GALLUP JOINT UTILITIES INTEGRATED RESOURCE PLAN

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Section 1
Purpose and Scope

EPAct 1992 requires all Western Area Power Administration ("Western") customers to file an integrated resource plan every 5 years. Western's Integrated Resource Plan ("IRP") criteria are contained in 10 CFR 905 Subpart B. The purpose of this report is to update the Integrated Resource Plan ("IRP") filed by GJU in 2002.

GJU is an end-use, non-generating customer of Western that has experienced steady year-over-year load growth since filing its initial IRP in 2002. This IRP will address both the status of the Action Plan in the 2002 IRP filing and the resource options that are technically and economically feasible for GJU to meet its future electric system power needs.

The specific IRP items addressed in this report include the following:

1. Historical GJU load information and a forecast of future loads

2. GJU's current supply resources

3. Options for resources to meet GJU's forecasted future power requirements.

4. An action plan to ensure that GJU's future power requirements are met in a timely and economic manner.

Section 2
Introduction

Gallup Joint Utilities is a municipally-owned utility that provides electric, water, waste water and solid waste services to the City of Gallup, New Mexico ["City" or "Gallup"]. The electric point of delivery through which GJU receives wholesale power is at the secondary side of four distribution substations owned by Public Service Company of New Mexico ("PNM"). The GJU electric department is responsible for maintaining the 13.8kV medium voltage distribution system to provide service to its customers.

This IRP considers strategies for both a five-year action plan and for a longer-term 10 year plan. However, the focus will be on an action plan for the next five years, through 2012. Although the report focuses on an action plan for the next five years, the impact of the load forecast on system power supply requirements through 2017 is also considered. The paramount purpose of this IRP is to evaluate practical alternatives for meeting GJU's load requirements and to identify the most cost-effective and reliable resources. For this IRP, supply-side resources are the predominant alternatives considered for meeting energy and capacity needs of GJU's electric system.

GJU ELECTRIC SYSTEM

Historically GJU has met the electric needs of its customers through wholesale purchased power contracts with Western and PNM. GJU's allocation of power from Western's Colorado River Storage Project was established in 1989, and provides approximately 11% of GJU's demand and 7% of the utility's energy needs on an annual basis. The remaining portion of GJU's power requirements are currently being supplied under a contract with PNM that began on July 1, 2002 and which will expire on June 30, 2013.

GJU takes delivery of its purchased power at the secondary side of four 115kV-13.8kV distribution substations owned by PNM. From these four distribution substations (Allison, Noe, Sunshine and Wingate) GJU provides electrical service to its customers through a 215 mile primary distribution system of overhead and underground 13.8kV lines.

INTEGRATED RESOURCE PLANNING

Section 114 of the Energy Policy Act of 1992 (EPAct), Public Law 102–486, requires integrated resource planning (IRP) by Western's customers. Western implemented EPAct through the Energy Planning and Management Program (EPAMP) in October 1995. EPAMP was published in the Code of Federal Regulations at 10 CFR part 905. CFR part 905, subparts A and B pertaining to IRP, were amended effective May 1, 2000.

Section 2
Introduction

As defined in 10 CFR 905.2, integrated resource planning means a planning process for new energy resources that evaluates the full range of alternatives; including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, to provide adequate and reliable service to a customer's electric consumers. An IRP supports customer-developed goals and schedules.

Western's rules require that the IRP take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other risk factors. IRP's must take into account the ability to verify energy savings achieved through energy efficiency and the projected durability of such savings measured over time; and must treat demand and supply resources on a consistent and integrated basis.

REQUIRED CONTENT OF IRPs

The content of Integrated Resource Plans submitted to Western is specified in 10 CFR 905.11. These IRP content requirements are the basis for the preparation of GJU's IRP. Applicable portions of 905.11 are cited below. A complete copy of 10 CFR 905 is included as Appendix A to this report.

905.11 WHAT MUST AN IRP INCLUDE?

(1) Identification of resource options. Identification and comparison of resource options is an assessment and comparison of existing and future supply-and demand-side resource options available to a customer based upon its size, type, resource needs, geographic area, and competitive situation. Resource options evaluated by the specific customer must be identified. The options evaluated should relate to the resource situation unique to each Western customer as determined by profile data (such as service area, geographical characteristics, customer mix, historical loads, projected growth, existing system data, rates, and financial information) and load forecasts. Specific details of the customer's resource comparison need not be provided in the IRP itself. They must, however, be made available to Western upon request.

(i) Supply-side options include, but are not limited to, purchased power contracts and conventional and renewable generation options.

(ii) Demand-side options alter the customer's use pattern to provide for an improved combination of energy services to the customer and the ultimate consumer.

(iii) Considerations that may be used to develop potential options include cost, market potential, consumer preferences, environmental impacts, demand or energy impacts, implementation issues, revenue impacts, and commercial availability.

(iv) The IRP discussion of resource options must describe the options chosen by the customer, clearly demonstrating that decisions were based on a reasonable analysis of the options. The IRP may strike a balance among the applicable resource evaluation factors.

(2) Action plan. IRPs must include an action plan describing specific actions the customer will take to implement its IRP.

(i) The IRP must state the time period that the action plan covers, and the action plan must be updated and resubmitted to Western when this time period expires. The customer may submit a revised action plan with the annual IRP progress report discussed in § 905.14.

(ii) For those customers not experiencing or anticipating load growth, the action plan requirement for the IRP may be satisfied by a discussion of current actions and procedures in place to periodically reevaluate the possible future need for new resources. The action plan must include a summary of:

(A) Actions the customer expects to take in accomplishing the goals identified in the IRP;

(B) Milestones to evaluate accomplishment of those actions during implementation; and

(C) Estimated energy and capacity benefits for each action planned.

(3) Environmental effects. To the extent practical, the customer must minimize adverse environmental effects of new resource acquisitions and document these efforts in the IRP. Customers are neither precluded from nor required to include a quantitative analysis of environmental externalities as part of the IRP process. IRPs must include a qualitative analysis of environmental effects in summary format.

(4) Public participation. The customer must provide ample opportunity for full public participation in preparing and developing an IRP (or any IRP revision or amendment). The IRP must include a brief description of public involvement activities, including how the customer gathered information from the public, identified public concerns, shared information with the public, and responded to public comments. Customers must make additional documentation identifying or supporting the full public process available to Western upon request.

(i) As part of the public participation process, the governing body of an MBA and each MBA member (such as a board of directors or city council) must approve the IRP, confirming that all requirements have been met. To indicate approval, a responsible official must sign the IRP submitted to Western or the customer must document passage of an approval resolution by the appropriate governing body included or referred to in the IRP.

(ii) For Western customers that do not purchase electricity for resale, such as some State, Tribal, and Federal agencies, the customer can satisfy the public participation requirement by having a top management official with resource acquisition responsibility review and concur on the IRP. The customer must note this concurrence in the IRP.

(5) Load forecasting. An IRP must include a statement that the customer conducted load forecasting. Load forecasting should include data that reflects the size, type, resource conditions, and demographic nature of the customer using an accepted load forecasting method, including but not limited to the time series, end-

use, and econometric methods. The customer must make the load forecasting data available to Western upon request.

(6) Measurement strategies. The IRP must include a brief description of measurement strategies for options identified in the IRP to determine whether the IRP's objectives are being met. These validation methods must include identification of the baseline from which a customer will measure the benefits of its IRP implementation. A reasonable balance may be struck between the cost of data collection and the benefits resulting from obtaining exact information. Customers must make performance validation and evaluation data available to Western upon request.

Section 3
Load Forecast

INTRODUCTION

In lieu of an econometric load forecast, three time-series trends of GJU's future power requirements (low, medium and high) were forecast for this IRP based on peak load data for the most recent 6 years. The low forecast utilizes the average annual compound growth rate of 2.08% implied by the capacity requirements listed in the 2002 IRP. The high forecast utilizes the average annual compound growth rate of 3.14% implied by the peak demands for the years 2002-2007. The medium growth rate forecast of 2.61% uses the average of the high and low growth rates.

HISTORICAL INFORMATION

Peak demand, energy sales and energy purchase data were collected by GJU and compiled for use in preparing the IRP. PNM invoices were used to compile GJU's total system peak demand and total energy purchases from PNM and Western for the years 2002 through 2007. Aggregate data for energy use by rate class and the number of customers for each rate class were compiled from GJU's records for the same 2002 through 2007 period.

With the exception of 2006, the GJU system peak demand has grown steadily from 2002 through 2007. There was a decrease in GJU's peak demand from 2005 to 2006 due to line outages which forced a major refinery customer to be served by the customer's backup generation instead of GJU for an extended period of time.

The average number of customers at year end for each of the customer classes is shown below in Table 1. Total annual energy sales by customer class are shown in Table 2.

Table 1
Year-End Number of Customers by Rate Class

Rate Class	2002	2003	2004	2005	2006	2007
Residential (R)	8,118	8,223	8,507	8,227	8,204	8,211
Small Commercial (GS)	1,844	1,825	1,828	1,771	1,753	1,774
Medium Commercial (GM)	41	41	45	46	52	51
Refinery (CO, GI)	2	2	1	1	1	1
Joint Utilities (JU)	15	15	14	12	12	11
Municipal Service (MU)	126	122	125	125[1]	117	119
Metered Street Light (ST)	31	31	30	31	27	31
Signal Light (SL)	23	28	29	28	30	32
TOTAL	**10,200**	**10,287**	**10,579**	**10,241**	**10,196**	**10,230**

[1]Decrease in number of MU accounts due to consolidation of accounts and reclassification of accounts to GS or GM

Table 2
Annual Energy Sales by Customer Rate Class (KWH)

Rate Class	2002	2003	2004	2005	2006	2007
Residential (R)	45,052,770	46,749,949	48,805,955	47,425,654	48,551,966	49,312,291
Small Commercial (GS)	78,430,993	79,606,542	84,350,226	83,237,805	80,897,404	77,928,289
Medium Commercial (GM)	52,467,060	53,796,560	57,539,170	56,594,720	60,255,707	61,903,118
Refinery (CO, GI)	8,875,821	6,995,660	705,852	5,162,920	5,438,440	6,624,520
Joint Utilities (JU)	8,111,653	8,017,781	7,043,327	6,358,759	5,674,567	5,244,576
Municipal Service (MU)	14,170,766	13,596,871	13,743,624	14,264,164	14,352,072	13,879,504
Metered Street Light (ST)	905,609	915,377	1,044,382	830,050	761,731	865,117
Signal Light (SL)	366,362	424,722	454,939	455,418	430,768	459,583
TOTAL	**208,381,034**	**210,103,462**	**213,687,475**	**214,329,490**	**216,362,655**	**216,216,998**

For the period from 2002 through 2007 the Small Commercial sector was the largest consumer of energy accounting for 38% of the total energy sales. The Small Commercial sector was followed by the Medium Commercial and Residential Sectors that accounted for 27% and 22% of the six years total energy sales.

Table 3 tabulates GJU's coincident system peak demand. The peak demand shown in Table 3 is the coincident peak demand of GJU's native peak load which is a little higher than the billing demand. The billing demand for the GJU invoices is the GJU coincident peak demand that is coincident with the time of peak demand of the PNM system.

Table 3
Annual GJU Peak Demand (KW)[1]

2002	34,872
2003	37,165
2004	35,213
2005	39,360
2006	38,682[2]
2007	40,703

[1]Native load coincident peak. Not PNM billing demand.
[2]Decrease attributed by GJU to storm damaged lines preventing service to refinery during peak load months.

Table 4 summarizes the total GJU energy purchases from Western and PNM. The demand and energy purchased data shown in Tables 3 & 4 are extracted from PNM billing invoices.

Table 4
Total GJU Energy Purchases (KWH)

Supply Resource	2002	2003	2004	2005	2006	2007
PNM	203,337,252	204,406,999	208,077,229	215,342,543	214,743,909	218,473,488
Western	17,600,145	17,954,287	15,436,484	14,321,039	15,189,470	15,392,659
TOTAL	220,937,397	222,361,286	223,513,713	229,663,582	229,933,379	233,866,147

The average annual compound rate of growth in GJU's peak demand is about 3.1% per year. This growth rate is about 48% greater than the 2.1% average compound annual growth rate implied in GJU's 2002 IRP. Table 4 also shows that GJU's average annual compound rate of growth in energy purchases has been about 1% per year.

A demand growth rate that is greater than the growth rate in energy consumption implies that there may be opportunities to meet a portion of GJU's capacity requirement through the implementation of load-side options such as load control or time-based rates.

FUTURE POWER REQUIREMENTS

The high growth rate forecast implies that the robust economic climate experienced during the past five years and the resultant in-migration of commercial and residential customers continues unabated well into the future. The low growth rate forecast implies that the economic climate erodes resulting in residential and commercial class load growth rates declining somewhat from their early decade levels. The medium load growth scenario implies that, although there may be some retreat in the conditions that have driven the growth in GJU's electrical loads over the past few years, load growth will continue at a healthy pace. This IRP employs the "medium" 2.61% compound annual growth rate as the "most likely" scenario for GJU. Table 5 compares the medium growth rate scenario with the forecast from the 2002 IRP.

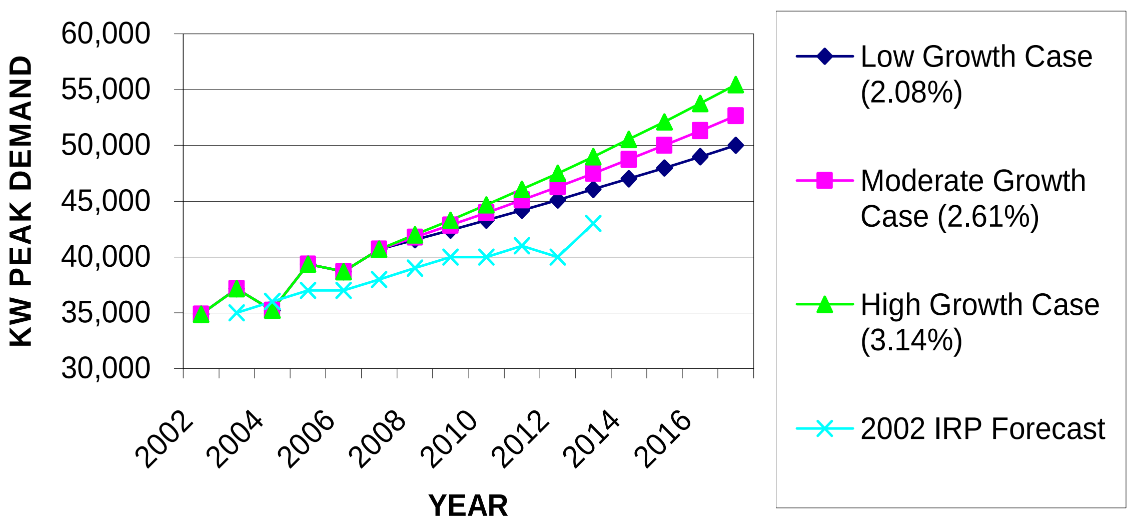
Table 5
GJU Medium (2.61%) Peak Demand Growth Rate (KW)

YEAR	Medium Growth Rate Forecast	Anticipated Capacity Needs From 2002 IRP
2002*	34,872	---------
2003*	37,165	35,000
2004*	35,213	36,000
2005*	39,360	37,000
2006*	38,682	37,000
2007*	40,703	38,000
2008	41,765	39,000
2009	42,855	40,000
2010	43,973	40,000
2011	45,121	41,000
2912	46,299	40,000
2013	47,507	43,000
2014	48,747	---------
2015	50,020	---------
2016	51,325	---------
2017	52,665	---------

* Measured GJU system peak demand

Figure 1 is a graph of GJU's historic peak demands and forecasted peak load growth scenarios.

Figure 1
GJU Demand Forecast Scenarios



Section 3
Load Forecast

As a regional hub for retail and service industries, growth in the GJU electric system demand during the past few years can largely be attributed to growth in the commercial sector through the addition of new customers and expansions of existing facilities with some demand growth attributable to additional customers in the residential sector. As the largest community situated along the 323 miles segment of Interstate Highway 40 between Flagstaff, Arizona and Albuquerque, the hospitality industry as well as traveler and transportation services have also been contributors to growth in the GJU electric system demand.

Although the contraction in credit markets that is currently being experienced will likely have some negative impact on load growth in the GJU system for several years into the future, there are other potential drivers that could have a significant influence to offset the impact of weakened credit markets. Among the factors potentially impacting GJU's future load growth are the City's role as a regional commercial center and the City's ongoing efforts to attract new commercial and manufacturing load to the area. Also potentially impacting GJU's electrical system load growth is a growing national interest in nuclear power as an electric energy resource. If the current interest in nuclear power results in new nuclear power plant licenses as well as extensions of existing licenses, there could be revival of the long dormant New Mexico uranium mining industry along the Interstate Highway 40 corridor east of Grants. Growth in the mining industry along the I-40 corridor has the potential to provide a significant stimulus for additional growth in GJU's commercial and residential loads.[1,2]

[1] In the Energy Information Administration's ("EIA's") Annual Energy Outlook for 2007, which forecasts long-range trend in energy supply and demand, Nuclear power generation decreases as percentage of the current total energy supply forecast. However in its 2007 Long-Term Reliability Assessment 2007-2016 the North American Electric Reliability Corporation (NERC) reports that by 2009 the Nuclear Regulatory Commission ("NRC") expects to receive applications for 32 new nuclear power plants totaling 12,000MW with projected in-service dates in 2015-2016.

[2] Growth may be somewhat limited due to the limited availability of developable land. i.e. Native American Lands and the single party ownership of approximately 26,000 acres by Gamerco and Associates.

Section 4
System Resources and Requirements

INTRODUCTION

The preceding section discussed the historic and projected requirements for power on GJU's electric system. This section discusses GJU's current supply resources, and projected resource needs for the future. Alternatives for future sources of power are discussed in Section 5 and Section 6.

CURRENT SOURCES OF POWER

GJU currently purchases all of its power requirements at wholesale from Western and PNM. GJU's allocation of power from Western provides approximately 11% of the annual system demand and 7% of the annual energy requirements. The remaining portion of GJU's annual power requirements are supplied by PNM. Power from both PNM and Western are delivered to Gallup over 115kV transmission lines owned by PNM and Tri-State Generation and Transmission Association ("TSGT" or "Tri-State"). GJU takes delivery of its purchased power at the secondary sides of four, PNM-owned 115-13.8kV distribution substations. Gallup is allowed under the renewed contract (July 1, 2002) with PNM to schedule, at any time, the maximum contract rate of delivery allocation from Western.

WESTERN CRSP ALLOCATION

GJU has a capacity and energy allocation from Western's Salt Lake City Area Integrated Project ["SLCA/IP"], which administers the Colorado River Storage Project (CRSP). The capacity and energy allocations from SLCA/IP are 3,439 KW of firm power during the summer season (April 1 through September 30), and 3,592 KW during the winter season (October 1 of a calendar year through March 31 of the following calendar year). After October 1, 2004 and upon 5 years' notice to the City, GJU's capacity and energy allocation from the SLCA/IP may be revised by Western to respond to changes in hydrology and river operations.

PNM SUPPLEMENTAL REQUIREMENTS CONTRACT

All of GJU's power requirements beyond its Western allocation are currently supplied by PNM under the terms of a ten-year contract that will expire at the end of June 30, 2013. GJU's contract with PNM represents about 89% of GJU's capacity requirement and 93% of GJU's annual energy requirement. The PNM contract allows GJU to establish and negotiate an industrial incentive discount rate to assist in GJU's retention of existing loads and to attract new large industrial retail loads, which would otherwise be lost or choose to locate elsewhere.

PNM's and Western's power are delivered to Gallup at 13.8kV side of the 115-13.8kV transformers at PNM's Noe, Allison, Sunshine and Ft. Wingate distribution substations. GJU has the option of purchasing the four point-of-delivery substations at any time during the term of the PNM contract. However, as soon as practical after termination of the current contract with PNM, GJU will be required to purchase the four PNM substations unless either the existing contract is extended or the point-of-delivery is addressed in a new contract with PNM.

INTRODUCTION

As a non-generating entity GJU purchases all of its power requirements beyond its Western allocation from PNM under the terms of a contract that will expire after June 30, 2013. The initial pricing stated in the current PNM contract is shown in Table 6.

Table 6
Energy and Demand Rates for PNM Contract

Contract Period	Demand Rate $/KW-Month	Energy Rate $/MWH
07/01/2002-06/30/2004	$14.75	$17.50
07/01/2004-06/30/2006	$15.00	$18.00
07/01/2006-06/30/2008	$15.25	$18.25
07/01/2008-06/30/2010	$15.50	$18.50
07/01/2010-06/30/2013	$15.75	$19.00

The PNM contract provides for adjustments to either increase or decrease the contract Energy Rates for the remaining term of the contract if PNM's System Average Energy Cost ("SAEC") in the SAEC for the preceding 12 month's is more than 5% higher or 5% lower than the rates stated in the initial contract rate schedule. As a consequence of PNM's increased SAEC, beginning in 2008 the energy rate charged to GJU will be $23.80/MWH through June 30, 2010 and $24.30 for the July 1, 2010 through June 30, 2013 period. GJU is currently negotiating with PNM to develop options to minimize the impact of this 30.4% increase in energy rates. The revised pricing for the PNM contract is shown in Table 7.

Table 7
Energy and Demand Rates for PNM Contract After SAEC Adjustment

Contract Period	Demand Rate $/KW-Month	Energy Rate $/MWH
07/01/2002-06/30/2004	$14.75	$17.50
07/01/2004-06/30/2006	$15.00	$18.00
07/01/2006-06/30/2008	$15.25	$18.25
07/01/2008-06/30/2010	$15.50	**$23.80**
07/01/2010-06/30/2013	$15.75	**$24.30**

Outlook for Future Power Prices

Following the expiration of GJU's current contract with PNM in 2013, GJU's costs for capacity and energy to supplement its purchases from

Western are expected to increase significantly regardless of whether the supply resources are acquired through another purchase power agreement, from a self-build generation resource or from partnership-build generation resource.

PNM's 30.4% increase in the energy rate for the GJU contract reflects the constrained availability and increased costs of energy production that exists throughout the west. The recent rate cases by Arizona Public Service, Tucson Electric Power and Public Service of New Mexico, all of whom are potential power suppliers for GJU, are also indicative of the fact that there is no longer a surplus of generating capacity in the region and that the cost of fuel, environmental regulation compliance and materials for maintenance are resulting in significant energy cost increases.[3]

Supply-Side Resources Outlook

Planning realistic future supply-side options for a non-generating load-serving entity like GJU relies on analyzing the planning window from the same perspective as a power supplier in the Arizona-New Mexico-Southern Nevada power supply area would. By understanding the fuel supplies, new generation, and load growth uncertainties that affect the power suppliers in this area, GJU can be better prepared to select future power suppliers or supply resource options that can provide reliable electrical service at a reasonable cost.

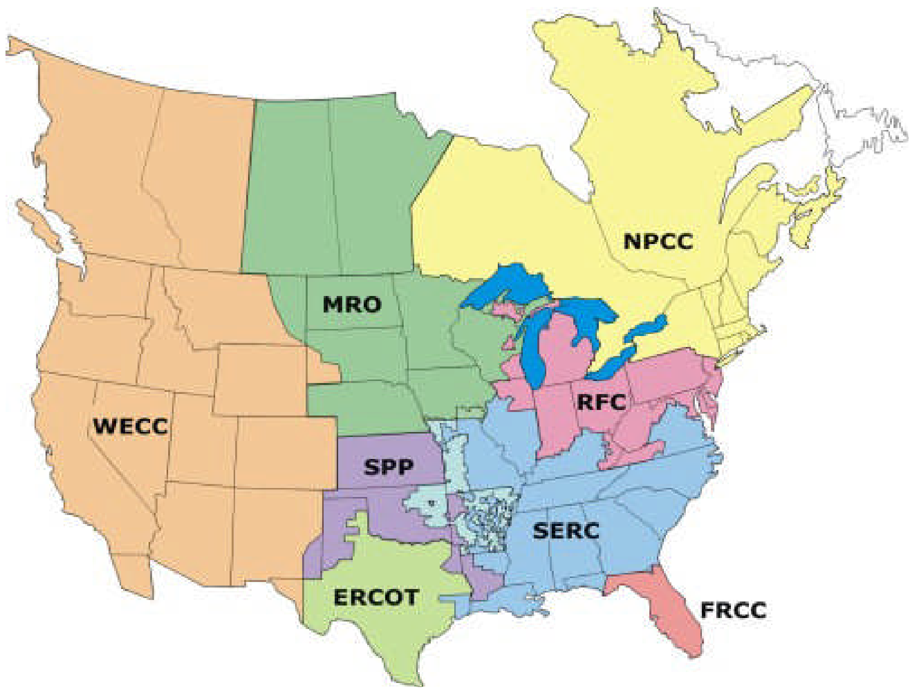
GJU's supply-side resource opportunities lie primarily within the Western Electricity Coordinating Council's ("WECC") Arizona-New Mexico-Southern Nevada Power Area ("AZ-NM-SNV") sub-region. As discussed further on, GJU also has a supply-side resource opportunity through the City's membership in the Utah Associated Municipal Power Systems ["UAMPS"] organization.

The WECC is one of eight reliability regions overseen by the North American Electric Reliability Corporation ("NERC") whose mission is to ensure that the North American bulk power system is reliable. Annually

[3] In 2005 Arizona Public Service received approval for a 4.25% rate increase. This was APS's first retail rate increase in 14 years. Specific in the APS rate increase was a provision for adjustments for fuel and purchased power costs. In July of 2007 Tucson Electric Power filed for a 22% rate increase that also includes provisions for fuel and purchased power adjustments. If TEP is successful in its case before the Arizona Corporation Commission it will be the first TEP rate increase in over a decade. In February of 2007 PNM filed for a nearly 15% rate increase that includes provision for fuel and purchased power cost adjustments. If successful, PNM's rate case will be the company's first increase in retail rates in 18 years.

the NERC publishes a ten year assessment of the reliability and adequacy of the bulk power system in North America. Based on reporting from each of the eight NERC reliability regions, the NERC's reliability assessments represent the NERC's independent judgment and recommendations concerning the adequacy of the bulk power system. Figure 2 shows the eight NERC reliability regions.

Figure 2
NERC Reliability Regions[4]



Fuel Supply

Coal, hydro and nuclear plants are the dominant electricity resources in the AZ-NM-SNV sub-region. Because of their comparatively low capital cost and relatively shorter lead time to construct, much of the focus on new power plant construction has been on natural gas fueled generation.[5] Unchanged from the 2002 IRP is the assessment that fuel supplies and availability are expected to be adequate for the next ten years, assuming that expansions of the natural gas pipeline systems are completed as planned. The completion of these planned natural gas pipeline projects involves not only financial concerns but environmental

[4] NERC 2007 Long-Term Reliability Assessment 2007-2016
[5] NERC 2007 Long-Term Reliability Assessment 2007-2016

and political as well. Even if these projects are completed as announced, gas supply and price can still change during extreme cold weather conditions and pose electric supply reliability problems.

Generating Capacity

The amount of announced new generating plant capacity across the entire WECC region greatly exceeds the expected increase in capacity requirements over the next ten years. However, the WECC considers nearly 70% of the announced new generation, 34,020MW out of 48,776MW, to be too speculative to include in its reliability forecast analyses. In the summer of 2011, assuming that there are no delays in completing plants currently under construction and excluding the new generation classified as speculative, supply-side resource capacity for the AZ-NM-SNV sub-region could fall below the WECC's 15.7% reserve margin planning criterion. Of the 34,020MW of announced new Class 3 generation that WECC has excluded from its planning and reliability assessments, only 3,028MW are projected for the AN-NM-SNV sub-region.[6]

By the summer of 2016 the shortfall in the capacity required to provide an adequate reserve margin for the projected peak load is 7,646MW. The WECC believes that as the need for additional capacity grows closer, some of the announced generating resource capacity that was not included in the NERC 2007 reliability assessment will become sufficiently active to be included.[7]

Over the next ten years the load growth forecast, which is impacted by weather as well as the addition of new end-use consumers and the expansion of business, presents the most uncertainty concerning supply requirements. If load growth exceeds the forecast, plans to add generating capacity may have to be modified to meet the additional requirements. However, resource plans that rely on the addition of smaller new generating units with two to three year lead times and generally fueled with natural gas, while requiring shorter lead times than larger coal and nuclear plants, do not offer long-range fuel cost stability. Even smaller natural gas fired units with their shorter lead times may require significant investments in transmission infrastructure to adequately integrate them into the grid. Transmission line siting, permitting and construction have the potential to introduce significant delays and additional costs when bringing any new generating capacity to market.

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[6] NERC 2007 Long-Term Reliability Assessment, pg 38.
[7] NERC 2007 Long-Term Reliability Assessment, pg 37.

Section 5
Supply-Side Resources

At this point in time, the power purchase option remains the preferred ten year supply side choice for GJU. The following are power supply options that were found to be attractive for GJU:

1. Purchase of power from a- privately owned electric utility
2. Ownership of a portion of a larger resource

Purchase of power from an IPP, which was considered in the 2002 IRP, is not considered as a reliable option for GJU at this time. Consideration of the purchase of power from an IPP in the 2002 IRP was during a period of time when separation of vertically integrated investor owned utilities into distinct generation, transmission and power delivery entities was still being contemplated throughout the southwest. Following the discontinuance of plans for deregulating utilities in New Mexico and in the other states in the region, many of the plans announced by IPPs for adding generation capacity were withdrawn. A large percentage of the announced plans for IPP plants that remain are insufficiently along in the planning and permitting process to be considered viable at this time.

PRIVATELY OWNED ELECTRIC UTILITY
Tucson Electric Power ("TEP") and PNM both remain viable options for supplying GJU's future power requirements. TEP has significant ownership in the 345kV transmission lines in the transmission line corridor along the New Mexico – Arizona border west of Gallup that form part of the transmission system connecting to the Four Corners Area Power Plants. Both utilities are planning to add significant amounts of new generating capacity within the next five years.

PART OWNERSHIP
As a member of the Utah Associated Municipal Power Systems, Gallup may have an opportunity to acquire a part ownership share of coal-fired baseload generation planned by UAMPS. This type of generation would offer GJU long-range fuel cost stability.

RENEWABLE RESOURCES
The GJU system is too small in size to make renewable resources a cost-effective resource option. Both wind and solar power are intermittent resources that must be backed up by conventional resources. Power production from wind resources throughout New Mexico typically does not match well with load requirements. Although progress has been made toward the commercialization of solar thermal power plants, solar remains the most expensive form of bulk power generation

CONCLUSIONS

The future for supply-side resource options for GJU looks optimistic. GJU can continue with its competitive firm energy and power purchases from PNM through June 2013. By that date it is expected that utilities in the region will have constructed sufficient new generating capacity for GJU to either enter into a long-term purchase power agreement or to purchase part ownership in one of the new plants coming on line.

At this time, however, it seems clear that the prices for firm long-term power purchased power will be significantly higher than the rates in GJU's June 2002 contract with PNM. Although construction costs as well as fuel and operating costs for new and existing power plants are increasing significantly; the part ownership option, depending on the timing, the fuel resource and the potential unavailability of long-term power purchase contracts at attractive rates, could be a more cost effective choice.

Section 6
Regulatory and Competitive Review

Legislation and regulation at the state and federal level have significant impacts on the future of power supply resources for GJU. Activities in these legislative and regulatory areas should continue to be monitored for GJU to be able take advantage of upcoming regulatory changes in the utility industry during its planning processes.

Regulatory Changes

Following the debacle of runaway electricity prices in California and the collapse of the energy trading giant Enron, in April 2003 New Mexico's Electric Utility Industry Restructuring Act of 1999 was repealed.

Through updates and clarifications to its Open Access Transmission Tariffs ("OATTs") the FERC has continued to strengthen implementation of its Rule 888. FERC Rule 888 requires public utilities to provide open access transmission service on a basis comparable to the transmission service utilities provide themselves. The FERC's objective in implementing Rule 888 is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.

The passage of the Energy Policy Act of 2005 ("EPact 2005") greatly strengthened the FERC's authority over the reliability of the nation's bulk power transmission systems. In July of 2006 the FERC certified the North American Electric Reliability Corporation ("NERC") as the single Electric Reliability Organization ("ERO") for the United States. As the ERO, the NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. As a provision of EPact 2005 the NERC is subject to audit by the U.S. Federal Energy Regulatory Commission.

Through the FERC's implementation of Rule 888 and the NERC's enforcement of bulk power system reliability and adequacy standards, GJU can remain confident in the availability of reliable power supply resource options at competitive prices in the future.

Retail Wheeling

The authority for regulation of retail wheeling, a practice that allows a retail customer to be located in one utility's service area and to obtain power from another utility or non-utility source, remains with state legislative and regulatory bodies. Retail wheeling is prohibited in New Mexico.

GJU'S SUPPLY SITUATION

All of GJU's power requirements beyond its Western allocation are currently supplied by PNM under a ten-year contract which expires June 2013. Purchases from PNM currently represent about 93% total energy and 89% of GJU's total capacity requirements. In December 2007 PNM adjusted the energy price for its contract with GJU by increasing the energy cost from $18.50/MWH to $23.80/MWH for July 1, 2008 through June 30, 2010 and from $19.00/MWH to $24.30/MWH for the from July 1, 2010 through June 30, 2013. These adjustments represent approximately 28.7% and 27.9% increases in the cost of energy for the final two periods of the PNM contract and are probably typical of what GJU will face when considering supply resources following the expiration of the PNM contract in 2013.

Table 8
PNM Contract Energy Rates After Adjustments

Effective Dates		Energy Rate
From	To	$/MWH
July 1, 2002	June 30, 2004	$17.50
July 1, 2004	June 30, 2006	$18.00
July 1, 2006	June 30, 2008	$18.25
July 1, 2008	June 30, 2010	~~$18.50~~ $23.80
July 1, 2010	June 30, 2013	~~$19.00~~ $24.30

Following the expiration of the current contract with PNM GJU will be required to purchase the four distribution substations through which it receives power from PNM and Western unless a new contract is executed with PNM. During the term of the current contract GJU has the option to purchase the four point-of-delivery substations. GJU has initiated a study to determine the staffing and cost impacts associated with purchasing and maintaining the four point-of-delivery substations that will be completed in 2008.

In addition to being faced with the potential for significantly higher costs for supply resources after the expiration of the current PNM contract, the drying up of the surplus generation that existed for so many years in the west is resulting in a growing reluctance to enter into long-term power sales contracts. This is because long term contracts limit the flexibility of generation owners to be able to take advantage of more attractive opportunities that are occurring in the market over a shorter period of time.

Before current contract with PNM expires in 2013, GJU should undertake a resource strategy as follows:

- A major power supply solicitation should be prepared at least one year to two years in advance of the expiration of the current PNM contract. The solicitation would cover both partial and full supplemental requirements, and be targeted to appropriate entities depending on market conditions at the time.
- Prior to soliciting power supply proposals GJU should undertake a study to understand the potential and cost of meeting a portion of its future power supply needs through energy efficiency, load control, demand response and distributed generation measures.
- An economic analysis of the power supply offers received, including generation ownership, energy efficiency, demand response and distributed generation options if applicable, should be conducted to determine the most cost effective power supply strategy.
- GJU should monitor closely the opportunity to acquire an ownership share of planned coal-fired baseload generation through its membership in the Utah Associated Municipal Power Systems organization or other joint ownership opportunities.

GJU'S LOAD-SIDE SITUATION

GJU is pursuing several initiatives to encourage conservation. These initiatives include:

- Water Conservation,
- Weatherization Program,
- Traffic Signal Conversion to LED lamps,
- Solar Powered Street Lights and
- Energy Efficiency

The City's water conservation and weatherization and energy efficiency programs are primarily focused on customer education and providing information. The Traffic Signal and Solar Powered Street Light initiatives are targeted at reducing the City's energy use through the deployment of energy efficient technologies. The primary goal of the water conservation program is a reduction in water use. However, the program has a secondary impact in reducing energy use for water pumping. The other four programs are targeted at reducing energy use. All but two of the City's traffic signals approximately 60% of the state owned traffic signals within the city have been converted from incandescent bulbs to LEDs. In 2008 the City will begin a trial installation of twelve 35W, solar powered, low pressure sodium street lights.

With the exception of the LED traffic signals and a potentially significant deployment of solar powered street lights, the City's current load-side initiatives are expected to have a minimal impact on GJU's electrical loads. Neither GJU nor the City have established a program to measure or monitor the electrical system impact of energy efficiency initiatives. Consequently, GJU does not specifically include the impact of load-side programs in its supply forecasts.

SHORT-TERM ACTION PLAN (1-5 YEARS)

1. A timeline based on this action plan will be developed and documented for use by the GJU Electric Department. The timeline will include responsibility, milestones, and a mechanism to monitor progress.

2. A five and ten year forecast of coincident system peak load and projected energy requirements will be completed annually. Included in the forecast will be forecasts of the individual peak loads on each distribution substation and feeder.

3. An evaluation of the potential for energy efficiency, load control, demand response, energy efficiency and distributed generation to cost effectively meet a portion of GJU's electric supply needs will be completed one to two years prior to the expiration of the current PNM contract.

4. An investigation in the operational and cost impacts of purchasing the four PNM distribution substations will be completed in 2008.

5. An investigation into generation ownership options will be conducted two to three years prior to the expiration of the current PNM contract. These options will include joint-ownership/participation opportunities in regional generation.

6. A major, power supply solicitation will be prepared at least one year prior to the expiration of the current PNM contract. The solicitation will cover both partial and full supplemental requirements, and will be targeted to appropriate entities depending on market conditions at the time.

LONG-TERM ACTION PLAN (5-10 YEARS)

1. This IRP, including these action plans, will be reviewed and updated periodically as required to reflect significant changes in:
    - Load projections
    - Power market conditions
    - Results of short-term action plan items

2. Options will be re-evaluated after significant changes in external conditions, such as:
    - A major load change (such as addition of a large industrial load).

- Changes in the power market (such as a major regulatory change, or a large, sustained change in fuel prices).

3. As market conditions change and appropriate technologies evolve, opportunities for energy efficiency, load control, demand response and distributed generation to cost effectively supply a portion of GJU's power needs will be investigated.

APPENDIX A

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Energy Planning and Management Program