study; however, we do explore the capital cost implications of a technology-based carbon policy on new capacity in Chapter 3.

The Brattle Group's RECAP Model Projections

In order to explore the impact of alternative assumptions and policies on the "projected" or "future" level and composition of new generation capacity builds, *The Brattle Group* used the proprietary Regional Capacity Model (RECAP). RECAP is a regional capacity expansion and economic dispatch model that can be configured to the regional detail that underlies the AEO modeling framework. It provides the optimum generation expansion plan (subject to reliability, technology, and policy constraints) under alternative assumptions regarding load growth, fuel prices, construction costs, and other inputs within the AEO modeling framework. RECAP is described in more detail in Appendix A.

When run with identical economic assumptions and constraints as the AEO 2008 forecast, RECAP projects a mix of generation plant additions (by technology type and region) that corresponds closely to the AEO 2008 projections, suggesting that RECAP provides an appropriate modeling framework to explore the impact of alternative assumptions.

The RECAP model also has the capability to estimate changes in demand for electricity from higher retail prices (i.e., RECAP can explore the implications of customer price elasticity in future load growth scenarios if retail prices change from baseline assumptions). This could occur, for example, as a result of persistently higher generation fuel prices or elevated construction costs as outlined elsewhere in this report. However, in keeping with the objective of maintaining an initial focus in this report on generation sector investment under different assumed scenarios of energy efficiency investment, such an analysis has not been prepared at this time.

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[14] As of August 2008, 27 states and the District of Columbia had RPS programs and an additional five states had renewable energy goals. While the program structure and qualifying renewable technologies for RPS programs differ from state to state, all encourage the development of renewable energy for electricity generation. The most common format is the definition of a target percentage for renewables within the state's energy portfolio during a set time frame (such as: 20 percent renewable energy either by sale or generation by 2015).

[15] The AEO is designed to provide projections under current policy, and the omission of potential carbon policy impacts is consistent with EIA's mandate. In other analyses, EIA has conducted extensive analysis of the impact of carbon policies on future outcomes in the U.S. energy sector.

Major Assumptions in *The Brattle Group's* Reference Scenario

The Brattle Group's Reference Scenario is based on altering a few key assumptions contained in the AEO 2008, particularly those relating to delivered generation fuel prices and construction costs.

Power Plant Construction Costs

In a September 2007 report prepared for The Edison Foundation, *The Brattle Group* observed that the AEO analyses from 2004 to 2007 had assumed that utility construction costs would increase at the general rate of inflation, while actual construction costs were increasing more rapidly.[16] For the AEO 2008, EIA increased the assumed real capital costs of most generation technologies by 15 to 20 percent. However, this adjustment still does not reflect recent increases in construction costs, which continue to occur. Part of this is due to the fact that the costs of many utility construction materials, such as steel, copper, aluminum, and crushed stone, continued to rise through 2007 and early 2008 because of high worldwide demand for these commodities. Many of these commodity-price increases are associated with the weak U.S. dollar, which increases the price of both imported commodities as well as those produced domestically.

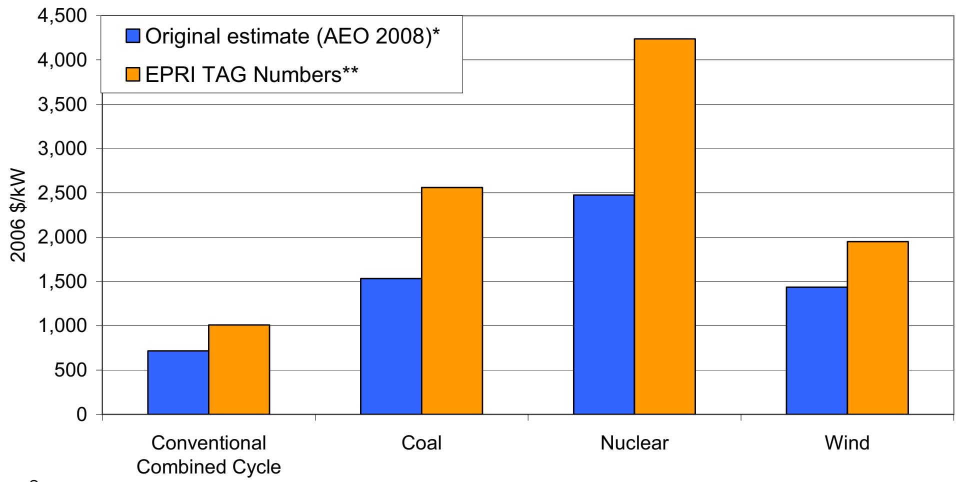
In order to reflect recent construction cost increases, *The Brattle Group* used construction cost figures developed by EPRI that were publicly released in July 2008.[17] These EPRI "Technical Assessment Guide" (TAG) estimates are substantially higher than those assumed by EIA in the AEO 2008, but in our judgment are more accurate than EIA's assumptions at this time.

Applying the EPRI data, in lieu of EIA's assumptions, has a substantial impact. Figure 1-4 compares the capital costs [in dollars per kilowatt (kW) of installed capacity] of the major generation technology types using the AEO 2008 assumptions and the recent EPRI study. As shown in this graph, EPRI's estimates of conventional coal (without CCS) and nuclear costs are about 60 percent higher than EIA's assumptions, and wind and combined-cycle costs are more than 33 percent higher than EIA's assumptions.

[16] See *Rising Utility Construction Costs: Sources and Impacts*, by Marc W. Chupka and Greg Basheda of *The Brattle Group,* prepared for The Edison Foundation, September 2007.

[17] See *Program on Technology Innovation: Power Generation (Central Station) Technology Options – Executive Summary*, Electric Power Research Institute, July 2008.

Figure 1-4
Updated Plant Construction Cost Estimates
(Including Construction Interest)



Sources:
* Annual Energy Outlook 2008, U.S. Department of Energy, Energy Information Administration, June 2008.
** Program on Technology Innovation: Power Generation (Central Station) Technology Options - Executive Summary, Electric Power Research Institute, July 2008.

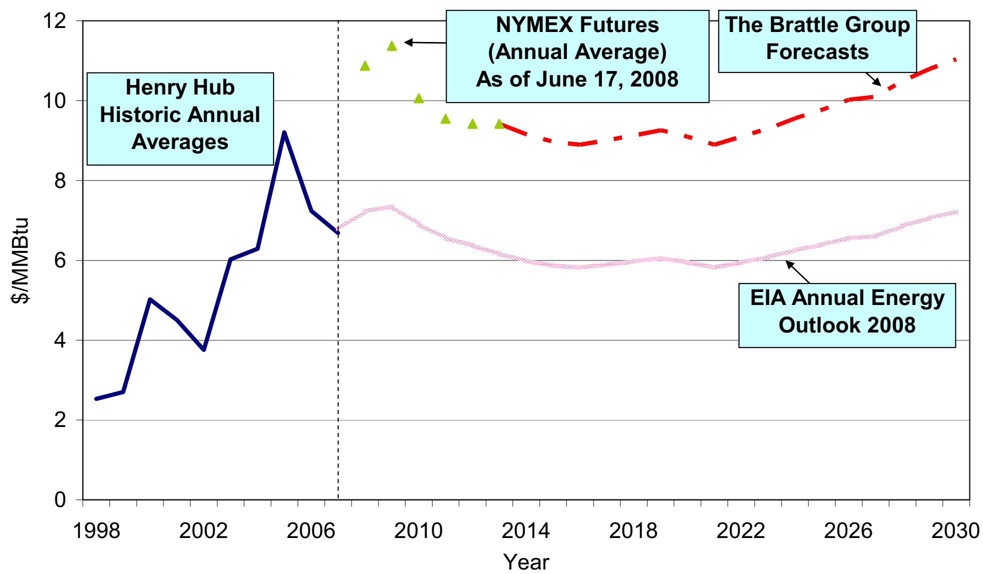
Generation Fuel Prices

The Brattle Group also assumed higher delivered generation fuel prices than EIA used in the AEO 2008. We did this because fuel prices have risen dramatically through this decade and currently are at historic highs. EIA's fuel price forecasts are based on models of long-term fuel market fundamentals, which tend to revert to historic norms and may not capture recent shifts in global markets adequately. Next, we describe how we construct alternative fuel price projections.

For natural gas and oil, *The Brattle Group* used forward prices as cited at The New York Mercantile Exchange (NYMEX), and then we assumed the EIA real price trend thereafter. The five-year forward curve in natural gas (Henry Hub) is roughly 50 percent higher than the prices projected in 2013 in the AEO 2008. Figure 1-5 compares the EIA Henry Hub natural gas fuel price forecast with *The Brattle Group's* projection based on futures market data and the long-term EIA trend.[18]

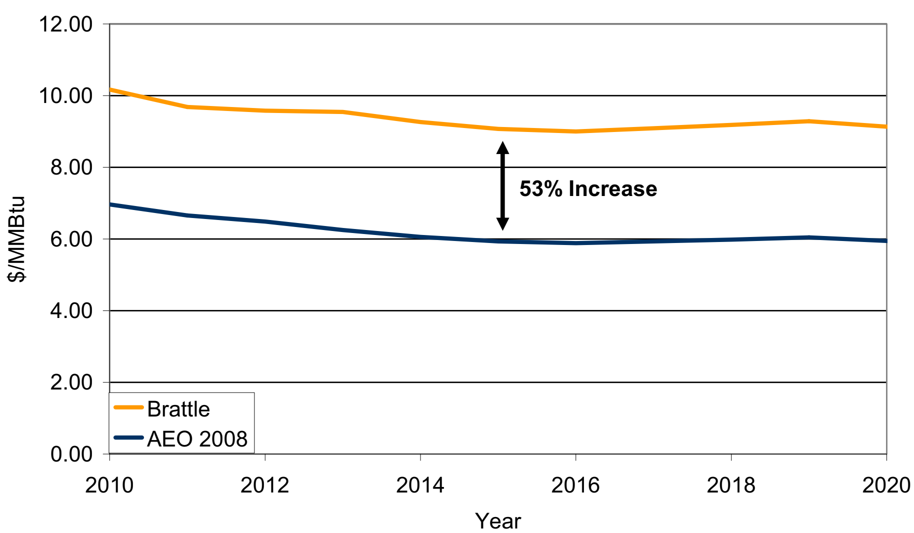
[18] For Figure 1-5, historical averages are brought into real 2006 dollars using Gross Domestic Product (GDP) deflators from the St. Louis Federal Reserve Bank. Forecasted and futures prices are converted to real 2006 dollars using EIA's AEO 2008 GDP deflator forecasts.

Figure 1-5
Historic and Forecasted Annual Average Natural Gas Henry Hub Prices
(2006 Dollars)



Regional basis differentials between the Henry Hub price and delivered prices were assumed to remain constant (in real terms) as projected by EIA. Likewise, the difference between EIA crude oil prices and regional product prices (#2 distillate fuel oil and #6 residual fuel oil) also were held constant. Figure 1-6 compares the average delivered natural gas price forecast from the AEO 2008 and the Reference Scenario. *The Brattle Group's* delivered natural gas prices across the regions are 50 percent to 60 percent higher, and the average delivered price is 53 percent higher (in real dollars) than the AEO 2008 forecast prices over the forecast period.

Figure 1-6
Comparison of U.S. Average Delivered Natural Gas Price Projections
(2006 Dollars)

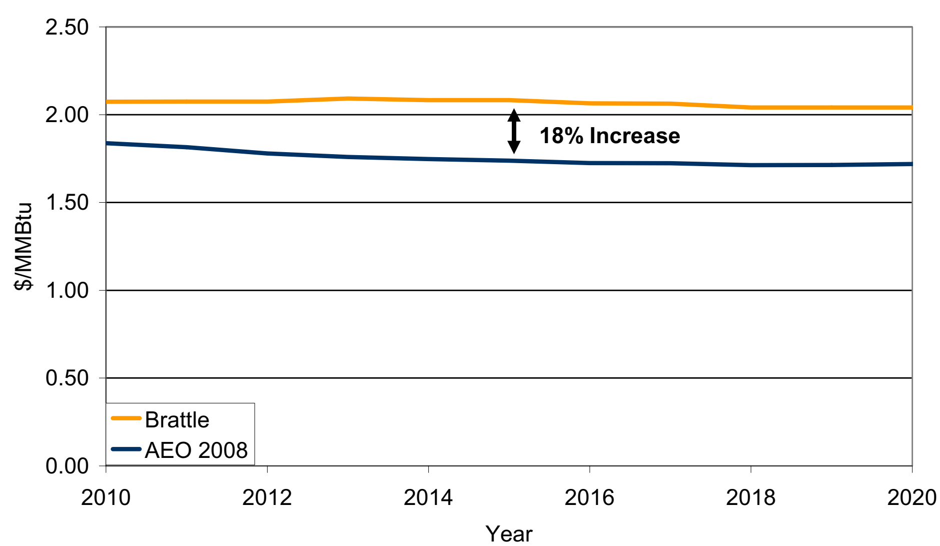


Compared to natural gas or crude oil, coal is a much more heterogeneous fuel, and futures markets for coal are far less developed than for liquid and gaseous fuel commodities. Nevertheless, coal prices clearly have risen in the past decade, in varying amounts across regions and coal types. In order to reflect these changes, *The Brattle Group's* projections for regional coal prices were increased above EIA's projected levels to reflect higher production and transportation costs, using the following assumptions:

- All minemouth prices were increased assuming that 15 percent of the minemouth price is energy-related costs, and this portion of the cost would increase by a factor equal to the difference between EIA's and *The Brattle Group's* forecasts of distillate fuel price;
- Appalachian coal minemouth price was raised by an additional 20 percent over the next 10 years to reflect increased export demand for this type of coal;
- Using origin-destination coal shipment and price data, we derived the implicit transportation costs, from which we derived cost adders assuming that 25 percent of transportation costs were fuel-related. We applied these adders to delivered prices.

As a result of these adjustments, *The Brattle Group* concluded that projected regional delivered prices for coal are roughly 10 percent to 25 percent higher than those projected by EIA in the AEO 2008 forecast. Figure 1-7 displays the average U.S. delivered coal price difference, showing that *The Brattle Group* forecast averages 18 percent higher than the AEO 2008 average forecast.

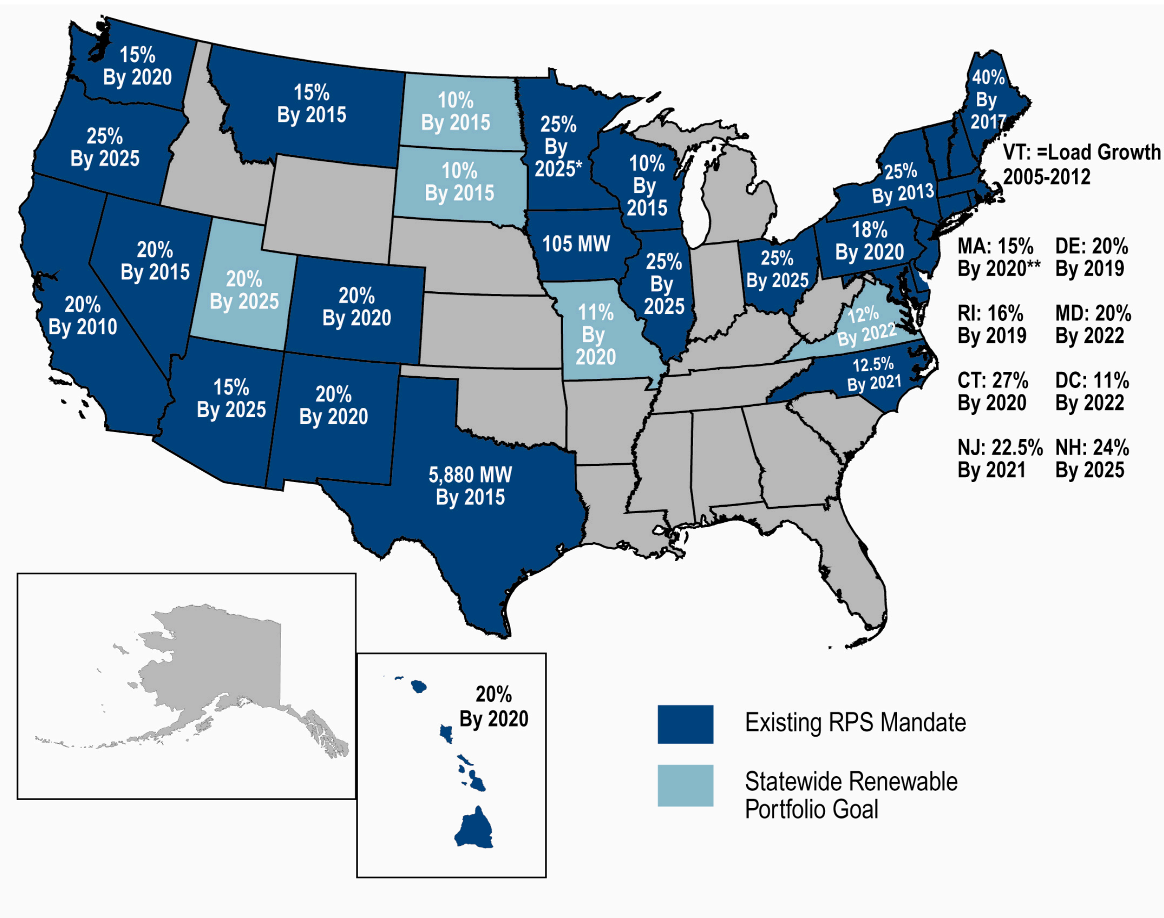
Figure 1-7
Comparison of U.S. Average Delivered Coal Price Projections
(2006 Dollars)



State Renewable Electricity Requirements

As of August 2008, 27 states and the District of Columbia had adopted RPS programs that require them to meet a percentage of the state's electricity needs with renewable generation. Another five states have instituted statewide renewable electricity goals that are not requirements. Because state RPS programs are driving investment in generation, we analyzed existing state-level RPS requirements and linked them to projections of demand growth. Figure 1-8 illustrates these renewable requirements and goals for each state. These requirements were maintained in the RECAP model.

Figure 1-8
State Renewable Portfolio Standards and Goals



*Xcel Energy: 30% By 2020 **Increasing 1% per year thereafter, with no stated expiration date

Source: Edison Electric Institute, status as of August 26, 2008.

Load Growth

As discussed earlier, we assumed the same regional load growth as in the AEO 2008 forecast. This enabled us to explicitly examine the impact of EE/DR investments on projected capacity growth without separately estimating how customers might respond to higher retail rates implied by the higher assumed fuel and construction costs.

Nuclear Limits

We placed limits on the amount of nuclear capacity that could be added in each region to reflect the lengthy regulatory process and construction schedules for new nuclear plants. For 2015, no new nuclear construction was assumed complete. For 2020, we constrained RECAP to limit nuclear construction to those projects that have applied for a Nuclear Regulatory Commission (NRC) license, representing approximately 18.5 GW of new capacity. For 2025, we limited nuclear construction to those projects that have applied or announced intentions to apply to the NRC for a license, which totals about 38.5 GW of new capacity. Between 2025 and 2030, we assumed that the industry could add between one GW and four GW of new nuclear capacity in each region, above the overall 2025 limit of 38.5 GW. This brings the total limit for 2030 to 64 GW.

The Brattle Group's Reference Scenario

As an interim step in our analysis, we created a "Reference Scenario." This scenario is similar to the AEO 2008 forecast, but reflects higher construction costs and fuel prices. The Reference Scenario should not be viewed as our "base" or "most likely" scenario, but rather a starting point for our analysis. Figure 1-9 shows the cumulative capacity built between 2010 and 2030 under the Reference Scenario. Compared to the AEO 2008 forecast of 231 GW of new capacity built, the Reference Scenario builds 214 GW of new capacity.[19] As in the AEO 2008 forecast, almost half of new generation capacity through 2030 is built in the South, followed by the Midwest and the West (Figure 1-10). New generation capacity in the Northeast constitutes less than 10 percent of nationwide capacity.[20]

[19] Further comparisons of our Reference Scenario and AEO forecasts are shown in Appendix A, Figure A-1.

[20] The difference in the overall amount of generation capacity may be due to differences in how load is modeled, capacity availability, and transmission losses.

Figure 1-9
Cumulative New Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)

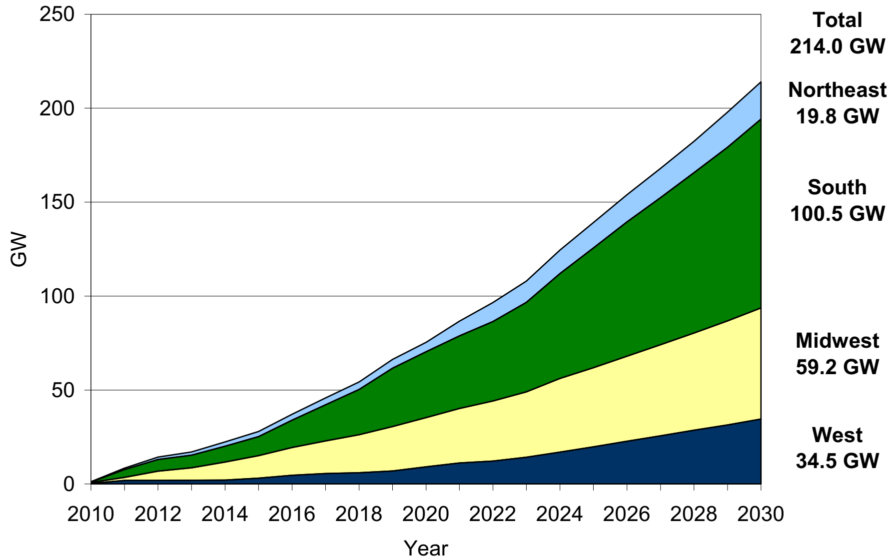
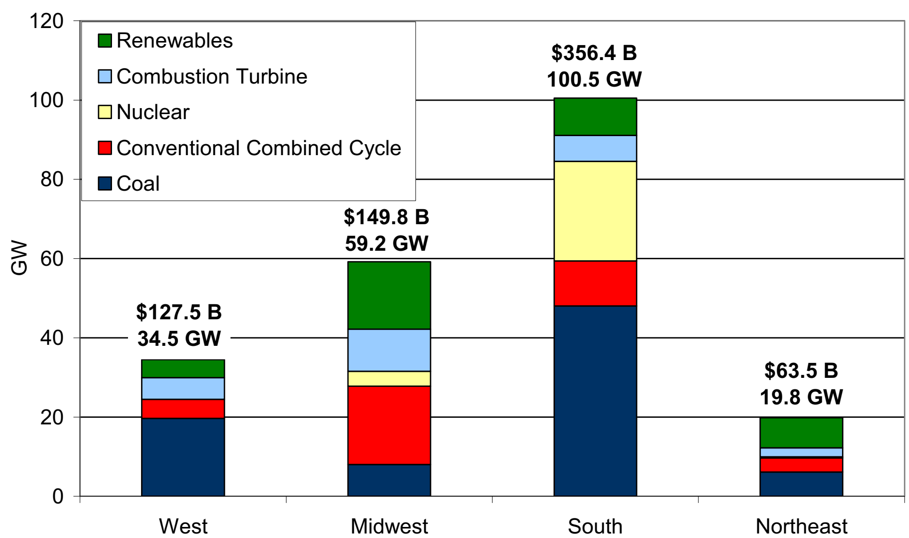


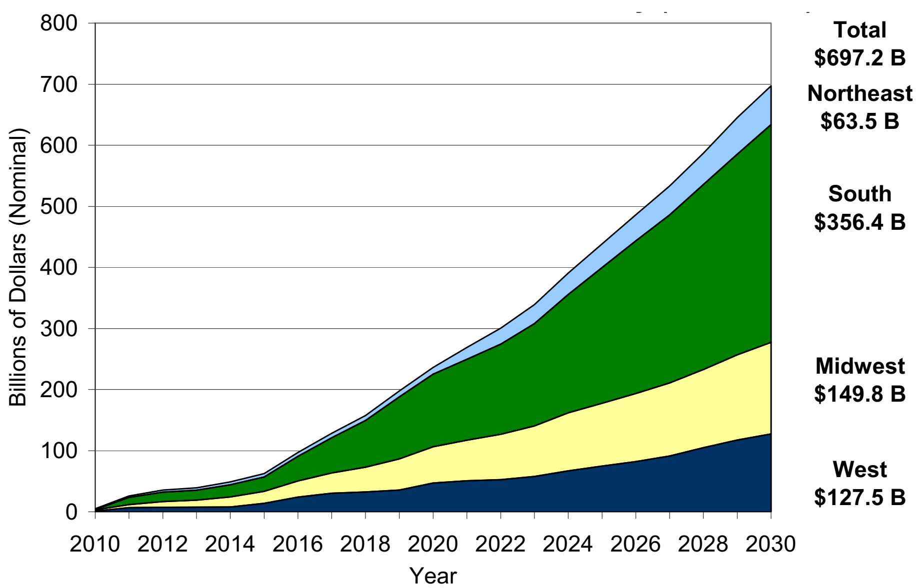
Figure 1-10
Required New Regional Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)



Generation Investment in the Reference Scenario

Under the assumed construction costs, the Reference Scenario capacity expansion would entail spending $697 billion over the 2010 to 2030 period (undiscounted, nominal, mixed-year dollars assuming a 1.9-percent annual inflation rate). Figure 1-11 shows the cumulative capital cost by region, where the South accounts for slightly more than half of the total ($356 billion). Although construction costs are somewhat lower in the South compared to the rest of the country, the cumulative capital costs reflect the prevalence of new baseload generation – coal and nuclear – that is being built in the South compared to other regions. On a cumulative installed basis, the mix of generation resources built in the South averages $3,560/kW, only slightly less expensive than capacity built in the West ($3,630/kW), higher than that built in the Northeast ($3,150/kW), and much higher than that built in the Midwest ($2,542/kW).

Figure 1-11
Cumulative Capital Requirements New Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)



Chapter 2: Energy Efficiency and Demand Response Programs and Their Impacts

For a number of reasons, there has been a strong revival of interest in utility EE/DR efforts. EE/DR generally are defined as measures that utilities undertake to reduce customer energy consumption and peak loads.[21] The Energy Independence and Security Act of 2007 (EISA) contained several initiatives to increase energy efficiency. Several states have set ambitious goals to reduce or even eliminate the growth in electricity demand. Utilities are facing increased opposition to building new power plants, in part because of public perceptions that robust efforts to intensify energy efficiency measures and rely more on renewable generation can eliminate the need for new generation capacity, particularly as a national policy to limit carbon emissions may be enacted in the next decade.

EE/DR Forecast Overview

As an increasing emphasis is placed on the importance of EE/DR as resources in the nation's energy mix, The Edison Foundation asked *The Brattle Group* to incorporate the potential peak demand and energy savings that EE/DR could provide and to estimate their impact on projected utility generation and investment requirements. *The Brattle Group* did so by relying upon a study by EPRI.[22] This study produced a regional forecast of the measure-specific potential savings that could be realized through the implementation of EE/DR programs in addition to important efficiency measures already imposed by EISA, which EIA already took into account in its AEO 2008 forecast. Specifically, the study produces two "potential" estimates.

- ***"Realistically Achievable Potential" (RAP) Efficiency Base Case Scenario***. This scenario recognizes imperfect dissemination of customer information and the real-world factors associated with utility program implementation (i.e., budgetary constraints, competing priorities, etc.). The RAP Efficiency Base Case Scenario also reflects realistic customer participation rates based on recent historical experience with EE/DR programs. These realistic customer participation rates take into account existing political and regulatory barriers that are likely to limit the amount of savings that might be achieved through EE/DR programs.

- ***"Maximum Achievable Potential" (MAP) Efficiency Scenario***. This scenario is a measure of all energy and peak demand savings that would be adopted by customers under ideal utility program conditions. The MAP Efficiency Scenario does not reach the full theoretical economic potential because there are barriers to customer adoption of measures that appear to be cost-effective that will

[21] The usage in this paper of "energy efficiency" or "EE/DR" includes energy efficiency efforts as well as demand response.

[22] A report on the results of the study, entitled *Assessment of Achievable Potential For Energy Efficiency and Demand Response in the U.S. (2010-2030),* by the Electric Power Research Institute will be published soon.

not be overcome with utility programs (e.g., customer unwillingness to purchase certain technologies or to enroll in cost-effective programs).

The EPRI study contains substantial additional detail on the derivation of these and other potential estimates. For the purposes of this study, we examine the regional RAP Efficiency Base Case Scenario and the MAP Efficiency Scenario savings trajectories and their associated costs. ***In particular, our RAP Efficiency Base Case Scenario includes EE/DR savings as our best estimate of projected demand for electricity prior to the full modeling of price response or a national carbon policy.***

Energy Efficiency

One of the two components of the EPRI forecasts is energy efficiency (EE). The EE forecasts consider an extensive set of technologies and measures for the residential, commercial, and industrial sectors. These EE technologies and measures affect different end uses. Programs, products, and services that encourage customers to adopt EE technologies and measures come in several forms, including rebates and subsidies. Following are some of the various technologies and measures considered in the EPRI study and the end uses they affect.

- ***Residential High-Efficiency Equipment:*** The residential high-efficiency equipment categories include: central and room air conditioners, heat pumps, efficient lighting, water heating, refrigerators, freezers, clothes washers and dryers, and dishwashers. Other measures and devices include: air conditioning maintenance, ceiling and whole-house fans, ceiling and wall insulation, duct insulation and repair, external shades, foundation and wall insulation, heat pump maintenance, infiltration control, programmable thermostats, reflective roofs, storm doors, faucet aerators, pipe insulation, and low-flow showerheads. These measures affect various end uses, such as cooling, space heating, lighting, water heating, refrigeration, clothes washing and drying, and dishwashing.

- ***Commercial High-Efficiency Equipment:*** The commercial high-efficiency equipment categories include: central air conditioners, chillers, heat pumps, fans, other water heating, lighting, refrigeration, and office equipment. Other measures and devices include duct insulation, economizers, energy management control systems, fans with energy-efficient motors, variable speed control fans, programmable thermostats, variable air volume systems, variable speed drive on pumps, water temperature reset devices, outdoor daylight controls, light-emitting diode exit lighting, occupancy sensors, task lighting, photovoltaic outdoor lighting, high-efficiency compressors, anti-sweat heater controls, floating head pressure controls, glass door installations, and vending machines. These technologies and measures affect various end uses, such as cooling, space heating, ventilation, lighting, water heating, and refrigeration.

- ***Industrial High-Efficiency Equipment:*** The industrial high-efficiency equipment categories include: motors of various types and sizes; electric resistance and radio frequency devices; heating, ventilating, and air conditioning systems; and incandescent, fluorescent, and high-intensity discharge lighting. These measures include various end uses, such as process heating, machine drives, and lighting.

Demand Response

While energy efficiency technologies and measures are designed for the purpose of reducing overall electricity consumption, DR programs focus specifically on reducing peak demand. They also provide a means for cutting back load during times of system emergencies, system peaks, or high market prices. The EPRI study modeled three types of DR programs for the residential, commercial, and industrial sectors.

- ***Direct Load Control (DLC):*** Customer end uses are controlled directly by the utility through a "switch" or other comparable two-way communication-capable control device. This DLC device allows for customers' end-use settings to be automatically and remotely altered such that the loads are reduced during short "critical" event periods when the reductions are needed most. Customers commonly have the option of overriding the functionality of the DLC devices before or during events. End uses commonly controlled through DLC include air conditioners and water heaters. In exchange for participation, customers are typically awarded a payment or a rebate on their bill.

- ***Interruptible Service:*** Interruptible service programs require customers to reduce their usage by a pre-specified amount when called upon by utilities during system emergencies. These programs are generally only available for commercial and industrial (C&I) customers. For their participation, these customers generally receive a lower rate and/or a payment for the load reduction they provide.

- ***Dynamic Pricing:*** Dynamic pricing includes rate designs that are time-varying and reflect the higher cost to the utility of providing electricity during the peak period of the day. These designs go beyond the basic flat rate or even the time-of-use (TOU) rate, and can be "dispatched" during times of high market prices or system emergencies. Examples include critical peak pricing (CPP), peak time rebates (PTR), and real-time pricing (RTP). Customers must be equipped with an interval meter or "smart meter" as part of the evolving advanced metering infrastructure (AMI) to be eligible to participate in any dynamic pricing program. For CPP and RTP, customers receive an incentive equal to the potential bill savings that would come from shifting load from higher-priced (peak) periods to lower-priced (off-peak) periods. For PTR, customers receive a credit on their bill equal to the peak reduction multiplied by the pre-determined rebate amount.

In the EPRI forecast, the residential DLC programs apply to central air conditioning and water heating loads. The C&I programs target cooling, lighting, and other end uses. The interruptible service programs apply only to C&I customers and include interruptible, demand bidding, emergency, and ancillary services. The combined peak demand reduction of all of these programs produces the systemwide impact.

Load Forecast Summary for AEO 2008 and EE/DR Scenarios

The resulting annual peak and energy forecasts used by *The Brattle Group* in this analysis are shown in Figure 2-1 and Figure 2-2. By 2030, the peak reduction from the AEO 2008 load forecast is 12 percent in the RAP Efficiency Base Case Scenario and 19 percent in the MAP Efficiency Scenario (Figure 2-1).[23] Energy savings in 2030, shown in Figure 2-2, are five percent in the RAP Efficiency Base Case Scenario and eight percent in the MAP Efficiency Scenario.

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[23] For a discussion of how these EE/DR projections differ from those presented in the final EPRI study, see Appendix A.

Figure 2-1
Comparison of U.S. Peak Demand Forecasts

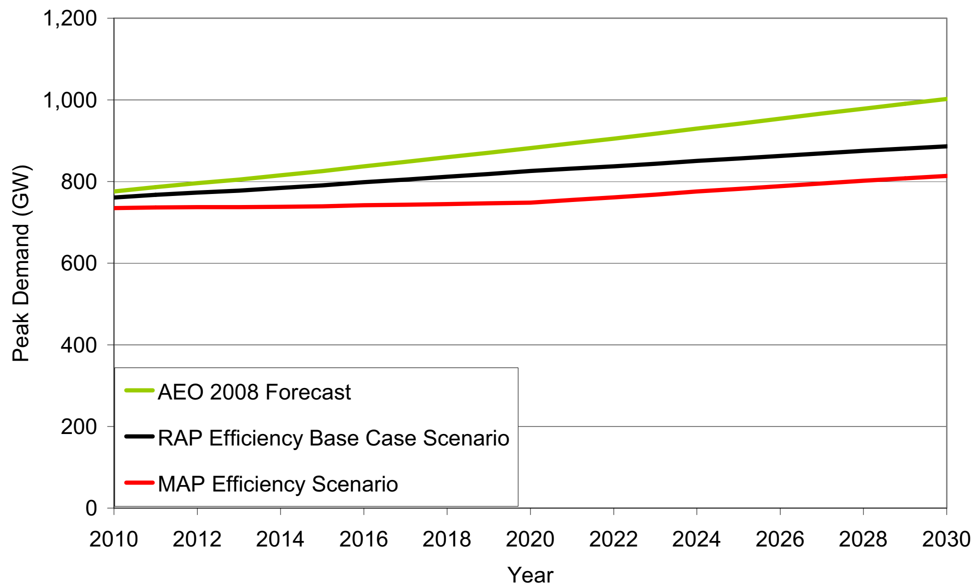
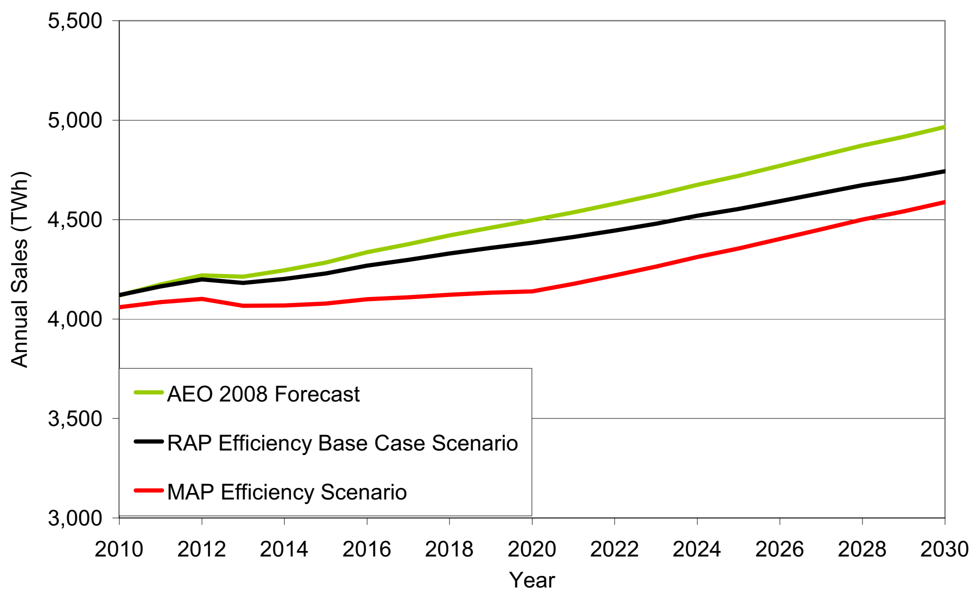


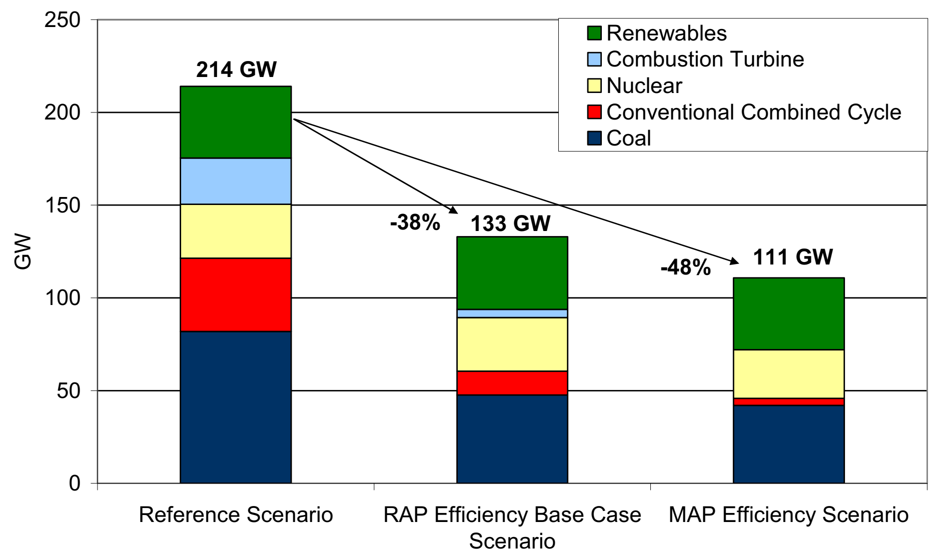
Figure 2-2
Comparison of U.S. Electricity Sales Forecasts



Impacts of EE/DR Forecasts on Capacity Expansion Projections

Relative to the Reference Scenario, the RAP Efficiency Base Case Scenario and the MAP Efficiency Scenario lead to a dramatic reduction in the amount of new generation capacity that would need to be built. Our projection of new generation capacity between 2010 and 2030 drops from 214 GW in the Reference Scenario to 133 GW in the RAP Efficiency Base Case Scenario. The amount of projected new capacity drops further to 111 GW in the more aggressive MAP Efficiency Scenario. These changes in total U.S. new generation capacity under the two energy efficiency (no carbon policy) scenarios are shown in Figure 2-3.

Figure 2-3
Impact of RAP and MAP EE/DR Programs on Reference Scenario Required Generation Capacity
No Carbon Policy (2010-2030)



The mix of new capacity also changes in the two EE/DR scenarios (no carbon policy) because they project an improving load factor for all regions of the United States. In other words, the RECAP projections for these scenarios suggest that, on a percentage basis, more peaking capacity will be avoided than baseload. As illustrated in Table 2-1, in the RAP Efficiency Base Case Scenario, new coal-based capacity decreases by 42 percent, while new combustion turbine (CT) capacity decreases by 83 percent. The load factor improvement also persists in the MAP Efficiency Scenario, where 49 percent of new coal capacity is avoided, and *all* new CT capacity is avoided. However, it is important to note that, despite the changing mix of new capacity, coal dominates the total amount of new builds across the three scenarios.

Table 2-1
Changes in New Capacity Under Energy Efficiency Scenarios

Changes in New Capacity from Reference Scenario Through 2030 (in GW)	RAP Efficiency Base Case Scenario No Carbon Policy		MAP Efficiency Scenario No Carbon Policy	
Renewables	+0.6 GW	(+ 1.5%)	+0.2 GW	(+ 0.5%)
Combustion Turbine	-20.6 GW	(-82.6%)	-25.0 GW	(-100.0%)
Nuclear	-0.2 GW	(- 0.8%)	-2.9 GW	(-10.1%)
Conventional Combined Cycle	-26.6 GW	(-67.3%)	-35.7 GW	(-90.5%)
Coal	-34.2 GW	(-41.8%)	-39.7 GW	(-48.6%)
Total Change in New Capacity (GW)	**-81.1 GW**	**(-37.9%)**	**-103.2 GW**	**(-48.2%)**

* Note: Totals may not equal sum of components due to independent rounding.

The mix of avoided generation capacity plays an important role in determining the avoided capital costs achieved through EE/DR. In the RAP Efficiency Base Case Scenario, the total cost of new capacity is projected to be $505 billion in nominal terms. This represents a 28-percent decrease from the Reference Scenario (Figure 2-4 and Figure 2-5).

Figure 2-4
Cumulative Capital Requirements for New Generation Capacity for RAP Efficiency Base Case Scenario No Carbon Policy (2010-2030)

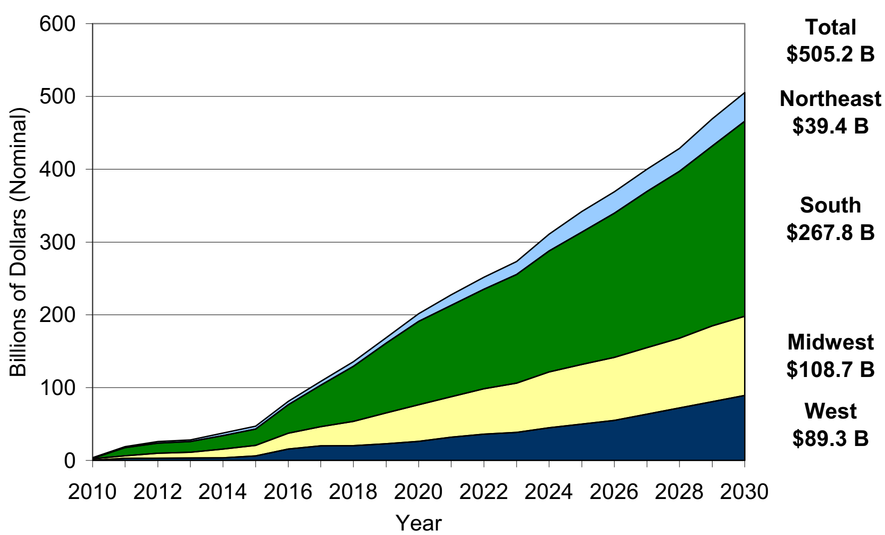
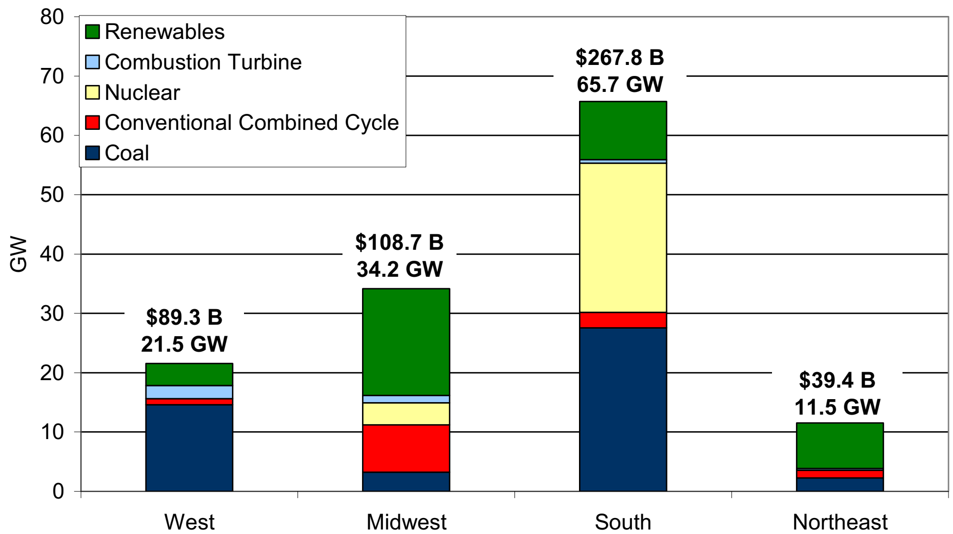


Figure 2-5
Required New Regional Generation Capacity for RAP Efficiency Base Case Scenario
No Carbon Policy (2010-2030)



The MAP Efficiency Scenario projects the total cost of new capacity to be around $455 billion in nominal terms, a 35-percent decrease from the Reference Scenario (Figure 2-6 and Figure 2-7).

Figure 2-6
Cumulative Capital Requirements for New Generation Capacity for MAP Efficiency Scenario
No Carbon Policy (2010-2030)

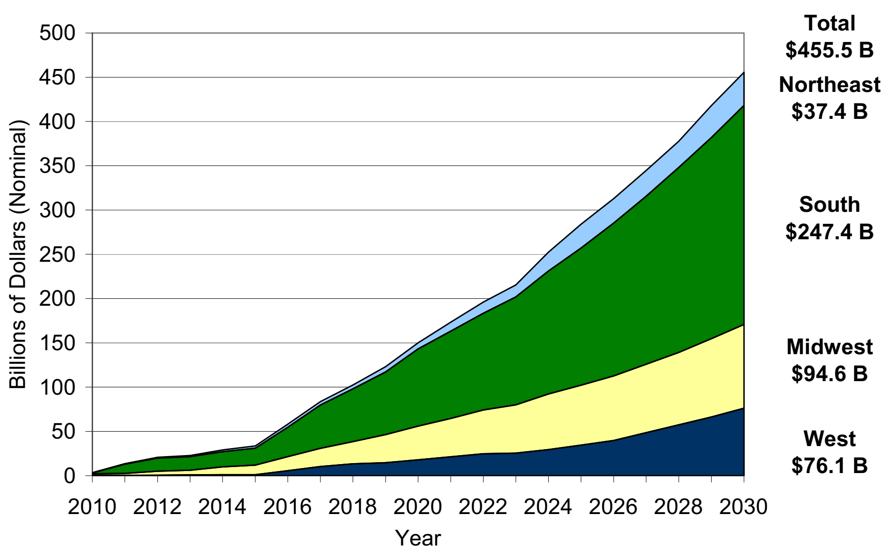
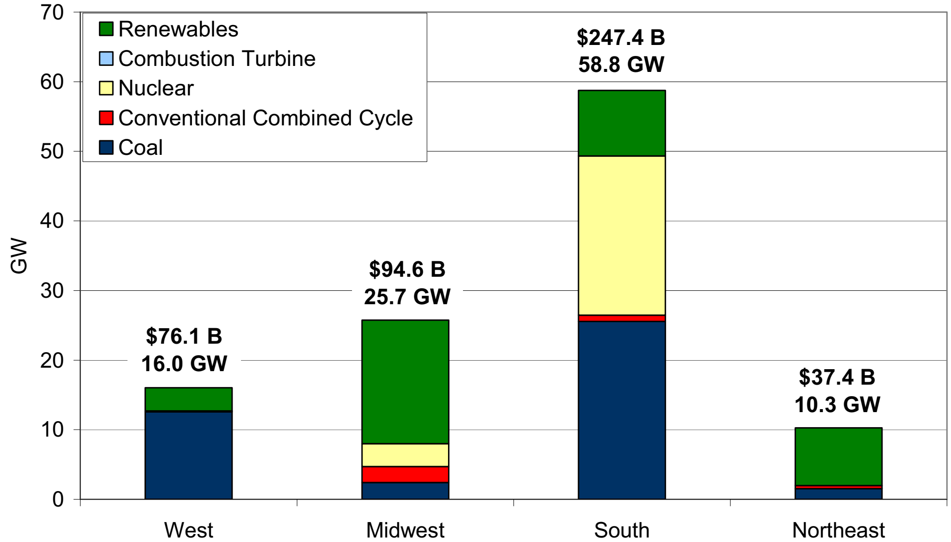


Figure 2-7
Required New Regional Generation Capacity for MAP Efficiency Scenario No Carbon Policy (2010-2030)



The larger relative reduction in new costs in the MAP Efficiency Scenario is driven by two factors. First, the EE/DR assumptions are more aggressive, resulting in larger peak reductions and a higher level of avoided capacity. Second, a higher relative percentage of coal capacity is avoided through this scenario, further reducing the total cost. Ultimately, in nominal dollars, the RAP Efficiency Base Case Scenario leads to a $192-billion (28-percent) reduction in the capital cost of new generation, while the MAP Efficiency Scenario leads to a $242-billion (35-percent) reduction.

Costs Associated with EE/DR Programs

The EE/DR forecasts that we have analyzed in this study are composed of a number of EE/DR programs, and each of these programs has its own associated costs. For example, in a program to encourage the adoption of more energy-efficient appliances, residential customers might receive a rebate for the purchase of a new air conditioner, refrigerator, or dishwasher. Similarly, for their participation in an interruptible service program, industrial customers might receive a discounted electricity rate or a rebate for each kilowatt-hour (kWh) of reduced consumption during peak periods.

A major cost that is likely to be capitalized in the EE/DR forecast is investment in AMI, the equipment that enables dynamic pricing (as well as a wide range of operational benefits and reliability improvements). Harvesting potential gains from DR programs will require a substantial capital investment in AMI, as well as customer adoption of dynamic pricing, which is necessary to enable customers to curtail loads or shift consumption patterns away from peak periods in response to price signals. To estimate the capital cost of

DR initiatives, we separately projected the investment in AMI that likely would be necessary to support these forecasts.[24]

Our projection of AMI investment costs is driven primarily by three factors:

- **Final AMI penetration rate**: For the MAP Efficiency Scenario, we have assumed that 30 percent of residential customers and 50 percent of C&I customers would be equipped with AMI. These participation rates were reduced by roughly 60 percent to produce the RAP Efficiency Base Case Scenario.
- **AMI deployment rate over time**: We assume that AMI deployment will begin in 2010 for C&I customers and in 2015 for residential customers. Full deployment will be reached in 2030 for the RAP Efficiency Base Case Scenario. Deployment is accelerated under the MAP Efficiency Scenario, reaching full deployment in 2020.
- **Cost of AMI per customer**: Based on a review of California shareholder filings for AMI budget approval, we have estimated the full cost per residential customer to be $300. The cost per C&I customer is estimated at $1,500.

In addition to estimating the cost of AMI, the measure costs of energy efficiency also were included. Energy efficiency measure costs do not include direct program costs, such as program design, administration, marketing, and evaluation. They are the specific costs of the measure, such as equipment and installation costs. Assumed average levelized measure costs were assumed to be: $0.0188 per kWh in 2010, $0.0299 per kWh in 2020, and $0.0279 per kWh in 2030.[25] With these assumptions, we are able to project the annual investment in AMI and energy efficiency between 2010 and 2030.

Table 2-2 shows these costs on an undiscounted nominal basis. Total EE/DR outlays are about 44 percent of the avoided capacity cost in the RAP Efficiency Base Case Scenario and 79 percent of avoided capacity costs in the MAP Efficiency Scenario.

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[24] These are very rough approximations that are intended only to provide an idea as to the magnitude of DR capital costs relative to the avoided capital costs of generation from Demand Side Management (DSM). A detailed, region-specific, bottom-up study would be necessary to provide precision to these estimates.

[25] Costs provided by Global Energy Partners as inputs to the forthcoming EPRI report, *Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030),* and used as the basis of our EE/DR scenarios.

Table 2-2
Estimated EE/DR Capital Costs (2010-2030)

	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy
EE/DR Capital Costs Through 2030 (rounded to nearest billion)		
AMI Capital Costs	$19	$27
Energy Efficiency Measure Cost	$66	$165
Total EE/DR Capital Costs, ($ Billions)	**$85**	**$192**

The Role of EE/DR in Displacing New Generation

The analysis indicates that aggressive EE/DR could be effective in displacing a significant amount of new generation capacity and in reducing overall capital requirements. However, it is equally clear that EE/DR (as modeled here) does not eliminate the need to build new generation, nor does it dramatically reduce the capital necessary to fund construction of new generating plants. The RAP Efficiency Base Case Scenario, which estimates the impact of aggressive EE/DR programs under likely real-world conditions, reduces the need for new generation capacity by about 38 percent by 2030. With correctly modeled price impacts and a national carbon policy, this percentage will be increased. However, the amount cannot be predicted due to several factors, including a number of plants already "in the pipeline" and mandated renewable capacity requirements already exceeding 39 GW.

In terms of reducing generation capital requirements, the impact of EE/DR is not proportional to the impact on reducing generation capacity. Because of the cost of implementing EE/DR programs, especially the cost of new AMI technology, the overall reduction in projected utility capital requirements is far less than the reduction in generation capacity. When EE/DR costs are factored in, overall capital requirements are reduced by seven percent under the MAP Efficiency Scenario and 15 percent under the RAP Efficiency Base Case Scenario (Table 2-3).

Table 2-3
Summary of Avoided Generation Capital Investment Due to EE/DR (2010-2030)

Total Investment after EE/DR

	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy
Total Reference Scenario investment	697	697
(Avoided) generation investment due to EE/DR	(192)*	(242)
Equals new scenario investment	505	455
Capital cost of EE/DR and AMI	85	192
Total Investment after EE/DR	**590**	**647**
Percent reduction in capital investment due to EE/DR	**-15%**	**-7%**

Net (avoided) generation investment

	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy
(Avoided) generation investment due to EE/DR	(192)	(242)
Capital cost of EE/DR and AMI	85	192
Net (avoided) generation investment	**(107)**	**(50)**

* Numbers in parentheses (#) indicate negative numbers.

Chapter 3: Projecting the Capital Cost Of Carbon-Related Investments: The Prism RAP Scenario

The issue of climate change is central to any long-term projection of electricity investment, particularly in generation capacity. In fact, the prospect that federal legislation will be enacted to reduce carbon emissions in the sector already has affected utility planning and investment analysis. Although the emission targets, timing, and form of a national carbon policy have yet to be determined, most industry and political observers believe that a federal climate change policy will be enacted within the next few years.

Recognizing the importance of this issue to future generation investments, as well as the current uncertainty regarding the eventual carbon policy, The Edison Foundation asked *The Brattle Group* to evaluate one particular scenario of generation and efficiency investments that EPRI has developed, known as the "Prism Analysis." The Prism Analysis represents a suite of technologies that EPRI has concluded are feasible to deploy in the 2010 to 2030 timeframe and will lead to reduced carbon emissions in the electricity sector.[26]

The EPRI Prism Analysis technology targets are estimates of technically feasible development and deployment of technologies, but do not necessarily reflect an optimal mix that might result from responses to carbon prices. In fact, the Prism Analysis results in more low-carbon generation capacity being built by 2030 than would be needed strictly to serve increased load. Given these observations, *The Brattle Group's* analysis under the Prism RAP Scenario assumes that only certain Prism technologies are deployed, and focuses on the carbon and capital cost implications.

Prism Analysis Technology Targets

Figure 3-1 shows the EPRI Prism Analysis targets for technology deployment compared to EIA's AEO 2008 forecast. The Prism consists of seven broad types of technologies:

- Energy efficiency that reduces load growth from the AEO 2008 forecast levels to approximately the levels in our RAP Efficiency Base Case Scenario;
- Roughly double the level of renewable generation capacity over the AEO 2008 forecast levels;

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[26] See *The Power to Reduce CO_2 Emissions: The Full Portfolio*, EPRI Discussion Paper, August 2007, for a description of the primary technologies. EPRI has updated this analysis to incorporate the AEO 2008 forecast as a benchmark. EPRI also has examined the role that the Prism technologies could play in reducing the cost of carbon-reduction policies. See *The Value of Technological Advance in Decarbonizing the U.S. Economy* by Richard Richels and Geoffrey Blanford, AEI/Brookings Joint Institute for Regulatory Studies, Working Paper 07-19, November 2007.

- A tripling of nuclear capacity by 2030 over the AEO 2008 forecast levels;
- Advanced coal generation technology that enhances the efficiency of existing and new coal plants;
- CCS widely deployed after 2020;
- Plug-in hybrid electric vehicles (PHEVs) reaching a third of new vehicle sales by 2030; and
- Increased penetration of distributed energy resources (DER), including solar power.

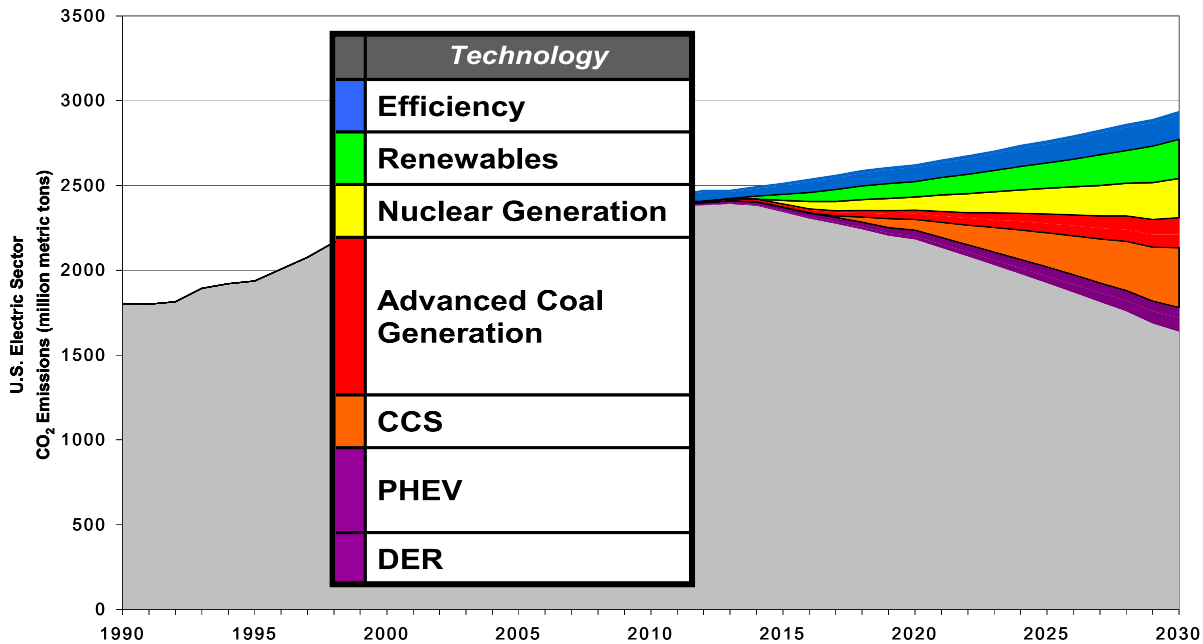
Figure 3-1
EPRI Prism Analysis Targets for Carbon-Related Technology Changes

Technology	EIA 2008 Reference	Target
Efficiency	Load Growth ~ +1.05%/yr	Load Growth ~ +0.75%/yr
Renewables	55 GWe by 2030	100 GWe by 2030
Nuclear Generation	15 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Heat Rate Improvement for Existing Plants 40% New Plant Efficiency by 2020–2030	1-3% Heat Rate Improvement for 130 GWe Existing Plants 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Light-Duty Vehicle Sales by 2017; 33% by 2030
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

Source: Based on data compiled by Electric Power Research Institute (EPRI), found at: http://www.iea.org/Textbase/work/2008/roadmap/2a_Tyran_EPRI%20Roadmaps.pdf.

Figure 3-2 shows the impact of these technologies on emissions from the electric generation sector of the industry, with colors of the "wedges" corresponding to the left column of Figure 3-1 (this depiction yields the "prism" effect from which the analysis draws its name). As seen in Figure 3-1, carbon emissions from electricity production would rise by about 20 percent from current levels in the AEO 2008 forecast, while the emissions resulting from the application of the Prism technologies represent about a 40-percent reduction from the AEO 2008 forecasted levels.

Figure 3-2
EPRI Prism Analysis Impacts of Technology Changes on Electric Sector CO_2 Emissions



Source: Based on data compiled by Electric Power Research Institute (EPRI), found at: http://www.iea.org/Textbase/work/2008/roadmap/2a_Tyran_EPRI%20Roadmaps.pdf.

It is also evident from Figure 3-2 that most of the reductions occur from four types of technologies: energy efficiency, CCS, nuclear, and renewables. Our analysis focuses on these technologies because they provide for the greatest emissions reductions.

Developing the Prism RAP Scenario

The four major technologies included in the Prism Analysis—energy efficiency, CCS, renewables, and nuclear—were incorporated into *The Brattle Group's* RECAP model simulations in the following manner:

- **Energy Efficiency** was included in the Prism RAP Scenario by incorporating the same EE/DR assumptions that were used in the RAP Efficiency Base Case Scenario. This scenario reduced the growth in electricity demand in a nearly identical manner as the Prism target (which reduced annual average load growth from 1.05 percent to 0.75 percent);

- **CCS** was modeled by requiring all coal builds in 2020 and after to incorporate CCS. The cost of CCS was derived from the EPRI analysis of integrated gasification combined-cycle (IGCC) with CCS capability that was 90 percent effective in capturing carbon emissions;

- **Renewables** were increased by assuming the expansion of RPS requirements between 2020 and 2030 in regions that already had such requirements, and adopting modest renewable goals after 2020 in regions that currently have no state-level requirements, to yield approximately the 100 GW capacity level in the EPRI Prism Analysis.

- **Nuclear** was introduced into the model by converting our regional nuclear build limits to requirements for nuclear construction in RECAP, as these were already at 64 GW by 2030;

Generation Capacity and Costs: The Prism RAP Scenario

The results of the Prism RAP Scenario are summarized in Figure 3-3, Figure 3-4, and Figure 3-5. The Prism RAP Scenario projects that 216 GW of new generation capacity would be built between 2010 and 2030, compared to 133 GW projected in the RAP Efficiency Base Case Scenario. This occurs primarily because the Prism RAP Scenario assumes specific investments in new low-carbon generation capacity, without regard to whether that generation mix is the least-cost way to meet the projected load growth. In fact, the investment requirements (including about 100 GW of renewables and 64 GW of nuclear) account for more capacity than the RAP Efficiency Base Case Scenario implies. Additional amounts of coal with CCS and small amounts of natural gas-based capacity are added in some regions, as required by reliability considerations for backing up renewable generation. The Prism RAP Scenario also estimates that about 20 GW of retirements (vs. 2 GW in the RAP Efficiency Base Case Scenario) would occur as a result of the nuclear, renewable, and coal with CCS investments that are assumed.

Figure 3-3
Cumulative New Generation Capacity in Prism RAP Scenario
With Carbon Policy (2010-2030)

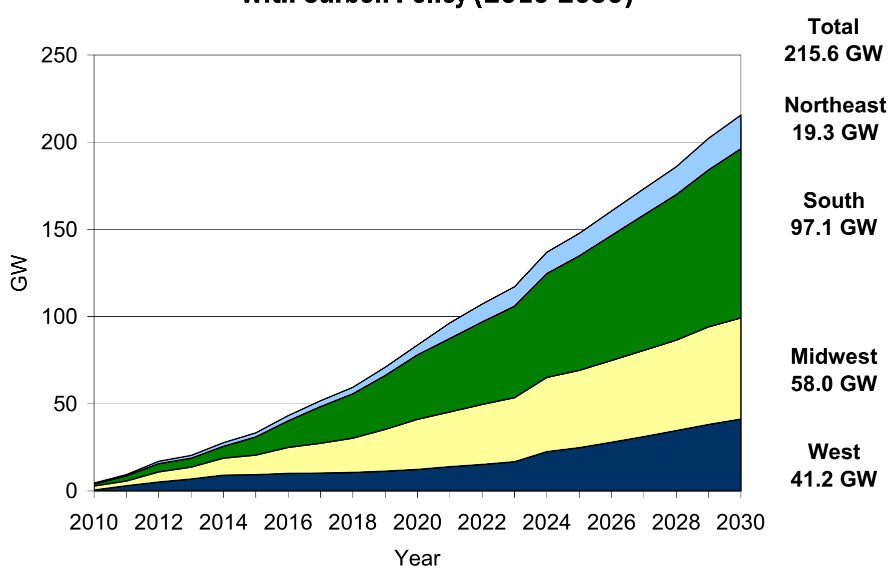


Figure 3-4
Regional Capacity Additions and Generation Capital Costs in Prism RAP Scenario With Carbon Policy (2010-2030)

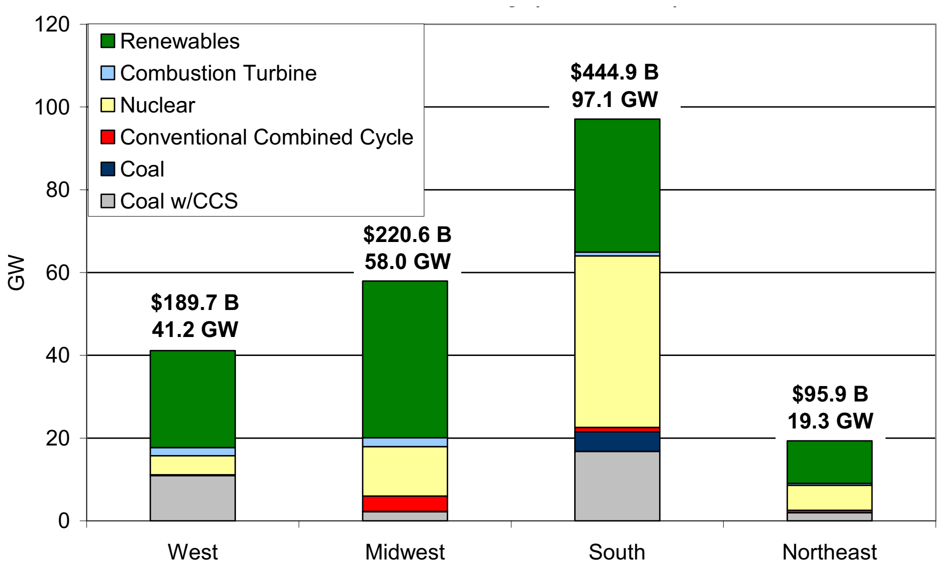
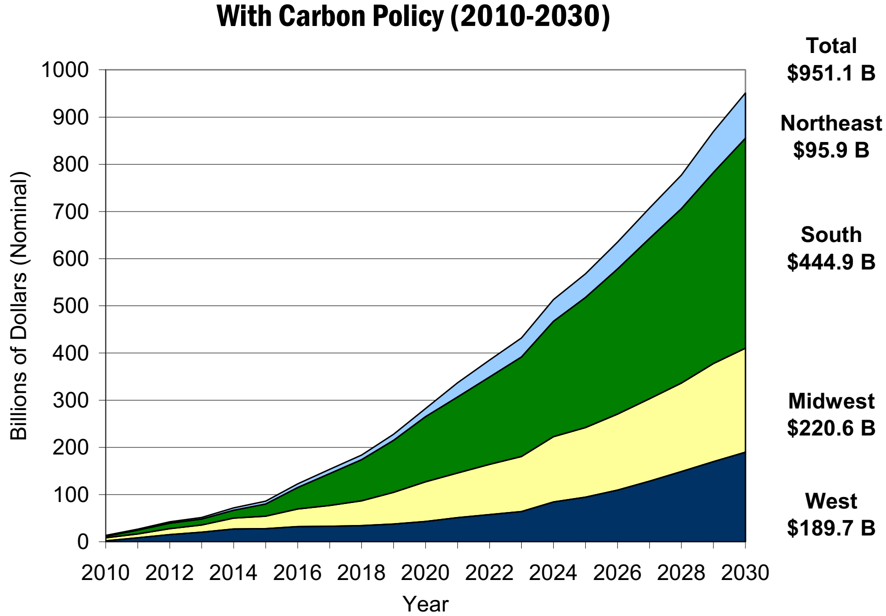


Figure 3-5
Cumulative Capital Requirements for New Generation Capacity in Prism RAP Scenario With Carbon Policy (2010-2030)



The capital cost associated with the supply investments in the Prism RAP Scenario is about $951 billion between 2010 and 2030. When AMI and program costs associated with the RAP Efficiency Base Case Scenario (a total of $85 billion) are added, the resulting figure is $1.036 trillion. This represents an increase of about 50 percent over the capital costs in the Reference Scenario and approximately a 75-percent increase above the overall capital costs of the RAP Efficiency Base Case Scenario.

Chapter 4: Projected Costs of Investments In Transmisson and Distribution Systems

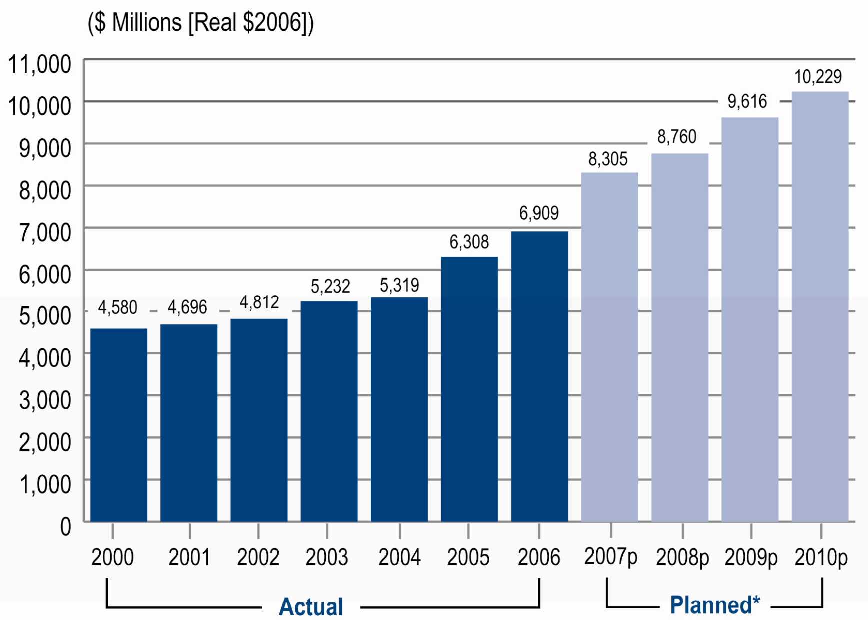
Investments in generation and EE/DR programs are the focus of much policy attention as utilities make major resource planning decisions in the face of substantial uncertainties regarding input commodity (e.g., cement, steel, and fuel) prices and emissions requirements. Utilities also will have to undertake major and growing investments in transmission and distribution systems.

Estimating future transmission capital requirements over a multi-decade horizon is extremely difficult. This is due to the variety of objectives and unique circumstances that motivate transmission investment, as well as the fact that the data available on announced projects, current transmission expenditures, and unit-level costs are neither comprehensive nor always reliable. It is particularly difficult to predict the timing or cost of major transmission additions – they are lumpy and frequently delayed or rerouted. Furthermore, proposed transmission developments exhibit a wide range of costs due to varying types of transmission lines (e.g., underground or overhead), the inclusion of different numbers of substations, the terrain crossed, and the cost of land. Finally, the recent historical pattern of new generating plants built at locations needing minimal grid build-out is shifting toward new plants in more distant, resource-rich areas. This phenomenon could considerably boost transmission miles built per installed megawatt (MW) of generation capacity, though we cannot reliably predict the magnitude of this effect.

Transmission System Costs and Data

The most detailed source of planned transmission projects is the “Coordinated Bulk Power Supply Program Report (Form EIA-411),” made publicly available by the North American Electric Reliability Corporation (NERC) through its annual Energy Supply & Demand (ES&D) database. The NERC ES&D data, which currently extend through 2015, include only announced or planned high-voltage projects [those that are rated at 230 kilovolts (kV) and above], thereby excluding investments in transmission lines of lower voltage (those that are rated below 230 kV) and other non-transmission line elements such as substations. The NERC ES&D data indicate that an additional 13,020 miles of high-voltage transmission lines will be built between 2007 and 2015. A second source of transmission data, which includes lower-voltage projects, comes from the Edison Electric Institute's "Electric Transmission Capital Budget & Forecast Survey."[27] This survey projects transmission investment from 2007 to 2010 based on responses from EEI's members. As seen in Figure 4-1, annual transmission investment by shareholder-owned electric utilities during the 2007 to 2010 period will be in the range of $8.3 billion to $10.2 billion, corresponding to approximately $37 billion in total investment (2006 dollars).

Figure 4-1
Actual and Planned Transmission Investment
By Shareholder-Owned Electric Utilities (2000-2010)



p = preliminary

Note: The Handy-Whitman Index of Public Utility Construction Costs used to adjust actual investment for inflation from year to year. The GDP Deflator used to adjust planned investment for inflation from year to year. Data represent both shareholder-owned utilities and stand-alone transmission companies.

*Planned total industry expenditures are estimated from 85% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey & FERC Form 1s.

Source: Edison Electric Institute, Business Information Group.

[27] The 2007 EEI "Electric Transmission Capital Budget & Forecast Survey" focuses on U.S. shareholder-owned electric utilities, including both vertically integrated and stand-alone transmission utilities. Sixty shareholder-owned electric utilities, whose stocks are publicly traded on major U.S. stock exchanges, were asked to participate. These utilities were either holding companies consisting of one or more operating subsidiaries or consolidated electric utilities. In addition, the survey also sought to capture data from 10 additional utilities that are either privately held or owned by non-U.S. corporations.

EEI's January 2008 "Transmission Projects: At a Glance" report also was used to estimate the per-unit costs of new transmission lines (i.e., investment dollar per mile and per MW-mile across various voltage classes). Our unit costs for new transmission are based on an EEI transmission project report, which contains recent estimates of project costs for a number of specific actual projects.[28] A summary of unit transmission costs based on that report is shown in Table 4-1.

Table 4-1
Recent Unit Transmission Costs
2008 Dollars

Voltage (kV)	Cost (Thousands of Dollars/Mile)	Capacity (MW)*	Cost (Millions of Dollars/GW-Mile)*
230	$2,076.5	500	$5.46
345	$2,539.4	967	$2.85
500	$4,328.2	2,040	$1.45
765	$6,577.6	5,000	$1.32

Assumptions, Sources, and Notes:
Source is EEI's "Transmission Projects at a Glance," January 2008.

Projects that use underground lines, have more than three segments, or have significantly mixed voltage levels are excluded.

The cost of projects is assumed to be given in 2007 dollars unless specified, and has been adjusted using the 2007 to 2008 percentage change in the Handy-Whitman Index.

*Based on a subset of projects where capacity was reported. Gigawatt miles are calculated by multiplying the capacity of the line (in GW) times the length of the line (in miles).

Using the dollar-per-mile figures for various voltage classes in Table 4-1 (adjusted for assumed 1.9 percent inflation), we estimate the overall nominal cost of the projects in the NERC ES&D dataset.[29] Table 4-2 shows that our estimates of transmission investments based on these data are approximately $32.5 billion through 2015.

[28] Note that these data are based on a partial sample of EEI members only.

[29] The long-run GDP deflator assumed in the AEO 2008 increases about 1.9 percent per year, a figure that we adopt to convert real dollars into future nominal dollars.

Table 4-2
Projected Cost of New Transmission 2008-2015
Millions of Dollars (Nominal)

	Voltage Level					
Year	**AC 230**	**AC 345**	**AC 500**	**AC 765**	**DC 500**	**Total AC & DC**
2008	$784.3	$421.1	$220.7	$0.0	$0.0	**$1,426.1**
2009	$1,916.4	$785.1	$2,467.7	$0.0	$0.0	**$5,169.2**
2010	$932.6	$1,346.7	$3,061.4	$0.0	$2,280.9	**$7,621.5**
2011	$816.9	$0.0	$2,662.3	$0.0	$0.0	**$3,479.2**
2012	$1,008.3	$3,776.1	$3,654.4	$0.0	$0.0	**$8,438.8**
2013	$79.0	$427.0	$2,151.2	$0.0	$0.0	**$2,657.2**
2014	$113.2	$607.1	$10.1	$0.0	$0.0	**$730.4**
2015	$176.9	$2,423.0	$410.8	$0.0	$0.0	**$3,010.7**
Total (2008-2015)	**$5,827.6**	**$9,786.1**	**$14,638.7**	**$0.0**	**$2,280.9**	**$32,533.2**

Note: Totals may not equal sum of components due to independent rounding.

Overview of Methods to Estimate Transmission Investment Through 2030

For purposes of this report, we examined two methods to estimate potential overall transmission investment through 2030 using the previously described data:

- The *Transmission Additions Method* (selected method); and
- The *Generation Additions Method.*

In simple terms, our first method (the *Transmission Additions Method)* takes the annual average number of miles of new transmission lines built or proposed between 2007 and 2015 and applies this annual average growth rate to the 2016 to 2030 time period. We then assume that future transmission line construction costs from 2016 to 2030 will reflect the dollar-per-mile costs shown in Table 4-1. Finally, we adjust these costs at the assumed rate of inflation (1.9 percent per year). This estimate assumes that recently proposed construction activity continues (in terms of miles per year and real dollars per mile) and adjusts these costs at the assumed rate of inflation, yielding a nominal dollar investment stream.

As explained in Chapters 1 to 3, we examine several generation scenarios with significant differences in the amount and type of generation constructed. Because the amount of generation varies in these scenarios, the amount of transmission investment also could vary. Accordingly, we employ a second method to estimate transmission investment, referred henceforth as the *Generation Additions Method*. This method derives the ratio of transmission miles built to MW of new generation capacity installed, and multiplies this ratio by different projections of generation capacity to estimate future miles of transmission required. We use the values reported in Table 4-1 to provide the cost of this projected transmission investment and escalate for assumed inflation. Both of these methods are explained further in the following two sections.

Resulting Transmission Investment Based on the *Transmission Additions Method*

The *Transmission Additions Method* uses different sources of data for high- and low-voltage transmission investments. This method treats the two voltage classes differently due to the dissimilarity in available data.

The NERC ES&D data for high-voltage transmission lines are fairly narrow in scope, containing primarily region, line voltage, and line length information. From these data we determine average annual total transmission line-miles (by voltage level) added or proposed between 2007 and 2015. We then multiply these average annual line-miles by their respective 2008 cost by voltage level (in dollars per mile) as shown in Table 4-1. This yields average annual transmission investments by voltage level at 2008 costs. We then assume that this level of transmission investment will remain constant (in real terms) between 2016 and 2030. Finally, we adjust these investments by the assumed rate of inflation of 1.9 percent per year. The projected amount of high-voltage transmission investment resulting from our analysis of the NERC ES&D data, combined with EEI's transmission cost figures (Table 4-1), is $113 billion (nominal) for the 2010 to 2030 period.

Because we do not have access to comparable data for low-voltage facilities, we use the following method to estimate this component of our projected total transmission investment under the *Transmission Additions Method*.

According to Table 4-2, the amount of high-voltage transmission investment for the 2008 to 2010 period is approximately $14.2 billion. EEI's 2007 "Electric Transmission Capital Budget & Forecast Survey" projects total shareholder-owned electric utility transmission investments of about $35.5 billion (nominal) during the same 2008 to 2010 period.[30] Netting out the $14.2 billion in high-voltage investments from the $35.5 billion in total transmission investments results in $21.3 billion in low-voltage investments over the three-year period, or $7.1 billion per year (nominal) of investments in low-voltage transmission facilities and other elements. Assuming that this amount of investment remains constant in real terms over the 2010 to 2030 period, the resulting amount of projected low-voltage transmission investment would be $184 billion (nominal).

Finally, we combine our low-voltage estimate with the high-voltage investment projection to reach a total annual transmission investment of $298 billion (nominal) for the 2010 to 2030 study period. Figure 4-2 shows the results from our selected method, the *Transmission Additions Method*.

In Figure 4-2, the navy blue line represents near-term estimated transmission investments from 2008 to 2015, while the pink line represents our long-term projection using the selected method, the *Transmission Additions Method*. As expected, our projected investments beyond 2015 are much smoother than the projections based directly upon forecast data from the NERC ES&D. This smooth investment from 2016 to 2030 reflects a constant level of real investment, adjusted for inflation.

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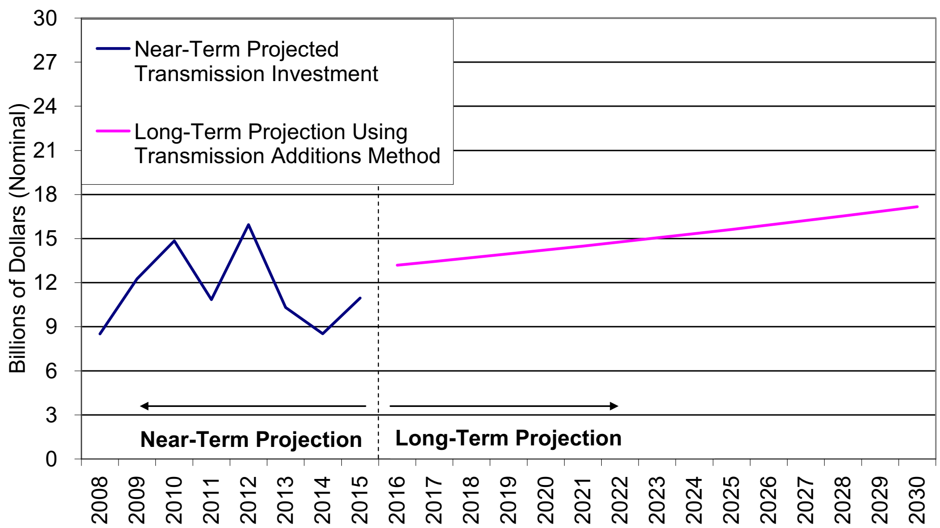
[30] Figure 4-1 shows projected transmission investment between 2008 and 2010 as $28.6 billion expressed in real 2006 dollars. Converting to nominal dollars, using the change in the Handy-Whitman Index for the years 2006 to 2008 and 1.9 percent assumed inflation thereafter, this amount increases to $35.5 billion.

Comparative Transmission Investment Based on the *Generation Additions Method*

As mentioned previously, cumulative transmission investments under our selected method, the *Transmission Additions Method*, equal $298 billion (nominal) over the 2010 to 2030 period—a figure that, by design, does not vary with the four generation scenarios covered in Chapters 1 to 3 of this report (i.e., the Reference Scenario, the RAP Efficiency Base Case Scenario, the MAP Efficiency Scenario, and the Prism RAP Scenario).

Figure 4-2
Annual Transmission Investment Projection
Transmission Additions Method (2008-2030)



The *Generation Additions Method* employs the average levels of transmission investment per MW of generation built for high-voltage transmission facilities. First, we derive the ratio of high-voltage transmission line-miles built per MW of installed capacity for the 2008 through 2015 period based on NERC ES&D data and the Reference Scenario RECAP results. Next, we use these ratios to project annual transmission line-miles built as a function of various projections of annual generation capacity builds and use the cost figures in Table 4-1 to estimate annual high-voltage transmission investments. Finally, we combine these figures with our average annual low-voltage investment estimate of $7.1 billion per year and adjust the resulting amount for inflation.

Figure 4-3 illustrates a single estimate of the annual investment costs using the *Transmission Additions Method* (pink line). It also shows three estimates of the annual investment costs using the *Generation Additions Method:* one for the RAP Efficiency Base Case Scenario (light blue line); one for the MAP Efficiency Scenario (brown line); and one for the Reference Scenario (purple line).

As one might expect, under the *Generation Additions Method*, the lower the level of projected generation capacity, the lower the level of projected transmission investment.[31] Under this method, the Reference Scenario has the highest level of generation builds followed by the RAP Efficiency Base Case Scenario and finally the MAP Efficiency Scenario.

Figure 4-3
Annual Transmission Investment Projections
All Methods (2008-2030)

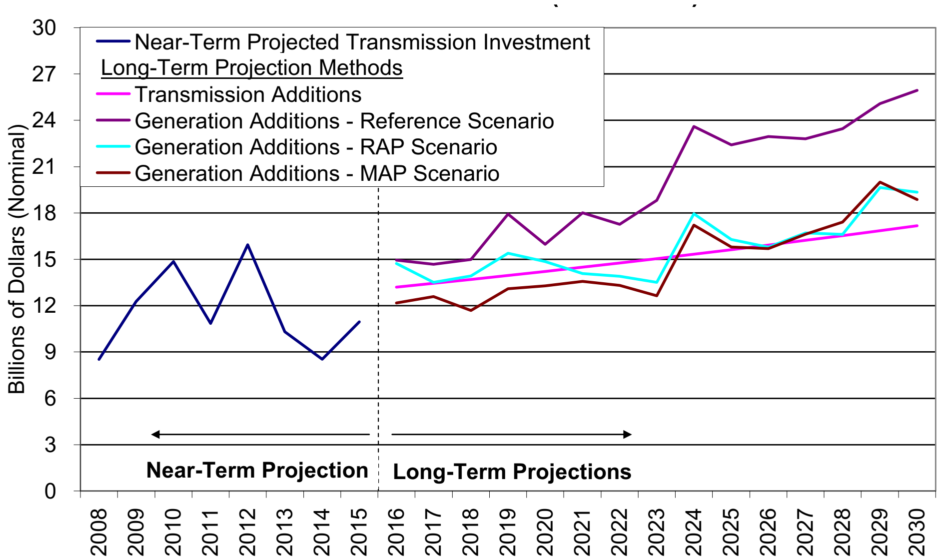


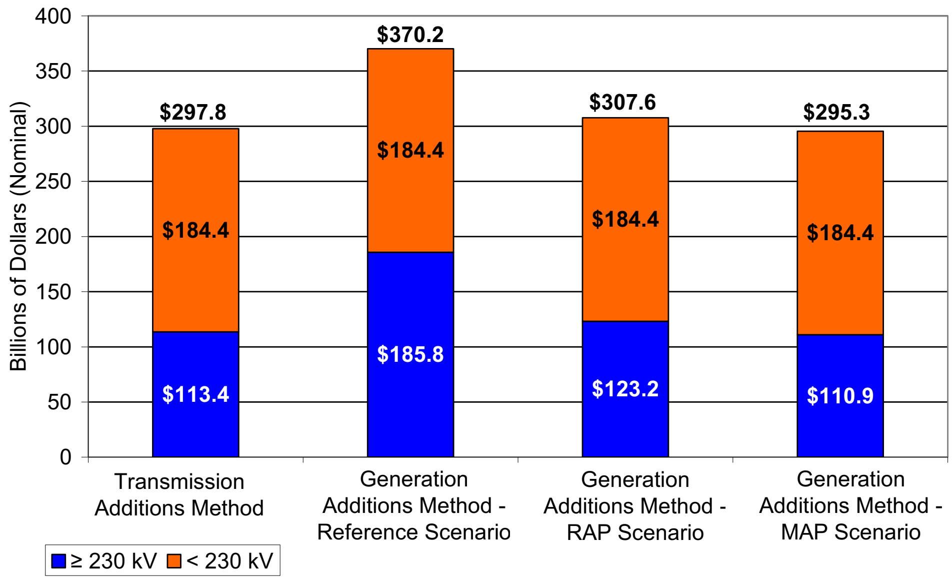
Figure 4-4 depicts four estimated cumulative projections of transmission investment for the 2010 to 2030 period: one estimate for the *Transmission Additions Method* and three estimates using the *Generation Additions Method* as applied to the three scenarios described in Chapter 1 and Chapter 2. As illustrated in Figure 4-4, the cumulative transmission investments range from a low of \$295 billion under the MAP Efficiency Scenario to a high of \$370 billion using the same method under the Reference Scenario.

The lower portion of each stacked bar in Figure 4-4 represents cumulative high-voltage transmission investments based on the two transmission projection methods and three of the generation scenarios. The upper portion of the bars corresponds to the low-voltage transmission investments. As discussed earlier in this chapter, estimating future transmission capital investments over a multi-decade horizon is extremely challenging due in large part to the difficulty of predicting the location and fuel characteristics of the future generation capacity requirements. For this reason, we selected the \$298-billion estimated transmission requirement derived from the *Transmission Additions Method* over the three transmission investment estimates produced under the *Generation Additions Method*. Based on our analysis and the results as

[31] The transmission investment results from the Prism RAP Scenario described in Chapter 3 are not shown because they are very similar to those shown for the Reference Scenario as a result of overall MW of generation capacity built between 2010 and 2030 being nearly identical. Note that a federal carbon policy could affect the mix of transmission projects to accommodate remote renewables and CCS sites. This potential effect was not quantified.

illustrated in Figure 4-4, we believe that our selected method produces an investment projection that is: 1) consistent and well within the range of transmission investment projections from the alternative generation-based methods, and 2) conservative, so that the results have not been influenced by uncertain future generation capacity scenarios.

Figure 4-4
Cumulative Transmission Investment Projections
(2010-2030)



Transmission and Renewable Generation

As discussed previously, gaining access to the amount of renewable generation implied by escalating RPS requirements will involve additional transmission development that may not be reflected in the recent data from NERC. While some of the projects in the NERC ES&D database and the EEI "At A Glance" report may be motivated in part by new renewable generation opportunities, it is plausible that additional transmission development beyond those projects will have to occur in order to significantly increase the contribution of renewables into the electricity supply mix.

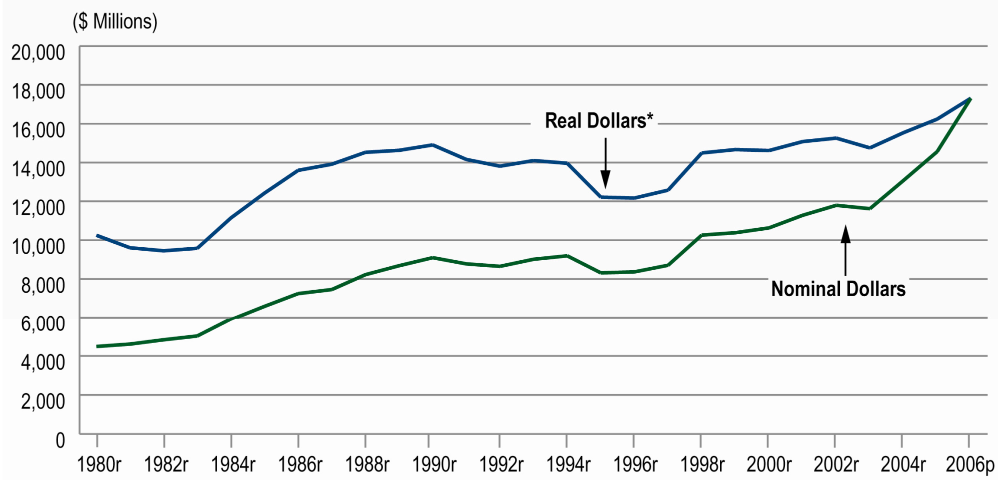
In order to provide a rough estimate of the magnitude of investment required, we assume that each GW of additional renewable capacity requires an associated transmission investment that increases slightly over time. This could occur, for example, as the most accessible resources are developed earlier, with more remote resources gradually becoming attractive as demand for renewables increases. We adopted the following rule of thumb: for each GW of renewable capacity built in 2011, we assume that 10 miles of transmission capacity are needed, and we escalate that mileage figure by 10 miles each successive year. Under this framework, renewable capacity built in 2015 needs 50 miles of transmission, renewable capacity built in 2020 needs 100 miles, renewable capacity built in 2025 needs 150 miles, and renewable capacity built in 2030 needs 200 miles. Since Table 4-1 shows that a 345-kV transmission link can support roughly one GW of power transfer and costs roughly $3 million per mile, we apply that cost to our estimated transmission builds for expanded renewable generation access.

For the amount of renewable capacity in the Reference Scenario, these assumptions would add about $15.5 billion between 2010 and 2030 in undiscounted nominal terms to account for transmission investments made in order to access increasing amounts of progressively more remote renewables. Although this is obviously a rough calculation, on the whole it is probably conservative. That is because there are many remote renewables–e.g., wind power in the central United States and northern New England–that may require transmission lines that are more than 200 miles long to connect them to the grid. While this calculation may understate the transmission costs associated with renewables, it still represents a significant capital cost that the utility sector will bear as it complies with state RPS requirements.

Distribution System Costs and Data

Shareholder-owned electric utility distribution-related construction expenditures have been rising in real and nominal terms since the mid-1990s, surpassing $17 billion per year in 2006. These investments have been made to expand distribution systems, replace aging equipment, enhance reliability, improve power quality, and to begin to integrate "Smart Grid" system elements. Figure 4-5 shows the trends of distribution investments over the past quarter-century. Distribution investments are a substantial portion of current utility capital expenditures—about 25 percent to 30 percent of overall capital expenditures—a share that is steady under current trends.

Figure 4-5
Distribution Investment by Shareholder-Owned Electric Utilities
(1980-2006)



* 2006 Dollars p = Preliminary r = Revised
Note: Real dollar results are shown using the Handy-Whitman Index of Public Utility Construction Costs to adjust for inflation from year to year.

Sources: Prior to 1999, data are from Edison Electric Institute's "Uniform Statistical Report". For 1999, data are from Edison Electric Institute's Construction Expenditures Survey, the Federal Energy Regulatory Commission (FERC Form 1), and company Annual Reports (10-K). For 2000-2006, data are from Edison Electric Institute's Annual Property & Plant Capital Investment Survey and the Federal Energy Regulatory Commission (FERC Form 1).

Some of the recent increases in distribution investment levels are attributable to the same drivers that are responsible for the construction cost increases observed in the generation and transmission segments of the industry.[32] Estimating and projecting distribution investments over a multi-decade horizon are prone to the same difficulties as those found with transmission. Discrete distribution investments are much smaller than transmission investments and are undertaken for a variety of reasons; some of these are discretionary and others are required to maintain system reliability and power quality. The industry's obligation to provide and maintain reliable electric service to its customers, combined with the prospects for "Smart Grid" investments to enable greater operating efficiencies, suggest that distribution system investment levels in the future are likely to reflect the recent growth observed in current investment trends. To explore the sensitivity of distribution investments to these key drivers and trends, we employ three methods to project distribution investments for the years 2010 to 2030, namely:

- *Real Investment Growth Rate Method:* Our selected method. This method extrapolates the recent trend in real distribution investment levels to provide a projection of nominal distribution costs from 2010 through 2030;

- *Per Capita Method*: A trend of per capita distribution expenditures based on forecasted population change. We examine nominal per capita investments under this method; and

[32] See *Rising Utility Construction Costs: Sources and Impacts*, prepared by Marc W. Chupka and Greg Basheda of *The Brattle Group* for The Edison Foundation, September 2007.

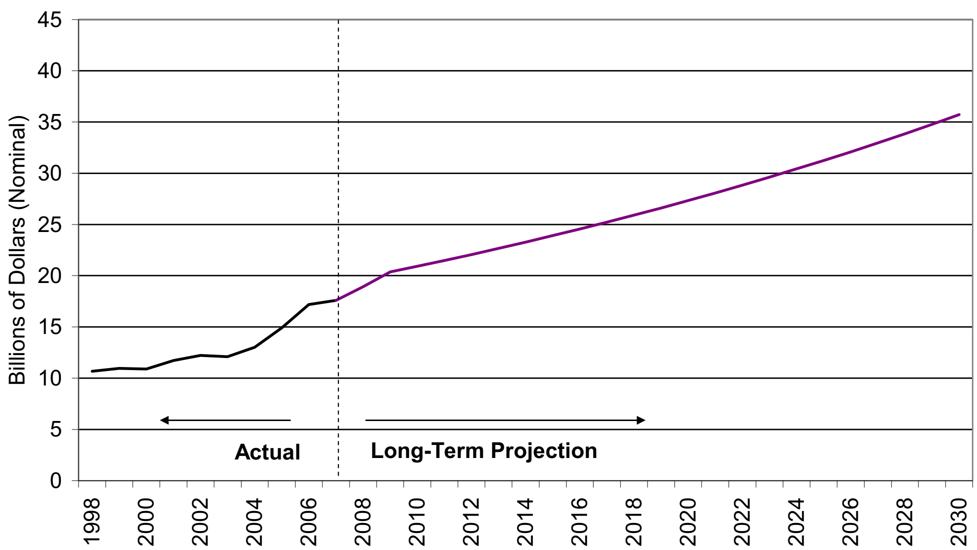
- *Nominal Growth Rate Method*: We present two nominal growth rate projections—one version that extrapolates recent growth rates in nominal distribution expenditures and another version that assumes that the 2007 distribution expenditures will grow at the assumed rate of inflation.

All three of these methods use the same basic underlying distribution investment input data to project future distribution investment requirements.

Real Investment Growth Rate Method

Historic distribution system investment figures from 1998 through 2007 were obtained from EEI's "Annual Property and Plant Capital Investment Survey."[33] The average real growth rate based on this historical data is about 0.8 percent per year. This real investment growth rate was applied to 2007 annual distribution investment expenditures and then adjusted annually at the rate of inflation (1.9 percent per year) to forecast distribution investments through 2030, as shown in Figure 4-6. The total distribution costs for the 2010 to 2030 period using the *Real Investment Growth Rate Method* are $582 billion in nominal terms. We chose this as our selected method to provide an estimate of distribution investment requirements to 2030, and used the alternative methods described next to provide comparisons to our selected method.

Figure 4-6
Annual Distribution Investment Projection
Real Investment Growth Rate Method



[33] These costs were converted from nominal dollars to 2008 dollars using the Handy-Whitman distribution cost index. Because we use the Handy-Whitman distribution cost index, the resulting growth in annual real costs should reflect increased physical investment in distribution systems.

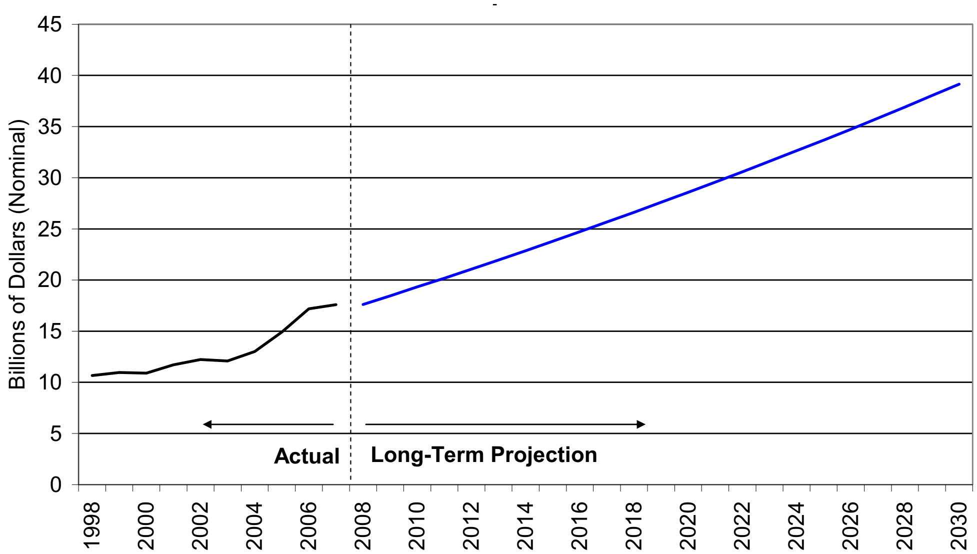
Per Capita Method

Our second method derives the historic relationship between distribution costs, time, and U.S. population, and uses population growth projections to yield a distribution investment forecast. We first calculate actual per capita distribution investment costs from 1998 through 2007 using EEI survey data and Census Bureau population data. We then project the trends in per capita distribution costs using the results of a regression that captures the relationship between per capita costs and time over the 1998 to 2007 period, where the trend equals 1 in 1998, 2 in 1999, and 3 in 2000, etc.[34]

$$\textbf{Nominal Per Capita Costs} = \mathbf{32.91 + 2.25 \times Trend}$$
$$\mathbf{R^2 = 0.83} \qquad\qquad \mathbf{(2.26)} \quad \mathbf{(0.37)}$$

This method produces a linear increase in the amount of distribution investment per year per capita, and in turn allows us to project the per capita distribution investments from 2008 to 2030 using projections of U.S. population growth.[35] Figure 4-7 presents the forecast results using the *Per Capita Method*, which yields a total industry distribution investment requirement of $605 billion for the years 2010 to 2030. Because this estimate is based on the total U.S. population, it reflects estimated investments by the entire U.S. utility industry.

Figure 4-7
Annual Distribution Investment Projection
Per Capita Method



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[34] Standard errors of the coefficients are shown in parentheses.

[35] We use the population projection reported in the assumption tables in the AEO 2008 for this calculation.

Nominal Growth Rate Method

This method projects distribution investment costs based on trends in total nominal distribution expenditures between 1998 and 2007. The growth rate in nominal distribution investment costs over this period averaged approximately 5.9 percent per year. This nominal growth rate was applied to 2007 distribution expenditures to project annual nominal distribution investments through 2030. An additional projection was constructed to examine an alternative possibility where 2007 distribution investments simply grow at the rate of overall inflation (assumed to be 1.9 percent per year). Implicit in this projection are the assumptions that distribution costs will grow at the rate of inflation (i.e., that trends in distribution costs will follow the overall inflation rate) and that real distribution investments will remain constant at 2007 levels.

Figure 4-8 displays the results of the two versions under the *Nominal Growth Rate Method*, which provide additional comparative projections of future distribution investments. The total investment using the historic nominal growth rate of distribution investment is $821 billion, while the general inflation-only projection results in a $475-billion investment.

Figure 4-8
Annual Distribution Investment Projections
Nominal Growth Rate Methods

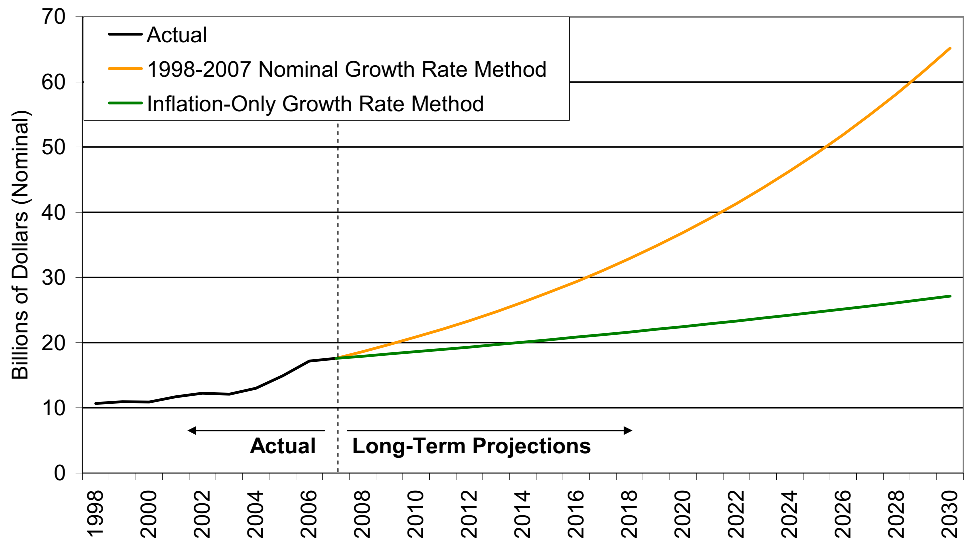


Figure 4-9 and Figure 4-10 illustrate the overall results from the three distribution investment methods, both over time and in total cumulative nominal dollars, respectively. These figures show that our selected method—the *Real Investment Growth Rate Method*—yields a distribution investment projection of $582 billion through 2030. As is the case with our transmission estimates, our selected method regarding distribution investments is solidly within the range (from nominal $475 billion to $821 billion) of the distribution investment estimates produced under the alternative methods (*Per Capita and Nominal Growth Rate Methods*) utilized in this report.

Beyond the fact that our selected method is well within the range of alternative methods, the estimated investment requirement under the *Real Investment Growth Rate Method* is strikingly close to the estimate under the *Per Capita Method*—both are approximately $600 billion through 2030—which provides us added confidence in the projections yielded from our selected method.

Figure 4-9
Annual Distribution Investment Projections
All Methods

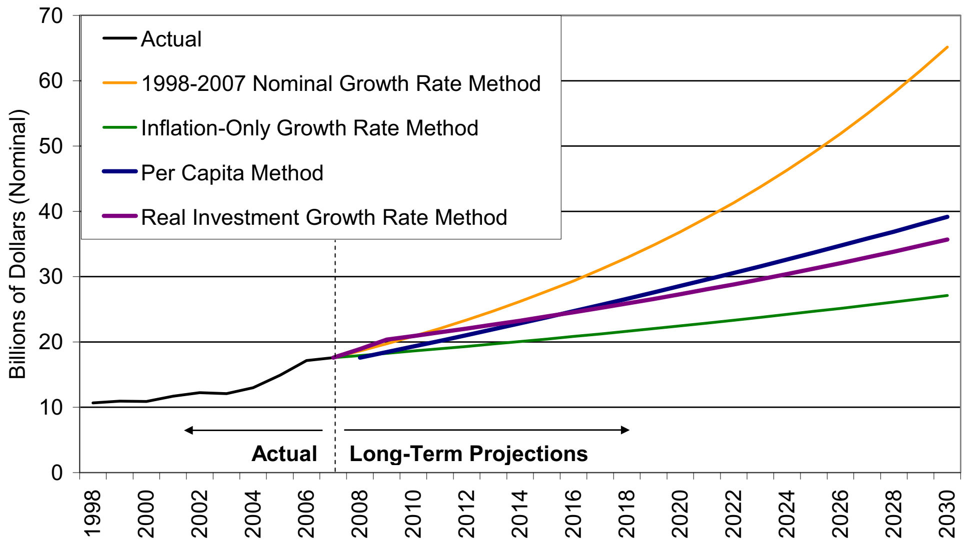
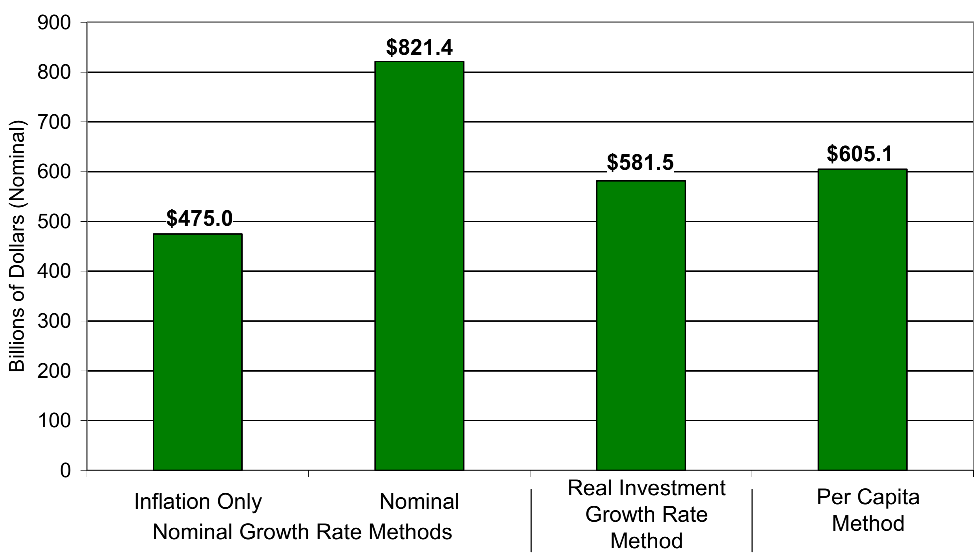


Figure 4-10
Cumulative Distribution Investment Projections
(2010-2030)

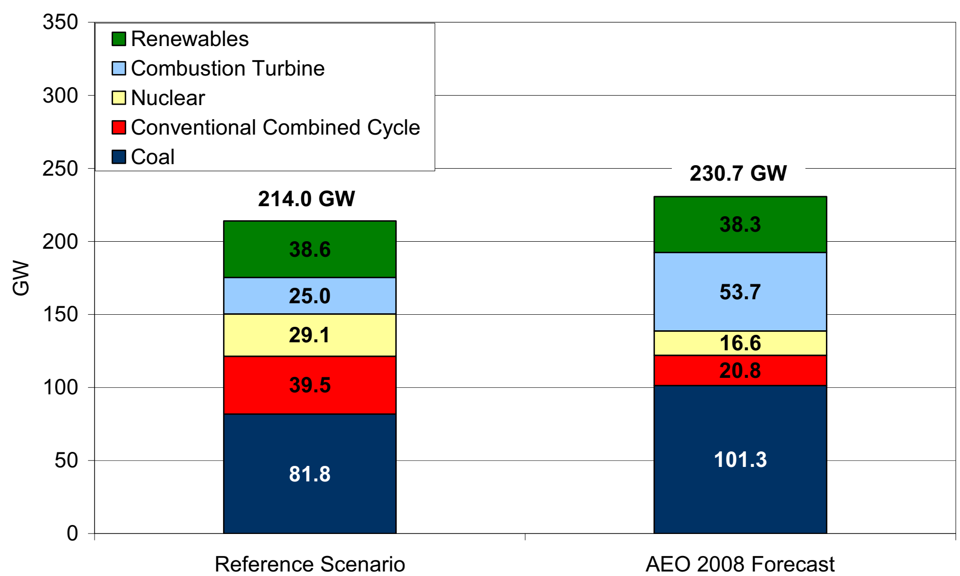


Appendix A

The Brattle Group's RECAP Model

All our scenario simulations were performed with RECAP, *The Brattle Group's* least-cost generation expansion planning model. The composition of capacity builds in our Reference Scenario is similar to the AEO 2008 forecast. Figure A-1 compares the AEO 2008 forecast of capacity by type to the RECAP results. As shown on Figure A-1, the RECAP model (Reference Scenario) builds almost 20 GW less of coal-based capacity, but about 18 GW more of natural gas combined-cycle capacity than in the AEO 2008. Although natural gas prices are higher in the Reference Scenario than in the AEO 2008, the construction costs associated with coal units are much higher, which means that natural gas-based capacity is relatively more attractive. This is consistent with recent trends where utilities have scaled back plans for expensive coal-based capacity and shifted toward natural gas, a trend also influenced by concerns about carbon emissions from coal. The Reference Scenario also builds about half the capacity of combustion turbines as in the AEO 2008 (25 GW compared to 54 GW in AEO 2008), which may be due to the fact that RECAP models system peak load in greater detail than does NEMS, the model underlying the AEO 2008 forecast. Renewable capacity in the Reference Scenario is nearly identical to the AEO 2008 forecast, as most renewable capacity is built to satisfy requirements that depend on load growth, which is identical. Finally, the Reference Scenario builds more nuclear generation than in the AEO 2008 projection, possibly because the AEO 2008 forecast has stricter limits on nuclear builds. (The 17 GW of nuclear capacity built in the AEO 2008 forecast is very similar to the amount of capacity represented by the project developers that had submitted applications to the NRC at the time the AEO 2008 forecast was performed.)

Figure A-1
Comparison of New Generation Capacity



Linking EE/DR Projections in the EPRI Study to RECAP

It is important to note two ways in which the EE/DR projections that were used in this analysis differ from the impacts that are being reported through the EPRI study. These differences are driven by: 1) the impact of retail electricity prices on EE/DR cost-effectiveness and 2) the reference load forecast by which the impacts are being measured.

First, the RAP Efficiency Base Case Scenario and the MAP Efficiency Scenario estimates will be affected by the projected level of the retail electricity price. As retail prices rise, more EE/DR measures will become cost effective and the overall impact of EE/DR will increase. Our analysis accounted for this relationship by relying on region-specific EE/DR projections that were a function of the projected retail electricity rate projected by RECAP. This served as an analytic point of departure from the EPRI projections, which relied solely on the price projections implied in the AEO 2008 forecasts. Due to the higher fuel price and installation cost assumptions in *The Brattle Group's* analysis (relative to the AEO 2008 forecast), and their impact on the projected retail electricity rate, our assumed EE/DR impacts were larger than those reported in the EPRI study.

Second, the EE/DR impacts projected in the EPRI study produce potential annual peak and energy-savings forecasts for the 2010 to 2030 period. These impact estimates assume no existing EE/DR in the load forecast. In other words, they represent a percentage change from a load forecast that does not include any existing EE/DR. However, for our analysis, we are using the AEO 2008 forecast as the starting point for our load forecast. This load forecast already includes a moderate amount of EE/DR and, thus, is lower than the starting point of the EPRI forecasts. As a result, we have scaled down the EPRI numbers such that they represent changes from the AEO 2008 load forecast.

Exhibit PPL/506
Bird/66

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Docket No. UE-210
Exhibit PPL/507
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Stefan A. Bird

Chupka, Marc. W and Earle, Robert, Transforming America's Power Industry: the Investment Challenge 2010-2030, The Brattle Group for The Edison Foundation

June 2009

Exhibit PPL/507
Bird/1

Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
Gregory Basheda

The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

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The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

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Exhibit PPL/507
Bird/3

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Exhibit PPL/507
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Introduction and Executive Summary

In *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), *The Brattle Group* identified fuel and purchased-power cost increases as the primary driver of the electricity rate increases that consumers currently are facing. That report also noted that utilities are once again entering an infrastructure expansion phase, with significant investments in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and new environmental controls. The report concluded that the industry could make the needed investments cost-effectively under a generally supportive rate environment.

The rate increase pressures arising from elevated fuel and purchased power prices continue. However, another major cost driver that was not explored in the previous work also will impact electric rates, namely, the substantial increases in the costs of building utility infrastructure projects. Some of the factors underlying these construction cost trends are straightforward—such as sharp increases in materials cost—while others are complex, and sometimes less transparent in their impact. Moreover, the recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to the "sticker shock" that utilities experience when obtaining cost estimates or bids and that state public utility commissions experience during the process of reviewing applications for approvals to proceed with construction. While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators.

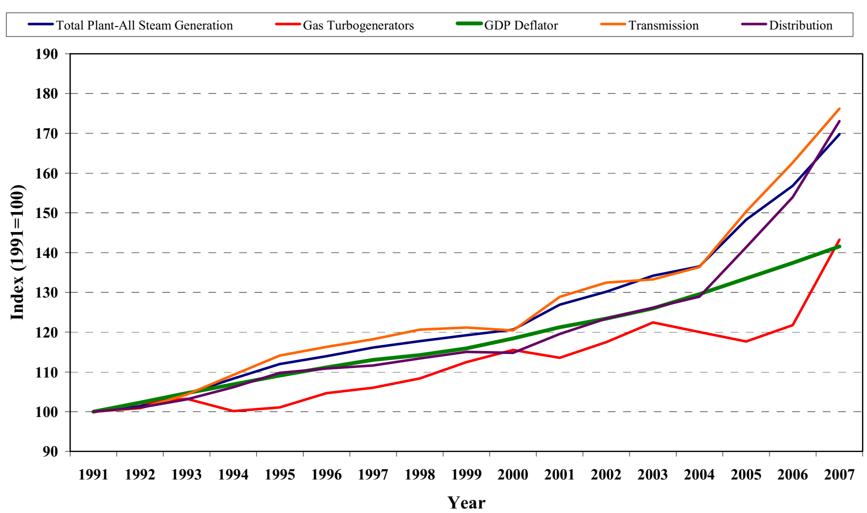
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment. This report also provides a reference for utilities, regulators and the public to understand the issues related to recent construction cost increases. In summary, we find the following:

- Dramatically increased raw materials prices (*e.g.,* steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.
- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or projected supply. There also is a growing backlog of

project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects. Large proposed transmission projects have undergone cost revisions, and distribution system equipment costs have been rising rapidly. This is seen in Figure ES-1, which shows recent price trends in generation, transmission and distribution infrastructure costs based on the Handy-Whitman Index© data series, compared with the general price level as measured by the gross domestic product (GDP) deflator over the same time period.[1] As shown in Figure ES-1, infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more—substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants—and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

Figure ES-1
National Average Utility Infrastructure Cost Indices



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

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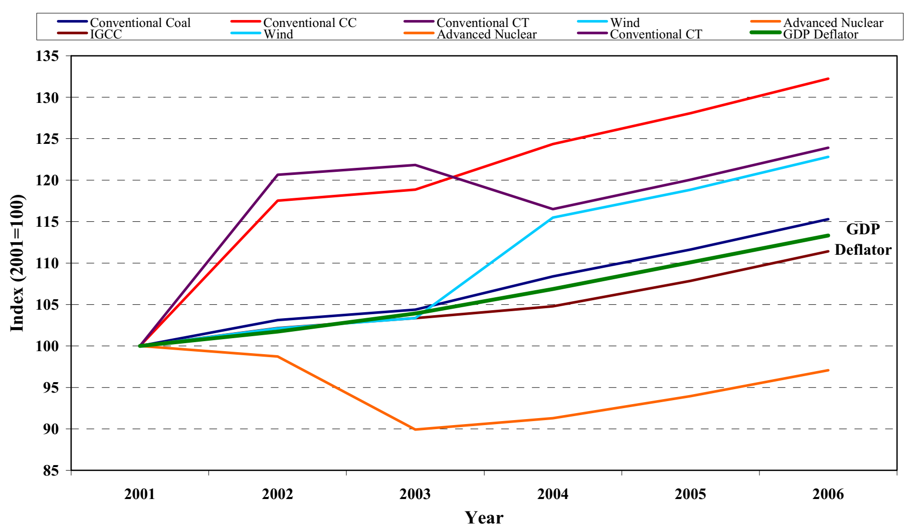
[1] The GDP deflator measures the cost of goods and services purchased by households, industry and government, and as such is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives in order to reduce the future rate impacts on consumers.
- Despite the overwhelming evidence that construction costs have risen and will be elevated for some time, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA's) 2007 *Annual Energy Outlook* (AEO). The AEO generation capital cost assumptions since 2001 are shown in Figure ES-2. Since 2004, capital costs of all technologies are assumed to grow at the general price level—a pattern that contradicts the market evidence presented in this report. The growing divergence between the AEO data assumptions and recent cost escalation is now so substantial that the AEO data need to be adjusted to reflect recent cost increases to provide reliable indicators of current or future capital costs.

Figure ES-2
EIA Generation Construction Cost Estimates



Sources: Data collected from the U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

Projected Investment Needs and Recent Infrastructure Cost Increases

Current and Projected U.S. Investment in Electricity Infrastructure

The electric power industry is a very capital-intensive industry. The total value of generation, transmission and distribution infrastructure for regulated electric utilities is roughly $440 billion (property in service, net of accumulated depreciation and amortization), and capital expenditures are expected to exceed $70 billion in 2007.[2] Although the industry as a whole is always investing in capital, the rate of capital expenditures was relatively stable during the 1990s and began to rise near the turn of the century. As shown in *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon: According to the *World Energy Investment Outlook 2006*, investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030.[3]

Generation

As of December 31, 2005, there were 988 gigawatts (GW) of electric generating capacity in service in the U.S., with the majority of this capacity owned by electric utilities. Close to 400 GW of this total, or 39 percent, consists of natural gas-fired capacity, with coal-based capacity comprising 32 percent, or slightly more than 300 GW, of the U.S. electric generation fleet. Nuclear and hydroelectric plants comprise approximately 10 percent of the electric generation fleet. Approximately 49 percent of energy production is provided by coal plants, with 19 percent provided by nuclear plants. Natural gas-fired plants, which tend to operate as intermediate or peaking plants, also provided about 19 percent of U.S. energy production in 2006.

The need for installed generating capacity is highly correlated with load growth and projected growth in peak demand. According to EIA's most recent projections, U.S. electricity sales are expected to grow at an annual rate of about 1.4 percent through 2030. According to the North American Electric Reliability Corporation (NERC), U.S. non-coincident peak demand is expected to grow by 19 percent (141 GW) from 2006 to 2015. According to EIA, utilities will need to build 258 GW of new generating capacity by 2030 to meet the

---

2 Net property in service figure as of December 31, 2006, derived from Federal Energy Regulatory Commission (FERC) Form 1 data compiled by the Edison Electric Institute (EEI). Gross property is roughly $730 billion, with about $290 billion already depreciated and/or amortized. Annual capital expenditure estimate is derived from a sample of 10K reports surveyed by EEI.

3 Richard Stavros. "Power Plant Development: Raising the Stakes." *Public Utilities Fortnightly*, May 2007, pp. 36-42.

projected growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-based capacity, that is more capital intensive than natural gas-fired capacity which dominated new capacity additions over the last 15 years, will account for about 54 percent of total capacity additions from 2006 to 2030. Natural gas-fired plants comprise 36 percent of the projected capacity additions in *AEO 2007*. EIA projects that the remaining 10 percent of capacity additions will be provided by renewable generators (6 percent) and nuclear power plants (4 percent). Renewable generators and nuclear power plants, similar to coal-based plants, are capital-intensive technologies with relatively high construction costs but low operating costs.

High-Voltage Transmission

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high voltage (230 kV and higher) transmission lines that ultimately serve more than 300 million customers. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers. Today, 134 control areas or balancing authorities manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since the beginning of 2000, the industry has invested more than $37.8 billion in the nation's transmission system. In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid, while the Edison Electric Institute (EEI) estimates that utility transmission investments will increase to $8.0 billion during 2007. A recent EEI survey shows that its members plan to invest $31.5 billion in the transmission system from 2006 to 2009, a nearly 60-percent increase over the amount invested from 2002 to 2005. These increased investments in transmission are prompted in part by the larger scale of base load generation additions that will occur farther from load centers, creating a need for larger and more costly transmission projects than those built over the past 20 years. In addition, new government policies and industry structures will contribute to greater transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

NERC projects that 12,873 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America over the 2006 to 2015 period. NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the PJM Interconnection LLC, such as the major new lines proposed by American Electric Power, Allegheny Power, and Pepco.

Distribution

While transmission systems move bulk power across wide areas, distribution systems deliver lower-voltage power to retail customers. The distribution system includes poles, as well as metering, billing, and other related infrastructure and software associated with retail sales and customer care functions. Continual investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to customers.

Continued customer load growth will require continued expansion in distribution system capacity. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over the investment levels incurred in 2004. EEI projects that distribution investment during 2007 will again exceed $17.0 billion. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of the increased dollar investment reflects the increased input costs of materials and labor to meet current distribution infrastructure needs.

Construction Costs for Recently Completed Generation

The majority of recently constructed plants have been either natural gas-fired or wind power plants. Both have displayed increasing real costs for several years. Since the 1990s, most of the new generating capacity built in the U.S. has been natural gas-fired capacity, either natural gas-fired combined-cycle units or natural gas-fired combustion turbines. Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years.

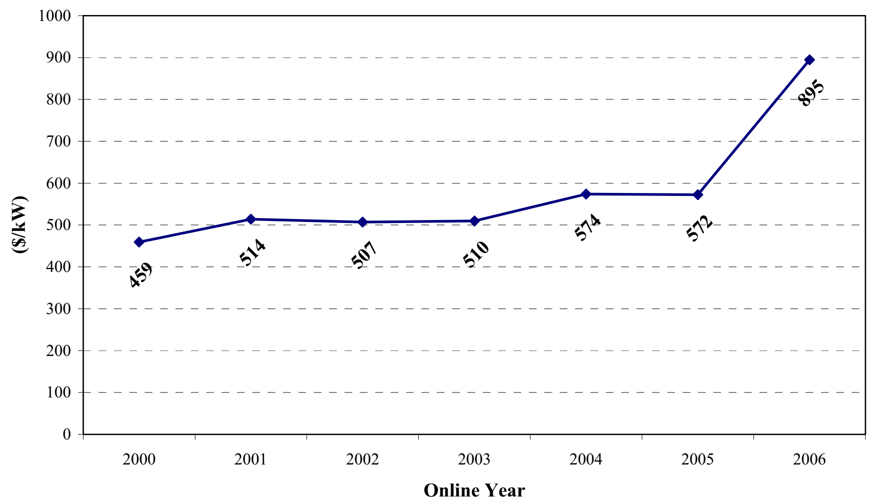
Using commercially available databases and other sources, such as financial reports, press releases and government documents, *The Brattle Group* collected data on the installation cost of natural gas-fired combined-cycle generating plants built in the U.S. during the last major construction cycle, defined as generating plants brought into service between 2000 and 2006. We estimated that the average real construction cost of all natural gas-fired combined-cycle units brought online between 2000 and 2006 was approximately $550/kilowatt (kW) (in 2006 dollars), with a range of costs between $400/kW to approximately $1,000/kW. Statistical analysis confirmed that real installation cost was influenced by plant size, the turbine technology, the NERC region in which the plant was located, and the commercial online date. Notably, we found a positive and statistically significant relationship between a plant's construction cost and its online date, meaning that, everything else equal, the later a plant was brought online, the higher its real installation cost.[4] Figure 1 shows the average yearly installation cost, in *nominal* dollars, as predicted by the regression analysis.[5] This figure shows that the average installation cost of combined-cycle units increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant construction costs.

---

4 To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

5 The nominal form regression results are discussed here to facilitate comparison with the GDP deflator measure used to compare other price trends in other figures in this report.

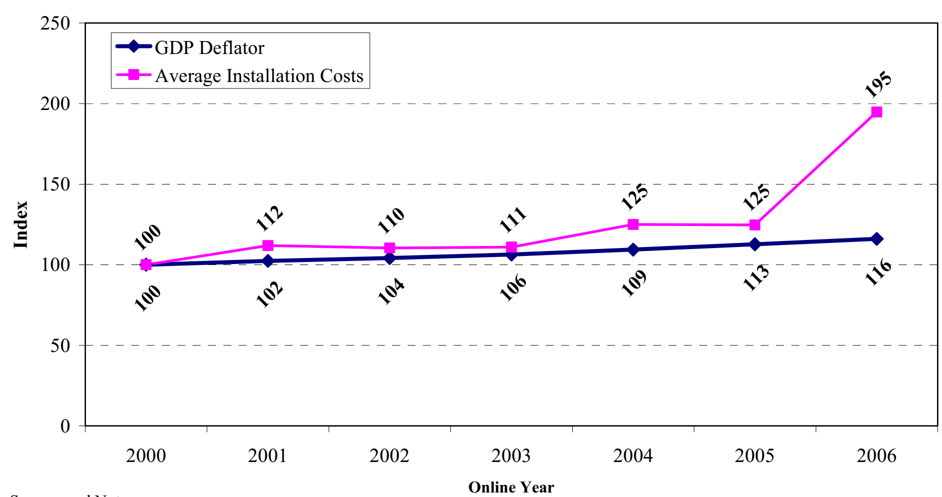
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



Sources and Notes:
* Data on summer capacity, total installation cost , turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.

Figure 2 compares the trend in plant installation costs to the GDP deflator, using 2000 as the base year. Over the period of 2000 to 2006, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

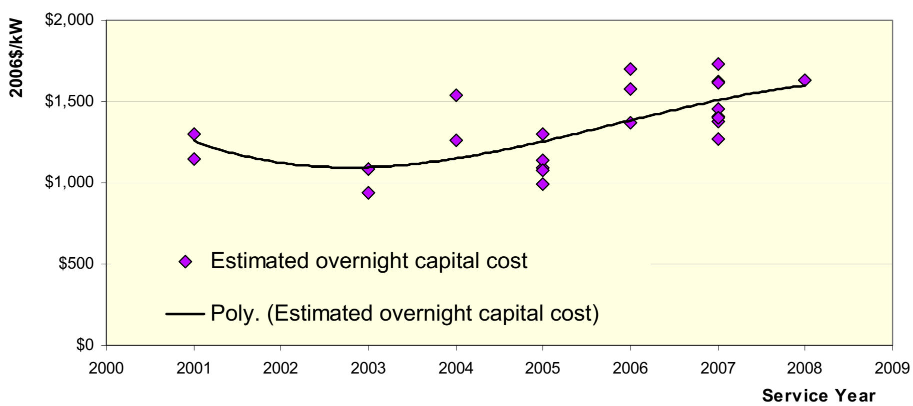
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



Sources and Notes:
* Data on summer capacity, total installation cost , turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.
** GDP Deflator data were collected from the U.S. Bureau of Economic Analysis.

Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, issued its most recent review of the cost of wind power in July 2006.[6] The Council found that the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than that assumed in its most recent resource plan. Specifically, the Council found that the levelized lifecycle cost of power for new wind projects rose 50 to 70 percent, with higher construction costs being the principal contributor to this increased cost. According to the Council, the construction cost of wind projects, in real dollars, has increased from about $1150/kW to $1300-$1700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. Factors contributing to the increase in wind power costs include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards established by a growing number of states. The Council notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel and resin have experienced significant cost increases in recent years. Figure 3 shows real construction costs of wind projects by actual or projected in-service date.

Figure 3
Wind Power Project Capital Costs



Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

These observations were confirmed recently in a May 2007 report by the U.S. Department of Energy (DOE), which found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/kW between 2002 and 2006, a nearly 60-percent increase.[7] Figure 4 is reproduced from the DOE report (Figure 21) and shows the significant upward trend in turbine prices since 2001.

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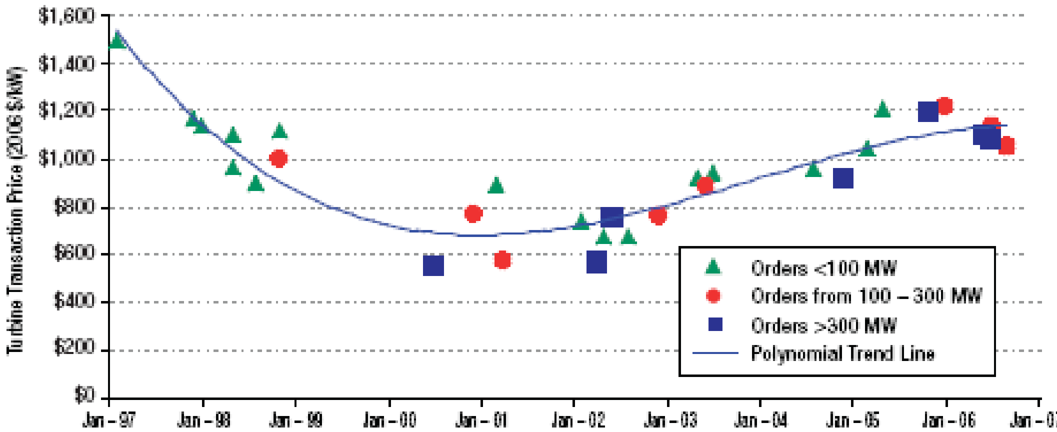
[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See “Biennial Review of the Cost of Windpower” July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower cost increases.

[7] See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006* Figure 21, page 16.

Figure 4
Wind Turbine Prices 1997 - 2007



Source: Berkeley Lab database.

Rising Projected Construction Costs: Examples and Case Studies

Although recently completed gas-fired and wind-powered capacity has shown steady real cost increases in recent years, the most dramatic cost escalation figures arise from *proposed* utility investments, which fully reflect the recent, sharply rising prices of various components of construction and installation costs. The most visible of these are generation proposals, although several transmission proposals also have undergone substantial upward cost revisions. Distribution-level investments are smaller and less discrete ("lumpy") and thus are not subject to similar ongoing public scrutiny on a project-by-project basis.

Coal-Based Power Plants

Evidence of the significant increase in the construction cost of coal-based power plants can be found in recent applications filed by utilities, such as Duke Energy and Otter Tail Power Company, seeking regulatory approval to build such plants. Otter Tail Power Company leads a consortium of seven Midwestern utilities that are seeking to build a 630-MW coal-based generating unit (Big Stone II) on the site of the existing Big Stone Plant near Milbank, South Dakota. In addition, the developers of Big Stone II seek to build a new high-voltage transmission line to deliver power from Big Stone II and from other sources, including possibly wind and other renewable forms of energy. Initial cost estimates for the power plant were about $1 billion, with an additional $200 million for the transmission line project. However, these cost estimates increased dramatically, largely due to higher costs for construction materials and labor.[8] Based on the most recent design refinements, the project, including transmission, is expected to cost $1.6 billion.

[8] Other factors contributing to the cost increase include design changes made by project participants to increase output and improve the unit's efficiency. For example, the voltage of the proposed transmission line was increased from 230 kV to 345 kV to accommodate more generation.

In June 2006, Duke submitted a filing with the North Carolina Utilities Commission (NCUC) seeking a certificate of public convenience and necessity for the construction of two 800 MW coal-based generating units at the site of the existing Cliffside Steam Station. In its initial application, Duke relied on a May 2005 preliminary cost estimate showing that the two units would cost approximately $2 billion to build. Five months later, Duke submitted a second filing with a significantly revised cost estimate. In its second filing, Duke estimated that the two units would cost approximately $3 billion to build, a 50 percent cost increase. The North Carolina Utilities Commission approved the construction of one 800 MW unit at Cliffside but disapproved the other unit, primarily on the basis that Duke had not made a showing that it needed the capacity to serve projected native load demands. Duke's latest projected cost for building one 800 MW unit at Cliffside is approximately $1.8 billion, or about $2,250/kW. When financing costs, or allowance for funds used during construction (AFUDC), are included, the total cost is estimated to be $2.4 billion (or about $3,000/kW).

Rising construction costs have also led utilities to reconsider expansion plans prior to regulatory actions. In December 2006, Westar Energy announced that it was deferring the consideration of a new 600 MW coal-based generation facility due to significant increases in the estimated construction costs, which increased from $1.0 billion to about $1.4 billion since the plant was first announced in May 2005.

Increased construction costs are also affecting proposed demonstration projects. For example, DOE announced earlier this year that the projected cost for one of its most prominent clean coal demonstration project, FutureGen, had nearly doubled.[9] FutureGen is a clean coal demonstration project being pursued by a public-private partnership involving DOE and an alliance of industrial coal producers and electric utilities. FutureGen is an experimental advanced Integrated Gasification Combined Cycle (IGCC) coal plant project that will aim for near zero emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, particulates and carbon dioxide (CO_2). Its initial cost was estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced that the project's price had increased to $1.7 billion.

Transmission Projects

NSTAR, the electric distribution company that serves the Boston metropolitan area, recently built two 345 kV lines from a switching station in Stoughton, Massachusetts, to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million. NSTAR stated that the increase is driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated. NSTAR further explained that there have been dramatic increases in material costs, with copper costs increasing by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

[9] U.S. Department of Energy, April 10, 2007, press release available at http://www.fossil.energy.gov/news/techlines/2007/07019-DOE_Signs_FutureGen_Agreement.html

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Another aspect of transmission projects is land requirements, and in many areas of the country land prices have increased substantially in the past few years. In March 2007, the California Public Utilities Commission (CPUC) approved construction of the Southern California Edison (SCE) Company's proposed 25.6-mile, 500 kV transmission line between SCE's existing Antelope and Pardee Substations. SCE initially estimated a cost of $80.3 million for the Antelope-Pardee 500 kV line. However, the company subsequently revised its estimate by updating the anticipated cost of acquiring a right-of-way, reflecting a rise in California's real estate prices. The increased land acquisition costs increased the total estimate for the project to $92.5 million, increasing the estimated costs to more than $3.5 million per mile.

Distribution Equipment

Although most individual distribution projects are small relative to the more visible and public generation and transmission projects, costs have been rising in this sector as well. This is most readily seen in Handy-Whitman Index© price series relating to distribution equipment and components. Several important categories of distribution equipment have experienced sharp price increases over the past three years. For example, the prices of line transformers and pad transformers have increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[10] The cost of overhead conductors and devices increased over the past three years by 34 percent, and the cost of station equipment rose by 38 percent. These are in contrast to the overall price increases (measured by the GDP deflator) of roughly 8 percent over the past three years.

[10] Handy-Whitman© Bulletin No. 165, average increase of six U.S. regions. Used with permission.

Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

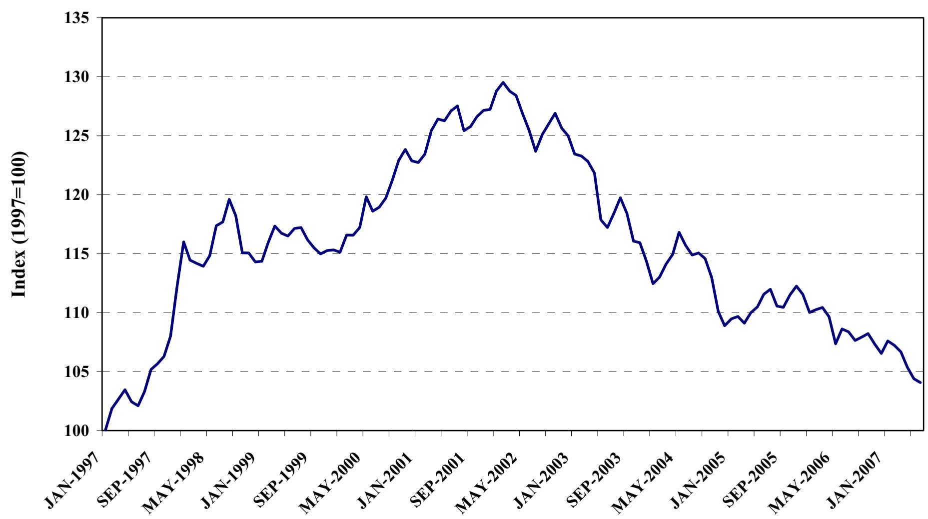
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

Exchange Rates

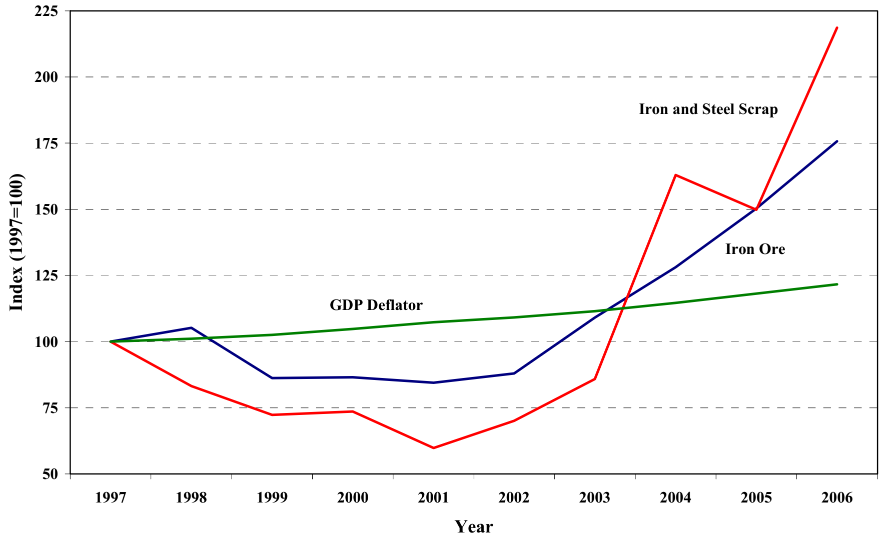
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar.

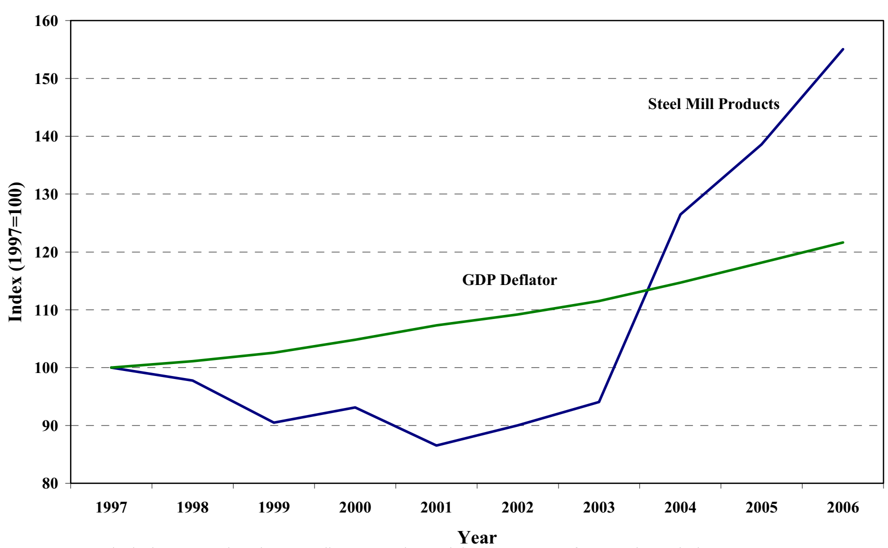
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



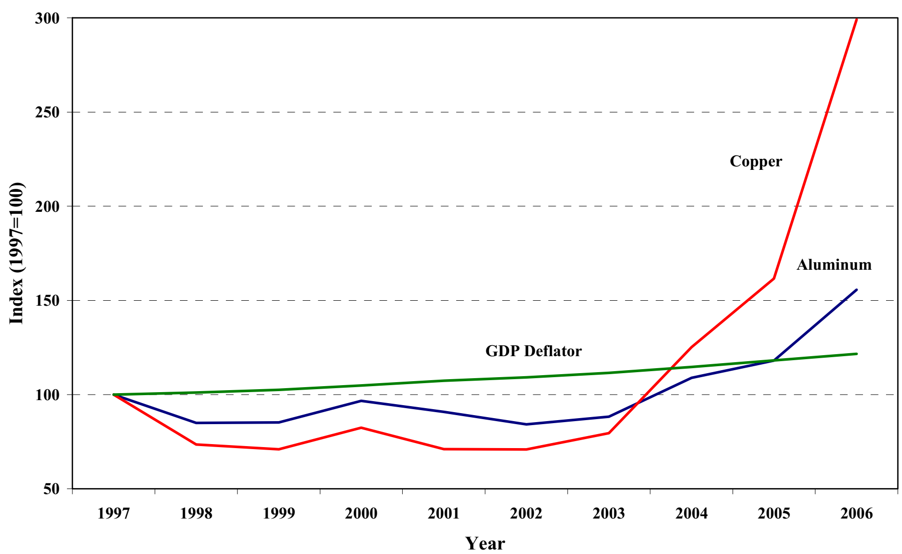
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

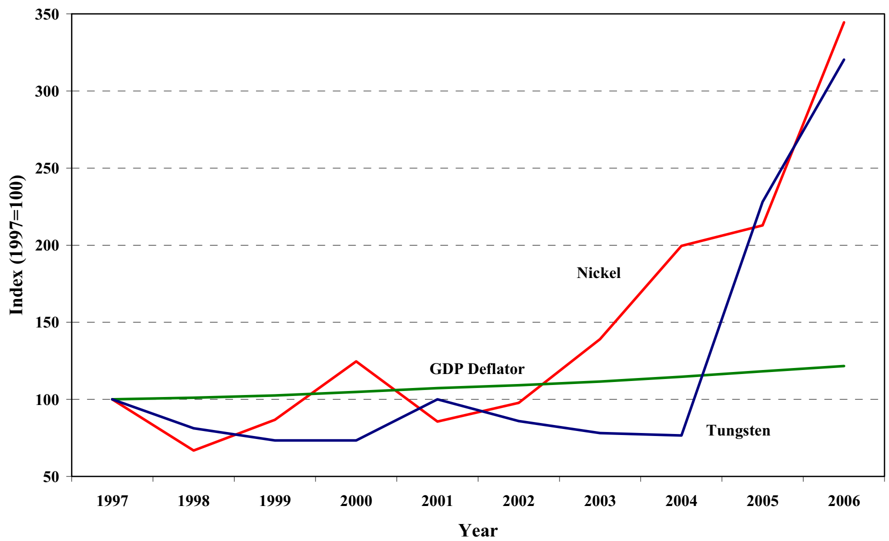


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

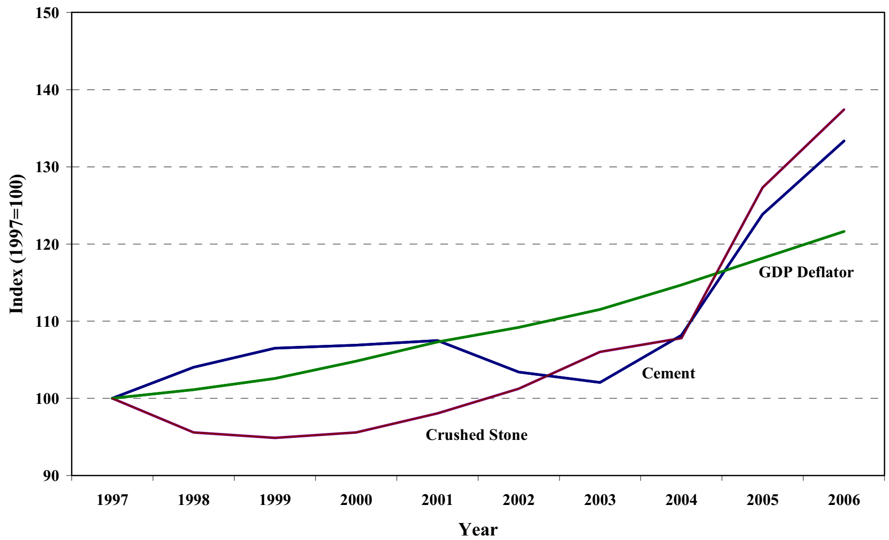


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

Figure 9
Cement and Crushed Stone Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

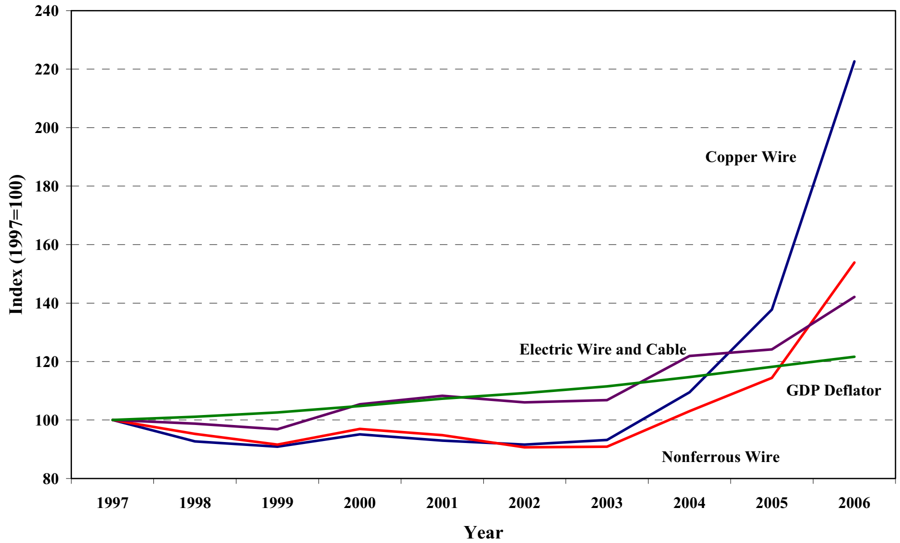
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

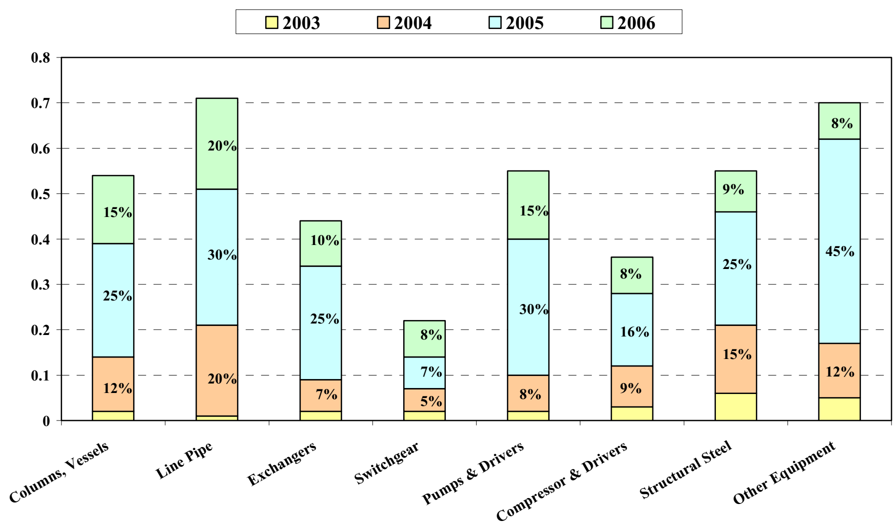
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

Figure 11
Equipment Price Increases

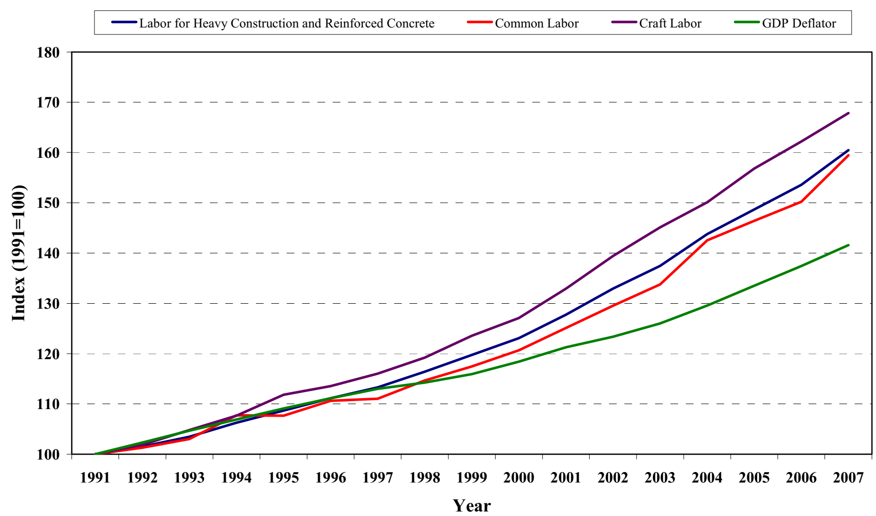


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage*. The Construction Users Roundtable, WP-401, June 2004, p. 1.

industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called “allowance for fund used during construction” (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

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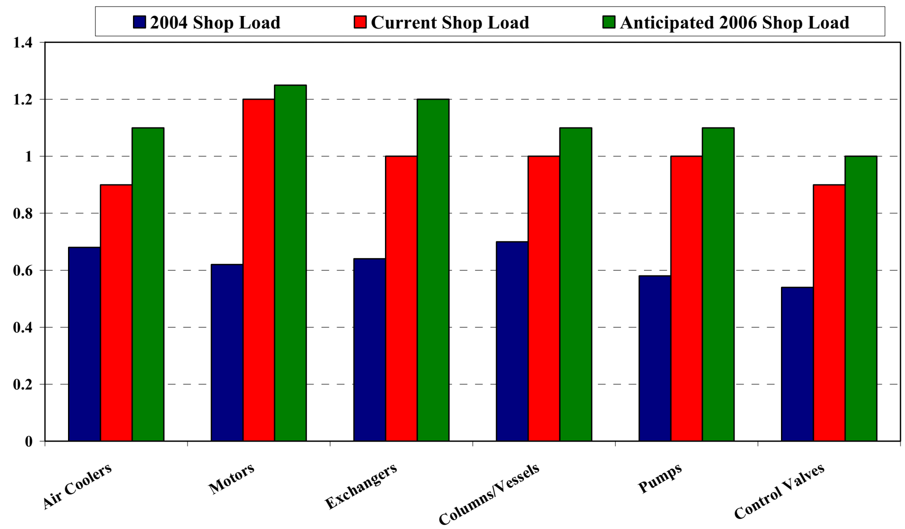
[14] *Id.*, p. 1.

[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005*. U.S. Department of Energy, August 2006, p. xi.

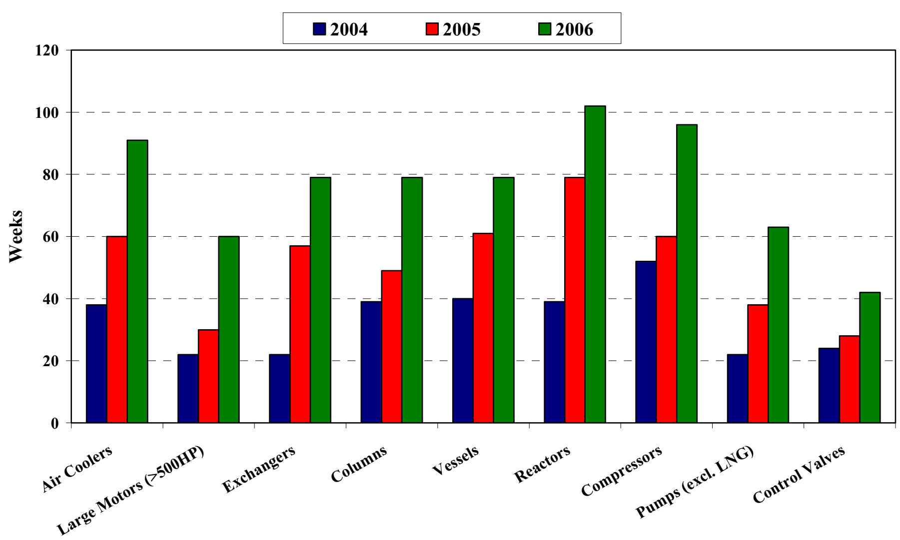
[16] *Id.*, p. 5.

Figure 13
Shop Capacity



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules

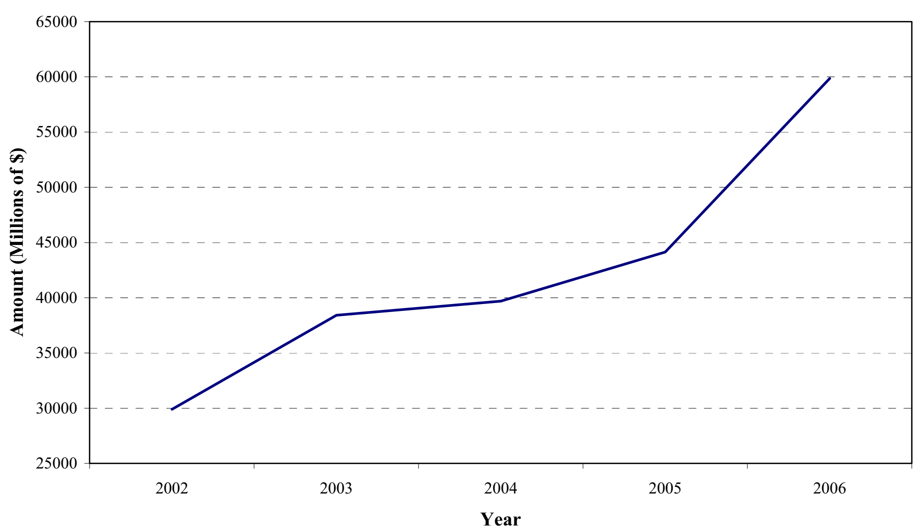


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints, combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

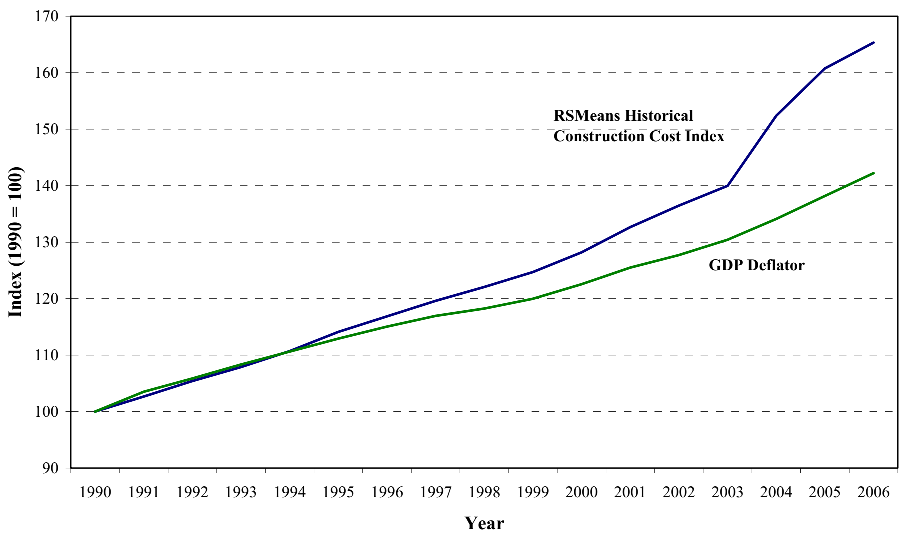
Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

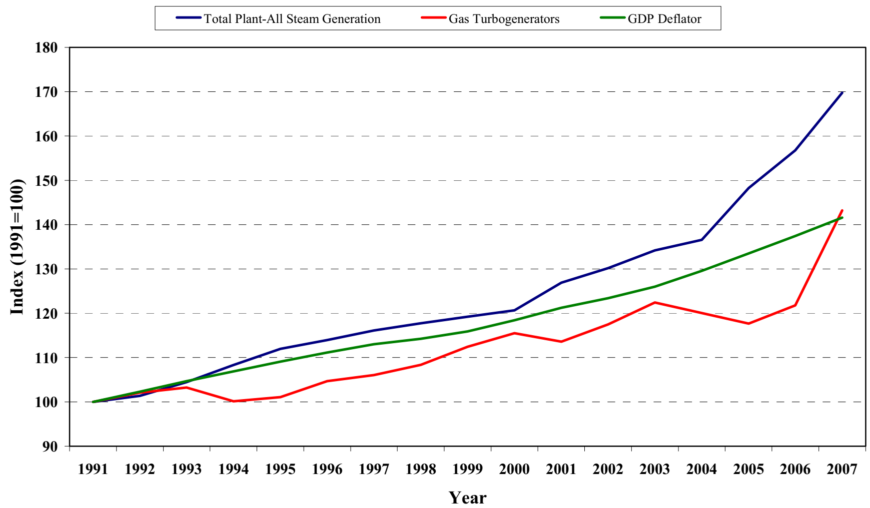
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

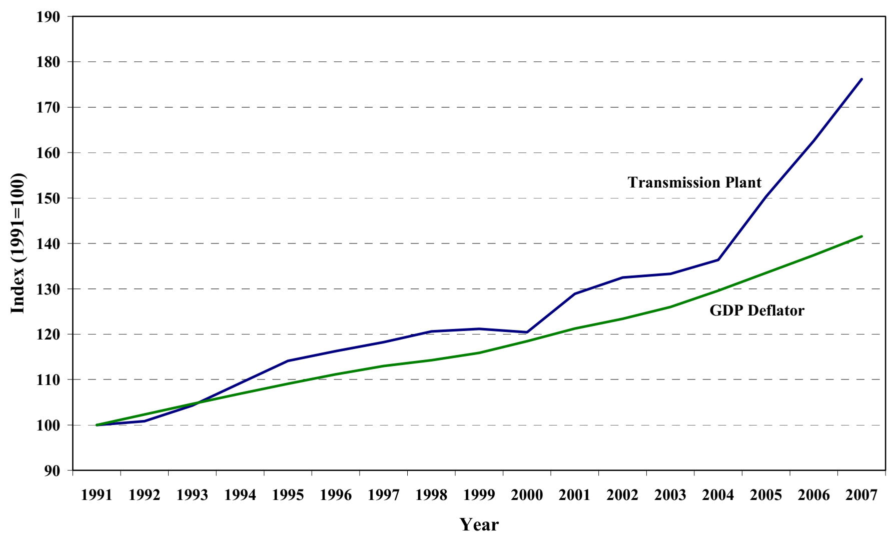
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components.

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

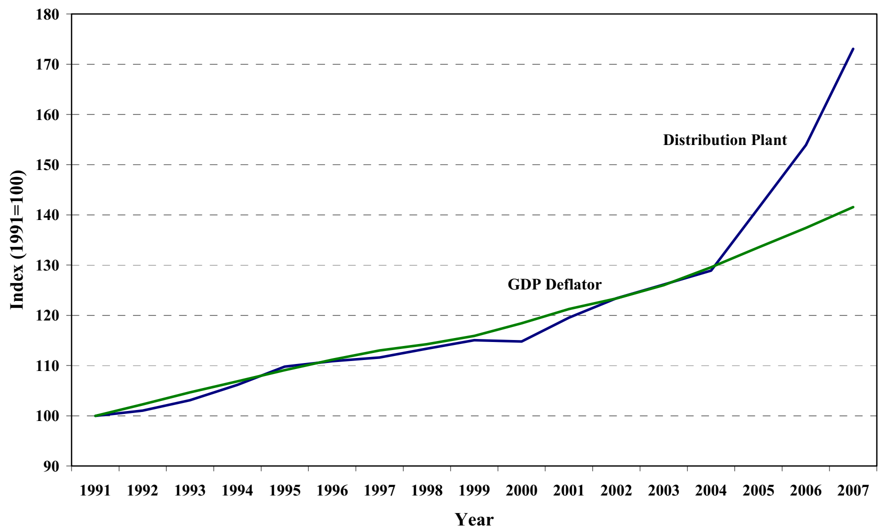
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices.

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g*., fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units *(i.e.,* the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

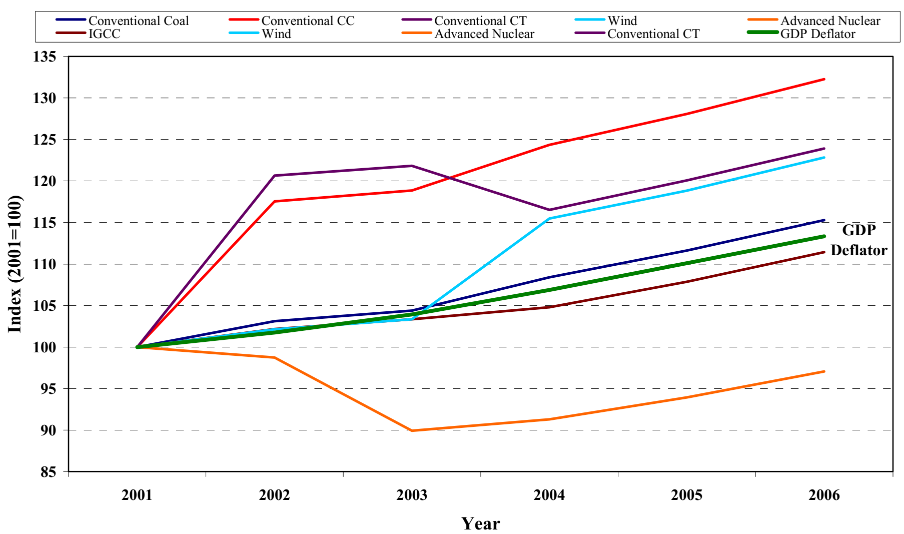
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

Conclusion

Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

Gregory N. Duvall
Exhibit PPL/605

Docket No. UE-210
Exhibit PPL/605
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Supplemental Direct Testimony of Gregory N. Duvall

June 2009

Q. Please state your name, business address and present position with PacifiCorp ("Company").

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232. My present title is Director, Long Range Planning and Net Power Costs.

Q. Are you the same Gregory N. Duvall that previously provided testimony in this docket?

A. Yes, as Exhibit PPL/600.

Purpose of Testimony

Q. Please explain the purpose of your testimony in this proceeding.

A. The purpose of this supplemental direct testimony is to respond to Requests 9, 10, 11, 12, 13, 15, 17, 18, 19 and 20 from the May 14, 2009 Ruling of the Administrative Law Judges on Supplemental Testimony ("Ruling on Supplemental Testimony"), in which PacifiCorp was ordered to file supplemental direct testimony. Each of these requests pertains to the Company's load forecast. I will also address Request 16 related to energy efficiency measures for each jurisdiction.

Q. How is your testimony organized?

A. First, I discuss temperature normalization and describe how the Company developed the forecast for kilowatt-hour sales at the meter ("sales"), and system loads and system peak loads at the system input level ("loads") for the twelve-month period ending December 31, 2010 (Requests 12 and 13). These forecasts are produced for all six states in which the Company serves retail customers and are necessary for the development of inter-jurisdictional allocation factors, forecasted revenues, and net power costs. Second, I discuss how the Company's historical sales and coincident peaks compare with the forecast (Requests 9 and 10). Third, I describe how the change in the definition of normal weather has affected Oregon's System Energy ("SE") and System Generation ("SG") allocation factors (Request 11). Fourth, I discuss how price elasticity is being treated in the load forecast (Request 15). Fifth, I focus on the improvements in modeling methodology and discuss various aspects of the modeling (Requests 17 through 20). Finally, I address energy efficiency achievements and the 2009 energy efficiency forecast in each jurisdiction (Request 16).

Request 12--Temperature Adjustment and Development of Forecast Sales

Q. What is the Request 12 in the Ruling on Supplemental Testimony?

A. Request 12 requires that the Company provide testimony explaining the methods used to adjust sales for temperature and to forecast sales, coincident peak loads, and customer numbers.

Temperature Adjustment

Q. Please describe the Company's temperature adjustment methodology.

A. Temperature is a critical factor in forecasting residential, commercial and irrigation customer loads. In forecasting, it is important to represent as well as possible the response of customer loads to temperature in a mathematical equation. To do this, the Company begins by conducting load research studies by class by state to collect observations of loads across different temperatures. Exhibit PPL/606 shows the different temperature responses across PacifiCorp's seven jurisdictions. The Company identified multipart slopes and breakpoints through a neural network framework. The neural network model identifies the break points and shape of the weather impacts. From this load research data, the Company analyzes the sensitivities of sales at different temperature levels and a composite weather variable is developed in order to capture extreme temperature within a month. The Oregon residential temperature response graph and composite equation are shown in Exhibit PPL/607. Temperature is not used as an input to the industrial forecast.

Forecast of Energy Sales (at the meter)

Q. How are monthly sales forecasts developed by customer class?

A. Monthly sales forecasts are developed as a product of two separate forecasts: the number of customers and sales per customer. This methodology is used for all customer classes except for the industrial customer class.

Q. How is average use per customer for customer classes forecasted?

A. Sales per customer for the residential class are modeled through a Statistically Adjusted End-use ("SAE") model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

For the commercial class, sales per customer are forecasted using regression analysis techniques with non-manufacturing employment used as the major economic driver in addition to weather-related variables.

For other non-industrial classes, sales per customer are forecasted through regression analysis techniques using monthly binary and weather variables.

Q. How does the Company forecast sales for the industrial customer class?

A. The industrial customers are separated into three categories: i) existing customers that are tracked by the Customer Account Managers ("CAMs"), ii) new large customers or expansions by existing large customers, and iii) industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if they have a peak load of one megawatt or more at a single site.

The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer and represents about 28 percent of the total system forecast and about 14 percent of the Oregon forecast. The CAMs have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on the direct input of the customers, forecasted load factors, and the probability of the project occurrence. The third category, industrial customers under one megawatt, is more homogeneous and is modeled using regression analysis with trend and economic variables. Manufacturing employment is the major economic driver.

The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories.

Q. Why are industrial sales forecasted by a different methodology than the other customer classes?

A. This class is forecasted differently because of the diverse makeup of the customers within the class. In the industrial class, there is no "typical" customer. Large customers have very diverse usage patterns and power requirements. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers.

In contrast, customer classes that are made up of mostly smaller, homogeneous customers are best forecasted as a use per customer multiplied by number of customers. Those customer classes are generally composed of many smaller customers that have similar behaviors and usage patterns. No small group of customers, or single customer, influences the movement of the entire class. This difference requires the different processes for forecasting.

Forecast of Customers

Q. Please describe the method used to forecast number of customers.

A. The forecast of number of customers is generally based on a combination of regression analysis and exponential smoothing techniques using historical data from 1997 to January 2009. For the residential class, the forecast of number of customers is developed using a regression model with Global Insight's forecast of each state's number of households as the major driver. For the commercial class, forecasts rely on a regression model with the forecasted residential customer numbers used as the major driver. For irrigation and street lighting classes, customer forecasts are developed based on exponential smoothing models.

Peak Forecast (at system input)

Q. Please describe the method used to forecast each state's contribution to the coincident peak loads.

A. Each state's contribution to the coincident peak is calculated from the hourly loads. After the hourly load forecasts for each state are developed, hourly loads are aggregated to the system level. The system peaks can then be identified as well as the contribution of each jurisdiction to those monthly peaks

Q. Please outline how the hourly load forecast is developed.

A. After the forecasts of monthly energy sales by customer class are developed, a forecast of hourly loads is developed in two steps:

First, monthly and seasonal peak forecasts for each state are developed for each jurisdiction. These are done at system input. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables. These weather variables include the average temperature on the peak day and lagged average temperatures. The peak forecast is based on average monthly historical peak-producing weather for the period 1990-2007. Use of the average peak producing weather results in a one-in-two forecast in which it is equally likely that the actual peak load is higher or lower than the forecast peak load.

Second, hourly load forecasts for each state are obtained from hourly load models using state-specific hourly load data and daily weather variables. Hourly loads are developed using a model which incorporates the twenty-year rank and average temperatures, a typical weather pattern for each year, and day-type variables such as weekends and holidays. The hourly loads are adjusted for line losses and calibrated to monthly and seasonal peaks.

Q. What do you mean by "rank and average"?

A. Rank and average occurs in three steps. First, the daily average temperatures for each month of the 20-year history are ranked from high to low. Second, these ranked monthly temperatures are averaged from the highest temperature to the lowest temperature. Third, the average temperatures are assigned to each day based on a typical weather pattern. Using this method allows the Company to accurately forecast hourly loads capturing peak producing weather.

Impact of Current Economic Conditions

Q. Please describe how the impact of the current economic conditions is reflected in the Company's sales forecast for Oregon.

The Company's sales forecast model was developed using historical sales data ending January 2009, and the most recent available economic data. This data reflected economic variables from late 2008 and early 2009. Next, to fully capture the effects of the current recession on the load forecast for the industrial class, the Company compared the model results to the load reduction experienced in the 2001-2002 recession, supplemented with information obtained by the Company's CAMs who talk with customers on a regular basis. During the 2001-2002 recession, Oregon's total retail sales dropped by 4 percent, and as indicated in my direct testimony (Exhibit PPL/600, Duvall/6-7), sales in 2008 started declining in the second quarter, and were down 5.3 percent in the last quarter of 2008 as compared to the last quarter of 2007. On an annual basis, 2008 sales in Oregon were about 1.5 percent below 2007 sales on a temperature adjusted basis. Based on the review of this information, the Company reduced the model-driven results for industrial sales forecast by 222,154 megawatt-hours ("MWh") in 2010. As a result, the 2010 forecast sales for Oregon are 2.4 percent lower than the weather normalized 2008 sales.

Request 13--Conversion of Sales Estimates to Energy Deliveries

Q. What is Request 13 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining how sales estimates are converted into energy deliveries.

Q. How does the Company convert sales estimates at the customer meter to energy deliveries at the system input level?

A. The Company uses the average of the most recent five years (ending December 31, 2007) of energy losses by state to convert metered sales forecasts to system input. The use of actual losses is a reasonable basis for capturing total system losses. Oregon's average line loss is 9.52 percent. Peak loads are forecast at the system input level for each state and therefore do not require any conversion.

Requests 9 & 10--Comparison of Historical Sales and Peak to the Forecast

Q. What is Request 9 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining how retail sales have changed or are forecasted to change from October 1, 2006, through the test year, as well as the key factors driving such changes.

Q. Has the Company compared Oregon's actual weather normalized retail sales to test period forecasted retail sales?

A. Yes, the Company made this comparison for Oregon in my direct testimony, Exhibit PPL/600, Duvall/7. Based on the recent history through January 2009, it was clear that the declining sales in Oregon are expected to continue and are driven by the nationwide economic downturn and housing market slowdown and closures in the wood products sector. Continuing this trend, the retail sales in 2010 (13,392,810 MWh) are 2.4 percent lower than the 2008 weather normalized sales (13,717,170 MWh). Table 1 details the 2006-2010 Oregon retail sales by class.

Table 1
Oregon Retail Sales by Class

Class	2006	2007	2008	2009	2010
Residential	5,516,750	5,526,360	5,503,230	5,400,708	5,438,620
Commercial	4,800,350	4,916,970	4,960,970	4,819,008	4,836,110
Industrial	3,245,220	3,183,040	2,964,750	2,780,724	2,815,620
Other	279,150	299,420	288,220	303,750	302,460
Total	13,841,470	13,925,790	13,717,170	13,304,190	13,392,810

Q. How does Oregon compare with the other states?

A. Comparing weather normalized retail sales between 2006 and 2008, Oregon and Washington declined by 0.45 percent and 1.16 percent, respectively, primarily driven by the economic downturn, housing market slowdown and closures in wood products sector. On the other hand, sales grew by 3.8 percent and 6.0 percent in Utah and Wyoming, respectively, with continuing industrial growth, in particular, attributed to the oil and gas growth in Wyoming.

Q. Has the Company compared actual weather normalized energy at system input to test period forecasted energy at system input?

A. Yes, Exhibit PPL/608 presents this comparison. The Company used actual weather normalized energy sales data for each month through January 2009, and used data from the February 2009 forecast from February 2009 through December 2010. Each point on the graphs in Exhibit PPL/608 represents a 12-month sum, consistent with the SE factor. For example, the first point is the 12-months ending October 2006, the second point is the 12-months ending November 2006, and the final point on the graphs is the 12-months ending December 2010, which is the basis of the SE factor used in this docket. The exhibit has a graph for each jurisdiction.

Q. Please explain how energy at input have changed or are forecast to change from October 1, 2006, through the test year, as well as the key factors driving such change.

A. As shown in Exhibit PPL/608, energy has been relatively flat over this time period in Oregon, Washington, California and Idaho, but has increased in Utah and Wyoming. Some slowdown in growth is seen in both Rocky Mountain Power and Pacific Power states near the end of 2008 and through 2009. This is due to the current economic recession. The growth in Utah and Wyoming is led by the industrial class, particularly the oil and gas customers in Wyoming.

Q. What is Request 10 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining how monthly coincident peak loads (12 CP) have changed or are forecasted to change from October 1, 2006, through the test year in this docket, including an explanation of key factors causing such changes.

Q. Has the Company compared actual weather normalized monthly coincident peak loads (12 CP) to test period forecasted monthly coincident peak loads (12 CP)?

A. Yes, Exhibit PPL/609 presents this comparison. The Company used weather normalized monthly coincident peak load data for each month through January 2009 and used that data to forecast February 2009 through December 2010 peak loads. Each point on the graphs in Exhibit PPL/609 represent a 12-month sum (12 CP), consistent with the System Capacity ("SC") factor, which makes up 75 percent of the SG factor, with the remaining 25 percent being derived from the SE factor. For example, the first point is the 12-months ending October 2006, the second point is the 12-months ending November 2006, and the final point on the graphs is the 12-months ending December 2010, which is the basis of the SC factor used in this docket. The exhibit has a graph for each jurisdiction.

Q. Please explain how the 12 CP has changed or is forecast to change from October 1, 2006, through the test year, as well as the key factors driving such change.

A. As shown in Exhibit PPL/609, coincident peaks have been relatively flat over this time period in Oregon, Washington, California and Idaho, but have increased in Utah and Wyoming. Some slowdown in growth is seen in both Rocky Mountain Power and Pacific Power states (more pronounced in Oregon) near the end of 2008 and through 2009. This is due to the current economic recession. The growth in Utah and Wyoming is led by the industrial class, particularly the oil and gas customers in Wyoming.

Request 11--Impact of Moving from 30-year NOAA Data to 20-Year Weather Data Set

Q. What is Request 11 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining how the adoption of the 20-year weather data set (1988 through 2007) changes the forecasted energy and peak allocation factors for the test year, relative to the previous 30-year NOAA data set (1971 through 2000).

Q. Has the Company quantified the impact on the allocation factors due to changing from 30 years (1971 – 2000) to 20 years (1988-2007) for temperature normalization?

A. Yes. The Company recast the February 2009 forecast using the 30 years from 1971 – 2000 as the basis of "normal" weather to make this determination. Use of the 20 years from 1988 – 2007 reduces Oregon's SE factor by 0.0014, from 0.2531 to 0.2517, and reduces Oregon's SG factor by less than 0.0001, from 0.26735 to 0.26733 for the test period. In addition, the Company assessed the impact of using peak producing weather to forecast the monthly peaks as opposed to the old method which used average daily temperatures to predict peak loads. This latter change increases Oregon's SG factor by 0.0042, from 0.2631 to 0.2673. Oregon's SE factor was unaffected by this latter change.

Q. Why does Oregon's SG factor increase when peak producing temperatures are used to forecast monthly peak loads?

A. When compared to Utah, Wyoming and Idaho, Oregon has more sales that vary with temperature. For example, about 50 percent of the sales in Utah, Wyoming and Idaho are from the industrial class, which is not affected by weather. Oregon's industrial sales comprise only about 22 percent of the total Oregon sales. This fact, combined with the use of using peak producing rather than average temperatures to predict peak loads, resulted in a small increase in Oregon's contribution to peak loads when compared to the prior forecast.

Q. Why does Oregon's SE factor decrease?

A. Normal temperatures are higher when moving to more recent data as shown in Exhibit PPL/610. As a result, forecasted winter loads are lower and summer loads are higher. Since Oregon has more winter load and less summer load relative to some of the other five jurisdictions, Oregon's energy allocation factor goes down.

Request 15--Price Elasticity

Q. What is Request 15 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining price elasticities, whether they are used in the load forecasts, their derivation (studies utilized by the PacifiCorp) and level, and their impact on test year 2010 energy volumes.

Q. Please explain what is meant by price elasticity?

A. Price elasticity is a measure of the change in electric sales in response to the change in the retail electric price (adjusted for inflation).

Q. Please elaborate on the different forms of the price elasticity?

A. There are two related concepts of price elasticity: short-run and long-run. The short-run elasticity is a measure of consumer response during the time frame when the consumer cannot change the appliance stock. During the short-run, the consumer response to an increase in price is limited to measures such as turning out lights and turning down thermostats. In the long-run, consumers have time to adjust their appliance choice in response to the retail price change. For example, in the long-run, consumers can purchase more energy efficient air conditioners or switch from an electric hot water heater to a gas hot water heater.

Q. How did the Company model short-term elasticity in the February 2009 forecast?

A. The Company explicitly modeled the residential price elasticity within the model as a 0.125 percent reduction in usage for each one percent real increase in price. The Company did not explicitly model short-run elasticity for the commercial and industrial customer classes. This is based on discussions with ITRON, the consultant that worked with the Company to update the forecasting methodology, and on industry experience. For forecasting purposes and because the Company is unable to predict the outcomes of rate cases, the Company assumed that the nominal rate increases match the rate of inflation so there are no real price increases in any state. As a result, the short-term elasticity response for residential customers did not result in any change to any states' loads.

Q. How would Oregon's loads change if the Company were to assume a real price increase in Oregon consistent with what the Company has requested in this filing?

A. Including the total proposed rate increase in the model would decrease Oregon residential sales for the test period by about 5 average megawatts, which is about 0.31 percent of total Oregon 2010 retail sales. Sensitivities were not conducted for any other state.

Q. Are the effects of long-term elasticity reflected in the load forecast for the test period?

A. Yes. While energy efficiency is not directly part of the load forecasting models, the Company is actively acquiring energy efficiency resources across its six-state service territory and expects over 150 megawatts of load reduction to be achieved through its energy efficiency programs in 2009 and 2010. These reductions are reflected in the load forecast used in this docket.

Request 17-20--Technical Discussion on Modeling and Refinements

Q. What is Request 17 in the Ruling on Supplemental Testimony?

A. This Request requires that the Company provide testimony explaining the statistical models used by PacifiCorp in developing the 2010 test year load forecast including theoretical bases, mathematical forms, and relevant statistics.

(a) Provide testimony explaining how such statistical models were developed (e.g., a discussion of any process involving step-wise regression).

(b) Provide testimony explaining forecasts of or trends in the independent variables used in such statistical models, including the source of any such forecasts or trends.

Q. How many statistical models were used by the Company to develop the 2010 test year load forecast?

A. The Company employed a total of 1,070 statistical models in preparing the 2010 test year load forecast. These models fall into three broad categories: neural network models, least squared models, and exponential smoothing models.

Q. What is a neural network model and when is it used?

A. The neural network model is a broad class of models that changes its structure based on the use of learning algorithms. The neural network models were used for developing temperature response relationships. The neural network model is the best choice for developing the temperature response functions because it can be used to model complex relationships or to find patterns in data.

Q. What are least squared models and when are they used?

A. Least squared models are a broad class of models which are estimated based on minimizing the sum of squared errors. Errors are the difference between the predicted values and actual values. Additionally, if the error terms are correlated, least squared models can be extended to non-linear least squares by adding a time series variable. Least squared models are the best choice of models to use when there are sufficient observations to estimate the equations (i.e., sufficient degrees of freedom) and when there are external drivers. The SAE model falls within this class of models. These models are the best choice for estimating residential use per customer because (1) they allow for changes in saturation and efficiency over time, (2) allow for correlation of the error term over time, and (3) they allow for economic drivers.

Q. What are exponential smoothing models and when are they used?

A. Exponential smoothing models are a broad class of models that are generally used to forecast a series over time if there are not any external drivers. These models give more weight to more recent data and less weight to older data. This model is the best choice of models to use when there are not any external drivers because these models tend to be very robust. Exhibit PPL/611 provides an overview of the model estimation techniques and objective functions.

Q. What is the theoretical basis for these models?

A. The theoretical basis for these models is to achieve an expected error of zero. That is, there is an equal chance that the results will over forecast or under forecast.

Q. What mathematical forms were used?

A. The Company used traditional statistical modeling forms. Though there are many models, a handful of the models, mathematical forms, and coefficients were provided to the Staff through data requests OPUC 27 and OPUC 180a. Confidential Exhibit PPL/612 provides a sample of the mathematical forms that were used in the Company's proprietary models for the Oregon residential, peak, and hourly models. In addition, the Company's load forecasting staff has already led a technical presentation with the Staff and is available to meet with Staff or intervenors to view and demonstrate the model.

Q. What relevant statistics did the Company rely upon?

A. The Company relied upon a variety of statistics, including the t-statistic, the Mean

Absolute Percentage Error, the R-squared, the Durbin Watson, and the F-statistic. Additionally, the Company reviewed the results to ensure consistency between the forecast results and what the Company has observed.

Q. How were the statistical models developed?

A. The Company developed each model based on the characteristics of the particular customer class. In each case, the Company reviewed a graph of the error terms and the test statistics. The Company then made the decision to add variables, delete variables, change variables, or not to make any change at all. For example, if the graph of the error term indicated a growing trend of under forecasting the summer cooling sales, the Company may include a time trend interacted with a cooling degree day variable. This decision to add, delete, or change variables can be viewed as one form of stepwise regression.

Q. How did the Company forecast or trend the independent variables used in the statistical models?

A. The Company relied on IHS Global Insight's forecast of independent economic variables. For the residential customer class, the Company relied on ITRON to provide forecasts of end use efficiencies.

Q. What is Request 18 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining in detail any non-statistical models used by PacifiCorp in developing the 2010 test year load forecast including theoretical bases and, if applicable, mathematical forms.

Q. Did PacifiCorp use any non-statistical models in developing the 2010 test year load forecast?

A. Yes, the Company developed the industrial forecast for large customers directly from information collected by the CAMs, therefore, this forecast is not done through statistical modeling. The detailed methodology and rationale behind the industrial forecast methodology have been described earlier in this testimony

Q. What theoretical basis did the Company use to develop these non-statistical models?

A. The Company recognized that the forecasting process could be improved by using information from the CAMs for large industrial customers. As mentioned earlier in this testimony, these customers are relatively heterogeneous and any changes in sales to these customers tends to be rather "lumpy." These characteristics support the use of a non-statistical model to forecast sales to these customers.

Q. What mathematical forms did the Company use in the non-statistical models?

A. The Company used a spreadsheet with details regarding each customer, the probability that the load would materialize, the load factor, the number of hours in the month, and the timing of the sales increase to develop a forecast of the expected sales by month.

Q. What is Request 19 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining how PacifiCorp's statistical and non-statistical models differ from those used in PacifiCorp's last Oregon general rate case for forecasting test year energy deliveries.

Q. Why did the Company improve its forecasting methodology?

A. The Company wanted to develop an integrated forecasting model that improves transparency and precision.

Q. How do the models used in this forecast compare with the models used in the previous general rate case in UE 179?

A. First, statistical models were refined to improve the accuracy of the forecast. In UE 179, energy deliveries were forecasted on an annual basis, and then monthly energy was derived based on monthly energy pattern. In the current filing, energy deliveries are directly forecast by month.

Second, the impact of weather on monthly retail sales and peaks by state by class was refined by using load research data.

Third, the time period used to define normal weather was updated from the NOAA's 30-year period of 1971-2000 to the 20-year time period of 1988-2007.

Fourth, the SAE models were used for forecasting residential class sales as compared to the simple end use modeling used in UE 179, which used a single year of end use information. In contrast, the SAE approach incorporates end use information on saturation and efficiency across multiple years that reflect market changes as well as changes in appliance and equipment efficiency standards. This more robust approach to incorporating end-use data allows continuity between history and the forecast while retaining the capability to make adjustments for end use changes, such as specific known changes in efficiency standards.

Fifth, for the commercial class, the Company has used an econometric model in the current filing instead of using an end use model. Inclusion of end use information in the commercial class forecast was not found to improve the accuracy of the forecast and was therefore not included as a matter of keeping the forecast as simple as possible while not compromising its accuracy.

Sixth, the current filing forecasts monthly peaks directly by using a peak model for each state using peak-producing weather obtained by averaging weather on peak days.

Lastly, for non statistical models, there is no difference between the methodology used in the last general rate case and current general rate case.

Q. What is Request 20 in the Ruling on Supplemental Testimony?

A. This request requires that the Company provide testimony explaining the risks and uncertainties associated with the 2010 test year load forecasts.

Q. Please identify the uncertainties associated with the 2010 load forecast.

A. As pointed out earlier in my testimony, this forecast is unbiased, that is, there is an equal chance that this forecast will over-forecast sales or under-forecast sales and peak. With that said, the uncertainty to the forecast largely centers on the economy and the recovery from the economic downturn. If the recovery is slower than forecasted, energy sales and peak will likely be less in all the states where PacifiCorp serves. If on the other hand, the recovery is faster, energy sales and peak will likely be higher in all states. Another uncertainty is if actual weather is significantly different from assumed normal weather.

Q. What are the risks associated with these uncertainties?

A. For customers, the risks are largely mitigated by the fact that forecast uncertainties will not change customer rates for PacifiCorp since the Company has no regulatory mechanisms that true-up customer rates to actual costs. For example, if actual loads turn out to be higher than the loads used to set rates, the Company receives more retail revenue. This is offset, however, by the loss of wholesale revenue. On the contrary, if actual loads are lower than the loads used to set rates, the Company receives fewer retail revenues but more wholesale revenues than were assumed for setting rates. If the retail rates for power costs are close to the wholesale power rate, then any errors in the forecast are largely mitigated.

Request 16--Energy Efficiency – 2006 to 2009

Q. What is Request 16 in the Ruling on Supplemental Testimony?

A. Request 16 requires that the Company provide testimony and exhibits related to volume changes from October 1, 2006, through calendar year 2009 related to energy efficiency measures for each jurisdiction.

Q. What was the Company's actual energy efficiency acquisitions for calendar years 2006 through 2008 and what is the forecast or planning assumption for energy efficiency acquisitions in 2009?

A. System-wide acquisitions of energy efficiency resources for 2006 through 2008 through Company and Energy Trust of Oregon administered programs were as follows:

Calendar Year 2006 - 297,856 MWh

Calendar Year 2007 - 309,306 MWh

Calendar Year 2008 - 392,390 MWh

The planning assumption for energy efficiency acquisitions in 2009 is 394,323 MWh. All amounts are estimated first year savings measured at the source, i.e. adjusted for line losses. Exhibit PPL/613 catalogs the actual energy efficiency resource acquisitions for calendar years 2006 through 2008 and the forecasted acquisitions for 2009, by jurisdiction.

Q. Is the 2009 planning assumption for energy efficiency resources the same assumption used in the development of the Company's current forecast in the rate case?

A. Yes. The planning assumption is for 394,323 MWh of energy efficiency resources, which is the same forecast used in the recently filed 2008 Integrated Resource Plan.

Q. What role does demand side management play in PacifiCorp's resource planning process?

A. PacifiCorp includes available demand-side management resources, specifically Class 1 load management and Class 2 energy efficiency resources, as comparable resources options to supply-side resources within the Company's integrated resource planning process.

Q. Have PacifiCorp's forecasted energy efficiency targets for planning purposes changed since the completion of the 2007 Integrated Resource Plan (2007 through 2016 planning period)?

A. Yes. The planning forecasts for energy efficiency resources in Company planning documents beginning with the 2007 Integrated Resource Plan Update (filed in

June 2008) doubled from those assumed in the 2007 Integrated Resource Plan. The increase was driven primarily by three factors: 1) the completion of the Company's June 2007 "Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources" study ("Potential Study"); 2) a revised acquisition forecast by the Energy Trust of Oregon (assisted by the passage of Oregon Senate Bill 838 and approval of the Company's Schedule 297); and 3) changes in the way the Company models demand-side management resources in the resource planning process. The Potential Study provided more granular information on resource costs and quantities from which to develop demand-side resource supply-curves and effectively helped reduce the risk of over reliance on demand-side resources through a better assessment resource availability within each of PacifiCorp's jurisdictions.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

Gregory N. Duvall
Exhibit PPL/606

Docket No. UE-210
Exhibit PPL/606
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

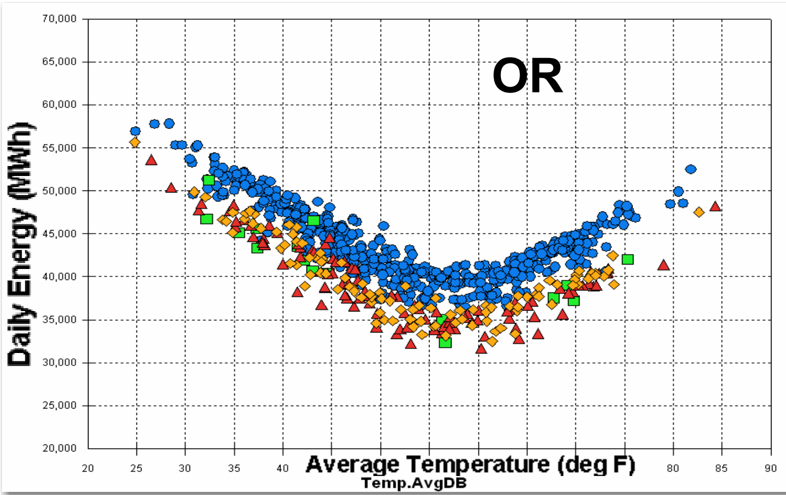
PACIFICORP

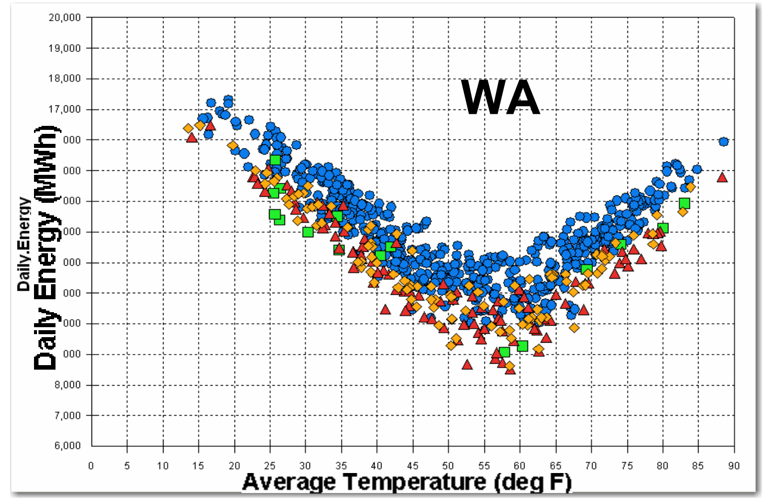
Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

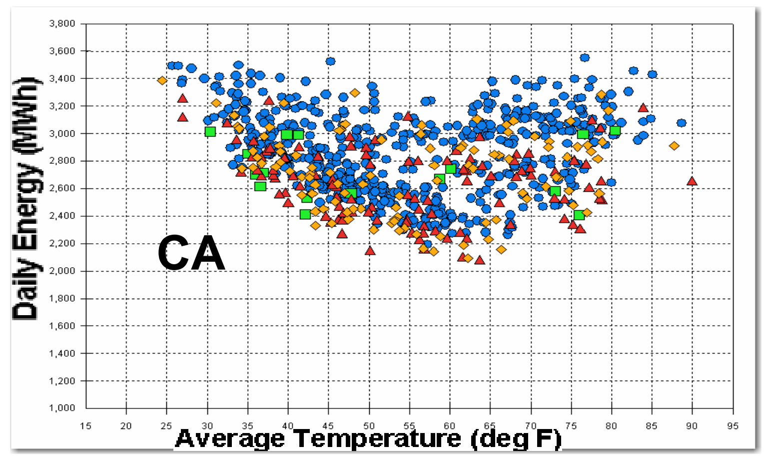
Temperature Responses by State

June 2009

Temperature Responses by State







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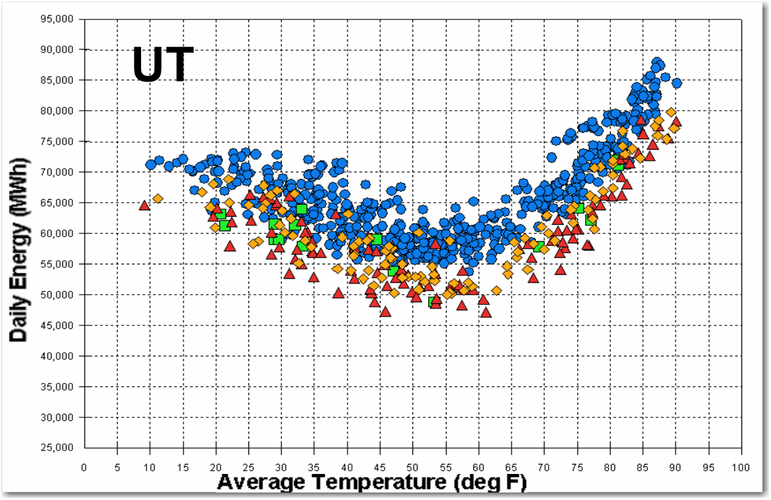
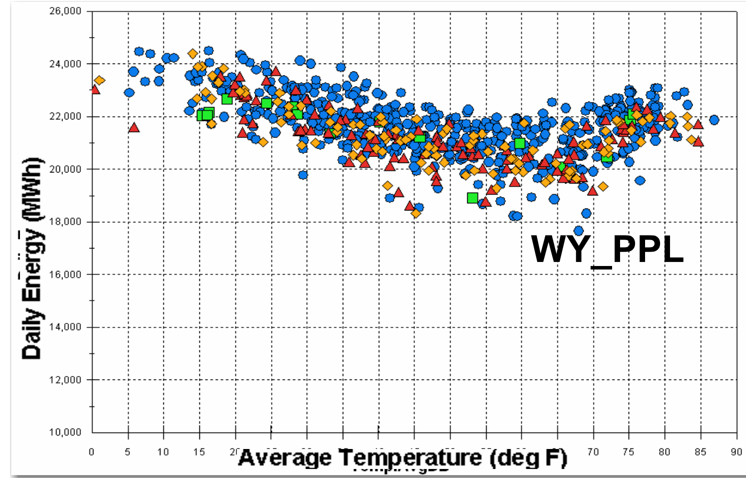
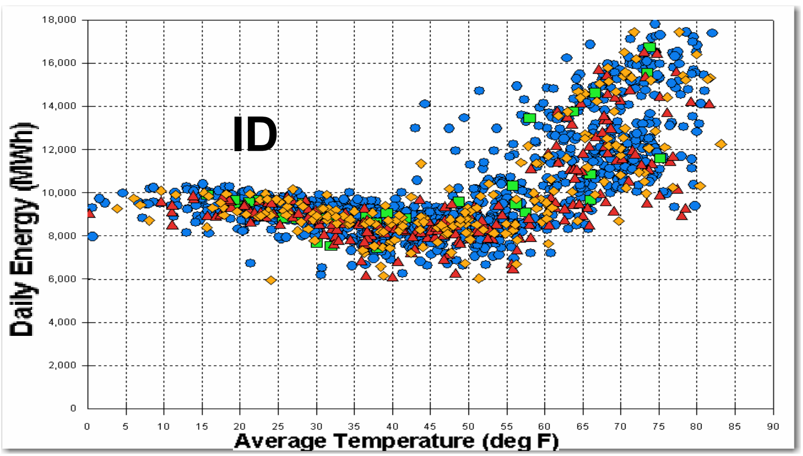
Temperature Responses by State







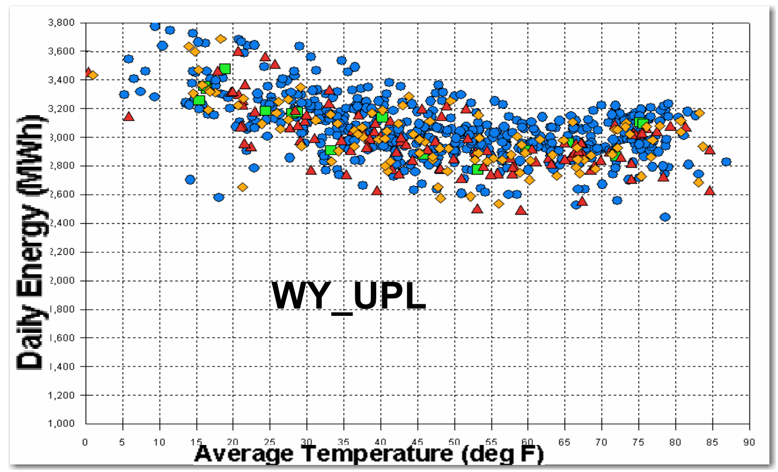


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Exhibit PPL/606
Duvall/2

Docket No. UE-210
Exhibit PPL/607
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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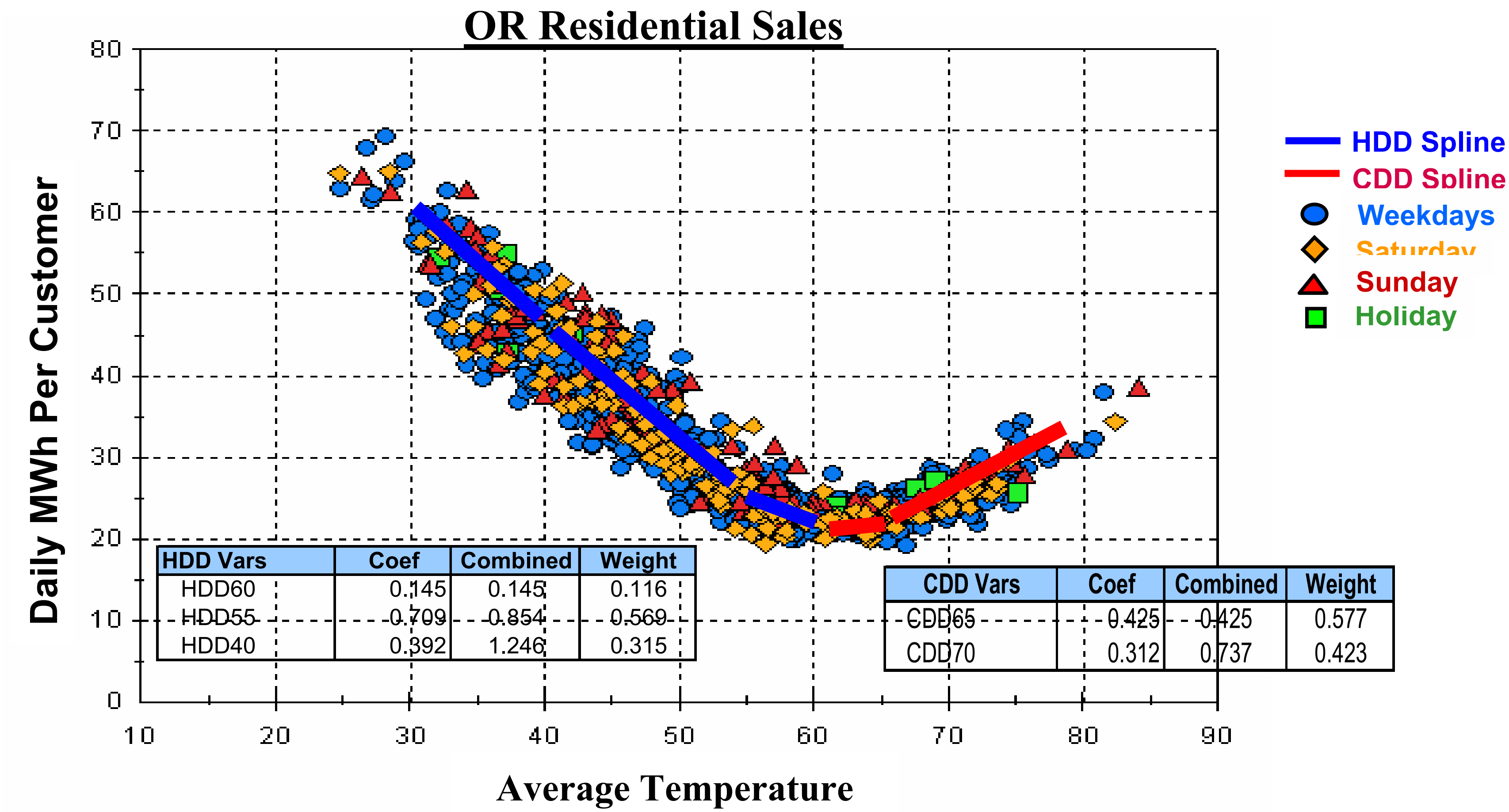
Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

Oregon Residential Temperature Response

June 2009

Oregon Residential Temperature Response Graph



HDD Vars	Coef	Combined	Weight
HDD60	0.145	0.145	0.116
HDD55	0.709	0.854	0.569
HDD40	0.392	1.246	0.315

CDD Vars	Coef	Combined	Weight
CDD65	0.425	0.425	0.577
CDD70	0.312	0.737	0.423

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Development of composite weather variable

Composite variable ⇓ | Weights ⇓ | Weather variables ⇓

CDDSpline = .577 × CDD65 + .423 × CDD70

HDDSpline = .116 × HDD60 + .569 × HDD55 + .315 × HDD40

Docket No. UE-210
Exhibit PPL/608
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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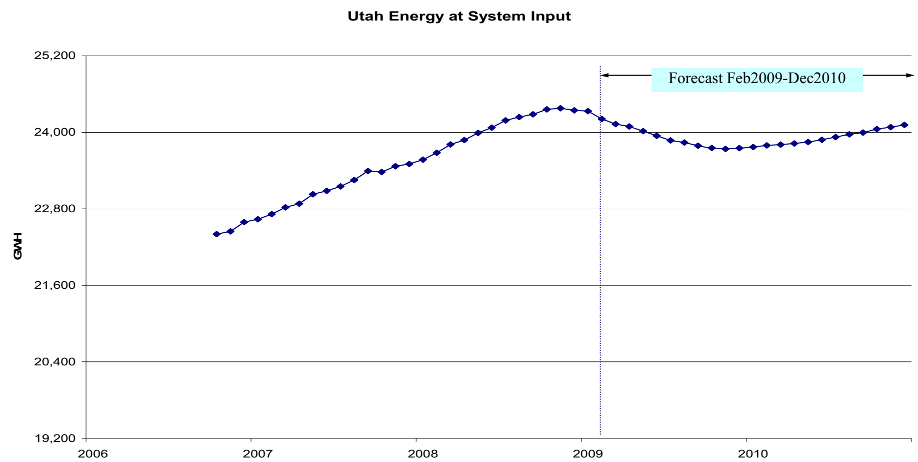
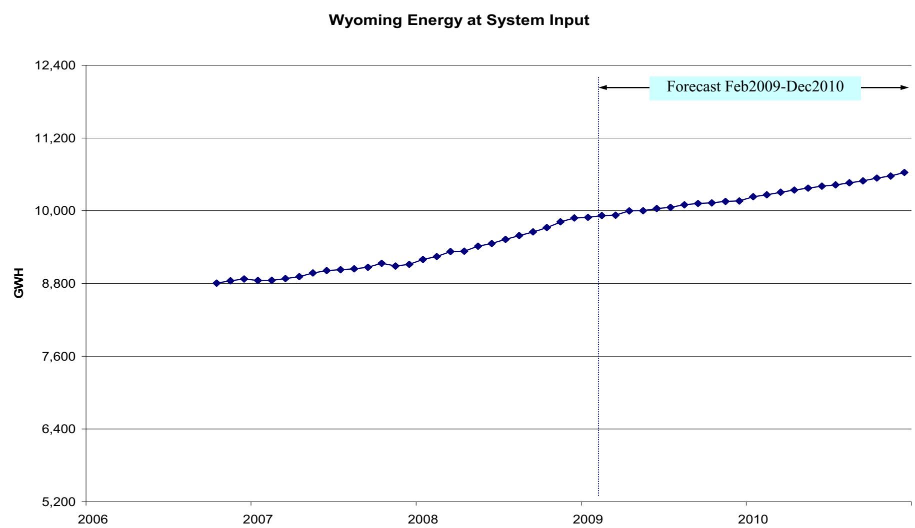
Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

Energy at System Input, by State

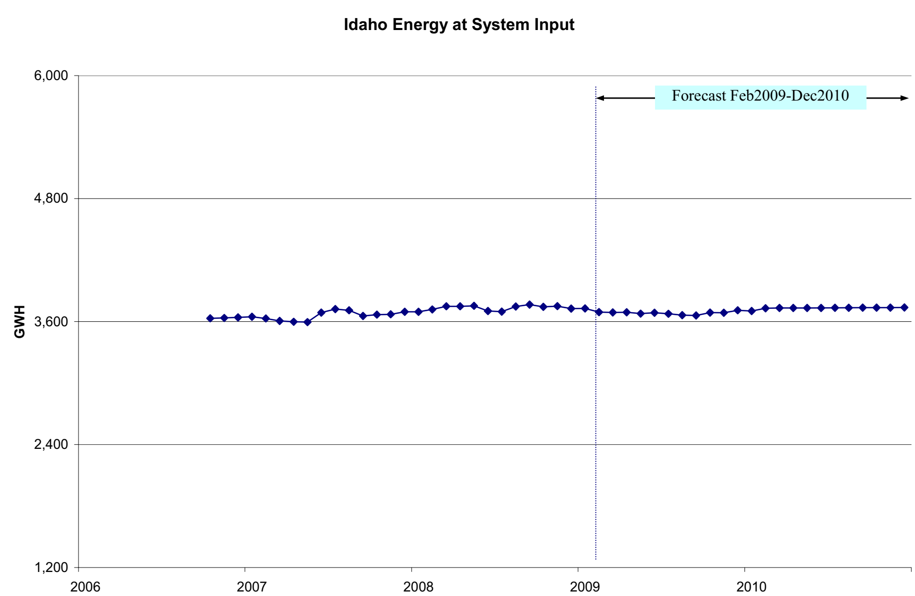
June 2009



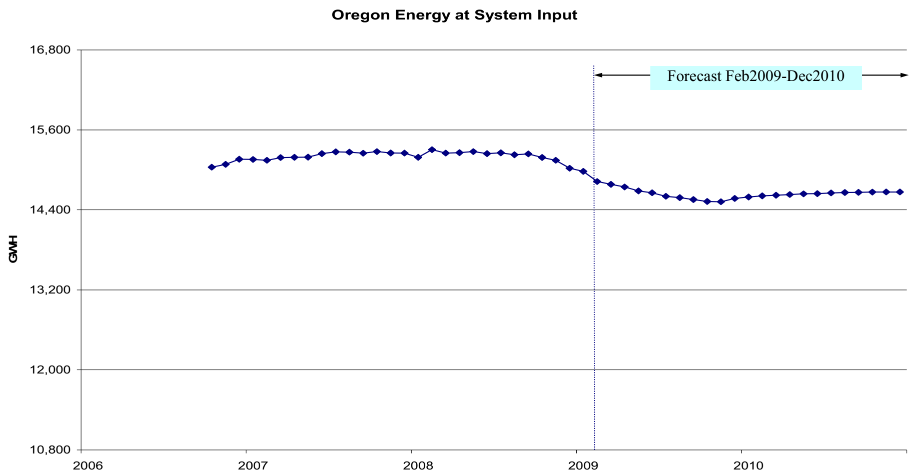
Note: Each point represents 12 month rolling energy at system input, so October 2006 represents the 12 month ending Octber 2006.



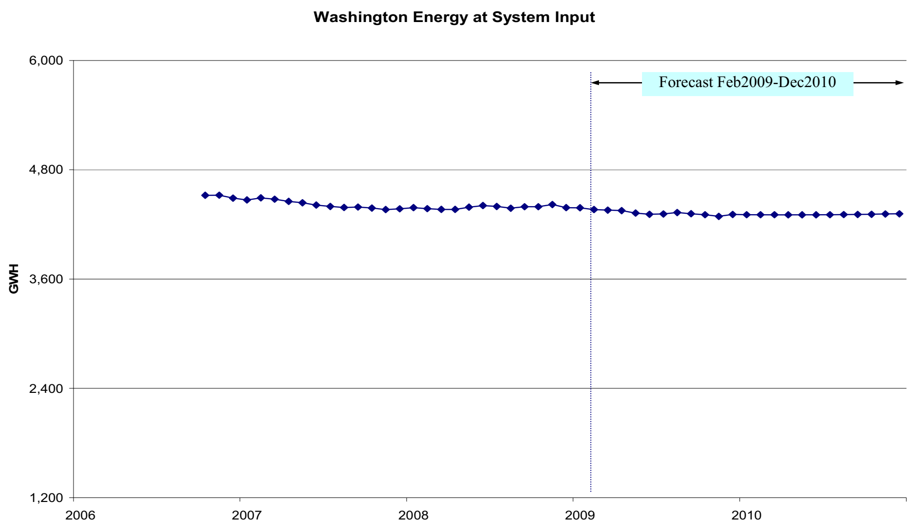
Note: Each point represents 12 month rolling energy at system input, so October 2006 represents the 12 month ending Octber 2006.



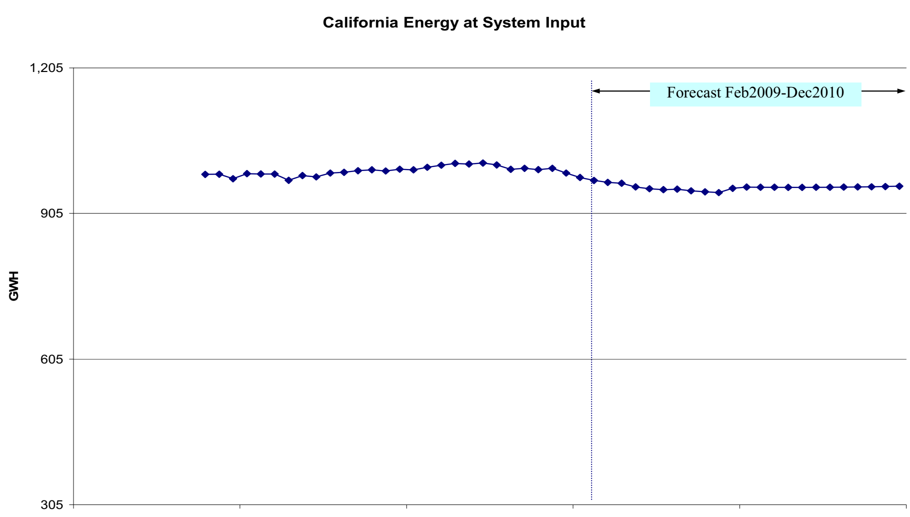
Note: Each point represents 12 month rolling energy at system input, so October 2006 represents the 12 month ending Octber 2006.



Note: Each point represents 12 month rolling energy at system input, so October 2006 represents the 12 month ending Octber 2006.



Note: Each point represents 12 month rolling energy at system input, so October 2006 represents the 12 month ending Octber 2006.



Note: Each point represents 12 month rolling energy at system input, so October 2006 represents the 12 month ending Octber 2006.

Gregory N. Duvall
Exhibit PPL/609

Docket No. UE-210
Exhibit PPL/609
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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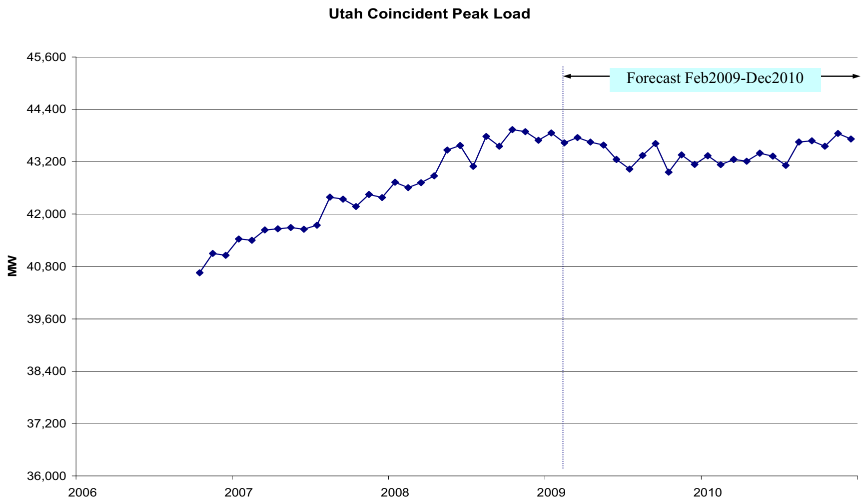
Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

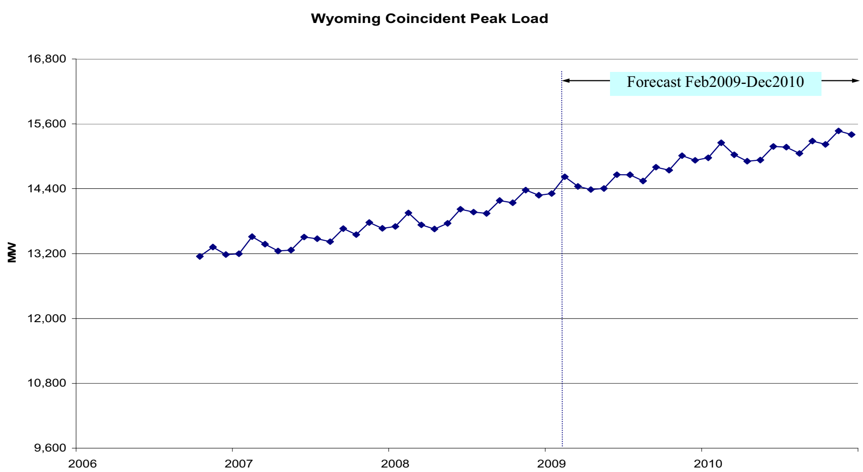
Coincident Peak Loads, by State

June 2009

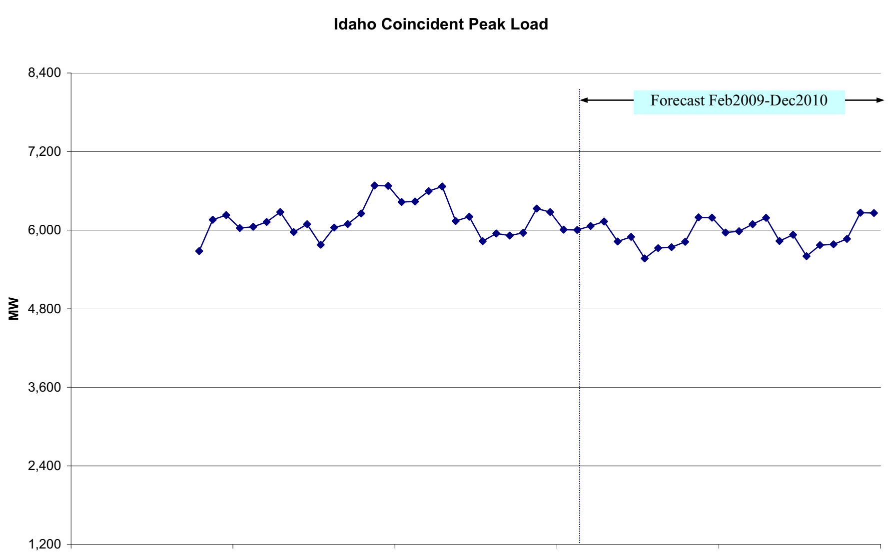
Exhibit PPL/609
Duvall/1



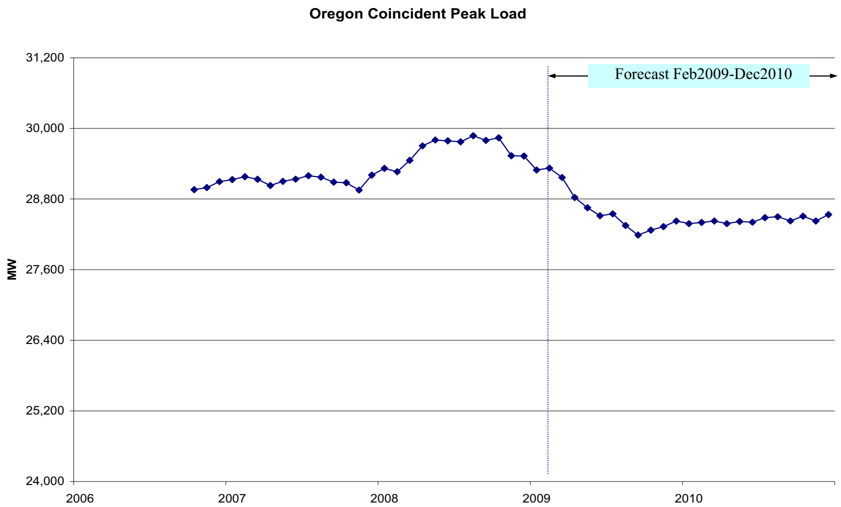
Note: Each point represents 12 month rolling coincident peak load, so October 2006 represents the 12 month ending Octber 2006.



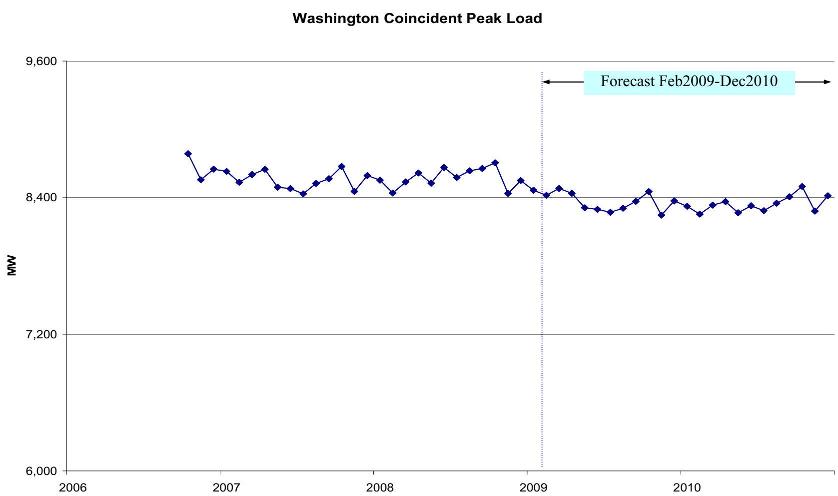
Note: Each point represents 12 month rolling coincident peak load, so October 2006 represents the 12 month ending Octber 2006.



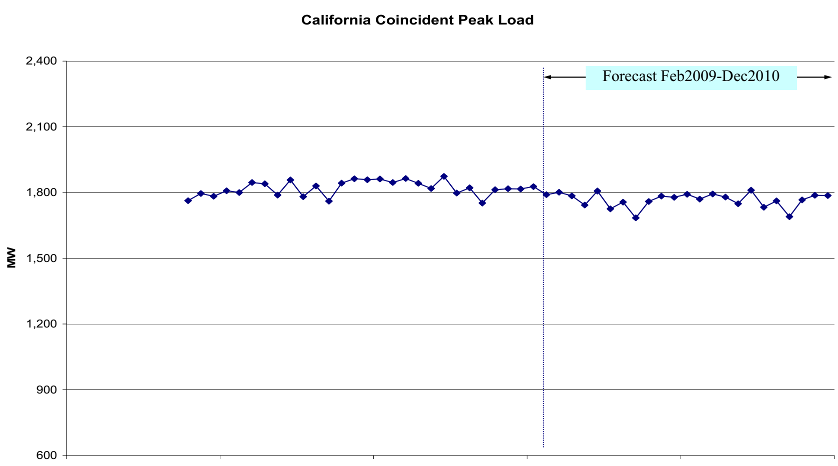
Note: Each point represents 12 month rolling coincident peak load, so October 2006 represents the 12 month ending Octber 2006.



Note: Each point represents 12 month rolling coincident peak load, so October 2006 represents the 12 month ending Octber 2006.



Note: Each point represents 12 month rolling coincident peak load, so October 2006 represents the 12 month ending Octber 2006.



Note: Each point represents 12 month rolling coincident peak load, so October 2006 represents the 12 month ending Octber 2006.

Gregory N. Duvall
Exhibit PPL/610

Docket No. UE-210
Exhibit PPL/610
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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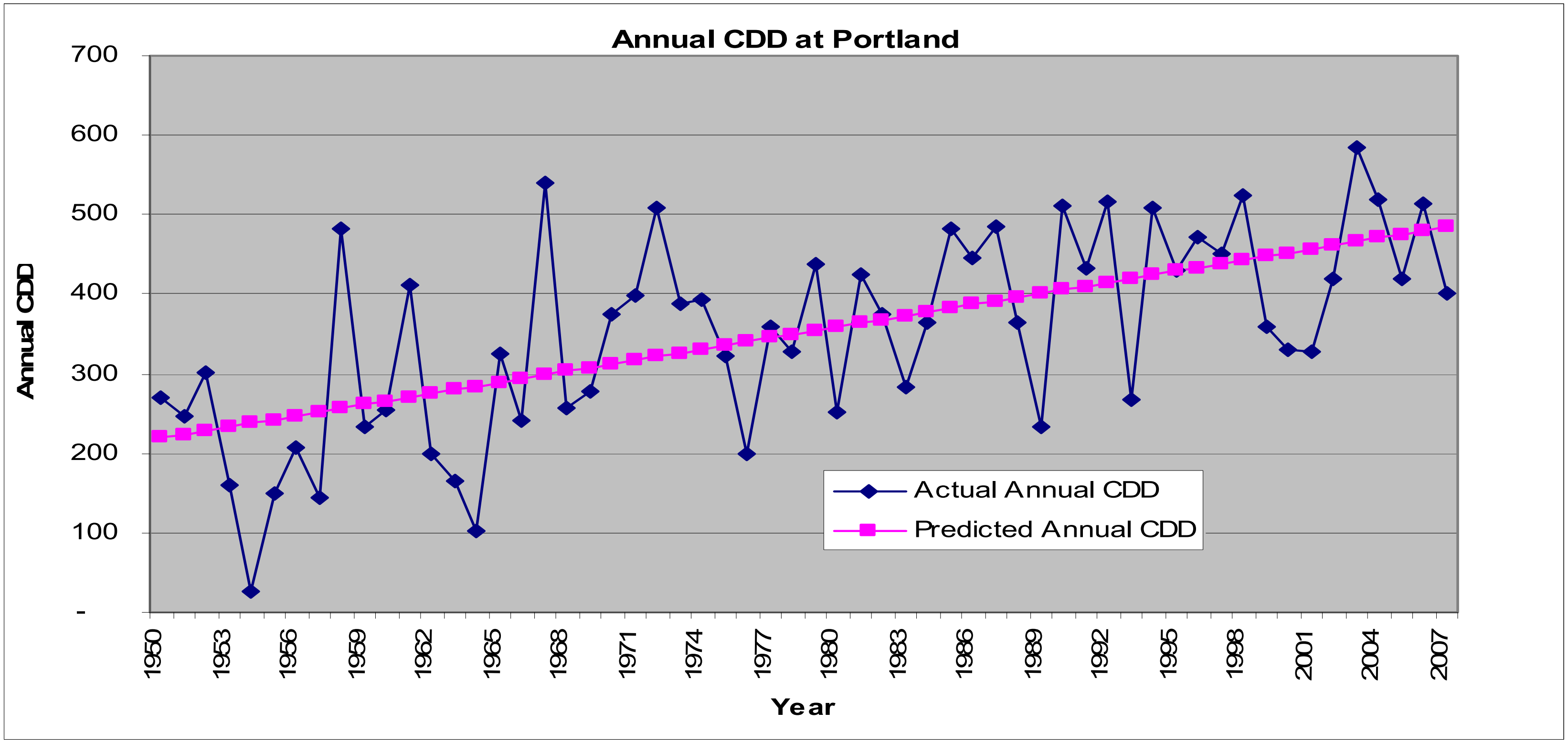
Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

Annual Cooling Degree Day Trend in Portland, OR

June 2009

Annual CDD Trend in Portland, Oregon

- Normal temperatures are higher as we move towards more recent data



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Gregory N. Duvall
Exhibit PPL/611

Docket No. UE-210
Exhibit PPL/611
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

Load Forecast Statistical Modeling Summary

June 2009

Load Forecast Statistical Modeling Summary

Step	Purpose	Dependent Variabe	Independent Variables	No. of Independent Variables	Total No. Indepdent Variables	No. of Statistical Models	Mathematical Forms
Load Research by class (residential, commercial, industrial and irrigation)	Understand the preliminary load research data to develop multi-part weather variables	Daily Energy	Calendar month binary variables Holiday binary variables Day type binary variables Daily dry bulb	11 16 6 1	34	3	Linear neural network model Sigmoid neural network model to represent heating and cooling effect
		Daily Energy	Calendar month binary variables Holiday binary variables Day type binary variables HDD35-CDD80	11 16 6 10	43	1	Regression Analysis
		Daily Energy	Calendar month binary variables Holiday binary variables Day type binary variables Selected HDD and CDD variables	11 16 6 1-7	40	1	Regression Analysis
		Daily Energy	Calendar month binary variables Holiday binary variables Day type binary variables One composite weather variable	11 16 6 1	34	1	Regression Analysis
Monthly Sales by class (residential, commercial, industrial, irrigation, lighting and public authority)	Forecast monthly sales by number of customer times usage per customer	Number of customer	Economic variables Trending variables Monthly binary variables Time series variables	1-2 1-4 11 1-5	22	1	Regression Analysis Exponential Smoothing
		Usage per Customer	Heating and cooling energy usage interact with composite weather variables Statistical end use variables Calendar month binary variables Trending variables Time series variables	4 1 11 1-6 1-2	24	1	Statistical End Use model
Peak	Forecast Monthly Peak	Monthly Noncoincident Peak	Heating and cooling energy usage interact with composite weather variables Heating and cooling energy usage interact with composite weather variables at lag one period Non weather sensitive load Calendar month binary variables Trending variables Time series variables	2 2 1 11 1-2 1-2	20	1	Regression Analysis
Hourly Load	Forecast 8760 hourly load	Daily Energy	Monthly cooling load interact with weather Monthly heating load interact with weather Monthly non weather sensitive load Other weather variables (seasonal, lag, and spline) Holiday binary variables Calendar month binary variables Day type binary variables Day counts variables	1 1 1 3-6 15 11 6 6	47	1	Regression Analysis
		Hourly Load	Heating and cooling energy usage interact with composite weather variables Daily Energy by day type Calendar month binary variables Holiday binary variables Day type binary variables	2 5 11 15 6	41	24	Regression Analysis
Rate Schedule	Forecast sales and bills	Bills	Number of customer at class level Trending variables	1 1-3	4	1	Regression Analysis
		Sales at rate schedule level	Monthly sales at class level Calendar month binary variables Treding variables	2 11 1-3	16	1	Regression Analysis
Total						**36**	
A complete set of all seven jurisdictional models						**1070**	

CONFIDENTIAL
Docket No. UE-210
Exhibit PPL/612
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL

Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

Examples of Mathematical Forms for Oregon Statistical Models

June 2009

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-210
Exhibit PPL/613
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Supplemental Direct Testimony of Gregory N. Duvall

Actual and Forecasted Energy Efficiency – 2006 to 2009

June 2009

PacifiCorp's forecasted and actual energy efficiency acquisitions for calendar years 2006 through 2009

Calendar Year	Oregon	Washington	California	Utah	Idaho	Wyoming	Total (mWh)[1]
2009[2]	144,695	30,257	6,472	183,965	16,434	12,500	394,323
2008	138,681	48,323	518	193,328	11,540	0	392,390
2007	109,651	38,415	210	148,969	12,061	0	309,306

[1] Estimate of first year savings as measured at source (adjusted for line losses by jurisdiction).
[2] Planning forecast used in PacifiCorp's 2008 Integrated Resource Plan.

R. Bryce Dalley
Exhibit PPL/705

Docket No. UE-210
Exhibit PPL/705
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Supplemental Direct Testimony of R. Bryce Dalley

June 2009

Q. Please state your name, business address and present position with PacifiCorp ("the Company").

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah, Suite 2000, Portland, Oregon, 97232. I am currently employed as Manager of Revenue Requirement.

Q. Are you the same R. Bryce Dalley that previously provided testimony in this docket?

A. Yes.

Purpose of Testimony

Q. Please explain the purpose of your supplemental direct testimony in this proceeding.

A. The purpose of my supplemental direct testimony is to respond to Requests 4, 6, 7, and 8 from the May 14, 2009 Ruling of the Administrative Law Judges on Supplemental Testimony ("Ruling on Supplemental Testimony"), in which PacifiCorp was ordered to file supplemental direct testimony.

Q. What issues does your testimony cover?

A. My testimony responds to questions on three main issues:

- The selection of the historic base period used to develop the revenue requirement;
- The Company's compliance with the Revised Protocol allocation methodology in this proceeding; and
- The consistency of the load forecast used to develop jurisdictional allocation factors, test year revenues and net power costs.

Request 4 – Explanation of the Company's Base Historical Period (12 months ended June 2008)

Q. What is Request 4 in the Ruling on Supplemental Testimony?

A. Request 4 requires the Company to provide testimony explaining why PacifiCorp used July 2007 through June 2008 as the historical basis for its 2010 test year rather than calendar year 2008.

Q. Please explain why the Company used July 2007 through June 2008 as the historical basis for its 2010 test year rather than calendar year 2008.

A. The Company selected the twelve-month period ended June 2008 as the historical basis for this proceeding because it was the most recent total Company data available for inter-jurisdictional allocations at the time of the Company's filing. The Company audits and extracts total company accounting information with the data components necessary for state allocations on a semi-annual basis for the twelve-month periods ending June and December each year. This semi-annual data extract and review procedure is a key control measure to ensure the accuracy and reliability of the data which serves as the basis for each of the Company's results of operations and general rate case filings.

Q. When was the December 2008 total Company financial data filed with the Securities and Exchange Commission ("SEC") and the Federal Energy Regulatory Commission ("FERC")?

A. The Company filed its 2008 10-K report with the SEC on February 27, 2009 and the 2008 Form 1 with the FERC on March 31, 2009. Only once total Company data is audited does it become available for analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total Company financial data is finalized to ensure accurate state-allocated data. Due to these complex steps, it is not possible for the Company to use the twelve-month period ending December 2008 for filing a general rate case in early April 2009.

Q. Why was an early April 2009 filing date necessary?

A. With a calendar year 2010 test period and a ten-month statutory period between when a case is filed and the date rates become effective, any filing date after the beginning of March 1 each year results in a mismatch between when rates are effective and the beginning of the test year. An early April filing minimizes this mismatch and more appropriately synchronizes the test periods used in both the rate case and the Transition Adjustment Mechanism ("TAM") proceedings. The current TAM is based on an April 1st filing date.

Q. Does the Company file annual Oregon financial reports with the Commission?

A. Yes. Each year the Company prepares and files the Oregon Results of Operations Report pursuant to OAR 860-027-0070(1).

Q. When does the Company make this filing with the Commission each year?

A. The Company files this information at the end of April each year. The Commission recognizes the time needed to prepare the historic report by granting each year a one-month extension from the statutory deadline. This approximate 120-day period is necessary to appropriately and accurately reflect state-allocated data on a historical basis. This historical data is then the basis to project a forecasted test period revenue requirement.

Q. Is the amount of time between the end of the historical period and the filing date in this proceeding comparable to that in UE 179, the Company's last general rate case?

A. Yes. Approximately 11 months separated the end of the historical period and the filing date in Docket UE 179, whereas approximately nine months separate the end of the June 2008 historical period used in this case and the April 2009 filing date.

Q. Are there other factors that need to be considered in future proceedings as to the historical period used in the Company's general rate case filings?

A. Yes. The TAM Stipulation and Agreement of the Parties on General Guidelines filed recently in Docket UE 199 states:

> "In all future TAM filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January rate effective date.*" Emphasis added.

If the Commission adopts this Stipulation, eight months will separate the end of the June historic period and the filing date in future general rate case filings.

Request 6 – Compliance with Revised Protocol Order No. 05-021

Q. What is Request 6 in the Ruling on Supplemental Testimony?

A. Request 6 states: "In PPL/700, Dalley/34, lines 13-18, witness Dalley indicates that PacifiCorp relied on the Revised Protocol adopted by the Commission in Order 05-021 to determine jurisdiction allocation in this docket. Please file additional testimony explaining how the jurisdictional allocations in this docket comply with the Revised Protocol."

Q. Please explain how the jurisdictional allocation factors applied in this proceeding comply with the Commission order approving the Revised Protocol.

A. Each of the jurisdictional allocation factors included in this proceeding is calculated in the same manner prescribed in the Revised Protocol approved by the Commission in Order No. 05-021, pursuant to a joint-party Stipulation. Specifically, Exhibit PPL/702, "Tab 2 - Results of Operations" applies allocation factors to the revenue requirement components as outlined in Appendix B of the Revised Protocol. In addition, the calculations of the allocation factors included in this proceeding are consistent with the algebraic definitions approved by the Commission shown in Appendix C of the Revised Protocol.

Q. What exhibits have been filed with the Commission in this proceeding that demonstrate compliance with Order No. 05-021?

A. Two main files have been provided as part of this filing to demonstrate the Company's compliance with Order No. 05-021. First, "Tab 11 – Allocation Factors" in Exhibit PPL/702 shows the calculation and derivation of each Revised Protocol factor included in the filing. An electronic version of this section of my exhibit was provided with the Company's workpapers. In addition, the Company's revenue requirement model, the Jurisdictional Allocation Model ("JAM"), was provided as part of the Company's workpapers. The "Factors" worksheet within the model shows the linked formulas and inputs used in the development of each of the allocation percentages. As noted above, the calculations in this section of the model were developed based on the algebraic definitions set forth in Appendix C of the Revised Protocol.

Q. Have there been any changes to the allocation factor calculations since the Commission issued Order No. 05-021?

A. No. In Order No. 05-021 the Commission stated:

> "In this order, we ratify the *Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol* (Revised Protocol) for use in future rate cases to determine how costs and wholesale revenues associated with PacifiCorp's generation, transmission, and distribution systems will be allocated among its six-state service territory."

Since this Order, the Company has used the approved factor calculations in each of its Oregon rate-making and Results of Operations filings.

Request 7 – Changes in Key Assumptions Underlying the Revised Protocol

Q. What is Request 7 in the Ruling on Supplemental Testimony?

A. Request 7 requires the Company to identify any changes to the key assumptions underlying the Revised Protocol and explain whether these changes were considered in determining the jurisdictional allocation factors used in PacifiCorp's filing.

Q. Have there been any changes to the key assumptions underlying the Revised Protocol?

A. No. There have been no changes to key assumptions to the Revised Protocol since the Commission approved the allocation methodology in Order No. 05-021. Key assumption changes would be addressed by the Multi-State Process ("MSP") standing committee, and potentially lead to proposed amendments to the Revised Protocol. As stated in Order No. 05-021,

> "An MSP Standing Committee will be formed, consisting of one member/delegate from each Commission. The MSP Standing Committee will appoint a Standing Neutral to assist the Committee, facilitate discussions among the states, and monitor issues. The Standing Neutral will convene at least one meeting of the MSP Standing Committee each calendar year to discuss inter-jurisdictional issues facing PacifiCorp and its customers. While the MSP Committee may consider possible amendments to the Revised Protocol, any amendments would only go into effect after each Commission that previously ratified the Revised Protocol also ratified the amendments."

Any amendments to the methodology would need to be implemented consistent with Section XIII of the Revised Protocol.

Request 8 – Forecast Loads Used For Jurisdictional Allocation Factors, Revenues, and Net Power Costs

Q. What is Request 8 in the Ruling on Supplemental Testimony?

A. Request 8 states: "Please provide testimony explaining whether the forecast loads used to derive the jurisdictional allocation factors are the same as the forecast loads used to develop test year revenues and net power costs. If different, please explain the differences."

Q. Please explain whether the forecast loads used to derive the jurisdictional allocation factors are the same as the forecast loads used to develop test year revenues and net power costs.

A. As explained on page 34 of my direct testimony, Exhibit PPL/700, the forecast loads used in the calculation of allocation factors are consistent with the loads used in the development of test period revenues and net power costs. By using the same load forecast for each of these revenue requirement components, an appropriate matching of revenues, expenses and rate base balances is achieved. The load forecast applied in this case is described in detail in the supplemental direct testimony of Company witness Mr. Gregory N. Duvall.

Q. Although a consistent load forecast is used for jurisdictional allocation factors, test year revenues, and net power costs, are there any differences in the application of these loads?

A. Yes. Net power costs and jurisdictional allocation factors are developed using forecasted loads at the system input level instead of the metered or sales level used in the development of test period revenues. The differences between the system input level and sales level are line losses. In addition, jurisdictional allocation factors are adjusted for load curtailments consistent with the Commission-approved Revised Protocol methodology.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

C. Craig Paice
Exhibit PPL/908

Docket No. UE-210
Exhibit PPL/908
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Supplemental Direct Testimony of C. Craig Paice

June 2009

Q. Please state your name.

A. My name is C. Craig Paice.

Q. Are you the same C. Craig Paice who provided direct testimony in this case as Exhibit PPL/900?

A. Yes, I am.

Purpose of Testimony

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to respond to Request 22 from the May 14, 2009 Ruling of the Administrative Law Judges on Supplemental Testimony ("Ruling on Supplemental Testimony"), in which PacifiCorp was ordered to file supplemental direct testimony.

Q. What is asked in Request 22?

A. Request 22 states: Provide testimony explaining the data in PPL/907, Paice Tab 17.4, including a discussion of how the customer load factors were derived.

Q. What is addressed in your supplemental testimony?

A. I will describe the data presented in Exhibit PPL/907, Tab 17.4 and discuss how the customer load factors were derived.

Request 22

Q. What data are presented in Exhibit PPL/907, Tab 17.4?

A. The data in Exhibit PPL/907, Tab 17.4 are 12 month average system, feeder and transformer load factors.

Q. What are customer load factors and how are they used?

A. Customer load factors are developed in order to estimate the customer class demands shown in the cost of service study, Exhibit PPL/907, Tab 2.3, Lines 5-7. Customer class demands are used to calculate demand-related marginal costs.

Q. Please explain the customer load factors used in the cost of service study and how they were developed.

A. Exhibit PPL/909 contains a summary page showing the three types of load factors used in the marginal cost of service study along with detailed data supporting their development. These load factors are defined and described below.

- System (coincident) load factors are annual customer load factors based on monthly estimated average demands for each of the twelve months of load data at the time of monthly *system* peak. These factors are developed by dividing each listed rate schedule's annual average kWh by the respective rate schedule's annual average kW at the time of system peak multiplied by the average hours (730) in a month.
- Feeder (jurisdictional) load factors are annual customer load factors based on monthly estimated average demands for each of the twelve months of load data at the time of monthly *jurisdictional* (i.e., Oregon) peak. These factors are developed by dividing each listed Oregon rate schedule's annual average kWh by the respective rate schedule's annual average kW at the time of jurisdictional peak multiplied by the average hours (730) in a month. Jurisdictional demand provides a good estimate of the feeder demand since the proportional mix of customers by load size group is the same for an average feeder as it is for the jurisdiction.
- Transformer (Individual Customer Maximum Demand or "ICMD") load factors are annual customer load factors based on the average of the highest estimated

non-coincident peak (NCP) values for each listed rate schedule for each of the twelve months of load data. These factors are developed by dividing each listed rate schedule's annual average kWh by the rate schedule's annual average maximum kW multiplied by average hours (730) in a month. To recognize transformer diversity, the average transformer load factor for each rate schedule is divided by the appropriate coincidence factor for that rate schedule's average number of customers per transformer. These calculations are illustrated in the electronic version of the cost of service model (see tab "Cust Data 4"). Coincidence factors are taken from PacifiCorp's Distribution Construction Standards handbook.

Q. Are you providing additional data to support your supplemental testimony?

A. Yes. In addition to Exhibit PPL/909 described above, Exhibit PPL/910 contains PacifiCorp's Distribution Construction Standards Handbook, Standard DA 411 ("Handbook"). Page 3, Table 5 of the Handbook shows coincidence factor values used in the cost of service study to adjust transformer load factors for Schedules 4 and 23 (0-15 kW and 15+ kW) to recognize load diversity. Coincidence factors are selected according to the number of Oregon customers per transformer. Exhibit PPL/911 contains Oregon customer per transformer data and shows Schedules 4 and 23 as the only schedules having more than one customer per transformer.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/909
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of C. Craig Paice

Load Factor Detail and Summary

June 2009

PacifiCorp
2009 Oregon Price Filing
Load Factor Summary
12 Months Ending December 2010 (Forecast)

Schedules by Load Size	Average Number of Customers[1]	Annual MWh[1]	System Load Factor	Feeder Load Factor	Transformer Load Factor
RESD Sch. 004					
Total	478,485	5,435,846	78.75%	57.08%	20.33%
GNSV Sch. 023					
0- 15 kW Secondary	64,648	582,532	88.41%	89.84%	24.51%
GT 15 kW Secondary	9,373	430,256	74.04%	73.88%	38.59%
Primary	34	1,152	75.50%	75.48%	36.12%
GNSV Sch. 028					
0- 50 kW Secondary	4,491	431,990	77.67%	74.08%	51.23%
51-100 kW Secondary	3,525	672,435	68.93%	69.79%	57.33%
GT-100 kW Secondary	2,034	922,391	75.29%	74.90%	59.62%
Primary	50	18,249	73.67%	73.48%	58.50%
GNSV Sch. 030					
0-300 kW Secondary	230	206,234	76.42%	76.00%	64.76%
GT-300 kW Secondary	572	1,078,480	77.06%	75.71%	68.98%
Primary	52	93,931	77.01%	75.73%	68.68%
LGSV Sch. 048					
1-4 MW Secondary	121	594,746	76.07%	74.77%	50.87%
1-4 MW Primary	56	414,743	82.02%	79.59%	56.16%
GT 4 MW Secondary	2	54,345	92.58%	98.15%	67.32%
GT 4 MW Primary	34	1,175,179	87.26%	87.10%	63.30%
Trans	2	404,889	99.33%	102.01%	74.34%
APSV Sch. 041	6,108	136,792	67.15%	67.15%	32.16%

(1) Based on Customer Accounting System, 12 Months Ending June 30, 2008

PacifiCorp
2009 Oregon Price Filing
Average Customer Loads
RESD 004

System Peak

Date/Time (actual)	RESD 004
Jan 22, 2010 @ 08:00	3.142
Feb 04, 2010 @ 08:00	2.685
Mar 30, 2010 @ 08:00	2.561
Apr 01, 2010 @ 08:00	2.152
May 19, 2010 @ 15:00	0.954
Jun 24, 2010 @ 15:00	1.163
Jul 19, 2010 @ 16:00	1.292
Aug 26, 2010 @ 16:00	0.982
Sep 09, 2010 @ 16:00	0.969
Oct 29, 2010 @ 08:00	2.278
Nov 24, 2010 @ 18:00	2.015
Dec 15, 2010 @ 18:00	2.902
Annual Average	1.925

Jurisdictional Peak

Date/Time	RESD 004
Jan 28, 2010 @ 09:00	3.763
Feb 09, 2010 @ 08:00	3.444
Mar 10, 2010 @ 08:00	2.95
Apr 06, 2010 @ 07:00	3.353
May 05, 2010 @ 08:00	2.639
Jun 09, 2010 @ 08:00	2.02
Jul 13, 2010 @ 18:00	2.103
Aug 05, 2010 @ 18:00	1.751
Sep 02, 2010 @ 18:00	1.719
Oct 29, 2010 @ 08:00	2.278
Nov 29, 2010 @ 08:00	2.701
Dec 16, 2010 @ 08:00	3.139
Annual Average	2.655

Class Peak

Date/Time	RESD 004
Jan 26, 2010 @ 07:00	3.981
Feb 13, 2010 @ 09:00	3.644
Mar 27, 2010 @ 08:00	3.153
Apr 03, 2010 @ 08:00	3.466
May 05, 2010 @ 08:00	2.639
Jun 09, 2010 @ 08:00	2.02
Jul 13, 2010 @ 18:00	2.103
Aug 05, 2010 @ 18:00	1.751
Sep 02, 2010 @ 20:00	1.817
Oct 30, 2010 @ 09:00	2.713
Nov 25, 2010 @ 10:00	3.094
Dec 12, 2010 @ 10:00	3.452
Annual Average	2.819

ICMD Peak

Date/Time	RESD 004
Jul-07	5.540
Aug-07	5.640
Sep-07	6.340
Oct-07	7.030
Nov-07	8.370
Dec-07	9.100
Jan-08	9.000
Feb-08	8.560
Mar-08	8.350
Apr-08	8.400
May-08	6.800
Jun-08	6.340
Annual Average	7.456

kWh

Date/Time	RESD 004
Jul-07	805.0
Aug-07	724.0
Sep-07	740.0
Oct-07	957.0
Nov-07	1,157.0
Dec-07	1,546.0
Jan-08	1,778.0
Feb-08	1,318.0
Mar-08	1,326.0
Apr-08	1,149.0
May-08	928.0
Jun-08	848.0
Annual Average	1,106.3

PacifiCorp

2009 Oregon Price Filing

Average Customer Loads

GNSV 023

System Peak

Date/Time (actual)	0 - 15 kW	GT 15 kW	Primary
Jan 22, 2010 @ 08:00	1.589	17.435	8.321
Feb 04, 2010 @ 08:00	1.531	18.175	8.602
Mar 30, 2010 @ 08:00	1.247	16.75	7.833
Apr 01, 2010 @ 08:00	1.107	16.462	7.630
May 19, 2010 @ 15:00	1.664	16.432	7.938
Jun 24, 2010 @ 15:00	1.22	16.882	7.874
Jul 19, 2010 @ 16:00	1.426	16.765	7.942
Aug 26, 2010 @ 16:00	1.098	16.992	7.850
Sep 09, 2010 @ 16:00	1.097	17.287	7.975
Oct 29, 2010 @ 08:00	1.32	14.891	7.085
Nov 24, 2010 @ 18:00	1.525	15.112	7.297
Dec 15, 2010 @ 18:00	1.86	16.313	8.000
Annual Average	1.390	16.625	7.862

Jurisdictional Peak

Date/Time	0 - 15 kW	GT 15 kW	Primary
Jan 28, 2010 @ 09:00	1.362	21.097	9.746
Feb 09, 2010 @ 08:00	2.218	18.178	8.998
Mar 10, 2010 @ 08:00	1.155	17.944	8.287
Apr 06, 2010 @ 07:00	1.138	16.79	7.787
May 05, 2010 @ 08:00	1.201	14.841	6.996
Jun 09, 2010 @ 08:00	1.162	13.134	6.248
Jul 13, 2010 @ 18:00	1.363	17.365	8.161
Aug 05, 2010 @ 18:00	1.237	16.263	7.620
Sep 02, 2010 @ 18:00	1.281	16.791	7.870
Oct 29, 2010 @ 08:00	1.32	14.891	7.085
Nov 29, 2010 @ 08:00	1.348	15.957	7.554
Dec 16, 2010 @ 08:00	1.634	16.673	8.023
Annual Average	1.368	16.660	7.865

Class Peak

Date/Time	0 - 15 kW	GT 15 kW	Primary
Jan 28, 2010 @ 11:00	1.549	21.085	9.848
Feb 09, 2010 @ 11:00	1.467	21.142	9.825
Mar 02, 2010 @ 11:00	1.711	18.652	8.908
Apr 21, 2010 @ 11:00	1.337	18.39	8.582
May 24, 2010 @ 14:00	1.356	21.189	9.782
Jun 24, 2010 @ 14:00	1.18	16.357	7.628
Jul 13, 2010 @ 14:00	1.345	19.797	9.184
Aug 05, 2010 @ 14:00	1.235	19.823	9.132
Sep 02, 2010 @ 15:00	1.478	20.065	9.374
Oct 26, 2010 @ 14:00	1.393	17.659	8.303
Nov 29, 2010 @ 11:00	1.517	18.657	8.798
Dec 14, 2010 @ 11:00	1.512	21.264	9.903

Annual Average	1.423	19.507	9.106	

ICMD Peak

Date/Time	0 - 15 kW	GT 15 kW	Primary
Jul-07	4.515	29.342	15.062
Aug-07	4.603	30.825	15.743
Sep-07	4.873	31.912	16.360
Oct-07	4.517	30.208	15.431
Nov-07	4.703	32.218	16.392
Dec-07	5.009	33.956	17.306
Jan-08	5.085	32.551	16.753
Feb-08	5.068	32.904	16.893
Mar-08	5.482	34.257	17.706
Apr-08	5.515	32.006	16.769
May-08	5.213	30.815	16.089
Jun-08	5.603	31.756	16.713
Annual Average	5.016	31.896	16.435

kWh

Date/Time	0 - 15 kW	GT 15 kW	Primary
Jul-07	831.0	8,770.0	4,203.672
Aug-07	786.0	9,158.0	4,342.621
Sep-07	761.0	8,282.0	3,956.096
Oct-07	874.0	8,847.0	4,261.116
Nov-07	901.0	8,898.0	4,298.312
Dec-07	1,052.0	9,543.0	4,659.175
Jan-08	1,142.0	10,144.0	4,966.260
Feb-08	950.0	9,351.0	4,518.941
Mar-08	940.0	9,389.0	4,529.332
Apr-08	883.0	8,795.0	4,244.202
May-08	823.0	8,443.0	4,060.154
Jun-08	825.0	8,210.0	3,962.320
Annual Average	897.3	8,985.8	4,333.5

PacifiCorp
2009 Oregon Price Filing
Average Customer Loads
GNSV 028

System Peak

Date/Time (actual)	0 - 50 kW	51 - 100 kW	GT 100 kW	Primary
Jan 22, 2010 @ 08:00	14.893	55.238	96.369	65.357
Feb 04, 2010 @ 08:00	15.333	49.900	91.149	61.305
Mar 30, 2010 @ 08:00	15.202	49.150	79.899	55.908
Apr 01, 2010 @ 08:00	14.607	48.025	81.494	56.134
May 19, 2010 @ 15:00	18.214	52.563	93.423	63.837
Jun 24, 2010 @ 15:00	17.167	47.663	82.446	56.993
Jul 19, 2010 @ 16:00	16.452	56.488	105.923	70.452
Aug 26, 2010 @ 16:00	13.810	53.925	93.869	63.553
Sep 09, 2010 @ 16:00	13.643	55.400	106.863	69.921
Oct 29, 2010 @ 08:00	15.655	52.963	96.411	64.784
Nov 24, 2010 @ 18:00	10.107	39.500	80.964	52.105
Dec 15, 2010 @ 18:00	14.607	47.950	85.994	58.157
Annual Average	14.974	50.730	91.234	61.542

Jurisdictional Peak

Date/Time	0 - 50 kW	51 - 100 kW	GT 100 kW	Primary
Jan 28, 2010 @ 09:00	22.095	58.838	103.399	71.286
Feb 09, 2010 @ 08:00	15.738	52.950	91.619	62.617
Mar 10, 2010 @ 08:00	17.702	49.300	85.315	58.956
Apr 06, 2010 @ 07:00	13.464	48.725	84.202	57.355
May 05, 2010 @ 08:00	13.595	44.613	76.054	52.310
Jun 09, 2010 @ 08:00	12.917	39.175	67.381	46.415
Jul 13, 2010 @ 18:00	18.036	46.638	100.345	64.983
Aug 05, 2010 @ 18:00	15.143	47.313	96.565	62.871
Sep 02, 2010 @ 18:00	13.345	51.850	99.649	65.396
Oct 29, 2010 @ 08:00	15.655	52.963	96.411	64.784
Nov 29, 2010 @ 08:00	16.702	53.338	101.268	67.342
Dec 16, 2010 @ 08:00	14.000	55.588	98.173	66.104
Annual Average	15.699	50.107	91.698	61.702

Class Peak

Date/Time	0 - 50 kW	51 - 100 kW	GT 100 kW	Primary
Jan 28, 2010 @ 11:00	22.16666667	59.725	103.7916667	71.774
Feb 09, 2010 @ 11:00	17.53571429	59.4	99.13690476	68.561
Mar 02, 2010 @ 11:00	20.5952381	55.975	83.07142857	60.766
Apr 21, 2010 @ 11:00	17.96428571	55.9375	81.91071429	59.664
May 24, 2010 @ 14:00	16.85714286	59.8625	102.1904762	69.960
Jun 24, 2010 @ 14:00	17.03571429	47.3	88.23214286	59.478
Jul 13, 2010 @ 14:00	17.94047619	58.85	111.1785714	73.945
Aug 05, 2010 @ 14:00	21.89285714	55.575	106.4940476	71.569
Sep 02, 2010 @ 15:00	16.42857143	65.4125	109.1547619	74.879
Oct 26, 2010 @ 14:00	19.82142857	55.1125	103.8869048	69.788
Nov 29, 2010 @ 11:00	21.60714286	58.95	108.4940476	73.538
Dec 14, 2010 @ 11:00	22.40476191	60.0125	105.327381	72.619
Annual Average	19.354	57.676	100.239	68.878

ICMD Peak

Date/Time	0 - 50 kW	51 - 100 kW	GT 100 kW	Primary
Jul-07	26.799	67.032	116.749	81.083
Aug-07	25.069	64.581	110.678	77.138
Sep-07	22.122	62.143	120.475	80.159
Oct-07	21.793	60.995	121.520	80.184
Nov-07	21.425	55.323	101.021	68.895
Dec-07	21.019	55.579	101.218	68.983
Jan-08	21.279	58.326	112.758	75.202
Feb-08	20.661	60.032	111.175	74.915
Mar-08	20.904	58.686	118.054	77.651
Apr-08	22.747	64.275	124.197	82.694
May-08	23.425	62.089	127.721	83.717
Jun-08	25.201	62.900	116.883	79.432
Annual Average	22.704	60.997	115.204	77.504

kWh

Date/Time	0 - 50 kW	51 - 100 kW	GT 100 kW	Primary
Jul-07	8,491.3	25,587.8	50,852.2	33,441.590
Aug-07	8,041.9	24,800.5	50,937.0	33,123.171
Sep-07	7,758.8	23,723.9	52,496.6	33,415.398
Oct-07	8,696.1	27,969.6	56,251.9	36,732.756
Nov-07	8,903.4	26,353.1	56,249.2	36,239.448
Dec-07	9,542.1	26,570.7	54,260.5	35,542.751
Jan-08	9,748.8	27,899.7	53,888.4	35,858.377
Feb-08	8,778.6	26,236.2	46,466.0	31,721.814
Mar-08	8,294.0	27,049.5	46,911.3	32,091.009
Apr-08	7,968.1	24,875.9	45,738.1	30,766.487
May-08	7,670.2	22,784.3	44,077.8	29,253.479
Jun-08	7,991.1	22,468.6	43,562.8	28,982.747
Annual Average	8,490.4	25,526.7	50,141.0	33,097.4

PacifiCorp				
2009 Oregon Price Filing				
Average Customer Loads				
GNSV 030				
System Peak				
Date/Time (actual)	0 - 300 kW	GT 300 kW	Primary	
Jan 22, 2010 @ 08:00	145.878	363.310	328.406	
Feb 04, 2010 @ 08:00	138.639	397.106	355.615	
Mar 30, 2010 @ 08:00	145.506	401.456	360.368	
Apr 01, 2010 @ 08:00	153.994	384.845	347.787	
May 19, 2010 @ 15:00	160.456	427.766	384.855	
Jun 24, 2010 @ 15:00	157.194	430.169	386.349	
Jul 19, 2010 @ 16:00	154.383	425.574	382.040	
Aug 26, 2010 @ 16:00	150.756	410.523	368.823	
Sep 09, 2010 @ 16:00	149.200	403.887	363.002	
Oct 29, 2010 @ 08:00	145.800	354.581	321.066	
Nov 24, 2010 @ 18:00	110.972	328.472	293.557	
Dec 15, 2010 @ 18:00	115.122	328.481	294.231	
Annual Average	143.992	388.014	348.842	
Jurisdictional Peak				
Date/Time	200 - 300 kW	GT 300 kW	Primary	

Jan 28, 2010 @ 09:00	164.583	417.537	376.931		
Feb 09, 2010 @ 08:00	155.767	413.648	372.251		
Mar 10, 2010 @ 08:00	142.211	378.308	340.407		
Apr 06, 2010 @ 07:00	142.767	386.993	347.788		
May 05, 2010 @ 08:00	132.511	388.486	347.395		
Jun 09, 2010 @ 08:00	128.422	399.975	356.382		
Jul 13, 2010 @ 18:00	142.106	417.863	373.596		
Aug 05, 2010 @ 18:00	142.472	406.829	364.392		
Sep 02, 2010 @ 18:00	136.772	375.741	337.379		
Oct 29, 2010 @ 08:00	145.800	354.581	321.066		
Nov 29, 2010 @ 08:00	150.150	397.340	357.659		
Dec 16, 2010 @ 08:00	153.967	401.419	361.696		
Annual Average	144.794	394.893	354.745		
Class Peak					
Date/Time	200 - 300 kW	GT 300 kW	Primary		
Jan 28, 2010 @ 11:00	166.417	422.525	381.413		
Feb 09, 2010 @ 11:00	169.689	422.426	381.854		
Mar 02, 2010 @ 11:00	155.661	405.940	365.763		
Apr 21, 2010 @ 11:00	154.000	412.449	370.960		
May 24, 2010 @ 14:00	175.628	458.898	413.425		
Jun 24, 2010 @ 14:00	152.383	452.618	404.422		
Jul 13, 2010 @ 14:00	187.644	491.025	442.324		
Aug 05, 2010 @ 14:00	187.289	467.324	422.370		
Sep 02, 2010 @ 15:00	173.417	439.301	396.619		
Oct 26, 2010 @ 14:00	166.056	422.771	381.561		
Nov 29, 2010 @ 11:00	171.289	419.873	379.968		
Dec 14, 2010 @ 11:00	164.878	421.669	380.446		
Annual Average	168.696	436.402	393.427		
ICMD Peak					
Date/Time	200 - 300 kW	GT 300 kW	Primary		
Jul-07	169.023	429.523	387.705		
Aug-07	164.589	428.529	386.159		
Sep-07	157.695	405.366	365.607		
Oct-07	166.873	433.408	390.622		
Nov-07	168.318	437.338	394.152		
Dec-07	168.816	454.660	408.773		
Jan-08	181.812	471.632	425.108		
Feb-08	184.991	456.724	413.103		
Mar-08	173.213	431.054	389.663		
Apr-08	174.910	437.076	394.991		
May-08	171.168	421.069	380.952		
Jun-08	157.528	395.346	357.169		
Annual Average	169.911	433.477	391.167		
kWh					
Date/Time	200 - 300 kW	GT 300 kW	Primary		

Jul-07	88,062.4	246,704.8	221,238.029		
Aug-07	86,137.5	238,778.5	214,275.115		
Sep-07	78,885.4	213,404.8	191,810.520		
Oct-07	83,038.2	219,683.7	197,748.097		
Nov-07	80,366.7	210,542.2	189,645.253		
Dec-07	79,530.2	206,889.9	186,444.952		
Jan-08	83,335.1	221,293.8	199,147.424		
Feb-08	75,308.9	204,563.2	183,814.135		
Mar-08	78,220.2	207,731.3	186,940.957		
Apr-08	76,855.7	210,407.0	188,968.137		
May-08	78,463.5	218,247.7	195,808.238		
Jun-08	75,716.0	220,921.1	197,611.428		
Annual Average	80,326.6	218,264.0	196,121.0		

PacifiCorp
2009 Oregon Price Filing
Average Customer Loads
LGSV 048

System Peak

Date/Time (actual)	Sec LT 4 MW	Pri LT 4 ME	Sec GT 4 MW	Pri GT 4 MW	Trans.
Jan 22, 2010 @ 08:00	791.748	1079.156	1199.375	4197.007	17577.625
Feb 04, 2010 @ 08:00	807.057	1172.964	1185.250	4163.051	19651.250
Mar 30, 2010 @ 08:00	798.929	1083.634	2542.750	4518.684	19336.875
Apr 01, 2010 @ 08:00	770.868	1112.710	2709.500	4446.088	17243.750
May 19, 2010 @ 15:00	824.083	1202.161	4307.750	5047.566	20591.125
Jun 24, 2010 @ 15:00	825.717	1168.433	6881.250	4838.206	20718.625
Jul 19, 2010 @ 16:00	837.073	1208.080	7437.750	5526.640	26361.250
Aug 26, 2010 @ 16:00	854.750	1230.067	7137.125	5531.096	19363.500
Sep 09, 2010 @ 16:00	808.421	1156.933	6574.875	5140.956	18723.250
Oct 29, 2010 @ 08:00	786.167	1015.170	1261.625	4187.566	19999.625
Nov 24, 2010 @ 18:00	618.512	880.129	1247.625	3738.309	27064.875
Dec 15, 2010 @ 18:00	718.220	1013.174	1157.500	4152.397	19083.500
Annual Average	786.795	1,110.218	3,636.865	4,623.964	20,476.271

Jurisdictional Peak

Date/Time	Sec LT 4 MW	Pri LT 4 MW	Sec GT 4 MW	Pri GT 4 MW	Trans.
Jan 28, 2010 @ 09:00	850.2	1232.3	1187.5	4618.8	21536.3
Feb 09, 2010 @ 08:00	803.4	1126.8	1185.9	4399.6	19649.6
Mar 10, 2010 @ 08:00	768.7	1142.8	1930.5	4439.8	18612.9
Apr 06, 2010 @ 07:00	788.8	1106.4	2685.6	4746.5	19317.0
May 05, 2010 @ 08:00	795.3	1152.7	3641.3	4996.7	20120.9
Jun 09, 2010 @ 08:00	778.0	1176.4	5318.0	4441.4	17435.4
Jul 13, 2010 @ 18:00	801.3	1155.0	7325.9	5232.4	21090.6
Aug 05, 2010 @ 18:00	790.6	1101.0	7041.8	5286.4	25516.5
Sep 02, 2010 @ 18:00	786.8	1163.2	7212.5	5101.9	17884.9
Oct 29, 2010 @ 08:00	786.2	1015.2	1261.6	4187.6	19999.6
Nov 29, 2010 @ 08:00	807.1	1179.7	1179.1	3808.9	18760.9
Dec 16, 2010 @ 08:00	849.7	1178.3	1196.6	4328.9	19333.8
Annual Average	800.504	1,144.132	3,430.521	4,632.415	19,938.188

Class Peak

Date/Time	Sec LT 4 MW	Pri LT 4 ME	Sec GT 4 MW	Pri GT 4 MW	Trans.
Jan 28, 2010 @ 11:00	855.1	1242.1	1219.8	4567.5	22400.8
Feb 09, 2010 @ 11:00	822.9	1141.6	1225.0	4525.6	19473.5
Mar 02, 2010 @ 11:00	782.1	1020.5	1201.6	4478.2	19079.0
Apr 21, 2010 @ 11:00	851.6	1159.6	3812.9	4937.9	20300.6
May 24, 2010 @ 14:00	861.4	1231.9	5202.4	4894.5	20471.4
Jun 24, 2010 @ 14:00	832.7	1243.2	6801.3	5262.8	20432.4
Jul 13, 2010 @ 14:00	942.5	1313.7	7428.3	5617.6	20936.1
Aug 05, 2010 @ 14:00	926.7	1224.6	7267.4	5501.9	26206.5
Sep 02, 2010 @ 15:00	914.3	1288.1	7249.9	5413.7	19076.3
Oct 26, 2010 @ 14:00	853.1	1154.6	1565.5	4663.3	19560.6
Nov 29, 2010 @ 11:00	833.4	1203.9	1222.1	4087.5	18352.5
Dec 14, 2010 @ 11:00	849.7	1161.5	1223.9	4386.5	18920.8
Annual Average	860.462	1,198.770	3,784.990	4,861.423	20,434.198

ICMD Peak					
Date/Time	Sec LT 4 MW	Pri LT 4 ME	Sec GT 4 MW	Pri GT 4 MW	Trans.
Jul-07	1,268.917	1,687.836	7,966.000	6,852.147	27,933.500
Aug-07	1,252.167	1,728.407	7,372.500	7,085.559	28,099.000
Sep-07	1,200.248	1,669.909	7,288.000	6,838.882	27,138.000
Oct-07	1,153.901	1,637.236	2,635.000	6,375.618	26,871.500
Nov-07	1,162.917	1,580.636	3,082.000	5,988.313	27,468.000
Dec-07	1,148.256	1,564.473	2,957.000	5,960.633	27,417.500
Jan-08	1,171.139	1,599.255	2,922.000	6,051.700	27,812.500
Feb-08	1,148.885	1,577.109	3,314.000	6,003.452	27,986.500
Mar-08	1,117.244	1,552.661	3,397.000	6,499.912	25,255.000
Apr-08	1,147.911	1,559.357	4,705.000	6,115.941	27,200.500
May-08	1,183.935	1,640.232	6,685.000	6,358.353	27,711.500
Jun-08	1,162.545	1,659.839	7,700.500	6,356.909	27,435.500
Annual Average	1,176.505	1,621.413	5,002.000	6,373.952	27,360.750

kWh					
Date/Time	Sec LT 4 MW	Pri LT 4 ME	Sec GT 4 MW	Pri GT 4 MW	Trans.
Jul-07	483,363.8	729,403.2	5,025,838.5	3,517,773.1	17,534,068.5
Aug-07	496,928.2	731,375.0	4,952,723.3	3,563,799.5	15,824,713.4
Sep-07	439,666.3	666,446.6	3,546,133.0	3,006,589.6	14,129,434.9
Oct-07	453,061.1	686,149.2	1,073,767.4	2,992,879.6	14,297,914.0
Nov-07	427,536.8	634,660.5	844,159.0	2,649,627.7	13,782,892.4
Dec-07	414,317.6	614,354.9	836,097.8	2,448,799.1	14,594,775.8
Jan-08	460,766.9	691,611.5	830,991.9	2,750,274.0	14,864,978.1
Feb-08	406,523.1	635,316.8	797,834.6	2,587,711.5	14,657,764.9
Mar-08	405,020.5	645,368.2	1,734,006.4	2,892,632.5	14,293,494.0
Apr-08	411,649.9	637,304.6	2,463,923.0	2,981,911.2	13,638,681.4
May-08	422,051.9	647,979.6	3,052,012.3	2,984,580.1	15,381,015.5
Jun-08	422,110.1	656,540.7	4,338,584.9	2,968,958.3	15,176,484.3
Annual Average	436,916.4	664,709.2	2,458,006.0	2,945,461.3	14,848,018.1

PacifiCorp
2009 Oregon Price Filing
Average Customer Loads

History Period: 12 Months Ended December 31, 2010

	a	b	c	d	e
	Monthly	Monthly	Monthly	Monthly	Est. Class
	ICMD	kWh	ICMD	Est. Class	Coin. Peak
	Total	Total	Max. LF	Coin. LF	kW Total
Secondary	(cust acct)	(cust acct)	b/HrsMo/a	.50+c/2	b/HrsMo/d
Jul-07	97,809	29,688,204	40.80%	70.40%	56,682
Aug-07	93,862	28,491,847	40.80%	70.40%	54,397
Sep-07	90,825	22,374,970	34.22%	67.11%	46,308
Oct-07	58,522	9,297,233	21.35%	60.68%	20,595
Nov-07	15,010	2,093,223	19.37%	59.68%	4,871
Dec-07	2,980	521,520	23.52%	61.76%	1,135
Jan-08	2,650	338,520	17.17%	58.58%	777
Feb-08	3,092	354,063	16.45%	58.23%	874
Mar-08	3,806	354,144	12.51%	56.25%	846
Apr-08	19,669	3,605,352	25.46%	62.73%	7,983
May-08	71,354	13,442,413	25.32%	62.66%	28,834
Jun-08	88,851	18,177,581	28.41%	64.21%	39,321
Average	45,703	10,728,256			21,885

	a	b	c	d	e
	Monthly	Monthly	Monthly	Monthly	Est. Class
	ICMD	kWh	ICMD	Est. Class	Coin. Peak
	Total	Total	Max. LF	Coin. LF	kW Total
Primary	(cust acct)	(cust acct)	b/HrsMo/a	.50+c/2	b/HrsMo/d
Jul-07	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Aug-07	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Sep-07	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Oct-07	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Nov-07	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Dec-07	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Jan-08	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Feb-08	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Mar-08	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Apr-08	0	0	#DIV/0!	#DIV/0!	#DIV/0!
May-08	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Jun-08	0	0	#DIV/0!	#DIV/0!	#DIV/0!
Average	0	0			#DIV/0!

Total	a Monthly ICMD Total (cust acct)	b Monthly kWh Total (cust acct)	c Monthly ICMD Max. LF b/HrsMo/a	d Monthly Est. Class Coin. LF .50+c/2	e Est. Class Coin. Peak kW Total b/HrsMo/d
Jul-07	97,809	29,688,204	40.80%	70.40%	56,682
Aug-07	93,862	28,491,847	40.80%	70.40%	54,397
Sep-07	90,825	22,374,970	34.22%	67.11%	46,308
Oct-07	58,522	9,297,233	21.35%	60.68%	20,595
Nov-07	15,010	2,093,223	19.37%	59.68%	4,871
Dec-07	2,980	521,520	23.52%	61.76%	1,135
Jan-08	2,650	338,520	17.17%	58.58%	777
Feb-08	3,092	354,063	16.45%	58.23%	874
Mar-08	3,806	354,144	12.51%	56.25%	846
Apr-08	19,669	3,605,352	25.46%	62.73%	7,983
May-08	71,354	13,442,413	25.32%	62.66%	28,834
Jun-08	88,851	18,177,581	28.41%	64.21%	39,321
Average	45,703	10,728,256			21,885

STREET LIGHTING LOAD FACTORS

Oregon Price Filing - 12 Months Ending December 2010 Test Year

ASSUMPTIONS

1. Street light are on 3,940 hours each year.

2. System 12 CP - all monthly system peaks occur during daylight hours when street lights are off except for the months of November and December.

3. Class 12 CP - all street lights are on at monthly class coincident peaks.

4. Winter system is calculated based on the hours ending 09:00, 10:00 and 19:00 PST. All street lights are off during the daylight hours (09:00 and 10:00) and on during the evening hours.

12 MONTH SYSTEM COINCIDENT PEAK LOAD FACTOR

$$12CPLF = \frac{kWh/8760}{kW} = \text{infinity}$$

12 MONTH JURISDICTIONAL COINCIDENT PEAK LOAD FACTOR

Same as 12CPLF above (Oregon jurisdictional peaks coincide with system peaks).

12 MONTH CLASS COINCIDENT PEAK LOAD FACTOR

$$12CLPLF = \frac{kWh/8760}{kW} = \frac{kW*3940/8760}{kW} = \frac{3940}{8760}$$

$$= \boxed{\mathbf{44.977\%}}$$

WINTER SYSTEM DIVERSIFIED LOAD FACTOR

kWh/8760 kW*3940/8760 3*3940

12CLPLF = ---------------	=	---------------	=	---------------
(0+0+kW)		kW/3		8760
	=	**134.932%**		

C. Craig Paice
Exhibit PPL/910

Docket No. UE-210
Exhibit PPL/910
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of C. Craig Paice

PacifiCorp Distribution Construction Standards Handbook, Standard DA 411

June 2009

General—Residential Electrical Demand

A. Scope

This guideline provides information regarding residential electrical demand calculations. Covered are customer class, load factor, peak demand, coincidence factor, and energy-to-demand conversion.

B. General

When actual values are not available, residential energy and demand information can be estimated using the following guidelines. These guidelines are to be used throughout the PacifiCorp System.Transformers must be sized to handle the worst case of both winter and summer loads.

C. Customer Group and Load Factor

Residential customers are categorized into four classes according to connected electrical load. The residential classes and electrical loads are defined below:

1. Class I includes LM
2. Class II includes LMRD
3. Class III includes LMRDW
4. Class IV includes LMRDWH/AIR

Where:

L	=	lights
M	=	miscellaneous, including small appliances
R	=	electric range
D	=	electric dryer
W	=	electric water heater
H/HP/AC	=	electric heat / heat pump / air conditioner

Table 1 relates residential customer class to annual load factor, based on past field tests. The annual load factor is defined as the ratio of the average load divided by the peak load over the time period of a year.

Table 1—Annual Load Factor

Load Factor	Single Family Frame House	Multiple Family Unit	Mobile Home
48.1%	Class I	—	—
40.4%	Class II	non-electric heat	—
40.1%	Class III	—	—
29.0%	Class IV	electric heat	electric heat

DA 411

D. Demand Usage

Good judgment should be exercised when using the peak demand tables. The following are examples of items which can vary greatly, and may require adjustment of peak demand values from tables:

1. **Type of Construction**

   insulation

2. **Location**

   elevation
   prevailing winds

3. **Unusual Connected Electrical Loads**

   duplicate major appliances
   hot tub
   sauna
   etc.

Table 2—Peak Demand for Single Family Frame Houses (kW)

	Class I			Class II		
Size of House	winter LM	winter LM+HP	summer LM+AC/HP	winter LMRD	winter LMRD+HP	summer LMRD+AC/HP
< 1300 sq. ft.	3	8	5	5	13	8
1300–2000 sq. ft.	5	10	7	7	17	10
2001–3500 sq. ft.	7	13	10	10	20	13
3501–4500 sq. ft.	—	—	—	—	—	—

	Class III			Class IV
Size of House	winter LMRDW	winter LMRDW+HP	summer LMRDW+AC/HP	summer LMRDW+AC/HP
< 1300 sq. ft.	8	13	13	13
1300–2000 sq. ft.	10	17	17	17
2001–3500 sq. ft.	13	20	20	20
3501–4500 sq. ft.	—	—	—	22

Table 3—Peak Demand per Unit for Multiple Family Units (kW)

Size of Apartment	Non-Electric Heat	Electric Heat
< 800 sq. ft.	4	10
800–1000 sq. ft.	5	13
1001–1400 sq. ft.	9	17

Table 4—Peak Demand for Mobile Homes with Electric Heat (kW)

Size of Mobile Home	Peak Demand
Single-Wide	13
Double-Wide	17
Triple-Wide	25

E. Coincidence Factor

The coincidence factor pertains to the total demand, at any one time, of customers served by a single transformer or set of conductors. Since all of the customers generally don't reach peak load at the same moment, the total load on the cables or transformer is generally less than the sum of the individual peak loads. The coincidental peak demand is determined by adding up the individual peak demands and multiplying by a coincidence factor less than or equal to 1. The coincidence factor is related to the number of customers, and is shown in Table 5:

Table 5—Coincidence Factor

Number Of Customers	1	2	3	4	5	6	7	8	9	10	11 or more
CF for Summer Loads	1.0	.90	.86	.82	.78	.76	.74	.72	.71	.70	.70
CF for Winter Loads	1.0	.77	.70	.67	.64	.62	.60	.59	.58	.57	.56

F. Transformer Facility Design and Loading Guidelines—Single Family Residential

Table 6 lists the maximum loads for single-family dwellings. When designing facilities to serve single-family residences, care must be taken to load transformers as close to these values as possible. Each transformer must be sized for all homes/lots it is designed to serve. It is not necessary to reserve transformer capacity for load growth within the homes unless unusual circumstances exist. Table 6 applies to both pole-mounted and pad-mounted transformers.

After determining the load requirements from Table 2 and Table 5, choose the appropriate transformer size listed in Table 6. Select the value for summer if the loads are expected to peak in summer. Select the value for winter if the loads are expected to peak in winter. Check the overall design for appropriate voltage levels and flicker constraints. Consult your engineer if you have questions.

The loading limits shown in Table 6 are based on 130 percent of nameplate for summer loads and 180 percent of nameplate for winter loads.

In areas with conditions requiring more conservative transformer loadings, use Table 7 when designing facilities. Use Table 6 when evaluating whether transformers already in service should be replaced. Table 7 is based on 100 percent of nameplate for summer loads and 150 percent of nameplate for winter loads.

Both tables apply to residential application with kW at .95 power factor.

DA 411

Table 6 —Standard Transformer Loading Guidelines
130 Percent Summer Loading, 180 Percent Winter Loading

	Ambient Temp.* (°C/°F)	Transformer Size 25 kVA	50 kVA	75 kVA	100 kVA
Winter	0/32	0–48	49–96	97–144	145–193
	10/50	0–46	47–91	92–137	138–182
	20/68	0–42	43–85	86–127	128–170
Summer	20/68	0–37	38–75	76–113	114–151
	30/86	0–35	36–69	70–104	105–139
	40/104	0–31	32–64	65–95	96–128

*Ambient temperature is the mean average temperature during the peak loading season +5 degrees C (or +9 degrees F) as a safety margin.

Table 7 —Conservative Transformer Loading Guidelines
100 Percent Summer Loading, 150 Percent Winter Loading

Transformer Size	25 kVA	50 kVA	75 kVA	100 kVA
Winter	0–37.5	38–75	76–112.5	113–150
Summer	0–25	26–50	51–75	76–100

G. Energy to Demand Conversion

When the actual energy usage (kWH/day) is available, the peak demand in kW can be approximated using the energy-to-demand conversion graph shown in Figure 1.

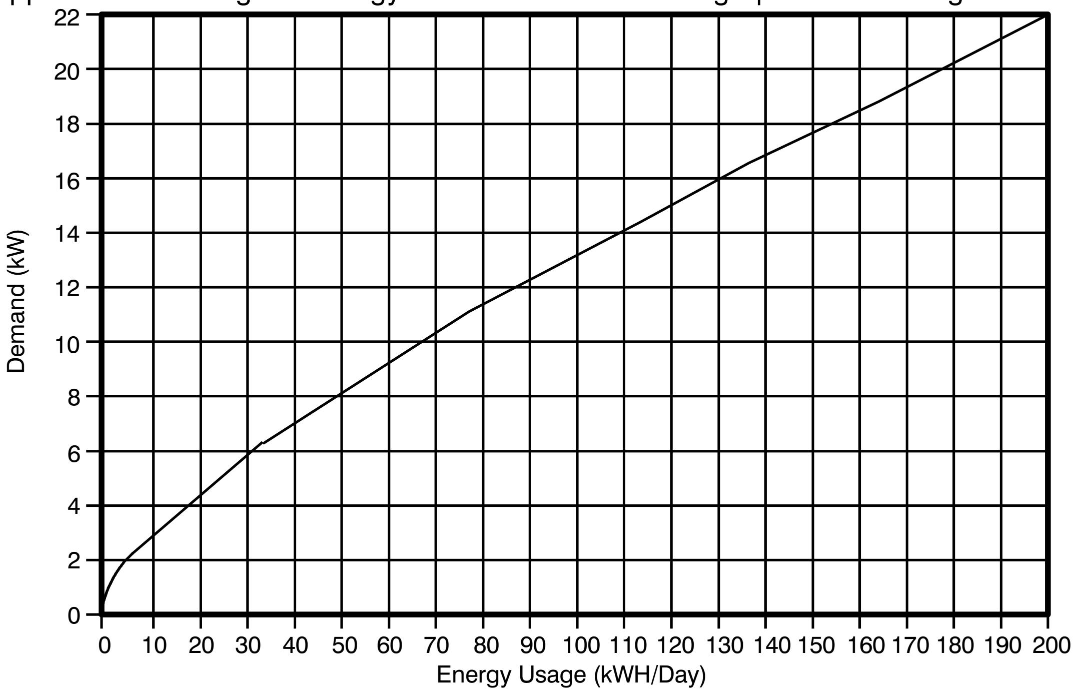

Figure 1—Energy-to-Demand Conversion

H. Example 1

Determine the coincidental peak demand and load factor for the following group of single family frame houses:

Number of Customers	Size of House	Class
1	1000 sq. ft.	II
2	1500 sq. ft.	III
1	2400 sq. ft.	IV

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1. **STEP 1**

Find the individual peak demand values in Table 2, and determine the sum total.

Peak Demands, from Table 2:

Number of Customers	Class	Individual Demand	Sum of Demands
1	II	5 kW	5 kW
2	III	10 kW	20 kW
1	IV	20 kW	20 kW

Total Demand = 45kw

2. **STEP 2**

Using Table 5, determine the group's winter (or summer) Coincidental Peak Demand.

From Table 5, Coincidence Factor for 4 Customers = 0.67

Therefore:
Winter Coincidental Peak Demand = Winter Coincidence Factor * Total Demand
= 0.67 * 45kW
= 30.15kW

3. **STEP 3**

Using Table 1 and Table 2, determine the group's load factor.

Recall that Load Factor = Average Load / Peak Demand Load.

Therefore:
Individual Average Load = Individual Load Factor * Individual Demand

(Example) Average Load

Number of Customers	Class	Individual Demand	Individual Load Factor	Individual Avg. Load	Sum of Avg. Loads
1	II	5 kW	40.4%	2.02 kW	2.02 kW
2	III	10 kW	40.1%	4.01 kW	8.02 kW
1	IV	20 kW	29.0%	5.80 kW	5.80 kW

Total Average Load = 15.84kW

Then:
Group Load Factor = (Total Avg. Load / Winter Coincidental Peak Demand)*100
= (15.84kW / 30.15kW) * 100
= 52.5%

These calculated values (i.e., Coincidental Peak Demand = 30.15kW) would be used in determining the group's transformer and secondary sizes. The service to each individual house would be determined based on the individual peak demand and individual load factor.

I. Example 2

Determine the appropriate size pad-mounted transformer to serve 10 single-family, 2,000 square-foot homes with gas heat and water heating, electric ranges and dryers, and no air conditioning. The mean average temperature in winter is 32° F. The mean average temperature in summer is 87° F.

1. STEP 1 Determine the Load of Each Home

According to Table 2, these homes fall into category II, and each has a load of 7 kW.

2. STEP 2 Determine the Peak Load for the Transformer

The total load for 10 homes is 7 kW $\times$ 10 = 70 kW.
According to Table 5, the winter coincidence factor for 10 homes is .57.
The coincident peak load on the transformer is therefore 70 kW $\times$ .57 = 39.9 kW.

3. STEP 3 Determine the Appropriate Size of Transformer to Serve the Load

From Table 6, choose the winter block and the row for 32° F. The proper size for the transformer is 25 kVA. From the summer block at 87° F (the 86° F block), the proper size for the transformer is 50 kVA. The 50 kVA transformer should be used.

J. Example 3

Size a pad-mounted transformer to serve 10 single-family, 2,000 square-foot homes with gas heat and water heating, electric ranges and dryers, and air conditioning. The mean average temperature in winter is 32° F. The mean average temperature in summer is 97° F.

1. STEP 1 Determine the Load of Each Home

According to Table 2, these homes fall into category II, and each has a load of 10 kW.

2. STEP 2 Determine the Peak Load for the Transformer

The total load for 10 homes is 10 kW $\times$ 10 = 100 kW.
According to Table 5, the summer coincidence factor for 10 homes is .7
The coincident peak load on the transformer is therefore 100 kW $\times$ .7 = 70 kW.

3. **STEP 3 Determine the Appropriate Size of Transformer to Serve the Load**

   From Table 6, choose the winter block and the row for 32° F. The proper size for the transformer is 50 kVA. From the summer block at 97° F (the 104° F block), the proper size for the transformer is 75 kVA. The 75 kVA transformer should be used.

K. Example 4

Determine the appropriate size pad mounted transformer to serve 10 single-family, 2,000 square-foot homes with gas heat and water heating, electric ranges and dryers, and heat pumps. The mean average temperature in winter is 32° F. The mean average temperature in summer is 87° F.

1. **STEP 1 Determine the Load of Each Home**

   According to Table 2, these homes fall into category II, and each has a load of 17 kW.

2. **STEP 2 Determine the Peak Load for the Transformer**

   The total load for 10 homes is 17 kW $\times$ 10 = 170 kW.
   According to Table 5, the winter coincidence factor for 10 homes is .57
   The coincident peak load on the transformer is therefore 170 kW $\times$ .57 = 96.9 kW.

3. **STEP 3 Determine the Appropriate Size of Transformer to Serve the Load**

   From Table 6, choose the winter block and the row for 32° F. The proper size for the transformer is 75 kVA. From the summer block at 87° F (the 86° F block), the proper size for the transformer is 75 kVA. The 75 kVA transformer should be used.

Docket No. UE-210
Exhibit PPL/911
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of C. Craig Paice

Oregon Customers per Transformer

June 2009

Customers Per Transformer

State	OR

		Data		
Schedule	Phase	**Sum of Customers**	**Sum of Sum of Units**	**Units per Customer**
4	**1**	479,925	129,172	4
	3	5,355	443	12
4 Total		485,280	129,615	**4**
23	**1**	59,717	23,473	3
	3	27,042	19,771	1
23 Total		86,759	43,244	**2**
28	**1**	17	10	2
	3	198	167	1
28 Total		215	177	**1**
30	**1**	2	1	2
	3	751	783	1
30 Total		753	784	**1**
33	**1**	74	44	
	3	2,013	4,314	
33 Total		2,087	4,358	
40	**1**	3	2	
	3	40	62	
40 Total		43	64	
41	**1**	1,333	760	2
	3	5,399	8,869	1
41 Total		6,732	9,629	**1**
47	**3**	7	9	
47 Total		7	9	
48	**3**	223	342	1
48 Total		223	342	**1**
53	**1**	66	33	
	3	4	2	
53 Total		70	35	
54	**1**	70	44	
	3	35	40	
54 Total		105	83	
Grand Total		582,274	188,340	

Docket No. UE-210
Exhibit PPL/1004
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Supplemental Direct Testimony of William R. Griffith

June 2009

Q. Please state your name.

A. My name is William R. Griffith. My business address is 825 NE Multnomah Avenue, Suite 2000, Portland, Oregon. My present position is Director, Pricing & Cost of Service, in the Regulation Department.

Q. Are you the same William R. Griffith who provided direct testimony in this case as Exhibit PPL/1000?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your Supplemental Direct Testimony?

A. The purpose of my Supplemental Direct Testimony is to respond to four requests—Requests 5, 14, 21, and 23—in the May 14, 2009 Ruling of the Administrative Law Judges on Supplemental Testimony ("Ruling on Supplemental Testimony"), which pertain to my Direct Testimony.

Request 5 – Rate Spread

Q. What is Request 5 in the Ruling on Supplemental Testimony?

A. Request 5 directs the Company to "Provide testimony explaining in detail how PacifiCorp's proposed rate spread appropriately reflects cost of service, including an explanation of why rate increases were relatively equal for all customer classes in docket UE 179, but the proposed rate increases in this docket vary significantly by customer class."

Q. Please more fully explain the difference between base and net revenues as shown in the rate spread in Exhibit PPL/1002, Griffith/1.

A. In order to explain how the Company's proposed rate spread appropriately reflects cost of service, it is important to distinguish between base and net revenues shown in Exhibit PPL/1002, Griffith/1. Base revenues are the Company's revenues under the rates in the standard tariff electric service rate schedules for delivery and supply service. Base revenues reflect the Company's revenue requirement. Base revenues do not include any adjustment schedules (i.e., tariff riders) which are applied in addition to each rate schedule's base rates. For example, Schedule 93, Independent Evaluator Cost Adjustment or Schedule 299, Rate Mitigation Adjustment are two of the tariff riders that are applied to customer's base rates.

Net rates include the effects of all tariff riders applicable to each rate schedule's base rates. Net revenues and net revenue increases are important because they better reflect the ultimate rates that customers will pay on their bills. Net rates include the effect of base rates plus the effect of all tariff riders applicable to each electric service rate schedule.

Q. Please discuss how the Company's proposed base rate spread appropriately reflects cost of service.

A. The Company's base rates are designed directly based on the results of the cost of service study as presented in the direct testimony of Mr. C. Craig Paice. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test year. Therefore, the base rate increase to each rate schedule exactly reflects the cost to serve consumers under that schedule, as determined by the cost of service study. Base proposed revenues by rate schedule shown in Exhibit PPL/1002, Griffith/1, column 9 are equal to the cost of service by rate schedule shown in Exhibit PPL/905, Paice/1, row 36. Minor differences are due to the rounding of rates.

Q. Is this methodology consistent with the methodology used in the Company's last general rate case, UE 179?

A. Yes. Base rate increases in UE 179 were also based directly on cost of service as required by the Commission's rules on direct access regulation adopted under OAR 860-038-0200.

Q. The base percentage rate increases for the major rate schedules shown in Exhibit PPL/1002 range from 69 to 159 percent of the overall average base rate increase. Is this level of variance consistent with the base rate increases proposed by the Company in UE 179?

A. Yes. Base rate increases proposed for the major rate schedules in UE 179 also varied widely, from 82 to 145 percent of the overall average base rate increase.

Q. Was the variance in the level of increase by rate schedule similar for the final ordered base rate increases in UE 179?

A. Yes. The final base rate increases in UE 179 by schedule varied from 82 to 146 percent of the overall average base rate increase.

Q. What is the variance in net rate increase by rate schedule proposed in this case?

A. Net rate increases proposed for the major rate schedules in this case vary from 69 to 192 percent of the overall average net rate increase.

Q. Do the adjustment schedules influence the net rate spread?

A. Yes. In particular, the Company's net rate spread reflects an ongoing Rate

Mitigation Adjustment ("RMA") which is designed to minimize price impacts on consumers while still sending them proper signals about the increasing costs of serving them

Q. Is the variance in the proposed net percentage increases by rate schedule in this case consistent with the variance in the proposed net percentage increases by rate schedule in UE 179?

A. Yes. Net rate increases proposed for the major rate schedules in UE 179 varied from 71 to 150 percent of the overall average net rate increase. The Company proposed a rate cap in UE 179, similar to the one proposed in this case, so that none of the major rate schedules would see an increase greater than 1.5 times the overall average net proposed rate increase.

Q. How were the final net rate increases in UE 179 determined?

A. The final net increases were settled as part of a stipulation which called for net rate increases "largely based upon equal percentage increases to all rate groups". The RMA was used to achieve this goal.

Q. Why did the Company not propose equal percentage increases to all rate groups in this docket?

A. As described in my direct testimony, the Company's proposed rate increase caps are intended to strike a balance between moderating rate impacts on consumers, sending proper price signals about the increasing costs to serve consumers, and not unreasonably impacting electric retail competition. The Company does not believe an equal percentage increase to all rate schedules would achieve these goals.

Request 14 – Actual and Forecast Monthly Energy Volumes

Q. What is Request 14 in the Ruling on Supplemental Testimony?

A. Request 14 directs the Company to "Provide testimony and exhibits showing energy volumes delivered from January 2006 through December 2008 in Oregon by month and by rate schedule.

(a) Provide testimony showing the same information in a combination of actual plus forecast for 2009.

(b) Provide testimony showing the same information as forecast for the 2010 test year by month, by rate schedule, and by peak and off-peak periods."

Q. Have you prepared exhibits containing the requested information?

A. Yes. I have prepared three exhibits with the requested information that is presently available or could reasonably be prepared.

Q. Please describe Exhibit PPL/1005.

A. Exhibit PPL/1005 contains actual monthly energy volumes by rate schedule for January 2006 through April 2009. These energy volumes have not been normalized.

Q. Please describe Exhibit PPL/1006.

A. Exhibit PPL/1006 contains the Company's current monthly energy forecasts by class for May 2009 through December 2009. A current forecast by rate schedule for 2009 has not been prepared and is not readily available.

Q. Please describe Exhibit PPL/1007.

A. Exhibit PPL/1007 contains monthly energy forecasts by rate schedule for the 2010 forecast test year. Energy forecasts for 2010 for Schedule 48, Large General

Service, and Schedule 47, Large General Service Partial Requirements, are split to show on- and off-peak time-of-use levels. The Company breaks down energy forecasts into on- and off- peak time-of-use levels based on collected actual time-of-use meter data. Time-of-use meter data is collected only for rate schedules which are billed on time-of-use rates. Time-of-use meter data is not available to break down energy forecasts for any of the other rate schedules.

Request 21 – Reconciliation of Test Year Load Forecast to Billing Determinants

Q. What is Request 21 in the Ruling on Supplemental Testimony?

A. Request 21 directs the Company to "Provide testimony and exhibits related to reconciliation of the 2010 test year load forecast with levels of billing determinants as used in PPL/1000 through PPL/1003."

Q. Please describe how the forecast test year billing determinants are developed.

A. Forecast test year billing determinants are developed based on the Company's forecast test year bills and energy forecasts along with the historic test year billing determinants.

A three step process occurs in developing test year billing determinants. First, monthly forecast test year bills and energy by class and by rate schedule are prepared by the Company as described in the supplemental direct testimony of Mr. Gregory N. Duvall.

Second a full set of billing determinants, including all rate elements such as demand amounts, load size quantities, kilovar quantities and kilowatt-hours by rate block, are retrieved at the customer invoice level from the Company's billing system for the historic test period – in this case, the twelve months ended June

2008. These historic billing determinants are summarized by class, rate schedule and voltage level.

Finally, a full set of forecast billing determinants is developed using the historic test period data and the forecast test period information. The forecast billing determinants are calculated based upon the ratio of historic bills and energy (temperature normalized) in the historic test period to the forecast bills and energy provided in the load forecast.

Q. Do the bills and energy in the forecast billing determinants match the Company's forecast of bills and energy?

A. Yes. When summed by class and by rate schedule, the bills and energy in the forecast billing determinants match the Company's forecast test year bills and energy forecast.

Q. Have you prepared an exhibit which compares the historic billing determinants in this case to the forecast billing determinants?

A. Yes. Exhibit PPL/1008 shows the historic billing determinants for the 12 months ended June 2008, the temperature normalized billing determinants for the same period, and the forecast billing determinants as filed in this case. This detail, with formulas intact, was included in the tab labeled "Blocking" in the Griffith GRC Rate Design Model provided electronically at the time of the original filing.

Q. Is the method of developing forecast billing determinants used in this docket consistent with the methods previously used by the Company in Oregon and in other jurisdictions?

A. Yes. This method of developing forecast billing determinants is the same method as has been used by the Company in all of its recent general rate cases in Oregon as well as all rate cases in other states where forecast test periods are used.

Request 23 – Removal of Net Power Costs from Schedule 200

Q. What is Request 23 in the Ruling on Supplemental Testimony?

A. Request 23 directs the Company to "Provide further testimony explaining the removal of net power costs from Schedule 200, and how Schedules 200 and 201 appropriately reflect cost causation principles."

Q. How are net power costs currently collected?

A. Net power costs are currently collected within Schedule 200, Cost Based Supply Service. Schedule 200 currently collects all functionalized generation costs, including all net power costs and other generation-related costs. In the Company's last general rate case, UE 179, Schedule 200 rates were designed to collect all functionalized Generation costs as identified by the cost of service study in that case. Increases to the Company's net power costs as approved in the Company's Transition Adjustment Mechanism ("TAM") filings since UE 179 have been collected through an increase to Schedule 200 rates.

Q. How have proposed net power costs by rate schedule been identified in this case?

A. Total net power costs included in the proposed revenue requirement in this docket have been allocated to the rate schedules in proportion to the spread of generation revenues to the rate schedules as indicated by the cost of service study.

Q. Have you prepared an exhibit showing net power costs by rate schedule for the rate schedules contained in the cost of service study?

A. Yes. Exhibit PPL/1009 provides the proposed functionalized Generation costs in this docket, as shown in the exhibit accompanying the direct testimony of Mr. Paice, PPL/905, further unbundled into Generation-Net Power Costs and Generation-Other categories by rate schedule. Generation – Net Power Costs by rate schedule are proposed to be collected through Schedule 201 in this docket. Generation-Other Generation costs are proposed to be collected through Schedule 200.

Q. Why is the Company proposing further unbundling of Generation costs?

A. The Company agreed to propose this additional unbundling as part of the UE 199 Stipulation and Agreement of the Parties on the General Guidelines for the TAM, filed on June 1, 2009. This change to rate design simply allows rates collecting net power costs to be more easily reviewed and revised in a TAM proceeding outside of a general rate case.

Q. Does this proposed rate design properly reflect cost causation principles?

A Yes. Cost causation principles and the direct access rules adopted under OAR 860-038-0200 indicate that costs, including Generation costs, must be allocated to the class of consumers who incur those costs. Under the Company's proposed rates, and under the Company's present rates, total Generation costs for each rate schedule as determined by the cost of service study will be collected through the base rates for each rate schedule. Each rate schedule will continue to pay its allocated generation costs as occurs today.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

Docket No. UE-210
Exhibit PPL/1005
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of William R. Griffith

Actual Monthly Energy Volumes by Rate Schedule
for January 2006 through April 2009

June 2009

Pacific Power
State of Oregon

Energy Sales
Actual 12 months ending December 2006 (un-normalized)

Schedule No.	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total 2006
4	653,572,876	553,088,331	559,705,551	471,421,149	384,630,837	359,214,841	383,246,070	413,718,558	368,300,453	354,082,724	451,130,353	620,817,720	5,572,929,463
15	1,875,281	1,062,074	1,277,584	967,415	968,397	966,888	959,781	950,757	944,719	960,685	943,116	942,635	12,819,332
23	113,372,029	97,083,751	99,976,428	86,026,632	84,753,151	85,448,791	91,464,770	100,171,943	94,032,813	83,617,138	88,988,071	105,794,118	1,130,729,635
28	193,413,660	168,240,945	170,322,706	159,067,579	155,963,290	161,756,687	172,072,136	192,678,848	172,456,441	166,563,170	167,032,328	187,499,424	2,067,067,214
30	111,310,675	100,690,864	102,417,286	96,038,826	101,239,526	104,831,437	107,845,700	117,236,395	108,949,103	105,812,630	104,837,586	115,910,032	1,277,120,060
33	466,255	1,219,453	835,284	859,717	8,664,084	20,591,300	25,285,313	25,407,501	20,884,648	7,244,894	108,475	108,297	111,675,221
41	301,695	260,743	861,360	3,302,631	9,427,724	15,105,053	25,919,326	31,762,616	22,582,038	12,131,434	3,067,631	427,278	125,149,529
47	38,535,000	44,356,200	36,674,400	39,623,200	33,302,200	41,264,000	32,703,200	38,659,400	51,035,130	46,505,689	49,473,792	48,187,329	500,319,540
48	241,502,947	248,604,393	231,503,340	244,898,042	243,038,570	250,795,890	286,377,970	294,547,328	275,407,720	263,544,880	260,799,200	245,632,950	3,086,653,230
50	1,210,560	1,053,040	1,172,245	949,264	949,813	927,370	922,067	920,201	883,861	953,522	921,069	921,378	11,784,390
51	1,924,487	1,966,124	1,778,172	1,303,020	1,272,103	1,278,529	1,284,277	1,285,940	1,217,171	1,366,886	1,302,827	1,303,772	17,283,308
52	244,276	238,430	204,743	166,095	147,115	143,209	143,660	140,844	103,511	173,121	136,409	138,824	1,980,237
53	1,405,664	964,796	1,423,925	688,030	681,006	680,914	677,282	686,114	680,937	700,723	731,954	728,158	10,049,503
54	48,748	48,998	52,957	52,253	45,569	67,524	89,639	76,419	94,186	100,127	144,570	76,835	897,825
Unbilled	(49,486,000)	(60,146,000)	7,927,000	(89,835,000)	59,101,000	15,149,000	76,201,000	(32,989,000)	(21,799,000)	65,517,000	38,442,000	(22,537,000)	(14,455,000)
Total	1,309,698,153	1,158,732,142	1,216,132,981	1,015,528,853	1,084,184,385	1,058,221,433	1,205,192,191	1,185,253,864	1,095,773,731	1,109,274,623	1,168,059,381	1,305,951,750	13,912,003,487

Pacific Power
State of Oregon

Energy Sales
Actual 12 months ending December 2007 (un-normalized)

Schedule No.	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total 2007
4	711,362,974	591,693,286	528,627,312	435,813,687	389,670,462	367,626,570	382,348,523	392,355,460	368,537,013	375,991,403	458,474,733	619,280,289	5,621,781,712
15	943,933	938,551	963,936	917,650	944,921	945,711	936,116	931,877	920,951	944,671	921,662	945,933	11,255,912
23	115,539,007	98,533,873	98,324,892	85,859,486	84,366,801	88,153,378	92,497,994	97,941,800	91,752,681	87,336,474	89,908,138	107,307,297	1,137,521,821
28	200,301,900	169,071,929	171,487,197	157,776,534	156,101,274	164,840,161	170,804,987	188,731,351	173,579,354	168,187,009	166,771,334	188,501,033	2,076,154,063
30	110,464,728	101,665,800	105,333,348	101,988,790	103,628,647	110,987,053	115,789,079	122,462,080	114,180,653	110,783,717	106,937,951	116,295,104	1,320,516,950
33	1,147,754	(746,701)	435,248	693,269	11,447,058	23,507,562	27,786,095	24,289,638	20,719,019	4,858,180	232,691	122,111	114,491,924
41	240,079	309,663	470,683	3,674,993	12,152,857	25,315,034	30,113,043	28,634,963	22,085,097	11,167,998	2,187,523	678,601	137,030,534
47	48,453,688	51,417,356	47,267,358	52,807,391	46,962,924	51,440,484	49,856,705	50,682,847	51,224,994	48,255,557	51,057,965	48,746,919	598,174,188
48	246,457,792	246,267,890	235,140,380	237,225,570	227,603,310	255,864,360	259,107,420	280,383,850	252,446,350	256,623,060	238,373,630	245,114,780	2,980,608,392
50	922,199	919,040	914,685	898,191	907,520	903,274	915,272	915,398	835,537	971,617	831,528	853,074	10,787,335
51	1,317,647	1,314,783	1,327,272	1,211,155	1,465,474	1,369,131	1,335,751	1,378,359	1,260,504	1,498,002	1,210,309	1,472,522	16,160,909
52	132,190	132,435	130,313	130,187	129,762	127,026	127,092	126,477	72,981	172,796	117,795	117,676	1,516,730
53	747,514	717,110	736,737	722,170	714,783	732,754	731,085	731,324	740,471	769,708	759,511	789,271	8,892,438
54	59,662	46,951	48,708	44,528	58,130	70,711	90,585	89,853	85,874	120,786	131,379	78,275	925,442
Unbilled	31,339,000	(128,436,000)	(28,047,000)	(22,807,000)	24,922,000	27,831,000	79,718,000	(11,639,000)	(37,025,000)	41,448,000	59,768,000	4,466,000	41,538,000
Total	1,469,430,067	1,133,845,966	1,163,161,069	1,056,956,601	1,061,075,923	1,119,714,209	1,212,157,747	1,178,016,277	1,061,416,479	1,109,128,978	1,177,684,149	1,334,768,885	14,077,356,350

Pacific Power
State of Oregon

Energy Sales
Actual 12 months ending December 2008 (un-normalized)

Schedule No.	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total 2008
4	694,423,606	642,494,374	510,511,212	502,659,807	430,133,238	376,781,506	397,305,453	397,755,473	376,665,095	363,562,979	420,275,172	600,752,368	5,713,320,283
15	926,511	936,000	925,357	916,079	917,484	919,384	913,875	897,686	921,228	929,348	916,311	892,352	11,011,615
23	112,084,473	108,114,514	94,928,686	93,368,432	88,700,883	85,909,652	93,346,102	95,119,121	93,655,046	87,809,225	86,717,756	103,156,463	1,142,910,353
28	190,655,425	184,057,571	167,610,604	165,309,951	159,796,198	163,376,941	174,756,981	182,176,777	184,036,870	170,214,118	160,688,478	183,508,021	2,086,187,935
30	109,896,290	105,229,770	102,936,984	102,260,764	100,891,459	108,190,359	109,531,081	113,939,104	112,836,577	107,771,622	103,903,528	111,974,122	1,289,361,660
33	225,383	309,183	397,774	696,509	11,083,089	13,750,169	26,394,571	22,808,677	20,257,667	7,803,033	470,606	122,107	104,318,768
41	237,638	360,907	355,940	3,684,200	13,548,130	17,618,184	30,517,708	28,328,209	23,676,034	12,473,987	3,136,326	468,352	134,405,615
47	48,544,680	51,148,185	47,520,899	50,126,403	45,655,392	50,902,516	49,959,508	49,735,020	53,698,316	48,064,934	43,081,996	38,461,370	576,899,219
48	213,165,699	248,279,710	224,362,090	228,859,070	226,506,610	239,497,670	259,169,850	272,050,160	251,611,840	239,781,700	224,730,520	224,611,520	2,852,626,439
50	890,424	880,299	896,040	894,510	928,755	937,639	936,667	968,191	925,171	946,059	859,426	860,239	10,923,420
51	1,245,286	1,508,743	1,419,687	1,439,478	1,278,791	1,486,587	1,340,171	1,559,382	1,311,309	1,592,156	1,457,636	1,318,275	16,957,501
52	117,675	101,497	121,457	105,570	95,303	57,770	115,520	94,421	75,082	104,920	89,935	90,906	1,170,056
53	806,408	809,000	821,892	779,749	768,915	768,285	763,451	747,883	767,414	558,141	787,131	796,308	9,174,577
54	64,899	75,801	63,317	58,188	66,702	85,011	86,264	97,150	95,104	120,399	140,469	103,463	1,056,767
Unbilled	(14,397,000)	(140,009,000)	87,872,000	(61,972,000)	(5,627,000)	24,853,000	64,797,000	(25,613,000)	(66,684,000)	36,561,000	37,400,000	131,260,000	68,441,000
Total	1,358,887,397	1,204,296,554	1,240,743,939	1,089,186,710	1,074,743,949	1,085,134,673	1,209,934,202	1,140,664,254	1,053,848,753	1,078,293,621	1,084,655,290	1,398,375,866	14,018,765,208

Pacific Power
State of Oregon

Energy Sales
Actual 4 months January 2009 through April 2009 (un-normalized)

Schedule No.	Jan-09	Feb-09	Mar-09	Apr-09	Total 4 Months
4	700,994,667	587,508,496	546,473,360	467,038,129	2,302,014,652
15	915,088	893,132	898,810	898,988	3,606,018
23	114,912,975	100,295,578	96,608,755	88,421,649	400,238,957
28	196,526,837	170,238,474	169,064,556	157,213,075	693,042,942
30	112,948,326	98,877,540	101,935,490	96,744,262	410,505,618
33	270,834	209,906	566,771	424,753	1,472,264
41	476,198	342,616	513,949	2,616,566	3,949,329
47	40,714,833	38,308,018	36,318,317	38,528,676	153,869,844
48	208,145,649	200,891,261	196,831,310	198,738,970	804,607,190
50	887,348	867,856	835,818	842,167	3,433,189
51	1,589,130	1,453,052	1,376,802	1,478,933	5,897,917
52	90,908	90,923	53,709	90,834	326,374
53	810,814	726,812	802,952	770,543	3,111,121
54	70,565	29,042	46,076	48,825	194,508
Unbilled	(148,987,000)	(96,094,000)	22,432,000	(41,713,000)	(264,362,000)
	1,230,367,172	1,104,638,706	1,174,758,675	1,012,143,370	4,521,907,923

William R. Griffith
Exhibit PPL/1006

Docket No. UE-210
Exhibit PPL/1006
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of William R. Griffith

Monthly Energy Forecasts by Class for May 2009 through December 2009

June 2009

Pacific Power
State of Oregon

Energy Sales
Forecast 8 months May 2009 through December 2009 by Class

Class	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total 8 Months
Residential	385,506,000	363,968,000	401,606,000	393,076,000	353,656,000	395,386,000	485,170,000	611,238,000	3,389,606,000
Commercial	389,416,000	389,848,000	436,396,000	438,436,000	405,976,000	395,926,000	383,140,000	418,378,000	3,257,516,000
Industrial	222,048,000	233,914,000	235,828,000	244,298,000	236,218,000	229,688,000	227,700,000	228,954,000	1,858,648,000
Irrigation	29,900,000	46,730,000	60,320,000	56,010,000	35,930,000	15,470,000	3,560,000	460,000	248,380,000
Public Street & Highway Lighting	3,150,000	3,430,000	3,460,000	3,260,000	3,370,000	3,330,000	2,690,000	2,760,000	25,450,000
	1,030,020,000	1,037,890,000	1,137,610,000	1,135,080,000	1,035,150,000	1,039,800,000	1,102,260,000	1,261,790,000	8,779,600,000

Docket No. UE-210
Exhibit PPL/1007
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of William R. Griffith

Monthly Energy Forecasts by Rate Schedule for the 2010 Forecast Test Year

June 2009

Pacific Power
State of Oregon

Energy Sales
Forecast 12 months ending December 2010

Schedule No.	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Forecast 2010
4	615,153,455	506,842,910	496,599,505	420,537,398	387,440,604	365,037,900	405,200,913	396,075,034	354,660,428	394,776,253	484,369,015	609,152,219	5,435,845,633
15	846,382	828,790	889,668	877,555	915,251	858,940	923,431	839,399	826,560	900,808	897,819	862,616	10,467,219
23	98,136,879	85,824,011	89,940,119	80,587,437	80,880,725	76,709,508	85,237,555	84,679,763	81,624,626	76,528,846	80,086,234	93,704,795	1,013,940,497
28	187,492,312	159,304,706	172,639,305	160,577,668	163,947,901	159,988,770	179,929,986	182,347,688	165,802,578	167,342,486	164,591,895	181,100,090	2,045,065,385
30	113,845,729	104,060,303	111,935,665	108,027,457	113,755,733	114,149,865	123,211,287	123,885,793	115,334,833	116,411,258	113,413,064	120,615,174	1,378,646,160
33	128,326	368,022	1,759,214	1,664,607	13,396,440	22,778,503	28,806,156	25,240,463	17,208,356	5,646,402	941,266	108,633	118,046,387
41	231	190,905	799,509	10,089,130	15,048,575	22,109,804	29,540,528	29,118,241	17,791,842	9,376,537	2,442,031	284,546	136,791,880
47	46,926,536	47,776,252	47,372,075	48,629,980	47,364,121	48,293,675	48,320,699	48,192,071	47,717,767	47,489,358	47,084,212	46,798,537	571,965,284
On Peak	26,341,013	26,820,592	26,613,163	27,321,646	26,607,028	27,061,027	27,067,399	27,006,707	26,828,506	26,698,294	26,470,519	26,268,650	321,104,544
Off Peak	20,020,835	20,381,875	20,198,391	20,733,709	20,195,946	20,631,035	20,647,561	20,586,144	20,333,781	20,237,467	20,064,819	19,966,516	243,998,079
Unscheduled	564,689	573,785	560,521	574,625	561,148	601,614	605,739	599,219	555,481	553,596	548,875	563,370	6,862,662
48	203,209,563	210,753,151	206,346,742	225,701,691	212,649,790	229,423,083	240,634,365	247,201,660	233,534,396	220,531,885	208,696,649	205,218,295	2,643,901,270
On Peak	123,238,844	127,757,888	125,094,508	136,834,135	129,049,853	139,300,394	146,224,765	150,227,514	141,863,404	133,905,412	126,626,924	124,515,054	1,604,638,695
Off Peak	79,970,719	82,995,262	81,252,233	88,867,556	83,599,937	90,122,688	94,409,600	96,974,146	91,670,992	86,626,473	82,069,724	80,703,240	1,039,262,570
50	879,749	801,551	874,036	795,774	918,749	1,017,878	1,021,282	956,297	1,005,821	966,743	735,598	764,553	10,738,031
51	1,318,901	1,209,902	1,311,543	1,202,449	1,374,902	1,511,761	1,515,692	1,426,632	1,496,128	1,439,502	1,118,204	1,159,081	16,084,697
52	117,675	101,497	121,457	105,570	95,303	57,770	115,520	94,421	75,082	104,920	89,935	106,576	1,185,726
53	773,226	766,611	752,513	745,767	760,586	842,123	807,040	782,187	792,497	818,377	745,832	729,352	9,316,113
54	51,037	41,389	48,648	47,518	51,321	60,419	85,547	70,351	79,084	96,626	118,247	65,532	815,719
Total	1,268,880,000	1,118,870,000	1,131,390,000	1,059,590,000	1,038,600,000	1,042,840,000	1,145,350,000	1,140,910,000	1,037,950,000	1,042,430,000	1,105,330,000	1,260,670,000	13,392,810,000

Docket No. UE-210
Exhibit PPL/1008
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of William R. Griffith

Billing Determinants

June 2009

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Schedule No. 4				
Residential Service				
Transmission & Ancillary Services Charge				
per kWh	5,757,030,628	5,546,124,729	5,435,845,633	kWh
Distribution Charge				
Basic Charge, per month	5,632,563	5,632,563	5,741,820	bill
Three Phase Demand Charge, per kW demand	17,680	17,680	17,328	kW
Three Phase Minimum Demand Charge, per month	1,526	1,526	1,556	bill
Distribution Energy Charge, per kWh	5,757,030,628	5,546,124,729	5,435,845,633	kWh
Energy Charge				
Schedule 200				
First Block kWh	2,514,471,640	2,422,356,640	2,374,190,522	kWh
Second Block kWh	1,588,620,353	1,530,420,353	1,499,989,488	kWh
Third Block kWh	1,653,938,635	1,593,347,736	1,561,665,624	kWh
Schedule 201				
First Block kWh	2,514,471,640	2,422,356,640	2,374,190,522	kWh
Second Block kWh	1,588,620,353	1,530,420,353	1,499,989,488	kWh
Third Block kWh	1,653,938,635	1,593,347,736	1,561,665,624	kWh
Subtotal	5,757,030,628	5,546,124,729	5,435,845,633	kWh
Renewable Adjustment Clause, per kWh	5,757,030,628	5,546,124,729	5,435,845,633	kWh
Klamath Rate Reconciliation Surcharge, per kWh	5,757,030,628	5,546,124,729	5,435,845,633	kWh
Total	5,757,030,628	5,546,124,729	5,435,845,633	kWh
Schedule No. 4 - Employee Discount				
Residential Service				
Transmission & Ancillary Services Charge				
per kWh	18,855,991	18,855,991	18,481,059	kWh
Distribution Charge				
Basic Charge, per month	14,088	14,088	14,361	bill
Three Phase Demand Charge, per kW demand	84	84	82	kW
Three Phase Minimum Demand Charge, per month	12	12	12	bill
Distribution Energy Charge, per kWh	18,855,991	18,855,991	18,481,059	kWh
Energy Charge				
Schedule 200				
First Block kWh	6,851,337	6,851,337	6,715,105	kWh
Second Block kWh	5,297,997	5,297,997	5,192,652	kWh
Third Block kWh	6,706,657	6,706,657	6,573,302	kWh
Schedule 201				
First Block kWh	6,851,337	6,851,337	6,715,105	kWh
Second Block kWh	5,297,997	5,297,997	5,192,652	kWh
Third Block kWh	6,706,657	6,706,657	6,573,302	kWh
Subtotal	18,855,991	18,855,991	18,481,059	kWh
Renewable Adjustment Clause, per kWh	18,855,991	18,855,991	18,481,059	kWh
Klamath Rate Reconciliation Surcharge, per kWh	18,855,991	18,855,991	18,481,059	kWh
Total	18,855,991	18,855,991	18,481,059	kWh
Total Employee Discount				
Schedule No. 23/723 - Composite				
General Service (Secondary)				
Transmission & Ancillary Services Charge				
per kWh	1,148,538,615	1,132,989,499	1,012,788,782	kWh
Distribution Charge				
Basic Charge				
Single Phase, per month	702,472	702,472	695,056	bill
Three Phase, per month	195,431	195,431	193,187	bill
Load Size Charge				
≤ 15 kW				kW
per kW for all kW in excess of 15 kW	857,804	857,804	767,514	kW
Demand Charge, the first 15 kW of demand				kW
Demand Charge, per kW for all kW in excess of 15 kW	469,225	469,225	419,716	kW
Reactive Power Charge, per kvar	60,146	60,146	54,155	kvar
Distribution Energy Charge, per kWh	1,148,538,615	1,132,989,499	1,012,788,782	kWh
Energy Charge				
Schedule 200				
1st 3,000 kWh, per kWh	883,222,383	871,259,383	778,802,018	kWh
All additional kWh, per kWh	265,316,232	261,730,116	233,986,764	kWh
Schedule 201				
1st 3,000 kWh, per kWh	883,222,383	871,259,383	778,802,018	kWh
All additional kWh, per kWh	265,316,232	261,730,116	233,986,764	kWh
Subtotal	1,148,538,615	1,132,989,499	1,012,788,782	kWh
Renewable Adjustment Clause, per kWh	1,148,538,615	1,132,989,499	1,012,788,782	kWh

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Klamath Rate Reconciliation Surcharge, per kWh	1,148,538,615	1,132,989,499	1,012,788,782	kWh
Total	1,148,538,615	1,132,989,499	1,012,788,782	kWh
Schedule No. 23/723 - Commercial General Service (Secondary)				
Transmission & Ancillary Services Charge				
per kWh	1,125,102,211	1,109,553,095	990,156,219	kWh
Distribution Charge				
Basic Charge				
Single Phase, per month	695,790	695,790	688,637	bill
Three Phase, per month	187,334	187,334	185,409	bill
Load Size Charge				
≤ 15 kW				kW
per kW for all kW in excess of 15 kW	830,300	830,300	740,953	kW
Demand Charge, the first 15 kW of demand				kW
Demand Charge, per kW for all kW in excess of 15 kW	455,809	455,809	406,760	kW
Reactive Power Charge, per kvar	53,579	53,579	47,813	kvar
Distribution Energy Charge, per kWh	1,125,102,211	1,109,553,095	990,156,219	kWh
Energy Charge				
Schedule 200				
1st 3,000 kWh, per kWh	865,527,705	853,564,705	761,714,247	kWh
All additional kWh, per kWh	259,574,506	255,988,390	228,441,972	kWh
Schedule 201				
1st 3,000 kWh, per kWh	865,527,705	853,564,705	761,714,247	kWh
All additional kWh, per kWh	259,574,506	255,988,390	228,441,972	kWh
Subtotal	1,125,102,211	1,109,553,095	990,156,219	kWh
Renewable Adjustment Clause, per kWh	1,125,102,211	1,109,553,095	990,156,219	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,125,102,211	1,109,553,095	990,156,219	kWh
Total	1,125,102,211	1,109,553,095	990,156,219	kWh
Schedule No. 23/723 - Industrial General Service (Secondary)				
Transmission & Ancillary Services Charge				
per kWh	23,436,404	23,436,404	22,632,563	kWh
Distribution Charge				
Basic Charge				
Single Phase, per month	6,682	6,682	6,419	bill
Three Phase, per month	8,097	8,097	7,778	bill
Load Size Charge				
≤ 15 kW				kW
per kW for all kW in excess of 15 kW	27,504	27,504	26,561	kW
Demand Charge, the first 15 kW of demand				kW
Demand Charge, per kW for all kW in excess of 15 kW	13,416	13,416	12,956	kW
Reactive Power Charge, per kvar	6,567	6,567	6,342	kvar
Distribution Energy Charge, per kWh	23,436,404	23,436,404	22,632,563	kWh
Energy Charge				
Schedule 200				
1st 3,000 kWh, per kWh	17,694,678	17,694,678	17,087,771	kWh
All additional kWh, per kWh	5,741,726	5,741,726	5,544,792	kWh
Schedule 201				
1st 3,000 kWh, per kWh	17,694,678	17,694,678	17,087,771	kWh
All additional kWh, per kWh	5,741,726	5,741,726	5,544,792	kWh
Subtotal	23,436,404	23,436,404	22,632,563	kWh
Renewable Adjustment Clause, per kWh	23,436,404	23,436,404	22,632,563	kWh
Klamath Rate Reconciliation Surcharge, per kWh	23,436,404	23,436,404	22,632,563	kWh
Total	23,436,404	23,436,404	22,632,563	kWh
Schedule No. 23/723 - Composite General Service (Primary)				
Transmission & Ancillary Services Charge				
per kWh	1,278,403	1,278,403	1,151,715	kWh
Distribution Charge				
Basic Charge				
Single Phase, per month	230	230	228	bill
Three Phase, per month	182	182	190	bill
Load Size Charge				
≤ 15 kW				kW

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
per kW for all kW in excess of 15 kW	3,269	3,269	2,989	kW
Demand Charge, the first 15 kW of demand				kW
Demand Charge, per kW for all kW in excess of 15 kW	2,691	2,691	2,440	kW
Reactive Power Charge, per kvar	4,248	4,248	3,872	kvar
Distribution Energy Charge, per kWh	1,278,403	1,278,403	1,151,715	kWh
Energy Charge				
Schedule 200				
1st 3,000 kWh, per kWh	594,365	594,365	535,677	kWh
All additional kWh, per kWh	684,038	684,038	616,038	kWh
Schedule 201				
1st 3,000 kWh, per kWh	594,365	594,365	535,677	kWh
All additional kWh, per kWh	684,038	684,038	616,038	kWh
Subtotal	1,278,403	1,278,403	1,151,715	kWh
Renewable Adjustment Clause, per kWh	1,278,403	1,278,403	1,151,715	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,278,403	1,278,403	1,151,715	kWh
Total	1,278,403	1,278,403	1,151,715	kWh
Schedule No. 23/723 - Commercial General Service (Primary)				
Transmission & Ancillary Services Charge				
per kWh	1,130,002	1,130,002	1,008,404	kWh
Distribution Charge				
Basic Charge				
Single Phase, per month	230	230	228	bill
Three Phase, per month	131	131	129	bill
Load Size Charge				
≤ 15 kW				kW
per kW for all kW in excess of 15 kW	2,285	2,285	2,039	kW
Demand Charge, the first 15 kW of demand				kW
Demand Charge, per kW for all kW in excess of 15 kW	2,162	2,162	1,929	kW
Reactive Power Charge, per kvar	3,139	3,139	2,801	kvar
Distribution Energy Charge, per kWh	1,130,002	1,130,002	1,008,404	kWh
Energy Charge				
Schedule 200				
1st 3,000 kWh, per kWh	522,465	522,465	466,243	kWh
All additional kWh, per kWh	607,537	607,537	542,161	kWh
Schedule 201				
1st 3,000 kWh, per kWh	522,465	522,465	466,243	kWh
All additional kWh, per kWh	607,537	607,537	542,161	kWh
Subtotal	1,130,002	1,130,002	1,008,404	kWh
Renewable Adjustment Clause, per kWh	1,130,002	1,130,002	1,008,404	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,130,002	1,130,002	1,008,404	kWh
Total	1,130,002	1,130,002	1,008,404	kWh
Schedule No. 23/723 - Industrial General Service (Primary)				
Transmission & Ancillary Services Charge				
per kWh	148,401	148,401	143,311	kWh
Distribution Charge				
Basic Charge				
Single Phase, per month	0	0	0	bill
Three Phase, per month	51	51	61	bill
Load Size Charge				
≤ 15 kW				kW
per kW for all kW in excess of 15 kW	984	984	950	kW
Demand Charge, the first 15 kW of demand				kW
Demand Charge, per kW for all kW in excess of 15 kW	529	529	511	kW
Reactive Power Charge, per kvar	1,109	1,109	1,071	kvar
Distribution Energy Charge, per kWh	148,401	148,401	143,311	kWh
Energy Charge				
Schedule 200				
1st 3,000 kWh, per kWh	71,900	71,900	69,434	kWh
All additional kWh, per kWh	76,501	76,501	73,877	kWh
Schedule 201				
1st 3,000 kWh, per kWh	71,900	71,900	69,434	kWh
All additional kWh, per kWh	76,501	76,501	73,877	kWh
Subtotal	148,401	148,401	143,311	kWh
Renewable Adjustment Clause, per kWh	148,401	148,401	143,311	kWh
Klamath Rate Reconciliation Surcharge, per kWh	148,401	148,401	143,311	kWh
Total	148,401	148,401	143,311	kWh

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Schedule No. 28/728 - Composite				
Large General Service - (Secondary)				
Transmission & Ancillary Services Charge				
per kW	6,836,337	6,836,337	6,689,074	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, per month	55,160	55,160	55,594	bill
Load Size 51-100 kW, per month	41,321	41,321	41,613	bill
Load Size 101-300 kW, per month	22,846	22,846	22,978	bill
Load Size > 300 kW, per month	422	422	422	bill
Load Size Charge				
≤ 50 kW	2,103,426	2,103,426	2,060,865	kW
51-100 kW, per kW	2,881,811	2,881,811	2,821,071	kW
101-300 kW, per kW	3,417,193	3,417,193	3,340,661	kW
>300 kW, per kW	188,751	188,751	183,259	kW
Demand Charge, per kW	6,836,337	6,836,337	6,689,074	kW
Reactive Power Charge, per kvar	579,707	579,707	562,858	kvar
Distribution Energy Charge, per kWh	2,070,090,171	2,070,090,171	2,026,816,182	kWh
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	1,463,921,462	1,463,921,462	1,433,359,115	kWh
All additional kWh, per kWh	606,168,709	606,168,709	593,457,067	kWh
Schedule 201				
1st 20,000 kWh, per kWh	1,463,921,462	1,463,921,462	1,433,359,115	kWh
All additional kWh, per kWh	606,168,709	606,168,709	593,457,067	kWh
Subtotal	2,070,090,171	2,070,090,171	2,026,816,182	kWh
Renewable Adjustment Clause, per kWh	2,070,090,171	2,070,090,171	2,026,816,182	kWh
Klamath Rate Reconciliation Surcharge, per kWh	2,070,090,171	2,070,090,171	2,026,816,182	kWh
Total	2,070,090,171	2,070,090,171	2,026,816,182	kWh
Schedule No. 28/728 - Commercial				
Large General Service - (Secondary)				
Transmission & Ancillary Services Charge				
per kW	6,377,111	6,377,111	6,259,491	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, per month	53,089	53,089	53,595	bill
Load Size 51-100 kW, per month	38,998	38,998	39,370	bill
Load Size 101-300 kW, per month	20,917	20,917	21,116	bill
Load Size > 300 kW, per month	342	342	345	bill
Load Size Charge				
≤ 50 kW	2,021,765	2,021,765	1,984,475	kW
51-100 kW, per kW	2,717,243	2,717,243	2,667,126	kW
101-300 kW, per kW	3,124,291	3,124,291	3,066,666	kW
>300 kW, per kW	145,147	145,147	142,470	kW
Demand Charge, per kW	6,377,111	6,377,111	6,259,491	kW
Reactive Power Charge, per kvar	446,188	446,188	437,958	kvar
Distribution Energy Charge, per kWh	1,959,628,234	1,959,628,234	1,923,484,654	kWh
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	1,386,673,899	1,386,673,899	1,361,097,946	kWh
All additional kWh, per kWh	572,954,335	572,954,335	562,386,708	kWh
Schedule 201				
1st 20,000 kWh, per kWh	1,386,673,899	1,386,673,899	1,361,097,946	kWh
All additional kWh, per kWh	572,954,335	572,954,335	562,386,708	kWh
Subtotal	1,959,628,234	1,959,628,234	1,923,484,654	kWh
Renewable Adjustment Clause, per kWh	1,959,628,234	1,959,628,234	1,923,484,654	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,959,628,234	1,959,628,234	1,923,484,654	kWh
Total	1,959,628,234	1,959,628,234	1,923,484,654	kWh
Schedule No. 28/728 - Industrial				
Large General Service - (Secondary)				
Transmission & Ancillary Services Charge				
per kW	459,226	459,226	429,583	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, per month	2,071	2,071	1,999	bill

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Load Size 51-100 kW, per month	2,323	2,323	2,243	bill
Load Size 101-300 kW, per month	1,929	1,929	1,862	bill
Load Size > 300 kW, per month	80	80	77	bill
Load Size Charge				
≤ 50 kW	81,661	81,661	76,390	kW
51-100 kW, per kW	164,568	164,568	153,945	kW
101-300 kW, per kW	292,902	292,902	273,995	kW
>300 kW, per kW	43,604	43,604	40,789	kW
Demand Charge, per kW	459,226	459,226	429,583	kW
Reactive Power Charge, per kvar	133,519	133,519	124,900	kvar
Distribution Energy Charge, per kWh	110,461,937	110,461,937	103,331,528	kWh
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	77,247,563	77,247,563	72,261,169	kWh
All additional kWh, per kWh	33,214,374	33,214,374	31,070,359	kWh
Schedule 201				
1st 20,000 kWh, per kWh	77,247,563	77,247,563	72,261,169	kWh
All additional kWh, per kWh	33,214,374	33,214,374	31,070,359	kWh
Subtotal	110,461,937	110,461,937	103,331,528	kWh
Renewable Adjustment Clause, per kWh	110,461,937	110,461,937	103,331,528	kWh
Klamath Rate Reconciliation Surcharge, per kWh	110,461,937	110,461,937	103,331,528	kWh
Total	110,461,937	110,461,937	103,331,528	kWh
Schedule No. 28/728 - Composite				
Large General Service - (Primary)				
Transmission & Ancillary Services Charge				
per kW	62,814	62,814	60,958	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, per month	58	58	59	bill
Load Size 51-100 kW, per month	175	175	174	bill
Load Size 101-300 kW, per month	358	358	356	bill
Load Size > 300 kW, per month	14	14	14	bill
Load Size Charge				
≤ 50 kW	2,196	2,196	2,153	kW
51-100 kW, per kW	12,837	12,837	12,408	kW
101-300 kW, per kW	60,527	60,527	58,741	kW
>300 kW, per kW	6,850	6,850	6,724	kW
Demand Charge, per kW	62,814	62,814	60,958	kW
Reactive Power Charge, per kvar	35,548	35,548	34,625	kvar
Distribution Energy Charge, per kWh	18,797,884	18,797,884	18,249,203	kWh
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	9,802,616	9,802,616	9,486,985	kWh
All additional kWh, per kWh	8,995,268	8,995,268	8,762,218	kWh
Schedule 201				
1st 20,000 kWh, per kWh	9,802,616	9,802,616	9,486,985	kWh
All additional kWh, per kWh	8,995,268	8,995,268	8,762,218	kWh
Subtotal	18,797,884	18,797,884	18,249,203	kWh
Renewable Adjustment Clause, per kWh	18,797,884	18,797,884	18,249,203	kWh
Klamath Rate Reconciliation Surcharge, per kWh	18,797,884	18,797,884	18,249,203	kWh
Total	18,797,884	18,797,884	18,249,203	kWh
Schedule No. 28/728 - Commercial				
Large General Service - (Primary)				
Transmission & Ancillary Services Charge				
per kW	47,683	47,683	46,804	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, per month	57	57	58	bill
Load Size 51-100 kW, per month	120	120	121	bill
Load Size 101-300 kW, per month	250	250	252	bill
Load Size > 300 kW, per month	14	14	14	bill
Load Size Charge				
≤ 50 kW	2,146	2,146	2,106	kW
51-100 kW, per kW	8,675	8,675	8,515	kW
101-300 kW, per kW	45,991	45,991	45,143	kW
>300 kW, per kW	6,850	6,850	6,724	kW
Demand Charge, per kW	47,683	47,683	46,804	kW
Reactive Power Charge, per kvar	29,733	29,733	29,185	kvar
Distribution Energy Charge, per kWh	14,417,384	14,417,384	14,151,468	kWh

PACIFIC POWER & LIGHT COMPANY
State of Oregon
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Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	6,878,296	6,878,296	6,751,432	kWh
All additional kWh, per kWh	7,539,088	7,539,088	7,400,036	kWh
Schedule 201				
1st 20,000 kWh, per kWh	6,878,296	6,878,296	6,751,432	kWh
All additional kWh, per kWh	7,539,088	7,539,088	7,400,036	kWh
Subtotal	14,417,384	14,417,384	14,151,468	kWh
Renewable Adjustment Clause, per kWh	14,417,384	14,417,384	14,151,468	kWh
Klamath Rate Reconciliation Surcharge, per kWh	14,417,384	14,417,384	14,151,468	kWh
Total	14,417,384	14,417,384	14,151,468	kWh
Schedule No. 28/728 - Industrial				
Large General Service - (Primary)				
Transmission & Ancillary Services Charge				
per kW	15,131	15,131	14,154	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, per month	1	1	1	bill
Load Size 51-100 kW, per month	55	55	53	bill
Load Size 101-300 kW, per month	108	108	104	bill
Load Size > 300 kW, per month	0	0	0	bill
Load Size Charge				
≤ 50 kW	50	50	47	kW
51-100 kW, per kW	4,162	4,162	3,893	kW
101-300 kW, per kW	14,536	14,536	13,598	kW
>300 kW, per kW	0	0	0	kW
Demand Charge, per kW	15,131	15,131	14,154	kW
Reactive Power Charge, per kvar	5,815	5,815	5,440	kvar
Distribution Energy Charge, per kWh	4,380,500	4,380,500	4,097,735	kWh
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	2,924,320	2,924,320	2,735,553	kWh
All additional kWh, per kWh	1,456,180	1,456,180	1,362,182	kWh
Schedule 201				
1st 20,000 kWh, per kWh	2,924,320	2,924,320	2,735,553	kWh
All additional kWh, per kWh	1,456,180	1,456,180	1,362,182	kWh
Subtotal	4,380,500	4,380,500	4,097,735	kWh
Renewable Adjustment Clause, per kWh	4,380,500	4,380,500	4,097,735	kWh
Klamath Rate Reconciliation Surcharge, per kWh	4,380,500	4,380,500	4,097,735	kWh
Total	4,380,500	4,380,500	4,097,735	kWh
Schedule No. 30/730 - Composite				
Large General Service - (Secondary)				
Transmission & Ancillary Services Charge				
per kW	3,595,762	3,595,762	3,534,295	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 200 kW, per month	162	162	155	bill
Load Size 201-300 kW, per month	2,838	2,838	2,716	bill
Load Size > 300 kW, per month	7,035	7,035	6,740	bill
Load Size Charge				
≤ 200 kW	14,976	14,976	14,627	kW
201-300 kW, per kW	728,118	728,118	714,392	kW
>300 kW, per kW	3,470,928	3,470,928	3,411,992	kW
Demand Charge, per kW	3,595,762	3,595,762	3,534,295	kW
Reactive Power Charge, per kvar	721,399	721,399	713,631	kvar
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	194,371,807	194,371,807	190,869,386	kWh
All additional kWh, per kWh	1,115,243,559	1,115,243,559	1,093,845,348	kWh
Schedule 201				
1st 20,000 kWh, per kWh	194,371,807	194,371,807	190,869,386	kWh
All additional kWh, per kWh	1,115,243,559	1,115,243,559	1,093,845,348	kWh
Subtotal	1,309,615,366	1,309,615,366	1,284,714,734	kWh
Renewable Adjustment Clause, per kWh	1,309,615,366	1,309,615,366	1,284,714,734	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,309,615,366	1,309,615,366	1,284,714,734	kWh
Total	1,309,615,366	1,309,615,366	1,284,714,734	kWh

Schedule No. 30/730- Commercial

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Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Large General Service - (Secondary)				
Transmission & Ancillary Services Charge				
per kW	2,749,827	2,749,827	2,681,366	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 200 kW, per month	144	144	137	bill
Load Size 201-300 kW, per month	2,317	2,317	2,205	bill
Load Size > 300 kW, per month	5,469	5,469	5,204	bill
Load Size Charge				
≤ 200 kW	14,249	14,249	13,894	kW
201-300 kW, per kW	595,377	595,377	580,554	kW
>300 kW, per kW	2,642,390	2,642,390	2,576,604	kW
Demand Charge, per kW	2,749,827	2,749,827	2,681,366	kW
Reactive Power Charge, per kvar	414,090	414,090	403,781	kvar
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	154,065,213	154,065,213	150,229,560	kWh
All additional kWh, per kWh	923,249,926	923,249,926	900,264,423	kWh
Schedule 201				
1st 20,000 kWh, per kWh	154,065,213	154,065,213	150,229,560	kWh
All additional kWh, per kWh	923,249,926	923,249,926	900,264,423	kWh
Subtotal	1,077,315,139	1,077,315,139	1,050,493,983	kWh
Renewable Adjustment Clause, per kWh	1,077,315,139	1,077,315,139	1,050,493,983	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,077,315,139	1,077,315,139	1,050,493,983	kWh
Total	1,077,315,139	1,077,315,139	1,050,493,983	kWh
Schedule No. 30/730 - Industrial				
Large General Service - (Secondary)				
Transmission & Ancillary Services Charge				
per kW	845,935	845,935	852,929	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 200 kW, per month	18	18	18	bill
Load Size 201-300 kW, per month	521	521	511	bill
Load Size > 300 kW, per month	1,566	1,566	1,535	bill
Load Size Charge				
≤ 200 kW	727	727	733	kW
201-300 kW, per kW	132,741	132,741	133,838	kW
>300 kW, per kW	828,538	828,538	835,388	kW
Demand Charge, per kW	845,935	845,935	852,929	kW
Reactive Power Charge, per kvar	307,309	307,309	309,850	kvar
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	40,306,594	40,306,594	40,639,826	kWh
All additional kWh, per kWh	191,993,633	191,993,633	193,580,925	kWh
Schedule 201				
1st 20,000 kWh, per kWh	40,306,594	40,306,594	40,639,826	kWh
All additional kWh, per kWh	191,993,633	191,993,633	193,580,925	kWh
Subtotal	232,300,227	232,300,227	234,220,751	kWh
Renewable Adjustment Clause, per kWh	232,300,227	232,300,227	234,220,751	kWh
Klamath Rate Reconciliation Surcharge, per kWh	232,300,227	232,300,227	234,220,751	kWh
Total	232,300,227	232,300,227	234,220,751	kWh
Schedule No. 30/730 - Composite				
Large General Service - (Primary)				
Transmission & Ancillary Services Charge				
per kW	285,266	285,266	279,833	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 200 kW, per month	0	0	0	bill
Load Size 201-300 kW, per month	111	111	106	bill
Load Size > 300 kW, per month	544	544	520	bill
Load Size Charge				
≤ 200 kW	0	0	0	kW
201-300 kW, per kW	28,251	28,251	27,640	kW
>300 kW, per kW	320,444	320,444	314,299	kW
Demand Charge, per kW	285,266	285,266	279,833	kW
Reactive Power Charge, per kvar	35,398	35,398	35,084	kvar
Energy Charge				
Schedule 200				

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Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
1st 20,000 kWh, per kWh	12,726,101	12,726,101	12,465,248	kWh
All additional kWh, per kWh	83,286,870	83,286,870	81,466,178	kWh
Schedule 201				
1st 20,000 kWh, per kWh	12,726,101	12,726,101	12,465,248	kWh
All additional kWh, per kWh	83,286,870	83,286,870	81,466,178	kWh
Subtotal	96,012,971	96,012,971	93,931,426	kWh
Renewable Adjustment Clause, per kWh	96,012,971	96,012,971	93,931,426	kWh
Klamath Rate Reconciliation Surcharge, per kWh	96,012,971	96,012,971	93,931,426	kWh
Total	96,012,971	96,012,971	93,931,426	kWh
Schedule No. 30/730 - Commercial				
Large General Service - (Primary)				
Transmission & Ancillary Services Charge				
per kW	234,929	234,929	229,080	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 200 kW, per month	0	0	0	bill
Load Size 201-300 kW, per month	99	99	94	bill
Load Size > 300 kW, per month	460	460	438	bill
Load Size Charge				
≤ 200 kW	0	0	0	kW
201-300 kW, per kW	25,473	25,473	24,839	kW
>300 kW, per kW	265,197	265,197	258,595	kW
Demand Charge, per kW	234,929	234,929	229,080	kW
Reactive Power Charge, per kvar	18,295	18,295	17,840	kvar
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	11,038,101	11,038,101	10,763,293	kWh
All additional kWh, per kWh	75,662,830	75,662,830	73,779,106	kWh
Schedule 201				
1st 20,000 kWh, per kWh	11,038,101	11,038,101	10,763,293	kWh
All additional kWh, per kWh	75,662,830	75,662,830	73,779,106	kWh
Subtotal	86,700,931	86,700,931	84,542,399	kWh
Renewable Adjustment Clause, per kWh	86,700,931	86,700,931	84,542,399	kWh
Klamath Rate Reconciliation Surcharge, per kWh	86,700,931	86,700,931	84,542,399	kWh
Total	86,700,931	86,700,931	84,542,399	kWh
Schedule No. 30/730 - Industrial				
Large General Service - (Primary)				
Transmission & Ancillary Services Charge				
per kW	50,337	50,337	50,753	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 200 kW, per month	0	0	0	bill
Load Size 201-300 kW, per month	12	12	12	bill
Load Size > 300 kW, per month	84	84	82	bill
Load Size Charge				
≤ 200 kW	0	0	0	kW
201-300 kW, per kW	2,778	2,778	2,801	kW
>300 kW, per kW	55,247	55,247	55,704	kW
Demand Charge, per kW	50,337	50,337	50,753	kW
Reactive Power Charge, per kvar	17,103	17,103	17,244	kvar
Energy Charge				
Schedule 200				
1st 20,000 kWh, per kWh	1,688,000	1,688,000	1,701,955	kWh
All additional kWh, per kWh	7,624,040	7,624,040	7,687,072	kWh
Schedule 201				
1st 20,000 kWh, per kWh	1,688,000	1,688,000	1,701,955	kWh
All additional kWh, per kWh	7,624,040	7,624,040	7,687,072	kWh
Subtotal	9,312,040	9,312,040	9,389,027	kWh
Renewable Adjustment Clause, per kWh	9,312,040	9,312,040	9,389,027	kWh
Klamath Rate Reconciliation Surcharge, per kWh	9,312,040	9,312,040	9,389,027	kWh
Total	9,312,040	9,312,040	9,389,027	kWh
Schedule No. 33				
Klamath Irrigation and Drainage Pumping				
Total Customers	2,187	2,187	2,062	
Monthly Bills	9,626			
Charges				
On-Project (Rate Code 40)	55,233,459	55,233,459	62,373,687	kWh

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Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Off-Project (Rate Code 35)	46,118,679	46,118,679	52,080,607	kWh
U.S. Government (Rate Code 33TX)	*3,180,888*	*3,180,888*	*3,592,093*	kWh
U.S. Gov - On Peak	1,273,221	1,273,221	1,437,815	kWh
U.S. Gov - Off Peak	1,907,667	1,907,667	2,154,278	kWh
Minimum Charges On-Project				
Minimum Charges Off-Project				
Subtotal	104,533,026	104,533,026	118,046,387	kWh
Renewable Adjustment Clause, per kWh	104,533,026	104,533,026	118,046,387	kWh
Total	104,533,026	104,533,026	118,046,387	kWh
Note: Rates reflect estimated rate changes through 2010.				
Schedule No. 41/741				
Agricultural Pumping Service (Secondary)				
Transmission & Ancillary Services Charge				
per kWh	128,386,530	128,386,530	134,221,373	kWh
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, or Single Phase Any Size	5,668	5,668	5,637	bill
Three Phase Load Size 51 - 300 kW, per month	456	456	453	bill
Three Phase Load Size > 300 kW, per month	13	13	13	bill
Total Customers	6,137	6,137	6,103	bill
Monthly Bills	34,163			
Load Size Charge				
Single Phase Any Size, Three Phase ≤ 50 kW	71,484	71,484	74,733	kW
Three Phase 51-300 kW, per kW	38,116	38,116	39,848	kW
Three Phase > 300 kW, kW	6,352	6,352	6,641	kW
Single Phase, Minimum Charge	843	843	838	bill
Three Phase, Minimum Charge	1,145	1,145	1,139	bill
Distribution Energy Charge, per kWh	128,386,530	128,386,530	134,221,373	kWh
Reactive Power Charge, per kvar	26,240	26,240	27,433	kvar
Energy Charge				
Schedule 200				
Winter, 1st 100 kWh/kW, per kWh	1,304,389	1,304,389	1,363,670	kWh
Winter, All additional kWh, per kWh	1,402,430	1,402,430	1,466,167	kWh
Summer, All kWh, per kWh	125,679,711	125,679,711	131,391,536	kWh
Schedule 201				
Winter, 1st 100 kWh/kW, per kWh	1,304,389	1,304,389	1,363,670	kWh
Winter, All additional kWh, per kWh	1,402,430	1,402,430	1,466,167	kWh
Summer, All kWh, per kWh	125,679,711	125,679,711	131,391,536	kWh
Subtotal	128,386,530	128,386,530	134,221,373	kWh
Renewable Adjustment Clause, per kWh	128,386,530	128,386,530	134,221,373	kWh
Klamath Rate Reconciliation Surcharge, per kWh	128,386,530	128,386,530	134,221,373	kWh
Total	128,386,530	128,386,530	134,221,373	kWh
Schedule No. 41/741				
Agricultural Pumping Service (Primary)				
Transmission & Ancillary Services Charge				
per kWh	2,458,762	2,458,762	2,570,507	kWh
Distribution Charge				
Basic Charge				
Load Size ≤ 50 kW, or Single Phase Any Size	3	3	3	bill
Three Phase Load Size 51 - 300 kW, per month	0	0	0	bill
Three Phase Load Size > 300 kW, per month	2	2	2	bill
Total Customers	5	5	5	bill
Monthly Bills	36			
Load Size Charge				
Single Phase Any Size, Three Phase ≤ 50 kW	44	44	46	kW
Three Phase 51-300 kW, per kW	0	0	0	kW
Three Phase > 300 kW, kW	2,075	2,075	2,169	kW
Single Phase, Minimum Charge	0	0	0	bill
Three Phase, Minimum Charge	1	1	1	bill
Distribution Energy Charge, per kWh	2,458,762	2,458,762	2,570,507	kWh
Reactive Power Charge, per kvar	2,933	2,933	3,066	kvar
Energy Charge				
Schedule 200				
Winter, 1st 100 kWh/kW, per kWh	10,152	10,152	10,613	kWh
Winter, All additional kWh, per kWh	59,179	59,179	61,869	kWh
Summer, All kWh, per kWh	2,389,431	2,389,431	2,498,025	kWh
Schedule 201				
Winter, 1st 100 kWh/kW, per kWh	10,152	10,152	10,613	kWh
Winter, All additional kWh, per kWh	59,179	59,179	61,869	kWh

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Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Summer, All kWh, per kWh	2,389,431	2,389,431	2,498,025	kWh
Subtotal	2,458,762	2,458,762	2,570,507	kWh
Renewable Adjustment Clause, per kWh	2,458,762	2,458,762	2,570,507	kWh
Klamath Rate Reconciliation Surcharge, per kWh	2,458,762	2,458,762	2,570,507	kWh
Total	2,458,762	2,458,762	2,570,507	kWh
Schedule No. 47/747 - Industrial				
Large General Service - Partial Requirement (Primary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	654,784	654,784	629,550	kW
credit per kW of on-peak demand	0	0	0	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	0	0	0	bill
Load Size > 4,000 kW, per month	36	36	36	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	0	0	0	kW
Load Size > 4,000 kW, per kW	682,277	682,277	655,984	kW
Demand Charge, per kW of on-peak demand	654,784	654,784	629,550	kW
Reactive Power Charge, per kvar	23,861	23,861	22,941	kvar
Reactive Hours, per kvarh	4,246,730	4,246,730	4,083,071	kvarh
Reserves Charges				
Spinning Reserves, per kW of Facility	682,277	682,277	655,984	kW
Supplemental Reserves, per kW of Facility	682,277	682,277	655,984	kW
Spinning Reserves Credit, per kW of Facility	541,575	541,575	520,704	kW
Supplemental Reserves Credit, per kW of Facility	541,575	541,575	520,704	kW
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	241,837,086	241,837,086	232,517,250	kWh
Off-Peak, per off-peak kWh	186,613,881	186,613,881	179,422,218	kWh
Schedule 201				
On-Peak, per on-peak kWh	241,837,086	241,837,086	232,517,250	kWh
Off-Peak, per off-peak kWh	186,613,881	186,613,881	179,422,218	kWh
Unscheduled Energy, per kWh	865,993	865,993	832,620	kWh
Subtotal	429,316,960	429,316,960	412,772,088	kWh
Renewable Adjustment Clause, per kWh	429,316,960	429,316,960	412,772,088	kWh
Klamath Rate Reconciliation Surcharge, per kWh	429,316,960	429,316,960	412,772,088	kWh
Total	429,316,960	429,316,960	412,772,088	kWh
Schedule No. 47/747 - Composite				
Large General Service - Partial Requirement (Transmission)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	293,228	293,228	291,068	kW
credit per kW of on-peak demand	0	0	0	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	24	24	24	bill
Load Size > 4,000 kW, per month	24	24	24	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	31,689	31,689	35,910	kW
Load Size > 4,000 kW, per kW	328,000	328,000	330,471	kW
Demand Charge, per kW of on-peak demand	293,228	293,228	291,068	kW
Reactive Power Charge, per kvar	43,784	43,784	43,402	kvar
Reactive Hours, per kvarh	862,200	862,200	977,033	kvarh
Reserves Charges				
Spinning Reserves, per kW of Facility	359,689	359,689	366,381	kW
Supplemental Reserves, per kW of Facility	359,689	359,689	366,381	kW
Spinning Reserves Credit, per kW of Facility	0	0	0	kW
Supplemental Reserves Credit, per kW of Facility	0	0	0	kW
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	91,858,163	91,858,163	88,587,292	kWh
Off-Peak, per off-peak kWh	66,780,706	66,780,706	64,575,860	kWh
Schedule 201				
On-Peak, per on-peak kWh	91,858,163	91,858,163	88,587,292	kWh
Off-Peak, per off-peak kWh	66,780,706	66,780,706	64,575,860	kWh
Unscheduled Energy, per kWh	6,207,444	6,207,444	6,030,044	kWh
Subtotal	164,846,313	164,846,313	159,193,196	kWh
Renewable Adjustment Clause, per kWh	164,846,313	164,846,313	159,193,196	kWh
Klamath Rate Reconciliation Surcharge, per kWh	164,846,313	164,846,313	159,193,196	kWh
Total	164,846,313	164,846,313	159,193,196	kWh

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Schedule No. 47/747 - Commercial				
Large General Service - Partial Requirement (Transmission)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	53,228	53,228	60,317	kW
credit per kW of on-peak demand				
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	24	24	24	bill
Load Size > 4,000 kW, per month	12	12	12	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	31,689	31,689	35,910	kW
Load Size > 4,000 kW, per kW	88,000	88,000	99,720	kW
Demand Charge, per kW of on-peak demand	53,228	53,228	60,317	kW
Reactive Power Charge, per kvar	7,600	7,600	8,612	kvar
Reactive Hours, per kvarh	862,200	862,200	977,033	kvarh
Reserves Charges				
Spinning Reserves, per kW of Facility	119,689	119,689	135,630	kW
Supplemental Reserves, per kW of Facility	119,689	119,689	135,630	kW
Spinning Reserves Credit, per kW of Facility	0	0	0	kW
Supplemental Reserves Credit, per kW of Facility	0	0	0	kW
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	1,567,213	1,567,213	1,775,944	kWh
Off-Peak, per off-peak kWh	2,147,209	2,147,209	2,433,187	kWh
Schedule 201				
On-Peak, per on-peak kWh	1,567,213	1,567,213	1,775,944	kWh
Off-Peak, per off-peak kWh	2,147,209	2,147,209	2,433,187	kWh
Unscheduled Energy, per kWh	360,000	360,000	407,947	kWh
Subtotal	4,074,422	4,074,422	4,617,077	kWh
Renewable Adjustment Clause, per kWh	4,074,422	4,074,422	4,617,077	kWh
Klamath Rate Reconciliation Surcharge, per kWh	4,074,422	4,074,422	4,617,077	kWh
Total	4,074,422	4,074,422	4,617,077	kWh
Schedule No. 47/747 - Industrial				
Large General Service - Partial Requirement (Transmission)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	240,000	240,000	230,751	kW
credit per kW of on-peak demand	0	0	0	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	0	0	0	bill
Load Size > 4,000 kW, per month	12	12	12	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	0	0	0	kW
Load Size > 4,000 kW, per kW	240,000	240,000	230,751	kW
Demand Charge, per kW of on-peak demand	240,000	240,000	230,751	kW
Reactive Power Charge, per kvar	36,184	36,184	34,790	kvar
Reactive Hours, per kvarh	0	0	0	kvarh
Reserves Charges				
Spinning Reserves, per kW of Facility	240,000	240,000	230,751	kW
Supplemental Reserves, per kW of Facility	240,000	240,000	230,751	kW
Spinning Reserves Credit, per kW of Facility	0	0	0	kW
Supplemental Reserves Credit, per kW of Facility	0	0	0	kW
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	90,290,950	90,290,950	86,811,348	kWh
Off-Peak, per off-peak kWh	64,633,497	64,633,497	62,142,673	kWh
Schedule 201				
On-Peak, per on-peak kWh	90,290,950	90,290,950	86,811,348	kWh
Off-Peak, per off-peak kWh	64,633,497	64,633,497	62,142,673	kWh
Unscheduled Energy, per kWh	5,847,444	5,847,444	5,622,097	kWh
Subtotal	160,771,891	160,771,891	154,576,118	kWh
Renewable Adjustment Clause, per kWh	160,771,891	160,771,891	154,576,118	kWh
Klamath Rate Reconciliation Surcharge, per kWh	160,771,891	160,771,891	154,576,118	kWh
Total	160,771,891	160,771,891	154,576,118	kWh

Schedule No. 76R/776R
Large General Service/Partial Requirements Service - Economic Replacement Power Rider

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand				
Secondary	0	0	0	kW
Primary	0	0	0	kW
Transmission	0	0	0	kW
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand				
Secondary	0	0	0	kW
Primary	0	0	0	kW
Transmission	0	0	0	kW
Schedule No. 48/748 - Composite				
Large General Service (Secondary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	1,837,744	1,837,744	1,680,446	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	1,489	1,489	1,466	bill
Load Size > 4,000 kW, per month	12	12	12	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	2,114,534	2,114,534	1,931,585	kW
Load Size > 4,000 kW, per kW	139,476	139,476	130,868	kW
Demand Charge, per kW of on-peak demand	1,837,744	1,837,744	1,680,446	kW
Reactive Power Charge, per kvar	538,768	538,768	486,931	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	453,657,975	453,657,975	415,357,613	kWh
Off-Peak, per off-peak kWh	255,084,614	255,084,614	233,733,537	kWh
Schedule 201				
On-Peak, per on-peak kWh	453,657,975	453,657,975	415,357,613	kWh
Off-Peak, per off-peak kWh	255,084,614	255,084,614	233,733,537	kWh
Subtotal	708,742,589	708,742,589	649,091,150	kWh
Renewable Adjustment Clause, per kWh	708,742,589	708,742,589	649,091,150	kWh
Klamath Rate Reconciliation Surcharge, per kWh	708,742,589	708,742,589	649,091,150	kWh
Total	708,742,589	708,742,589	649,091,150	kWh
Schedule No. 48/748 - Commercial				
Large General Service (Secondary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	904,929	904,929	849,080	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	689	689	687	bill
Load Size > 4,000 kW, per month	12	12	12	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	999,562	999,562	937,872	kW
Load Size > 4,000 kW, per kW	139,476	139,476	130,868	kW
Demand Charge, per kW of On-Peak demand	904,929	904,929	849,080	kW
Reactive Power Charge, per kvar	143,650	143,650	134,784	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	234,646,175	234,646,175	220,164,527	kWh
Off-Peak, per off-peak kWh	135,862,293	135,862,293	127,477,286	kWh
Schedule 201				
On-Peak, per on-peak kWh	234,646,175	234,646,175	220,164,527	kWh
Off-Peak, per off-peak kWh	135,862,293	135,862,293	127,477,286	kWh
Subtotal	370,508,468	370,508,468	347,641,813	kWh
Renewable Adjustment Clause, per kWh	370,508,468	370,508,468	347,641,813	kWh
Klamath Rate Reconciliation Surcharge, per kWh	370,508,468	370,508,468	347,641,813	kWh
Total	370,508,468	370,508,468	347,641,813	kWh
Schedule No. 48/748 - Industrial				
Large General Service (Secondary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	932,815	932,815	831,366	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	800	800	779	bill
Load Size > 4,000 kW, per month	0	0	0	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	1,114,972	1,114,972	993,713	kW

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Load Size > 4,000 kW, per kW	0	0	0	kW
Demand Charge, per kW of on-peak demand	932,815	932,815	831,366	kW
Reactive Power Charge, per kvar	395,118	395,118	352,147	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	219,011,800	219,011,800	195,193,086	kWh
Off-Peak, per off-peak kWh	119,222,321	119,222,321	106,256,251	kWh
Schedule 201				
On-Peak, per on-peak kWh	219,011,800	219,011,800	195,193,086	kWh
Off-Peak, per off-peak kWh	119,222,321	119,222,321	106,256,251	kWh
Subtotal	338,234,121	338,234,121	301,449,337	kWh
Renewable Adjustment Clause, per kWh	338,234,121	338,234,121	301,449,337	kWh
Klamath Rate Reconciliation Surcharge, per kWh	338,234,121	338,234,121	301,449,337	kWh
Total	338,234,121	338,234,121	301,449,337	kWh
Schedule No. 48/748 - Composite				
Large General Service (Primary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	3,824,236	3,824,236	3,454,326	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	682	682	673	bill
Load Size > 4,000 kW, per month	408	408	400	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	1,298,929	1,298,929	1,185,743	kW
Load Size > 4,000 kW, per kW	3,173,748	3,173,748	2,859,392	kW
Demand Charge, per kW of on-peak demand	3,824,236	3,824,236	3,454,326	kW
Reactive Power Charge, per kvar	891,427	891,427	800,170	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	1,065,724,850	1,065,724,850	962,377,337	kWh
Off-Peak, per off-peak kWh	695,040,800	695,040,800	627,543,923	kWh
Schedule 201				
On-Peak, per on-peak kWh	1,065,724,850	1,065,724,850	962,377,337	kWh
Off-Peak, per off-peak kWh	695,040,800	695,040,800	627,543,923	kWh
Subtotal	1,760,765,650	1,760,765,650	1,589,921,260	kWh
Renewable Adjustment Clause, per kWh	1,760,765,650	1,760,765,650	1,589,921,260	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,760,765,650	1,760,765,650	1,589,921,260	kWh
Total	1,760,765,650	1,760,765,650	1,589,921,260	kWh
Schedule No. 48/748 - Commercial				
Large General Service (Primary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	977,826	977,826	917,478	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	370	370	369	bill
Load Size > 4,000 kW, per month	84	84	84	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	596,938	596,938	560,097	kW
Load Size > 4,000 kW, per kW	654,924	654,924	614,504	kW
Demand Charge, per kW of on-peak demand	977,826	977,826	917,478	kW
Reactive Power Charge, per kvar	120,977	120,977	113,511	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	266,926,600	266,926,600	250,452,703	kWh
Off-Peak, per off-peak kWh	172,041,400	172,041,400	161,423,528	kWh
Schedule 201				
On-Peak, per on-peak kWh	266,926,600	266,926,600	250,452,703	kWh
Off-Peak, per off-peak kWh	172,041,400	172,041,400	161,423,528	kWh
Subtotal	438,968,000	438,968,000	411,876,231	kWh
Renewable Adjustment Clause, per kWh	438,968,000	438,968,000	411,876,231	kWh
Klamath Rate Reconciliation Surcharge, per kWh	438,968,000	438,968,000	411,876,231	kWh
Total	438,968,000	438,968,000	411,876,231	kWh
Schedule No. 48/748 - Industrial				
Large General Service (Primary)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	2,846,410	2,846,410	2,536,848	kW

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	312	312	304	bill
Load Size > 4,000 kW, per month	324	324	316	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	701,991	701,991	625,646	kW
Load Size > 4,000 kW, per kW	2,518,824	2,518,824	2,244,888	kW
Demand Charge, per kW of on-peak demand	2,846,410	2,846,410	2,536,848	kW
Reactive Power Charge, per kvar	770,450	770,450	686,659	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	798,798,250	798,798,250	711,924,634	kWh
Off-Peak, per off-peak kWh	522,999,400	522,999,400	466,120,395	kWh
Schedule 201				
On-Peak, per on-peak kWh	798,798,250	798,798,250	711,924,634	kWh
Off-Peak, per off-peak kWh	522,999,400	522,999,400	466,120,395	kWh
Subtotal	1,321,797,650	1,321,797,650	1,178,045,029	kWh
Renewable Adjustment Clause, per kWh	1,321,797,650	1,321,797,650	1,178,045,029	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,321,797,650	1,321,797,650	1,178,045,029	kWh
Total	1,321,797,650	1,321,797,650	1,178,045,029	kWh
Schedule No. 48/748 - Industrial				
Large General Service (Transmission)				
Transmission & Ancillary Services Charge				
per kW of on-peak demand	695,089	695,089	619,494	kW
Distribution Charge				
Basic Charge				
Load Size ≤ 4,000 kW, per month	0	0	0	bill
Load Size > 4,000 kW, per month	24	24	23	bill
Load Size/Facility Charge				
Load Size ≤ 4,000 kW, per kW	0	0	0	kW
Load Size > 4,000 kW, per kW	845,056	845,056	753,152	kW
Demand Charge, per kW of on-peak demand	695,089	695,089	619,494	kW
Reactive Power Charge, per kvar	142,703	142,703	127,183	kvar
Energy Charge				
Schedule 200				
On-Peak, per on-peak kWh	254,592,000	254,592,000	226,903,748	kWh
Off-Peak, per off-peak kWh	199,704,000	199,704,000	177,985,113	kWh
Schedule 201				
On-Peak, per on-peak kWh	254,592,000	254,592,000	226,903,748	kWh
Off-Peak, per off-peak kWh	199,704,000	199,704,000	177,985,113	kWh
Subtotal	454,296,000	454,296,000	404,888,861	kWh
Renewable Adjustment Clause, per kWh	454,296,000	454,296,000	404,888,861	kWh
Klamath Rate Reconciliation Surcharge, per kWh	454,296,000	454,296,000	404,888,861	kWh
Total	454,296,000	454,296,000	404,888,861	kWh
Schedule No. 15 - Composite				
Outdoor Area Lighting Service				
No. of Customers	7,620	7,620	7,404	
Transmission & Ancillary Services Charge				
per kWh	11,114,728	11,114,728	10,467,219	kWh
Distribution Charge				
Distribution Charge, per kWh	11,114,728	11,114,728	10,467,219	kWh
Energy Charge				
Sch 200, per kWh	11,114,728	11,114,728	10,467,219	kWh
Sch 201 TAM, per kWh	11,114,728	11,114,728	10,467,219	kWh
Subtotal	11,114,728	11,114,728	10,467,219	kWh
Renewable Adjustment Clause, per kWh	11,114,728	11,114,728	10,467,219	kWh
Klamath Rate Reconciliation Surcharge, per kWh	11,114,728	11,114,728	10,467,219	kWh
Total	11,114,728	11,114,728	10,467,219	kWh
Schedule No. 15 - Residential				
Outdoor Area Lighting Service				
No. of Customers	3,054	3,054	2,999	
Transmission & Ancillary Services Charge				
per kWh	2,735,890	2,735,890	2,774,367	kWh
Distribution Charge				
Distribution Charge, per kWh	2,735,890	2,735,890	2,774,367	kWh
Energy Charge				
Sch 200, per kWh	2,735,890	2,735,890	2,774,367	kWh
Sch 201 TAM, per kWh	2,735,890	2,735,890	2,774,367	kWh

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Subtotal	2,735,890	2,735,890	2,774,367	kWh
Renewable Adjustment Clause, per kWh	2,735,890	2,735,890	2,774,367	kWh
Klamath Rate Reconciliation Surcharge, per kWh	2,735,890	2,735,890	2,774,367	kWh
Total	2,735,890	2,735,890	2,774,367	kWh
Schedule No. 15 - Commercial				
Outdoor Area Lighting Service				
No. of Customers	4,396	4,396	4,254	
Transmission & Ancillary Services Charge				
per kWh	7,994,784	7,994,784	7,322,033	kWh
Distribution Charge				
Distribution Charge, per kWh	7,994,784	7,994,784	7,322,033	kWh
Energy Charge				
Sch 200, per kWh	7,994,784	7,994,784	7,322,033	kWh
Sch 201 TAM, per kWh	7,994,784	7,994,784	7,322,033	kWh
Subtotal	7,994,784	7,994,784	7,322,033	kWh
Renewable Adjustment Clause, per kWh	7,994,784	7,994,784	7,322,033	kWh
Klamath Rate Reconciliation Surcharge, per kWh	7,994,784	7,994,784	7,322,033	kWh
Total	7,994,784	7,994,784	7,322,033	kWh
Schedule No. 15 - Industrial				
Outdoor Area Lighting Service				
No. of Customers	164	164	146	
Transmission & Ancillary Services Charge				
per kWh	375,797	375,797	365,386	kWh
Distribution Charge				
Distribution Charge, per kWh	375,797	375,797	365,386	kWh
Energy Charge				
Sch 200, per kWh	375,797	375,797	365,386	kWh
Sch 201 TAM, per kWh	375,797	375,797	365,386	kWh
Subtotal	375,797	375,797	365,386	kWh
Renewable Adjustment Clause, per kWh	375,797	375,797	365,386	kWh
Klamath Rate Reconciliation Surcharge, per kWh	375,797	375,797	365,386	kWh
Total	375,797	375,797	365,386	kWh
Schedule No. 15 - PS&HW Lighting				
Outdoor Area Lighting Service				
No. of Customers	6	6	5	
Transmission & Ancillary Services Charge				
per kWh	8,257	8,257	5,433	kWh
Distribution Charge				
Distribution Charge, per kWh	8,257	8,257	5,433	kWh
Energy Charge				
Sch 200, per kWh	8,257	8,257	5,433	kWh
Sch 201 TAM, per kWh	8,257	8,257	5,433	kWh
Subtotal	8,257	8,257	5,433	kWh
Renewable Adjustment Clause, per kWh	8,257	8,257	5,433	kWh
Klamath Rate Reconciliation Surcharge, per kWh	8,257	8,257	5,433	kWh
Total	8,257	8,257	5,433	kWh
Schedule No. 50				
Mercury Vapor Street Lighting Service				
No. of Customers	286	286	287	
Transmission & Ancillary Services Charge				
per kWh	10,754,350	10,754,350	10,738,031	kWh
Distribution Charge				
Distribution Charge, per kWh	10,754,350	10,754,350	10,738,031	kWh
Energy Charge				
Sch 200, per kWh	10,754,350	10,754,350	10,738,031	kWh
Sch 201 TAM, per kWh	10,754,350	10,754,350	10,738,031	kWh
Subtotal	10,754,350	10,754,350	10,738,031	kWh
Renewable Adjustment Clause, per kWh	10,754,350	10,754,350	10,738,031	kWh
Klamath Rate Reconciliation Surcharge, per kWh	10,754,350	10,754,350	10,738,031	kWh
Total	10,754,350	10,754,350	10,738,031	kWh
Schedule No. 51/751				
High Pressure Sodium Vapor Street Lighting Service				
No. of Customers	674	674	686	
Transmission & Ancillary Services Charge				
per kWh	16,615,292	16,615,292	16,084,697	kWh

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Customer Accounting Units	Normalized 7/07-6/08 Units	Forecast 1/10 - 12/10 Units	
Distribution Charge				
Distribution Charge, per kWh	16,615,292	16,615,292	16,084,697	kWh
Energy Charge				
Sch 200, per kWh	16,615,292	16,615,292	16,084,697	kWh
Sch 201 TAM, per kWh	16,615,292	16,615,292	16,084,697	kWh
Subtotal	16,615,292	16,615,292	16,084,697	kWh
Renewable Adjustment Clause, per kWh	16,615,292	16,615,292	16,084,697	kWh
Klamath Rate Reconciliation Surcharge, per kWh	16,615,292	16,615,292	16,084,697	kWh
Total	16,615,292	16,615,292	16,084,697	kWh
Schedule No. 52/752				
Company-Owned Street Lighting Service				
No. of Customers	86	86	79	
Transmission & Ancillary Services Charge				
per kWh	1,356,205	1,356,205	1,185,726	kWh
Distribution Charge				
Distribution Charge, per kWh	1,356,205	1,356,205	1,185,726	kWh
Energy Charge				
Sch 200, per kWh	1,356,205	1,356,205	1,185,726	kWh
Sch 201 TAM, per kWh	1,356,205	1,356,205	1,185,726	kWh
Subtotal	1,356,205	1,356,205	1,185,726	kWh
Renewable Adjustment Clause, per kWh	1,356,205	1,356,205	1,185,726	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,356,205	1,356,205	1,185,726	kWh
Total	1,356,205	1,356,205	1,185,726	kWh
Schedule No. 53/753				
Customer-Owned Street Lighting Service				
No. of Customers	249	249	250	
Transmission & Ancillary Services Charge				
per kWh	9,277,495	9,277,495	9,316,113	kWh
Distribution Charge				
Distribution Charge, per kWh	9,277,495	9,277,495	9,316,113	kWh
Energy Charge				
Sch 200, per kWh	9,277,495	9,277,495	9,316,113	kWh
Sch 201 TAM, per kWh	9,277,495	9,277,495	9,316,113	kWh
Subtotal	9,277,495	9,277,495	9,316,113	kWh
Renewable Adjustment Clause, per kWh	9,277,495	9,277,495	9,316,113	kWh
Klamath Rate Reconciliation Surcharge, per kWh	9,277,495	9,277,495	9,316,113	kWh
Total	9,277,495	9,277,495	9,316,113	kWh
Schedule No. 54/754				
Recreational Field Lighting				
Transmission & Ancillary Services Charge				
per kWh	1,004,784	1,004,784	815,719	kWh
Distribution Charge				
Basic Charge, Single Phase, per month	840	840	865	bill
Basic Charge, Three Phase, per month	385	385	397	bill
Distribution Energy Charge, per kWh	1,004,784	1,004,784	815,719	kWh
Energy Charge				
Sch 200, per kWh	1,004,784	1,004,784	815,719	kWh
Sch 201 TAM, per kWh	1,004,784	1,004,784	815,719	kWh
Subtotal	1,004,784	1,004,784	815,719	kWh
Renewable Adjustment Clause, per kWh	1,004,784	1,004,784	815,719	kWh
Klamath Rate Reconciliation Surcharge, per kWh	1,004,784	1,004,784	815,719	kWh
Total	1,004,784	1,004,784	815,719	kWh
TOTAL OREGON	14,204,832,722	13,978,377,707	13,392,810,002	

Docket No. UE-210
Exhibit PPL/1009
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Supplemental Direct Testimony of William R. Griffith

December 31, 2010 Generation Revenue Requirement by Rate Schedule – Unbundled to Show Net Power Costs

June 2009

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Generation Revenue Requirement by Rate Schedule - Unbundled to Show Net Power Costs

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
	Functionalized Class Revenue Requirement - (Target)													
1	**Generation**	**$612,171**	**$264,191**	**$48,936**	**$55**	**$99,644**	**$869**	**$62,675**	**$4,437**	**$31,648**	**$73,835**	**$18,010**	**$6,835**	**$1,037**
2	Generation - Net Power Costs	$261,609	$112,901	$20,913	$23	$42,583	$371	$26,784	$1,896	$13,525	$31,553	$7,696	$2,921	$443
3	Generation - Other	$350,562	$151,290	$28,023	$31	$57,061	$497	$35,891	$2,541	$18,123	$42,282	$10,313	$3,914	$594