Rick Rigel, *General Manager*
P O Box 70
Lamar, Colorado 81052
Phone: (719) 336-3496
Fax: (719) 336-5966
E-mail: rrigel@arpapower.org

June 15, 2012

SENT CERTIFIED MAIL 7007 1490 0004 6514 6792

David Neumayer
Western Area Power Administration
Rocky Mountain Region
P. O. Box 3700
Loveland, CO 80539

Dear Mr. Neumayer:

Pursuant to the requirements of 10 CFR Part 905, enclosed please find a copy of the Arkansas River Power Authority's (ARPA) 2012 Integrated Resource Plan (IRP) for your review and approval. ARPA received approval from the Western Area Power Administration in a letter dated December 27, 1995 to file its IRPs under IRP Cooperative status. If you have any questions regarding this submittal, please contact me at (719) 336-3496.

For informational purposes, electronic copies of this IRP have also been e-mailed to you, Paula Fronk and Bob Langenberger at the CRSP Customer Service Center.

Sincerely,

Rick Rigel

Rick Rigel
General Manager
Arkansas River Power Authority

Enclosure a/s

cc: Paula Fronk, fronk@wapa.gov
Bob Langenberger, Langenberger@wapa.gov

Integrated Resource Plan
2012

Prepared for

Arkansas River Power Authority

Prepared by

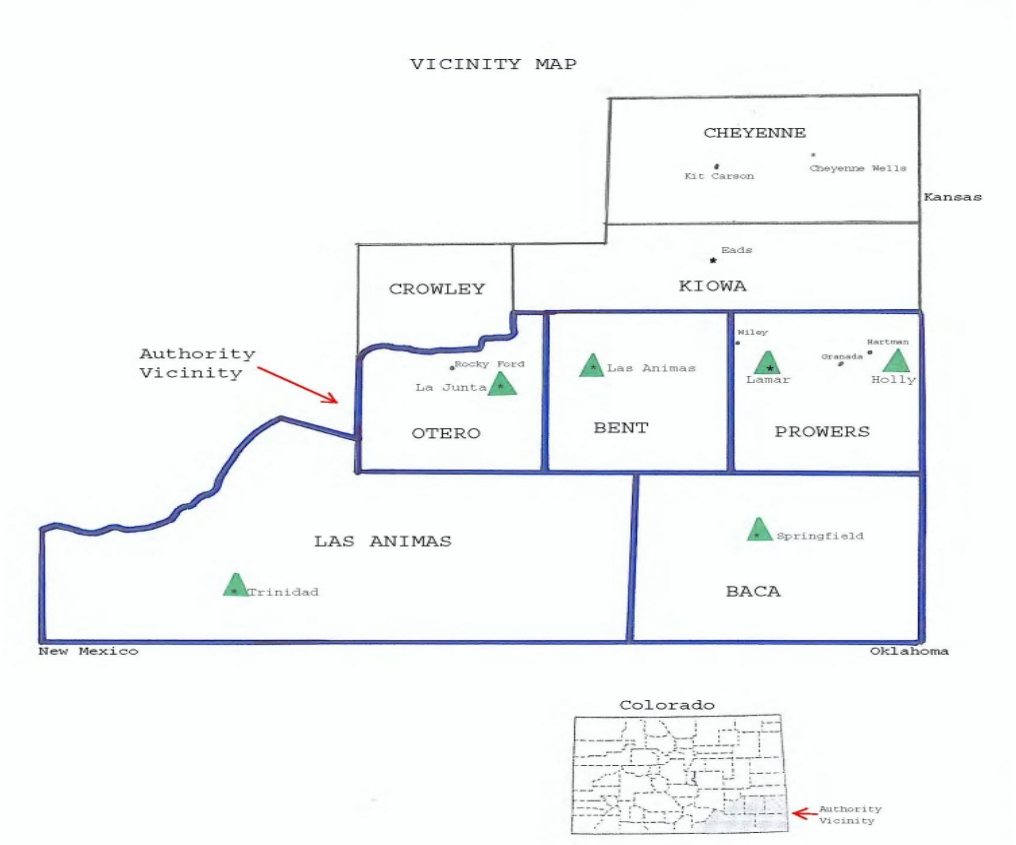
JK Energy Consulting, LLC
4727 North 26th Street, Suite A
Lincoln, Nebraska 68521
402-440-0227
jk@jkenergyconsulting.com

Section I. Summary 1
Purpose 2
Overview of Past IRPs 2
Approach to 2012 IRP 2
Goals and Objectives 3
Section II. ARPA Member Systems 4
Demographics 6
Load Profile 6
Section III. Load Forecast 7
Introduction 7
Forecast Methodology 8
2013-2022 Load Forecast 9
Section IV. Supply Side Resources 11
ARPA-Owned Generation 12
Purchased Power Arrangements 14
Energy Resource Mix 15
Transmission 15
Section V. Future Supply Side Resources 16
Comparison of Loads and Resources 16
Load Duration Curve 17
Section VI. Supply–Side Resource Evaluation 19
Introduction 19
Evaluation Criteria 20
LRP Operation Modes 21
Economic and Operational Parameters 22
Economic Comparison of Operational Changes 23
Conclusions 26
Section VII. Demand Side Management Analysis 27
Introduction 27
Current DSM Activities 27
Review of Load Shape Objectives 28
Changes in DSM Approach 30
Screening Analysis 31
Qualitative Screening 32

Selected DSM Programs 34
Economic Evaluation 37
Section VIII. Supply/Demand Side Resource Integration 39
Development of Integrated Resource Plan 39
Preferred Alternative 39
Environmental Impacts 40
Section IX. Action Plans 40
Two Year 41
Five Year 41
Public Participation [To be completed after public hearing.] 42
Measurement Strategies and Annual Updates 43
Appendix A
Appendix B

Section I. Summary

The Arkansas River Power Authority (ARPA) is a wholesale electric service provider in southeastern Colorado that supplies power to the communities of Holly, La Junta, Lamar, Las Animas, Springfield, and Trinidad. Unlike larger, investor-owned utilities, ARPA was formed and is owned by the communities it serves. Each of ARPA's municipal members own and operate an electric system that distributes electricity to residential, commercial, and industrial customers. Also known as a not-for-profit utility corporation, ARPA is governed by a 12-person board with two board representatives appointed by each member community.



Purpose

In 1995, Western Area Power Administration (Western) established a program called the Energy Planning and Management Program (EPAMP), which was developed to meet the objectives of Section 114 of the Energy Policy Act of 1992, and enables its customers to maintain their current allocations of capacity and energy from Western. EPAMP requires its customers to prepare and submit an IRP to Western every five years. This IRP is intended to meet the requirements of the EPAMP as well as be used as a planning document for ARPA.

ARPA and one of its members (City of Lamar) have allocations of federal hydropower supplied by Western. ARPA submits a single IRP on behalf of all its members. This is referred to under the EPAMP as a "cooperative" IRP. The purpose of this IRP is to review new generating resources and demand side measures that will reliably serve ARPA's members, and to complete this review in a manner consistent with the EPAMP.

Overview of Past IRPs

ARPA has completed three IRPs since the EPAMP became effective. ARPA submitted its first IRP in 1996, followed by two additional IRPs in 2003 and 2007. In general, ARPA has implemented the recommendations of its previous IRPs.

Approach to 2012 IRP

This IRP was prepared based on the procedures suggested by the EPAMP and is consistent with prior IRPs submitted by ARPA. The tasks completed to prepare this IRP are summarized below:

- Prepared ARPA peak demand and energy requirements forecast.
- Compared forecasted peak demand and energy requirements to existing ARPA power supply resources to estimate future resource needs.

- Reviewed power supply resource options to identify economical resources to include in the integration analysis.
- Identified potential demand side management (DSM) measures and assessed their economic and technical feasibility.
- Integrated DSM options with supply resources to develop preferred plan.
- Considered environmental impacts and costs of each IRP option.
- Solicited public participation and incorporated comments into the IRP.

Goals and Objectives

ARPA's mission is to promote the long-term economic well-being of its municipal members and their consumers by providing a dependable and competitively priced supply of wholesale electric power in an environmentally sound manner.

To achieve this stated mission, ARPA focused on the following objectives in developing the IRP:

- Providing reliable wholesale electric power at competitive and affordable rates.
- Preserving its allocation of low cost federal hydropower.
- Ensuring adequate transmission rights are available to economically deliver wholesale power to the members.
- Maintaining the viability of member-owned and controlled electric systems through integration of existing member-owned generation facilities with ARPA-owned local generating resources and supplemental purchase power; thus, preserving local generation and associated jobs.
- Optimizing the operation of generation owned by ARPA and its members, based on current market conditions and the operating costs associated with this generation.

- Furnishing and coordinating support services for the members in order to encourage energy efficiency programs and achieve economic and operational efficiencies.

Section II. ARPA Member Systems

As stated earlier, ARPA has six member systems located in southeast Colorado. A former member purchases capacity and energy under an arrangement that will expire in 2013. Each of the members has exclusive rights to serve retail loads within their respective service territories under existing Colorado law, including the portion of the service territories located outside the corporate limits. There have been no legislative attempts to change provisions related to the exclusive rights of utilities to serve customers within the service territory of electric providers since 1998.

Holly, Colorado: The Town of Holly purchased its municipal utility in 1949. The utility serves an area of approximately 24 square miles with 31 miles of distribution facilities. Approximately 16% of Holly's revenues are derived from customers outside municipal boundaries. Approximately 10% of Holly's load base was lost during a tornado that devastated the region in the spring of 2007. The load base continues to rebuild.

La Junta, Colorado: The La Junta municipal electric utility was created in 1939 and serves an area of approximately 10 square miles. La Junta operates approximately 55 miles of distribution line and 6.3 miles of transmission line. Approximately 14% of the power sold by La Junta is delivered to customers outside municipal boundaries.

Lamar, Colorado: The Lamar municipal electric utility has been in existence since 1920 and serves approximately 170 square miles, comprised of areas both within and outside the municipal boundaries. Lamar's facilities include approximately 320 miles of distribution line

and 30 miles of transmission line. The Lamar Utilities Board, which operates and oversees the electric utility, was established in 1962 pursuant to the Lamar Home Rule Charter.

Las Animas, Colorado: The Las Animas municipal electric utility was established in 1941 and serves an area of approximately 22 square miles. Approximately 59% of its sales occur outside the municipality. Las Animas' facilities include about 50 miles of distribution line and 13 miles of transmission line.

Springfield, Colorado: The Springfield municipal electric utility was established in 1947 and serves an area of approximately 2 square miles. Less than 2% of Springfield's sales are attributable to customers outside municipal boundaries. Springfield has approximately 26 miles of distribution line, which includes 4 miles of distribution line to the ARPA wind turbine in Springfield.

Trinidad, Colorado: The Trinidad municipal electric utility was established in 1949 and serves an area of approximately 7 square miles. Less than 1% of Trinidad's total sales are comprised of sales to customers outside municipal boundaries. Trinidad's facilities include approximately 72 miles of distribution line.

Raton, New Mexico (former member): The City of Raton was a member since ARPA's inception in 1979. In January 2010, ARPA and Raton entered a settlement agreement under which Raton would terminate its membership in ARPA, but continue to purchase capacity and energy through January 2013. For planning purposes under this IRP, Raton was not included in the capacity and energy requirements of ARPA through the study period. Any capacity and energy needs related to Raton in 2013 would be provided under ARPA's purchase agreement with Tri-State as described below. Raton was not included in the development of the load forecast or included in the resource plan under this IRP.

Demographics

Over the past 40 years, the population in ARPA member communities has steadily declined, with the exception of the City of Lamar, whose population has remained steady. Between 1970 and 2010, Las Animas' population has declined by 23% while Holly has seen its population decline 19%. Springfield has experienced a 13% reduction in population, La Junta has decreased 11%, and Trinidad's population has declined 8%.

The causes of the population decline in ARPA member communities are numerous and well documented. There have been a number of key employers that have reduced or eliminated operations in recent years. Water that was previously used for irrigation has been sold to communities in the Front Range, reducing agricultural activity in the area between La Junta and Lamar. These factors, along with aging of the local population and reduced birth rates, have caused the population to steadily decline as shown in Table 1. These population declines have contributed to flat retail energy sales over the last few years.

Table 1
Population (1)

Member	1970	1980	1990	2000	2010
Holly	993	969	877	1,048	802
La Junta	7,938	8,338	7,637	7,568	7,077
Lamar	7,797	7,713	8,343	8,869	7,804
Las Animas	3,148	2,818	2,481	2,758	2,410
Springfield	1,660	1,657	1,475	1,562	1,451
Trinidad	9,901	9,663	8,580	9,078	9,096
TOTAL	31,437	31,158	29,393	30,883	28,640

(1) Sources: State of Colorado, Department of Local Affairs, Historical Census Population

Load Profile

Table 2 shows the peak demand and energy profile for the six member communities as well as the entire ARPA system. The six members have a demand and energy usage profile

typical of small municipal systems. Peak demands are driven by weather patterns in the summer and winter season. Load factors for each of the member communities are typical of a predominately residential and small commercial customer base. All of the members, except Trinidad, are summer peaking systems, with peak demand driven by air conditioning demand. The City of Trinidad has a significant amount of electric heating load and tends to have colder winters than the other ARPA members.

Table 2
2011 Peak Demand and Energy Profile

Member	Winter Peak (kW)	Summer Peak (kW)	Energy Purchases (MWh) (1)	Load Factor (%)
Holly	1,187	2,225	7,489	38.4%
La Junta	13,296	19,261	81,972	48.6%
Lamar	17,564	31,064	89,236	32.8%
Las Animas	4,640	7,034	30,610	49.7%
Springfield	2,359	4,190	12,546	34.2%
Trinidad	10,188	9,292	54,790	61.4%
ARPA TOTALS (2)	**45,000**	**70,000**	**276,643**	**45.1%**

(1) Member energy purchases from ARPA. Does not match data on Table 3 because this figure includes distribution losses but does not include transmission losses.
(2) ARPA summer peak and winter peak is the Coincident Peak rounded to nearest MW, not the sum of the individual Member peaks.

Section III. Load Forecast

Introduction

A load forecast was prepared to project ARPA's peak demand and energy requirements for the period of 2013 through 2022. The forecast incorporated econometric forecasting methods to attempt to relate historical energy consumption to economic and population growth, employment, real per capita income, number of customers, heating and cooling degree days, and

the real wholesale and retail price of electricity. Subsequently, the relationships were applied to projected econometric variables to project future energy consumption.

Forecast Methodology

Annual energy sales forecasts were developed using weather data and attempted to correlate future energy use with historical econometric data. A model was developed by selecting factors that may have influenced energy requirements in the past and may likely influence each member's future energy use. The data that was evaluated is available to the public upon request.

Rather than forecasting each City's use individually, the forecast treated ARPA as a single entity. Weather data for the City of La Junta was used for purposes of the weather normalization process, based on the availability of data and central location relative to all of the members.

- Econometrics. The study considered econometric data to explain historical energy consumption. Historical and projected economic factors that influence the members load include population, employment, number of customers, real per capita income, and the real wholesale and retail price of electricity. The factors that influenced energy usage varied by member. The influencing factors for each member were used to estimate future energy requirements. To the extent that actual trends deviate from projections used in this forecast, actual peak demands and energy usage should deviate from these projections.
- Weather. The effect of weather on energy usage was also considered. Heating and cooling degree days for 2002 through 2011 were collected from the City of La Junta

and compared to historical averages. A regression analysis was used to assess the relationship between degree days and annual energy requirements.

2013-2022 Load Forecast

The load forecast is summarized in Table 3 (see page 10). The correlation with econometric data, including population data and economic activity, was relatively low. The three variables shown to have reasonable correlation with the historical energy use data were the previous year's energy sales, heating degree days and cooling degree days.

Table 3
Summary of Load Forecast

Year	Retail Energy Sales (1) (MWh)	Energy Resources (2) (MWh)	Summer Coincident Peak (MW) (2)	Winter Coincident Peak (MW)
ACTUAL				
2002	261,990	288,189	64	45
2003	253,895	279,285	64	48
2004	252,094	277,303	62	46
2005	260,275	286,303	70	48
2006	254,831	280,314	64	47
2007	262,780	289,058	64	44
2008	256,817	282,499	65	46
2009	251,675	276,843	61	48
2010	261,471	287,618	67	48
2011	254,896	280,386	70	45
FORECAST				
2012	258,725	284,597	71	46
2013	256,649	282,314	70	45
2014	257,774	283,552	71	46
2015	257,164	282,881	71	45
2016	257,495	283,245	71	45
2017	257,316	283,047	71	45
2018	257,413	283,154	71	45
2019	257,360	283,096	71	45
2020	257,389	283,128	71	45
2021	257,373	283,111	71	45
2022	257,382	283,120	71	45

(1) The energy requirement shown in this column is based on retail sales of members.
(2) Projected energy resource needs, based on generation resources required to supply member's retail energy sales requirements, plus distribution losses and transmission losses for applicable resources (primarily ARPA generation transmitted between members). Excludes Raton, NM.

The historical data showed no energy sales growth over the previous 10 years, with energy sales in future years projected to decline slightly. This is not unexpected given area population trends, economic activity and improved energy efficiency standards for appliances, heating and air conditioning equipment, lighting and practically every other electricity-consuming device manufactured today. Summer peak demand usage of 71 MW was forecasted

in 2022, which is essentially the same as the 2011 actual peak demand. Energy requirements were projected to be essentially flat for the period 2013 through 2022.

Section IV. Supply Side Resources

When ARPA was established in 1979, each ARPA member owned local generation. ARPA members are responsible for the continued upkeep, operation, and maintenance of this existing member-owned generation so long as these activities do not become economically detrimental to the member. ARPA coordinates with its members when member-owned generation is needed to assist with power supply. Members are reimbursed for the usage of their member-owned generation in accordance with ARPA's current tariff and reimbursement schedules as approved at least annually by the Board of Directors.

While members are responsible for their existing generation, ARPA is responsible for acquiring power supplies and to construct, operate and maintain new generation, transmission, and related facilities for the purpose of delivering wholesale electric power to its members. Since the 2007 IRP, ARPA completed the Lamar Repowering Project (LRP).

ARPA and its members own approximately 80 MW of generating resources. These resources include baseload generation, peaking and standby generation, and wind turbines that provide renewable energy.

Table 4 (see page 12) lists ARPA's existing supply side capacity resources, including installation date, capacity, primary fuel, location, and operational type. With the exception of the LRP, ARPA and member-owned generation is predominately peaking generation fueled by diesel or natural gas. There is also 7.5 MW of wind generation that supplies intermittent renewable energy without firm capacity.

Table 4
Summary of ARPA and Member-Owned Generation

Location	Year Installed	Owned By	Capacity (MW)	Fuel	Type
Holly	1991-1997	Member	1.0	Diesel	Emergency Only (1)
	2007	ARPA	1.8	Diesel	Peaking
La Junta	1939-1971	Member	15.0	Diesel	Emergency Only (1)
Lamar	2004	Member	4.5	Wind	Intermittent
	2004	ARPA	1.5	Wind	Intermittent
	2009	LRP	38.5 (2)	Coal	Baseload
Las Animas	1941-1967	Member	5.0	Diesel	Emergency Only (1)
Springfield	1950-1962	Member	2.8	Diesel/Dual	Emergency Only (1)
	2004	ARPA	1.5	Wind	Intermittent
Trinidad	1965	Member	3.5	Diesel/Dual	Emergency Only (1)
	1999	ARPA	5.6	Diesel	Peaking

Notes:
(1) These units are only operable during emergencies and other limited uses permitted under the Reciprocating Internal Combustion Engine (RICE) emissions rules.
(2) Although LRP design net capability was 38.5 MW, it is typically operated with 35 MW net capacity.

ARPA-Owned Generation

- Lamar Repowering Project (LRP): The LRP was a joint effort by ARPA, the Lamar Utilities Board (LUB) and the City of Lamar to repower LUB's existing 25 MW steam generating unit from natural gas-fired to coal-fired operation. The new coal-fired boiler, in conjunction with the existing LUB steam turbine and a new condensing steam turbine, increased the capacity of steam generation at the facility from 25 MW to approximately 44 MW (gross output). The design incorporated an increase in net output rating to approximately 38.5 MW. During normal operations, the net capability of LRP is approximately 35 MW. LUB dedicated certain existing facilities (25 MW turbine, generator, water supply, land, transmission interconnect, and other associated equipment) to the LRP at no capital cost to ARPA and its members.

- Holly Generation Project: In 2000, ARPA and the Town of Holly jointly financed the installation of a used 2 MW diesel-fired internal combustion engine generating set to provide backup power for the Town. This used unit proved to be unreliable for backup purposes. As a result, in 2007 ARPA replaced the unit with a used, but significantly newer diesel-fired generating set with a Tier I emission rating, meaning it did not need retrofits to comply with the Reciprocating Internal Combustion Engine (RICE) rule issued by Environmental Protection Agency (EPA) in 2010.
- Trinidad Generation Project: ARPA constructed 5.6 MW of peaking generation in Trinidad in the late 1990s. This project is RICE compliant. This generation is available during transmission outages and can be used to supply energy during periods of high market prices.
- Wind Turbines: In 2004, ARPA installed two 1.5 MW wind turbines – one in Lamar and one in Springfield. Although ARPA is responsible for all future generation, the ARPA Board executed an agreement with Lamar Light and Power that allowed them to own and install an additional three 1.5 MW wind turbines at the site in Lamar. The energy from the LUB owned turbine is sold to ARPA at cost. All five turbines are maintained via an agreement with the LUB and are monitored remotely from the Lamar Power Plant. This 7.5 MW of ARPA/member wind typically provides over 6% of ARPA's annual energy requirements. When possible, ARPA and Lamar sell the energy attributes of the wind generation in order to help offset the energy cost associated with the turbines.
- Member-Owned Peaking Generation: The majority of member-owned generation is reaching the end of its life cycle, ranging in age from 30-60 years. This member-

owned generation has been and will continue to be vital to ARPA, particularly during transmission outages. ARPA recognized that unit reliability, availability of spare parts, and environmental compliance costs will become greater issues as these units continue to age and has reduced its reliance on these older generating units in the last 10-15 years.

There are no additional ARPA or member-owned units slated for retirement, replacement, or additions in the near term.

Purchased Power Arrangements

Western - Colorado River Storage Project (CRSP): Western provides an allocation of firm capacity and energy to ARPA and LUB. ARPA acts as the agent for the LUB Western-CRSP allocation. This agreement terminates on September 30, 2024. Tri-State provides scheduling and transmission of all monthly and support energy, that ARPA members are entitled to under its agreement with Western.

Western - Loveland Area Projects: ARPA has a capacity and energy allocation from Western associated with the Loveland Area Projects. This agreement terminates on September 30, 2024. Tri-State provides scheduling and transmission of all monthly energy, support, and pumped storage energy that ARPA members are entitled to under its agreement with Western.

Tri-State Generation and Transmission Association (Tri-State): Through the terms of the Services Agreement between ARPA and Tri-State, effective February 1, 2012, ARPA purchases its supplemental power supply needs exclusively from Tri-State. Under this agreement, Tri-State provides all power supply needs not supplied from the existing Western allocations and owned generation facilities (including the LRP and Wind Generation). This agreement provides service through February 1, 2015.

Energy Resource Mix

Table 5 summarizes the historical energy supply mix for ARPA for 2007 through 2011. There have been significant changes during this time with the termination of the MEAN agreement, the commencement of a new energy purchase agreement with Tri-State, and uncertainty about the operations of the LRP based on environmental compliance issues and market conditions.

Table 5
Energy Provided by ARPA's Historical
Supply Side Resources (MWh) (1)

Source	2007	2008	2009	2010	2011
Conventional Generation (2)	22,733	14,517	49,729	119,292	63,912
Wind Generation (3)	20,054	24,284	21,672	24,032	22,335
MEAN	215,102	235,462	199,993	127,735	184,365
Western	82,411	95,558	85,155	87,594	99,840
Xcel Energy	19,708	0	0	0	0
TOTAL	360,008	369,821	356,549	358,653	370,452

(1) Includes resources used to serve Raton, NM.
(2) Includes ARPA-owned and member-owned generation resources. Excludes wind.
(3) Includes ARPA-owned and member-owned wind generation resources.

Transmission

ARPA and its members do not own any transmission (115 kV and higher) and is dependent upon wheeling over the transmission facilities of other utilities in order to supply power to the ARPA member systems. ARPA is a network integration transmission service customer of Tri-State. Tri-State provides network service to Holly, La Junta, Lamar, Trinidad, and Springfield. Las Animas receives transmission service from Black Hills Power and Light under a grandfathered (pre-Order 888) transmission service agreement. These agreements allow ARPA to serve its member needs from multiple points of receipt, much like a vertically integrated utility does, without reserving redundant capacity since charges for service are based on the measured load of the members.

Section V. Future Supply Side Resources

Comparison of Loads and Resources

Table 6 compares ARPA's existing and committed capacity resources to the projected capacity requirements. Based on the Projected Capacity Requirements and Resources, ARPA has sufficient capacity resources through 2022. If all existing generating capacity were kept in service, surplus capacity of 20 MW would be available in 2013, decreasing to 19 MW in 2022.

Table 6
Projected Capacity Requirements and Resources

Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Peak Demand	70	71	71	71	71	71	71	71	71	71
Reserves (1)	6	6	6	6	6	6	6	6	6	6
Total Capacity Requirements	76	77	77	77	77	77	77	77	77	77
Existing Resources										
Western (2)	32	32	32	32	32	32	32	32	32	32
Lamar Repowering Project	39	39	39	39	39	39	39	39	39	39
Tri-State G&T	-	-	-	-	-	-	-	-	-	-
Local Generation (3)	26	26	26	26	26	26	26	26	26	26
Wind (4)	-	-	-	-	-	-	-	-	-	-
Total Resources	96	96	96	96	96	96	96	96	96	96
Surplus / (Deficit)	20	19	19	19	19	19	19	19	19	19

Notes:
(1) Includes 15% reserves for capacity resources that do not include reserves.
(2) Based on July Contract Rate of Delivery.
(3) Includes generation available for peaking operation.
(4) Assumes that wind is not available to supply capacity during peak conditions.

Table 7 (see page 17) shows the comparison of energy requirements to energy resources. There are sufficient energy resources to serve projected energy requirements, provided that LRP is available in baseload operation mode. If LRP is not available or is converted to seasonal operations, there would likely be the need for short-term, non-firm energy purchases similar to the existing Tri-State agreement. If LRP were placed in a cold standby mode, ARPA would likely need to purchase firm capacity and associated energy to ensure continued reliable service to its members.

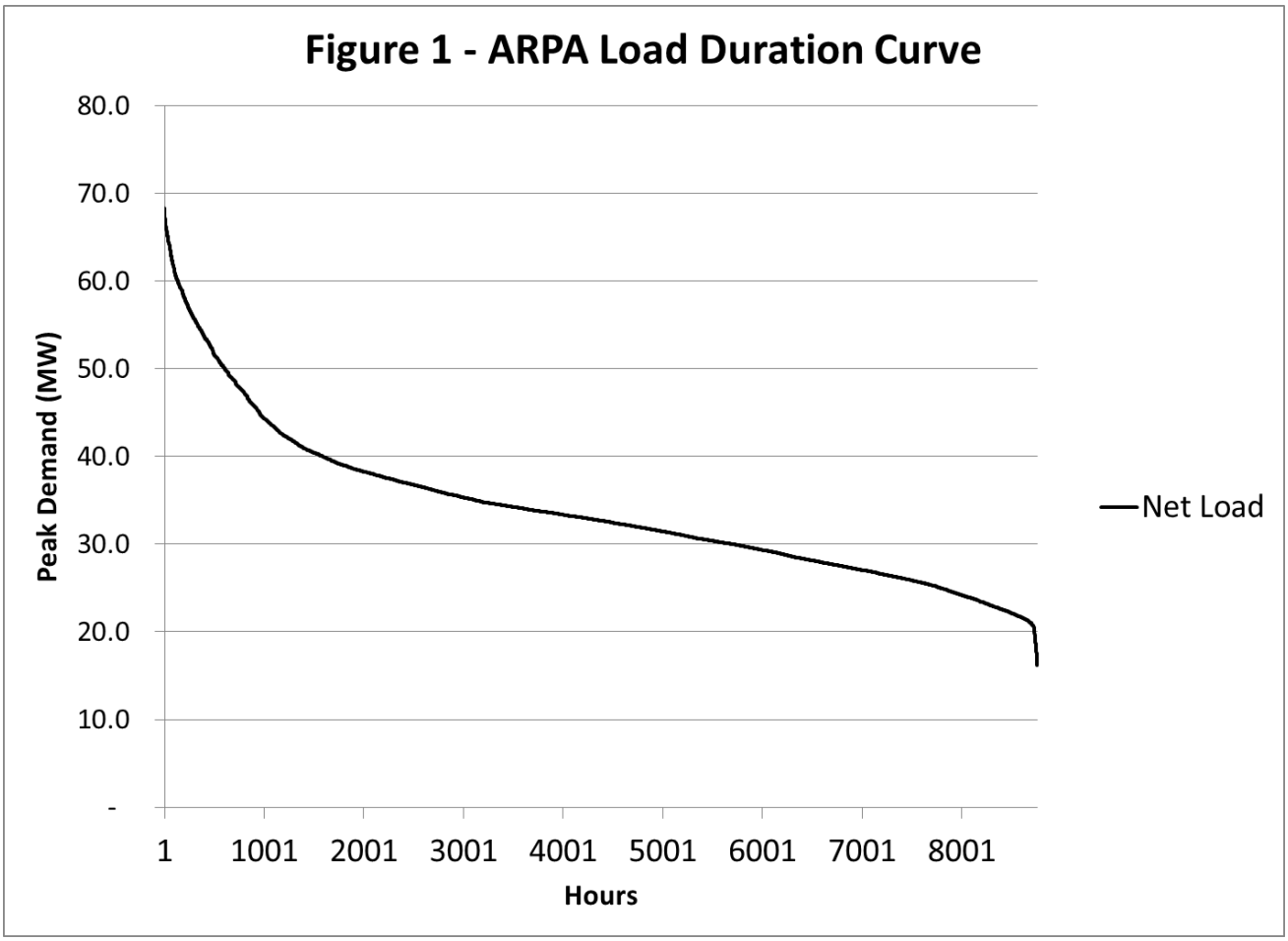
Table 7
Projected Energy Requirements and Resources

Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Retail Energy Sales	256,649	257,774	257,164	257,495	257,316	257,413	257,360	257,389	257,373	257,382
Losses (1)	25,665	25,777	25,716	25,750	25,732	25,741	25,736	25,739	25,737	25,738
Total Energy Requirements	282,314	283,552	282,881	283,245	283,047	283,154	283,096	283,128	283,111	283,120
Existing Resources										
Western	90,589	90,589	90,589	90,589	90,589	90,589	90,589	90,589	90,589	90,589
LRP (2)	286,671	286,671	286,671	286,671	286,671	286,671	286,671	286,671	286,671	286,671
Tri-State G&T (3)	-	-	-	-	-	-	-	-	-	-
Local Generation (4)	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,269
Wind (5)	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
Total Energy Resources	402,209	402,209	402,209	402,209	402,209	402,209	402,209	402,209	402,209	402,209
Surplus / (Deficit)	119,895	118,657	119,328	118,964	119,162	119,055	119,113	119,081	119,098	119,089

(1) Includes transmission losses for ARPA generation delivered between members and distribution losses.
(2) Based on 85% capacity factor.
(3) Although agreement goes through 2015, purchases are set to zero since LRP is assumed to be available.
(4) Based on annual capacity factor of 1%.
(5) Based on average wind energy production from 2009 through 2011.

Load Duration Curve

Figure 1 (see page 18) shows the annual load duration curve for ARPA. This is a graphical representation of the system's hourly loads over the course of the year where loads are sorted from highest to lowest. This approach enables a resource planner to assess how many hours during the year the system load exceeds a given amount. This information can be used to identify what types of resources are needed to serve the load most cost-effectively. For example, baseload resources are most cost-effective when they can be used during most hours of the year. Peaking resources are cost-effective when they are only needed for a small number of hours each year (for example, less than 500 hours per year).



ARPA's load duration curve is typical of most small municipal systems. The minimum load is approximately 20 MW, which is approximately 30% of the peak load. During the highest 500 hours of peak demand, hourly loads range from 52 MW to approximately 70 MW, indicating that approximately 20 MW of peaking generation would reasonably serve the peaking generation need. The local peaking generation owned and operated by ARPA and its members is a reasonable resource to serve this need. Load exceeds 25 MW approximately 7500 hours per year, indicating this is the approximate baseload capacity need. LRP is an ideal resource to supply this need. Intermediate capacity, including purchased capacity and energy from Western or others, would be an ideal resource to serve needs when loads range between the amount served by LRP (38.5 MW) and the peaking generation need (50 MW).

These amounts are approximate and based on developing a resource plan without regard for existing resources or changes in load (for example, the termination of Raton's membership). In addition, the cost of operating generation, as determined by fuel costs and other factors, can change the characteristics of generation over time. For example, when natural gas prices are low, a combined cycle generating plant can be operated cost-effectively as a baseload resource. When natural gas prices are high, it may be more effective to operate a combined cycle as a peaking or intermediate resource. Some coal plants that were operated in baseload mode as recently as 20 years ago are now operated as an intermediate resource or, in some cases, operated on a seasonal basis as an intermediate or peaking resource because of operating cost increases, environmental compliance costs, or resource reliability issues.

Section VI. Supply–Side Resource Evaluation

Introduction

The EPAMP indicates the IRP should consider all practicable energy supply resource options. Since ARPA has sufficient capacity and energy resources throughout the study period, the focus of the supply-side resource evaluation was to optimize future operations of existing power supply resources. One key parameter of the evaluation was that existing generation would be maintained and none of the ARPA or member-owned generation would be permanently decommissioned. These parameters assume that LRP would resolve any outstanding environmental compliance issues and be able to operate in baseload mode going forward.

Optimization of existing resources can take multiple forms. LRP's operational mode was a key issue that was evaluated since it is the largest resource and does not have the scheduling constraints of purchases from Western. Several operational changes could be evaluated, including:

- LRP could be operated only during high-load summer months.
- LRP could be placed on cold standby with reduced staffing for a period of time, with reactivation at some future point based on market conditions.
- Converting from baseload operation to seasonal load-following or cycling mode based on system load and market prices. This operational mode would require additional operational analysis and consultation with ARPA's design engineers to determine it is feasible given operational constraints, including compliance with emissions limits. Because of the uncertainty of the technical feasibility of this mode of operation, an economic evaluation of this option was not completed.

Selecting one of these options would not preclude changing future operations based on market conditions, provided that LRP is kept operational and sufficient staffing is available to support the change in operating mode.

Evaluation Criteria

ARPA established several criteria for evaluating the various operations changes, including:

- Ability to meet ARPA's resource needs.
- Reliability and availability of resources.
- Operational flexibility of the resource including ramp rates and scheduling provisions.
- Environmental impacts and compliance costs.
- Economic analysis of proposed cost of the resource.

LRP Operation Modes

Three operational modes for LRP were considered. These modes would each involve different staffing levels and hours of operation. Some of these cases may have an adverse effect on reliability, heat rate, plant life, power cost risk or operational flexibility. For example, placing the unit in a cold standby condition may have lower near-term costs, but offer reduced operational flexibility and place ARPA at greater risk for exposure to higher power costs.

The operational modes considered were:

1. Base Case – Baseload Operations: This case is similar to the operational mode the LRP was originally designed for. Baseload operations would entail 24 hour per day, seven days per week operations at energy output approaching the rated capacity of the unit during most hours.

2. Extended Cold Standby: This case would involve an extended shutdown of the plant, including laying off all but the most essential operating staff. Equipment would be idled in a manner that would avoid corrosion or other damage from exposure to weather and other adverse elements. For example, a "nitrogen blanket" system may be installed on the boiler to reduce the likelihood of oxidation of parts internal to the boiler. This approach would ensure the unit could be reactivated when either market prices increase or loads increase. It would also ensure that the plant could be operated in a reliable fashion when it is reactivated and would reduce the risk of equipment damage from the extended shutdown period.

3. Seasonal Operation: This case would involve operating LRP during the summer season when ARPA typically experiences its peak loads. This period coincides with the time of year when market prices during on-peak periods is highest. In the fall, the unit would be placed in a cold standby condition as described above in the cold standby option. Any required

maintenance to the unit would be performed during the non-summer months when the unit is in cold standby mode.

Economic and Operational Parameters

Several economic and operational parameters were used to prepare the various cases. These parameters were either provided by ARPA staff or based on information provided from third party information sources that were deemed reliable. To the extent the actual future values for these parameters are different from what was estimated for this report, the preferred option may not end up being the lowest cost option. The following parameters were used to prepare the economic evaluation of the various operational modes for LRP. The detailed power cost cases were not included in this report because they include information that is subject to confidentiality agreements with fuel suppliers and other third parties.

1. The econometric load forecast developed as part of this study was used to project the capacity factor for LRP. An annual capacity factor of 65% was calculated and used for the operational mode analyses.

2. LRP would complete all necessary capital improvements necessary to comply with its environmental permits for baseload operations. As of the preparation of this IRP, ARPA was working with the boiler manufacturer to make boiler modifications that would enable LRP to operate within the limits established under the construction permit. ARPA would also add mercury controls to the LRP to enable compliance with the "Mercury MACT" rule, regardless of the selected mode of operation. Upon completion of the planned boiler modifications and mercury control equipment, the LRP should be compliant with all applicable environmental requirements.

3. Natural gas prices for the Rocky Mountain Region were based on the Henry Hub futures price index from CME Group (often referred to as New York Mercantile Exchange or NYMEX). A basis differential of minus $0.30/MMBtu was used to calculate prices in the Rocky Mountain Region.

4. A typical heat rate, or "spark spread" based on recent market conditions, was used to determine the monthly market price for on-peak and off-peak periods.

5. Operating and maintenance costs for LRP were based on contracted fuel costs and an estimated heat rate of 14,000 Btu/kWh. Fixed and variable operating and maintenance (O&M) costs were based on information provided by ARPA.

6. Under scenarios where LRP is placed in cold standby, fixed operating and maintenance costs would decrease by approximately 50% from existing costs, or approximately $960,000 per year.

7. Under scenarios where LRP is operated on a seasonal basis, fixed O&M costs would decrease by 30% from existing costs.

8. The operational evaluation was completed for a one calendar year period (2013) that would take into account monthly and seasonal variances in fuel and electric market prices.

9. There would be no appreciable differences in emissions between the cases. The Tri-State agreement provides energy from a variety of coal and natural gas-fired resources that would likely have a similar emissions profile to LRP.

Economic Comparison of Operational Changes

1. Base Case – Baseload Operations: Under this scenario, annual power costs would be approximately $13.3 million, including fuel, variable operating and maintenance costs, and fixed operating and maintenance costs. Estimated power and energy costs were $62.11/MWh.

2. Extended Cold Standby: Under this scenario, annual power costs would be approximately $8 million, including purchased energy costs and fixed operating and maintenance costs associated with maintaining LRP in a cold standby condition that would enable it to be reactivated with reasonable advance notice. Estimated power and energy costs for this scenario were $37.25/MWh. This scenario would save ARPA approximately $5.3 million per year compared to the Base Case.

3. Seasonal Mode: Under this scenario, annual power costs would be approximately $9.1 million, including purchased energy costs and fixed operating and maintenance costs associated with maintaining LRP in a condition that would enable it to be operated in June through August. Energy would be purchased from market-priced resources the remaining nine months of the year. Estimated power and energy costs for this scenario were $42.66/MWh. This scenario would save ARPA approximately $4.2 million per year compared to the Base Case.

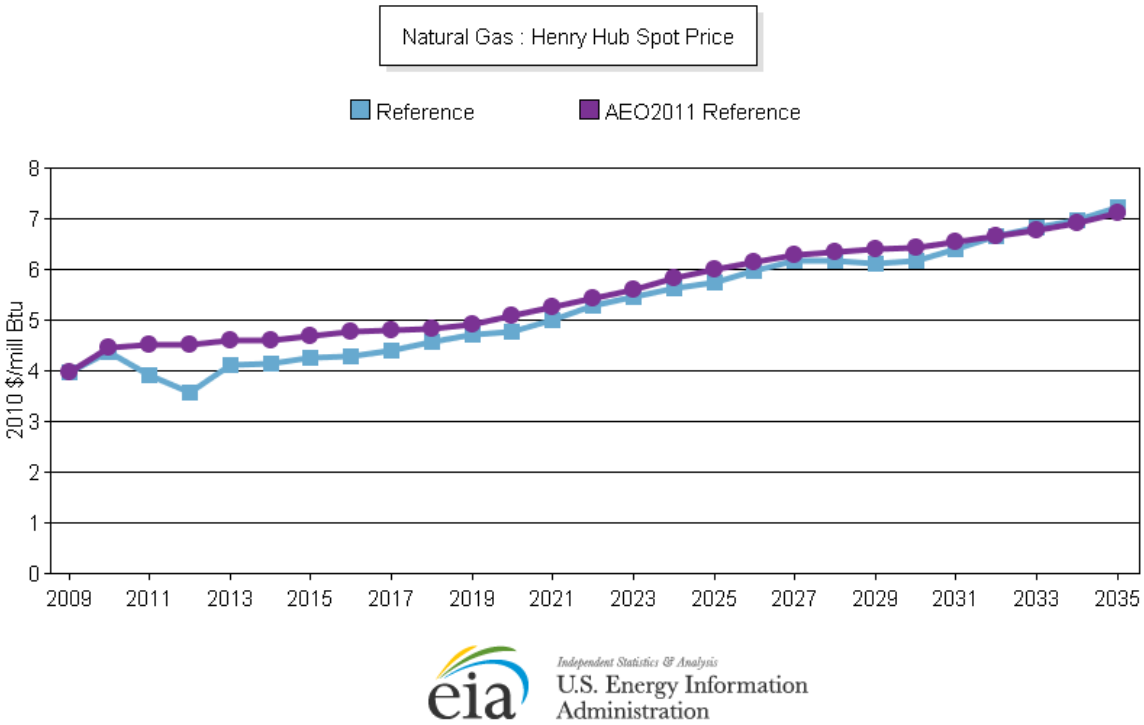
4. Break-even Analysis – Baseload: An analysis was prepared to determine at what natural gas price LRP would be economically feasible to operate in baseload mode. This analysis took into account increased fixed O&M costs and the estimated market price of energy. This analysis is subject to some uncertainty based on the appropriate spark spread between natural gas prices and market-priced electrical energy. Electrical energy market prices would need to exceed $57.70/MWh for LRP to be economical. Based on projected heat rates and spark spreads in the Rocky Mountain region, natural gas prices would need to increase to approximately $5.25/MMBtu for baseload operations of LRP to be economical. This natural price is approximately 70% higher than current natural gas prices.

A preliminary analysis of future natural gas price projections, prepared by the Energy Information Administration and shown in Figure 2 (see page 25), shows that natural gas prices

are not projected to equal this amount until 2021. This projection is not unexpected, given recent increases in natural gas reserves from hydraulic fracturing of shale formations. There has been significant natural gas reserve increases in the Rocky Mountain area, including the Front Range of Colorado, over the last three years.

Figure 2

Natural Gas Price Projections
2012 – 2035



Source: Annual Energy Outlook 2012 Early Release Overview, U.S. Energy Information Administration.

The economic analysis of the various operational modes was summarized in Table 8 (see page 26). The lowest cost option based on current energy and natural gas prices is to place LRP into cold standby mode and purchase energy from market-priced resources. The existing Tri-State purchase agreement provides for market-priced energy purchases through 2015. This

agreement would need to be evaluated and compared to market prices to determine the feasibility of either extending the agreement or returning LRP from cold standby mode.

Table 8
Comparison of Operating Modes
Lamar Repowering Project

	Power Cost	
Annual Operations	**($000)**	**$/MWh**
Operate LRP	13,330	62.11
Cold Standby	7,994	37.25
Cost / (Savings)	(5,336)	(24.86)
	Power Cost	
Seasonal Operations Case	**($000)**	**$/MWh**
Operate LRP	13,330	62.11
Seasonal Operations	9,156	42.66
Cost / (Savings)	(4,174)	(19.45)

Conclusions

1. Based on current market conditions, the most cost-effective operating mode for LRP is year-round cold standby for the foreseeable future.
2. Natural gas prices would likely need to increase from their current price of less than $3.00/MMBtu to at least $5.50/MMBtu for market prices to be high enough to justify baseload operations of LRP.
3. Converting to seasonal operations does not appear to be economically feasible based on current market prices of energy.
4. With recent increases in proven natural gas reserves and no additional pipeline development anticipated, natural gas prices in Colorado are expected to remain relatively low for the foreseeable future. Low natural gas prices would likely keep electrical energy prices relatively low, given the amount of natural gas-fired generation in the Rocky Mountain region.

5. After the existing Tri-State agreement expires in 2015, ARPA should evaluate replacement purchased power agreements and consider whether to reactivate LRP from cold standby mode.

Section VII. Demand Side Management Analysis

Introduction

DSM options were considered as a method of deferring capacity resource acquisitions. DSM options modify the customer or end-use load shape. New DSM options were considered, as were broadening of existing DSM programs offered through ARPA member communities.

Current DSM Activities

Table 9 (see page 28) lists recent DSM expenditures by the ARPA membership. While ARPA can encourage its members to participate in various DSM activities, it is ultimately the decision of the member whether or not to implement a given measure.

Table 9
Historical DSM Expenditures

Member	Service	Expenditures
Holly	Distribution tree trimming	$ 1,008
La Junta	Flag pole lighting	$ 30
	LED signs	$ 1,000
	Tree trimming	$ 9,200
Lamar	Conservation / Promo	$ 12,797
	Energy audits	$ 1,397
	Hot water heater	$ 150
	New street lights	$ 2,907
	Transformers	$ 67,617
	Tree trimming	$ 18,413
Las Animas	LED street lights	$ 4,074
	Tree trimming	$ 5,995
Springfield	None	$ -
Trinidad	None	$ -
All / ARPA (1)	Customer Education Technical Assistance	
TOTAL		**$ 124,588**

Notes:
(1) ARPA and its members provide customer education and technical assistance as needed. This includes answering customer questions, providing websites and brochures to customers, and assisting with technical questions from customers.

One DSM measure that was included in the 2007 IRP was for ARPA to implement a demand rate structure that would encourage members to pursue peak clipping strategies. ARPA's previous rate structure only included an energy rate component, which provided little incentive for members to implement strategies that reduce their annual or monthly peak demand. A demand rate structure was implemented in 2009.

Review of Load Shape Objectives

The Electric Power Research Institute (ERPI) developed six industry accepted load shape objectives:

1. Strategic Load Growth – involves promoting increased loads in all hours for utilities with surplus capacity for all periods of the year.

2. Peak Clipping – the reduction of system peak loads in order to reduce the reliance on peaking units with high fuel costs. Air conditioning load cycling is an example of a peak clipping program.

3. Strategic Conservation – directed at reducing end-use consumption through the conservation of energy and environmental resources. Strategic conservation has a levelized effect on end-use consumption; thus, has a minimal effect on peak load. An example of strategic conservation is an appliance efficiency program.

4. Valley Filling – a load management program that involves increasing off-peak loads. Street lighting is an example of a program that may build evening loads that are normally off-peak.

5. Load Shifting – involves shifting load from peak to off-peak periods. Irrigation load control and thermal energy storage systems are examples of load shifting.

6. Flexible Load Shape – involves modifying the load shape on short notice to meet demand requirements without modifying load during periods when it is not needed. Interruptible rates are an example of flexible load shape.

Based on ARPA's resources and load profile, the types of DSM most suitable are:

- Strategic conservation (summer season) to reduce end-use consumption during peak periods.
- Strategic load building (winter season) to build loads during periods of surplus energy.
- Peak clipping (summer season) to reduce peaking energy needs.

Changes in DSM Approach

Several of the DSM programs that were evaluated in 2002 and 2007 have been rendered obsolete by changes in energy efficiency standards at the federal level. For example, the new DOE standard for central air conditioners requires a minimum SEER of 13. This is 30% more efficient than the standard in 2002. Commercial lighting retrofits that were considered DSM activities in 2007 will now be required as T12 light bulbs and magnetic ballasts are phased out and replaced with T8 bulbs and electronic ballasts. Incandescent light bulbs for residential use are being phased out, beginning in 2012. Since these improved efficiency standards are now a minimum requirement, it is not necessary for ARPA member communities to spend utility funds to encourage implementing these measures. Table 10 (see page 31) lists some of the new energy efficiency standards that have been implemented since the last IRP was submitted in 2007.

Table 10
New or Revised Federal Energy Standards Implemented
Since 2007 Integrated Resource Plan

Product Regulated	Effective Date
Air Conditioners and Heat Pumps (Residential) (2)	October 25, 2011
Battery Chargers and External Power Supplies	July 1, 2008
Clothes Washers (Commercial)	January 1, 2011
Consumer Dehumidifier Products	October 1, 2012
Dishwashers (Residential)	January 1, 2010
Ice Makers (Commercial)	January 1, 2010
Motors	December 17, 2010
Distribution Transformers (Low Voltage)	January 1, 2007
Distribution Transformers (Medium Voltage, Dry-Type and Liquid-Immersed Distribution Transformers)	January 1, 2010
Packaged Air Conditioners and Heat Pumps (Commercial ≥65,000 Btu/h)	January 1, 2010
Refrigerators and Freezers (Commercial)	January 1, 2010
Single-Package Vertical Air Conditioners and Heat Pumps	January 1, 2010
Walk-in Coolers and Walk-in Freezers (Commercial)	January 1, 2009
Fluorescent Lamp Ballasts	Beginning 10/1/2009 and phasing in through 7/2010
Incandescent General-Service Lamps	Beginning 1/1/2012 and phasing in through 2014
Incandescent Reflector Lamps	June 1, 2008
Metal Halide Lamp Fixtures	January 1, 2009

(1) Source: Sixth Northwest Conservation and Electric Power Plan, Northwest Power and Conservation Council, February 2010

(2) Compliance with new standards will be required by January 1, 2015, for central air conditioners and heat pumps.

Screening Analysis

The screening analysis consisted of two steps:

1. Qualitative Screening. This step ranked the potential DSM measures according to subjective criteria, such as customer preference, market potential, and ease of implementation. A score was assigned to each DSM measure and the measures were ranked. This narrowed the list of measures to be economically evaluated.

2. Economic Feasibility. Avoided costs for capacity and energy were calculated in the supply side resource evaluation and used to calculate the costs and benefits of each DSM measure.

Qualitative Screening

The DSM technologies that satisfy ARPA members' load shape objectives were reviewed by qualitative screening. The qualitative screening involved the use of six criteria to identify those technologies most relevant to ARPA's objectives. The criteria evaluated included:

1. Costs. Costs include start-up, marketing, and equipment.

2. Customer Preferences. A customer's acceptance of a technology is determined by such factors as the customer's cost perspective, comfort level with the technology, and willingness to use the measure.

3. Environmental Impacts. DSM technologies can postpone the need to add supply-side resources that emit pollutants into the environment, but some DSM measures also have environmental impacts. For example, hazardous waste disposal will be an issue when disposing old refrigerator compressors containing CFCs and old ballasts with PCBs.

4. Market Potential. In order for the program to realize its maximum potential, intended markets and end-uses must be identified.

5. Ease of Implementation. The success of a program is heavily dependent on the relative ease of implementation. Some programs may require the simple replacement of lights or appliances, while others require major changes in the building structure.

6. Availability. The DSM technology must be commercially available and reliable. Since ARPA member communities have relatively small utility staff, it would be difficult to manage a program with high administrative burdens.

All technologies were scored from 0 to 3 according to their ability to satisfy each of the preceding criteria. Those technologies with higher total scores were considered more likely to be successful in achieving ARPA's load shape goals than those with lower scores. Tables 11 and 12 show the scores for each technology applicable to a particular customer class.

Table 11
Qualitative Screening
Residential Demand Side Measures

Technology Alternative	Cost	Customer Preference	Environmental Impact	Market Potential	Ease of Implementation	Commercial Availability/ Reliability	Total
Old Refrigerator Recycling	3	2	3	3	3	3	17
Whole-House Audits	3	2	2	3	3	3	16
High Efficiency Air Conditioners	3	2	3	2	2	3	15
Air Conditioning Load Cycling	3	1	2	3	2	3	14
Water Heater Load Shedding	3	2	2	2	2	3	14
HVAC Replacement Loans	3	1	3	2	2	2	13
Energy-Efficient New Home	2	2	3	1	2	2	12
Room Air Conditioner Rebates	1	2	2	1	1	2	9

Table 12
Qualitative Screening
Commercial/Industrial Demand Side Measures

Technology Alternative	Cost	Customer Preference	Environmental Impact	Market Potential	Ease of Implementation	Commercial Availability/ Reliability	Total
LED Street Lighting	3	3	2	3	3	2	16
High Efficiency Air Conditioners	2	3	3	3	2	2	15
HVAC Efficiency Improvement	2	3	3	3	2	2	15
Interruptible Rates	3	1	3	2	2	2	13
Customized Rebate Program	1	2	3	2	2	2	12
Process Improvement	1	1	2	1	2	2	9
Compressed Air Efficiency	1	2	2	1	1	2	9

All applicable technologies were ranked from high to low for each customer class. ARPA then selected 13 technologies for further evaluation. Any measure with a score greater than 10 was deemed to have passed the qualitative screening. The measures that passed the qualitative screening included eight residential measures and five commercial/industrial measures. This pre-screening only used qualitative factors to narrow the list of technologies that would be further evaluated. The 13 measures were then subjected to an economic evaluation.

Selected DSM Programs

The following DSM programs were selected through the screening analysis and assessed for economic feasibility.

1. Residential Central Air Conditioning Load Cycling. This DSM program requires the installation of a load-control device that will cycle off the air conditioner during summer peak load periods. ARPA does not have a large proportion of homes with central air conditioning, but there would be enough homes to achieve reasonable demand reduction. The customer incentive is estimated to be $20/year with an average load reduction of .85 kW.

2. Residential Electric Water Heater Load Shedding. A customer incentive of $20/year would be given to customers already participating in the air conditioner load cycling program and who also have their electric water heater cycled off for periods of time during summer peak load hours.

3. Residential High Efficiency Central Air Conditioners. For customers needing to replace their existing air conditioner, this program would provide rebates or incentives when ARPA members' utilities select the size of the customer's new or replacement air conditioner. The requirements include that the unit's size will not be more than 125% of design heat gain according to Manual J standards, and a minimum SEER of 16, which is more efficient than

current DOE established standards. Local contractors market high efficiency equipment, although no rebates or incentives are provided.

4. Residential Room and Window Air Conditioner Rebates. This program is for customers needing to replace their existing room or window air conditioner. Rebates of $50-$55 would be available to customers selecting a unit with a CEER that is 20% more efficient than the current minimum standard established by the DOE (CEER varies based on size).

5. Old Refrigerator Recycling Program. The purpose of this program is to remove refrigerators that are used as second units from homes and the refrigerator market. The program educates customers about the costs of the second refrigerator, and would provide a $50 incentive to customers for turning in old frost-free refrigerators that are still operable. Coordination must occur with local dealers who will dispose of the old refrigerators.

6. Improved Home Loan Program for Furnace and Air Conditioning Replacement. This program would provide a loan subsidy to customers installing properly sized high-efficiency equipment. This would be achieved by ARPA's members providing loan funds or by making a payment directly to the bank granting the loan.

7. Energy-Efficient New Home (ENERGY STAR®). Customers would receive an incentive in the form of a rebate, rate discount or a loan subsidy from the ARPA member community for building a new home to meet certain energy efficiency standards. This program requires a central air conditioner and furnace that are high efficiency and not oversized. This program also requires additional insulation, reduction of infiltration, and reduction of heat gain or loss.

8. Residential Energy Audits. Energy efficient improvements, including additional insulation, reduction of infiltration, and full basement insulation, would be assessed by a trained

energy audit specialist. Cost-effective energy efficiency measures would be identified for the homeowner.

9. Commercial High-Efficiency Air Conditioners. Small commercial customers would receive incentives for installing high-efficiency air conditioners when replacing their existing units. Examples of qualifying equipment are room air conditioners, packaged terminal units, rooftop units, and split systems.

10. Commercial HVAC Efficiency Improvement Program. Commercial and industrial customers with large cooling systems would be eligible for incentives, rebates, or loans when they reduce their electrical energy consumption of their HVAC systems. Adding cooling towers, higher efficiency cooling equipment, and energy management controls are examples of eligible improvements.

11. Large Customer Customized Rebate Program. This program would provide incentives to commercial and industrial customers who save energy in ways that are not covered by other DSM programs. Examples of eligible energy-efficiency improvements include energy-efficient motors and energy management systems as long as the energy savings would be lasting.

12. Interruptible Rates. Large industrial customers would receive a credit for interrupting all or part of their load during summer peak periods when asked to do so by an ARPA member. The customer would sign up before the summer begins and be obligated to interrupt a certain amount of their load up to 10 times during a year for periods of eight hours or less.

13. Street Lighting Conversion. This would involve replacing existing high-pressure sodium street lights with either LED or induction lights, which offer higher quality light at lower energy costs.

Economic Evaluation

Once the technical data for each DSM measure was collected, an economic evaluation was completed. The projected annual cost for each measure was compared to the projected power cost savings to calculate the net present value of the cost or savings of each measure.

The following parameters were used in the economic evaluation of DSM measures:

- The evaluation was done on a system-wide basis, meaning the analysis evaluated ARPA-wide installation of the given measure.
- Technical information for the measures was based on experience, when possible. When information from past experience was not available, updated information from local vendors and public data sources was collected.
- Avoided demand and energy costs from ARPA's existing supply side resources were used. It was assumed that summer peak demand savings were used to make excess capacity available for sale, with the summer season being defined as June-September and the winter season as October-May.
- A discount rate of 4.5% was used.
- The Total Resource Cost test was used. This compared the total costs of the measure, including costs incurred by ARPA or the end-user, to the total cost savings realized by ARPA.

The economic evaluation considered the installation, O&M, and administrative and general expenses that would be incurred over the life of the measure. DSM expenses were compared to ARPA's avoided capacity and energy cost, and the net cost or savings to ARPA was calculated on an annual basis and discounted to 2013 dollars. Measures with a positive net present value were considered economically feasible.

A summary of the economic evaluations are shown in Tables 13 and 14. The analysis of each individual DSM measure is shown in Appendix A.

Table 13
Impact of Demand Side Measures Alternatives - Residential

Impact of DSM Alternatives	Net Present Value 2013 $		
	5-Year	10-Year	Life
Air Conditioning Load Cycling	$ (371,431)	$ (407,958)	$ (483,482)
Water Heater Load Shedding	$ (366,075)	$ (407,492)	$ (507,242)
High Efficiency Air Conditioners	$ (367,451)	$ (327,870)	$ (256,795)
Old Refrigerator Recycling	$ (45,721)	$ (27,164)	$ 6,324
HVAC Replacement Loans	$ (441,217)	$ (409,144)	$ (349,889)
Whole-House Audits	$ (663,697)	$ (518,437)	$ (383,014)

Table 14
Impact of Demand Side Measures Alternatives - Commercial/Industrial

Impact of DSM Alternatives	Net Present Value 2013 $		
	5-Year	10-Year	Life
Interruptible Rates	$ (70,937)	$ (77,467)	$ (89,193)
LED Street Lighting	$ (390,481)	$ (206,908)	$ (39,249)
High Efficiency Air Conditioners	$ (187,709)	$ (150,693)	$ (84,225)
HVAC Efficiency Improvement	$ (158,465)	$ (138,431)	$ (102,458)
Customized Rebate Program	$ (482,313)	$ (285,461)	$ (99,640)

It appears the only DSM measure that was economically feasible was a refrigerator disposal program. ARPA's marginal power supply costs are relatively low, based on low natural gas prices and a surplus of capacity and energy in the region. These low marginal costs eliminate many DSM measures that have been implemented by other utilities. ARPA member communities should consider offering a refrigerator disposal program and consider working with local refuse companies or appliance dealers to ensure proper disposal. In addition, ARPA member communities should continue low-cost DSM options, such as promoting energy efficiency via the ARPA and local member community website and customer newsletters.

One measure that should be re-evaluated on a regular basis is high-efficiency street lighting. The capital cost for LED street lighting has decreased dramatically since the last IRP. It has been shown to be cost-effective in a number of municipalities, particularly if energy costs are high or if grant funding is available to offset a portion of the capital costs. There are a number of grant programs available to help fund efficient street lighting, including from the Department of Energy and United States Department of Agriculture. Some of ARPA's members have installed high-efficiency street lighting in the last five years, based on the capital cost and energy savings from installing the measure.

Section VIII. Supply/Demand Side Resource Integration

Development of Integrated Resource Plan

Implementation of a refrigerator disposal program and potential implementation of high-efficiency street lighting would have negligible impact on resource additions or the other supply-side plans identified in the supply-side evaluation. Peak demand savings of this measure would reduce ARPA members' peak demand by much less than 1 MW, which is typically the smallest sized resource increment considered.

Preferred Alternative

Based on the analyses prepared, it appears ARPA and its members should take the following steps:

1. Place LRP into cold standby mode.
2. Evaluate purchased power arrangements in 2015 when the existing Tri-State agreement expires and consider reactivating LRP based on then-current market conditions.
3. Encourage ARPA members to implement an old refrigerator disposal / recycling program to reduce energy consumption.

4. Consider high efficiency street lighting based on a life-cycle economic comparison, particularly as capital costs associated with induction or LED street lights decrease.

Environmental Impacts

ARPA and its members comply with all applicable provisions of state and federal environmental regulations at its power plants and substation facilities. Any new projects would include emissions control technology as required to help reduce environmental impacts. Encouraging DSM through no cost or low cost methods would reduce energy usage and emissions. Implementing a refrigerator disposal program would reduce future energy usage. Any refrigerator disposal program would comply with environmental rules for disposal of hazardous materials.

One other key component of ARPA's efforts to minimize environmental impact has been its wind energy purchase program. More than 6% of ARPA's energy comes from wind energy, and the percentage will be higher after the termination of Raton's agreement in 2013. These purchases were undertaken voluntarily without a renewable portfolio standard requirement at the state or local level.

ARPA's allocation of capacity and energy from WAPA is a clean, renewable resource. Steps are continually taken to ensure that this resource is available and that the contract provisions (including compliance with EPAMP) are followed.

Section IX. Action Plans

To the extent that costs for power supply resources, DSM and transmission change, ARPA should review and modify this action plan accordingly. Based on the assumptions used, analyses completed and conclusions reached in this study, the following action plans are recommended. The plans outline near-term and longer-term recommendations.

Two Year

- Consider placing LRP into a cold standby condition, where it could be reactivated with reasonable notice based on changes in market conditions.
- Purchase market-priced energy under the agreement with Tri-State.
- Investigate replacement purchased power agreements as the end of the current agreement with Tri-State approaches. Options may include purchasing energy from Tri-State or any of a number of other of wholesale providers in the region. These may include vertically integrated investor-owned utilities like Xcel Energy or Black Hills Energy, power marketing firms that are active in the area, and other public power utilities like Colorado Springs Utilities or Platte River Power Authority.
- ARPA members should consider implementing a refrigerator recycling program to retire old, inefficient refrigerators.
- Continue to investigate high-efficiency street light fixtures, particularly as the capital cost for LED or induction lighting decreases.

Five Year

- Continue actions from Two Year action plan.
- Continue to evaluate the cost of market-priced energy relative to operating LRP and consider reactivating the plant from cold standby if market prices increase.
- Evaluate other supply-side and demand-side alternatives that may become commercially feasible.

Public Participation

Part of the IRP implementation process involves public participation. ARPA has involved the public in developing the IRP and will continue to solicit public participation as it implements the IRP.

ARPA's monthly Board of Directors meetings are open to the public and a notice of the meeting is published in advance along with the agenda. The monthly agenda solicited public comments on the ARPA IRP process at its February and March meetings, prior to the publication of the draft IRP (see Appendix B – February 2012 Public Notice, February 2012 Agenda, March 2012 Public Notice, March 2012 Agenda, Public Comment Solicitation). No public comments were received.

A draft of the IRP was presented at a public hearing held in La Junta, Colorado, on April 26, 2012, as part of the regularly monthly ARPA Board meeting (see Appendix B – April 2012 Agenda). A notice of the public hearing appeared along with the publication of the meeting notice (see Appendix B – April 2012 Public Notice). The purpose of this hearing was to provide information to and gather input from groups and individuals with an interest in ARPA's Integrated Resource Plan. Public comments were solicited immediately after the presentation and for 10 working days after the hearing. Despite the encouragement for public participation, no members of the general public attended the hearing nor was there any comments received from the general public. The final version of the IRP was provided to member municipalities via copies to their ARPA Board representatives. On May 31, 2012, the ARPA Board adopted a Resolution approving this 2012 IRP (see Appendix B – May 2012 Public Notice, May 2012 Agenda, May 2012 Resolution).

Measurement Strategies and Annual Updates

ARPA compares its load forecasts to actual usage on an annual and monthly basis. This comparison will be continually updated in the future. In addition, ARPA will continue to verify the effectiveness of DSM programs in its annual updates to this IRP. Annual information submittals to Western will continue to be submitted as they have been historically. The format of these submittals will be similar to past submittals.

Appendix A

DSM Program Name: Air Conditioning Load Cycling
Customer Class: Residential

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	0.85	-	
Annual Energy Usage			
Energy Savings (%)			0%
Energy Savings (kWh per unit)			10

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	39.00
Rate Escalation (%/yr)	3.00%
Measure Life	25
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	2,000.00
Capital Cost ($/unit)	125.00
Maintenance Cost ($/year/unit)	13.38
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Residential Customers	13,115
Estimated Application Saturation	50%
Market Eligibility	40%
Feasibility	100%
Estimated Units	2,623

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-mon)	Annual Energy Charge ($/MWh)	Power Cost Savings ($)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	2,230	-	26,230	12.00	-	39.00	27,777.57	327,875.00	37,095.74	(337,193.17)	(337,193.17)
2014	2,230	-	26,230	12.36	-	40.17	28,610.90	-	38,023.13	(9,412.24)	(9,006.92)
2015	2,230	-	26,230	12.73	-	41.38	29,469.22	-	38,973.71	(9,504.49)	(8,703.54)
2016	2,230	-	26,230	13.11	-	42.62	30,353.30	-	39,948.05	(9,594.75)	(8,407.85)
2017	2,230	-	26,230	13.51	-	43.89	31,263.90	-	40,946.76	(9,682.86)	(8,119.67)
2018	2,230	-	26,230	13.91	-	45.21	32,201.82	-	41,970.42	(9,768.61)	(7,838.83)
2019	2,230	-	26,230	14.33	-	46.57	33,167.87	-	43,019.69	(9,851.81)	(7,565.17)
2020	2,230	-	26,230	14.76	-	47.97	34,162.91	-	44,095.18	(9,932.27)	(7,298.51)
2021	2,230	-	26,230	15.20	-	49.40	35,187.79	-	45,197.56	(10,009.76)	(7,038.72)
2022	2,230	-	26,230	15.66	-	50.89	36,243.43	-	46,327.50	(10,084.07)	(6,785.61)
2023	2,230	-	26,230	16.13	-	52.41	37,330.73	-	47,485.68	(10,154.95)	(6,539.05)
2024	2,230	-	26,230	16.61	-	53.99	38,450.65	-	48,672.83	(10,222.17)	(6,298.89)
2025	2,230	-	26,230	17.11	-	55.60	39,604.17	-	49,889.65	(10,285.47)	(6,064.97)
2026	2,230	-	26,230	17.62	-	57.27	40,792.30	-	51,136.89	(10,344.59)	(5,837.16)
2027	2,230	-	26,230	18.15	-	58.99	42,016.07	-	52,415.31	(10,399.24)	(5,615.31)
2028	2,230	-	26,230	18.70	-	60.76	43,276.55	-	53,725.69	(10,449.14)	(5,399.29)
2029	2,230	-	26,230	19.26	-	62.58	44,574.85	-	55,068.83	(10,493.99)	(5,188.96)
2030	2,230	-	26,230	19.83	-	64.46	45,912.09	-	56,445.56	(10,533.46)	(4,984.19)
2031	2,230	-	26,230	20.43	-	66.39	47,289.45	-	57,856.69	(10,567.24)	(4,784.85)
2032	2,230	-	26,230	21.04	-	68.39	48,708.14	-	59,303.11	(10,594.97)	(4,590.82)
2033	2,230	-	26,230	21.67	-	70.44	50,169.38	-	60,785.69	(10,616.31)	(4,401.98)
2034	2,230	-	26,230	22.32	-	72.55	51,674.46	-	62,305.33	(10,630.87)	(4,218.20)
2035	2,230	-	26,230	22.99	-	74.73	53,224.70	-	63,862.96	(10,638.27)	(4,039.36)
2036	2,230	-	26,230	23.68	-	76.97	54,821.44	-	65,459.54	(10,638.10)	(3,865.36)
2037	2,230	-	26,230	24.39	-	79.28	56,466.08	-	67,096.03	(10,629.95)	(3,696.07)

NPV in 2013	**Five Year**	(371,431.16)
	Ten Year	(407,958.00)
	Life	(483,482.44)

DSM Program Name: Water Heater Load Shedding
Customer Class: Residential

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	0.45	-	
Annual Energy Usage			
Energy Savings (%)			0%
Energy Savings (kWh per unit)			5

Program Costs	Amount
Admin Cost (total $/year)	2,000.00
Capital Cost ($/unit)	325.00
Maintenance Cost ($/year/unit)	13.38
Cost Escalation (%/year)	2.50%

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	25
Discount Rate	4.50%

Estimated Applicability	Amount
Estimated Residential Customers	13,115
Estimated Application Saturation	15%
Market Eligibility	50%
Feasibility	100%
Estimated Units	984

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-mon)	Annual Energy Charge ($/MWh)	Power Cost Savings ($)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	443	-	4,920	12.00	-	37.25	5,496.87	319,800.00	15,165.92	(329,469.05)	(329,469.05)
2014	443	-	4,920	12.36	-	38.37	5,661.78	-	15,545.07	(9,883.29)	(9,457.70)
2015	443	-	4,920	12.73	-	39.52	5,831.63	-	15,933.69	(10,102.07)	(9,250.76)
2016	443	-	4,920	13.11	-	40.70	6,006.58	-	16,332.04	(10,325.46)	(9,048.16)
2017	443	-	4,920	13.51	-	41.93	6,186.78	-	16,740.34	(10,553.56)	(8,849.81)
2018	443	-	4,920	13.91	-	43.18	6,372.38	-	17,158.85	(10,786.47)	(8,655.61)
2019	443	-	4,920	14.33	-	44.48	6,563.55	-	17,587.82	(11,024.27)	(8,465.49)
2020	443	-	4,920	14.76	-	45.81	6,760.46	-	18,027.51	(11,267.06)	(8,279.35)
2021	443	-	4,920	15.20	-	47.19	6,963.27	-	18,478.20	(11,514.93)	(8,097.13)
2022	443	-	4,920	15.66	-	48.60	7,172.17	-	18,940.16	(11,767.99)	(7,918.73)
2023	443	-	4,920	16.13	-	50.06	7,387.33	-	19,413.66	(12,026.33)	(7,744.08)
2024	443	-	4,920	16.61	-	51.56	7,608.95	-	19,899.00	(12,290.05)	(7,573.11)
2025	443	-	4,920	17.11	-	53.11	7,837.22	-	20,396.48	(12,559.25)	(7,405.74)
2026	443	-	4,920	17.62	-	54.70	8,072.34	-	20,906.39	(12,834.05)	(7,241.89)
2027	443	-	4,920	18.15	-	56.34	8,314.51	-	21,429.05	(13,114.54)	(7,081.50)
2028	443	-	4,920	18.70	-	58.03	8,563.94	-	21,964.77	(13,400.83)	(6,924.48)
2029	443	-	4,920	19.26	-	59.78	8,820.86	-	22,513.89	(13,693.03)	(6,770.78)
2030	443	-	4,920	19.83	-	61.57	9,085.49	-	23,076.74	(13,991.25)	(6,620.33)
2031	443	-	4,920	20.43	-	63.42	9,358.05	-	23,653.66	(14,295.61)	(6,473.06)
2032	443	-	4,920	21.04	-	65.32	9,638.79	-	24,245.00	(14,606.21)	(6,328.90)
2033	443	-	4,920	21.67	-	67.28	9,927.96	-	24,851.13	(14,923.17)	(6,187.78)
2034	443	-	4,920	22.32	-	69.30	10,225.80	-	25,472.40	(15,246.61)	(6,049.66)
2035	443	-	4,920	22.99	-	71.37	10,532.57	-	26,109.21	(15,576.64)	(5,914.47)
2036	443	-	4,920	23.68	-	73.52	10,848.55	-	26,761.94	(15,913.40)	(5,782.13)
2037	443	-	4,920	24.39	-	75.72	11,174.00	-	27,430.99	(16,256.99)	(5,652.61)

NPV in 2013		
	Five Year	(366,075.48)
	Ten Year	(407,491.80)
	Life	(507,242.32)

DSM Program Name: High Efficiency Air Conditioners
Customer Class: Residential

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	0.60	-	
Annual Energy Usage			
Energy Savings (%)			0%
Energy Savings (kWh per unit)			500

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	39.00
Rate Escalation (%/yr)	3.00%
Measure Life	20
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	-
Capital Cost ($/unit)	1,250.00
Maintenance Cost ($/year/unit)	-
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Residential Customers	13,115
Estimated Application Saturation	50%
Market Eligibility	5%
Feasibility	100%
Estimated Units	328

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-mon)	Annual Energy Charge ($/MWh)	Power Cost Savings ($)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	197	-	164,000	12.00	-	39.00	8,757.60	410,000.00	-	(401,242.40)	(401,242.40)
2014	197	-	164,000	12.36	-	40.17	9,020.33	-	-	9,020.33	8,631.89
2015	197	-	164,000	12.73	-	41.38	9,290.94	-	-	9,290.94	8,507.99
2016	197	-	164,000	13.11	-	42.62	9,569.67	-	-	9,569.67	8,385.87
2017	197	-	164,000	13.51	-	43.89	9,856.76	-	-	9,856.76	8,265.49
2018	197	-	164,000	13.91	-	45.21	10,152.46	-	-	10,152.46	8,146.85
2019	197	-	164,000	14.33	-	46.57	10,457.03	-	-	10,457.03	8,029.91
2020	197	-	164,000	14.76	-	47.97	10,770.74	-	-	10,770.74	7,914.65
2021	197	-	164,000	15.20	-	49.40	11,093.87	-	-	11,093.87	7,801.04
2022	197	-	164,000	15.66	-	50.89	11,426.68	-	-	11,426.68	7,689.06
2023	197	-	164,000	16.13	-	52.41	11,769.48	-	-	11,769.48	7,578.70
2024	197	-	164,000	16.61	-	53.99	12,122.57	-	-	12,122.57	7,469.91
2025	197	-	164,000	17.11	-	55.60	12,486.24	-	-	12,486.24	7,362.69
2026	197	-	164,000	17.62	-	57.27	12,860.83	-	-	12,860.83	7,257.00
2027	197	-	164,000	18.15	-	58.99	13,246.66	-	-	13,246.66	7,152.83
2028	197	-	164,000	18.70	-	60.76	13,644.06	-	-	13,644.06	7,050.16
2029	197	-	164,000	19.26	-	62.58	14,053.38	-	-	14,053.38	6,948.96
2030	197	-	164,000	19.83	-	64.46	14,474.98	-	-	14,474.98	6,849.22
2031	197	-	164,000	20.43	-	66.39	14,909.23	-	-	14,909.23	6,750.90
2032	197	-	164,000	21.04	-	68.39	15,356.50	-	-	15,356.50	6,654.00

NPV in 2013	**Five Year**	(367,451.16)
	Ten Year	(327,869.64)
	Life	(256,795.26)

DSM Program Name: Old Refrigerator Recycling
Customer Class: Residential

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	0.065	0.065	
Annual Energy Usage			
Energy Savings (%)			0%
Energy Savings (kWh per unit)			171

Program Costs	Amount
Admin Cost (total $/year)	600.00
Capital Cost ($/unit)	100.00
Maintenance Cost ($/year/unit)	-
Cost Escalation (%/year)	2.50%

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	20
Discount Rate	4.50%

Estimated Applicability	Amount
Estimated Residential Customers	13,115
Estimated Application Saturation	5%
Market Eligibility	100%
Feasibility	100%
Estimated Units	656

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-mon)	Annual Energy Charge ($/MWh)	Power Cost Savings ($)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	43	43	112,058	12.00	-	37.25	4,685.84	65,600.00	600.00	(61,514.16)	(61,514.16)
2014	43	43	112,058	12.36	-	38.37	4,826.41	-	615.00	4,211.41	4,030.06
2015	43	43	112,058	12.73	-	39.52	4,971.21	-	630.38	4,340.83	3,975.03
2016	43	43	112,058	13.11	-	40.70	5,120.34	-	646.13	4,474.21	3,920.73
2017	43	43	112,058	13.51	-	41.93	5,273.95	-	662.29	4,611.66	3,867.16
2018	43	43	112,058	13.91	-	43.18	5,432.17	-	678.84	4,753.33	3,814.31
2019	43	43	112,058	14.33	-	44.48	5,595.14	-	695.82	4,899.32	3,762.17
2020	43	43	112,058	14.76	-	45.81	5,762.99	-	713.21	5,049.78	3,710.72
2021	43	43	112,058	15.20	-	47.19	5,935.88	-	731.04	5,204.84	3,659.96
2022	43	43	112,058	15.66	-	48.60	6,113.96	-	749.32	5,364.64	3,609.89
2023	43	43	112,058	16.13	-	50.06	6,297.37	-	768.05	5,529.32	3,560.48
2024	43	43	112,058	16.61	-	51.56	6,486.30	-	787.25	5,699.04	3,511.74
2025	43	43	112,058	17.11	-	53.11	6,680.88	-	806.93	5,873.95	3,463.66
2026	43	43	112,058	17.62	-	54.70	6,881.31	-	827.11	6,054.20	3,416.22
2027	43	43	112,058	18.15	-	56.34	7,087.75	-	847.78	6,239.97	3,369.41
2028	43	43	112,058	18.70	-	58.03	7,300.38	-	868.98	6,431.40	3,323.24
2029	43	43	112,058	19.26	-	59.78	7,519.39	-	890.70	6,628.69	3,277.68
2030	43	43	112,058	19.83	-	61.57	7,744.98	-	912.97	6,832.00	3,232.74
2031	43	43	112,058	20.43	-	63.42	7,977.32	-	935.80	7,041.53	3,188.41
2032	43	43	112,058	21.04	-	65.32	8,216.64	-	959.19	7,257.45	3,144.67

NPV in 2013		
	Five Year	(45,721.18)
	Ten Year	(27,164.13)
	Life	6,324.12

DSM Program Name: HVAC Replacement Loans
Customer Class: Residential

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	0.50	0.50	
Annual Energy Usage			
Energy Savings (%)			0%
Energy Savings (kWh per unit)			750

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	20
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	6,000.00
Capital Cost ($/unit)	1,250.00
Maintenance Cost ($/year/unit)	-
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Residential Customers	13,115
Estimated Application Saturation	50%
Market Eligibility	6%
Feasibility	100%
Estimated Units	380

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-mon)	Annual Energy Charge ($/MWh)	Power Cost Savings ($)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	190	190	285,000	12.00	-	37.25	12,896.25	475,000.00	6,000.00	(468,103.75)	(468,103.75)
2014	190	190	285,000	12.36	-	38.37	13,283.14	-	6,150.00	7,133.14	6,825.97
2015	190	190	285,000	12.73	-	39.52	13,681.63	-	6,303.75	7,377.88	6,756.15
2016	190	190	285,000	13.11	-	40.70	14,092.08	-	6,461.34	7,630.74	6,686.79
2017	190	190	285,000	13.51	-	41.93	14,514.84	-	6,622.88	7,891.97	6,617.90
2018	190	190	285,000	13.91	-	43.18	14,950.29	-	6,788.45	8,161.84	6,549.48
2019	190	190	285,000	14.33	-	44.48	15,398.80	-	6,958.16	8,440.64	6,481.53
2020	190	190	285,000	14.76	-	45.81	15,860.76	-	7,132.11	8,728.65	6,414.06
2021	190	190	285,000	15.20	-	47.19	16,336.58	-	7,310.42	9,026.17	6,347.07
2022	190	190	285,000	15.66	-	48.60	16,826.68	-	7,493.18	9,333.50	6,280.56
2023	190	190	285,000	16.13	-	50.06	17,331.48	-	7,680.51	9,650.97	6,214.53
2024	190	190	285,000	16.61	-	51.56	17,851.43	-	7,872.52	9,978.91	6,148.99
2025	190	190	285,000	17.11	-	53.11	18,386.97	-	8,069.33	10,317.64	6,083.94
2026	190	190	285,000	17.62	-	54.70	18,938.58	-	8,271.07	10,667.51	6,019.37
2027	190	190	285,000	18.15	-	56.34	19,506.74	-	8,477.84	11,028.89	5,955.30
2028	190	190	285,000	18.70	-	58.03	20,091.94	-	8,689.79	11,402.15	5,891.72
2029	190	190	285,000	19.26	-	59.78	20,694.70	-	8,907.03	11,787.66	5,828.64
2030	190	190	285,000	19.83	-	61.57	21,315.54	-	9,129.71	12,185.83	5,766.05
2031	190	190	285,000	20.43	-	63.42	21,955.00	-	9,357.95	12,597.05	5,703.95
2032	190	190	285,000	21.04	-	65.32	22,613.65	-	9,591.90	13,021.75	5,642.35
2033	-	-	-	21.67	-	67.28	-	-	-	-	-
2034	-	-	-	22.32	-	69.30	-	-	-	-	-
2035	-	-	-	22.99	-	71.37	-	-	-	-	-
2036	-	-	-	23.68	-	73.52	-	-	-	-	-
2037	-	-	-	24.39	-	75.72	-	-	-	-	-
2038	-	-	-	25.13	-	77.99	-	-	-	-	-
2039	-	-	-	25.88	-	80.33	-	-	-	-	-
2040	-	-	-	26.66	-	82.74	-	-	-	-	-
2041	-	-	-	27.46	-	85.23	-	-	-	-	-
2042	-	-	-	28.28	-	87.78	-	-	-	-	-

NPV in 2013 $	Five Year	(441,216.95)
	Ten Year	(409,144.26)
	Life	(349,889.43)

DSM Program Name: Whole-House Audits
Customer Class: Residential

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	0.15	0.15	
Annual Energy Usage			
Energy Savings (%)			0%
Energy Savings (kWh per unit)			526

Program Costs	Amount
Admin Cost (total $/year)	3,000.00
Capital Cost ($/unit)	500.00
Maintenance Cost ($/year/unit)	-
Cost Escalation (%/year)	2.50%

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	15
Discount Rate	4.50%

Estimated Applicability	Amount
Estimated Residential Customers	13,115
Estimated Application Saturation	50%
Market Eligibility	25%
Feasibility	100%
Estimated Units	1639

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-mon)	Annual Energy Charge ($/MWh)	Power Cost Savings ($)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	246	246	861,458	12.00	-	37.25	35,039.53	819,500.00	3,000.00	(787,460.47)	(787,460.47)
2014	246	246	861,458	12.36	-	38.37	36,090.71	-	3,075.00	33,015.71	31,593.98
2015	246	246	861,458	12.73	-	39.52	37,173.43	-	3,151.88	34,021.56	31,154.56
2016	246	246	861,458	13.11	-	40.70	38,288.64	-	3,230.67	35,057.96	30,721.17
2017	246	246	861,458	13.51	-	41.93	39,437.29	-	3,311.44	36,125.86	30,293.75
2018	246	246	861,458	13.91	-	43.18	40,620.41	-	3,394.22	37,226.19	29,872.19
2019	246	246	861,458	14.33	-	44.48	41,839.03	-	3,479.08	38,359.95	29,456.44
2020	246	246	861,458	14.76	-	45.81	43,094.20	-	3,566.06	39,528.14	29,046.40
2021	246	246	861,458	15.20	-	47.19	44,387.02	-	3,655.21	40,731.81	28,642.01
2022	246	246	861,458	15.66	-	48.60	45,718.63	-	3,746.59	41,972.04	28,243.17
2023	246	246	861,458	16.13	-	50.06	47,090.19	-	3,840.25	43,249.94	27,849.83
2024	246	246	861,458	16.61	-	51.56	48,502.90	-	3,936.26	44,566.64	27,461.91
2025	246	246	861,458	17.11	-	53.11	49,957.98	-	4,034.67	45,923.32	27,079.32
2026	246	246	861,458	17.62	-	54.70	51,456.72	-	4,135.53	47,321.19	26,702.01
2027	246	246	861,458	18.15	-	56.34	53,000.43	-	4,238.92	48,761.50	26,329.89

NPV in 2013	**Five Year**	(663,697.01)
	Ten Year	(518,436.80)
	Life	(383,013.84)

DSM Program Name: Interruptible Rates
Customer Class: Commercial

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	30	30	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			1,500

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	30
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	6,000.00
Capital Cost ($/unit)	2,500.00
Maintenance Cost ($/year/unit)	250.00
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Industrial Customers	99
Estimated Appliance Saturation	100%
Market Eligibility	25%
Feasibility	100%
Estimated Units	25

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-yr)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	750	750	37,500	12.00	-	37.25	10,396.88	62,500.00	12,250.00	(64,353.13)	(64,353.13)
2014	750	750	37,500	12.36	-	38.37	10,708.78	-	12,556.25	(1,847.47)	(1,767.91)
2015	750	750	37,500	12.73	-	39.52	11,030.04	-	12,870.16	(1,840.11)	(1,685.05)
2016	750	750	37,500	13.11	-	40.70	11,360.95	-	13,191.91	(1,830.96)	(1,604.47)
2017	750	750	37,500	13.51	-	41.93	11,701.77	-	13,521.71	(1,819.93)	(1,526.13)
2018	750	750	37,500	13.91	-	43.18	12,052.83	-	13,859.75	(1,806.92)	(1,449.97)
2019	750	750	37,500	14.33	-	44.48	12,414.41	-	14,206.24	(1,791.83)	(1,375.94)
2020	750	750	37,500	14.76	-	45.81	12,786.84	-	14,561.40	(1,774.56)	(1,303.99)
2021	750	750	37,500	15.20	-	47.19	13,170.45	-	14,925.44	(1,754.99)	(1,234.08)
2022	750	750	37,500	15.66	-	48.60	13,565.56	-	15,298.57	(1,733.01)	(1,166.15)
2023	750	750	37,500	16.13	-	50.06	13,972.53	-	15,681.04	(1,708.51)	(1,100.15)
2024	750	750	37,500	16.61	-	51.56	14,391.71	-	16,073.06	(1,681.36)	(1,036.05)
2025	750	750	37,500	17.11	-	53.11	14,823.46	-	16,474.89	(1,651.43)	(973.79)
2026	750	750	37,500	17.62	-	54.70	15,268.16	-	16,886.76	(1,618.60)	(913.33)
2027	750	750	37,500	18.15	-	56.34	15,726.21	-	17,308.93	(1,582.72)	(854.63)
2028	750	750	37,500	18.70	-	58.03	16,197.99	-	17,741.65	(1,543.66)	(797.64)
2029	750	750	37,500	19.26	-	59.78	16,683.93	-	18,185.19	(1,501.26)	(742.33)
2030	750	750	37,500	19.83	-	61.57	17,184.45	-	18,639.82	(1,455.37)	(688.65)
2031	750	750	37,500	20.43	-	63.42	17,699.98	-	19,105.82	(1,405.84)	(636.56)
2032	750	750	37,500	21.04	-	65.32	18,230.98	-	19,583.46	(1,352.48)	(586.03)
2033	750	750	37,500	21.67	-	67.28	18,777.91	-	20,073.05	(1,295.14)	(537.02)
2034	750	750	37,500	22.32	-	69.30	19,341.25	-	20,574.88	(1,233.63)	(489.49)
2035	750	750	37,500	22.99	-	71.37	19,921.49	-	21,089.25	(1,167.76)	(443.40)
2036	750	750	37,500	23.68	-	73.52	20,519.13	-	21,616.48	(1,097.35)	(398.72)
2037	750	750	37,500	24.39	-	75.72	21,134.71	-	22,156.89	(1,022.19)	(355.42)
2038	750	750	37,500	25.13	-	77.99	21,768.75	-	22,710.82	(942.07)	(313.45)
2039	750	750	37,500	25.88	-	80.33	22,421.81	-	23,278.59	(856.78)	(272.80)
2040	750	750	37,500	26.66	-	82.74	23,094.46	-	23,860.55	(766.09)	(233.42)
2041	750	750	37,500	27.46	-	85.23	23,787.30	-	24,457.06	(669.77)	(195.28)
2042	750	750	37,500	28.28	-	87.78	24,500.92	-	25,068.49	(567.57)	(158.36)

NPV in 2013 $ Five Year	(70,936.68)
Ten Year	(77,466.81)
Life	(89,193.33)

DSM Program Name: LED Street Lighting
Customer Class: Commercial

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	-	0.10	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			400

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	27.00
Rate Escalation (%/yr)	3.00%
Measure Life	15
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	
Capital Cost ($/unit)	650.00
Maintenance Cost ($/year/unit)	(35.00)
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Streetlight Fixtures	1,300
Estimated Appliance Saturation	100%
Market Eligibility	100%
Feasibility	70%
Estimated Units	910

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-yr)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	-	91	364,000	12.00	-	27.00	9,828.00	591,500.00	(31,850.00)	(549,822.00)	(549,822.00)
2014	-	91	364,000	12.36	-	27.81	10,122.84	-	(32,646.25)	42,769.09	40,927.36
2015	-	91	364,000	12.73	-	28.64	10,426.53	-	(33,462.41)	43,888.93	40,190.41
2016	-	91	364,000	13.11	-	29.50	10,739.32	-	(34,298.97)	45,038.29	39,466.90
2017	-	91	364,000	13.51	-	30.39	11,061.50	-	(35,156.44)	46,217.94	38,756.58
2018	-	91	364,000	13.91	-	31.30	11,393.35	-	(36,035.35)	47,428.70	38,059.21
2019	-	91	364,000	14.33	-	32.24	11,735.15	-	(36,936.24)	48,671.38	37,374.55
2020	-	91	364,000	14.76	-	33.21	12,087.20	-	(37,859.64)	49,946.84	36,702.36
2021	-	91	364,000	15.20	-	34.20	12,449.82	-	(38,806.13)	51,255.95	36,042.42
2022	-	91	364,000	15.66	-	35.23	12,823.31	-	(39,776.29)	52,599.60	35,394.50
2023	-	91	364,000	16.13	-	36.29	13,208.01	-	(40,770.69)	53,978.70	34,758.38
2024	-	91	364,000	16.61	-	37.37	13,604.25	-	(41,789.96)	55,394.21	34,133.84
2025	-	91	364,000	17.11	-	38.50	14,012.38	-	(42,834.71)	56,847.09	33,520.67
2026	-	91	364,000	17.62	-	39.65	14,432.75	-	(43,905.58)	58,338.33	32,918.66
2027	-	91	364,000	18.15	-	40.84	14,865.73	-	(45,003.22)	59,868.95	32,327.61

NPV in 2013 $ Five Year	(390,480.75)
Ten Year	(206,907.72)
Life	(39,248.55)

DSM Program Name: High Efficiency Air Conditioners
Customer Class: Commercial/Industrial

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	1	-	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			2,000

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	39.00
Rate Escalation (%/yr)	3.00%
Measure Life	20
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	-
Capital Cost ($/unit)	2,500.00
Maintenance Cost ($/year/unit)	-
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Commercial/Industrial Customers	3,647
Estimated Appliance Saturation	100%
Market Eligibility	10%
Feasibility	25%
Estimated Units	91

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-yr)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	91	-	182,000	12.00	-	39.00	8,190.00	227,500.00	-	(219,310.00)	(219,310.00)
2014	91	-	182,000	12.36	-	40.17	8,435.70	-	-	8,435.70	8,072.44
2015	91	-	182,000	12.73	-	41.38	8,688.77	-	-	8,688.77	7,956.57
2016	91	-	182,000	13.11	-	42.62	8,949.43	-	-	8,949.43	7,842.36
2017	91	-	182,000	13.51	-	43.89	9,217.92	-	-	9,217.92	7,729.79
2018	91	-	182,000	13.91	-	45.21	9,494.45	-	-	9,494.45	7,618.84
2019	91	-	182,000	14.33	-	46.57	9,779.29	-	-	9,779.29	7,509.47
2020	91	-	182,000	14.76	-	47.97	10,072.67	-	-	10,072.67	7,401.68
2021	91	-	182,000	15.20	-	49.40	10,374.85	-	-	10,374.85	7,295.44
2022	91	-	182,000	15.66	-	50.89	10,686.09	-	-	10,686.09	7,190.72
2023	91	-	182,000	16.13	-	52.41	11,006.68	-	-	11,006.68	7,087.50
2024	91	-	182,000	16.61	-	53.99	11,336.88	-	-	11,336.88	6,985.77
2025	91	-	182,000	17.11	-	55.60	11,676.98	-	-	11,676.98	6,885.49
2026	91	-	182,000	17.62	-	57.27	12,027.29	-	-	12,027.29	6,786.66
2027	91	-	182,000	18.15	-	58.99	12,388.11	-	-	12,388.11	6,689.24
2028	91	-	182,000	18.70	-	60.76	12,759.75	-	-	12,759.75	6,593.23
2029	91	-	182,000	19.26	-	62.58	13,142.55	-	-	13,142.55	6,498.59
2030	91	-	182,000	19.83	-	64.46	13,536.82	-	-	13,536.82	6,405.30
2031	91	-	182,000	20.43	-	66.39	13,942.93	-	-	13,942.93	6,313.36
2032	91	-	182,000	21.04	-	68.39	14,361.21	-	-	14,361.21	6,222.74

NPV in 2013 $	**Five Year**	(187,708.84)
	Ten Year	(150,692.70)
	Life	(84,224.81)

DSM Program Name: HVAC Efficiency Improvement
Customer Class: Commercial/Industrial

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	5	5	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			5,000

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	20
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	-
Capital Cost ($/unit)	10,000.00
Maintenance Cost ($/year/unit)	-
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Commercial/Industrial Customers	3,647
Estimated Appliance Saturation	100%
Market Eligibility	5%
Feasibility	10%
Estimated Units	18

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-yr)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	90	90	90,000	12.00	-	37.25	4,432.50	180,000.00	-	(175,567.50)	(175,567.50)
2014	90	90	90,000	12.36	-	38.37	4,565.48	-	-	4,565.48	4,368.88
2015	90	90	90,000	12.73	-	39.52	4,702.44	-	-	4,702.44	4,306.16
2016	90	90	90,000	13.11	-	40.70	4,843.51	-	-	4,843.51	4,244.35
2017	90	90	90,000	13.51	-	41.93	4,988.82	-	-	4,988.82	4,183.43
2018	90	90	90,000	13.91	-	43.18	5,138.48	-	-	5,138.48	4,123.38
2019	90	90	90,000	14.33	-	44.48	5,292.64	-	-	5,292.64	4,064.19
2020	90	90	90,000	14.76	-	45.81	5,451.42	-	-	5,451.42	4,005.86
2021	90	90	90,000	15.20	-	47.19	5,614.96	-	-	5,614.96	3,948.36
2022	90	90	90,000	15.66	-	48.60	5,783.41	-	-	5,783.41	3,891.68
2023	90	90	90,000	16.13	-	50.06	5,956.91	-	-	5,956.91	3,835.82
2024	90	90	90,000	16.61	-	51.56	6,135.62	-	-	6,135.62	3,780.76
2025	90	90	90,000	17.11	-	53.11	6,319.69	-	-	6,319.69	3,726.49
2026	90	90	90,000	17.62	-	54.70	6,509.28	-	-	6,509.28	3,673.00
2027	90	90	90,000	18.15	-	56.34	6,704.55	-	-	6,704.55	3,620.28
2028	90	90	90,000	18.70	-	58.03	6,905.69	-	-	6,905.69	3,568.31
2029	90	90	90,000	19.26	-	59.78	7,112.86	-	-	7,112.86	3,517.09
2030	90	90	90,000	19.83	-	61.57	7,326.25	-	-	7,326.25	3,466.61
2031	90	90	90,000	20.43	-	63.42	7,546.03	-	-	7,546.03	3,416.85
2032	90	90	90,000	21.04	-	65.32	7,772.42	-	-	7,772.42	3,367.80

NPV in 2013 $		
	Five Year	(158,464.68)
	Ten Year	(138,431.21)
	Life	(102,458.21)

DSM Program Name: Customized Rebate Program
Customer Class: Commercial/Industrial

DSM Measure Effectiveness	Summer Demand	Winter Demand	Annual Energy
Load Reduction (kW per Unit)	5	5	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			8,750

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	37.25
Rate Escalation (%/yr)	3.00%
Measure Life	15
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	5,000.00
Capital Cost ($/unit)	3,795.22
Maintenance Cost ($/year/unit)	124.21
Cost Escalation (%/year)	2.50%

Estimated Applicability	Amount
Estimated Commercial/Industrial Customers	3,647
Estimated Appliance Saturation	100%
Market Eligibility	5%
Feasibility	100%
Estimated Units	182

Year	Summer Capacity Savings (kW)	Winter Capacity Savings (kW)	Annual Energy Savings (kWh)	Summer Capacity Charge ($/kW-yr)	Winter Capacity Charge ($/kW-yr)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)	Capital Costs ($)	O&M Costs ($)	Annual Savings / (Costs) ($)	Present Value ($)
2013	910	910	1,592,500	12.00	-	37.25	70,240.63	690,730.04	27,606.22	(648,095.64)	(648,095.64)
2014	910	910	1,592,500	12.36	-	38.37	72,347.84	-	28,296.38	44,051.47	42,154.52
2015	910	910	1,592,500	12.73	-	39.52	74,518.28	-	29,003.78	45,514.49	41,678.99
2016	910	910	1,592,500	13.11	-	40.70	76,753.83	-	29,728.88	47,024.95	41,207.80
2017	910	910	1,592,500	13.51	-	41.93	79,056.44	-	30,472.10	48,584.34	40,740.95
2018	910	910	1,592,500	13.91	-	43.18	81,428.14	-	31,233.90	50,194.23	40,278.41
2019	910	910	1,592,500	14.33	-	44.48	83,870.98	-	32,014.75	51,856.23	39,820.18
2020	910	910	1,592,500	14.76	-	45.81	86,387.11	-	32,815.12	53,571.99	39,366.22
2021	910	910	1,592,500	15.20	-	47.19	88,978.72	-	33,635.50	55,343.22	38,916.53
2022	910	910	1,592,500	15.66	-	48.60	91,648.08	-	34,476.39	57,171.70	38,471.09
2023	910	910	1,592,500	16.13	-	50.06	94,397.53	-	35,338.30	59,059.23	38,029.87
2024	910	910	1,592,500	16.61	-	51.56	97,229.45	-	36,221.75	61,007.70	37,592.87
2025	910	910	1,592,500	17.11	-	53.11	100,146.34	-	37,127.30	63,019.04	37,160.05
2026	910	910	1,592,500	17.62	-	54.70	103,150.73	-	38,055.48	65,095.25	36,731.40
2027	910	910	1,592,500	18.15	-	56.34	106,245.25	-	39,006.87	67,238.38	36,306.90

NPV in 2013 $		
	Five Year	(482,313.38)
	Ten Year	(285,460.95)
	Life	(99,639.86)

Appendix B

PUBLIC NOTICE

A meeting of the Arkansas River Power Authority (ARPA) Operating Committee will be on Wednesday, February 15, 2012, at 10:00 a.m., at La Junta Municipal Utilities, 515 Lacey, La Junta, CO.

The next regularly scheduled meeting of the ARPA Board of Directors will be held on Thursday, February 23, 2012, at 10:00 a.m. at the Otero Junior College-McDonald Hall (Administration Building-Room 120), 18th and Colorado, La Junta, CO. The agenda will include a scheduled hearing at 10:05 to provide an opportunity for any member of the public to submit comments regarding the Authority's Integrated Resource Plan (IRP). The IRP outlines plans for meeting the future electric power needs of ARPA and its member communities. The Arkansas River Power Authority is a political subdivision of the state of Colorado, supplying wholesale electric power to its municipal members of Holly, La Junta, Lamar, Las Animas, Springfield and Trinidad, Colorado. ARPA Operating Committee and Board meetings are open to the public.

A proposed agenda for each of the two meetings will be posted at a designated location in each of the member cities at least 24 hours in advance of the meeting. If any member of the public desires a copy of either agenda prior to the meeting you may request one by calling the ARPA office at 719-336-3496.

Bringing the Power to You
Arkansas River Power Authority

BOARD MEETING AGENDA

Thursday, February 23, 2012, 10:00 a.m.
McDonald Hall – Administration-Room 120
18th & Colorado (OJC Campus)
La Junta, Colorado 81050

Board Members:

Holly:	David Willhite*	*Springfield:*	Darwin Hansen
	Marsha Willhite, Treas.		Dusty Turner*
La Junta:	A.W. Hill	*Trinidad:*	Ed Gil de Rubio*
	Bob Freidenberger, Pres.*		Franklin Shew
Lamar:	Houssin Hourieh		
	William Pfeilsticker	*Executive Committee Members	
Las Animas:	Ron Clodfelter*	Secretary Arvenia Morris	
	Richard Stwalley, V.P.		

All agenda items are for discussion and action will be taken as noted or as deemed appropriate.

1. Roll Call and Introduction of Guests
2. Approval of Agenda
3. Approval of the Minutes of the January 26 Regular Meeting
4. Integrated Resource Plan (IRP) – Public Comments-10:05 a.m.
5. Financial Report and Approval of Outstanding Bills-Aarin Ritter
6. Operating Report
7. Operating Committee Report-Marsha Willhite
8. General Manager Report-Rick Rigel
   a. Monthly Report
   b. CAMU Legislative Update
9. Planning and Communication
10. Member Cities Reports
11. New Business
    a. ARPA Committees-Review
    b. Western States Power Corporation-Appoint Director-Alt.Director/Voting Delegates
12. Old Business

13. Executive Session: CRS § 24-6-402 (4)(b)(e)
    a. WEG Litigation
    b. Lamar Repowering Project
        i. Receive Legal Advice Regarding Potential Litigation
    c. Trinidad Litigation

14. Approval to Retain Mediator in Connection with Trinidad Litigation

15. Next Meeting Date and Location – March 22, 2012 @ La Junta

16. Adjourn

PUBLIC NOTICE

A meeting of the Arkansas River Power Authority (ARPA) Board of Directors will be held on Thursday, March 22, 2012, at 10:00 a.m. at the Otero Junior College Student Center, La Junta, CO. The agenda will include a scheduled hearing at 10:05 to provide an opportunity for any member of the public to submit comments regarding the Authority's Integrated Resource Plan (IRP). The IRP outlines plans for meeting the future electric power needs of ARPA and its member communities. The Arkansas River Power Authority is a political subdivision of the state of Colorado, supplying wholesale electric power to its municipal members of Holly, La Junta, Lamar, Las Animas, Springfield and Trinidad, Colorado. ARPA Board meetings are open to the public.

A proposed agenda for the meeting will be posted at a designated location in each of the member cities at least 24 hours in advance of the meeting. If any member of the public desires a copy of the agenda prior to the meeting you may request one by calling the ARPA office at 719-336-3496.

Bringing the Power to You
Arkansas River Power Authority

BOARD MEETING AGENDA

Thursday, March 22, 2012, 10:00 a.m.
Otero Junior College Student Center
2001 San Juan
La Junta, Colorado 81050

Board Members:

Holly:	David Willhite*	*Springfield:*	Darwin Hansen
	Marsha Willhite, Treas.		Dusty Turner*
La Junta:	A.W. Hill	*Trinidad:*	Ed Gil de Rubio*
	Bob Freidenberger, Pres.*		Franklin Shew
Lamar:	Houssin Hourieh		
	Vacant	*Executive Committee Members	
Las Animas:	Ron Clodfelter*	Secretary Arvenia Morris	
	Richard Stwalley, V.P.		

All agenda items are for discussion and action will be taken as noted or as deemed appropriate.

1. Roll Call and Introduction of Guests
2. Approval of Agenda
3. Approval of the Minutes of the February 23, 2012 Regular Meeting
4. Integrated Resource Plan (IRP) – Public Comments-10:05 a.m.
5. Financial Report and Approval of Outstanding Bills-Aarin Ritter
6. Operating Report
7. General Manager Report-Rick Rigel
   a. Monthly Report
   b. Letter of Credit - Report
8. Planning and Communication
9. Member Cities Reports
10. New Business
    a. Discussion of Board Officer Positions for April Elections
    b. Review of Annual Meeting Agenda
11. Old Business
12. Executive Session: CRS § 24-6-402 (4)(b)(e)

a. WEG Litigation
b. Lamar Repowering Project
   i. Receive Legal Advice Regarding Potential Litigation
c. Trinidad Litigation

13. Next Meeting Date and Location – April 26, 2012 @ La Junta

14. Adjourn

The following was read aloud at the February and March ARPA Board meetings as part of the IRP Public Comment section of the agendas:

> The Arkansas River Power Authority is in the process of preparing an Integrated Resource Plan (IRP), as required by the Western Area Power Administration (WAPA) under its Energy Planning and Management Program (EPAMP). The IRP will consider all practicable energy efficiency and energy supply resource options to meet future needs. The IRP must adhere to several criteria, which are listed on the WAPA website under the IRP section. ARPA is working with an outside consultant to complete the IRP and submit it to WAPA by June 1, 2012.
>
> One of the requirements of EPAMP is to "provide ample opportunity for full public participation." ARPA will be accepting written and verbal comments from affected retail customers of the six ARPA communities at the February and March 2012 meetings. A public presentation of the draft IRP will be given at the April 2012 meeting and public comment will be solicited immediately after the presentation and for a ten working day period after the April meeting. At the end of the comment period, all comments received from the public will be reviewed and, if necessary, changes will be incorporated into the IRP. The final IRP will be approved at a public meeting of the ARPA Board of Directors in May 2012.
>
> Interested parties may provide written comments directly to ARPA outside of the listed public meetings by sending them electronically or via US Mail to the following address:

Rick Rigel
General Manager
Arkansas River Power Authority
P O Box 70
Lamar, CO 81052
rrigel@arpapower.org

Public comments were solicited at that time.

PUBLIC NOTICE

The regular (and annual) meeting of the Arkansas River Power Authority (ARPA) Board of Directors will be held on Thursday, April 26, 2012, at 9:00 a.m. at the Otero Junior College Student Center, La Junta, CO. The agenda will include an executive session beginning at 9:00 a.m. followed by an open session beginning at 10:30. It will also include a comment period to provide an opportunity for any member of the public to submit comments regarding the Authority's Integrated Resource Plan (IRP). The IRP outlines plans for meeting the future electric power needs of ARPA and its member communities. The Arkansas River Power Authority is a political subdivision of the state of Colorado, supplying wholesale electric power to its municipal members of Holly, La Junta, Lamar, Las Animas, Springfield and Trinidad, Colorado. ARPA Board meetings are open to the public.

A proposed agenda for the meeting will be posted at a designated location in each of the member cities at least 24 hours in advance of the meeting. If any member of the public desires a copy of the agenda prior to the meeting you may request one by calling the ARPA office at 719-336-3496.

Bringing the Power to You
Arkansas River Power Authority

BOARD MEETING AGENDA

Thursday, April 26, 2012
9:00 a.m. Executive Session
10:30 a.m. Open Session
Otero Junior College Student Center
2001 San Juan
La Junta, Colorado 81050

Board Members:

Holly:	David Willhite*	*Springfield:*	Darwin Hansen
	Marsha Willhite, Treas.		Dusty Turner*
La Junta:	A.W. Hill	*Trinidad:*	Ed Gil de Rubio*
	Bob Freidenberger, Pres.*		Franklin Shew
Lamar:	Houssin Hourieh		
	Garth Nieschburg	*Executive Committee Members	
Las Animas:	Ron Clodfelter*	Secretary Arvenia Morris	
	Richard Stwalley, V.P.		

All agenda items are for discussion and action will be taken as noted or as deemed appropriate.

1. (9:00) Roll Call

2. Approval of Agenda

3. (9:05) Executive Session: CRS § 24-6-402 (4)(b)(e)
   a. WEG Litigation
   b. Lamar Repowering Project
      i. Receive Legal Advice Regarding Potential Litigation
   c. Trinidad Litigation

4. (10:30-Open Session) Welcome and Introduction of Guests-Bob Freidenberger, ARPA Board President

5. Approval of the Minutes of the March 22, 2012 Regular Meeting

6. Election of Officers

7. Financial Report and Approval of Outstanding Bills - Aarin Ritter

8. Operating Report - Rick Rigel

9. General Manager Report
   a. Addendum to Extend REC Purchase Agreement with Platte River Power Authority – Action Item
   b. 2011 Year in Review - Rick Rigel

10. Presentation of the 2012 IRP – John Krajewski

11. Public Comment (IRP)

    Recess for lunch

12. *The Western Power Landscape: Three Developments and How They Will Impact ARPA* – John Krajewski, JK Energy Consulting

13. *Rebuilding After a Natural Disaster* – Marsha Willhite, Administrator, Town of Holly

14. *Connections Overview* – Bill Smart, Senior V.P. of Business Development, Hometown Connections, APPA

15. Member Cities' Reports

16. Other Business
    a. Consider Date for Power Supply Work Session

17. Next Meeting Date and Location – May 24, 2012 @ Springfield

18. Adjourn

PUBLIC NOTICE

The Arkansas River Power Authority will hold a work session on Monday, May 14, 2012 at 10:00 a.m. at its offices at 3409 South Main, Lamar, CO. The work session will be primarily in executive session for the principal purpose of receiving legal advice and advising negotiators on matters relating to the Lamar Repowering Project.

An executive session for this topic of discussion is permitted under Colorado law, specifically, C.R.S. section 24-6-402 (4)(b)(e). The Board will not make any decisions during the course of the executive session that must be made in open public session. The Board may convene in open public session immediately following the executive session if it determines actions need to be taken in open public session.

The regular monthly meeting of the Arkansas River Power Authority (ARPA) Board of Directors will be held on Thursday, May 31, 2012, at 10:00 a.m. at the Lion's Den, 200 Main Street, Springfield, CO 81073. Arkansas River Power Authority (ARPA) is a political subdivision of the state of Colorado, supplying wholesale electric power to its municipal members of Holly, La Junta, Lamar, Las Animas, Springfield and Trinidad, Colorado. ARPA Board meetings are open to the public.

A proposed agenda for the meeting(s) will be posted at a designated location in each of the member cities at least 24 hours in advance of the meeting. If any member of the public desires a copy of the agenda prior to the meeting you may request one by calling the ARPA office at 719-336-3496.

Bringing the Power to You
Arkansas River Power Authority

BOARD MEETING AGENDA

Thursday, May 31, 2012
10:00 a.m.
Lion's Den, 200 Main Street
Springfield, Colorado 81073

Board Members:

Holly:	David Willhite*	*Springfield:*	Darwin Hansen
	Marsha Willhite, Treas.		Dusty Turner*
La Junta:	A.W. Hill	*Trinidad:*	Bernadette Baca Gonzales
	Bob Freidenberger, Pres.*		Franklin Shew
Lamar:	Houssin Hourieh		
	Garth Nieschburg		*Executive Committee Members
Las Animas:	Ron Clodfelter*		Secretary Arvenia Morris
	Richard Stwalley, V.P.		

All agenda items are for discussion and action will be taken as noted or as deemed appropriate.

1. Roll Call

2. Approval of Agenda

3. Approval of the Minutes of the April 26 Regular Meeting and the May 14 Work Session

4. 2011 Audit Presentation and Associated Resolutions-Ronny Farmer

5. Financial Report and Approval of Outstanding Bills-Aarin Ritter
   a. Review of Quarterly Financials-Rick Rigel
   b. Discussion on Establishing a Cash Reserve Policy-Rick Rigel

6. Operating Report-Rick Rigel
   a. Lamar Repowering Project-Rick Rigel
   b. Wind Turbine Report-Arvenia Morris

7. Integrated Resource Plan – Action Item

8. Operating Committee Report – Marsha Willhite

9. General Manager Report
   a. Monthly Report

10. Member Cities' Reports

11. New Business

12. Old Business

13. Executive Session: CRS § 24-6-402 (4)(b)(e)
    a. WEG Litigation
    b. Lamar Repowering Project
        i. Receive Legal Advice Regarding Potential Litigation
    c. Trinidad Litigation

14. Next Meeting Date and Location – July 26, 2012 @ Las Animas

15. Adjourn

RESOLUTION NO. 03 - 12

A RESOLUTION OF THE BOARD OF DIRECTORS OF THE ARKANSAS RIVER POWER AUTHORITY APPROVING AN INTEGRATED RESOURCE PLAN AND DIRECTING ITS SUBMITTAL TO THE WESTERN AREA POWER ADMINISTRATION

WHEREAS, the Arkansas River Power Authority (ARPA or "Authority"), an intergovernmental entity and political subdivision of the State of Colorado, provides the wholesale electric requirements to its member municipalities of Holly, Lamar, La Junta, Las Animas, Springfield and Trinidad, Colorado, each of whom furnish retail electric service in their local communities; and

WHEREAS, t he Authority obtains a portion of its wholesale power requirements from the Western Area Power Administration ("Western") under long term, firm power contracts. ARPA receives federal hydropower from Western produced at both the Loveland Area Projects and the Salt Lake City Integrated Projects; and

WHEREAS, under provisions of the 1992 Energy Policy Act ("EPAct"), firm power customers of Western are obligated to periodically prepare an Integrated Resource Plan ("IRP"), taking into account certain criteria set forth in this statutory enactment. Western has issued certain rules implementing this EPAct requirement. These rules require the Authority to submit an IRP to Western every five years, with progress reports submitted annually; and

WHEREAS, ARPA has prepared its 2012 IRP in compliance with Western's implementing rules; and

WHEREAS, the 2012 IRP incorporates a public participation plan, the purpose of which is to provide information to the public in the ARPA member communities on the IRP and seek public input; and

WHEREAS, ARPA was advised by Western in written correspondence dated July 17, 2006 that approval of the IRP is required by the ARPA Board of Directors but is not required by each of ARPA's individual member governing bodies; and

WHEREAS, a presentation and written summary of the 2012 IRP was presented to the public and the Authority's Board of Directors at its meeting on April 26, 2012; and

WHEREAS, A final draft of the 2012 IRP was provided to the Authority's Board of Directors at their meeting on May 31, 2012 for review, final comment and approval.

NOW, THEREFORE, BE IT RESOLVED BY THE BOARD OF DIRECTORS OF THE ARKANSAS RIVER POWER AUTHORITY:

1. The Integrated Resource Plan for the Arkansas River Power Authority, dated May 31, 2012, is hereby approved.

2. The 2012 IRP as hereby approved shall be submitted to the Western Area Power Administration.

3. Management of the Authority shall periodically advise the Board on the status of the action plan items incorporated in the approved 2012 IRP.

4. The Board of Directors reserves the right to modify the 2012 IRP to take into account changed circumstances and operational and economic considerations.

Approved by the Board of Directors on this 31st day of May 2012.

Robert L. Freidenberger

Robert L. Freidenberger

President, Board of Directors

I, Arvenia L. Morris, the duly appointed secretary of the Arkansas River Power Authority, do hereby certify that the foregoing is a true and correct copy of Resolution No.03 - 12 adopted by the Board of Directors of the Arkansas River Power Authority at a regularly scheduled meeting on May 31, 2012, at which a quorum of the Board was present and voting.

(SEAL)

Arvenia L. Morris

Arvenia L. Morris