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and considered to be contributions to the plan, were $0.4 million in the three months ended June 30, 2010 and 2009, $0.7 million and $0.8 million in the six months ended June 30, 2010 and 2009, and are expected to total $1.5 million during 2010.

TNMP Plans

The following tables present the components of the TNMP Plans' net periodic benefit cost (income):

	Three Months Ended June 30,					
	Pension Plan		Other Postretirement Benefits		Executive Retirement Program	
	2010	2009	2010	2009	2010	2009
	(In thousands)					
Components of Net Periodic Benefit Cost (Income)						
Service cost	$ -	$ -	$ 72	$ 65	$ -	$ -
Interest cost	1,032	1,099	178	183	13	19
Long-term return on plan assets	(1,449)	(1,523)	(129)	(124)	-	-
Amortization of net gain	-	-	(49)	(66)	(1)	-
Amortization of prior service cost	-	-	15	15	-	-
Net Periodic Benefit Cost (Income)	$ (417)	$ (424)	$ 87	$ 73	$ 12	$ 19

	Six Months Ended June 30,					
	Pension Plan		Other Postretirement Benefits		Executive Retirement Program	
	2010	2009	2010	2009	2010	2009
	(In thousands)					
Components of Net Periodic Benefit Cost (Income)						
Service cost	$ -	$ -	$ 144	$ 130	$ -	$ -
Interest cost	2,063	2,198	356	366	26	38
Long-term return on plan assets	(2,897)	(3,047)	(257)	(247)	-	-
Amortization of net gain	-	-	(98)	(132)	(2)	-
Amortization of prior service cost	-	-	30	30	-	-
Net Periodic Benefit Cost (Income)	$ (834)	$ (849)	$ 175	$ 147	$ 24	$ 38

TNMP made no contributions to its pension plan trust in the three and six months ended June 30, 2010 and 2009 but anticipates making contributions of approximately $0.3 million in 2010. Based on current law and estimates of portfolio performance, TNMP estimates making contributions to its pension plan trust that total $10.5 million for years 2011-2014. The estimated contributions were developed using a probabilistically weighted average discount rate of 5.9% to determine the projected benefit obligation under the pension plan. Actual amounts to be funded in the future will be dependent on the actuarial assumptions at that time, including the appropriate discount rate. For the three months ended June 30, 2010 and 2009, TNMP made $0.6 million and $0.3 million in contributions to the trust for other postretirement benefits and $0.6 million and $0.3 million for the six months ended June 30, 2010 and 2009. TNMP does not expect to make additional contributions during the remainder of 2010. Disbursements under the executive retirement program, which are funded by the Company and considered to be contributions to the plan, were less than $0.1 million in the three and six months ended June 30, 2010 and 2009, and are expected to total $0.1 million during 2010.

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(9) Commitments and Contingencies

Overview

There are various claims and lawsuits pending against the Company. The Company is also subject to federal, state and local environmental laws and regulations, and is currently participating in the investigation and remediation of numerous sites. In addition, the Company periodically enters into financial commitments in connection with its business operations. The Company is also involved in various legal proceedings in the normal course of its business. It is not possible at this time for the Company to determine fully the effect of all litigation and other legal proceedings on its results of operations or financial position. It is the Company's policy to accrue for expected liabilities in accordance with GAAP when it is probable that a liability has been incurred and the amount to be incurred is reasonably estimable. The Company cannot make any assurances that the amount of reserves or potential insurance coverage will be sufficient to cover the cash obligations that might be incurred as a result of litigation or regulatory proceedings. Outside legal costs for these and regulatory matters are recorded when the expenses are incurred. The Company does not expect that any known lawsuits, environmental costs, and commitments will have a material adverse effect on its financial condition, results of operations, or cash flows, although the outcome of litigation, investigations, and other legal proceedings is inherently uncertain.

With respect to some of the items listed below, the Company has determined that a loss is not probable or that, to the extent probable, is not reasonably estimable. In some cases, the Company is not able to predict with any degree of certainty the range of possible loss that could be incurred. Notwithstanding these facts, the Company has assessed these matters based on current information and made judgments concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of damages sought, and the probability of success. Such judgments are made subject to the known uncertainty of litigation. The Company has established appropriate reserves for matters where it is probable a loss has been incurred and the amount of loss is reasonably estimable. The actual outcomes of the items listed below could ultimately differ from the judgments made and the differences could be material.

Additional information concerning commitments and contingencies is contained in Note 16 of Notes to Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K.

Commitments and Contingencies Related to the Environment

Nuclear Spent Fuel and Waste Disposal

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Policy Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE announced that it would not be able to open the repository by 1998 and sought to excuse its performance under the contract. In November 1997, the U.S. 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. Based on this decision and the DOE's delay, a number of utilities, including APS (on behalf of itself and the other PVNGS owners, including PNM), filed damages actions against the DOE in the Court of Federal Claims. 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 awarded APS and the other PVNGS owners, including PNM, $30.2 million. PNM's share of this amount is $3.1 million. Because the appeal period of this decision has not yet passed, PNM has not recorded this amount on its financial statements. PNM currently estimates that it will incur approximately $46.1 million (in 2007 dollars) over the current life of PVNGS for its share of the fuel costs related to the on-site interim storage of spent nuclear fuel during the operating life of the plant. PNM accrues these costs as a component of fuel expense, meaning that the charges are accrued as the fuel is burned. At June 30, 2010 and December 31, 2009, PNM had $15.4 million and $15.0 million recorded as a liability on its Condensed Consolidated Balance Sheets for interim storage costs.

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The Clean Air Act

Regional Haze

The EPA has established rules addressing regional haze and guidelines for BART determinations. The rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas. In particular, the alternatives rule defines how an SO_2 emissions trading program developed by the Western Regional Air Partnership, a voluntary organization of western states, tribes and federal agencies, can be used by western states. New Mexico will be participating in the SO_2 program, which is a trading program that will be implemented if SO_2 reduction milestones, which are still being developed, are not met.

SJGS

In November 2006, the NMED requested a BART analysis for NO_x and particulates for each of the four units at SJGS. PNM submitted the analysis to the NMED in early June 2007, recommending against installing additional pollution control equipment on any of the SJGS units beyond those planned at that time, the installation of which was completed in March 2009. PNM subsequently provided additional data in response to requests from the NMED. On June 21, 2010, the NMED filed its proposed regional haze SIP with the EIB. The NMED filing included a finding by the NMED that BART for NO_x at SJGS is a technology known as "selective catalytic reduction" ("SCR") plus "sorbent injection." PNM disagrees with this BART determination and plans to vigorously challenge the finding.

As part of its 2007 submission, PNM analyzed SCR and concluded it was not appropriate as BART. However, PNM estimated that, at that time, the cost of installation of the SCR technology at SJGS would be approximately $750 million for the entire station, of which PNM's share would be approximately 46.3% based on its SJGS ownership percentage. In its filing, the NMED stated that it did not necessarily agree with PNM's estimate and that it expected the actual costs for SCR technology to be lower than PNM's estimate. Installation of the sorbent injection technology would cost an additional approximately $40 million for the entire station. These technologies would also increase operating costs at SJGS. PNM would seek recovery from its ratepayers of all costs that may ultimately be incurred.

The EIB has set the matter for hearing in October 2010. Following the hearing and if approved by EIB, the approved SIP would be submitted to EPA Region 6 for approval. The EPA process would include a sixty day public comment period. If the SIP and BART determination proposed by the NMED are ultimately approved and upheld, the SJGS participants would have five years to achieve compliance with such BART requirements. PNM continues to assess the NMED proposal and is unable at this time to predict the ultimate outcome of this matter or the financial impact of these requirements on PNM or PNM's ratepayers.

Four Corners

The EPA previously requested APS to perform a BART analysis for Four Corners. APS submitted an analysis to the EPA concluding that certain combustion control equipment constitutes BART for Four Corners. Based on the analyses and comments received through EPA's rulemaking process, the EPA will determine what it believes constitutes BART for Four Corners. The EPA recently issued an Advanced Notice of Proposed Rulemaking seeking public comments on its BART determination. The public comment period initially expired in October 2009, but the EPA extended the comment period until March 20, 2010. APS anticipates the EPA will issue proposed and final BART determinations for Four Corners in 2010. The participant owners of Four Corners will have five years after the EPA issues its final determination to achieve compliance with their respective BART requirements. In addition, on February 16, 2010, a group of environmental organizations filed a petition with the U.S. Departments of Interior and Agriculture requesting those agencies to certify to the EPA that visibility impairment in sixteen national park and wilderness areas is reasonably attributable to emissions from Four Corners.

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If those agencies certify impairment, the EPA is required to evaluate and, if necessary, determine BART for Four Corners. APS' recommended plan for Four Corners includes the installation of combustion control equipment with an estimated cost to PNM, based on preliminary engineering estimates, of approximately $6.8 million. If the EPA determines that post-combustion controls are required, PNM's total costs could be up to approximately $69.0 million for Four Corners. PNM would seek recovery from its ratepayers of all costs that may ultimately be incurred. The obligation to comply with the EPA's final BART determinations, coupled with the financial impact of future climate change legislation, other environmental regulations, and other business considerations, could jeopardize the economic viability of Four Corners or the ability of individual participants to continue their participation in the plant. In particular, SCE, a participant in Four Corners, has indicated that certain California legislation may prohibit it from making emission control expenditures at the plant. In order to coordinate with Four Corners' other scheduled activities, APS is currently implementing portions of its recommended plan on a voluntary basis. Costs related to the implementation of these portions of the recommended plan are included in PNM's 2010 and 2011 construction expenditure estimates.

While the Company continues to monitor this matter, at the present time, the Company cannot predict whether the EPA will agree with APS' BART recommendations. If the EPA disagrees with APS' recommendations for Four Corners, the Company cannot predict the nature of the BART controls the EPA may ultimately mandate or the resulting financial or operational impact.

Ozone Non-Attainment

In March 2009, the NMED published its draft recommendation of area designations for the 2008 revised ozone national ambient air quality standard. The draft recommended that San Juan County, New Mexico be designated as non-attainment for ozone. SJGS is situated in San Juan County. However, the NMED subsequently determined that the monitor indicating high ozone levels was not reliable and did not recommend to the EPA that San Juan County be designated as non-attainment. On January 6, 2010, EPA announced it would strengthen the 8-hour ozone standard by setting the standard in a range of 0.060-0.070 parts per million ("ppm"). The EPA will make its final determination of the exact number by August 31, 2010. If EPA sets the standard at 0.070 ppm, it is projected that San Juan County and Dona Ana County will be designated as non-attainment for ozone. If the standard is set lower than 0.070 ppm, other counties in the state, including Bernalillo County, may be designated as non-attainment. A non-attainment designation for Bernalillo County could result in the requirement to reduce NOx emissions from Reeves Station by 2014, and a non-attainment designation for San Juan County could result in the requirement to reduce NO_x emissions from SJGS by 2014. The Company cannot predict the outcome of this matter or if additional NO_x controls would be required as a result of ozone non-attainment designation.

Citizens Suit under the Clean Air Act

On May 10, 2005, PNM and the other owners of SJGS resolved the Grand Canyon Trust's and Sierra Club's Citizens Suit under the Clean Air Act and NMED's threatened administrative compliance order by entry of a Consent Decree. As required by the Consent Decree, PNM submitted reports addressing mercury emission controls for SJGS. Plaintiffs and NMED rejected PNM's reports. PNM disputes the validity of the rejection of the reports. On May 17, 2010, PNM filed a petition with the federal district court seeking a judicial determination on the dispute relating to PNM's mercury controls. NMED and plaintiffs seek to require PNM to implement mercury controls that PNM estimates would increase annual operating costs for the entire station by as much as $42 million. PNM cannot predict the outcome of these disputes.

Navajo Nation Environmental Issues

Four Corners is located on the Navajo Reservation and is held under an easement granted by the federal government as well as a lease from the Navajo Nation. The Navajo Acts, enacted in 1995 by the Navajo Nation, purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners. In October 1995, the Four Corners participants filed a lawsuit in the District Court of the Navajo Nation, Window Rock

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District, challenging the applicability of the Navajo Acts as to Four Corners. The District Court stayed these proceedings pursuant to a request by the parties and the parties are seeking to negotiate a settlement.

In 2000, the Navajo Tribal Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. The Four Corners participants believe that the regulations fail to recognize that the Navajo Nation did not intend to assert jurisdiction over Four Corners. Each of the Four Corners participants filed a petition with the Navajo Nation Supreme Court for review of the operating permit regulations. Those proceedings have been stayed, pending the outcome of the settlement negotiations mentioned above.

In May 2005, APS and the Navajo Nation signed a Voluntary Compliance Agreement ("VCA") resolving the dispute regarding the Navajo Nation Air Pollution Prevention and Control Act portion of the lawsuit. On March 21, 2006, the EPA determined that the Navajo Nation was eligible for "treatment as a state" for the purpose of entering into a supplemental delegation agreement with the EPA to administer the Clean Air Act Title V, Part 71 federal permit program over Four Corners. The EPA entered into the supplemental delegation agreement with the Navajo Nation on the same day. Because the EPA's approval was consistent with the requirements of the VCA, APS sought dismissal of the pending litigation in the Navajo Nation Supreme Court, as well as the pending litigation in the Navajo Nation District Court to the extent the claims relate to the Clean Air Act, and the Courts have dismissed the claims accordingly. The agreement does not address or resolve any dispute relating to other aspects of the Navajo Acts.

The Company cannot currently predict the outcome of these matters.

Section 114 Request

On April 6, 2009, APS received a request from the EPA under Section 114 of the Clean Air Act seeking detailed information regarding projects at and operations of Four Corners. This request is part of an enforcement initiative that the EPA has undertaken under the Clean Air Act. 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 NSR provisions of the Clean Air Act. Other electric utilities have received and responded to similar Section 114 requests, and several of them have been the subject of notices of violation and lawsuits by the EPA. APS has responded to the EPA's request. The Company is currently unable to predict the timing or content of EPA's response or any resulting actions.

Four Corners Notice of Intent to Sue

On May 7, 2010, APS received a Notice of Intent to Sue from Earthjustice, on behalf of several environmental organizations, related to alleged violations of the Clean Air Act at Four Corners. The notice alleges new source review-related violations and new source performance standard violations. Under the Clean Air Act, a citizens group is required to provide 60 days advance notice of its intent to file a lawsuit. Within that 60-day time period, the EPA may step in and file a lawsuit regarding the allegations. If the EPA does so, the citizens group is precluded from filing its own lawsuit, but it may still intervene in the EPA's lawsuit, if it so desires. The 60-day period lapsed in early July, and the EPA did not take any action. At this time, the Company cannot predict whether or when Earthjustice might file a lawsuit.

Santa Fe Generating Station

PNM and the NMED conducted investigations of gasoline and chlorinated solvent groundwater contamination detected beneath the site of the former Santa Fe Generating Station to determine the source of the contamination pursuant to a 1992 settlement agreement between PNM and the NMED.

PNM believes that the data compiled indicates observed groundwater contamination originated from off-site sources. However, to avoid a prolonged legal dispute, PNM entered into settlement agreements with the NMED under which PNM agreed to install a remediation system to treat water from a City of Santa Fe municipal supply well and install an additional extraction well and two new monitoring wells to address gasoline contamination in the groundwater at and in the vicinity of the site. PNM will continue to operate the remediation facilities until the groundwater meets applicable federal and state standards or until such time as the NMED determines that additional remediation is not required, whichever is earlier. The well continues to operate and meets federal drinking water standards. PNM is not able to assess the duration of this project.

The Superfund Oversight Section of the NMED has conducted multiple investigations into the chlorinated solvent plume in the vicinity of the site of the former Santa Fe Generating Station. In February 2008, a NMED site inspection report was submitted to the EPA, which states that neither the source nor extent of contamination has been determined and also states that the source may not be the former Santa Fe Generating Station. The NMED investigation is ongoing. The Company is unable to predict the outcome of this matter.

Coal Combustion By-Products

Regulation

SJGS does not operate any CCB impoundments. SJCC currently disposes of CCBs consisting of fly ash, bottom ash, and gypsum from SJGS in the surface mine pits adjacent to the plant. The Mining and Minerals Division of the New Mexico Energy, Minerals and Natural Resources Department currently regulates mine placement of ash at the mine with federal oversight by the U.S. Department of Interior's Office of Surface Mining ("OSM"). APS currently disposes of CCBs in ash ponds and dry storage areas at Four Corners, and also sells a portion of its fly ash for beneficial uses, such as a constituent in concrete production. Ash management at the Four Corners plant is regulated by the EPA and the New Mexico State Engineer's Office.

On May 4, 2010, the EPA issued a proposed rulemaking to regulate CCBs. The proposal asks for public comment on two approaches for regulating CCBs. One option is to regulate CCBs under Subtitle C of the RCRA as a hazardous waste which allows the EPA to create a comprehensive federal program for waste management and disposal of CCBs. The other option is to regulate CCBs under RCRA Subtitle D as a non-hazardous waste. This provides the EPA with the authority to develop performance standards for waste management facilities handling the CCBs and would be enforced primarily through citizen suits. Both options allow for continued use of CCBs in beneficial applications. EPA's proposal does not address the placement of CCBs in surface mine pits for reclamation. The EPA has indicated that it will work with the OSM to develop federal regulations for placement of CCBs in minefill operations. The proposed rule also states that the EPA and OSM will consider the recommendations of the National Research Council, which, at the direction of Congress, studied the health, safety and environmental risks associated with the placement of CCBs in U.S. coal mines. The 2006 report concluded that the "placement of coal combustion residues in mines as part of coal mine reclamation may be an appropriate option for the disposal of this material". On June 21, 2010, the EPA published the proposed rule in the Federal Register. There is a 90-day public comment period for the proposal. PNM, along with other utility companies and industry representatives, has requested a 120-day extension of the comment period on which EPA has yet to make a ruling.

PNM advocates for the non-hazardous regulation of CCBs under Subtitle D of RCRA. PNM is encouraged by the EPA's proposed decision to develop separate federal regulations in conjunction with the OSM for mine placement of CCBs and believes the proper place for regulatory oversight should come from the OSM and state mining and mining reclamation agencies. In addition, PNM believes the decision by EPA to consider the conclusions of the National Research Council study in the development of federal regulations regarding placement of CCBs in minefilling operations is a prudent one. PNM cannot predict the outcome of the EPA's or OSM's proposed rulemaking regarding CCB regulation, including mine placement of CCBs, or whether these actions will have a material adverse impact on its operations or financial position.

Sierra Club Actions

In December 2009, PNM and PNMR received a Notice of Intent to Sue ("RCRA Notice") under the RCRA from the Sierra Club. The RCRA Notice was also sent to all SJGS owners, to SJCC, which operates the San Juan Mine that supplies coal to SJGS, and to BHP. Additionally, PNM was informed that SJCC and BHP received a separate notice of intent to sue under the Surface Mine Control and Reclamation Act ("SMCRA") from the Sierra Club. On April 8, 2010, the Sierra Club filed suit in the U.S. District Court for the District of New Mexico against PNM, PNMR, SJCC, and BHP. In the suit, the Sierra Club alleges that activities at SJGS and the San Juan Mine are causing imminent and substantial harm to the environment, including ground and surface water in the region, and that placement of CCBs at the San Juan Mine constitutes "open dumping" in violation of RCRA. The claims under RCRA are asserted with respect to PNM, PNMR, SJCC and BHP. The suit also includes claims under SMCRA, which are directed only against SJCC and BHP. The complaint requests judgment for the following relief: an injunction requiring the parties to undertake certain mitigation measures with respect to the placement of CCBs at the mine or to cease placement of CCBs at the mine; the imposition of civil penalties; and an award of plaintiff's attorney's fees and costs. On July 10, 2010, the Sierra Club filed an amended complaint that corrected some technical deficiencies in its original complaint. The factual allegations remained the same. PNM and PNMR plan an aggressive defense of the RCRA claims and cannot predict the outcome of this matter at the present time.

Gila River Indian Reservation Superfund Site

In April 2008, the EPA informed PNM that it may be a PRP in the Gila River Indian Reservation Superfund Site in Maricopa County, Arizona. PNM, along with SRP, APS and EPE, owns a parcel of property on which a transmission pole and a portion of a transmission line are located. The property abuts the Gila River Indian Community boundary and, at one time, may have been part of an airfield where crop dusting took place. Currently, the EPA is only seeking payment from PNM and other PRPs for past cleanup-related costs involving contamination from the crop dusting. Based upon the total amount of cleanup costs reported by the EPA in its letter to PNM, the resolution of this matter is not expected to have a material adverse impact on PNM's financial position, results of operations, or cash flows.

Other Commitments and Contingencies

Coal Supply

The coal requirements for SJGS are being supplied by SJCC, a wholly owned subsidiary of BHP. In addition to coal delivered to meet the current needs of SJGS, PNM prepays SJCC for certain coal mined but not yet delivered to the plant site. At June 30, 2010 and December 31, 2009, prepayments for coal amounted to $33.8 million. APS purchases all of Four Corners' coal requirements from a supplier with a long-term lease of coal reserves with the Navajo Nation. The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. In 2003, PNM completed a comprehensive review of the final reclamation costs for both the surface mines that previously provided coal to SJGS and the current underground mine providing coal. Based on this study, PNM revised its estimates of the final reclamation costs. In 2009, this study was updated. In July 2010, the mining contract for Four Corners, which runs through 2016, was restructured with pricing to be determined using an escalating base-price. The estimate for decommissioning the Four Corners mine is being revised with completion expected later in 2010. Based on the most recent estimates, the final costs of mine reclamation, net of contract buyout costs paid to SJCC and reclamation payments made through June 30, 2010, are estimated to be $58.1 million for the surface mines at both SJGS and Four Corners and $23.3 million for the underground mine at SJGS, in future dollars. As of June 30, 2010 and December 31, 2009, obligations of $25.6 million and $26.6 million for surface mine reclamation and $2.5 million and $2.3 million for underground mining activities were recognized on PNM's Condensed Consolidated Balance Sheets using the fair value method to determine the liability.

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PVNGS Liability and Insurance Matters

The PVNGS participants are insured against public liability for a nuclear incident up to $12.6 billion per occurrence. As required by the Price Anderson Nuclear Industries Indemnity Act, the PVNGS participants maintain the maximum available nuclear liability insurance in the amount of $375 million, which is provided by commercial insurance carriers. The remaining balance of $12.2 billion is provided through a mandatory industry wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, PNM could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is $117.5 million, subject to an annual limit of $17.5 million per incident, to be periodically adjusted for inflation. Based on PNM's 10.2% interest in the three PVNGS units, PNM's maximum potential assessment per incident for all three units is $36.0 million, with an annual payment limitation of $5.4 million.

The PVNGS participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at PVNGS in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. PNM and certain other participants have also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). PNM is subject to retrospective assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount of retrospective assessments PNM could incur under the current NEIL policies totals $5.8 million. The insurance coverage discussed in this and the previous paragraph is subject to policy conditions and exclusions.

Water Supply

Because of New Mexico's arid climate and periodic drought conditions, there is a growing concern in New Mexico about the use of water for power plants. PNM has secured water rights in connection with the existing plants at Afton, Luna and Lordsburg. Water availability does not appear to be an issue for these plants at this time.

The "four corners" region of New Mexico, in which SJGS and Four Corners are located, experienced drought conditions during 2002 through 2004 that could have affected the water supply for PNM's generation plants. In future years, if adequate precipitation is not received in the watershed that supplies the four corners region, these plants could be impacted. Consequently, PNM, APS, and BHP have undertaken activities to secure additional water supplies for SJGS, Four Corners, and related mines. PNM has reached an agreement for a voluntary shortage sharing agreement with tribes and other water users in the San Juan Basin for a term ending December 31, 2012. Further, PNM and BHP have reached agreement on a long-term supplemental contract relating to water for SJGS with the Jicarilla Apache Nation that ends in 2016. APS and BHP have entered into a similar contract for Four Corners. Although the Company does not believe that its operations will be materially affected by the drought conditions at this time, it cannot forecast the weather situation or its ramifications, or how regulations and legislation may impact the Company should shortages occur in the future.

In April 2010, APS signed an agreement on behalf of the PVNGS participants with five cities to provide cooling water essential to power production at PVNGS for the next forty years.

PVNGS Water Supply Litigation

A summons was served on APS in 1986 that required all water claimants in the Lower Gila River Watershed of Arizona to assert any claims to water on or before January 20, 1987, in an action pending in the Maricopa County Superior Court. PVNGS is located within the geographic area subject to the summons. APS' rights and the rights of the other PVNGS participants to the use of groundwater and effluent at PVNGS are potentially at issue in this action. APS filed claims that dispute the court's jurisdiction over PVNGS' groundwater rights and their contractual

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rights to effluent relating to PVNGS and, alternatively, seek confirmation of those rights. In 1999, the Arizona Supreme Court issued a decision finding that certain groundwater rights may be available to the federal government and Indian tribes. In addition, the Arizona Supreme Court issued a decision in 2000 affirming the lower court's criteria for resolving groundwater claims. Litigation on both these issues has continued in the trial court. No trial dates have been set in these matters. PNM does not expect that this litigation will have a material adverse impact on its results of operation, financial position, or cash flows.

San Juan River Adjudication

In 1975, the State of New Mexico filed an action entitled "State of New Mexico v. United States, et al.", in the District Court of San Juan County, New Mexico, to adjudicate all water rights in the San Juan River Stream System. PNM was made a defendant in the litigation in 1976. The action is expected to adjudicate water rights used at Four Corners and at SJGS. In 2005, the Navajo Nation and various parties announced a settlement of the Navajo Nation's reserved surface water rights. On March 30, 2009, President Obama signed legislation confirming the settlement with the Navajo Nation. The Company cannot determine the effect, if any, of any water rights adjudication on the present arrangements for water at SJGS and Four Corners. Final resolution of the case cannot be expected for several years. The Company is unable to predict the ultimate outcome of this matter. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss.

Conflicts at San Juan Mine Involving Oil and Gas Leaseholders

SJCC, through leases with the federal government and the State of New Mexico, owns coal interests with respect to the San Juan underground mine. Certain gas producers have leases in the area of the underground coal mine and have asserted claims against SJCC that its coal mining activities are interfering with gas production. SJCC has reached settlement with several gas leaseholders and has other claimants and potential claimants. PNM cannot predict the outcome of existing or future disputes between SJCC and gas leaseholders.

Rights-of-Way Matters

Many of PNM's electric transmission and distribution facilities are located on lands that require the grant of rights-of-way from governmental entities, Native American tribes, or private parties. Several of the agreements granting the rights-of-way have expired or will expire within the next few years. PNM is actively reviewing these matters and negotiating with certain parties, as appropriate, for the renewal of these rights-of-way. However, there can be no assurance that all of these rights-of-way will be renewed. If PNM is not successful in renewing the rights-of-way on Native American lands, it could be forced to remove its facilities from or abandon its facilities on the property covered by the rights-of-way and seek alternative routes for its transmission or distribution facilities. If rights-of-way on Native American lands are renewed, it is likely they will be renewed at prices that are higher than historical levels, based on current renewal experience. With respect to non-tribal government land and private land, PNM may have condemnation rights. Rights-of-way costs have historically been recovered in rates charged to customers. PNM will seek to recover such costs in future rates.

Republic Savings Bank Litigation

In 1992, Meadows Resources, Inc. ("MRI"), an inactive subsidiary of PNM, and its subsidiaries ("Plaintiffs") filed suit against the Federal government in the U.S. Court of Claims, alleging breach of contract arising from the seizure of Republic Savings Bank ("RSB"). RSB was seized and liquidated after Federal legislation prohibited certain accounting practices previously authorized by contracts with the Federal government. The Federal government filed a counterclaim alleging breach of obligation to maintain RSB's net worth and moved to dismiss Plaintiffs' claims for lack of standing.

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Plaintiffs filed a motion for summary judgment in December 1999 on the issue of liability and on the issue of damages. The Federal government filed a cross motion for summary judgment and opposed Plaintiffs' motion.

On January 25, 2008, the court entered its opinion granting the Federal government's motion to dismiss MRI, denying the Federal government's motion for summary judgment and granting the remaining Plaintiffs' motion for summary judgment on the issues of liability and damages, awarding the Plaintiffs damages in the amount of $14.9 million. MRI had previously received payment from the FDIC in the amount of $0.3 million. This payment reduced the amount of damages owed to $14.6 million.

The federal government appealed this matter to the U.S. Court of Appeals for the Federal Circuit and Plaintiffs cross-appealed. On October 21, 2009, the Federal Circuit issued its opinion, affirming in part and reversing in part the decision of the Court of Claims, resulting in an award to the Plaintiffs of $9.7 million. The period for requesting rehearing and for filing a petition for certiorari in the U.S. Supreme Court expired in January 2010, and the Circuit Court has issued its mandate, returning the case to the Court of Claims. The government and Plaintiffs filed a Joint Motion for Entry of Final Judgment, which the Court of Claims has granted, entering final judgment for $9.7 million, which amount was received in April 2010. PNM recorded the amount, net of legal expenses of $1.2 million, as other income in the three months ended March 31, 2010.

Western United States Wholesale Power Market

Various circumstances, including electric power supply shortages, weather conditions, gas supply costs, transmission constraints, and alleged market manipulation by certain sellers, resulted in the well-publicized California and Western markets energy crisis of 2000-2001 and the bankruptcy filings of the Cal PX and PG&E. As a result of the conditions in the Western markets during this time period, between late-2000 and mid-2003, FERC, the California Attorney General, and private parties (collectively, the "California Parties") initiated investigations, litigation, and other proceedings relevant to PNM and other sellers in the Western markets at FERC and in both California State and Federal District Courts, seeking a determination whether sellers of wholesale electric energy during the crisis period, including PNM, should be ordered to pay monetary refunds to buyers of such energy. These proceedings were pending at FERC as well as before the U.S. Court of Appeals for the Ninth Circuit. PNM participated in these proceedings at FERC, the Federal District Courts and the Ninth Circuit, including filing appeals to that court.

In December 2009, PNM and the California Parties reached an agreement in principle to settle all remaining claims against PNM in these proceedings and on February 11, 2010, PNM entered into a "Settlement and Release of Claims Agreement" (the "Settlement Agreement"), which was filed with FERC on February 12, 2010. The settlement contemplated by this agreement was subject to FERC approval, which was received on April 29, 2010. On May 27, 2010, the Sacramento Municipal Utility District, whose earlier comments opposing the settlement were rejected by FERC, filed with FERC a request for rehearing of the April 29 approval order. That request remains pending before FERC. The terms of the Settlement Agreement provide, among other things, for PNM to pay to the California Parties the amount of $45.0 million, consisting of the assignment of PNM receivables plus interest as of December 31, 2009 from the Cal ISO and the Cal PX in the amount of $13.1 million plus a cash payment of $31.9 million and for the California Parties to release PNM from claims arising from the California energy crisis of 2000 and 2001. PNM recorded the settlement, which was included in other current liabilities, at December 31, 2009. Additionally, the Settlement Agreement provides that certain of California Parties will assume liability that PNM may have to entities that choose not to opt in to the settlement. PNM expressly denies any wrongdoing or culpability with respect to the claims against it that are released by the Settlement Agreement and, in entering into the settlement, does not admit any fault or liability.

On January 15, 2010, PNM transferred the cash payment, which was included in special deposits, to an escrow account established by the California Parties. Pursuant to the Settlement Agreement, the receivables and the cash payment have been or will be distributed to the California Parties and other entities that purchased electricity through the Cal ISO and Cal PX during the relevant time period as settlement funds in accordance with the terms and conditions of the Settlement Agreement. Upon receiving FERC approval of the Settlement Agreement, the special deposit, assigned receivables, and current liability were removed from the Condensed Consolidated Balance Sheets of PNMR and PNM.

Complaint Against Southwestern Public Service Company

In September 2005, PNM filed a complaint under the Federal Power Act against SPS. PNM argued that SPS' rates for sale of interruptible energy were excessive and that SPS had been overcharging PNM for deliveries of energy through its fuel cost adjustment clause practices. PNM also intervened in a complaint proceeding brought by other customers raising similar arguments relating to SPS' fuel cost adjustment clause practices (the "Golden Spread complaint proceeding"). Additionally, in November 2005, SPS filed an electric rate case at FERC proposing to unbundle and raise rates charged to customers effective July 2006. PNM intervened in the case and objected to the proposed rate increase. In September 2006, PNM and SPS filed a settlement agreement providing for resolution of issues relating to rates for sales of interruptible energy, but not resolving the fuel clause issues. In September 2008, FERC issued its order approving the settlement between PNM and SPS.

In April 2008, FERC issued its order in the Golden Spread complaint proceeding. FERC affirmed in part and reversed in part an ALJ's initial decision, which had, among other things, ordered SPS to pay refunds to PNM with respect to the fuel clause issues. FERC affirmed the decision of the ALJ that SPS violated its fuel cost adjustment clause tariffs. However, FERC shortened the refund period applicable to the violation of the fuel cost adjustment clause issues. PNM and SPS have filed petitions for rehearing and clarification of the scope of the remedies that were ordered and reversal of various rulings in the order. FERC has not yet acted upon the requests for rehearing or clarification and they remain pending further decision. PNM cannot predict the final outcome of the case at FERC.

Begay v. PNM et al

A putative class action was filed against PNM and other utilities on February 11, 2009 in the United States District Court in Albuquerque. Plaintiffs claim to be allottees, members of the Navajo Nation, who pursuant to the Dawes Act of 1887, were allotted ownership in land carved out of the Navajo Nation. Plaintiffs, including an allottee association, make broad, general assertions that defendants, including PNM, are right-of-way grantees with rights-of-way across the allotted lands and are either in trespass or have paid insufficient fees for the grant of rights-of-way or both. The plaintiffs, who have sued the defendants for breach of fiduciary duty, seek a constructive trust. They have also included a breach of trust claim against the United States and its Secretary of the Interior. PNM and the other defendants filed motions to dismiss this action. On March 31, 2010, the court ordered that the entirety of the plaintiffs' case be dismissed. The court did not grant plaintiffs leave to amend their complaint, finding that they instead must pursue and exhaust their administrative remedies before seeking redress in federal court.

On May 10, 2010, Plaintiffs filed a Notice of Appeal with the Bureau of Indian Affairs. PNM intends to participate in order to preserve its interests regarding any PNM-acquired rights-of-way implicated in the appeal. As the administrative appeal process is only in its initial stages, PNM cannot predict the outcome of the proceeding at this time.

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(10) Regulatory and Rate Matters

Information concerning regulatory and rate matters is contained in Note 17 of Notes to Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K.

PNMR

First Choice Request for ERCOT Alternative Dispute Resolution

In June 2008, First Choice filed a request for alternative dispute resolution with ERCOT alleging that ERCOT incorrectly applied its protocols with respect to congestion management during the first quarter of 2008. First Choice requested that ERCOT resolve the dispute by restating certain elements of its first quarter 2008 congestion management data and by refunding to First Choice allegedly overstated congestion management charges. The amount at issue in First Choice's claim can only be determined by running ERCOT market models with corrected inputs but First Choice believes that the amount is significant. ERCOT protocols provide that ERCOT will notify potentially impacted market participants and subsequently consider the merits of First Choice's allegations. The Company is unable to predict the outcome of this matter.

PNM

Emergency FPPAC

On March 20, 2008, PNM and the IBEW filed a joint motion in PNM's 2007 Electric Rate Case requesting NMPRC authorization to implement an Emergency FPPAC on an interim basis. On May 22, 2008, the NMPRC issued a final order that approved the Emergency FPPAC with certain modifications. PNM implemented the Emergency FPPAC from June 2, 2008 through the effective date of the 2008 Electric Rate Case order described below.

The Albuquerque Bernalillo County Water Utility Authority and the New Mexico Industrial Energy Consumers Inc. filed notices of appeal to the New Mexico Supreme Court seeking to vacate the NMPRC order approving the Emergency FPPAC. On March 19, 2010, the New Mexico Supreme Court affirmed the NMPRC order approving the Emergency FPPAC.

The NMPRC order approving the Emergency FPPAC required PNM to pay for an audit of PNM's monthly FPPAC reports and a prudence review of PNM's fuel and purchased power costs, to be conducted by auditors selected by the NMPRC. Costs of the audit incurred by PNM will be recoverable through future rate proceedings. On February 19, 2010, the audit report of findings and recommendations was submitted to the NMPRC. The report recommended operational changes in several areas but did not identify any imprudent activities or find that PNM's fuel or purchased power costs were unreasonable. The audit report findings and recommendations are subject to NMPRC review and approval. PNM is unable to predict the outcome of this matter.

The NMPRC order approving the Emergency FPPAC also provided that if PNM's base load generating units did not operate at or above a specified capacity factor and PNM was required to obtain replacement power to serve jurisdictional customers, PNM would be required to make a filing with the NMPRC seeking approval of the replacement power costs. In its required filing, PNM stated that the costs of the replacement power amounting to $8.0 million were prudently incurred and made a motion that they be approved. The NMPRC staff opposed PNM's motion and recommended that PNM be required to refund the amount collected. On January 12, 2010, the NMPRC directed the Emergency FPPAC auditor to investigate whether the replacement power costs were prudently incurred. The order also directed PNM to file a response to the auditors' report, to provide certain additional information, and to show cause why it should not be fined for recovering replacement power costs without prior NMPRC approval. PNM filed its response to the show cause order on February 12, 2010. On February 19, 2010, the auditor's report on replacement power costs was submitted to the NMPRC. The report concluded that the methodology used to estimate

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the cost of replacement power was reasonable, that PNM purchased power at the lowest reasonable cost, and that outage planning and scheduling and plant operations were reasonable. These findings are subject to NMPRC review and approval. On April 12, 2010, the NMPRC staff filed a request for a hearing on whether the replacement power costs should be approved and whether any penalty should be imposed, to which PNM responded. PNM will continue to assert that its recovery of replacement power costs was proper and did not violate the NMPRC's order, but is unable to predict the outcome of this matter.

2008 Electric Rate Case

On September 22, 2008, PNM filed a general rate case ("2008 Electric Rate Case") requesting the NMPRC to approve an increase in electric service rates to all PNM retail customers except those formerly served by TNMP. The case was concluded on June 18, 2009 when a stipulation among the parties that authorized a two-phase rate increase was approved by the NMPRC. On April 1, 2010, PNM implemented the second phase increase of $27.0 million.

Renewable Portfolio Standard

The Renewable Energy Act of 2004 was enacted to encourage the development of renewable energy in New Mexico. The act, as amended, establishes a mandatory renewable energy portfolio standard requiring a utility to acquire a renewable energy portfolio equal to 5% of retail electric sales by January 1, 2006, increasing to 10% by 2011, 15% by 2015 and 20% by 2020. The NMPRC requires renewable energy portfolios to be "fully diversified" beginning in 2011 when no less than 20% of the renewable portfolio requirement must be met by wind energy, no less than 20% by solar energy, no less than 10% by other renewable technologies, and no less than 1.5% by distributed generation. The act provides for streamlined proceedings for approval of utilities' renewable energy procurement plans, assures utilities recovery of costs incurred consistent with approved procurement plans and requires the NMPRC to establish a RCT for the procurement of renewable resources to prevent excessive costs being added to rates. The NMPRC has established a RCT that began at 1% of all customers' aggregated overall annual electric charges, increasing by 0.2% annually until 2011, at which time it will be 2%, and then increasing by 0.25% annually until reaching 3% in 2015.

On July 1, 2009, PNM filed its annual Renewable Energy Portfolio Procurement Plan for 2010 with the NMPRC. Under the plan, PNM proposed to rely on a mixture of solar, wind, and biogas resources and the purchase of RECs to meet its renewable energy requirements for 2010 and 2011 and committed to file for additional projects later in the year.

In September 2009, PNM entered into settlement discussions with various parties to address issues related to the distributed generation programs, the RCT, and PNM's prospective additional projects. In recognition of these settlement negotiations, the NMPRC issued an order on September 22, 2009 that rejected certain provisions of PNM's July 1 st plan and ordered PNM to file a revised plan at the conclusion of the settlement discussions. PNM and several parties to the proceeding filed a stipulation and PNM filed its revised 2010 procurement plan with the NMPRC on January 25, 2010. Under the revised plan, PNM would invest approximately $265 million on solar PV facilities and implement a customer-sited PV distributed generation program to replace its current PV programs. The plan and stipulation were opposed by a number of parties, including the AG and the NMPRC staff. A public hearing on the stipulation and revised procurement plan was held in May 2010. The Hearing Examiner in the case issued a Recommended Decision on August 3, 2010. The Hearing Examiner recommended that the NMPRC reject the revised plan and that the stipulation should be disapproved. The NMPRC has the authority to approve, reject or modify the Recommended Decision. A decision from the NMPRC is anticipated by August 31, 2010. PNM cannot predict the outcome of these proceedings.

On July 1, 2010, PNM filed a new renewable energy plan for 2011. This plan assumes approval of the stipulation and revised renewable energy plan for 2010 that are currently before the NMPRC. The 2011 plan proposes the procurement of 250,000 MWh of renewable energy certificates from another New Mexico public utility to be used for compliance with the renewable portfolio standard in 2011. NMPRC action on this plan is anticipated by the end of 2010.

NMPRC Inquiry on Fuel and Purchased Power Adjustment Clauses

In October 2007, the NMPRC issued a NOI that could lead to the adoption of an amended rule for the implementation of FPPACs for all investor-owned utilities and electric cooperatives in New Mexico. The investor-owned utilities and electric cooperatives have responded to a series of questions and the NMPRC staff made a filing dealing with the need for consistency of FPPACs, streamlining FPPACs, and whether a single FPPAC methodology should be applied to all utilities. Workshops were held to discuss the comments filed by PNM and others and the proposed changes. At the conclusion of the workshop process, the Hearing Examiner presented proposed rule amendments to the NMPRC for its consideration. On April 29, 2010, the NMPRC issued a Notice of Proposed Rulemaking proposing the adoption of the rule amendments that were developed in the workshop process and presented by the Hearing Examiner. A public hearing was held on July 1, 2010. The outcome of this proceeding is not expected to have a material impact on PNM.

NMPRC Rulemaking on Disincentives to Energy Efficiency Programs

In January 2008, the NMPRC issued a NOI to identify disincentives in utility expenditures on energy efficiency and measures to address those disincentives, including specific rate making alternatives, and appointed a Hearing Examiner to conduct workshops to develop proposals for possible rule changes. Based on the workshops, the NMPRC issued proposed amendments to its energy efficiency rule. After a hearing, the NMPRC approved the amended rule on April 8, 2010 to be effective May 3, 2010. The amended rule allows electric utilities to collect rate adders of $0.01 per KWh for lifetime energy savings and $10 per kilowatt for demand savings related to energy efficiency and demand response programs beginning in 2010. In addition, investor-owned electric utilities were required to make filings by July 1, 2010 that propose rate design and ratemaking methods to remove regulatory disincentives or barriers to achieve energy efficiency savings. PNM included its proposals in the 2010 Electric Rate Case described below. After such ratemaking measures become effective, the rate adder for energy saving will be reduced to $0.005 per KWh. Certain intervenors have filed notices of appeal of the NMPRC order to the New Mexico Supreme Court. PNM cannot predict the outcome of these appeals.

On May 5, 2010, PNM filed proposed tariffs under the amended rule. PNM proposed to recover $6.2 million over a twelve-month period following NMPRC approval. The NMPRC suspended these tariffs through December 1, 2010, and has established a procedural schedule for the case. A public hearing is scheduled to begin on September 14, 2010. PNM cannot predict the outcome of this proceeding.

PNM Electric Energy Efficiency and Load Management Programs

The NMPRC requires public utilities to obtain approval to implement energy efficiency and load management programs. Costs to implement approved programs are recovered through a rate rider. On September 15, 2008, PNM filed a plan, which included new programs, modifications to existing programs and a request to recover program costs. After proceedings before the NMPRC, a final order approving the programs was issued on May 19, 2009. In August 2009, PNM began recovering the costs of the programs through a rate rider amounting to 1.881% of customers' bills, before taxes and franchise fees, based on program costs of $14.1 million. The new programs are being implemented.

On July 7, 2009, the NMPRC ordered an investigation into whether it is prudent for PNM to continue certain load management programs initiated in 2008 with NMPRC approval, considering its recent addition of supply-side resources. PNM offers these programs through contracts with third-party vendors that contain substantial fees for early termination. On March 10, 2010, the NMPRC issued an order concluding that it would not be prudent to terminate the programs, and remanded the case to a hearing examiner to consider whether freezing the programs at current levels would be possible and, if so, prudent. A hearing was held June 22, 2010 on the issues identified in the order on remand. Although none of the parties to the proceeding on remand recommended freezing the programs, PNM is unable to predict the outcome of this proceeding.

Rates for Former TNMP Customers in New Mexico

PNM serves the former New Mexico customers of TNMP ("TNMP-NM" or "PNM South") under rates approved by the NMPRC in its order approving PNMR's acquisition of TNMP. Under that order, rates charged to customers were set through December 31, 2010. In January 2009, the NMPRC directed PNM to estimate the revenue requirement increase that would be reflected in a TNMP-NM rate application for rates effective January 2011. PNM estimated that the rate increase could be between 40% and 56% depending on fuel costs. In April 2009, the NMPRC directed PNM, the NMPRC staff, and other parties to attempt to reach consensus on ways to mitigate the impact of this potential rate increase and appointed a mediator. Several mediations were held but no agreement was reached. In March 2010, the NMPRC issued its Order Initiating Investigation and Requiring Informational Filings to which PNM and other parties filed timely responses. On May 25, 2010, the NMPRC issued an order setting a procedural schedule for the submission of testimony and a hearing. The order further directed PNM and the NMPRC staff to file testimony addressing certain matters related to cost allocation, which was filed on June 17, 2010. On July 14, 2010, the NMPRC vacated the hearing date without setting a new date. The former customers of TNMP have been included in the rate filing discussed under 2010 Electric Rate Case below. PNM cannot predict the outcome of this matter.

Third-Party Arrangements for Renewable Distributed Generation

On June 16, 2009, the NMPRC initiated a proceeding and requested legal briefs on the topic of whether third-party arrangements for the sale of renewable energy from customer-sited distributed generation facilities were permissible under New Mexico law. On December 31, 2009, the NMPRC issued an order that in part declared that a third party that owns renewable generation equipment that is installed on a utility customer's premises pursuant to a long-term contract with the customer to supply a portion of that customer's electricity use, payments for which are based on a kilowatt-hour charge, is not a public utility subject to regulation by the NMPRC. PNM and two other parties appealed the order to the New Mexico Supreme Court.

In early 2010, legislation was enacted that nullified the NMPRC order and, effective January 1, 2011, excludes non-utility power generators from the definition of public utilities under state law, subject to certain limitations as to size and provided that such generators produce renewable energy, the generators are located on the site of the power consumer, and do not utilize retail wheeling of power. A separate provision of the legislation directs the NMPRC to authorize public utilities to establish rates that assure the utilities' recovery of an appropriate portion of their fixed costs from owners of interconnected generators. After enactment of this legislation, appeals of the NMPRC order were dismissed. On March 9, 2010, the NMPRC issued an order setting workshops for the purpose of obtaining comments and views on implementation of the rate-making aspect of the statute. The workshops are ongoing. PNM is unable to predict the outcome of this proceeding.

Application to Hedge Fuel and Purchased Power Costs

In August 2009, PNM filed an application for approval of a plan to manage fuel and purchased power costs by entering into certain forward market transactions relating to the procurement of fuel and purchased power and the sale of excess electrical energy in the wholesale market. PNM's application sought NMPRC authorization to conduct these activities, which involve hedging practices, and to pass through the costs and benefits of the transactions to jurisdictional customers using PNM's FPPAC. The NMPRC staff filed testimony recommending approval of PNM's application with minor modifications. PNM filed rebuttal testimony agreeing with the proposed modifications. A hearing was held on February 23, 2010. The NMPRC approved the program on April 20, 2010.

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2010 Electric Rate Case

PNM filed a general rate case application with the NMPRC on June 1, 2010 for rate increases for all PNM retail customers to be effective April 1, 2011. The application proposed separate rate increases for those customers served by PNM ("PNM North") prior to its acquisition of TNMP and for the customers formerly served by TNMP ("PNM South"). The proposed total increase of $165.2 million represents a 22% increase for PNM North and a 20% increase for PNM South. The filed revenue requirements are based on a future test period ending December 31, 2011. If the NMPRC grants the entire relief requested, PNM proposes to implement the increase in two steps. Phase 1 would become effective April 1, 2011 (PNM North: $111.1 million; 16%; PNM South: $8.7 million; 14%), and Phase 2 would become effective January 1, 2012 (PNM North: $41.7 million, 6%; PNM South: $3.6 million, 6%). PNM also proposed to implement a FPPAC for PNM South. This is the first rate case filing in New Mexico proposing a future test year consistent with the recently enacted SB 477. The NMPRC has suspended the rates until April 1, 2011 and a hearing has been scheduled to begin December 1, 2010. NMPRC staff, the AG, and the Albuquerque-Bernalillo County Water Utility Authority each filed motions to either dismiss the case or extend the suspension period. After PNM had responded to the other parties' motions, the NMPRC issued an order on July 27, 2010. The NMPRC granted the other parties' motions in part. The NMPRC determined that PNM's rate filing was incomplete, ordered PNM to supplement its rate application, directed that the suspension period not begin to run until PNM's rate application was made complete, and extended the suspension period by one month. However, PNM believes that the order is erroneous both in its assessment of the completeness of PNM's filing and in its application of the governing legal standards. On August 5, 2010, PNM supplemented its rate case application in conformance with the NMPRC's order and also on August 5, 2010 made a filing in the New Mexico Supreme Court requesting the Court to vacate the NMPRC's July 27, 2010 order and for other equitable relief. PNM is unable to predict the outcome of this case.

TNMP

TNMP Competitive Transition Charge True-Up Proceeding

A true-up proceeding to quantify and reconcile the amount of stranded costs that TNMP may recover from its transmission and distribution customers was held at the PUCT. A 2004 PUCT decision established $87.3 million as TNMP's stranded costs. TNMP and other parties appealed the ruling and the appeals are currently pending before the Texas Supreme Court. TNMP is unable to predict if the Texas Supreme Court will review the decision or the ultimate outcome of this matter.

Interest Rate Compliance Tariff

Following a revision of the interest rate on TNMP's carrying charge, TNMP filed a compliance tariff to implement the new 8.31% rate. TNMP's filing proposed to put the new rates into effect on February 1, 2008. Intervenors asserted objections to the compliance filing. PUCT staff urged that the PUCT make the new rate effective as of December 27, 2007 when the PUCT's order establishing the correct rate became final. After regulatory proceedings, the PUCT issued an order making the new rate retroactive to July 20, 2006. TNMP filed an appeal of this order in the District Court in Austin, Texas. A hearing was held on June 17, 2010. On June 28, 2010, the district court decided to reverse the PUCT decision and remand the matter back to the PUCT for a determination that is not retroactive. The PUCT and/or other parties may appeal the decision to the Texas 3 rd Court of Appeals. While there is inherent uncertainty in this type of proceeding, TNMP believes it will ultimately be successful in overturning any ruling that the effective date should be prior to December 27, 2007.

Transmission Rate Filing

On March 2, 2010, TNMP filed an application to update its transmission rates to reflect changes in its invested capital. The requested increase in total rate base is $33.8 million, with a total revenue requirement increase of $5.5 million. The requested updated rates reflect the addition and retirement of transmission facilities, including appropriate depreciation, federal income tax and other associated taxes, and the approved rate of return on such facilities. The PUCT staff filed a recommendation to approve TNMP's application on April 6, 2010. The ALJ filed a proposed order approving TNMP's application on April 13, 2010. The PUCT approved the interim adjustment on May 14, 2010.

Energy Efficiency

On October 28, 2009, TNMP filed an application for approval of its 2010 energy efficiency programs and requested recovery through an energy efficiency cost recovery factor. TNMP estimated the costs of its 2010 energy efficiency programs to be $2.6 million and requested to collect this amount based on a per customer charge over 11 months. The PUCT staff and intervenors did not take issue with TNMP's application. TNMP implemented the factor effective February 1, 2010. On April 30, 2010, TNMP made a similar filing seeking recovery of $2.7 million of costs to be incurred in its 2011 programs. The 2011 energy cost recovery rider was approved by the PUCT on July 8, 2010.

Advanced Meter System Deployment and Surcharge Request

On May 26, 2010, TNMP filed a request with PUCT to approve TNMP's proposed advanced meter deployment. The filing also requested a surcharge to collect $158 million in costs over 12 years, including recovery of capital expenditures incurred through 2015 of $70.6 million. On June 1, 2010, the PUCT referred the matter to the State Office of Administrative Hearings. This matter is currently set for hearing in October 2010.

(11) Optim Energy

Optim Energy was created by PNMR and ECJV, a wholly owned subsidiary of Cascade, to serve expanding U.S. markets, principally the areas of Texas covered by ERCOT. PNMR and ECJV each have a 50 percent ownership interest in Optim Energy, a limited liability company. See Note 22 of the Notes to Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K.

On June 1, 2007, Optim Energy entered into a bank financing arrangement with a term of five years, which includes a revolving line of credit. This facility also provides for bank letters of credit to be issued as credit support for certain contractual arrangements entered into by Optim Energy. Cascade and ECJV have guaranteed Optim Energy's obligations on this facility and, to secure Optim Energy's obligation to reimburse Cascade and ECJV for any payments made under the guaranty, have a first lien on all assets of Optim Energy and its subsidiaries.

In January 2010, Optim Energy entered into floating-to-fixed interest rate swaps with an aggregate notional amount of $650.0 million. The effect of these swaps is to convert $650.0 million of borrowings under Optim Energy's credit facility from an interest rate based on the one-month LIBOR rate to a fixed rate of 1.33% through January 7, 2011, exclusive of loan guaranty fees. These swaps are accounted for as cash-flow hedges. At June 30, 2010, these swaps had a pre-tax fair value loss of $0.7 million, which is included in current liabilities below.

In April 2010, PNMR and ECJV each made an equity contribution to Optim Energy of $15.0 million in cash. PNMR and ECJV also agreed to make additional cash contributions during 2010 that would aggregate approximately $5.0 million from each owner of which each had contributed $2.6 million as of July 29, 2010. Optim Energy used the equity contributions to reduce amounts outstanding under its bank financing arrangement and will also use the additional contributions to reduce debt. PNMR has no other commitments or guarantees with respect to Optim Energy.

In June 2009, Optim Energy and NRG Cedar Bayou completed a jointly developed 550 MW combined-cycle natural gas unit at the existing NRG Cedar Bayou Generating Station near Houston. Optim Energy's share of this unit is 275 MW and its share of the construction costs was $209.6 million. Optim Energy financed its portion of the Cedar Bayou construction with borrowings under its existing credit facility and operating cash flows.

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Summarized financial information for Optim Energy is as follows:

Results of Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Operating revenues	$ 86,871	$ 58,102	$ 192,465	$ 136,499
Cost of sales	61,235	42,655	138,532	87,841
Gross margin	25,636	15,447	53,933	48,658
Non-fuel operations and maintenance expenses	6,450	7,854	16,970	16,452
Administrative and general expenses	4,944	7,961	10,556	15,885
Depreciation and amortization expense	12,852	7,425	24,909	15,084
Taxes other than income tax	3,162	3,244	6,596	6,573
Operating income (loss)	(1,772)	(11,037)	(5,098)	(5,336)
Interest charges	(4,661)	(3,020)	(9,332)	(5,500)
Other income (deductions)	2	(126)	66	(69)
Earnings (loss) before income taxes	(6,431)	(14,183)	(14,364)	(10,905)
Income taxes (benefit) (1)	36	(51)	68	111
Net earnings (loss)	$ (6,467)	$ (14,132)	$ (14,432)	$ (11,016)
50 percent of net earnings (loss)	$ (3,234)	$ (7,066)	$ (7,216)	$ (5,508)
Amortization of basis difference in Optim Energy	(624)	(287)	(994)	(450)
PNMR equity in net earnings (loss) of Optim Energy	$ (3,858)	$ (7,353)	$ (8,210)	$ (5,958)

(1) Represents the Texas Margin Tax, which is considered an income tax under GAAP.

Financial Position

	June 30, 2010	December 31, 2009
	(In thousands)	
Current assets	$ 126,086	$ 128,619
Net property plant and equipment	940,206	951,757
Other long-term assets	128,626	137,384
Total assets	1,194,918	1,217,760
Current liabilities	53,264	66,190
Long-term debt	737,000	755,000
Other long-term liabilities	5,720	5,710
Total liabilities	795,984	826,900
Owners' equity	$ 398,934	$ 390,860
50 percent of owners' equity	$ 199,467	$ 195,430
Unamortized PNMR basis difference in Optim Energy	209	236
PNMR equity investment in Optim Energy	$ 199,676	$ 195,666

Optim Energy has a hedging program the level of which varies at any given time depending on current market conditions and other factors. Economic hedges that do not qualify, or are not designated, as cash flow hedges or normal purchases/sales and that are derivative instruments are required to be marked to market. In the three months ended June 30, 2010, Optim Energy recorded a loss of $1.3 million on the mark-to-market of economic hedges, compared to a loss of $15.8 million in 2009. In the six months ended June 30, 2010, Optim Energy recorded income of $3.0 million on the mark-to-market of economic hedges, compared to a loss of $6.4 million in 2009.

Optim Energy individually valued each asset and liability received in the Altura (Twin Oaks) and Altura Cogen transactions and initially recorded them on its balance sheet at the determined fair value. For both transactions, this accounting results in a significant amount of amortization since the acquired contracts' terms differed significantly from fair value at the date of acquisition and emission allowances, while acquired from government programs without future cost to Optim Energy, had significant market value at the date of acquisition. Optim Energy recorded amortization of contracts acquired of $4.2 million and $8.2 million for the three months and six months ended June 30, 2010 and $3.2 million and $6.3 million for the three months and six months ended June 30, 2009, which reduced operating revenues. Optim Energy also recorded amortization expense on emission allowances of $1.3 million and $2.6 million for the three months and six months ended June 30, 2010 and $1.1 million and $2.4 million for the three months and six months ended June 30, 2009, which is recorded in cost of sales.

The contribution of Altura created a basis difference between PNMR's recorded investment in Optim Energy and 50 percent of Optim Energy's equity. While the portion of the basis difference related to contract amortization will only continue through 2010, other basis differences, including a difference related to emission allowances, will continue to exist through the life of the Altura plant. For the three months and six months ended June 30, 2010 and 2009, the basis difference adjustment detailed above relates mainly to contract amortization with insignificant offsets related to the other minor basis difference components.

LCC is Optim Energy's counterparty in several agreements for power and steam sales. In addition, LCC leases Optim Energy the land for the Altura Cogen facility and provides other services, including water, to that facility. On January 6, 2009, LCC filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. The pre-petition net amount due from LCC is immaterial and was fully reserved as of December 31, 2008. LCC has continued to perform under the existing contracts. LCC's bankruptcy plan was confirmed by the bankruptcy court on April 23, 2010. LCC has filed documents with the bankruptcy court indicating its intent to assume its contracts with Altura Cogen. As part of this process, LCC is required to cure pre-petition defaults under its contracts with Altura Cogen and in the three months and six months ended June 30, 2010, Optim Energy reversed the $1.0 million that had been reserved previously. At present, Altura Cogen and LCC are negotiating the terms of a stipulation to formalize the cure of these defaults.

(12) Related Party Transactions

PNMR, PNM, TNMP, and Optim Energy are considered related parties as defined under GAAP. PNMR Services Company provides corporate services to PNMR, its subsidiaries, and Optim Energy in accordance with shared services agreements. There is also a services agreement for Optim Energy to provide services to PNMR. Additional information concerning the Company's related party transactions is contained in Note 20 of the Notes to Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K. See Note 7 for information on intercompany borrowing arrangements and Note 11 for information concerning Optim Energy.

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The table below summarizes the nature and amount of related party transactions of PNMR, PNM and TNMP:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In thousands)			
Transmission and distribution related services billings:				
TNMP to PNMR	$ 9,635	$ 10,179	$19,221	$ 19,482
Services billings:				
PNMR to PNM*	21,913	16,845	43,575	33,873
PNMR to TNMP	5,804	5,018	12,292	10,302
PNM to TNMP	178	133	278	266
TNMP to PNMR	93	95	214	344
PNMR to Optim Energy	1,371	1,441	2,809	2,930
Optim Energy to PNMR	33	89	51	216
Income tax sharing payments:				
PNM to PNMR	-	45,740	-	45,740
TNMP to PNMR	-	3,027	-	3,027
PNMR to PNM	35,190	-	35,190	-
Interest payments:				
TNMP to PNMR	102	171	185	601

* PNM shared services include billings to PNM Gas of zero and $0.9 million for the three months and six months ended June 30, 2009.

(13) New Accounting Pronouncements

Information concerning recently issued accounting pronouncements that have not been adopted by the Company and could have a material impact, is presented below.

Accounting Standard Update 2010-06 – Fair Value Measurements and Disclosures: Improving Disclosures about Fair Value Measurements

The FASB released amended guidance related to disclosures of fair value measurements. The update requires entities to enhance interim and annual disclosures about fair value measurements, specifically:

-Further disaggregate the level presented for debt and equity securities
-Disclose the amount and reason for significant transfers between fair value categories Level 1 and Level 2
-Disclose information about the purchases, sales, issuances, and settlements for items in Level 3 of the fair value measurements on a gross basis rather than net

The enhanced disclosure for the first two items was effective for the interim period ended March 31, 2010 and is included in Note 4 to the extent applicable. The third item regarding Level 3 information is effective for the interim period ended March 31, 2011 and will be included at that time.

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Accounting Standard Update 2010-20 – Receivables: Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses

In July 2010, the FASB released guidance requiring enhanced disclosures providing a greater level of disaggregated information about the credit quality of an entity's financing receivables and the allowance for credit losses, as well as credit quality indicators, past due accounts information, and modifications of financing receivables. The enhanced disclosures required for the end of a reporting period are effective at December 31, 2010 and the disclosures about activity that occurs during a reporting period are effective beginning January 1, 2011. The Company is currently evaluating the impact of this update.

(14) Discontinued Operations

As discussed in Note 2, PNM sold its gas operations, which comprised the PNM Gas segment, in January 2009. Under GAAP, the assets and liabilities of PNM Gas were considered to be held-for-sale and presented as discontinued operations. The PNM Gas results of operations were excluded from continuing operations and presented as discontinued operations on the statements of earnings. In accordance with GAAP, no depreciation was recorded on assets held for sale. There is nothing reported as discontinued operations in 2010. Summarized 2009 financial information for PNM Gas, which has been retroactively adjusted as discussed in Note 1, is as follows:

Results of Operations

	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
	(In thousands)	
Operating revenues	$ -	$ 65,696
Cost of energy	-	44,698
Gross margin	-	20,998
Operating expenses	4,194	10,011
Depreciation and amortization	-	-
Operating income (loss)	(4,194)	10,987
Other income (deductions)	-	292
Interest charges	-	(962)
Gain on disposal	(278)	101,090
Segment earnings (loss) before income taxes	(4,472)	111,407
Income taxes (benefit)	(1,861)	38,166
Segment earnings (loss)	$ (2,611)	$ 73,241

(15) Variable Interest Entities

Information concerning the Company's assessment of potential variable interest entities is contained in Note 9 of Notes to the Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K.

On January 1, 2010, the Company adopted an amendment to GAAP that changes how an enterprise evaluates and accounts for its involvement with variable interest entities. This amendment modifies the determination of the primary beneficiary of a variable interest entity by focusing primarily on whether the enterprise has the power to direct the activities that most significantly impact the economic performance of a variable interest entity. The amendment also requires continual reassessment of the primary beneficiary of a variable interest entity and increases disclosure requirements. The adoption of this amendment did not change how the Company accounts for its existing

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arrangements with variable interest entities and the disclosures presented below reflect the requirements of the amendment.

On April 18, 2007, PNM entered into a PPA to purchase all of the electric capacity and energy from Valencia, a natural gas-fired power plant near Belen, New Mexico. Valencia became operational on May 30, 2008. A third-party built, owns, and operates the facility while PNM is the sole purchaser of the electricity generated. The total construction cost for the facility was $90.0 million. The term of the PPA is for 20 years beginning June 1, 2008, with the full output of the plant estimated to be 145 MW. During the term of the PPA, PNM has the option to purchase and own up to 50% of the plant or the variable interest entity. PNM estimates that the plant will typically operate during peak periods of energy demand in summer. PNM is obligated to pay fixed O&M and capacity charges in addition to variable O&M charges under this PPA. For the three months and six months ended June 30, 2010, PNM paid $4.5 million and $9.0 million for fixed charges and $0.2 million and $0.3 million for variable charges. For the three months and six months ended June 30, 2009, PNM paid $4.6 million and $8.7 million for fixed charges and $0.1 million and $0.1 million for variable charges. PNM does not have any other financial obligations related to Valencia. The assets of Valencia can only be used to satisfy obligations of Valencia and creditors of Valencia do not have any recourse against PNM's assets.

PNM has evaluated the accounting treatment of this arrangement and concluded that the third party entity that owns Valencia is a variable interest entity and that PNM is the primary beneficiary of the entity under GAAP since PNM has the power to direct the activities that most significantly impact the economic performance of Valencia and will absorb the majority of the variability in the cash flows of the plant. The significant factors considered in reaching that conclusion are that PNM sources fuel for the plant, controls when the facility operates through its dispatch, and receives the entire output of the plant, which factors directly and significantly impact the economic performance of Valencia. As the primary beneficiary, PNM has consolidated the entity in its financial statements beginning on the commercial operations date. Accordingly, the assets, liabilities, operating expenses, and cash flows of Valencia are included in the consolidated financial statements of PNM although PNM has no legal ownership interest or voting control of the variable interest entity. The assets and liabilities of Valencia set forth below are immaterial to PNM and, therefore, not shown separately on the Condensed Consolidated Balance Sheets. The owner's equity and net income of Valencia are considered attributable to non-controlling interest. PNM did not consolidate Valencia prior to May 30, 2008 since PNM had no financial risk.

Summarized financial information for Valencia is as follows:

Results of Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Operating revenues	$ 4,725	$ 4,494	$ 9,227	$ 8,552
Operating expenses	(1,433)	(1,719)	(2,831)	(3,198)
Earnings attributable to non-controlling interest	$ 3,292	$ 2,775	$ 6,396	$ 5,354

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Financial Position

	June 30, 2010	December 31, 2009
	(In thousands)	
Current assets	$ 4,494	$ 3,981
Net property, plant and equipment	85,032	86,349
Total assets	89,526	90,330
Current liabilities	790	971
Owners' equity – non-controlling interest	$ 88,736	$ 89,359

Changes in Owner's Equity – Non-controlling Interest

	Six Months Ended June 30, 2010
	(In thousands)
Balance at beginning of period	$ 89,359
Earnings attributable to non-controlling interest	6,396
Net equity transactions with Valencia's owner	(7,019)
Balance at end of period	$ 88,736

PNM leases interests in Units 1 and 2 of PVNGS under arrangements, which were entered into in 1985 and 1986, that are accounted for as operating leases. There are currently eight separate lease agreements with eight different trusts whose beneficial owners are five different institutional investors. PNM is not the legal or tax owner of the leased assets. The beneficial owners of the trusts possess all of the voting control and pecuniary interests in the trusts. PNM has an option to purchase the leased assets at appraised value at the end of the leases, but does not have a fixed price purchase option and does not provide residual value guarantees. PNM has options to renew the leases at fixed rates set forth in the leases for two years beyond the termination of the original lease terms. The option periods on certain leases may be further extended for up to an additional six years if the appraised remaining useful lives and fair value of the leased assets are greater than parameters set forth in the leases. Under GAAP, these renewal options are considered to be variable interests in the trusts and result in the trusts being considered variable interest entities. PNM is only obligated to make payments to the trusts for the scheduled semi-annual lease payments, which, net of amounts that will be returned to PNM through its ownership in related lessor notes, aggregate $124.6 million over the remaining terms of the leases. Under certain circumstances (for example, final shutdown of the plant, the NRC issuing specified violation orders with respect to PVNGS, or the occurrence of specified nuclear events), PNM would be required to make specified payments to the beneficial owners and take title to the leased interests. If such an event had occurred as of June 30, 2010, PNM could have been required to pay the beneficial owners up to approximately $176.9 million, which would result in PNM taking ownership of the leased assets and termination of the leases. PNM has no other financial obligations or commitments to the trusts or the beneficial owners. Creditors of the trusts have no recourse to PNM's assets other than with respect to the contractual lease payments. PNM has no additional rights to the assets of the trusts other than the use of the leased assets. PNM has no assets or liabilities recorded on its consolidated balance sheets related to the trusts other than the accrual of lease payments between the scheduled payment dates. For additional information regarding these leases, see Risk Factors, MD&A – Off Balance Sheet Arrangements, and Note 7 of the Notes to Consolidated Financial Statements in the Annual Reports on Form 10-K.

PNM has evaluated the PVNGS lease arrangements and concluded that it does not have the power to direct the activities that most significantly impact the economic performance of the trusts and, therefore, is not the primary beneficiary of the trusts under GAAP. The significant factors considered in reaching this conclusion are: the periods covered by fixed price renewal options are significantly shorter than the anticipated remaining useful lives of the assets, particularly since it appears reasonably likely that the operating licenses for the plants will be extended for twenty years through 2045 for Unit 1 and 2046 for Unit 2; PNM's only financial obligation to the trusts is to make the fixed lease payments and the payments do not vary based on the output of the plants or their performance; during the lease term, the economic performance of the trusts is substantially fixed due to the fixed lease payments; PNM is only one of several participants in PVNGS and is not the operating agent for the plants, so does not significantly influence the day to day operations of the plants; furthermore, the operations of the plants, including plans for their decommissioning, are highly regulated by the NRC, leaving little room for the participants to operate the plants in a manner that impacts the economic performance of the trusts; the economic performance of the trusts at the end of the lease terms is dependent upon the fair value and remaining lives of the plants at that time, which are determined by factors such as power prices, outlook for nuclear power, and the impacts of potential carbon legislation or regulation, all which are outside of PNM's control; and while PNM has some potential benefit from its renewal options, the vast majority of the value at the end of the leases will accrue to the beneficial owners of the trusts, particularly given increases in the value of existing nuclear generating facilities, which have no GHG, resulting from anticipated carbon legislation or regulation.

As discussed in Note 9 of the Notes to Consolidated Financial Statements in the Annual Reports on Form 10-K, PNM has a PPA covering the entire output of Delta, which is a variable interest under GAAP. This arrangement was entered into prior to December 31, 2003 and PNM has been unsuccessful in obtaining the information necessary to determine if it is the primary beneficiary of the entity that owns Delta, or to consolidate that entity if it were determined that PNM is the primary beneficiary. Accordingly, PNM is unable to make those determinations and, as provided in GAAP, continues to account for this PPA as an operating lease. PNM makes fixed and variable payments to Delta under the PPA. PNM also controls the dispatch of the generating plant, which impacts the variable payments made under the PPA and impacts the economic performance of the entity that owns Delta. During the three months and six months ended June 30, 2010, PNM incurred fixed payments of $1.7 million and $3.0 million and variable payments of less than $0.1 million and $0.2 million under the PPA. During the three months and six months ended June 30, 2009, PNM incurred fixed payments of $1.4 million and $3.1 million and variable payments of $0.1 million and $0.1 million under the PPA. PNM's only quantifiable obligation under the PPA is to make the fixed payments, which as of June 30, 2010, aggregated $60.1 million through the end of the PPA in 2020. PNM will also pay variable costs, which cannot be quantified since the amounts are based on how much the generating plant is in operation. PNM has no other obligations or commitments with respect to Delta.

(16) Goodwill and Other Intangible Assets

The excess purchase price over the fair value of the assets acquired and the liabilities assumed by PNMR for its June 6, 2005 acquisition of TNP was recorded as goodwill and was pushed down to the businesses acquired. In 2007, the TNMP assets that were included in its New Mexico operations, including goodwill, were transferred to PNM. Additionally, other intangible assets, the trade name "First Choice" and the First Choice customer list, were acquired in the TNP acquisition. The trade name is considered to have an indefinite useful life; therefore, no amortization is recorded. The useful life of the customer list was estimated to be approximately eight years.

The Company evaluates its goodwill and non-amortizing intangible assets for impairment annually at the reporting unit level or more frequently if circumstances indicate that the goodwill or intangible assets may be impaired. Application of the impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, and determination of the fair value of each reporting unit. The fair value of each reporting unit is estimated using a discounted cash flow methodology. This analysis requires significant judgments, including estimation of future cash flows, which is dependent on internal forecasts, estimation of long-term growth rates for the business, and determination of appropriate weighted average cost of capital for each reporting unit. Changes in these estimates and assumptions could materially affect the determination of fair value and the conclusion of impairment for each reporting unit.

For non-amortizing intangibles other than goodwill, the Company compares the fair value of the intangible asset to its recorded value. For goodwill, the first step of the impairment test requires that the Company compare the

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fair value of each reporting unit with its carrying value, including goodwill. If as a result of this analysis, the Company concludes there is an indication of impairment in a reporting unit having goodwill, the Company is required to perform the second step of the impairment analysis, determining the amount of goodwill impairment to be recorded. The amount is calculated by comparing the implied fair value of the goodwill to its carrying amount. This exercise would require the Company to allocate the fair value determined in step one to the individual assets and liabilities of the reporting unit. Any remaining fair value would be the implied fair value of goodwill on the testing date. To the extent the recorded amount of goodwill of a reporting unit exceeds the implied fair value determined in step two, an impairment loss would be reflected in results of operations.

The annual evaluations performed as of April 1, 2010 and 2009 did not indicate impairments of any of PNMR's reporting units or other intangible assets. Since the annual evaluation, there have been no indications that the fair values of the reporting units with recorded goodwill have decreased below the carrying values.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis of Financial Condition and Results of Operations for PNMR is presented on a combined basis, including certain information applicable to PNM and TNMP. The MD&A for PNM and TNMP is presented as permitted by Form 10-Q General Instruction H (2). For discussion purposes, this report will use the term "Company" when discussing matters of common applicability to PNMR, PNM, and TNMP. A reference to a "Note" in this Item 2 refers to the accompanying Notes to Condensed Consolidated Financial Statements (Unaudited) included in Item 1, unless otherwise specified. Certain of the tables below may not appear visually accurate due to rounding.

MD&A FOR PNMR

BUSINESS AND STRATEGY

Overview

PNMR provides electricity and energy efficiency products and services in both regulated and unregulated markets to help customers meet and manage their energy needs. PNM sold its gas operations on January 30, 2009 and is now focused on its regulated electric business going forward.

PNM

Critical to PNMR's success for the foreseeable future is the financial health of PNM, PNMR's largest subsidiary, which is highly dependent on continued favorable regulatory treatment. PNM filed its 2008 Electric Rate Case requesting the NMPRC to approve an increase in electric service rates of $123.3 million. PNM also proposed a more traditional FPPAC. In June 2009, the NMPRC approved a stipulation resolving all issues in the rate case. The approved stipulation allowed for an increase in annual non-fuel revenues of $77.1 million, 65% of which was implemented for bills rendered beginning July 1, 2009 and the remainder of which was implemented April 1, 2010. As an offset to the non-fuel revenue increase, PNM implemented a credit to customers totaling $26.3 million, representing the amount of revenues from past sales of SO_2 allowances, over 21 months beginning July 1, 2009. The stipulation also provided for a more traditional FPPAC that went into effect with the new rates.

PNM anticipates a trend toward increasing costs of providing electric service and a period of plant expansion, primarily from renewable energy sources under the renewable energy portfolio requirements established pursuant to New Mexico's Renewable Energy Act and related regulations of the NMPRC. PNM also anticipates increases in costs related to renewals of rights-of-way on Native American lands, pension and benefits, and depreciation at SJGS. PNM will seek to recover these increased costs of providing service to regulated customers through future rate filings, which may occur more frequently than in the past. The impact that rate increases may have on customers' usage and their ability to pay is unknown.

Senate Bill 477 ("SB 477") was passed by the New Mexico legislature and became effective in June 2009. SB 477 is designed to promote more timely recovery of reasonable costs of providing utility service in two ways. First, SB 477 requires the NMPRC, when setting rates, to use the test period that best reflects the conditions the utility will experience when new rates are anticipated to go into effect. The NMPRC is required to give due consideration that a future test period may be the one that best meets this requirement. A future test period is defined as a twelve month period beginning no later than the date a proposed rate change is expected to take effect. Traditionally, the NMPRC has used a historical test period, adjusted for known and measurable changes occurring within five to six months after the end of the test period, which reflects costs that could be up to two years old at the time new rates become effective. It is possible that NMPRC staff or intervenors could argue that continued use of a historical test period, adjusted for known and measurable changes, best meets the requirement. Second, SB 477 requires the NMPRC to include construction work in progress in rate base, without an offset for allowance for funds used during construction, for environmental improvement projects and generation and transmission projects for which a certificate of public convenience and necessity has been issued. This provision will allow utilities to collect costs as projects are being built rather than waiting until they are finished to include them in rate base, so long as the projects will be in service no later than two years after the filing date of the rate case.

PNM filed a general rate case application with the NMPRC on June 1, 2010 for rate increases for all PNM retail customers to be effective April 1, 2011. The application proposed separate rate increases for those customers served by PNM ("PNM North") prior to its acquisition of TNMP and for the customers formerly served by TNMP ("PNM South"). The proposed total increase of $165.2 million represents a 22% increase for PNM North and 20% increase for PNM South. The filed revenue requirements are based on a future test period ending December 31, 2011. If the NMPRC grants the entire relief requested, PNM proposes to implement the increase in two steps. Phase 1 would become effective April 1, 2011 (PNM North: $111.1 million; 16%, PNM South: $8.7 million; 14%), and Phase 2 would become effective January 1, 2012 (PNM North: $41.7 million; 6%, PNM South: $3.6 million; 6%). PNM also proposed to implement a fuel and purchase power adjustment clause for PNM South. This is the first rate case filing in New Mexico proposing a future test year consistent with the recently enacted SB 477. On July 27, 2010, the NMPRC issued an order that determined PNM's rate filing was incomplete, ordered PNM to supplement its rate application, directed that the suspension period not begin to run until PNM's rate application was made complete, and extended the suspension period by one month. However, PNM believes the order is erroneous both in its assessment of the completeness of PNM's filing and in its application of the governing legal standards. On August 5, 2010, PNM supplemented its rate case application in conformance with the NMPRC's order and also on August 5, 2010 made a filing in the New Mexico Supreme Court requesting the Court to vacate the NMPRC's July 27, 2010 order and for other equitable relief. See Note 10. PNM is unable to predict the outcome of this case.

The use of a future test year should help PNM to mitigate the adverse effects of regulatory lag, which is inherent when using a historical test year, by focusing on what costs are likely to be when new rates go into effect rather than what they were in the past. The mitigation of the adverse effects of regulatory lag should result in PNM's earnings more closely approximating the rate of return allowed by the NMPRC. PNMR believes that achieving earnings that approximate its allowed rate of return is an important factor in attracting equity investors, as well as being considered by credit rating agencies and financial analysts. PNM currently expects it will access the credit and capital markets in order to finance at least a portion of the anticipated construction expenditures discussed in Capital Requirements under Liquidity and Capital Resources below. To the extent such financing includes the issuance of debt securities that are rated below investment grade, the debt would carry a higher interest rate than if the securities were investment grade. Those higher interest costs would then be included in requests for rate relief, placing additional upward pressure on rates charged to customers.

As with any forward looking financial information, utilizing a future test year in a rate filing presents challenges that are inherent in the forecasting process. PNM is required to forecast both operating and capital expenditures that necessitates reliance on many assumptions concerning future conditions. Among others, these would include assumptions about future economic conditions in PNM's service territory, levels of employment, load growth and conservation, weather, usage patterns of customers, availability and technology regarding renewable energy sources, interest rates and other financing costs, access to capital markets, inflation, and impacts of regulatory actions. In the rate making process, PNM's assumptions are subject to challenge by regulators and intervenors who may assert different interpretations or assumptions.

PNM also anticipates filing a rate case with FERC in the fourth quarter of 2010 for its firm transmission customers. The magnitude of the rate increase is currently unknown and PNM cannot predict the amount FERC will approve.

TNMP

TNMP's financial health is also highly dependent on continued favorable regulatory treatment. In August 2008, TNMP filed with the PUCT for an $8.7 million increase in revenues, which was subsequently amended to request an additional revenue increase of $15.7 million. In June 2009, TNMP and the other parties in the rate case reached a unanimous settlement resolving all issues in the rate case and permitting TNMP to increase its rates by $12.7 million annually. This increase reflects interest and other costs associated with debt refinancing in March 2009 and the settlement adjusts the interest rate TNMP is allowed to collect on its CTC to reflect those costs. The rate increase includes recovery of Hurricane Ike restoration costs plus carrying costs over five years. The settlement was approved by the PUCT in August 2009 and allows TNMP to update its transmission rates annually to reflect changes in its invested capital. TNMP filed a request to update its rates under this provision in March 2010, increasing annual revenues by $5.5 million, which was approved by the PUCT on May 14, 2010. Updated rates reflect the addition and retirement of transmission facilities, including appropriate depreciation, federal income tax and other associated taxes, and the approved rate of return on such facilities. TNMP has filed a request with PUCT to approve TNMP's proposed advanced meter deployment and to collect $158 million in costs over 12 years, including recovery of capital expenditures incurred through 2015 of $70.6 million, for that program. See Note 10. TNMP anticipates filing for its next general rate case in the third quarter of 2010.

Environmental Sustainability

The Company's focus on the electric businesses also includes environmental sustainability efforts. These efforts include environmental upgrades, improving energy efficiency, expanding the renewable energy portfolio of generation resources, and proactively addressing climate change. In early 2009, PNM completed environmental upgrades to each of the four units at SJGS. PNM's share of the costs of these upgrades, which reduced the levels of particulate matter, NO_X, SO_2, and mercury emissions, amounted to $161 million. As described in Note 10, PNM is subject to the renewable portfolio standard established by New Mexico's Renewable Energy Act and related regulations issued by the NMPRC, which require utilities to achieve certain levels of energy sales from renewable sources within its generation mix, including wind, solar, distributed generation, and other sources. PNM is actively engaged in activities to meet the NMPRC standard. PNM has also established various programs to promote energy efficiency, subject to the approval of the NMPRC. The Company monitors initiatives regarding legislation or regulation regarding climate change, including GHG, and participates in organizations and forums concerning climate change. The Company has expressed support for the Waxman-Markey bill and is generally supportive of a federal program that includes an economy-wide system of limitations on GHG that would include a cap and trade provision and a system of allowances and offsets designed to mitigate rate increases to utility customers. The Company is exploring various methods to mitigate its GHG in anticipation of climate change legislation or regulation, including increasing energy efficiency programs and increased reliance on renewable energy resources. See Climate Change Issues under Other Issues Facing the Company below for additional discussion of climate change matters. All of these efforts involve costs that the Company believes should be recoverable through rates charged to customers to the extent the costs are attributable to regulated operations. However, recovery of these costs is subject to the approval of regulators and will cause upward pressure on rates.

First Choice

As a REP, First Choice operates in the highly competitive Texas retail market, which experienced extreme price volatility and transmission congestion in 2008. ERCOT controls the transmission of power in the areas that First Choice supplies. ERCOT historically has operated through a series of geographic zones, which has led to congestion of the transmission system when large volumes of power were being transmitted between zones. Congestion tends to drive prices up in the spot market. These anomalies negatively impacted the margins realized from end use customers. These conditions were exacerbated by the impacts of Hurricane Ike and depressed economic conditions resulting in very high levels of customer turnover and levels of uncollectible accounts significantly higher than historical experience. ERCOT has made changes in its control protocols and is scheduled to change from the zonal system to a nodal system in December 2010, both of which should reduce congestion and price volatility. During 2009 and early 2010, the Texas retail market was more stable and First Choice does not anticipate the levels of extreme congestion and price volatility will reoccur in the near future. In addition, both power and natural gas prices decreased significantly, resulting in a substantial increase in margins realized by First Choice. These factors and increased focus on growing commercial accounts, customer credit standards, and improved customer service have improved results of operations at First Choice. The above factors have also contributed to a significant reduction in the level of bad debt expense, which has improved results of operations. First Choice expects market conditions to continue to be a key factor for the business and believes margins will return to more historic levels during 2010.

Economic Conditions

In the last half of 2008 and early 2009, global economic conditions deteriorated dramatically, encompassing the U.S. residential housing market, and global and domestic equity and credit markets, which resulted in reduced usage of electricity by the Company's customers. Although New Mexico and Texas do not seem to be impacted as greatly as some other areas of the United States, with unemployment rates that are somewhat lower than the rest of the nation, the territories served by the Company's electric businesses have been impacted by the recession and general economic downturn. The Company believes that electric sales volume will be relatively flat for the immediate future.

The unprecedented disruption in the credit markets in late 2008 and early 2009 had a significant adverse impact on numerous financial institutions, including several of the financial institutions that have dealings with the

Company. However, at this time, the Company's existing liquidity instruments have not been materially impacted by the credit environment and management does not expect that it will be materially impacted in the near future. The Company's revolving credit facilities expire in 2011 and 2012 and will need to be renegotiated or replaced in order to provide sufficient liquidity to finance operations and construction expenditures. The availability of such credit facilities and their terms and conditions will depend on the credit markets at that time, as well as the Company's credit ratings and operating results.

Optim Energy

PNMR's 50 percent ownership of Optim Energy allows it to participate in the operation of Optim Energy's assets and business and the formulation of Optim Energy's business strategy. Optim Energy owns electric generating assets in one of the nation's growing power markets. In 2009, Optim Energy was affected by continuing adverse market conditions, primarily low natural gas and power prices, and changed its near-term focus. Optim Energy is currently focused on utilizing cash flow from operations to reduce debt and optimizing its current generation assets as a stand-alone independent power producer. The goal is to position Optim Energy to optimize its performance under current market conditions with the expectation of being able to take advantage of any economic recovery in the power and gas markets over the next several years. The markets for power and natural gas are currently depressed. Optim is unable to predict what prices will be in the future or what impact prices will have on Optim's results of operations.

Any decisions in the future to grow capacity will be subject to the approval of both of Optim Energy's members and will be based on many then-existing market and other factors, including the cost to acquire or construct capacity, the anticipated demand for power, the anticipated market prices for power, the ability and cost to deliver power to the anticipated markets, and Optim Energy's financial resources.

RESULTS OF OPERATIONS

Executive Summary

A summary of net earnings (loss) attributable to PNMR is as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions, except earnings per share)					
Earnings from continuing operations	$ 22.9	$ 0.5	$ 22.4	$ 14.4	$ 14.2	$ 0.2
Earnings (loss) from discontinued operations, net of income taxes	-	(2.6)	2.6	-	73.2	(73.2)
Net earnings (loss)	$ 22.9	$ (2.1)	$ 25.0	$ 14.4	$ 87.5	$ (73.0)
Average common and common equivalent shares outstanding	91.8	91.5	0.3	91.7	91.5	0.2
Earnings from continuing operations per diluted share	$ 0.25	$ 0.01	$ 0.24	$ 0.16	$ 0.16	$ -
Net earnings (loss) per diluted share	$ 0.25	$ (0.02)	$ 0.27	$ 0.16	$ 0.96	$ (0.80)

The components of the change in earnings from continuing operations attributable to PNMR are:

	Three Months Ended	Six Months Ended
	June 30, 2010	June 30, 2010
	(In millions)	
PNM Electric	$ 16.9	$ 26.2
TNMP Electric	2.3	2.6
First Choice	0.6	(13.9)
Corporate and Other	0.5	(13.4)
Optim Energy	2.1	(1.3)
Net change	$ 22.4	$ 0.2

Detailed information regarding the changes in earnings from continuing operations is included in the segment information below. The after-tax changes for the three months ended June 30, 2010 relate primarily to charges in 2009 for a $16.1 million regulatory disallowance related to prior sales of SO_2 emission allowances and $7.6 million associated with an increase in legal reserve at PNM Electric. The after-tax changes for the six months ended June 30, 2010 also reflect losses on unrealized economic hedges at First Choice, which decreased earnings by $12.0 million in 2010 compared with gains of $3.6 million in 2009. In addition, gains at Corporate and Other in 2009 relating to a $9.1 million fee received upon termination of the proposed CRHC acquisition and $4.5 million on the re-acquisition of $157.4 million of PNMR's 9.25% senior unsecured notes were partially offset by a $5.1 million gain at PNM for a settlement of the Republic Savings Bank litigation in 2010.

Segment Information

The following discussion is based on the segment methodology that PNMR's management uses for making operating decisions and assessing performance of its various business activities. See Note 3 for more information on PNMR's operating segments.

The following discussion and analysis should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto. Trends and contingencies of a material nature are discussed to the extent known. Refer also to Disclosure Regarding Forward Looking Statements and to Part II, Item 1A. Risk Factors.

PNM Electric

The table below summarizes operating results for PNM Electric:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions)					
Total electric operating revenues	$ 243.1	$ 226.5	$ 16.6	$ 473.6	$ 458.5	$ 15.1
Cost of energy	79.6	91.1	(11.5)	166.1	192.7	(26.6)
Gross margin	163.4	135.4	28.1	307.5	265.8	41.7
Operating expenses	107.1	122.9	(15.8)	215.9	220.4	(4.5)
Depreciation and amortization	22.9	22.9	-	45.8	45.4	0.4
Operating income (loss)	33.4	(10.4)	43.8	45.8	-	45.8
Other income (deductions)	3.1	17.5	(14.5)	19.2	18.6	0.6
Interest charges	(18.4)	(17.4)	(1.0)	(36.5)	(34.6)	(1.9)
Earnings (loss) before income taxes	18.1	(10.3)	28.4	28.6	(16.0)	44.6
Income (taxes) benefit	(5.9)	5.1	(11.0)	(8.8)	8.5	(17.3)
Valencia non-controlling interest	(3.3)	(2.8)	(0.5)	(6.4)	(5.4)	(1.0)
Preferred stock dividend requirements	(0.1)	(0.1)	-	(0.3)	(0.3)	-
Segment earnings (loss)	$ 8.8	$ (8.1)	$ 16.9	$ 13.1	$ (13.1)	$ 26.2

The table below summarizes the significant changes to total revenues, cost of energy, and gross margin:

	2010/2009 Change					
	Three Months Ended June 30,			Six Months Ended June 30,		
	Total Revenues	Cost of Energy	Gross Margin	Total Revenues	Cost of Energy	Gross Margin
	(In millions)					
Retail rate increases	$ 15.4	$ 6.6	$ 8.8	$ 26.0	$ 13.2	$ 12.8
Retail load, fuel and transmission	(0.5)	(8.2)	7.7	(4.5)	(17.3)	12.8
Unregulated margins	1.3	(14.4)	15.7	(1.9)	(21.1)	19.2
Net unrealized economic hedges	0.4	4.7	(4.3)	(4.5)	(0.7)	(3.8)
Consolidation of Valencia PPA	-	(0.2)	0.2	-	(0.7)	0.7
Total increase (decrease)	$ 16.6	$(11.5)	$ 28.1	$15.1	$(26.6)	$ 41.7

The following table shows PNM Electric operating revenues by customer class, including intersegment revenues and average number of customers:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions, except customers)					
Residential	$ 79.2	$ 69.8	$ 9.4	$ 163.6	$ 143.6	$ 20.0
Commercial	91.7	82.7	9.0	164.6	152.6	12.0
Industrial	20.7	19.0	1.7	41.0	38.0	3.0
Public authority	5.0	4.8	0.2	9.4	9.2	0.2
Other retail	3.0	3.7	(0.7)	4.9	6.7	(1.8)
Transmission	9.1	7.4	1.7	18.9	15.1	3.8
Firm requirements wholesale	6.9	6.1	0.8	15.1	13.6	1.5
Other sales for resale	28.6	34.9	(6.3)	59.2	78.4	(19.2)
Mark-to-market activity	(1.1)	(1.9)	0.8	(3.1)	1.3	(4.4)
	$ 243.1	$ 226.5	$ 16.6	$ 473.6	$ 458.5	$ 15.1
Average retail customers (thousands)	501.3	498.7	2.6	501.1	498.3	2.8

The following table shows PNM Electric GWh sales by customer class:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(Gigawatt hours)					
Residential	744.3	727.2	17.1	1,602.8	1,522.9	79.9
Commercial	1,024.6	976.1	48.5	1,905.8	1,831.7	74.1
Industrial	363.9	362.3	1.6	713.7	717.6	(3.9)
Public authority	63.6	64.7	(1.1)	117.8	116.4	1.4
Firm requirements wholesale	163.1	156.3	6.8	340.3	340.0	0.3
Other sales for resale	544.2	1,172.0	(627.8)	1,085.4	2,232.1	(1,146.7)
	2,903.7	3,458.6	(554.9)	5,765.8	6,760.7	(994.9)

The results of operations of PNM Electric are primarily driven by the rate making decisions and other actions of the NMPRC. In 2010, margins improved due to the implementation of new rates in PNM's 2008 Electric Rate Case. Beginning April 1, 2010, PNM implemented the second phase of a $77.1 million non-fuel base rate increase, for retail customers except those formerly served by TNMP. The first phase or 65% of the $77.1 million was implemented on July 1, 2009.

Increases in retail loads, driven by warmer weather in the second quarter and an increase in average customers, as well as increases in transmission revenues from new transmission contracts, increased revenues and margins. Decreases to revenues were driven by lower off-system sales volumes due to lower available excess generation from baseload facilities due to outages and increased loads. These reductions in revenues, along with reductions in generation fuel costs due to outages and an increase in economy purchases volumes and pricing are offset through the FPPAC for retail customers, except those customers formerly served by TNMP and certain wholesale customers.

The revenues and costs associated with Luna, Lordsburg, and the Valencia PPA were included in unregulated margins prior to May 2009, when the costs of those plants, net of off-system sales, began being recovered through the regulatory process. Improvements in unregulated margins relate to a pre-tax charge recorded to unregulated revenues in 2009 of $12.6 million associated with an increase in legal reserves. See Note 9. In 2009, unregulated margins were negatively impacted due to the fixed demand charges associated with the Valencia PPA, which were not being recovered in retail rates prior to July 1, 2009.

PNM Electric analyzes results associated with the Valencia PPA as costs of energy. Under GAAP, the Valencia PPA is consolidated, which results in costs being reflected as operating expenses and non-controlling interest that would have been included in cost of energy if the Valencia PPA was not consolidated.

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Operating expenses in 2010 decreased due to a $26.6 million regulatory disallowance recorded in the second quarter 2009, primarily related to prior sales of SO_2 emission allowances. Planned outage and maintenance costs incurred at SJGS in the second quarter 2010, higher medical and pension plan costs, and increases in allocated corporate costs partially offset the decrease in operating expenses. For the six months ended June 30, 2010, planned outage costs at Four Corners and increased outage and maintenance costs incurred at SJGS due to unplanned repairs on San Juan Unit 2 further increased operating expenses.

Increases in depreciation and amortization expense due to higher utility plant and amortization of certain regulatory assets are offset by lower depreciation expense on PVNGS and Reeves Station due to extension of their useful lives.

In the second quarter of 2010, other income decreased due to interest income recorded in 2009 related to uncertain income tax positions associated with changes in book to tax differences on capitalized overheads. Realized losses in the second quarter of 2010 associated with the NDT assets further reduced other income. For the six months ended June 30, 2010, a pre-tax $8.5 million gain from the Republic Savings Bank litigation increased other income. See Note 9.

TNMP Electric

The table below summarizes the operating results for TNMP Electric:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions)					
Total electric operating revenues	$ 52.6	$ 46.8	$ 5.8	$100.7	$ 88.0	$ 12.7
Cost of energy	9.1	8.7	0.4	18.1	17.3	0.8
Gross margin	43.5	38.1	5.4	82.6	70.8	11.9
Operating expenses	19.0	18.8	0.2	37.8	36.7	1.1
Depreciation and amortization	10.0	8.9	1.1	20.1	17.5	2.6
Operating income	14.4	10.4	4.0	24.7	16.5	8.2
Other income (deductions)	0.3	0.5	(0.2)	0.6	0.9	(0.3)
Interest charges	(8.0)	(7.9)	(0.1)	(15.8)	(12.0)	(3.8)
Earnings before income taxes	6.8	3.0	3.8	9.5	5.4	4.1
Income (taxes)	(2.7)	(1.2)	(1.5)	(3.7)	(2.2)	(1.5)
Segment earnings	$ 4.1	$ 1.8	$ 2.3	$ 5.8	$ 3.2	$ 2.6

The table below summarizes the significant changes to total revenues, cost of energy, and gross margin:

	2010/2009 Change					
	Three Months Ended June 30,			Six Months Ended June 30,		
	Total Revenues	Cost of Energy	Gross Margin	Total Revenues	Cost of Energy	Gross Margin
	(In millions)					
Rate increases	$ 2.2	$ -	$ 2.2	$ 3.4	$ -	$ 3.4
Customer usage/load	0.5	-	0.5	3.7	-	3.7
Other	3.1	0.4	2.7	5.6	0.8	4.8
Total increase	$ 5.8	$ 0.4	$ 5.4	$12.7	$ 0.8	$ 11.9

The following table shows TNMP Electric operating revenues by customer class, including intersegment revenues, and average number of customers:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions, except customers)					
Residential	$ 20.1	$ 17.3	$ 2.8	$ 39.0	$ 31.7	$ 7.3
Commercial	19.7	19.2	0.5	37.2	35.2	2.0
Industrial	3.1	3.2	(0.1)	6.0	6.1	(0.1)
Other	9.7	7.1	2.6	18.5	15.0	3.5
	$ 52.6	$ 46.8	$5.8	$100.7	$ 88.0	$ 12.7
Average customers (thousands) (1)	229.4	228.5	0.9	229.0	228.3	0.7

(1) Under TECA, customers of TNMP Electric in Texas have the ability to choose First Choice or any other REP to provide energy. The average customers reported above include 76,768 and 87,538 customers of TNMP Electric for the three months ended June 30, 2010 and 2009, and 77,981 and 88,716 for the six months ended June 30, 2010 and 2009, who have chosen First Choice as their REP. These customers are also included in the First Choice segment.

The following table shows TNMP Electric GWh sales by customer class:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(Gigawatt hours (1))					
Residential	643.7	617.9	25.8	1,255.2	1,127.8	127.4
Commercial	588.5	584.4	4.1	1,064.9	1,044.8	20.1
Industrial	577.0	529.6	47.4	1,093.8	953.7	140.1
Other	25.8	26.2	(0.4)	50.6	52.0	(1.4)
	1,835.0	1,758.1	76.9	3,464.5	3,178.3	286.2

(1) The GWh sales reported above include 246.9 and 281.0 GWhs for the three months ended June 30, 2010 and 2009, and 496.4 and 529.4 GWhs for the six months ended June 30, 2010 and 2009 used by customers of TNMP Electric, who have chosen First Choice as their REP. These GWhs are also included below in the First Choice segment.

Implementation of new base rates on September 1, 2009 and the May 14, 2010 increase in TNMP's annual transmission rates of $5.5 million to reflect changes in invested capital through December 31, 2009 increased revenues and margins. For the six months ended June 30, 2010, increased retail load driven by cooler temperatures in the first quarter of 2010 also increased revenues and margins. Increases in revenues associated with Hurricane Ike recovery and energy efficiency programs are partially offset with increases in expenses discussed below.

In the second quarter 2010, energy efficiency program costs, lower capitalized administrative and general costs due to lower capital expenditures, increased corporate allocation costs, and higher street rental taxes increased operating expenses. These costs were partially offset by a $0.7 million write-off in 2009 associated with Hurricane Ike costs. For the six months ended June 30, 2010, higher self insurance premiums and losses further increased operating expenses.

Depreciation and amortization increased related to the amortization of Hurricane Ike restoration costs and higher depreciation costs due to increases in transmission plant, which are covered in rates as discussed above.

For the six months ended June 30, 2010, interest charges increased primarily due to higher interest rates on long-term debt issued in March 2009. The higher cost of debt is reflected in the rate increase discussed above.

PNM Gas

The table below summarizes the 2009 operating results for PNM Gas, which is classified as discontinued operations in the Condensed Consolidated Statements of Earnings (Loss):

	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
	(In millions)	
Total revenues	$ -	$ 65.7
Cost of energy	-	44.7
Gross margin	-	21.0
Operating expenses	4.2	10.0
Depreciation and amortization	-	-
Operating income (loss)	(4.2)	11.0
Other income (deductions)	-	0.3
Interest charges	-	(1.0)
Gain on disposal	(0.3)	101.1
Earnings (loss) before income taxes	(4.5)	111.4
Income (taxes) benefit	1.9	(38.2)
Segment earnings (loss)	$ (2.6)	$ 73.2

PNM completed the sale of the PNM Gas business on January 30, 2009. PNM Gas is reported as discontinued operations as required under GAAP. PNM Gas purchased natural gas in the open market and sold it at no profit to its sales-service customers. As a result, increases or decreases in gas revenues driven by gas costs did not impact the gross margin or operating income of PNM Gas. Increases or decreases to gross margin caused by changes in sales-service volumes represented margin earned on the delivery of gas to customers based on regulated rates.

As a result of the sale, the above table reflects operations from the PNM Gas business from January 1 through January 30, 2009. Milder weather combined with lower usage-per customer reduced overall sales volumes in 2009. A pre-tax gain of $101.1 million, which reflects the retroactive adjustment discussed in Note 1, was recognized on the sale of the PNM Gas business. There is nothing reported as discontinued operations in 2010.

First Choice

The table below summarizes the operating results for First Choice:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions)					
Total electric operating revenues	$ 119.9	$ 138.0	$ (18.1)	$ 234.3	$ 260.1	$ (25.8)
Cost of energy	72.1	85.6	(13.5)	177.1	166.0	11.1
Gross margin	47.8	52.3	(4.5)	57.2	94.1	(36.9)
Operating expenses	21.3	26.1	(4.8)	41.7	55.4	(13.7)
Depreciation and amortization	0.2	0.5	(0.3)	0.5	1.0	(0.5)
Operating income	26.3	25.8	0.5	15.0	37.7	(22.7)
Other income (deductions)	(0.1)	(0.1)	-	(0.1)	-	(0.1)
Interest charges	(0.4)	(0.8)	0.4	(0.7)	(1.8)	1.1
Earnings before income taxes	25.9	24.9	1.0	14.2	35.9	(21.7)
Income (taxes)	(9.3)	(9.0)	(0.3)	(5.1)	(12.9)	7.8
Segment earnings	$ 16.6	$ 16.0	$ 0.6	$ 9.1	$ 23.0	$ (13.9)

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The following table summarizes the significant changes to total revenues, cost of energy, and gross margin:

	2010/2009 Change					
	Three Months Ended June 30,			Six Months Ended June 30,		
	Total Revenues	Cost of Energy	Gross Margin	Total Revenues	Cost of Energy	Gross Margin
	(In millions)					
Weather	$ 0.3	$ 0.2	$ 0.1	$ 11.4	$ 7.2	$ 4.2
Customer growth/usage	(8.9)	(6.1)	(2.8)	(15.1)	(10.8)	(4.3)
Retail margins	(9.3)	(3.5)	(5.7)	(22.0)	(9.4)	(12.6)
Trading margins	(0.2)	-	(0.2)	(0.1)	-	(0.1)
Unrealized economic hedges	-	(4.1)	4.1	-	24.1	(24.1)
Total increase (decrease)	$ (18.1)	$ (13.5)	$ (4.5)	$ (25.8)	$ 11.1	$ (36.9)

The following table shows First Choice operating revenues by customer class, including intersegment revenues, and actual number of customers:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions, except customers)					
Residential	$ 75.3	$ 92.8	$ (17.5)	$ 150.0	$ 168.7	$ (18.7)
Mass-market	4.1	6.4	(2.3)	8.4	14.7	(6.3)
Mid-market	36.4	33.7	2.7	67.3	65.8	1.5
Trading gains (losses)	(0.1)	0.1	(0.2)	(0.1)	-	(0.1)
Other	4.2	5.0	(0.8)	8.7	10.9	(2.2)
	$ 119.9	$ 138.0	$ (18.1)	$ 234.3	$ 260.1	$ (25.8)
Actual customers (thousands) (1,2)	216.1	243.3	(27.2)	216.1	243.3	(27.2)

(1) See note above in the TNMP Electric segment discussion about the impact of TECA.

(2) Due to the competitive nature of First Choice's business, actual customer counts are presented in the table above as a more representative business indicator than the average customers that are shown in the table for TNMP customers.

The following table shows First Choice GWh electric sales by customer class:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(Gigawatt hours) (1)					
Residential	549.3	644.1	(94.8)	1,099.4	1,145.9	(46.5)
Mass-market	24.9	37.3	(12.4)	51.4	79.3	(27.9)
Mid-market	321.2	273.8	47.4	572.4	522.5	49.9
Other	1.4	2.9	(1.5)	3.5	5.3	(1.8)
	896.8	958.1	(61.3)	1,726.7	1,753.0	(26.3)

(1) See note above in the TNMP Electric segment discussion about the impact of TECA.

During 2010, favorable weather resulted in an increase to segment earnings. Decreases in the number of customers, MWh sales, and average revenue rates compared to 2009 resulted in decreased margins for both the second quarter and year-to-date 2010.

First Choice manages its exposure to fluctuations in market energy prices by matching sales contracts with supply instruments designed to preserve targeted margins. Accordingly, First Choice has forward energy contracts in place to cover the future load requirements for most of its fixed price sales contracts. Gains or losses on unrealized economic hedges represent changes in unrealized fair value estimates related to these forward energy contracts. Changes in the fair value of supply contracts that are not designated or are not eligible for hedge or normal purchase/sales accounting are marked to market through current period earnings as required by GAAP. During the first quarter of 2010, market energy prices decreased significantly, which resulted in GAAP losses on certain of First Choice's forward supply contracts. First Choice is not required to mark the related fixed price sales contracts to market, which would likely show offsetting gains as market energy prices decrease. Year-to-date losses on unrealized economic hedges decreased segment earnings by $18.5 million in 2010 compared with gains of $5.6 million in 2009. These mark-to-market losses are not necessarily indicative of the amounts that will be realized upon settlement or the retail margin First Choice will realize.

The allowance for uncollectible accounts and related bad debt expense is based on collections and write-off experience. In late 2008 and early 2009, the customer default rates experienced were significantly above historic levels due to overall economic conditions, higher average final bills, and an increase in customer churn. Recently, lower customer departures, lower default rates and significantly lower average final bills attributable to lower sales prices have reduced bad debts. As a result, bad debt expense decreased, which increased segment earnings by $12.4 million year-to-date and $3.9 million in the second quarter of 2010 compared to 2009. This reduction can be partially attributed to several initiatives undertaken by management to reduce bad debt expense. These initiatives include efforts to reduce the default rate experienced for customers switching to another REP and increased focus on identifying new customer prospects that are more likely to demonstrate desired payment behavior. First Choice is focusing its marketing efforts on commercial customers and customers with established payment patterns. First Choice has also increased the credit score required to become a customer and expanded the circumstances where customers are required to provide advance deposits to obtain service, or both. In addition, possible regulatory changes are under discussion with the PUCT that would impede a customer's ability to switch REPs until past due balances are paid.

First Choice had lower customer acquisition expenses and support service costs for both the second quarter and year-to-date 2010 compared 2009.

Corporate and Other

The table below summarizes the operating results for Corporate and Other:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions)					
Total electric operating revenues	$ (9.7)	$(10.2)	$ 0.5	$(19.4)	$(19.7)	$ 0.3
Cost of energy	(9.6)	(10.2)	0.6	(19.2)	(19.5)	0.3
Gross margin	(0.1)	-	(0.1)	(0.2)	(0.2)	-
Operating expenses	(3.8)	(3.8)	-	(7.1)	(9.9)	2.8
Depreciation and amortization	4.2	4.6	(0.4)	8.3	9.2	(0.9)
Operating income (loss)	(0.5)	(0.9)	0.4	(1.4)	0.5	(1.9)
Equity in net earnings (loss) of Optim Energy	(3.9)	(7.4)	3.5	(8.2)	(6.0)	(2.2)
Other income (deductions)	(1.6)	(1.4)	(0.2)	(2.8)	18.8	(21.6)
Net interest charges	(5.0)	(5.7)	0.7	(10.2)	(12.4)	2.2
Earnings (loss) before income taxes	(10.9)	(15.3)	4.4	(22.7)	1.0	(23.7)
Income (taxes) benefit	4.4	6.2	(1.8)	9.1	0.1	9.0
Segment earnings (loss)	$ (6.6)	$ (9.2)	$ 2.6	$(13.5)	$ 1.1	$(14.6)

The Corporate and Other Segment includes consolidation eliminations of revenues and cost of energy between business segments, primarily related to TNMP's sale of transmission and distribution services to First Choice. Corporate and Other also includes equity in Optim Energy's results of operations, which are further explained below.

Other operating expenses increased in the three months and six months ended June 30, 2010 compared to 2009 primarily due to elimination of operating lease expense of $2.4 million per quarter paid by PNM to PNMR related to a portion of PVNGS Unit 2, which was transferred to PNM in July 2009. This amount is offset in PNM Electric. The increases are partially offset by a decrease in administrative and general expenses of $2.0 million in the second quarter.

Depreciation expense decreased in 2010 compared to 2009 related to a decrease in asset base, primarily resulting from the transfer of a portion of PVNGS Unit 2 to PNM in July 2009.

Other income and deductions decreased in 2010 compared to 2009 primarily due to a $15.0 million payment received upon termination of the CRHC acquisition agreement and a gain of $7.3 million on the re-acquisition of $157.4 million of PNMR's 9.25% senior unsecured notes, both of which occurred in the first quarter of 2009.

Interest charges decreased in 2010 compared to 2009 primarily due to lower long-term borrowings due to the re-acquisition of $157.4 million of PNMR's 9.25% senior unsecured notes, which occurred in February 2009.

Optim Energy

The table below summarizes the operating results for Optim Energy:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(In millions)					
Operating revenues	$ 86.9	$ 58.1	$ 28.8	$ 192.5	$ 136.5	$ 56.0
Cost of energy	61.2	42.7	18.5	138.5	87.8	50.7
Gross margin	25.7	15.4	10.3	53.9	48.7	5.2
Operating expenses	14.6	19.0	(4.4)	34.1	38.9	(4.8)
Depreciation and amortization	12.9	7.4	5.5	24.9	15.1	9.8
Operating income (loss)	(1.8)	(11.0)	9.2	(5.1)	(5.3)	0.2
Other income (deductions)	-	(0.1)	0.1	0.1	(0.1)	0.2
Interest charges	(4.7)	(3.0)	(1.7)	(9.3)	(5.5)	(3.8)
Earnings (loss) before income taxes	(6.4)	(14.2)	7.8	(14.4)	(10.9)	(3.5)
Income (tax) benefit on margin	-	0.1	(0.1)	(0.1)	(0.1)	-
Net earnings (loss)	$ (6.5)	$ (14.1)	$ 7.6	$ (14.4)	$ (11.0)	$ (3.4)
50 percent of net earnings (loss)	$ (3.2)	$ (7.1)	$ 3.9	$ (7.2)	$ (5.5)	$ (1.7)
Plus amortization of basis difference in Optim Energy	(0.6)	(0.3)	(0.3)	(1.0)	(0.5)	(0.5)
PNMR equity in net earnings (loss) of Optim Energy	$ (3.9)	$ (7.4)	$ 3.5	$ (8.2)	$ (6.0)	$ (2.2)

In 2009, Optim Energy was affected by continuing adverse market conditions, primarily low natural gas and power prices, and changed its near-term focus. Optim Energy's current strategy and near-term focus is on utilizing cash flow from operations to reduce debt and optimizing its generation assets as a stand-alone independent power producer. The goal is to position Optim Energy to optimize its performance in the current market with expectation of being able to take advantage of any economic recovery in the power and gas market over the next several years. Optim's results of operations are primarily determined by the prices at which its power is sold and it procures fuel, principally natural gas, to generate power. Additionally, power prices in the ERCOT market are directly correlated to natural gas prices. The markets for power and natural gas are currently depressed. Optim is unable to predict what prices will be in the future or what impact prices will have on Optim's results of operations.

Optim Energy's management evaluates the results of operations on an ongoing earnings before interest, income taxes, depreciation, amortization, mark-to-market, and certain other items ("Ongoing EBITDA") basis. Altura (Twin Oaks), Altura Cogen, and Cedar Bayou 4 generating stations comprise Optim Energy's core business. Revenue related to power sales and purchases is included net in operating revenues. Costs related to fuel purchases and sales are recorded net in cost of sales.

Commercial optimization of generation, increased wind generation in Texas, and well-positioned assets resulted in an increase in ancillary revenues of $3.2 million and $7.4 million for the three and six months ended June 30, 2010 compared to 2009. This increase was partially offset by a decrease in sales of excess emission allowances of $1.6 million for the six months ended June 30, 2010 compared to 2009. For the three months ended June 30, 2010, sales of emission allowances increased by $0.2 million. Lower realized power and steam prices combined with increased fuel expense reduced earnings $6.6 million and $12.3 million in the three months and six months ended June 30, 2010. Operating expense reductions decreased costs $2.0 million and $4.6 million in the three months and six months ended June 30, 2010.

Ongoing EBITDA excludes purchase accounting amortization included in gross margin related to out of market contracts and emission allowances that were recorded at the acquisition of Altura and Altura

Cogen. Amortization related to out of market contracts decreased total operating revenues by $4.2 million and $8.2 million for the three months and six months ended June 30, 2010 and $3.2 million and $6.3 million for the three months and six months ended June 30, 2009. Amortization for out of market contracts will continue through the expiration of each contract, which is 2010 for Altura and 2021 for Altura Cogen. In addition, cost of energy includes amortization related to emission allowances acquired in the acquisitions of $1.3 million and $2.6 million for the three months and six months ended June 30, 2010 and $1.1 million and $2.4 million for the three months and six months ended June 30, 2009. The amortizations for emission allowances are recorded as the allowances are used in plant operations, sold or expire.

Ongoing EBITDA excludes interest expense and depreciation. Construction of Cedar Bayou 4 was completed in June 2009. Optim Energy capitalized interest of $1.5 million and $2.9 million in the three months and six months ended June 30, 2009 related to this development, resulting in a 2010 increase in interest expense. Depreciation of Cedar Bayou 4 began after completion and amounted to $3.5 million and $5.4 million in the three months and six months ended June 30, 2010. Other asset additions in 2009 and shortened asset lives resulted in the additional depreciation increases.

Optim Energy has a hedging program the level of which varies at any given time depending on current market conditions and other factors. Economic hedges that do not qualify, or are not designated, as cash flow hedges or normal purchases/sales are derivative instruments that are required to be marked to market. Ongoing EBITDA for the three months ended June 30, 2010 and 2009 excludes forward mark-to-market losses of $1.3 million and $15.8 million. Ongoing EBITDA for the six months ended June 30, 2010 and 2009 excludes forward mark-to-market gains of $3.0 million and the losses of $6.4 million.

LCC is Optim Energy's counterparty in several agreements for power and steam sales. In addition, LCC leases Optim Energy the land for the Altura Cogen facility and provides other services, including water, to that facility. On January 6, 2009, LCC filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. The pre-petition amount due from LCC is immaterial and was fully reserved as of December 31, 2008. LCC has continued to perform under the existing contracts since the filing. LCC's bankruptcy plan was confirmed by the bankruptcy court on April 23, 2010. LCC has filed documents with the bankruptcy court indicating its intent to assume its contracts with Altura Cogen. As part of this process, LCC is required to cure pre-petition defaults under its contracts with Altura Cogen and in the three months and six months ended June 30, 2010, Optim Energy reversed the $1.0 million that had been reserved previously. At present, Altura Cogen and LCC are negotiating the terms of a stipulation to formalize the cure of these defaults.

The contribution of Altura created a basis difference between PNMR's recorded investment in Optim Energy and 50 percent of Optim Energy's equity. The PNMR net earnings impact does not equal 50 percent of the Optim Energy amortization because of this basis difference. While the portion of the basis difference related to contract amortization will only continue through 2010, other basis differences, including a difference related to emission allowances, will continue to exist through the life of the Altura plant. The basis difference adjustment detailed above relates primarily to contract amortization with insignificant offsets related to the other minor basis difference components.

LIQUIDITY AND CAPITAL RESOURCES

Statements of Cash Flows

The changes in PNMR's cash flows for the three months ended June 30, 2010 compared to 2009 are summarized as follows:

	Six Months Ended June 30,		
	2010	2009	Change
		(In millions)	
Net cash flows from:			
Operating activities	$ 76.2	$ (34.4)	$ 110.6
Investing activities	(138.6)	509.8	(648.4)
Financing activities	66.9	(590.0)	656.9
Net change in cash and cash equivalents	$ 4.5	$ (114.6)	$ 119.1

The change in PNMR's cash flows from operating activities reflects net refunds of income taxes of $63.4 million in 2010, including the settlement of issues related to changes in book to tax differences on capitalized overheads, compared to net payments of $49.0 million in 2009, primarily related to the sale of PNM Gas. Improved results of operations at PNM and TNMP in 2010, primarily due to the impact of rate increases also contributed to the change. In 2010, the operating results of First Choice were negatively impacted by $18.5 million of mark-to-market losses on derivative contracts, which do not impact cash flows from operations. Cash flows from operating activities were negatively impacted by increased collateral required to be posted by PNM and First Choice in 2010.

The changes in cash flows from investing activities relate primarily to the proceeds from the sale of PNM Gas in 2009. An increase in utility plant additions of $4.3 million in 2010 was primarily due to increased payments for rights-of-way renewals. In addition, PNMR made equity contributions of $16.4 million to Optim Energy in the first six months of 2010.

The changes in cash flows from financing activities relate primarily to the use of the proceeds from the sale of PNM Gas to retire short-term borrowings at PNM and PNMR, as well as the retirement of long-term borrowings at PNMR in 2009. At TNMP, the retirement of both short-term and long-term borrowings was financed by new long-term borrowings in 2009. In 2010, short-term borrowings were used to fund continuing construction expenditures.

Financing Activities

See Note 7 for information concerning the Company's financing activities during the six months ended June 30, 2010, including the refinancing of $403.8 million of PCRBs in June 2010. The Company has from time to time refinanced or repurchased portions of its outstanding debt. Depending on market conditions, the Company may refinance other debt issuances or make additional debt repurchases in the future. Additional information on the Company's financing activities is contained in Note 6 of Notes to Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K.

Capital Requirements

Total capital requirements consist of construction expenditures and cash dividend requirements for both common and preferred stock. PNMR's Series A convertible preferred stock is entitled to receive dividends equivalent to any dividends paid on PNMR common stock as if the preferred stock had been converted into common stock. The main focus of PNMR's current construction program is upgrading generation resources, constructing renewable energy resources to be owned by PNM, upgrading and expanding the electric transmission and distribution systems, and purchasing nuclear fuel. Projections, including amounts expended through June 30, 2010, for total capital requirements for 2010 are $326.4 million, including construction expenditures of $280.2 million. Total capital requirements for the years 2010-2014 are projected to be $1,800.2 million, including construction expenditures of $1,568.9 million. These amounts do not include forecasted construction expenditures of Optim Energy. These estimates are under continuing review and subject to ongoing adjustment, as well as to Board review and approval. TNMP has requested PUCT approval to undertake a project to install an advanced metering system for customers it serves. This would require an investment through 2015 of $70.6 million, of which $57.9 million is included in the above numbers. TNMP will not commit to this project before the method of recovery of the investment is authorized by the PUCT. During the first six months of 2010, the Company utilized its liquidity arrangements, to meet its capital requirements, including construction expenditures.

In April 2010, PNMR and ECJV each made an equity contribution to Optim Energy of $15.0 million in cash. PNMR and ECJV also agreed to make additional cash contributions during 2010 that would aggregate approximately $5.0 million from each owner of which each had contributed $2.6 million as of July 29, 2010. Optim Energy used the equity contributions to reduce amounts outstanding under its bank financing arrangement and will also use the additional contributions to reduce debt. If Optim Energy undertakes additional projects, which require funds that would exceed the capacity of its current credit facility and Optim Energy is unable to obtain additional financing capabilities, PNMR and ECJV may be asked to provide additional funding, but such funding would be at the option of PNMR and ECJV and no assurance can be given that such funding will be available to Optim Energy. PNMR is unable to predict if additional funding will be required or, if required, the amount or timing of additional funds that would be provided to Optim Energy.

Liquidity

PNMR's liquidity arrangements include the PNMR Facility and the PNM Facility both of which primarily expire in 2012 and the TNMP Revolving Credit Facility, which expires in April 2011. These facilities provide short-term borrowing capacity and also allow letters of credit to be issued, which reduce the available capacity under the facilities. These credit facilities will need to be renegotiated or replaced prior to their expirations in order to provide sufficient liquidity to finance operations and construction expenditures. The availability of such credit facilities, including their amounts for borrowing thereunder and their terms and conditions, will depend on the credit markets at that time, as well as the Company's credit ratings and operating results. Both PNMR and PNM also have lines of credit with local financial institutions. As of July 29, 2010, the Company had short-term debt outstanding of $296.0 million at an average interest rate of 1.19%.

Although accessing the capital markets at the current time could be difficult as well as costly, the Company currently believes that its internal cash generation, existing credit arrangements, and access to public and private capital markets will provide sufficient resources to meet the Company's capital requirements. To cover the difference in the amounts and timing of cash generation and cash requirements, the Company intends to use short-term borrowings under its current and future liquidity arrangements. However, if market difficulties experienced during the recession resurge or worsen, the Company may not be able to access the capital markets or renew credit facilities when they expire. In such event, the Company would seek to improve cash flows by reducing capital expenditures and PNM would consider seeking authorization for the issuance of first mortgage bonds in order to improve access to the capital markets, as well as any other alternatives that may remedy the situation at that time.

In addition to its internal cash generation, the Company anticipates that it will be necessary to obtain additional long-term financing in the form of debt refinancing, new debt issuances, and/or new equity in order to fund its capital requirements during the 2010-2014 period.

The Company's ability, if required, to access the credit and capital markets at a reasonable cost and to provide for other capital needs is largely dependent upon its ability to earn a fair return on equity, its results of operations, its credit ratings, its ability to obtain required regulatory approvals and conditions in the financial markets. The credit ratings for PNMR, PNM, and TNMP are set forth under the heading Liquidity in the MD&A contained in the 2009 Annual Reports on Form 10-K. On March 9, 2010, Moody's revised its outlook to stable from negative for PNMR, PNM, and TNMP. In addition, Moody's upgraded the senior secured obligations of TNMP to Baa1 from Baa2. All other credit ratings remain unchanged.

A summary of liquidity arrangements as of July 29, 2010 is as follows:

	PNMR Separate	PNM Separate	TNMP Separate	PNMR Consolidated
		(In millions)		
Financing Capacity:				
Revolving credit facility	$ 568.0	$ 400.0	$ 75.0	$ 1,043.0
Local lines of credit	5.0	5.0	-	10.0
Total financing capacity	$ 573.0	$ 405.0	$ 75.0	$ 1,053.0
Amounts outstanding as of July 29, 2010:				
Revolving credit facility	$ 99.0	$ 197.0	$ -	$ 296.0
Local lines of credit	-	-	-	-
Total short-term debt outstanding	99.0	197.0	-	296.0
Letters of credit	69.0	9.7	0.3	79.0
Total short–term debt and letters of credit	$ 168.0	$ 206.7	$ 0.3	$ 375.0
Remaining availability as of July 29, 2010	$ 405.0	$ 198.3	$ 74.7	$ 678.0
Invested cash as of July 29, 2010	$ 20.1	$ 5.6	$ -	$ 25.7

The above table excludes intercompany debt. The remaining availability under the revolving credit facilities varies based on a number of factors, including the timing of collections of accounts receivables and payments for construction and operating expenditures. LBB was a lender under the PNMR Facility and the PNM Facility. LBH, the parent of LBB, has filed for bankruptcy protection. Subsequent to the bankruptcy filing by LBH, LBB declined to fund a borrowing request under the PNMR Facility. In March 2010, the PNMR Facility was amended to remove LBB as a lender and reduce the total capacity under the PNMR Facility from $600.0 million to $568.0 million. In addition to the reduction in the PNMR Facility related to LBB, the PNMR Facility and the PNM Facility will reduce by $26.0 million and $14.0 million in August 2010 and an additional $25.0 million and $18.0 million in August 2011 according to their terms. The Company does not believe amending the PNMR Facility to remove LBB or the scheduled reduction in the facilities will have a significant impact on PNMR's and PNM's liquidity.

For offerings of debt securities registered with the SEC, PNMR has an effective shelf registration statement expiring in April 2011. This shelf registration statement has unlimited availability and can be amended to include additional securities, subject to certain restrictions and limitations. PNMR can offer new shares of PNMR common stock through the PNM Resources Direct Plan under a separate SEC shelf registration statement that expires in August 2012. In April 2008, PNM filed a new shelf registration statement for the issuance of up to $750.0 million of senior unsecured notes that expires in April 2011. As of July 29, 2010, PNM had $600.0 million of remaining unissued securities registered under this and a prior shelf registration statement.

As discussed above and in Note 7, disruption in the credit markets has had a significant adverse impact on a number of financial institutions and several of the financial institutions that the Company deals with have been impacted. However, at this point in time, the Company's liquidity has not been materially impacted and management does not expect that it will be materially impacted in the near-future.

Off-Balance Sheet Arrangements

PNMR's off-balance sheet arrangements include PNM's operating lease obligations for PVNGS Units 1 and 2, the EIP transmission line, and the entire output of Delta, a gas-fired generating plant. These arrangements help ensure PNM the availability of lower-cost generation needed to serve customers. See MD&A – Off-Balance Sheet Arrangements and Note 7 of Notes to Consolidated Financial Statements in the 2009 Annual Reports on Form 10-K.

Commitments and Contractual Obligations

PNMR, PNM, and TNMP have contractual obligations for long-term debt, operating leases, purchase obligations, and certain other long-term liabilities. See MD&A – Commitments and Contractual Obligations in the 2009 Annual Reports on Form 10-K.

Contingent Provisions of Certain Obligations

As discussed in the 2009 Annual Reports on Form 10-K, PNMR, PNM, and TNMP have a number of debt obligations and other contractual commitments that contain contingent provisions. Some of these, if triggered, could affect the liquidity of the Company. The contingent provisions include contractual increases in the interest rate charged on certain of the Company's short-term debt obligations in the event of a downgrade in credit ratings and the requirement to provide security under certain contractual agreements. The Company believes its financing arrangements are sufficient to meet the requirements of the contingent provisions.

Capital Structure

The capitalization tables below include the current maturities of long-term debt, but do not include operating lease obligations as debt.

	June 30, 2010	December 31, 2009
PNMR		
PNMR common stockholders' equity	49.5%	49.6%
Convertible preferred stock	3.0%	3.0%
Preferred stock of subsidiary	0.3%	0.3%
Long-term debt	47.2%	47.1%
Total capitalization	100.0%	100.0%
PNM		
PNM common stockholder's equity	52.0%	51.9%
Preferred stock	0.5%	0.5%
Long-term debt	47.5%	47.6%
Total capitalization	100.0%	100.0%
TNMP		
Common stockholder's equity	59.5%	59.3%
Long-term debt	40.5%	40.7%
Total capitalization	100.0%	100.0%

OTHER ISSUES FACING THE COMPANY

Climate Change Issues

Background

In 2009, PNMR's interests in generating plants, through PNM and Optim Energy, emitted approximately 9.6 million metric tons of carbon dioxide, the vast majority of its GHG. By comparison, the total GHG in the United States in 2008, the latest year for which the EPA has compiled this data, were approximately 7.0 billion metric tons, of which approximately 5.9 billion metric tons were carbon dioxide. Electricity generation accounted for approximately 2.4 billion metric tons of the carbon dioxide emissions.

PNM has several programs underway to mitigate its GHG, and thereby to reduce its climate change risk. See Note 10. On January 25, 2010, PNM filed with the NMPRC its revised renewable procurement plan that, if approved, will result in up to 80 MWs of new solar generation on PNM's system by the end of 2013. On July 1, 2010, PNM filed a new renewable energy plan for 2011. In 2008, PNM filed requests for approval to implement additional electric energy efficiency and load management programs with the NMPRC, which approved the programs in May 2009. Over the next 19 years, PNM projects the expanded energy efficiency and load management programs will provide the equivalent of approximately 15,000 GWh of electricity, which will avoid at least 1.8 million metric tons of CO_2 based upon projected emissions from PNM's system-wide portfolio with and without these programs. These estimates are subject to change given that it is difficult to accurately estimate avoidance because of the many variables that impact it, including changes in demand for electricity.

The Board is updated by management and regularly considers the issues around climate change, our GHG and potential financial consequences that might result from potential federal and/or state regulation of GHG. In particular, management periodically reports to the Board on all of the matters discussed in this section. In December 2008, the Board established a new stand-alone committee, the Public Policy and Sustainability Committee. This committee monitors Company practices and procedures to assess the sustainability impacts of our operations and products on the environment. This committee also has responsibility to review the Company's environmental management systems, monitor the implementation of the Company's corporate environmental policy, monitor the promotion of energy efficiency, and the use of renewable energy resources. The committee reports to the Board on a periodic basis regarding the Company's activities and initiatives in these areas.

EPA Regulation

In April 2007, the U.S. Supreme Court held that the EPA has the authority to regulate GHG under the Clean Air Act. This decision, coupled with an increased focus in the Obama administration and Congress on legislation to address climate change, has heightened the importance of this issue for the energy industry. Although there continues to be debate over the details and best design for state and federal programs, increased state and federal legislative and regulatory activities calling for regulation of GHG indicate that climate change protection legislation and regulation are likely in the future.

In July 2008, the EPA published the Greenhouse Gas Advanced Notice of Proposed Rulemaking. The notice identified, but did not choose among, options for GHG regulation and requested comments on the options presented. Absent Congressional action, in due course the Company expects the EPA to adopt regulations relating to GHG.

In December 2009, the EPA released its final endangerment finding stating that the atmospheric concentrations of six key greenhouse gases (carbon dioxide, methane, nitrous oxides, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) endanger the public health and welfare of current and future generations. The finding does not by itself impose any requirements on producers of GHG, but the finding does set the groundwork for the EPA to regulate GHG from new and existing stationary sources such as power plants and for new motor vehicles. The EPA proposed several rules regulating GHG in anticipation of the final endangerment finding. In September 2009, the EPA proposed GHG motor vehicle standards. The final standards were issued on April 1, 2010. Although promulgation of the motor vehicle standards triggers the applicability of PSD and operating permit ("Title V") requirements for stationary sources that emit GHG, the EPA concluded, in its reconsideration of when GHG regulation under the PSD program will commence, that PSD program requirements will apply to GHG upon the date the motor vehicle standards actually take effect. EPA stated those standards will take effect when the 2012 model year begins which is no earlier than January 2, 2011. The reconsideration did not specify which sources would be regulated in January 2011. This same date applies to operating permits. On May 13, 2010, the EPA released the final PSD and Title V Greenhouse Gas Tailoring Rule. The purpose of the rule is to "tailor" the applicability of two programs, PSD and Title V operating permit programs, to avoid impacting millions of small GHG emitters. As expected, the rule focuses on the largest sources of GHG, including fossil-fueled electric generating units. The final rule establishes three major phases for regulating GHG.

Phase 1 starts January 2, 2011 and addresses only those new or modified sources that emit 75,000 tons per year or more of GHGs and are currently subject to the PSD and Title V operating permit programs due to the amount of other regulated emissions. All of PNM's existing generating plants are subject to the PSD and Title V programs because of the magnitude of non-GHG. Any modification at these facilities resulting in an increase of greater than or equal to 75,000 tons per year of GHG – a margin of 0.6 percent of SJGS's 2009 emissions – would trigger PSD permitting requirements, including a BACT analysis for GHG.

Phase 2 starts July 1, 2011 and addresses any large source of GHG that was not previously subject to the PSD and Title V regulatory programs. Phase 3, effective in July 2013, will phase in smaller GHG sources.

EPA regulation of GHG from large stationary sources will impact PNM's operations due to the Company's reliance on fossil-fueled electric generation. The impact to PNM is unknown because the regulatory requirements, including what is considered BACT, are not yet defined but could involve investments in efficiency improvements and/or control technologies at the fossil-fueled generating plants.

Federal Legislation

In addition, several legislative initiatives are under consideration in Congress that would regulate GHG. These initiatives range from general limitations on GHG to the imposition of a so-called "cap and trade" system to the imposition of a tariff on GHG.

In June 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009. This bill, commonly referred to as the Waxman-Markey Bill, if ultimately passed into law, would establish an economy-wide program, with cap and trade as its cornerstone, regulating GHG. The bill defines specific emissions reductions requirements and timelines, provides for the allocation of free allowances to electric utilities in the early years of the program to help mitigate cost impacts to ratepayers and allows for compliance flexibility through cost control mechanisms including the establishment of an offset program that will further help mitigate costs to consumers.

On November 5, 2009, the Senate Environment and Public Works Committee reported the Clean Energy Jobs and American Power Act ("S. 1733") out of committee. While the bill is broadly similar to the climate change framework in the Waxman-Markey Bill, there are significant differences, including a more aggressive GHG reduction target for 2020. It appears unlikely that S. 1733 has the bipartisan support required to pass the Senate. Consequently, since November 2009, Senator Kerry (D, MA), an original cosponsor of S. 1733, Senator Graham (R, SC) and Senator Lieberman (I, CN) have been working together to develop climate change legislation that could attract the bipartisan support necessary for enactment. In May 2010, Senators Kerry and Lieberman released a draft comprehensive climate bill, but Senator Graham declined to support the bill.

It is unclear whether or when legislation will be passed.

The Company has assessed, and continues to assess, the impacts of potential climate change legislation or regulation on its business. This assessment is preliminary, and changes in the legislative or regulatory process could impact the assessment significantly. The Company's assessment includes assumptions regarding the specific GHG limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the development of technologies for renewable energy and to reduce emissions, the cost of emissions allowances, the degree to which offsets may be used for compliance, and provisions for cost containment. Moreover, the assessment assumes various market reactions such as with respect to the price of coal and gas and regional plant economics. These assumptions, at best, are preliminary and speculative. However, based upon these assumptions, the enactment of climate change legislation would likely, among other things, result in significant compliance costs, including significant capital expenditures by the Company, and could jeopardize the economic viability of certain generating facilities. For example, see the discussion of Four Corners in Note 9 under the caption The Clean Air Act – Regional Haze. In turn, these consequences would lead to increased costs to customers and could affect results of operations, cash flows, and financial condition if the incurred costs are not fully recovered through regulated rates. Higher rates could also contribute to reduced demand for electricity. The Company's assessment process is ongoing but too preliminary and speculative at this time for the meaningful prediction of financial impact.

USCAP

In 2006, the Company became a founding member of the United States Climate Action Partnership ("USCAP"), a coalition currently consisting of 35 businesses and national environmental organizations calling on the federal government to enact national legislation to reduce GHG at the earliest practicable date. USCAP released *A Call To Action* , a set of principles and recommendations outlining a policy framework for federal climate protection legislation in January 2007, and released its *Blueprint for Legislative Action to the U.S. Congress and the Obama Administration* in January 2009. It is the Company's longstanding position that a mandatory, economy-wide, market-driven approach that includes a cap and trade program, combined with other complementary state and federal policies, is the most cost effective and environmentally efficient means of addressing GHG reductions. In addition, by eliminating the regulatory uncertainty of GHG regulation, a properly designed federal program could result in clean energy investment and allow utilities to make informed long-term investments. The Company intends to continue working with USCAP, government agencies, and Congress to advocate for federal action to address this challenging environmental issue that is closely linked with the U.S. economy, energy supply, and energy security. The basic framework of the part of the Waxman-Markey Bill described above that addresses global warming is consistent with the framework proposed by USCAP in its *Blueprint for Legislative Action* .

State and Regional Activity

Pursuant to New Mexico law, each utility must submit an integrated resource plan to the NMPRC every three years to evaluate renewable energy, energy efficiency, load management, distributed generation, and conventional supply-side resources on a consistent and comparable basis. The integrated resource plan is required to take into consideration risk and uncertainty of fuel supply, price volatility, and costs of anticipated environmental regulations when evaluating resource options to meet supply needs of PNM's customers. The NMPRC issued an order in June 2007, requiring that New Mexico utilities factor a standardized cost of carbon emissions into their integrated resource plans using prices ranging between \$8 and \$40 per metric ton of CO_2 emitted and escalating these costs by 2.5% per year. Under the NMPRC order, each utility must analyze these standardized prices as projected operating costs in 2010 and thereafter. Reflecting the developing nature of this issue, the NMPRC order states that these prices may be changed in the future to account for additional information or changed circumstances. PNM is required, however, to use these prices for purposes of its integrated resource plan, and the prices may not reflect the costs that it ultimately will incur. PNM's integrated resource plan filed with the NMPRC in September 2008 showed that incorporation of the NMPRC required carbon emissions costs did not significantly change the dispatch of existing facilities or the resource decisions regarding future facilities over the next 20 years. Much higher GHG costs than assumed in the NMPRC analysis are necessary to impact the dispatch of existing resources or future resource decisions. The primary consequence of GHG costs was an increase to generation portfolio costs. The public involvement phase of PNM's next integrated resource plan began in July 2010.

In December 2008, New Energy Economy ("NEE"), a non-profit environmental advocacy organization, petitioned the New Mexico Environmental Improvement Board ("EIB") to amend existing regulations and adopt new regulations that would reduce GHG from sources regulated by the State of New Mexico. The EIB ordered legal briefs to be filed on the issue of the EIB's authority to regulate GHG. After review of the briefs and a hearing in April 2009, the EIB decided it does have authority to regulate GHG. On January 13, 2010, PNM along with a diverse group of New Mexico businesses, legislators, and agriculture interests filed a lawsuit in state court requesting a preliminary and permanent injunction enjoining the EIB from conducting further proceedings on the NEE petition based on a challenge of the EIB's authority to regulate GHG as proposed in the NEE petition. On April 13, 2010, the state court granted the preliminary injunction requested in the lawsuit, prohibiting the EIB from conducting further proceedings on the NEE petition pending a final ruling on the question of the EIB's authority to regulate GHG. The New Mexico Supreme Court vacated the injunction on June 7, 2010. The Supreme Court's decision should not be interpreted as an indication of the legal merits of the challenge. In fact, the Court specifically stated that its decision did not include consideration of the substantive legal issues in the lawsuit regarding EIB's authority to regulate GHG, but rather focused on the question of whether it is appropriate for a court to intervene in a rulemaking proceeding within the executive branch of state government. On June 21, the EIB established the calendar for resuming the hearing on this petition. On July 16, 2010 PNM filed testimony showing that adopting the petition will impose a cost on electricity customers in New Mexico without effectively reducing GHG. The potential cost increase is capped by the NEE's petition at approximately \$8 million per year. The hearing on this petition is scheduled to begin on August 16, 2010. It is expected the EIB will rule on the petition before the end of the year. If the rule is adopted, PNM will seek to recover in rates any increased costs due to this proposed rule.

Seven western states, including New Mexico, and three Canadian provinces have entered into an accord, called the Western Regional Climate Action Initiative (the "WCI"), to reduce GHG from automobiles and certain industries, including utilities. The WCI released design recommendations for elements of a regional cap and trade program in September 2008, and has created several subcommittees to develop detailed implementation recommendations. The subcommittees are slated to complete their work in 2010. Under the WCI recommendations, GHG from the electricity sector and fossil fuel consumption of the industrial and commercial sectors would be capped at then current levels and subject to regulation starting in 2012. Over time, producers will be required to reduce their GHG. Implementation of the design elements for GHG reductions would fall to each state and province. In New Mexico, the Company believes this would require new legislation and rulemaking.

In February 2009, a bill was introduced in the New Mexico legislature proposing to require the implementation by EIB of a cap and trade system designed to reduce GHG. This legislation died in committee during the session. The New Mexico House of Representatives did pass a memorial, which requests the New Mexico Legislative Council to direct the appropriate committee to study the WCI final design recommendations as well as federal proposals relating to reducing GHG. The memorial is a study of impacts and not a regulation. The memorial further states that the committee is requested to report its findings and recommendations to the New Mexico legislature by December 2010.

In January 2010, a similar bill was introduced in the New Mexico House of Representatives that would have allowed EIB to adopt rules for implementing particular portions of WCI, including rules of early reduction allowances, offset allowances and mandatory reporting of GHG for persons importing electricity or heating or transportation fuels. The bill was tabled in committee where it died. In March 2010, the NMED announced a process that will result in NMED requesting that the EIB adopt rules required to implement a WCI cap and trade program. On July 16, 2010, NMED filed its testimony in support of its proposed cap-and-trade rule. PNM is evaluating NMED's filing and the proposal's potential impacts on the cost of PNM's operations. PNM will file testimony by August 16, 2010 responding to the NMED's proposal. A hearing is scheduled to begin on September 16, 2010 and the EIB is expected to rule before the end of the year.

Impact of International Accords, Indirect Consequences, and Physical Impacts

Approximately 82.8% of PNM's owned and leased generating capacity consists of coal or gas-fired generation that produces GHG, all of which is located within the United States. The Company does not anticipate any direct impact from any near term international accords. All of Optim Energy's owned generation produces GHG and is located within the United States. Based on current forecasts, the Company does not expect its output of GHG to increase significantly in the near-term. Many factors affect the amount of GHG, including plant performance. For example, if PVNGS experienced prolonged outages, it may require PNM to utilize other power supply resources such as gas-fired generation, which could increase GHG. Because of the Company's dependence on fossil-fueled generation, any legislation that imposes a limit or cost on GHG will impact the cost at which electricity is produced. While PNM expects to be entitled to recover that cost through rates, the timing and outcome of proceedings for cost recovery is uncertain. In addition, to the extent that any additional costs are recovered through rates, customers may reduce their demand, relocate facilities to other areas with lower energy costs, or take other actions that ultimately will adversely impact the Company.

Given the geographic location of its facilities and customers, the Company generally has not been exposed to the extreme weather events and other physical impacts commonly attributed to climate change, with the possible exception of drought conditions periodically, and physical changes are generally not expected to be of material consequence in the near-term. Drought conditions in northwestern New Mexico could impact the availability of water for cooling coal plants. Water shortage sharing agreements have been in place since 2003, although no shortage has been declared due to sufficient snow pack in the San Juan Basin. PNM also has a supplemental water contract in place with the Jicarilla Tribe to help address any water shortages from primary sources. The contract expires December 31, 2016.

Financial Reform Legislation

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act, which is intended to improve regulation of financial markets, was signed into law. The Company is currently evaluating this legislation and cannot predict the impact it may have on the Company's financial condition, results of operations, or cash flows.

Other Matters

See Notes 9 and 10 herein and Notes 16, 17 and 18 in the 2009 Annual Reports on Form 10-K for a discussion of commitments and contingencies, rate and regulatory matters and environmental issues facing the Company.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires Company management to select and apply accounting policies that best provide the framework to report the results of operations and financial position for PNMR, PNM, and TNMP. The selection and application of those policies requires management to make difficult, subjective and/or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

The Company's critical accounting policies are disclosed in PNMR's, PNM's, and TNMP's 2009 Annual Reports on Forms 10-K. The policies disclosed included unbilled revenues, regulatory accounting, impairments, decommissioning costs, derivatives, pension and other postretirement benefits, accounting for contingencies, income taxes, and market risk. As of June 30, 2010, there have been no significant changes with regard to the critical accounting policies except as set forth below.

Impairments

Tangible long-lived assets and amortizable intangible assets are evaluated for impairment when events and circumstances indicate that the assets might be impaired in accordance with GAAP. These potential impairment indicators include management's assessment of fluctuating market conditions as a result of industry deregulation; planned and scheduled customer purchase commitments; future market penetration; fluctuating market prices resulting from factors including changing fuel costs and other economic conditions; weather patterns; and other market trends. The amount of impairment recognized, if any, is the difference between the fair value of the asset and the carrying value of the asset and would reduce both the asset and current period earnings. Variations in the assessment of potential impairment or in the assumptions used to calculate an impairment could result in different outcomes, which could lead to significant effects on the consolidated financial statements.

Goodwill and non-amortizable other intangible assets are evaluated for impairment at least annually, or more frequently if events and circumstances indicate that the goodwill and intangible assets might be impaired. Note 16 contains information on the impairment testing performed by the Company on goodwill and intangible assets. No impairments were indicated in the Company's annual goodwill testing, which was performed as of April 1, 2010. Since the annual evaluation, there have been no indications that the fair values of the reporting units with recorded goodwill have decreased below the carrying values. The annual testing was based on certain critical estimates and assumptions. Changes in the estimates or the use of different assumptions could affect the determination of fair value and the conclusion of impairment for each reporting unit.

Application of the impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units and determination of the fair value of each reporting unit. The fair value of each reporting unit is estimated using a discounted cash flow methodology. This analysis requires significant judgments, including estimation of future cash flows, which is dependent on internal forecasts, estimation of long-term growth rates for the business and determination of appropriate weighted average cost of capital ("WACC") for each reporting unit.

In determining the fair value of each reporting unit, the WACC is a significant factor. The Company considers many factors in selecting a WACC, including the market view of risk for each individual reporting unit, the appropriate capital structure, and the borrowing rate appropriate for each reporting unit. The Company considers available market-based information and may consult with third parties to help us to determine the WACC. The selection of a WACC is subjective and modifications to this rate could significantly increase or decrease the fair value of a reporting unit.

The other primary factor impacting the determination of the fair value of each reporting unit is the estimation of future cash flows. The Company considers budgets, long-term forecasts, historical trends and expected growth rates in order to estimate future cash flows. Any forecast contains a degree of uncertainty and modifications to these cash flows could significantly increase or decrease the fair value of a reporting unit. For the reporting units subject to rate-regulation, a fair recovery of and return on costs prudently incurred to serve customers is assumed. Should the regulators not allow recovery of certain costs or not allow these reporting units to earn a fair rate of return on invested capital, the fair value of the reporting units could decrease. For the unregulated reporting unit, assumptions regarding customer usage, pricing, retention and payment behavior, in addition to fluctuations in the cost of energy, significantly impact estimates of future cash flows. Negative impacts of changes in these assumptions would cause the fair value of this reporting unit to decrease.

The Company believes that the WACCs and cash flow projections utilized in the 2010 testing appropriately reflect the fair value of each reporting unit. Since any cash flow projection contains uncertainty, the Company adjusted the WACCs used to reflect that uncertainty. The Company does not believe that there are indications of goodwill impairment in any of its reporting units, but this analysis is highly subjective. As of the impairment testing for April 1, 2010, the fair value of the PNM reporting unit, which had goodwill of $51.6 million, exceeded its carrying value by 8.0% and the fair value of the TNMP reporting unit, which had goodwill of $226.7 million, exceeded its carrying value by 5.3%. The fair value of the First Choice reporting unit, which had goodwill of $43.0 million, exceeded its carrying value by more than ten percent. Due to the subjectivity and sensitivities of the assumptions and estimates underlying the impairment analysis, there can be no assurance that future analyses, which will be based on the appropriate assumptions and estimates at that time, will not result in impairments.

PNMR also has an investment in Optim Energy, which is accounted for using the equity method. Optim Energy's operating assets consist of two gas-fired electric generating plants and one coal-fired generating plant. Optim's results of operations are primarily determined by the prices at which its power is sold and it procures fuel, principally natural gas, to generate power. Additionally, power prices in the ERCOT market are directly correlated to natural gas prices. The markets for power and natural gas are currently depressed. The low levels of gas and power prices are indicators of possible impairment of PNMR's investment in Optim Energy. Accordingly, PNMR performed an impairment test of its investment in Optim Energy using a discounted cash flow methodology. This analysis utilized the power and gas forward price curve information, which provides projections for five years, combined with management of Optim Energy's fundamental view of its business for periods after the end of the price curves. This analysis indicated that PNMR's proportionate share of the fair value of Optim Energy exceeded its carrying value. The impairment analysis for Optim Energy requires the same assumptions, judgments, and estimations described above and there can be no assurance that future analyses, which will be based on the appropriate assumptions and estimates at that time, will not result in impairments.

MD&A FOR PNM

RESULTS OF OPERATIONS

PNM's continuing operations are presented in the PNM Electric segment, which is identical to the segment presented above in Results of Operations for PNMR. PNM's discontinued operations are presented in the PNM Gas segment, which is identical to the total earnings from discontinued operations, net of income taxes, shown on the Condensed Consolidated Statements of Earnings for both PNM and PNMR. See Note 14.

MD&A FOR TNMP

RESULTS OF OPERATIONS

TNMP operates in only one reportable segment, TNMP Electric, as presented above in Results of Operations for PNMR.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

Statements made in this filing that relate to future events or PNMR's, PNM's, or TNMP's expectations, projections, estimates, intentions, goals, targets and strategies, are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and estimates and PNMR, PNM, and TNMP assume no obligation to update this information.

Because actual results may differ materially from those expressed or implied by these forward-looking statements, PNMR, PNM, and TNMP caution readers not to place undue reliance on these statements. PNMR's, PNM's, and TNMP's business, financial condition, cash flow and operating results are influenced by many factors, which are often beyond their control, that can cause actual results to differ from those expressed or implied by the forward-looking statements. These factors include:

- Conditions affecting the Company's ability to access the financial markets and negotiate new credit facilities for those expiring in 2011 and 2012, or Optim Energy's access to additional debt financing following the utilization of its existing credit facility, including actions by ratings agencies affecting the Company's credit ratings,
- The recession, its consequent extreme disruption in the credit markets, and its impacts on the electricity usage of the Company's customers,
- State and federal regulatory and legislative decisions and actions, including appeals of prior regulatory proceedings, and including provisions relating to climate change, reduction of GHG, CCBs, and other power plant emissions,
- The ability of PNM to meet the renewable energy requirements established by the NMPRC, including the resource diversity requirement, within the specified cost parameters,
- The ability of PNM to successfully utilize a future test year in its rate filing with the NMPRC, including PNM's ability to accurately forecast operating and capital expenditures and withstand challenges by regulators and intervenors,
- The performance of generating units, including PVNGS, SJGS, Four Corners, and Optim Energy generating units, and transmission systems,

- The risk that Optim Energy desires to expand its generation capacity but is unable to identify and implement profitable acquisitions or that PNMR and ECJV will not agree to make additional capital contributions to Optim Energy,
- The potential unavailability of cash from PNMR's subsidiaries or Optim Energy due to regulatory, statutory or contractual restrictions,
- The impacts of the decline in the values of marketable equity securities on the trust funds maintained to provide nuclear decommissioning funding and pension and other postretirement benefits, including the levels of funding and expense,
- The ability of First Choice to attract and retain customers and collect amounts billed,
- Changes in ERCOT protocols,
- Changes in the cost of power acquired by First Choice,
- Collections experience,
- Insurance coverage available for claims made in litigation,
- Fluctuations in interest rates,
- Weather,
- Water supply,
- Changes in fuel costs,
- Availability of fuel supplies,
- Uncertainty regarding the requirements and related costs of decommissioning power plants owned or partially owned by PNM and Optim Energy and coal mines supplying certain PNM power plants, as well as the ability to recover decommissioning costs through charges to customers,
- The risk that replacement power costs incurred by PNM related to not meeting the specified capacity factor for its generating units under its Emergency FPPAC will not be approved by the NMPRC,
- The risk that PNM may not be able to renew rights-of-way on Native American lands or that the costs of rights-of-way are not allowed to be recovered through rates charged to customers,
- The effectiveness of risk management and commodity risk transactions,
- Seasonality and other changes in supply and demand in the market for electric power,
- The impact of mandatory energy efficiency measures on customer energy usage,
- Variability of wholesale power prices and natural gas prices,
- Volatility and liquidity in the wholesale power markets and the natural gas markets,
- Uncertainty regarding the ongoing validity of government programs for emission allowances,
- Changes in the competitive environment in the electric industry,
- The risk that the Company and Optim Energy may have to commit to substantial capital investments and additional operating costs to comply with new environmental requirements including possible future requirements to address concerns about global climate change, and the resultant impacts on the operations and economic viability of generating plants in which PNM and Optim Energy have interests,
- The risks associated with completion of generation, transmission, distribution, and other projects, including construction delays and unanticipated cost overruns,
- Uncertainty surrounding the status of PNM's participation in jointly-owned projects resulting from the scheduled expiration of the operational documents for the projects beginning in 2015 and potential changes in the objectives of the participants in the projects,
- The outcome of legal proceedings,
- Changes in applicable accounting principles, and
- The performance of state, regional, and national economies.

Any material changes to risk factors occurring after the filing of PNMR's, PNM's, or TNMP's 2009 Annual Report on Form 10-K are disclosed in Item 1A, Risk Factors, in Part II of this Form 10-Q.

For information about the risks associated with the use of derivative financial instruments see Item 3. "Quantitative and Qualitative Disclosures About Market Risk."

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SECURITIES ACT DISCLAIMER

Certain securities described in this report, have not been registered under the Securities Act of 1933, as amended, or any state securities laws and may not be reoffered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act of 1933 and applicable state securities laws. This Form 10-Q does not constitute an offer to sell or the solicitation of an offer to buy any securities.

WEB SITE

The PNMR website, www.pnmresources.com , is an important source of Company information and PNMR encourages investors, analysts and other interested parties to visit the website frequently. PNMR keeps the site updated and routinely posts new information or updated information for public consumption. PNMR encourages analysts, investors and other interested parties to register on the website to automatically receive Company financial information by email. Once registered, participants can choose from a menu to automatically receive requested information, including news releases, notices of webcasts and filings with the SEC. Participants can unsubscribe at any time and will not receive information that was not requested. The contents of the website are not part of this Form 10-Q.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PNMR controls the scope of its various forms of risk through a comprehensive set of policies and procedures and oversight by senior level management and the Board. The Board's Finance Committee sets the risk limit parameters. The RMC, comprised of corporate and business segment officers, oversees all of the risk management activities, which include commodity risk, credit risk, interest rate risk, and business risk. The RMC has oversight for the ongoing evaluation of the adequacy of the risk control organization and policies. PNMR has risk control organizations, which are assigned responsibility for establishing and enforcing the policies, procedures, and limits and evaluating the risks inherent in proposed transactions, on an enterprise-wide basis.

The RMC's responsibilities specifically include: establishment of policies regarding risk exposure levels and activities in each of the business segments; authority to approve the types of derivatives entered into; authority to establish a general policy regarding counterparty exposure and limits; authorization and delegation of transaction limits; review and approval of controls and procedures for derivative activities; review and approval of models and assumptions used to calculate mark-to-market and market risk exposure; authority to approve and open brokerage and counterparty accounts for derivatives; review of hedging and risk activities; the extent and type of reporting to be performed for monitoring of limits and positions; and quarterly reporting to the Audit and Finance Committees on these activities. The RMC also proposes risk limits, such as VaR and GEaR, to the Finance Committee for its approval.

It is the responsibility of each business segment to create its own control procedures and policies within the parameters established by the Corporate Financial Risk Management Policy, approved by the Finance Committee. The RMC reviews and approves these policies, which are created with the assistance of the Risk Management Department and the Vice President and Treasurer. Each business segment's policies address the following controls: authorized instruments and markets; authorized personnel; policies on segregation of duties; policies on mark-to-market accounting; responsibilities for deal capture; confirmation responsibilities; responsibilities for reporting results; statement on the role of derivative transactions; and limits on individual transaction size (nominal value).

To the extent an open position exists, fluctuating commodity prices can impact financial results and financial position, either favorably or unfavorably. As a result, the Company cannot predict with certainty the impact that its risk management decisions may have on its businesses, operating results or financial position.

Information concerning accounting for derivatives and the risks associated with commodity contracts is set forth in Note 4. Note 4 also contains a summary of the fair values of mark-to-market energy related derivative contracts included in the Condensed Consolidated Balance Sheets.