EL PASO ELECTRIC CO /TX/
Form 10-K
February 27, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number 001-14206
El Paso Electric Company
(Exact name of registrant as specified in its charter)

Texas	74-0607870
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Stanton Tower, 100 North Stanton, El Paso, Texas	79901
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (915) 543-5711
Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES x NO ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES ¨ NO x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x NO ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 126-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES ¨ NO x

As of June 30, 2011, the aggregate market value of the voting stock held by non-affiliates of the registrant was $1,330,697,564 (based on the closing price as quoted on the New York Stock Exchange on that date).

As of January 31, 2012, there were 40,119,381 shares of the Company’s no par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s definitive Proxy Statement for the 2012 annual meeting of its shareholders are incorporated by reference into Part III of this report.

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DEFINITIONS

The following abbreviations, acronyms or defined terms used in this report are defined below:

Abbreviations, Acronyms or Defined Terms	Terms
ANPP Participation Agreement	Arizona Nuclear Power Project Participation Agreement dated August 23, 1973, as amended
APS	Arizona Public Service Company
ASU	Accounting Standards Updates
Company	El Paso Electric Company
DOE	United States Department of Energy
El Paso	City of El Paso, Texas
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fort Bliss	Fort Bliss the United States Army post next to El Paso, Texas
Four Corners	Four Corners Generating Station
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt-hour(s)
Las Cruces	City of Las Cruces, New Mexico
MW	Megawatt(s)
MWh	Megawatt-hour(s)
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
Net dependable generating capability	The maximum load net of plant operating requirements which a generating plant can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress
NRC	Nuclear Regulatory Commission
Palo Verde	Palo Verde Nuclear Generating Station
Palo Verde Participants	Those utilities who share in power and energy entitlements, and bear certain allocated costs, with respect to Palo Verde pursuant to the ANPP Participation Agreement
PNM	Public Service Company of New Mexico
PUCT	Public Utility Commission of Texas
RGEC	Rio Grande Electric Cooperative
RGRT	Rio Grande Resources Trust II
TEP	Tucson Electric Power Company
TNP	Texas-New Mexico Power Company

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K other than statements of historical information are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe", "anticipate", "target", "expect", "pro forma", "estimate", "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning and include, but are not limited to, such things as:

- capital expenditures,
- earnings,
- liquidity and capital resources,
- ratemaking/regulatory matters,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- nuclear operations, and
- the overall economy of our service area.

These forward-looking statements involve known and unknown risks that may cause our actual results in future periods to differ materially from those expressed in any forward-looking statement. Factors that would cause or contribute to such differences include, but are not limited to, such things as:

- our rates in Texas following the rate case filed on February 1, 2012 pursuant to the El Paso City Council's resolution ordering us to show cause why our base rates for El Paso customers should not be lower,
- our ability to recover our costs and earn a reasonable rate of return on our invested capital through rates,
- ability of our operating partners to maintain plant operations and manage operation and maintenance costs at the Palo Verde and Four Corners plants, including costs to comply with any potential new or expanded regulatory requirements,
- reductions in output at generation plants operated by us,
- unscheduled outages including outages at Palo Verde,
- the size of our construction program and our ability to complete construction on budget and on a timely basis,
- electric utility deregulation or re-regulation,
- regulated and competitive markets,
- ongoing municipal, state and federal activities,
- economic and capital market conditions,
- changes in accounting requirements and other accounting matters,
- changing weather trends and the impact of severe weather conditions,
- rates, cost recovery mechanisms and other regulatory matters including the ability to recover fuel costs on a timely basis,
- changes in environmental laws and regulations and the enforcement or interpretation thereof, including those related to air, water or greenhouse gas emissions or other environmental matters,
- political, legislative, judicial and regulatory developments,

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- the impact of lawsuits filed against us,
- the impact of changes in interest rates,
- changes in, and the assumptions used for, pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan and other post-retirement plan assets,
- the impact of recent U.S. health care reform legislation,
- the impact of changing cost escalation and other assumptions on our nuclear decommissioning liability for Palo Verde,
- Texas, New Mexico and electric industry utility service reliability standards,
- homeland security considerations, including those associated with the U.S./Mexico border region,
- coal, uranium, natural gas, oil and wholesale electricity prices and availability, and
- other circumstances affecting anticipated operations, sales and costs.

These lists are not all-inclusive because it is not possible to predict all factors. A discussion of some of these factors is included in this document under the headings “Risk Factors” and “Management’s Discussion and Analysis” “–Summary of Critical Accounting Policies and Estimates” and “–Liquidity and Capital Resources.” This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made, except as required by applicable laws or regulations.

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PART I

Item 1. Business

General

El Paso Electric Company (the "Company") is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The Company also serves a full requirements wholesale customer in Texas. The Company owns or has significant ownership interests in six electrical generating facilities providing it with a net dependable generating capability of approximately 1,785 MW. For the year ended December 31, 2011, the Company’s energy sources consisted of approximately 45% nuclear fuel, 30% natural gas, 6% coal, 19% purchased power and less than 1% generated by wind turbines.

The Company serves approximately 380,000 residential, commercial, industrial, public authority and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico (representing approximately 63% and 11%, respectively, of the Company’s retail revenues for the year ended December 31, 2011). In addition, the Company’s wholesale sales include sales for resale to other electric utilities and power marketers. Principal industrial, public authority and other large retail customers of the Company include United States military installations, including Fort Bliss in Texas and White Sands Missile Range and Holloman Air Force Base in New Mexico, oil refining, two large universities, steel production and copper refining facilities.

The Company’s principal offices are located at the Stanton Tower, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of January 31, 2012, the Company had approximately 1,000 employees, 41% of whom are covered by a collective bargaining agreement.

The Company makes available free of charge through its website, www.epelectric.com, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (“SEC”). In addition, copies of the annual report will be made available free of charge upon written request. The SEC also maintains an internet site that contains reports, proxy and information statements and other information for issuers that file electronically with the SEC. The address of that site is www.sec.gov. The information on the internet site is not incorporated into this document by reference.

Facilities

As of December 31, 2011, the Company’s net dependable generating capability of 1,785 MW consists of the following:

Station	Primary Fuel Type	Net Dependable Generating Capability * (MW)
Palo Verde Station	Nuclear	633
Newman Power Station	Natural Gas	752
Rio Grande Power Station	Natural Gas	229
Four Corners Station	Coal	108
Copper Power Station	Natural Gas	62
Hueco Mountain Wind Ranch	Wind	1
Total		1,785

* During summer peak period.

Palo Verde Station

The Company owns a 15.8% interest, or approximately 633 MW, in the three nuclear generating units and common facilities (“Common Facilities”) at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company (“SCE”), PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District (“SRP”) and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde, and under the Arizona Nuclear Power Project ("ANPP") Participation Agreement, the Company has limited ability to influence operations and costs at Palo Verde.

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Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units, and each participant is required to fund its share of fuel, other operations, maintenance and capital costs. The ANPP Participation Agreement provides that, if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

NRC. The NRC regulates the operation of all commercial nuclear power reactors in the United States, including Palo Verde. The NRC periodically conducts inspections of nuclear facilities and monitors performance indicators to enable the agency to arrive at objective conclusions about a licensee’s safety performance.

License Extension. On April 21, 2011, the Company, along with the other Palo Verde Participants, was notified that the NRC had renewed the operating licenses for all three units at Palo Verde. The renewed licenses for Units 1, 2 and 3 will now expire in 2045, 2046 and 2047, respectively. For the last three quarters of 2011 combined, the extension of the operating licenses had the effect of reducing depreciation and amortization expense by approximately $8.2 million and reducing the accretion expense on the Palo Verde asset retirement obligation by approximately $3.1 million.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company is required to maintain a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company has established external trusts with an independent trustee, which enables the Company to record a current deduction for federal income tax purposes for most of the amounts funded. At December 31, 2011, the Company’s decommissioning trust fund had a balance of $168.0 million, and the Company was above its minimum funding level. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. On March 30, 2011, the Palo Verde Participants approved the 2010 Palo Verde decommissioning study (the “2010 Study”). The 2010 Study reflects the increase in the license life from 40 years to 60 years. The 2010 Study estimated that the Company must fund approximately $357.4 million (stated in 2010 dollars) to cover its share of decommissioning costs which was an increase in decommissioning costs of $33.0 million (stated in 2010 dollars) from the 2007 Palo Verde decommissioning study (the “2007 Study”). The net effect of these changes lowered the asset retirement obligation by $41.7 million and will lower annual expenses in the future. Although the 2010 Study was based on the latest available information, there can be no assurance that decommissioning cost estimates will not increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste are subject to significant uncertainty. See “Spent Fuel Storage” and “Disposal of Low-Level Radioactive Waste” below.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which will be stored at the on-site facilities until accepted by the DOE for permanent disposal. The 2010 Study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2057. APS believes that spent fuel storage or disposal methods will be available to allow each Palo Verde unit to continue to operate through the current term of its operating license.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the “Waste Act”), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation in the near future. In November 1997, the United States Court of Appeals for the District of Columbia Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. The Company cannot predict when spent fuel shipments to the DOE will commence.

The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs are assigned to fuel requiring the additional on-site storage and amortized as that fuel is burned until an agreement is reached with the DOE for recovery of these costs.

In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE's acceptance of spent fuel. APS pursued a damages claim for costs incurred through December 2006 in a trial that began on January 28, 2009. On June 18, 2010, the court

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awarded APS and the other Palo Verde Participants approximately $30 million. In October 2010, the Company received $4.8 million, representing its share of the award. The majority of the award was refunded to customers through the applicable fuel adjustment clauses. APS is continuing to pursue settlement of damage claims for costs incurred after 2006.

Disposal of Low-level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. The construction and opening of low-level radioactive waste disposal sites have been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed sites. The opposition, delays, uncertainty and costs that have been experienced demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available to allow each Palo Verde unit to continue to operate and to store safely low-level waste until a permanent disposal facility is available.

Oversight of the Nuclear Energy Industry in the Wake of the Earthquake and Tsunami in Japan. On March 11, 2011, a 9.0 magnitude earthquake occurred off the northeastern coast of Japan. The earthquake produced a tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Station in Japan. Preliminary data available from the Fukushima Daiichi plant operator and Japanese government have each indicated that the earthquake and tsunami were beyond the plant's required licensing and design parameters. Validation of that data will continue as more information becomes available.

Following the March 11, 2011 earthquake and tsunami in Japan, the NRC launched a two-pronged review of U.S. nuclear power plant safety. The NRC supported the establishment of an agency task force to conduct both a near- and long-term analysis of the lessons that can be learned from the situation in Japan. The near-term task force issued a report on July 12, 2011, and on October 3, 2011, the NRC staff issued a plan for implementing the near-term task force's recommendations.

On October 18, 2011, the NRC Commissioners directed the NRC staff to implement, without delay, the near-term task force recommendations, subject to certain conditions. One such condition is that the agency should strive to complete and implement lessons learned from the earthquake and tsunami in Japan within five years. A second condition is that the staff should designate the recommendation for a rulemaking to address extended loss of offsite power to be completed within 24 to 30 months.

Until further action is taken by the NRC as a result of this event, the Company cannot predict any financial or operational impacts on Palo Verde.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law, which is currently at $12.6 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $375 million, and the balance is covered by an industry-wide retrospective assessment program. If a loss at a nuclear power plant covered by the programs exceeds the accumulated funds in the primary level of protection, the Company could be assessed retrospective premium adjustments on a per incident basis. Under federal law, the maximum assessment per reactor under the program for each nuclear incident is approximately $117.5 million, subject to an annual limit of $17.5 million. Based upon the Company's 15.8% interest in the three Palo Verde units, the Company's maximum potential assessment per incident for all three units is approximately $55.7 million, with an annual payment limitation of approximately $8.3 million.

The Palo Verde Participants maintain “all risk” (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions. A mutual insurance company whose members are utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by this mutual insurance company were to exceed the accumulated funds for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $9.57 million for the current policy period.

Newman Power Station

The Company's Newman Power Station, located in El Paso, Texas, consists of three steam electric generating units and two combined cycle generating units, including a 278 MW combined cycle generating unit designated as Newman Unit 5. Construction of Newman Unit 5 began in July 2008 and was completed in two phases. The first phase, consisting of two 70 MW gas turbine generators, was completed in May 2009. The second phase consisted of the addition of two heat recovery steam generators and a steam turbine with a net peak period capability of 138 MW and was made commercially available in April 2011. The current aggregate net capability of the Newman Power Station is approximately 752 MW. The station operates primarily on natural gas but can also operate on fuel oil.

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Rio Grande Power Station

The Company's Rio Grande Power Station, located in Sunland Park, New Mexico, adjacent to El Paso, Texas, consists of three steam-electric generating units with an aggregate net peak period capability of approximately 229 MW. The units operate on natural gas. Construction has begun on Rio Grande Unit 9 to add an aeroderivative unit with a net dependable generating capacity of 87MW that should reach commercial operation by May 2013.

Four Corners Station

The Company owns a 7% interest, or approximately 108 MW, in Units 4 and 5 at Four Corners, located in northwestern New Mexico. Each of the two coal-fired generating units has a total net peak period capability of 770 MW. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other participants, PNM, TEP, SCE and SRP.

Four Corners is located on land under easements from the federal government and a lease from the Navajo Nation that expires in 2016, with a one-time option to extend the term for an additional 25 years. Certain of the facilities associated with Four Corners, including transmission lines and almost all of the contracted coal sources, are also located on Navajo land. Units 4 and 5 are located adjacent to a surface-mined supply of coal.

APS, on behalf of the Four Corners participants, has negotiated amendments to the existing facility lease with the Navajo Nation that would extend the Four Corners leasehold interest to 2041. Execution by the Navajo Nation of the lease amendments is a condition to closing of a purchase by APS of SCE's interests in Four Corners. The execution of these amendments by the Navajo Nation require the approval of the Navajo Nation Council and the Nation's President, which occurred in February and March 2011. The effectiveness of the amendments also requires the approval of the Department of the Interior ("DOI"), as does a related Federal rights-of-way grant which the Four Corners participants will pursue. A Federal environmental review will be conducted as part of the DOI review process.

Copper Power Station

The Company's Copper Power Station, located in El Paso, Texas, consists of a 62 MW combustion turbine used primarily to meet peak demand. The unit operates on natural gas.

Hueco Mountain Wind Ranch

The Company's Hueco Mountain Wind Ranch, located in Hudspeth County, east of El Paso County and adjacent to Horizon City, currently consists of two wind turbines with a total capacity of 1.32 MW of which a portion, currently 10%, is used as net capability for resource planning purposes.

Transmission and Distribution Lines and Agreements

The Company owns or has significant ownership interests in four 345 kV transmission lines in New Mexico, three 500 kV lines in Arizona, and owns the transmission and distribution network within its New Mexico and Texas retail service area and operates these facilities under franchise agreements with various municipalities. The Company is also a party to various transmission and power exchange agreements that, together with its owned transmission lines, enable the Company to deliver its energy entitlements from its remote generation sources at Palo Verde and Four Corners to its service area. Pursuant to standards established by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council, the Company operates its transmission system in a way that allows it to maintain system integrity in the event that any one of these transmission lines is out of service.

Springerville-Macho Springs-Luna-Diablo Line. The Company owns a 310-mile, 345 kV transmission line from TEP's Springerville Generating Plant near Springerville, Arizona, to the Company's Diablo Substation near Sunland Park, New Mexico. This line also contains two other substations; the Macho Springs Substation near Hatch, New Mexico, and the Luna Substation near Deming, New Mexico. This transmission line provides an interconnection with TEP for delivery of the Company's generation entitlements from Palo Verde and, if necessary, Four Corners. The Macho Springs Substation was commissioned in 2011 to interconnect a wind farm that provides renewable power to TEP.

West Mesa-Arroyo Line. The Company owns a 202-mile, 345 kV transmission line from PNM's West Mesa Substation located near Albuquerque, New Mexico, to the Company's Arroyo Substation located near Las Cruces, New Mexico. West Mesa Substation is the primary delivery point for the Company's generation entitlement from Four Corners, which is transmitted from Four Corners to the West Mesa Substation over approximately 150 miles of transmission lines owned by PNM.

Greenlee-Hidalgo-Luna-Newman Line. The Company owns 40% of a 60-mile, 345 kV transmission line between TEP's

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Greenlee Substation near Duncan, Arizona to the Hidalgo Substation near Lordsburg, New Mexico, approximately 57% of a 50-mile, 345 kV transmission line between the Hidalgo Substation and the Luna Substation and 100% of an 86-mile, 345 kV transmission line between the Luna Substation and the Newman Power Station. These lines provide an interconnection with TEP for delivery of the Company's entitlements from Palo Verde and, if necessary, Four Corners. The Company owns the Afton 345 kV Substation located approximately 57 miles from the Luna Substation on the Luna-to-Newman portion of the line. The Afton Substation interconnects a generator owned and operated by PNM.

Eddy County-AMRAD Line. The Company owns 66.7% of a 125 mile, 345 kV transmission line from the Company's and PNM's high voltage direct current terminal at the Eddy County Substation near Artesia, New Mexico to the AMRAD Substation near Oro Grande, New Mexico. The Company also owns 66.7% of the terminal. This terminal enables the Company to connect its transmission system to that of SPS (a subsidiary of Xcel Energy), providing the Company with access to purchased and emergency power from SPS and power markets to the east.

Palo Verde Transmission and Switchyard. The Company owns 18.7% of two 45-mile, 500 kV lines from Palo Verde to the Westwing Substation located northwest of Phoenix near Peoria, Arizona. The Company also owns 18.7% of a 75-mile, 500 kV line from Palo Verde to the Jojoba Substation, then to the Kyrene Substation located near Tempe, Arizona. These lines provide the Company with a transmission path for delivery of power from Palo Verde. The Company owns 14.94% and 9.35% respectively of two 500 kV switchyards connected to the Palo Verde-Kyrene 500 kV line: the Hassayampa switchyard, adjacent to the southern edge of the Palo Verde 500 kV switchyard and the Jojoba switchyard approximately 24 miles from Palo Verde. These switchyards were built to accommodate the addition of new generation and transmission in the Palo Verde area.

Environmental Matters

General. The Company is subject to laws and regulations with respect to air, soil and water quality, waste disposal and other environmental matters by federal, state, regional, tribal and local authorities. Those authorities govern facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these requirements can result in actions by regulatory agencies or other authorities that might seek to impose on the Company administrative, civil and/or criminal penalties or other sanctions. In addition, releases of pollutants or contaminants into the environment can result in costly cleanup liabilities. These laws and regulations are subject to change and, as a result of those changes, the Company may face additional capital and operating costs to comply. Certain key environmental issues, laws and regulations facing the Company are described further below.

Air Emissions. The U.S. Clean Air Act (“CAA”) and comparable state laws and regulations relating to air emissions impose, among other obligations, limitations on pollutants generated during the Company's operations, including sulfur dioxide (“SO2”), particulate matter (“PM”), nitrogen oxides (“NOx”) and mercury.

Clean Air Interstate Rule. The U.S. Environmental Protection Agency's (“EPA”) Clean Air Interstate Rule (“CAIR”), as applied to the Company, involves requirements to limit emissions of NOx from the Company's power plants in Texas and/or purchase allowances representing other parties' emissions reductions starting in 2009. The U.S. Court of Appeals for the District of Columbia voided CAIR in 2008; however, the Company has complied with CAIR since 2009, and such rule is binding. The annual reconciliation to comply with CAIR is due by March 31 of the following year. The Company has purchased allowances and expensed the following costs to meet its annual requirements (in thousands):

Compliance Year	Amount
2010	$370
2011	62

Cross-State Air Pollution Rule. In July 2011, the EPA finalized the Cross-State Air Pollution Rule (“CSAPR”) which is intended to replace CAIR. CSAPR requires 28 states, including Texas, to further reduce power plant emissions of SO_2 and NOx. Under CSAPR, reductions in annual SO_2 and NOx emissions were required to begin January 1, 2012, with further reductions required beginning January 1, 2014. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued its ruling to stay CSAPR, including the supplemental final rule, pending judicial review, which delays CSAPR's implementation date beyond January 1, 2012. The court is scheduled to hear the cases against the rule in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. As the outcome of the judicial review and any other legal or Congressional challenges are uncertain, the Company is unable to determine what impact CSAPR may ultimately have on its operations and consolidated financial results, but it could be material. Until the legal challenges to CSAPR are resolved, the Company's obligations under CAIR remains in effect.

National Ambient Air Quality Standards. Under the CAA, the EPA sets National Ambient Air Quality Standards ("NAAQS") for six criteria emissions considered harmful to public health and the environment, including PM, NOx, CO and SO_2.

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Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals. In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. The Company is currently evaluating what impact this could have on its operations. If the Company is required to install additional equipment to control emissions at its facilities, the revised NAAQS could have a material impact on its operations and consolidated financial results. In addition, the EPA is currently reviewing the PM NAAQS. The Company cannot at this time predict the impact of this review and any possible new standards on its operations or consolidated financial results, but it could be material. The EPA had been in the process of revising the NAAQS for ozone. However, in September 2011, President Obama ordered the EPA to withdraw its proposal. Work, however, is underway to support EPA's planned reconsideration of the standards in 2013.

Utility MACT. The operation of coal-fired power plants, such as the Company's Four Corners plant, results in emissions of mercury and other air toxics. In December 2011, the EPA finalized Mercury and Air Toxics Standards (known as the "Utility MACT") for power plants, which replaces the prior federal Clean Air Mercury Rule and requires significant reductions in emissions of mercury and other air toxics. Companies impacted by the new standards will have up to four (and in certain cases five) years to comply. The Company is currently evaluating the new standards and cannot at this time determine the impact they may have on its Four Corners plant, but the cost of compliance could be material.

Climate Change. A significant portion of the Company's generation assets are nuclear or gas-fired, and as a result, the Company believes that its greenhouse gas (“GHG”) emissions are low relative to electric power companies who rely on more coal-fired generation. However, regulations governing the emission of GHGs, such as carbon dioxide, could impose significant costs or limitations on the Company. In recent years, the U.S. Congress has considered new legislation to restrict or regulate GHG emissions, although federal efforts directed at enacting comprehensive climate change legislation stalled in 2010 and appear unlikely to recommence in the near future. Nonetheless, it is possible that federal legislation related to GHG emissions will be considered by Congress in the future. The EPA has also proposed using the CAA to limit carbon dioxide and other GHG emissions, and other measures are being imposed or offered by individual states, municipalities and regional agreements with the goal of reducing GHG emissions.

In September 2009, the EPA adopted a rule requiring approximately 10,000 facilities comprising a substantial percentage of annual U.S. GHG emissions to inventory their emissions starting in 2010 and to report those emissions to the EPA beginning in 2011. The Company's fossil fuel-fired power generating assets are subject to this rule, and the first report containing 2010 emissions was submitted to the EPA prior to the September 30, 2011 due date. The Company also has inventoried and implemented procedures for electrical equipment containing sodium hexafluoride ("SF6"), another GHG. The Company is tracking these GHG emissions pursuant to the EPA's new SF6 reporting rule that was finalized in late 2010 and became effective January 1, 2011. The first report to EPA under this rule was originally due on March 31, 2012, but in November 2011, EPA delayed its submittal to September 26, 2012.

The EPA has also proposed and finalized other rulemakings on GHG emissions that affect electric utilities. Under EPA regulations finalized in May 2010 (referred to as the “Tailoring Rule”), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications (referred to as the “PSD” program). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or 100,000 tons per year, depending on various factors), will be required to implement “best available control technology,” or “BACT”. Pursuant to the rule, the EPA may reduce the 75,000 tons threshold referenced above in 2012 or thereafter. The EPA has issued guidance on what BACT entails for the control of GHGs, and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of these new regulations on the

Company's operations cannot be determined at this time, but the cost of compliance with new regulations could be material. Also, on December 23, 2010, the EPA announced a settlement agreement with states and environmental groups regarding setting new source performance standards for GHG emissions from new and existing coal-, gas- and oil-based power plants. Pursuant to this agreement, and certain agreed upon extensions, the EPA intends to issue proposed rules for new and modified electric generating units ("EGUs") in 2012. It is unclear when the EPA will propose a GHG New Source Performance Standard ("NSPS") for existing EGUs and how stringent it would be, but this rule is expected. The impact of these rules on the Company is unknown at this time, but they could result in significant costs.

In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to consider how to address GHG emissions and are actively considering the development of emission inventories or regional GHG cap and trade programs.

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It is not currently possible to predict with confidence how any pending, proposed or future GHG legislation by Congress, the states, or multi-state regions or regulations adopted by EPA or the state environmental agencies will impact the Company's business. However, any such legislation or regulation of GHG emissions or any future related litigation could result in increased compliance costs or additional operating restrictions or reduced demand for the power the Company generates, could require the Company to purchase rights to emit GHG, and could have a material adverse effect on the Company's business, financial condition, reputation or results of operations.

Climate change also has potential physical effects that could be relevant to the Company's business. In particular, some studies suggest that climate change could affect the Company's service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

The Company believes that material effects on the Company's business or operations may result from the physical consequences of climate change, the regulatory approach to climate change ultimately selected and implemented by governmental authorities, or both. Substantial expenditures may be required for the Company to comply with such regulations in the future and, in some instances, those expenditures may be material. Given the very significant remaining uncertainties regarding whether and how these issues will be regulated, as well as the timing and severity of any physical effects of climate change, the Company believes it is impossible at present to meaningfully quantify the costs of these potential impacts.

Contamination Matters. The Company has a provision for environmental remediation obligations of approximately $0.3 million at December 31, 2011, related to compliance with federal and state environmental standards. However, unforeseen expenses associated with environmental compliance or remediation may occur and could have a material adverse effect on the future operations and financial condition of the Company.

The EPA has investigated releases or potential releases of hazardous substances, pollutants or contaminants at the Gila River Boundary Site, on the Gila River Indian Community reservation in Arizona and designated it as a Superfund site. The Company currently owns 16.29% of the site and will share in the cost of cleanup of this site. The Company has an agreement with the EPA and a former property owner to resolve this matter and on June 30, 2011, the Company entered into a consent decree with the EPA at a cost to the Company of less than $0.1 million.

Environmental Litigation and Investigations. On April 6, 2009, APS received a request from the EPA under Section 114 of the CAA seeking detailed information regarding projects and operations at Four Corners. The EPA has taken the position that many utilities have made certain physical or operational changes at their plants that should have triggered additional regulatory requirements under the New Source Review provisions of the CAA. APS responded to this request in 2009. The Company is unable to predict the timing or content of the EPA's response, if any, or any resulting actions.

The Company received word that Earthjustice filed a lawsuit in the United States District Court for New Mexico on October 4, 2011 for alleged violations of the Prevention of Significant Deterioration provisions of the CAA. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the CAA's NSPS program. Among other things, the plaintiffs seek to have the court enjoin operations at Four Corners until APS applies for and obtains any required PSD permits and complies with the NSPS. The plaintiffs further request the court to order the payment of civil penalties, including a beneficial mitigation project. APS advised that it believes the claims in this matter are without merit and will vigorously defend against them. The Company is unable to predict the outcome of these alleged violations.

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Construction Program

Utility construction expenditures reflected in the following table consist primarily of local generation, expanding and updating the transmission and distribution systems, and the cost of capital improvements and replacements at Palo Verde. Studies indicate that the Company will need additional power generation resources to meet increasing load requirements on its system and to replace retiring plants, the costs of which are included in the table below. The Company's estimated cash construction costs for 2012 through 2016 are approximately $1.4 billion. Actual costs may vary from the construction program estimates shown. Such estimates are reviewed and updated periodically to reflect changed conditions.

By Year (1)(2) (in millions)		By Function (in millions)	
2012	$242	Production (1)(2)	$892
2013	232	Transmission	120
2014	267	Distribution	281
2015	311	General	96
2016	337		
Total	$1,389	Total	$1,389

(1) Does not include acquisition costs for nuclear fuel. See "Energy Sources – Nuclear Fuel."

(2) $700 million has been allocated for new generating capacity including $38 million to complete Rio Grande Unit 9, $186 million to construct two 87 MW gas-fired LMS-100 units that are scheduled to come on line in 2014 and 2015, $174 million for two 87 MW gas-fired LMS-100 units scheduled to come on line in 2016, and $284 million of initial expenditures for two additional 292 MW combined cycle generating units that are anticipated to come on line in 2018 and 2019 and $18 million for anticipated renewable projects to be built in El Paso. Total production expenditures also include $24 million for other local generation, $14 million for the Four Corners Station and $154 million for the Palo Verde Station.

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Energy Sources

General

The following table summarizes the percentage contribution of nuclear fuel, natural gas, coal and purchased power to the total kWh energy mix of the Company. Energy generated by wind turbines accounted for less than 1% of the total kWh energy mix.

	Years Ended December 31,					
Power Source	2011		2010		2009	
Nuclear	45	%	45	%	45	%
Natural gas	30		27		22	
Coal	6		6		7	
Purchased power	19		22		26	
Total	100	%	100	%	100	%

Allocated fuel and purchased power costs are generally recoverable from customers in Texas and New Mexico pursuant to applicable regulations. Historical fuel costs and revenues are reconciled periodically in proceedings before the PUCT and the NMPRC. See "Regulation – Texas Regulatory Matters" and "– New Mexico Regulatory Matters."

Nuclear Fuel

The nuclear fuel cycle for Palo Verde consists of the following stages: the mining and milling of uranium ore to produce uranium concentrates; the conversion of the uranium concentrates to uranium hexafluoride ("conversion services"); the enrichment of uranium hexafluoride ("enrichment services"); the fabrication of fuel assemblies ("fabrication services"); the utilization of the fuel assemblies in the reactors; and the storage and disposal of the spent fuel.

Pursuant to the ANPP Participation Agreement, the Company owns an undivided interest in nuclear fuel purchased in connection with Palo Verde. The Palo Verde participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The Palo Verde participants have contracted for 95% of Palo Verde's requirements for uranium concentrates through 2015, 90% of its requirements in 2016-2017 and 80% of its requirements in 2018. The participants have also contracted for all of Palo Verde's conversion services through 2015 and 95% of its requirements in 2016-2018, all of Palo Verde's enrichment services through 2020 and all of Palo Verde's fuel assembly fabrication services through 2016.

Nuclear Fuel Financing. The Company's financing of nuclear fuel is accomplished through Rio Grande Resources Trust ("RGRT"), a Texas grantor trust, which is consolidated in the Company's financial statements. RGRT has $110 million aggregate principal amount borrowed through senior notes. The Company guarantees the payment of principal and interest on the senior notes. The nuclear fuel financing requirements of RGRT are met with a combination of the senior notes and amounts borrowed under the revolving credit facility (the "RCF").

The Company maintains a $200 million RCF for the financing of nuclear fuel and for working capital and general corporate purposes. On November 15, 2011, the Company, along with RGRT, refinanced and extended the credit facility, which includes an option, subject to lenders' approval, to expand the size to $300 million. The amended facility reduces our borrowing costs and extends the maturity from September 2014 to September 2016. The total amount borrowed for nuclear fuel by RGRT at December 31, 2011 was $123.4 million of which $13.4 million had been borrowed under the RCF, and $110 million was borrowed through the senior notes. Interest costs on borrowings to finance nuclear fuel are accumulated by RGRT and charged to the Company as fuel is consumed and recovered from customers through fuel recovery charges.

Natural Gas

The Company manages its natural gas requirements through a combination of a long-term supply contract and spot market purchases. The long-term supply contract provides for firm deliveries of gas at market-based index prices. In 2011, the Company's natural gas requirements at the Newman and Rio Grande Power Stations were met with both short-term and long-term natural gas purchases from various suppliers, and this practice is expected to continue in 2012. Interstate gas is delivered under a base firm transportation contract. The Company anticipates it will continue to purchase natural gas at spot market prices on a monthly basis for a portion of the fuel needs for the Newman and Rio Grande Power Stations. The Company will continue to evaluate the availability of short-term natural gas supplies versus long-term supplies to maintain a reliable and economical supply for the Newman and Rio Grande Power Stations.

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Natural gas for the Newman and Copper Power Stations is also supplied pursuant to an intrastate natural gas contract that became effective October 1, 2009 and continues through 2017. The intrastate natural gas agreement was amended effective September 1, 2010.

Coal

APS, as operating agent for Four Corners, purchases Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. In June 2010, the Four Corners coal contract was renegotiated with the coal supplier, resulting in reduced coal prices for the remaining term of the agreement. The Four Corners coal contract expires in mid-2016. Based upon information from APS, the Company believes that Four Corners has sufficient reserves of coal to meet the plant's operational requirements through mid-2016.

Purchased Power

To supplement its own generation and operating reserves and to meet required renewable portfolio standards, the Company engages in firm power purchase arrangements which may vary in duration and amount based on evaluation of the Company's resource needs, the economics of the transactions and specific renewable portfolio requirements.

The Company has a Power Purchase and Sale Agreement with Freeport-McMoran Copper and Gold Energy Services LLC ("Freeport") which provides for Freeport to deliver energy to the Company from its ownership interest in the Luna Energy Facility (a natural gas fired combined cycle generation facility located in Luna County, New Mexico) and for the Company to deliver a like amount of energy at Greenlee, Arizona. The Company may purchase up to 125 MW at a specified price at times when energy is not exchanged under the Power Purchase and Sale Agreement. Upon mutual agreement, the contract allows the parties to increase the amount of energy that is purchased and sold under the Power Purchase and Sale Agreement. The parties have agreed to increase the amount to 125 MW through December 2013. The contract was approved by the FERC and continues through December 31, 2021.

The Company entered into an agreement in 2009 to purchase capacity of up to 40 MW and unit contingent energy during 2010 from Shell Energy North America ("Shell"). Under the agreement, the Company provides natural gas to Pyramid Unit No. 4 where Shell has the right to convert natural gas to electric energy. The Company entered into a contract with Shell on May 17, 2010 to extend the term of the capacity and unit contingent energy purchase from January 1, 2011 through September 30, 2014.

The Company entered into a 20-year contract with NRG Solar Roadrunner, LLC ("NRG") for the purchase of all of the output of a solar photovoltaic plant built in southern New Mexico which began commercial operation in August 2011. (See "Regulation - New Mexico Regulatory Matters.") The Company has a 25-year purchase power agreement with NextEra Energy Resource for a solar photovoltaic project located in southern New Mexico which began commercial operation in July 2011. The Company has 25-year purchase power agreements for two additional solar photovoltaic projects located in southern New Mexico, SunEdison 1 and SunEdison 2 which commercial operation is estimated to begin in 2012. The Company entered into these contracts to help meet its renewable portfolio requirements.

Other purchases of shorter duration were made during 2011 to supplement the Company's generation resources during planned and unplanned outages and for economic reasons as well as to supply off system sales.

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Operating Statistics

	Years Ended December 31, 2011	2010	2009
Operating revenues (in thousands):			
Non-fuel base revenues:			
Retail:			
Residential	$234,086	$217,615	$195,798
Commercial and industrial, small	196,093	188,390	175,328
Commercial and industrial, large	45,407	43,844	34,804
Sales to public authorities	94,370	86,460	77,370
Total retail base revenues	569,956	536,309	483,300
Wholesale:			
Sales for resale	2,122	1,943	2,037
Total non-fuel base revenues	572,078	538,252	485,337
Fuel revenues:			
Recovered from customers during the period	145,130	170,588	196,081
Under (over) collection of fuel	13,917	(35,408)	(66,608)
New Mexico fuel in base rates	73,454	71,876	69,026
Total fuel revenues	232,501	207,056	198,499
Off-system sales:			
Fuel cost	74,736	93,516	101,665
Shared margins	3,883	6,114	3,596
Retained margins	(560)	5,687	10,803
Total off-system sales	78,059	105,317	116,064
Other	35,375	26,626	28,096
Total operating revenues	$918,013	$877,251	$827,996
Number of customers (end of year):			
Residential	337,659	334,729	328,553
Commercial and industrial, small	37,942	37,202	36,306
Commercial and industrial, large	49	50	48
Other	4,596	4,841	4,964
Total	380,246	376,822	369,871
Average annual kWh use per residential customer	7,832	7,560	7,244
Energy supplied, net, kWh (in thousands):			
Generated	8,936,776	8,465,659	7,979,290
Purchased and interchanged	2,112,596	2,420,869	2,745,500
Total	11,049,372	10,886,528	10,724,790
Energy sales, kWh (in thousands):			
Retail:			
Residential	2,633,390	2,508,834	2,361,650
Commercial and industrial, small	2,352,218	2,295,537	2,251,399
Commercial and industrial, large	1,096,040	1,087,413	1,024,186
Sales to public authorities	1,579,565	1,542,389	1,482,448
Total retail	7,661,213	7,434,173	7,119,683
Wholesale:			
Sales for resale	62,656	53,637	56,931
Off-system sales	2,687,631	2,822,732	2,995,984
Total wholesale	2,750,287	2,876,369	3,052,915
Total energy sales	10,411,500	10,310,542	10,172,598

Losses and Company use	637,872	575,986	552,192
Total	11,049,372	10,886,528	10,724,790
Native system:			
Peak load, kW	1,711,000	1,616,000	1,571,000
Net dependable generating capability for peak, kW (1)	1,785,000	1,643,000	1,643,000
Total system:			
Peak load, kW (2)	1,965,000	1,889,000	1,723,000
Net dependable generating capability for peak, kW (1) (3)	1,785,000	1,643,000	1,643,000

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(1) 2011 includes a 138,000 kW increase in net generating capability at Newman related to the completion of the second phase of the Newman Unit 5 construction which consists of two heat recovery steam generators and a steam turbine.

(2) Includes spot sales and net losses of 254,000 kW, 273,000 kW and 152,000 kW for 2011, 2010 and 2009, respectively.

(3) Excludes spot firm purchases, as well as 65,000 kW, 100,000 kW and 233,000 kW for 2011, 2010 and 2009, respectively, of long-term firm on-peak purchases.

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Regulation

General

The rates and services of the Company are regulated by incorporated municipalities in Texas, the PUCT, the NMPRC, and the FERC. The PUCT and the NMPRC have jurisdiction to review municipal orders, ordinances and utility agreements regarding rates and services within their respective states and over certain other activities of the Company. The FERC has jurisdiction over the Company's wholesale transactions and compliance with federally-mandated reliability standards. The decisions of the PUCT, NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

2009 Texas Retail Rate Case. On December 9, 2009, the Company filed an application with the PUCT for authority to change rates, to reconcile fuel costs, to establish formula-based fuel factors and to establish an energy efficiency cost-recovery factor. This case was assigned PUCT Docket No. 37690. The filing included a base rate increase which was based upon an adjusted test year ended June 30, 2009.

On July 30, 2010, the PUCT approved a settlement in the 2009 Texas retail rate case in PUCT Docket No. 37690. The settlement called for an annual non-fuel base rate increase of $17.15 million effective for usage beginning July 1, 2010. The new rate structure resulted in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. This increase was partially offset by the provision that, consistent with a prior rate agreement, effective July 1, 2010, the Company shares 90% of off-system sales margins with customers and retains 10% of such margins. Previously, the Company retained 75% of off-system sales margins. All additions to electric plant in service since June 30, 1993 through June 30, 2009 were deemed to be reasonable and necessary with the exception of one small addition. The Company's new customer information system completed in April 2010 was also included in base rates with a 10-year amortization. The settlement provided for the reconciliation of fuel costs incurred through June 30, 2009 except for the recovery of final Four Corners' coal mine reclamation costs. The fuel reconciliation (Docket No. 38361, discussed below) was bifurcated from the rate case to allow for litigation of the final coal mine reclamation costs. The PUCT also approved the use of a formula-based fuel factor which provides for more timely recovery of fuel costs. The PUCT approved a $19.7 million or 11% reduction in the Company's fixed fuel factor as the initial rate under the approved fuel factor formula. The PUCT also approved an energy efficiency cost-recovery factor that includes the recovery of deferred energy efficiency costs over a three-year period.

2012 Texas Retail Rate Case. The Company filed a request with the PUCT (Docket No. 40094), the City of El Paso, and other Texas cities on February 1, 2012 for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring the Company to show cause why its base rates for customers in the El Paso city limits should not be reduced. The City has until August 4, 2012 to make a determination regarding the Company's base rates in the City of El Paso. The rate filing used a historical test year ended September 30, 2011, adjusted for known and measurable items, and a return on equity of 10.6%. The filing at the PUCT also includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011.

On November 15, 2011, the El Paso City Council adopted a resolution which established current rates as temporary rates for the Company's customers residing within the city limits of El Paso. Temporary rates will be effective from November 15, 2011 until a final determination is made by the PUCT on the Company's rates in the rate proceeding initiated by the City's Show Cause Order. Upon a final determination by the PUCT, the PUCT may order a refund to customers of money collected in excess of the rate finally ordered, including interest, or shall authorize the Company to surcharge bills to recover the amount, including interest, by which the money collected under the temporary rates is less than the money that would have been collected under the rate finally ordered. The rates proposed by the Company in the Texas rate case included increases for some customer classes and decreases for other customer classes. As a result, consistent implementation of the proposed rates may require the PUCT to reflect the differences in temporary and final rates from November 15, 2011 for each affected class.

While cities in Texas have jurisdiction over rates in their city limits, the PUCT has appellate authority over city rate decisions on a “de novo” basis; therefore, the ultimate authority to set the Company's Texas electric rates is vested in the PUCT. The Company cannot predict the outcome of this proceeding. If the rate case results in implementing lower rates, the resulting lower rates would have a negative impact on the Company's revenues, net income and cash from operations.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in the Company's 2009 rate case, the PUCT established Docket No. 38361 to address the one fuel reconciliation issue not settled by the parties. That single issue was a determination of the proper amount of the Four Corners' coal mine final reclamation costs to be recovered from the Company's Texas retail customers. The hearing on the merits of the case was held on August 11, 2010. On November 23, 2010 the Administrative Law Judge (the “ALJ”) issued the Proposal for Decision which approved the Company's request. The PUCT issued a final order approving the Proposal for Decision on January 27, 2011.

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Fuel and Purchased Power Costs. The Company's actual fuel costs, including purchased power energy costs, are recoverable from its customers. The PUCT has adopted a fuel cost recovery rule ("Texas Fuel Rule") that allows the Company to seek periodic adjustments to its fixed fuel factor. The Company received approval on July 30, 2010 in PUCT Docket No. 37690 (discussed above), to implement a formula to determine its fuel factor which adjusts natural gas and purchased power to reflect natural gas futures prices. The Company can seek to revise its fixed fuel factor based upon the approved formula at least four months after its last revision except in the month of December. The Texas Fuel Rule requires the Company to request to refund fuel costs in any month when the over-recovery balance exceeds a threshold material amount and it expects fuel costs to continue to be materially over-recovered. The Texas Fuel Rule also permits the Company to seek to surcharge fuel under-recoveries in any month the balance exceeds a threshold material amount and it expects fuel cost recovery to continue to be materially under-recovered. Fuel over and under-recoveries are considered material when they exceed 4% of the previous twelve months' fuel costs. All such fuel revenue and expense activities are subject to periodic final review by the PUCT in fuel reconciliation proceedings.

The Company has filed the following petitions with the PUCT to refund recent fuel cost over-recoveries, due primarily to fluctuations in natural gas markets and consumption levels. The table summarizes the docket number assigned by the PUCT, the dates the Company filed the petitions and the dates a final order was issued by the PUCT approving the refunds to customers. The fuel cost over-recovery periods represent the months in which the over-recoveries took place and the refund periods represent the billing month(s) in which customers received the refund amounts shown, including interest:

Docket No.	Date Filed	Date Approved	Recovery Period	Refund Period	Refund Amount (In thousands)
37788	December 17, 2009	February 11, 2010	September – November 2009	February 2010	$11,800
38253	May 12, 2010	July 15, 2010	December 2009 – March 2010	July – August 2010	11,100
38802	October 20, 2010	December 16, 2010	April – September 2010	December 2010	12,800
39159	February 18, 2011	May 3, 2011	October – December 2010	April 2011	11,800

The Company has filed the following petitions with the PUCT to revise its fixed fuel factor pursuant to the fuel factor formula authorized in PUCT Docket No. 37690:

Docket No.	Date Filed	Date Approved	Increase (Decrease) in Fuel Factor		Effective Billing Month
38895	November 23, 2010	January 6, 2011	(14.7	)%	January 2011
39599	July 15, 2011	August 30, 2011	9.4	%	August 2011

As noted above, the rate filing filed with the PUCT on February 1, 2012 (Docket No. 40094), includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011. However, this filing does not request a change in the fixed fuel factor.

Application for Approval to Revise Energy Efficiency Cost Recovery Factor for 2012. On May 2, 2011, the Company filed with the PUCT an application for approval to revise its energy efficiency cost recovery factor ("EECRF"), which was assigned PUCT Docket No. 39376. A unanimous settlement resolving all issues was filed with the PUCT on July 15, 2011. The settlement allows the Company to recover $8.3 million and supports the Company's request to revise its demand and energy goals and EECRF cost caps as well as the Company's request to increase its 2012 EECRF, effective beginning with the first billing cycle of its January 2012 billing month. A final order in the case was issued August 23, 2011, approving the settlement.

Petition for Approval to Revise Military Base Discount Recovery Factor. On July 14, 2011, the Company filed with the PUCT a petition requesting approval to revise its Military Base Discount Recovery Factor ("MBDRF") tariff to account for under-recovery of discount charges during 2010 and for 2011 discounts. A final order was issued January 12, 2012 revising the MBDRF to 0.936% and allowing $3.9 million dollars of under-recovered discount charges to begin February 1, 2012.

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Application for a Certificate of Convenience and Necessity (“CCN”) for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a CCN to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned PUCT Docket No. 38717. A unanimous settlement to approve the CCN was filed on March 2, 2011, and a final order granting the CCN was approved on April 8, 2011.

Project to Investigate Early February 2011 Outages and Curtailments. On February 8, 2011, the PUCT opened Project No. 39134, Investigation into Power Outages in El Paso Electric's Service Territory. In this project, the PUCT is investigating the Company's power plant outages and customer curtailments that occurred February 2-4, 2011, as a result of the extreme cold weather in the El Paso area. The PUCT Staff conducted discovery in the investigation. On February 14, 2011, the Company also filed a report on this weather event. On May 13, 2011, the PUCT Staff issued a report stating that, as of then, it had not identified violations by the Company of the Texas electric utility regulatory statute or PUCT rules. The report also stated that the PUCT Staff would continue to monitor the extreme cold weather event results and subsequent forthcoming information as the Company and other regulatory agencies complete their ongoing investigations.

On February 15, 2011, the City Council of El Paso passed a motion that, upon the conclusion of other hearings and investigations into the extreme cold weather event, the Mayor would call for Special City Council meetings or public hearings to evaluate how the three utility companies operating within the city, including the Company, performed during the extreme weather event. The El Paso City Council retained a consultant to assess the Company's activities during the weather event and the Company's subsequent actions to prevent outages during a similar future event. The El Paso City Council's consultant presented the following three recommendations to the El Paso City Council on December 20, 2011: (i) request the Company to prepare and present an updated reliability study; (ii) request the Company and El Paso Water Utilities to present their coordinated plans for power and water supply to critical loads during severe weather events; and (iii) request the Company to file an updated emergency operations plan with both the PUCT and the El Paso City Council which will be completed in 2012. The El Paso City Council unanimously passed a motion to approve the three recommendations. At the January 10, 2012 El Paso City Council Meeting, the Company presented information requested in recommendations (i) and (ii) above.

Application of El Paso Electric Company to Amend its Certificate of Convenience and Necessity for Five Solar Power Generation Projects. On December 9, 2011, the Company filed a petition seeking a CCN to construct five solar powered generation projects, totaling approximately 2.6 MW, at four locations within the City of El Paso and one location in the Town of Van Horn. This case was assigned PUCT Docket No. 39973 and is still pending.

New Mexico Regulatory Matters

2009 New Mexico Stipulation. On May 29, 2009, the Company filed a general rate case using a test year ended December 31, 2008. The 2009 rate case was docketed as NMPRC Case No. 09-00171-UT. A comprehensive unopposed stipulation (the “2009 New Mexico Stipulation”) was reached in this general rate case and filed on October 8, 2009. The 2009 New Mexico Stipulation provided for an increase in New Mexico jurisdictional non-fuel and purchased power base rate revenues of $5.5 million. The new rate structure resulted in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. The 2009 New Mexico Stipulation provided for the revision of depreciation rates for the Palo Verde nuclear generating plant to reflect a 20-year life extension and a revision of depreciation rates for other plant in service. The 2009 New Mexico Stipulation also provided for the continuation of the Company's Fuel and Purchased Power Cost Adjustment Clause (“FPPCAC”) without conditions or variance. In addition, it modified the market pricing of capacity and energy provided by Palo Verde Unit 3 using a methodology based upon a previous purchased power contract with Credit Suisse Energy, LLC. On December 10, 2009, the NMPRC issued a final order conditionally approving and clarifying the unopposed stipulation, and the stipulated rates went into effect with January 2010 bills.

Application for Approval to Recover Regulatory Disincentives and Incentives. On August 31, 2010, the Company filed an application for approval of its proposed rate design methodology to recover regulatory disincentives and incentives associated with the Company's energy efficiency and load management programs in New Mexico. On March 18, 2011, the Company entered into an uncontested stipulation which would provide for a rate per kWh of energy efficiency savings that would be recovered through the efficient use of energy rider. A hearing on the uncontested stipulation was held on April 26, 2011 and briefs were filed on September 26, 2011. A final order was issued on November 22, 2011 in which the NMPRC did not adopt the unopposed stipulation, but modified the structure of the energy rider to reduce the return to two percent and made the mechanism temporary. The Company filed a Notice of Appeal with the Supreme Court of the State of New Mexico on January 20, 2012 on the grounds that the NMPRC's decision is arbitrary and without substantial evidence.

Application for a CCN for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a CCN to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the

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City of Sunland Park in southeast New Mexico. This case was assigned NMPRC Case No. 10-00301-UT. On April 13, 2011 an unopposed stipulation was filed in this case seeking approval of a CCN for the Company to construct, own and operate the 87 MW generating unit. A final order on this case approving the CCN was issued on June 23, 2011.

Application for Approval of 2011 New and Modified Energy Efficiency Programs. On February 15, 2011, the Company filed its Application for Approval of New and Modified Energy Efficiency Programs for 2011 with the NMPRC. On June 22, 2011, parties to this case entered into a partial stipulation, agreeing on all issues, except for a military base free-ridership issue. On June 24, 2011, the New Mexico Attorney General filed a statement in opposition to the proposed partial stipulation. On January 25, 2012, a hearing examiner issued a recommended decision modifying the stipulation by approving the Energy Efficiency programs and budgets with the exception of the Commercial Lighting Program, approving the adder for 2011 but not for 2012 or 2013 and excluding the Military Research & Development Class from participation in the rate rider and reducing the Company's required saving goals accordingly. On February 2, 2012, the Company filed certain exceptions to the recommended decision and requested an interim order related to this matter.

2011 Renewable Procurement Plan Pursuant to the Renewable Energy Act. On July 1, 2011, the Company filed its Application for Approval of its 2011 Renewable Procurement Plan with the NMPRC, which was assigned NMPRC Case No. 11-00263-UT. The filing identified renewable resources intended to meet the Company's Renewable Portfolio Standard (“RPS”) requirements in 2012 and 2013. The renewable resources in the 2011 Renewable Procurement Plan which were previously approved by the NMPRC, will allow the Company to meet the full RPS requirement of 10% of the Company's jurisdictional retail energy sales for 2012 and 2013. The Company's 2011 Renewable Procurement Plan also addresses the diversity targets in 2012 and 2013 required by NMPRC Rule 572 and demonstrates that the Company will meet those targets. The 2011 Renewable Procurement Plan also demonstrates that the Company will meet its solar diversity target in 2012 and comply with the terms of a previously-approved variance for 2011. A hearing in this case was held on October 13, 2011. A final order was issued on December 15, 2011 approving the 2011 Renewable Procurement Plan.

Investigation into Rates for Church Customers. On July 12, 2011, the NMPRC initiated an investigation into the rates the Company charges its church customers which were approved in Case No. 09-00171-UT. The investigation, Case No. 11-00276-UT, was ordered to determine whether the Company's rates to its church customers are unjust and unreasonable and should be revised. The Company filed a response on August 1, 2011. A mediation conference was held on August 23, 2011 which resulted in an Unopposed Joint Stipulation, filed on October 14, 2011. The stipulation limits billing impacts to religious organizations that take service under the Company's standard small commercial rate. The stipulation was approved by the NMPRC on October 27, 2011.

Revolving Credit Facility and Guarantee of Debt. On October 13, 2011, the Company received final approval from the NMPRC in Case No. 11-00349-UT to amend and restate the Company's $200 million revolving credit facility ("RCF"), which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016. The Company still has the ability to request that the RCF be increased to $300 million during the term of the RCF, subject to lender's approval. All other terms remain substantially the same.

Federal Regulatory Matters

Transmission Dispute with Tucson Electric Power Company ("TEP"). In January 2006, the Company filed a complaint with the FERC to interpret the terms of a Power Exchange and Transmission Agreement (the "Transmission Agreement") entered into with TEP in 1982. TEP filed a complaint with the FERC one day later raising virtually identical issues. TEP claimed that, under the Transmission Agreement, it was entitled to up to 400 MW of firm transmission rights on the Company's transmission system that would enable it to transmit power from the Luna Energy Facility ("LEF") located near Deming, New Mexico to Springerville or Greenlee in Arizona. The Company asserted that TEP's rights under the Transmission Agreement do not include transmission rights necessary to transmit such power as contemplated by TEP and that TEP must acquire any such rights in the open market from the Company at applicable tariff rates or from other transmission providers. On April 24, 2006, the FERC ruled in the Company's favor, finding that TEP does not have transmission rights under the Transmission Agreement to transmit power from the LEF to Arizona. The ruling was based on written evidence presented and without an evidentiary hearing. TEP's request for a rehearing of the FERC's decision was granted in part and denied in part in an order issued October 4, 2006, and hearings on the disputed issues were held before an administrative law judge. In the initial decision dated September 6, 2007, the administrative

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law judge found that the Transmission Agreement allows TEP to transmit power from the LEF to Arizona but limits that transmission to 200 MW on any segment of the circuit and to non-firm service on the segment from Luna to Greenlee. The Company and TEP filed exceptions to the initial decision.

On November 13, 2008, the FERC issued an order on the initial decision finding that the transmission rights given to TEP in the Transmission Agreement are firm and are not restricted for transmission of power from Springerville as the receipt point to Greenlee as the delivery point. Therefore, pursuant to the order, TEP can use its transmission rights granted under the Transmission Agreement to transmit power from the LEF to either Springerville or Greenlee so long as it transmits no more than 200 MW over all segments at any one time.

The FERC also ordered that the Company refund to TEP all sums with interest that TEP had paid it for transmission under the applicable transmission service agreements since February 2006 for service relating to the LEF. On December 3, 2008, the Company refunded $9.7 million to TEP. The Company had established a reserve for the rate refund of approximately $7.2 million as of September 30, 2008, resulting in a pre-tax charge to earnings of approximately $2.5 million in 2008. The Company
also paid TEP interest on the refunded balance of approximately $0.9 million, which was also charged to earnings in 2008. The Company filed a request for rehearing of the FERC's decision on December 15, 2008, seeking reversal of the order on the merits and a return of any refunds made in the interim, as well as compensation for all service that the Company may provide to TEP from the LEF over the Company's transmission system on a going forward basis. On July 7, 2010, the FERC denied the Company's request for rehearing. On July 23, 2010, the Company filed a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the “Court of Appeals”) and on August 18, 2010, TEP filed a motion to intervene in the proceeding. On January 14, 2011, the Company and TEP filed a joint consent motion, asking the Court to hold the proceedings in abeyance while the parties engaged in settlement discussions. The Court granted the motion on January 19, 2011.

On August 31, 2011, the FERC issued an order approving a settlement between TEP and the Company that became effective November 1, 2011. The settlement reduces TEP's transmission rights under the Transmission Agreement from 200 MW to 170 MW, and TEP and the Company have entered into two new firm transmission capacity agreements at applicable tariff rates for a total of 40 MW. Those two new service agreements were entered into and became effective November 1, 2011. Also under the terms of the settlement, TEP made a lump-sum cash payment to the Company of approximately $5.4 million for the period February 1, 2006 through September 30, 2011, including interest income. This adjustment was recorded in the three months ended September 30, 2011. The Company shared with its customers 25% of the transmission revenues earned before July 1, 2010, or approximately $0.7 million, through a credit to Texas fuel recoveries. As part of the settlement, the Company withdrew its appeal before the Court of Appeals.

In an ancillary proceeding, TEP filed a lawsuit in the United States District Court for the District of Arizona in December 2008, seeking reimbursement for amounts TEP paid a third party transmission provider for purchases of transmission capacity between April 2006 and May 2007, allegedly totaling approximately $1.5 million, plus accrued interest. TEP alleges that the Company was obligated to provide TEP with that transmission capacity without charge under the Transmission Agreement. As part of the settlement, this lawsuit was dismissed.

With the implementation of the settlement effective November 1, 2011, these matters between the Company and TEP were fully resolved.

Inquiry into Early February 2011 Outages and Curtailments. On February 14, 2011, the FERC directed its staff to initiate an inquiry into power plant outages and customer curtailments by power generators and gas suppliers in the Southwestern United States, including the Company, in early February 2011, as a result of the extreme cold weather. The FERC specifically stated that its inquiry is not an enforcement investigation. On August 16, 2011, the FERC released its staff report, Docket No. AD11-9-000, where it made recommendations to help prevent a recurrence of such outages in the future, and making no finding of violations or assessments of penalties.

Revolving Credit Facility and Guarantee of Debt. On October 13, 2011, the Company received final approval from the FERC in Docket No. ES11-43-000 to amend and restate the Company's $200 million RCF, which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016. The Company still has the ability to request that the RCF be increased to $300 million,

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subject to lender's approval. All other terms remain substantially the same. See "Energy Sources - Nuclear Fuel - Nuclear Fuel Financing."

Department of Energy. The DOE regulates the Company's exports of power to the Comisión Federal de Electricidad in Mexico pursuant to a license granted by the DOE and a presidential permit.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See "Facilities-Palo Verde Station-Spent Fuel Storage" for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission ("NRC"). The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards. The NRC also has the authority to grant license extensions pursuant to the Atomic Energy Act of 1954, as amended.

Sales for Resale

The Company provides firm capacity and associated energy to the RGEC pursuant to an ongoing contract with a two-year notice to terminate provision. The Company also provides network integrated transmission service to RGEC pursuant to the Company's Open Access Transmission Tariff ("OATT"). The contract includes a formula-based rate that is updated annually to recover non-fuel generation costs and a fuel adjustment clause designed to recover all eligible fuel and purchased power costs allocable to RGEC.

Power Sales Contracts

The Company has entered into several short-term (three months or less) off-system sales contracts throughout 2012.

Franchises and Significant Customers

El Paso and Las Cruces Franchises

The Company has a franchise agreement with El Paso, the largest city it serves. The franchise agreement allows the Company to utilize public rights-of-way necessary to serve its retail customers within El Paso. The Company also provides electric distribution service to Las Cruces under an implied franchise by satisfying all obligations under the franchise agreement that expired April 30, 2009.

The franchise agreements held between the Company and the cities of El Paso and Las Cruces are detailed below:

City	Period	Franchise Fee	(a)
El Paso	July 1, 2005 - August 1, 2010	3.25%	
El Paso	August 1, 2010 - Present	4.00%	(b)
Las Cruces	February 1, 2000 - Present	2.00%	

(a) Based on a percentage of revenue.
(b) The additional fee of 0.75% is to be placed in a restricted fund to be used solely for economic development and renewable energy purposes.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and Fort Bliss. The Company's sales to the military bases represent approximately 5% of annual retail revenues. The Company entered into a contract with Fort Bliss in October 2008, under which Fort Bliss takes retail electric service from the Company. The contract with Fort Bliss expired in 2010, and the Company is serving Fort Bliss under the applicable Texas tariffs. In April 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. The contract with White Sands expired in 2009, and the Company is serving White Sands under the applicable New Mexico tariffs. In March 2006, the Company signed a contract with Holloman for the Company to provide retail electric service and limited wheeling services to Holloman for a ten-year term expiring in January 2016.

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Item 1A. Risk Factors

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory, market prices for power, fuel prices, and the decisions of regulatory agencies. Our common stock price and creditworthiness will be affected by local, regional and national macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial condition and results of operations. These are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Our Revenues and Profitability Depend upon Regulated Rates

Our retail rates are subject to regulation by incorporated municipalities in Texas, the PUCT, the NMPRC and the FERC. The settlement approved in the Company's 2009 Texas rate case, PUCT Docket No. 37690, established the Company's current retail base rates in Texas, effective July 1, 2010. In addition, the settlement in the Company's 2009 New Mexico rate case, NMPRC Case No. 09 00171 UT, established rates in New Mexico that became effective January 2010. On February 1, 2012, we filed a request with the PUCT (Docket No. 40094), the City of El Paso and other Texas cities, for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring us to show cause why our base rates for customers in El Paso should not be reduced.

Our profitability depends on our ability to recover the costs, including a reasonable return on invested capital, of providing electric service to our customers through base rates approved by our regulators. These rates are generally established based on an analysis of the expenses we incur in a historical test year, and as a result, the rates ultimately approved by our regulators may or may not match our expenses at any given time. Rates in New Mexico may be established using projected costs and investment for a future test year period in certain instances. While rate regulation is based on the assumption that we will have a reasonable opportunity to recover our costs and earn a reasonable rate of return on our invested capital, there can be no assurance that our current and future Texas rate cases or our future rate cases in New Mexico will result in base rates that will allow us to fully recover our costs including a reasonable return on invested capital. There can be no assurance that regulators will determine that all of our costs are reasonable and have been prudently incurred. It is also likely that third parties will intervene in any rate cases and challenge whether our costs are reasonable and necessary. If all of our costs are not recovered through the retail base rates ultimately approved by our regulators, our profitability and cash flow could be adversely affected which, over time, could adversely affect our ability to meet our financial obligations.

We May Not Be Able To Recover All Costs of New Generation

The construction of our next generating plant addition, Rio Grande Unit 9, will add an aeroderivative unit with a generating capacity of 87 MW. It should reach commercial operation by May 2013. We have risk related to recovering all costs associated with the completion of the construction of Rio Grande Unit 9 and other new units.

In 2011, we refinanced and extended our revolving credit facility which could help fund the construction of this and other new units. The costs of financing and constructing these units will be reviewed in future rate cases in both Texas and New Mexico. To the extent that the PUCT or NMPRC determines that the costs of construction are not reasonable because of cost overruns, delays or other reasons, we may not be allowed to recover these costs from customers in base rates.

In addition, if this unit is not completed on time, we may be required to purchase power or operate less efficient generating units to meet customer requirements. Any replacement purchased power or fuel costs will be subject to regulatory review by the PUCT and NMPRC. We face financial risks to the extent that recovery is not allowed for any replacement fuel costs resulting from delays in the completion of this unit.

Continuing Weakness in the Economy and Uncertainty in the Financial Markets Could Reduce Our Sales, Hinder Our Capital Programs and Increase Our Funding Obligations for Pensions and Decommissioning

In recent years, the global credit and equity markets and the overall economy have been through a state of turmoil. These and future events could have a number of effects on our operations and our capital programs. For example, tight credit and capital markets could make it difficult and more expensive to raise capital to fund our operations and capital programs. If we are unable to access the credit markets, we could be required to defer or eliminate important capital projects in the future. In addition, recent stock market performance has provided returns that are below historic average for our financial assets and decommissioning trust investments. Such market results may also increase our funding obligations for our pension plans, other post-retirement benefit plans and nuclear decommissioning trusts. Changes in the corporate interest rates which we use as the discount rate to determine our pension and other post-retirement liabilities may have an impact on our funding obligations for such plans and trusts. Further, the continued volatile economy may result in reduced customer demand, both in the retail and wholesale markets, and increases

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in customer delinquencies and write-offs. The credit markets and overall economy may also adversely impact the financial health of our suppliers. If that were to occur, our access to and prices for inventory, supplies and capital equipment could be adversely affected. Our power trading counterparties could also be adversely impacted by the market and economic conditions which could result in reduced wholesale power sales or increased counterparty credit risk. This is not intended to be an exhaustive list of possible effects, and we may be adversely impacted in other ways.

Our Costs Could Increase or We Could Experience Reduced Revenues if
There are Problems at the Palo Verde Nuclear Generating Station

A significant percentage of our generating capacity, off-system sales margins, assets and operating expenses is attributable to Palo Verde. Our 15.8% interest in each of the three Palo Verde units totals approximately 633 MW of generating capacity. Palo Verde represents approximately 35% of our available net generating capacity and provided approximately 45% of our energy requirements for the twelve months ended December 31, 2011. Palo Verde comprises approximately 32% of our total net plant-in-service and Palo Verde expenses comprise a significant portion of operation and maintenance expenses. APS is the operating agent for Palo Verde, and we have limited ability under the ANPP Participation Agreement to influence operations and costs at Palo Verde. Palo Verde operated at a capacity factor of 90.7% and 90.4% in the twelve months ended December 31, 2011 and 2010, respectively.

Our ability to increase retail base rates in Texas and New Mexico is limited. We cannot assure that revenues will be sufficient to recover any increased costs, including any increased costs in connection with Palo Verde or other operations, whether as a result of inflation, changes in tax laws, regulatory requirements, or other causes.

We May Not Be Able to Recover All of Our Fuel Expenses from Customers

In general, by law, we are entitled to recover our reasonable and necessary fuel and purchased power expenses from our customers in Texas and New Mexico. NMPRC Case No. 09-00171-UT provides for energy delivered to New Mexico customers from the deregulated Palo Verde Unit 3 to be recovered through fuel and purchased power costs based upon a previous purchased power contract with Credit Suisse Energy, LLC. Fuel and purchased power expenses in New Mexico and Texas are subject to reconciliation by the PUCT and the NMPRC. Prior to the completion of a reconciliation, we record fuel and purchased power costs such that fuel revenues equal recoverable fuel and purchased power expense including the repriced energy costs for Palo Verde Unit 3 in New Mexico. Our current rate filing at the PUCT (Docket No. 40094) includes a request to reconcile $356.6 million of fuel expense for the period July 1, 2009 through September 30, 2011. In the event that recovery of fuel and purchased power expenses is denied in a reconciliation proceeding, the amounts recorded for fuel and purchased power expenses could differ from the amounts we are allowed to collect from our customers, and we would incur a loss to the extent of the disallowance.

In New Mexico, the FPPCAC allows us to reflect current fuel and purchased power expenses in the FPPCAC and to adjust for under-recoveries and over-recoveries with a two-month lag. In Texas, fuel costs are recovered through a fixed fuel factor. In Texas, we can seek to revise our fixed fuel factor based upon our approved formula at least four months after our last revision except in the month of December. If we materially under-recover fuel costs, we may seek a surcharge to recover those costs at any time the balance exceeds a threshold material amount and is expected to continue to be materially under-recovered. During periods of significant increases in natural gas prices, the Company realizes a lag in the ability to reflect increases in fuel costs in its fuel recovery mechanisms in Texas. As a result, cash flow is impacted due to the lag in payment of fuel costs and collection of fuel costs from customers. To the extent the fuel and purchased power recovery processes in Texas and New Mexico do not provide for the timely recovery of such costs, we could experience a material negative impact on our cash flow. At December 31, 2011 and 2010, the Company had a net under-collection balance of $7.0 million and a net over-collection balance of $19.0 million, respectively.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity require the use of expensive and complex equipment. While we have a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure and severe weather conditions. The advanced age of several of our gas-fired generating units in or near El Paso increases the vulnerability of these units. In addition, we are seeking to extend the lives of these plants. In the event of unplanned outages, we must acquire power from others at unpredictable costs in order to supply our customers and comply with our contractual agreements. This additional purchased power cost would be subject to review and approval of the PUCT and the NMPRC in reconciliation proceedings. As noted above, in the event that recovery for fuel and purchased power expenses could differ from the amounts we are allowed to collect from our customers, we would incur a loss to the extent of the disallowance. This can materially increase our costs and prevent us from selling excess power at wholesale, thus reducing our profits. In addition, actions of other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. We are particularly vulnerable to this because a significant portion of our available energy

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(at Palo Verde and Four Corners) is located hundreds of miles from El Paso and Las Cruces and must be delivered to our customers over long distance transmission lines. In addition, Palo Verde's availability is an important factor in realizing off-system sales margins. These factors, as well as interest rates, economic conditions, fuel prices and price volatility, are largely beyond our control, but may have a material adverse effect on our consolidated earnings, cash flow and financial position.

Competition and Deregulation Could Result in a Loss of Customers and Increased Costs

As a result of changes in federal law, our wholesale and large retail customers already have, in varying degrees, alternative sources of power, including co-generation of electric power. Deregulation legislation is in effect in Texas requiring us to separate our transmission and distribution functions, which would remain regulated, from our power generation and energy services businesses, which would operate in a competitive market, in the future. In 2004, the PUCT approved a rule delaying retail competition in our Texas service territory. This rule was codified in the Public Utility Regulatory Act ("PURA") in June 2011. PURA identifies various milestones that we must reach before retail competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of a regional transmission organization in the area that includes our service territory. This and other milestones are not likely to be achieved for a number of years, if they are achieved at all. There is substantial uncertainty about both the regulatory framework and market conditions that would exist if and when retail competition is implemented in our Texas service territory, and we may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect our future operations, cash flow and financial condition.

Future Costs of Compliance with Environmental Laws and Regulations Could
Adversely Affect Our Operations and Consolidated Financial Results

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to discharges into the air, air quality, discharges of effluents into water, water quality, the use of water, the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, natural resources, and health and safety. Compliance with these legal requirements, which change frequently and often become more restrictive, could require us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of air quality control equipment and purchases of air emission allowances and/or offsets. Costs of compliance with environmental laws and regulations or fines or penalties resulting from non-compliance, if not recovered in our rates, could adversely affect our operations and/or consolidated financial results, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increases. We cannot estimate our compliance costs or any possible fines or penalties with certainty, or the degree to which such costs might be recovered in our rates, due to our inability to predict the requirements and timing of implementation of environmental rules or regulations. For example, the EPA has issued in the recent past various final and proposed regulations regarding air emissions from our operations as well as the rest of the utility sector, including the CSAPR and the Utility MACT. If these regulations survive legal and Congressional challenges, the cost to us to comply could adversely affect our operations and consolidated financial results.

Climate Change and Related Legislation and Regulatory Initiatives Could Affect Demand for
Electricity or Availability of Resources, and Could Result in Increased Compliance Costs

The Company emits GHGs through the operation of its power plants. Federal legislation had been introduced in both houses of Congress to regulate the emission of GHGs and numerous states have adopted programs to stabilize or reduce GHG emissions. Additionally, the EPA is proceeding with regulation of GHG under the CAA. Under EPA regulations finalized in May 2010, the EPA began regulating GHG emissions from certain stationary sources, such as power plants, in January 2011. In 2012, EPA plans to publish draft rules to regulate GHG from new or modified power plants. Further, state regulation may precede federal GHG legislation. In the State of New Mexico, where we operate one facility and have an interest in another facility, the New Mexico Environmental Improvement Board approved two separate rulemakings in November and December 2010 to limit GHG emissions. To date, one of these rulemakings has been repealed by the New Mexico Environmental Improvement Board. There are various uncertainties relating to the remaining regulation, including whether current legal challenges to it will be successful,

but as drafted, we do not expect this regulation to result in significant costs to us.
It is not currently possible to predict how any pending, proposed or future GHG legislation by Congress, the states or multi-state regions or any such regulations adopted by the EPA or state environmental agencies will impact our business. However, any legislation or regulation of GHG emissions or any future related litigation could result in increased compliance costs or additional operating restrictions or increased or reduced demand for our services, could require us to purchase rights to emit GHG, and could have a material adverse effect on our business, financial condition, reputation or results of operations.

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Item 1B. Unresolved Staff Comments
None.

Executive Officers of the Registrant
The executive officers of the Company are elected annually and serve at the discretion of the Board of Directors. The executive officers of the Company as of February 24, 2012, were as follows:

Name	Age	Current Position and Business Experience
Thomas V. Shockley III	66	Interim Chief Executive Officer since January 2012; Vice – Chairman and Chief Operating Officer for American Electric Power from June 2000 to August 2004; retired in 2004.
David W. Stevens *	52	Chief Executive Officer since November 2008; Principal of Professional Consulting Services, LLC from December 2007 to November 2008; President, Chief Executive Officer and Board Member for Cascade Natural Gas Corporation from April 2005 to July 2007.
David G. Carpenter	56	Senior Vice President and Chief Financial Officer since August 2009; Vice President – Regulatory Services and Controller from September 2008 to August 2009; Vice President – Corporate Planning and Controller from August 2005 to September 2008.
Richard G. Fleager	61	Senior Vice President – Customer Care and External Affairs since April 2009; Vice President for Texas Gas Service from September 1997 to March 2009.
Mary E. Kipp	44	Senior Vice President, General Counsel and Chief Compliance Officer since June 2010; Vice President – Legal and Chief Compliance Officer from December 2009 to June 2010; Assistant General Counsel and Director of FERC Compliance from December 2007 to December 2009; Senior Enforcement Attorney – FERC from January 2004 to December 2007.
Rocky R. Miracle	58	Senior Vice President – Corporate Planning and Development since August 2009; Vice President – Corporate Planning from September 2008 to August 2009; Director of Business Operations Support – Texas Operations for American Electric Power Services Corporation from August 2004 to August 2008.
Hector R. Puente	55	Senior Vice President – Operations since May 2011; Vice President – Transmission and Distribution from May 2006 to May 2011.
Steven T. Buraczyk	44	Vice President – System Operations and Planning since January 2011; Vice President – Power Marketing and Fuels from July 2008 to January 2011; Director of Power Marketing and Fuels from August 2006 to July 2008.
Steven P. Busser	43	Vice President – Treasurer since January 2011; Vice President – Treasurer and Chief Risk Officer from May 2006 to January 2011.
Robert C. Doyle	52	Vice President – Transmission and Distribution since June 2011; Vice President – New Mexico Affairs from February 2007 to June 2011; Director – New Mexico Affairs from January 2007 to February 2007.
Nathan T. Hirschi	48	Vice President and Controller since March 2010; Vice President – Special Projects from December 2009 to February 2010; Partner for KPMG LLP from October 2003 to April 2009.
Kerry B. Lore	52	Vice President – Customer Care since December 2008; Vice President – Administration from May 2003 to December 2008.

Andres R. Ramirez	51	Vice President – Power Generation since February 2006.
Guillermo Silva, Jr.	58	Corporate Secretary since February 2006.
John A. Whitacre	62	Vice President – Power Marketing and Fuels since January 2011; Vice President – System Operations and Planning from May 2006 to January 2011.

* On January 30, 2012, Mr. Stevens resigned from his position as Chief Executive Officer of the Company, effective March 2, 2012, and as a Director immediately. The Board of Directors appointed Mr. Shockley to serve as interim Chief Executive Officer initially during a transition period until Mr. Stevens' departure and thereafter while a search is conducted to replace Mr. Stevens.

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Item 2. Properties

The principal properties of the Company are described in Item 1, “Business,” and such descriptions are incorporated herein by reference. Transmission lines are located either on private rights-of-way, easements, or on streets or highways by public consent.

The Company owns an executive and administrative office building in El Paso. The Company leases land in El Paso adjacent to the Newman Power Station under a lease which expires in June 2033 with a renewal option of 25 years. The Company also leases certain warehouse facilities in El Paso under a lease which expires in December 2014. The Company has several other leases for office and parking facilities which expire within the next five years.

Item 3. Legal Proceedings

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, to the extent that the Company has been able to reach a conclusion as to its ultimate liability, it believes that none of these claims will have a material adverse effect on the financial position, results of operations or cash flows of the Company.

See “Environmental Matters” and “Regulation” for discussion of the effects of government legislation and regulation on the Company.

Item 4. Removed and Reserved

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PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Company's common stock trades on the New York Stock Exchange ("NYSE") under the symbol "EE." The high, low and close sales prices for the Company's common stock, as reported in the consolidated reporting system of the New York Stock Exchange, and quarterly dividends per share paid by the Company for the periods indicated below were as follows:

	Sales Price High	Low	Close (End of period)	Dividends
2010				
First Quarter	$20.98	$18.74	$20.60	$—
Second Quarter	22.15	18.76	19.35	—
Third Quarter	23.82	18.81	23.78	—
Fourth Quarter	28.65	23.51	27.53	—
2011				
First Quarter	$30.68	$26.65	$30.40	$—
Second Quarter	32.40	29.09	32.30	0.22
Third Quarter	35.65	29.82	32.09	0.22
Fourth Quarter	35.71	30.29	34.64	0.22

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Performance Graph

The following graph compares the performance of the Company's Common Stock to the performance of the NYSE Composite, and the Edison Electric Institute's Index of investor-owned electric utilities setting the value of each at December 31, 2006 to a base of 100. The table sets forth the relative yearly percentage change in the Company's cumulative total shareholder return as compared to the NYSE, and the EEI, as reflected in the graph.

	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
EE	100	105	74	83	113	142
EEI	100	117	86	96	102	123
NYSE US	100	107	63			