Integrated Resource Plan 2022

Prepared for

Arkansas River Power Authority

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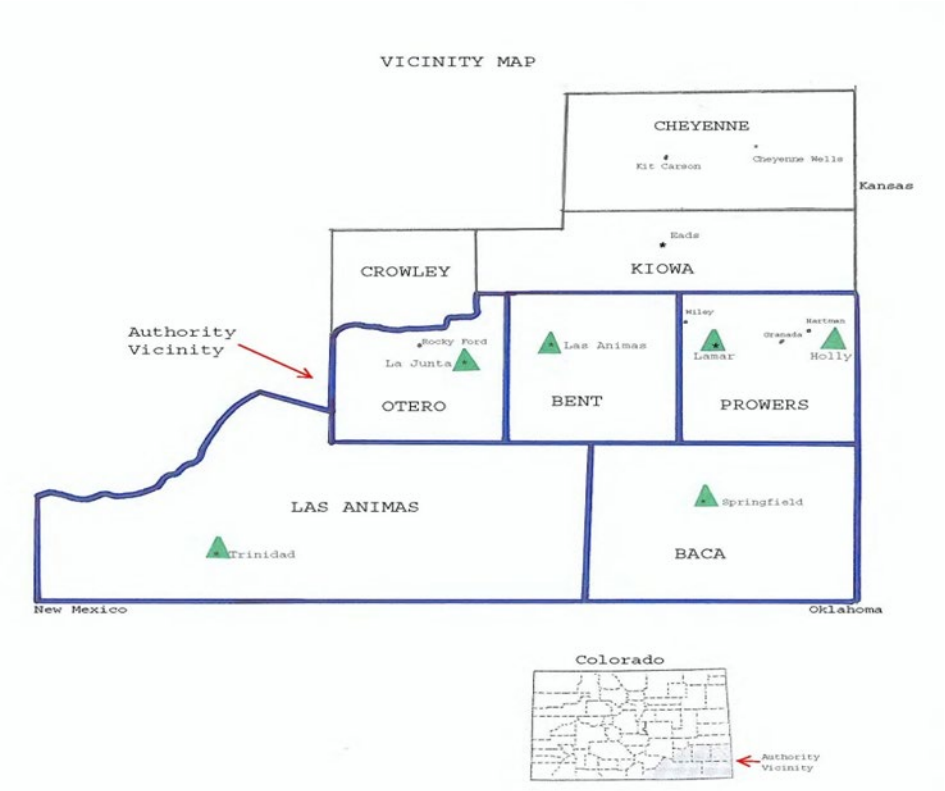
Section I. Summary

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. As a public power entity, 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 five IRPs since the EPAMP became effective. ARPA submitted its first IRP in 1996, followed by four additional IRPs in 2003, 2007, 2012 and 2017. In general, ARPA has implemented the recommendations of its previous IRPs.

Approach to 2022 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. 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 24% of Holly's revenues are derived from customers outside municipal boundaries.

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 sub-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 345 miles of distribution line and 36 miles of sub-transmission line. The Lamar Utilities Board (LUB), 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 43% of its sales occur outside the municipality. Las Animas' facilities include about 50 miles of distribution line and 13 miles of sub-transmission line.

Springfield, Colorado: The Springfield municipal electric utility was established in 1947 and serves an area of approximately two 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 four 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 9 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.

Demographics

Over the past 70 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 2020, Las Animas' population has declined by 27% while Springfield has seen its population decline 20%. Holly and Trinidad have experienced a 16% reduction in population and La Junta'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	2020
Holly	993	969	877	1,048	802	837
La Junta	7,938	8,338	7,637	7,568	7,077	7,322
Lamar	7,797	7,713	8,343	8,869	7,804	7,687
Las Animas	3,148	2,818	2,481	2,758	2,410	2,300
Springfield	1,660	1,657	1,475	1,562	1,451	1,325
Trinidad	9,901	9,663	8,580	9,078	9,096	8,329
TOTAL	31,437	31,158	29,393	30,883	28,640	27,800

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

Load Profile

Table 2 (see page 7) 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
2021 Peak Demand and Energy Profile

Member	Winter Peak (kW)	Summer Peak (kW)	Energy Purchases (MWh) (1)	Load Factor (%)
Holly	1,335	2,521	8,059	36.5%
La Junta	13,801	19,139	81,214	48.4%
Lamar (2)	16,337	23,106	85,686	42.3%
Las Animas	4,012	6,514	26,026	45.6%
Springfield	1,924	3,383	11,416	38.5%
Trinidad	9,974	9,917	54,714	62.6%
ARPA TOTALS (3)	**47,383**	**64,580**	**267,115**	**47.2%**

Notes:
(1) Energy measured at City meter. Does not include transmission or sub-transmission losses.
(2) Does not include 7,465 MWh of WAPA CRSP energy and approximately 1.4 MW of CRSP that was directly assigned to Lamar.
(3) Summer and winter peak on Table 3 varies from total of individual peaks shown here due to a coincidence factor and inclusion of Lamar WAPA CRSP allocation in ARPA total peak demand.

Section III. Load Forecast

Introduction

A load forecast was prepared to project ARPA's peak demand and energy requirements for the period of 2022 through 2031. The forecast incorporated 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.

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 Lamar 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 2021 were collected from the City of Lamar and compared to historical averages. A regression analysis was used to assess the relationship between degree days and annual energy requirements.

2022-2031 Load Forecast

The load forecast is summarized in Table 3 (see page 9). The correlation with econometric data, including population data and economic activity, was relatively low.

The three factors determined to impact the load forecast were cooling degree days, the previous year's energy consumption and the inclusion of known point load additions.

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
2012	239,218	263,140	64	41
2013	238,359	262,195	61	41
2014	230,814	253,895	59	40
2015	236,467	260,114	61	39
2016	235,075	258,583	65	42
2017	237,227	260,950	64	41
2018	243,418	267,760	67	41
2019	251,698	276,868	68	41
2020	251,105	276,216	65	43
2021	250,645	275,710	65	43
FORECAST				
2022	250,497	275,546	65	43
2023	250,497	275,546	65	43
2024	250,497	275,546	65	43
2025	250,497	275,546	65	43
2026	250,497	275,546	65	43
2027	250,497	275,546	65	43
2028	250,497	275,546	65	43
2029	250,497	275,546	65	43
2030	250,497	275,546	65	43
2031	250,497	275,546	65	43

(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).

The historical data showed no energy sales growth over the previous 20 years, with energy sales in future years projected to remain stable unless specific new loads are added to a member system. 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 65 MW was forecasted in 2031, which is essentially the same as the 2021 actual peak demand. Energy requirements were projected to be essentially flat for the period 2022 through 2031.

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. In recent years, a number of member-owned generators have been retired or converted to “emergency only” status as a result of increasing compliance costs associated with environmental and other regulations. ARPA coordinates with its members when member-owned generation is needed to assist with power supply. Those members who continue to operate generation are reimbursed for the usage of their generators 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. ARPA and its members own approximately 27 MW of generating

resources. These resources include peaking generation, emergency-only generation, and wind turbines that provide renewable energy.

Table 4 lists ARPA's existing supply side capacity resources, including installation date, capacity, primary fuel, location, and operational type. ARPA and member-owned generation is primarily 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.

The only significant change in ARPA's member-owned generation since the 2017 IRP was the retirement by La Junta of 1 MW of emergency-only generation in 2018 and approximately 14 MW of emergency-only generation in 2021. This generation was not used to meet ARPA's resource adequacy requirements. The retirement of this generation does not affect the ARPA's resource plan going forward.

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
Lamar	2004	Member	4.5	Wind	Intermittent
	2004	ARPA	1.5	Wind	Intermittent
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.

ARPA-Owned Generation

- Holly Generation Project: In 2007, ARPA replaced an existing generating unit with a used diesel-fired generating set with a Tier I emission rating, meaning it complied with the Reciprocating Internal Combustion Engine (RICE) rule issued by Environmental Protection Agency (EPA) in 2010. This project is capable of operating during transmission and sub-transmission outages and can be used to supply energy during period of high market prices.
- 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 turbines 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 approximately 8% of ARPA's annual energy requirements. When possible, ARPA and Lamar sell the energy attributes (Renewable Energy Credits) of the wind generation in order to help offset the energy cost associated with the turbines.

- Member-Owned Peaking Generation: All remaining member-owned generation has been transitioned to “emergency only” status, meaning they only operate in the event of a transmission or distribution system outage that precludes delivery of energy from the grid. This member-owned generation has been and will continue to be vital to ARPA members but is no longer included in ARPA’s power supply plan. 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 eliminated its reliance on these older generating units for serving resource adequacy requirements over 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 September 30, 2057. Xcel Energy provides scheduling and transmission of all monthly and support energy that ARPA members are entitled to under its agreement with Western. Upon termination of the agreement with Xcel Energy, all scheduling and transmission activities will be conducted by Guzman Energy.

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, 2054. Xcel Energy provides scheduling and transmission of all monthly

energy, support, and pumped storage energy that ARPA members are entitled to under its agreement with Western. Upon termination of the agreement with Xcel Energy, all scheduling and transmission activities will be conducted by Guzman Energy.

Xcel Energy: Xcel Energy currently provides all energy needs in excess of Western allocations and wind energy generation. This agreement was originally entered into with Twin Eagle Resource Management (TERM) in 2013 and was assigned to Xcel Energy in 2019. The agreement expires on January 31, 2025. This agreement provides for scheduling and transmission agent services for all ARPA resources, including the Western allocations.

Guzman Energy: Effective February 1, 2025, Guzman Energy will provide all energy needs in excess of Western allocations, existing wind energy generation and eligible renewable resources in the future. This agreement is effective through October 2043, coinciding with the current expiration date of ARPA's Organic Agreement. This agreement provides for scheduling and transmission agent services for all ARPA resources, including the Western allocations.

Energy Resource Mix

Table 5 (see page 15) summarizes the historical energy supply mix for ARPA for 2017 through 2021. The only significant change in ARPA's supply mix during this period of time was the assignment of the TERM agreement to Xcel Energy in 2019. There has been a decline in the availability of WAPA-CRSP energy as a result of changes in hydrology in the Colorado River basin. All other resources, including Western Loveland Area Project allocations and ARPA/Lamar wind energy production were relatively consistent over this period of time.

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

Source	2017	2018	2019	2020	2021
ARPA Units (1)	80	18	22	11	42
Wind Generation (2)	18,899	19,642	18,895	23,512	22,339
Western	86,118	87,134	82,313	82,326	81,749
TERM/Xcel Energy (3)	177,356	186,154	188,598	179,537	177,377
TOTAL	282,453	292,948	289,828	285,387	281,508

Note:

(1) Energy from testing and emergency use of ARPA member-owned generation.

(2) Includes ARPA-owned and member-owned wind generation resources.

(3) Original partial requirements agreement with TERM assigned to Xcel in 2019.

Transmission

ARPA and its members do not own any transmission facilities (115 kV and higher) and are 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 Generation and Transmission, Inc. (Tri-State) and of Black Hills Colorado Electric Utility Company, LP (BHEC). Tri-State provides network service to Holly, La Junta, Lamar, Trinidad, and Springfield. Las Animas receives network transmission service from BHEC. ARPA also has agreements with Southeast Colorado Power Association, Lamar Utilities Board, BHEC, and San Isabel Electric Association for use of lower-voltage sub-transmission facilities. Collectively, 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

Changes Since 2017 IRP

Since the last IRP was completed, two key changes have occurred to the ARPA power supply situation. The first key change was the assignment of the existing purchased energy contract from TERM to Xcel Energy in 2019. This assignment was a result of changes in operations at TERM and was not a result of any decision by ARPA.

The second key change was executing an agreement with Guzman Energy, effective February 1, 2025, to supply energy currently being provided by Xcel Energy. This agreement will continue through 2043 when the ARPA Organic Agreement expires. Guzman was selected after the completion of a multi-source request for proposals process that included consideration of total requirements agreements as well as individual resource proposals for solar, wind and conventional resources. The Guzman Energy agreement provides a resource portfolio that will provide a reduction in carbon intensity of 80% by 2030, consistent with legislation applicable to the largest utilities in Colorado. The agreement permits ARPA to continue to use its existing wind turbines and potentially replace them at some point with newer, more efficient wind turbines.

Comparison of Loads and Resources

Table 6 (see page 17) 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 January 2025 when the Xcel Energy agreement expires. Additional capacity resources will need to be secured when the existing Xcel Energy agreement expires.

Table 6
Projected Capacity Requirements and Resources

Description	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Peak Demand	65	65	65	65	65	65	65	65	65	65
Reserves (1)	4	4	4	4	4	4	4	4	4	4
Total Capacity Requirements	69	69	69	69	69	69	69	69	69	69
Existing Resources										
Western (2)	30	30	30	30	30	30	30	30	30	30
Xcel	32	32	32	32	-	-	-	-	-	-
Guzman Energy	-	-	-	-	32	32	32	32	32	32
Local Generation (3)	7	7	7	7	7	7	7	7	7	7
Wind (4)	-	-	-	-	-	-	-	-	-	-
Total Resources	69	69	69	69	69	69	69	69	69	69
Surplus / (Deficit)	-	-	-	-	-	-	-	-	-	-

Notes:
(1) Includes 12% reserves for load that is not served by Western. Reserves are not carried for load served by Western since that resource is firm.
(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 19) shows the comparison of energy requirements to energy resources. The Xcel Energy agreement will supply all of ARPA's supplemental energy requirements through January 31, 2025. The Guzman Energy agreement will provide supplemental energy requirements through 2043. Other than a potential replacement of the existing ARPA and Lamar wind turbines, no resources are needed until beyond the end of the five-year action plan included in this IRP.

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Table 7
Projected Energy Requirements and Resources

Description	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Retail Energy Sales	250,497	250,497	250,497	250,497	250,497	250,497	250,497	250,497	250,497	250,497
Losses (1)	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050
Total Energy Requirements	275,546	275,546	275,546	275,546	275,546	275,546	275,546	275,546	275,546	275,546
Existing Resources										
Western	81,749	81,749	81,749	81,749	81,749	81,749	81,749	81,749	81,749	81,749
Xcel (2)	173,090	173,090	173,090	15,000	-	-	-	-	-	-
Guzman (3)	-	-	-	158,090	173,090	173,090	173,090	173,090	173,090	173,090
Local Generation (4)	30	30	30	30	30	30	30	30	30	30
Wind (5)	20,678	20,678	20,678	20,678	20,678	20,678	20,678	20,678	20,678	20,678
Total Energy Resources	275,546	275,546	275,546	275,546	275,546	275,546	275,546	275,546	275,546	275,546
Surplus / (Deficit)	-	-	-	-	-	-	-	-	-	-

(1) Includes 10% transmission and distribution losses.
(2) All requirements not supplied by other resources through January 31, 2025.
(3) All requirements not supplied by other resources commencing February 1, 2025.
(4) Based on annual capacity factor of 1%.
(5) Based on historical average wind energy production.

One factor that may affect ARPA over the next five years is the development of a regional transmission organization (RTO) that would operate some form of an organized energy market. In other regions, changes in pricing and availability of resources occurred and evolved after the implementation of the organized energy market. There is already an energy imbalance (EI) market that includes several utilities in Colorado and Wyoming. Public Service Company of Colorado (PSCo), which operates the balancing authority where ARPA's loads are located, is planning to join the EI market in April 2023. ARPA's partial requirements suppliers (Xcel Energy and Guzman) will be responsible for scheduling and operations when and if an EI market or RTO becomes operational for the balancing authority and transmission providers where ARPA is located.

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, there was no need to consider additional capacity and energy resources at this time. The existing agreement with Xcel Energy restricts the ability of ARPA to procure energy from alternate resources; however, the new agreement with Guzman Energy allows ARPA to purchase a portion of its energy supply from alternate sources, including a potential repowering of the ARPA and Lamar wind turbines.

The existing wind turbines have been in service for nearly 20 years. It is becoming more difficult to procure spare parts and the efficiency of these turbines is less than newer turbines. Other entities with similar projects have considered repowering of turbines. For example, the Municipal Energy Agency of Nebraska (MEAN) completed a repowering and

expansion of its Kimball wind project which replaced 10.5 MW of capacity with approximately 30 MW of new capacity. ARPA has been approached by one entity with some interest in pursuing a similar arrangement and is in further discussions on the economic viability of this project. Given limitations within the agreement with Guzman Energy and the likely need to consider retirement of the ARPA wind portfolio, this resource is the most practicable potential modification to ARPA's resource plan.

Conclusions

1. The existing agreement with Xcel Energy greatly limits resource options that can be pursued before 2025.

2. Upon the expiration of the Xcel Energy agreement on January 31, 2025, ARPA has secured power supply resources with Guzman Energy, effective February 1, 2025.

3. Repowering and expanding of the existing wind turbines may provide additional efficiency, lower costs, and longer project life. The Guzman Energy agreement provides the ability to replace and potentially expand ARPA's wind energy portfolio.

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 8 (see page 22) 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. Expenditures in 2021 were much greater than those reported in the 2017 IRP. The largest factor in the increased expenditures was the implementation of LED street lighting in four member communities.

Table 8
DSM Expenditures - 2021

	DSM Services Provided ($)								
Member	**Energy Audits**	**Tree Trimming**	**Conservation Advertising**	**Lower Loss Transformers**	**LED Lighting**	**Wind**	**SCADA**	**AMI**	**TOTAL**
Holly		1,291		7,366					8,657
La Junta		25,000			25,000				50,000
Lamar	4,800	28,703	9,300	35,736	40,000	90,342	60,518	186,699	456,098
Las Animas		76,064			5,227				81,291
Springfield									-
Trinidad					72,742			50,000	122,742
All / ARPA (1)									-
TOTAL	$ 4,800	$ 131,058	$ 9,300	$ 43,102	$ 142,969	$ 90,342	$ 60,518	$ 236,699	**$ 718,788**

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.

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, 2007, 2012 and 2017 have been rendered obsolete by changes in energy efficiency standards at the federal level. This reduces the number of DSM measures that are evaluated and eliminates several measures that may have passed the screening because they are now mandated by law. One measure that was evaluated in the 2012 IRP, installation of LED street lighting, was not evaluated in this study since a majority of ARPA's members have already converted to LED street lighting for replacement fixtures and new construction.

Another issue that has arisen in the past is the difficulty in finding contractors to provide services in rural areas of Colorado. For example, the 2012 IRP identified old refrigerator recycling as a potential measure. When it was selected, the cost was based on the typical fee for national providers used by large utilities. In further discussions, the economics were less favorable because of the distance from ARPA communities to their primary service centers in cities like Denver and Colorado Springs. There is also difficulty finding contractors to perform energy audits and similar services. The DSM measures that were reviewed were limited to those that could be implemented with existing utility staff or via contractors that are readily available locally.

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 9 and 10 (see page 26) show the scores for each technology applicable to a particular customer class.

Table 9
Qualitative Screening
Residential Demand Side Measures

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

Table 10
Qualitative Screening
Commercial/Industrial Demand Side Measures

Technology Alternative	Cost	Customer Preference	Environmental Impact	Market Potential	Ease of Implementation	Commercial Availability/ Reliability	Total
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 12 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 five residential measures and four commercial/industrial measures. This pre-screening only used qualitative factors to

narrow the list of technologies that would be further evaluated. The nine 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. There would be minimum efficiency standards as well as a limit on the size of the unit based on the needed cooling capacity of the home. Local contractors market high efficiency equipment, although no rebates or incentives are provided.

4. 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.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

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. Summer peak demand savings were related to reduced transmission costs since the Xcel Energy does not include a demand rate component. 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 2022 dollars. Measures with a positive net present value were considered economically feasible.

A summary of the economic evaluations are shown in Tables 11 and 12. The analysis of each individual DSM measure is shown in Appendix A.

Table 11
Impact of Demand Side Measures Alternatives - Residential

Impact of DSM Alternatives	Net Present Value 2022 $		
	5-Year	10-Year	Life
Air Conditioning Load Cycling	$ (453,240)	$ (565,055)	$ (829,510)
Water Heater Load Shedding	$ (399,458)	$ (471,372)	$ (647,177)
High Efficiency Air Conditioners	$ (438,497)	$ (395,310)	$ (327,445)
HVAC Replacement Loans	$ (419,758)	$ (379,166)	$ (321,439)
Whole-House Audits	$ (767,547)	$ (600,903)	$ (471,840)

Table 12
Impact of Demand Side Measures Alternatives - Commercial/Industrial

Impact of DSM Alternatives	Net Present Value 2022 $		
	5-Year	10-Year	Life
Interruptible Rates	$ (68,113)	$ (73,522)	$ (85,624)
High Efficiency Air Conditioners	$ (175,553)	$ (134,535)	$ (71,628)
HVAC Efficiency Improvement	$ (151,688)	$ (128,964)	$ (93,474)
Customized Rebate Program	$ (418,319)	$ (190,785)	$ (24,754)

None of the evaluated DSM measures were economically feasible. ARPA's marginal power supply costs are relatively low, particularly after 2025 when the Guzman Energy agreement becomes effective. These low marginal costs eliminate many DSM measures that have been implemented by other utilities. 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.

Section VIII. Supply/Demand Side Resource Integration

Preferred Alternative

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

1. Implement the transition for partial requirements service from Xcel Energy to Guzman Energy at the end of the existing Xcel Energy agreement in January 2025.

2. Consider repowering of the five existing wind turbines based on economic and technical feasibility.

3. Monitor developments related to regional transmission organizations and energy markets that may affect ARPA in the future.

4. Encourage ARPA members to continue low-cost energy efficiency measures.

Environmental Impacts

The transition from Xcel Energy to Guzman Energy will result in a decrease in the greenhouse gas intensity of ARPA's energy portfolio. The new portfolio establishes greenhouse gas emissions reductions consistent with requirements will be applicable to the largest utilities in Colorado and that are voluntary for ARPA and its members. The greenhouse gas intensity of ARPA's partial requirements service will decrease 80% by

2030 when compared to a 2005 baseline. In addition, energy supplied by the ARPA wind portfolio and WAPA is free of greenhouse gas emissions.

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. Conversion of street lighting from high-pressure sodium fixtures to LED reduces energy usage, thus reducing environmental impacts.

One key component of ARPA's efforts to minimize environmental impact has been its wind energy purchase program. Approximately 8% of ARPA's energy comes from wind energy. 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

- Work on the transition of partial requirements supply from Xcel Energy to Guzman Energy at the end of the existing agreement in January 2025.

- Consider repowering of the existing wind turbines, taking into account economic feasibility and the expected life of the existing turbines.
- Monitor developments related to regional transmission organization (RTO) and organized energy markets.
- Continue low-cost energy efficiency measures.
- Continue trend toward replacing street lighting with LED fixtures.

Five-Year

- Complete transition from Xcel Energy to Guzman Energy for partial requirements supply.
- Continue actions from Two Year action plan.

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 notice of the meetings are published in advance along with the agenda. Prior to the publication of the draft IRP, ARPA solicitated comments on the IRP process via their newsletter (see Appendix B – December 2021 Newsletter, March 2022 Newsletter) and on ARPA's website (www.arpapower.org/irp/). The February 2022 public notice and agenda also solicited public comments on the ARPA IRP process (see Appendix B - February 2022 Public Notice, February 2022 Agenda). No public comments were received prior to the February 2022 meeting.

A draft of the IRP was presented at a public hearing held in La Junta, Colorado, and via webcast on February 24, 2022, as part of the regular monthly ARPA Board meeting (see Appendix B – February 2022 Agenda). The purpose of the meeting was to provide information to and gather input from groups and individuals with an interest in ARPA's IRP. Public comments were solicited immediately after the presentation and for 20 working days after the hearing. Despite the encouragement for public participation, no members of the general public attended the hearing nor were 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 and reviewed by the ARPA Operating Committee at their May 19, 2022, meeting (see Appendix B – May 2022 Public Notice – Operating Committee, May 2022 Agenda – Operating Committee). On May 26, 2022, the ARPA Board adopted a Resolution approving this 2022 IRP (see Appendix B – May 2022 Public Notice – Board of Directors, May 2022 Agenda – Board of Directors and Resolution 02-22).

Measurement Strategies and Annual Updates

ARPA compares its load forecasts to actual usage on an annual and monthly basis and tracks the energy production and cost of its various resources on a monthly and annual basis. This tracking will continue in the future. In addition, ARPA will continue to quantify its expenditures on 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 – Demand Side Management Measures

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)	42.00
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)	20.00
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) ($)	Present Value ($)
2022	2,230	-	26,230	12.00	-	52.30	28,126.43	327,875.00	54,460.00	(354,208.57)	(354,208.57)
2023	2,230	-	26,230	12.36	-	54.20	28,978.90	-	55,821.50	(26,842.60)	(25,686.69)
2024	2,230	-	26,230	12.73	-	55.70	29,844.97	-	57,217.04	(27,372.07)	(25,065.43)
2025	2,230	-	26,230	13.11	-	57.00	30,730.58	-	58,647.46	(27,916.88)	(24,463.47)
2026	2,230	-	26,230	13.51	-	61.00	31,712.57	-	60,113.65	(28,401.08)	(23,816.05)
2027	2,230	-	26,230	13.91	-	63.00	32,668.40	-	61,616.49	(28,948.09)	(23,229.42)
2028	2,230	-	26,230	14.33	-	65.00	33,651.34	-	63,156.90	(29,505.56)	(22,657.20)
2029	2,230	-	26,230	14.76	-	45.00	34,085.13	-	64,735.83	(30,650.69)	(22,523.00)
2030	2,230	-	26,230	15.20	-	46.35	35,107.69	-	66,354.22	(31,246.53)	(21,972.10)
2031	2,230	-	26,230	15.66	-	47.74	36,160.92	-	68,013.08	(31,852.16)	(21,433.46)
2032	2,230	-	26,230	16.13	-	49.17	37,245.75	-	69,713.40	(32,467.66)	(20,906.82)
2033	2,230	-	26,230	16.61	-	50.65	38,363.12	-	71,456.24	(33,093.12)	(20,391.94)
2034	2,230	-	26,230	17.11	-	52.17	39,514.01	-	73,242.65	(33,728.63)	(19,888.56)
2035	2,230	-	26,230	17.62	-	53.73	40,699.43	-	75,073.71	(34,374.28)	(19,396.43)
2036	2,230	-	26,230	18.15	-	55.34	41,920.41	-	76,950.55	(35,030.14)	(18,915.32)
2037	2,230	-	26,230	18.70	-	57.00	43,178.03	-	78,874.32	(35,696.29)	(18,445.00)
2038	2,230	-	26,230	19.26	-	58.71	44,473.37	-	80,846.18	(36,372.81)	(17,985.24)
2039	2,230	-	26,230	19.83	-	60.48	45,807.57	-	82,867.33	(37,059.76)	(17,535.80)
2040	2,230	-	26,230	20.43	-	62.29	47,181.80	-	84,939.01	(37,757.22)	(17,096.48)
2041	2,230	-	26,230	21.04	-	64.16	48,597.25	-	87,062.49	(38,465.24)	(16,667.06)
2042	2,230	-	26,230	21.67	-	66.08	50,055.17	-	89,239.05	(39,183.88)	(16,247.32)
2043	2,230	-	26,230	22.32	-	68.07	51,556.82	-	91,470.03	(39,913.21)	(15,837.06)
2044	2,230	-	26,230	22.99	-	70.11	53,103.53	-	93,756.78	(40,653.25)	(15,436.08)
2045	2,230	-	26,230	23.68	-	72.21	54,696.63	-	96,100.70	(41,404.06)	(15,044.17)
2046	2,230	-	26,230	24.39	-	74.38	56,337.53	-	98,503.22	(42,165.68)	(14,661.15)

NPV in 2022 $		
	Five Year	(453,240.21)
	Ten Year	(565,055.38)
	Life	(829,509.82)

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

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Annual Energy Cost ($/MWh)	42.00
Rate Escalation (%/yr)	3.00%
Measure Life	25
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	2,500.00
Capital Cost ($/unit)	325.00
Maintenance Cost ($/year/unit)	20.00
Cost Escalation (%/year)	2.50%

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) ($)	Present Value ($)
2022	443	-	4,920	12.00	-	52.30	5,570.92	319,800.00	22,180.00	(336,409.08)	(336,409.08)
2023	443	-	4,920	12.36	-	54.20	5,739.67	-	22,734.50	(16,994.83)	(16,262.99)
2024	443	-	4,920	12.73	-	55.70	5,911.24	-	23,302.86	(17,391.62)	(15,926.03)
2025	443	-	4,920	13.11	-	57.00	6,086.75	-	23,885.43	(17,798.68)	(15,596.92)
2026	443	-	4,920	13.51	-	61.00	6,280.62	-	24,482.57	(18,201.95)	(15,263.45)
2027	443	-	4,920	13.91	-	63.00	6,469.88	-	25,094.63	(18,624.76)	(14,945.45)
2028	443	-	4,920	14.33	-	65.00	6,664.52	-	25,722.00	(19,057.48)	(14,634.16)
2029	443	-	4,920	14.76	-	45.00	6,756.46	-	26,365.05	(19,608.59)	(14,408.95)
2030	443	-	4,920	15.20	-	46.35	6,959.15	-	27,024.18	(20,065.02)	(14,109.43)
2031	443	-	4,920	15.66	-	47.74	7,167.93	-	27,699.78	(20,531.85)	(13,815.98)
2032	443	-	4,920	16.13	-	49.17	7,382.96	-	28,392.28	(21,009.31)	(13,528.48)
2033	443	-	4,920	16.61	-	50.65	7,604.45	-	29,102.08	(21,497.63)	(13,246.81)
2034	443	-	4,920	17.11	-	52.17	7,832.59	-	29,829.63	(21,997.05)	(12,970.86)
2035	443	-	4,920	17.62	-	53.73	8,067.56	-	30,575.37	(22,507.81)	(12,700.52)
2036	443	-	4,920	18.15	-	55.34	8,309.59	-	31,339.76	(23,030.17)	(12,435.67)
2037	443	-	4,920	18.70	-	57.00	8,558.88	-	32,123.25	(23,564.37)	(12,176.19)
2038	443	-	4,920	19.26	-	58.71	8,815.64	-	32,926.33	(24,110.69)	(11,922.00)
2039	443	-	4,920	19.83	-	60.48	9,080.11	-	33,749.49	(24,669.38)	(11,672.97)
2040	443	-	4,920	20.43	-	62.29	9,352.52	-	34,593.23	(25,240.71)	(11,429.00)
2041	443	-	4,920	21.04	-	64.16	9,633.09	-	35,458.06	(25,824.97)	(11,190.00)
2042	443	-	4,920	21.67	-	66.08	9,922.09	-	36,344.51	(26,422.43)	(10,955.87)
2043	443	-	4,920	22.32	-	68.07	10,219.75	-	37,253.13	(27,033.38)	(10,726.50)
2044	443	-	4,920	22.99	-	70.11	10,526.34	-	38,184.45	(27,658.11)	(10,501.81)
2045	443	-	4,920	23.68	-	72.21	10,842.13	-	39,139.06	(28,296.93)	(10,281.69)
2046	443	-	4,920	24.39	-	74.38	11,167.40	-	40,117.54	(28,950.15)	(10,066.07)

NPV in 2022 $		
	Five Year	(399,458.48)
	Ten Year	(471,372.45)
	Life	(647,176.90)

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)	42.00
Rate Escalation (%/yr)	3.00%
Measure Life	20
Discount Rate	4.50%

Program Costs	Amount
Admin Cost (total $/year)	-
Capital Cost ($/unit)	1,500.00
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) ($)	Present Value ($)
2022	197	-	164,000	12.00	-	52.30	10,938.80	492,000.00	-	(481,061.20)	(481,061.20)
2023	197	-	164,000	12.36	-	54.20	11,321.25	-	-	11,321.25	10,833.73
2024	197	-	164,000	12.73	-	55.70	11,640.22	-	-	11,640.22	10,659.30
2025	197	-	164,000	13.11	-	57.00	11,928.58	-	-	11,928.58	10,452.98
2026	197	-	164,000	13.51	-	61.00	12,662.00	-	-	12,662.00	10,617.87
2027	197	-	164,000	13.91	-	63.00	13,069.74	-	-	13,069.74	10,487.83
2028	197	-	164,000	14.33	-	65.00	13,479.87	-	-	13,479.87	10,351.14
2029	197	-	164,000	14.76	-	45.00	10,284.47	-	-	10,284.47	7,557.32
2030	197	-	164,000	15.20	-	46.35	10,593.00	-	-	10,593.00	7,448.84
2031	197	-	164,000	15.66	-	47.74	10,910.79	-	-	10,910.79	7,341.92
2032	197	-	164,000	16.13	-	49.17	11,238.12	-	-	11,238.12	7,236.54
2033	197	-	164,000	16.61	-	50.65	11,575.26	-	-	11,575.26	7,132.66
2034	197	-	164,000	17.11	-	52.17	11,922.52	-	-	11,922.52	7,030.28
2035	197	-	164,000	17.62	-	53.73	12,280.20	-	-	12,280.20	6,929.37
2036	197	-	164,000	18.15	-	55.34	12,648.60	-	-	12,648.60	6,829.90
2037	197	-	164,000	18.70	-	57.00	13,028.06	-	-	13,028.06	6,731.86
2038	197	-	164,000	19.26	-	58.71	13,418.90	-	-	13,418.90	6,635.23
2039	197	-	164,000	19.83	-	60.48	13,821.47	-	-	13,821.47	6,539.99
2040	197	-	164,000	20.43	-	62.29	14,236.11	-	-	14,236.11	6,446.12
2041	197	-	164,000	21.04	-	64.16	14,663.20	-	-	14,663.20	6,353.59

NPV in 2022 $		
	Five Year	(438,497.33)
	Ten Year	(395,310.28)
	Life	(327,444.74)

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)	42.00
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) ($)	Present Value ($)
2022	190	190	285,000	12.00	-	52.30	17,185.50	475,000.00	6,000.00	(463,814.50)	(463,814.50)
2023	190	190	285,000	12.36	-	54.20	17,795.40	-	6,150.00	11,645.40	11,143.92
2024	190	190	285,000	12.73	-	55.70	18,293.35	-	6,303.75	11,989.60	10,979.24
2025	190	190	285,000	13.11	-	57.00	18,736.42	-	6,461.34	12,275.07	10,756.61
2026	190	190	285,000	13.51	-	61.00	19,951.16	-	6,622.88	13,328.28	11,176.58
2027	190	190	285,000	13.91	-	63.00	20,598.14	-	6,788.45	13,809.70	11,081.60
2028	190	190	285,000	14.33	-	65.00	21,247.44	-	6,958.16	14,289.28	10,972.68
2029	190	190	285,000	14.76	-	45.00	15,629.11	-	7,132.11	8,497.00	6,243.84
2030	190	190	285,000	15.20	-	46.35	16,097.99	-	7,310.42	8,787.57	6,179.29
2031	190	190	285,000	15.66	-	47.74	16,580.93	-	7,493.18	9,087.75	6,115.19
2032	190	190	285,000	16.13	-	49.17	17,078.35	-	7,680.51	9,397.85	6,051.53
2033	190	190	285,000	16.61	-	50.65	17,590.70	-	7,872.52	9,718.18	5,988.33
2034	190	190	285,000	17.11	-	52.17	18,118.42	-	8,069.33	10,049.09	5,925.59
2035	190	190	285,000	17.62	-	53.73	18,661.98	-	8,271.07	10,390.91	5,863.30
2036	190	190	285,000	18.15	-	55.34	19,221.84	-	8,477.84	10,743.99	5,801.47
2037	190	190	285,000	18.70	-	57.00	19,798.49	-	8,689.79	11,108.70	5,740.09
2038	190	190	285,000	19.26	-	58.71	20,392.45	-	8,907.03	11,485.41	5,679.18
2039	190	190	285,000	19.83	-	60.48	21,004.22	-	9,129.71	11,874.51	5,618.74
2040	190	190	285,000	20.43	-	62.29	21,634.35	-	9,357.95	12,276.39	5,558.76
2041	190	190	285,000	21.04	-	64.16	22,283.38	-	9,591.90	12,691.48	5,499.24
2042	-	-	-	21.67	-	66.08	-	-	-	-	-
2043	-	-	-	22.32	-	68.07	-	-	-	-	-
2044	-	-	-	22.99	-	70.11	-	-	-	-	-
2045	-	-	-	23.68	-	72.21	-	-	-	-	-
2046	-	-	-	24.39	-	74.38	-	-	-	-	-
2047	-	-	-	25.13	-	76.61	-	-	-	-	-
2048	-	-	-	25.88	-	78.91	-	-	-	-	-
2049	-	-	-	26.66	-	81.28	-	-	-	-	-
2050	-	-	-	27.46	-	83.71	-	-	-	-	-
2051	-	-	-	28.28	-	86.22	-	-	-	-	-

NPV in 2022 $		
	Five Year	(419,758.15)
	Ten Year	(379,165.56)
	Life	(321,439.34)

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 $/year)	4,000.00
Capital Cost ($/unit)	600.00
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)	42.00
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) ($)	Present Value ($)
2022	246	246	861,458	12.00	-	52.30	48,004.47	983,400.00	4,000.00	(939,395.53)	(939,395.53)
2023	246	246	861,458	12.36	-	54.20	49,729.75	-	4,100.00	45,629.75	43,664.83
2024	246	246	861,458	12.73	-	55.70	51,113.10	-	4,202.50	46,910.60	42,957.44
2025	246	246	861,458	13.11	-	57.00	52,326.89	-	4,307.56	48,019.33	42,079.18
2026	246	246	861,458	13.51	-	61.00	55,869.44	-	4,415.25	51,454.19	43,147.49
2027	246	246	861,458	13.91	-	63.00	57,691.97	-	4,525.63	53,166.34	42,663.38
2028	246	246	861,458	14.33	-	65.00	59,517.49	-	4,638.77	54,878.72	42,141.13
2029	246	246	861,458	14.76	-	45.00	42,394.00	-	4,754.74	37,639.26	27,658.40
2030	246	246	861,458	15.20	-	46.35	43,665.82	-	4,873.61	38,792.21	27,278.11
2031	246	246	861,458	15.66	-	47.74	44,975.80	-	4,995.45	39,980.34	26,902.95
2032	246	246	861,458	16.13	-	49.17	46,325.07	-	5,120.34	41,204.73	26,532.87
2033	246	246	861,458	16.61	-	50.65	47,714.82	-	5,248.35	42,466.48	26,167.79
2034	246	246	861,458	17.11	-	52.17	49,146.27	-	5,379.56	43,766.71	25,807.65
2035	246	246	861,458	17.62	-	53.73	50,620.66	-	5,514.04	45,106.61	25,452.38
2036	246	246	861,458	18.15	-	55.34	52,139.27	-	5,651.90	46,487.38	25,101.92

NPV in 2022 $		
	Five Year	(767,546.58)
	Ten Year	(600,902.61)
	Life	(471,840.00)

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)	42.00
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 Application 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) ($)	Present Value ($)
2022	91	-	182,000	12.00	-	52.30	10,610.60	227,500.00	-	(216,889.40)	(216,889.40)
2023	91	-	182,000	12.36	-	54.20	10,989.16	-	-	10,989.16	10,515.94
2024	91	-	182,000	12.73	-	55.70	11,295.90	-	-	11,295.90	10,344.00
2025	91	-	182,000	13.11	-	57.00	11,567.26	-	-	11,567.26	10,136.35
2026	91	-	182,000	13.51	-	61.00	12,331.06	-	-	12,331.06	10,340.35
2027	91	-	182,000	13.91	-	63.00	12,731.93	-	-	12,731.93	10,216.75
2028	91	-	182,000	14.33	-	65.00	13,133.91	-	-	13,133.91	10,085.47
2029	91	-	182,000	14.76	-	45.00	9,533.02	-	-	9,533.02	7,005.14
2030	91	-	182,000	15.20	-	46.35	9,819.01	-	-	9,819.01	6,904.58
2031	91	-	182,000	15.66	-	47.74	10,113.58	-	-	10,113.58	6,805.47
2032	91	-	182,000	16.13	-	49.17	10,416.99	-	-	10,416.99	6,707.79
2033	91	-	182,000	16.61	-	50.65	10,729.50	-	-	10,729.50	6,611.50
2034	91	-	182,000	17.11	-	52.17	11,051.39	-	-	11,051.39	6,516.60
2035	91	-	182,000	17.62	-	53.73	11,382.93	-	-	11,382.93	6,423.06
2036	91	-	182,000	18.15	-	55.34	11,724.41	-	-	11,724.41	6,330.87
2037	91	-	182,000	18.70	-	57.00	12,076.15	-	-	12,076.15	6,239.99
2038	91	-	182,000	19.26	-	58.71	12,438.43	-	-	12,438.43	6,150.42
2039	91	-	182,000	19.83	-	60.48	12,811.58	-	-	12,811.58	6,062.14
2040	91	-	182,000	20.43	-	62.29	13,195.93	-	-	13,195.93	5,975.12
2041	91	-	182,000	21.04	-	64.16	13,591.81	-	-	13,591.81	5,889.36

NPV in 2022 $		
	Five Year	(175,552.77)
	Ten Year	(134,535.35)
	Life	(71,628.49)

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)	42.00
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 Application 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) ($)	Present Value ($)
2022	90	90	90,000	12.00	-	52.30	5,787.00	180,000.00	-	(174,213.00)	(174,213.00)
2023	90	90	90,000	12.36	-	54.20	5,990.40	-	-	5,990.40	5,732.44
2024	90	90	90,000	12.73	-	55.70	6,158.77	-	-	6,158.77	5,639.77
2025	90	90	90,000	13.11	-	57.00	6,310.15	-	-	6,310.15	5,529.56
2026	90	90	90,000	13.51	-	61.00	6,705.55	-	-	6,705.55	5,623.01
2027	90	90	90,000	13.91	-	63.00	6,922.02	-	-	6,922.02	5,554.58
2028	90	90	90,000	14.33	-	65.00	7,139.58	-	-	7,139.58	5,482.45
2029	90	90	90,000	14.76	-	45.00	5,378.26	-	-	5,378.26	3,952.10
2030	90	90	90,000	15.20	-	46.35	5,539.61	-	-	5,539.61	3,895.37
2031	90	90	90,000	15.66	-	47.74	5,705.80	-	-	5,705.80	3,839.46
2032	90	90	90,000	16.13	-	49.17	5,876.97	-	-	5,876.97	3,784.35
2033	90	90	90,000	16.61	-	50.65	6,053.28	-	-	6,053.28	3,730.03
2034	90	90	90,000	17.11	-	52.17	6,234.88	-	-	6,234.88	3,676.48
2035	90	90	90,000	17.62	-	53.73	6,421.93	-	-	6,421.93	3,623.71
2036	90	90	90,000	18.15	-	55.34	6,614.59	-	-	6,614.59	3,571.70
2037	90	90	90,000	18.70	-	57.00	6,813.02	-	-	6,813.02	3,520.43
2038	90	90	90,000	19.26	-	58.71	7,017.41	-	-	7,017.41	3,469.90
2039	90	90	90,000	19.83	-	60.48	7,227.94	-	-	7,227.94	3,420.09
2040	90	90	90,000	20.43	-	62.29	7,444.77	-	-	7,444.77	3,371.00
2041	90	90	90,000	21.04	-	64.16	7,668.12	-	-	7,668.12	3,322.61

NPV in 2022 $		
	Five Year	(151,688.21)
	Ten Year	(128,964.25)
	Life	(93,473.97)

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

Program Costs	Amount
Admin Cost (total $/year)	6,000.00
Capital Cost ($/unit)	4,000.00
Maintenance Cost ($/year/unit)	140.00
Cost Escalation (%/year)	2.50%

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	42.00
Rate Escalation (%/yr)	3.00%
Measure Life	15
Discount Rate	4.50%

Estimated Applicability	Amount
Estimated Commercial/Industrial Customers	3,647
Estimated Application 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) ($)	Present Value ($)
2022	910	910	1,592,500	12.00	-	52.30	94,207.75	728,000.00	31,480.00	(665,272.25)	(665,272.25)
2023	910	910	1,592,500	12.36	-	54.20	97,561.10	-	32,267.00	65,294.10	62,482.39
2024	910	910	1,592,500	12.73	-	55.70	100,287.28	-	33,073.68	67,213.60	61,549.51
2025	910	910	1,592,500	13.11	-	57.00	102,705.08	-	33,900.52	68,804.56	60,293.20
2026	910	910	1,592,500	13.51	-	61.00	109,433.06	-	34,748.03	74,685.03	62,627.98
2027	910	910	1,592,500	13.91	-	63.00	112,986.77	-	35,616.73	77,370.04	62,085.67
2028	910	910	1,592,500	14.33	-	65.00	116,551.55	-	36,507.15	80,044.40	61,465.76
2029	910	910	1,592,500	14.76	-	45.00	85,092.72	-	37,419.83	47,672.90	35,031.40
2030	910	910	1,592,500	15.20	-	46.35	87,645.50	-	38,355.32	49,290.18	34,660.12
2031	910	910	1,592,500	15.66	-	47.74	90,274.87	-	39,314.21	50,960.66	34,291.66
2032	910	910	1,592,500	16.13	-	49.17	92,983.12	-	40,297.06	52,686.05	33,926.01
2033	910	910	1,592,500	16.61	-	50.65	95,772.61	-	41,304.49	54,468.12	33,563.19
2034	910	910	1,592,500	17.11	-	52.17	98,645.79	-	42,337.10	56,308.69	33,203.20
2035	910	910	1,592,500	17.62	-	53.73	101,605.16	-	43,395.53	58,209.63	32,846.05
2036	910	910	1,592,500	18.15	-	55.34	104,653.32	-	44,480.42	60,172.90	32,491.73

NPV in 2022 $		
	Five Year	(418,319.17)
	Ten Year	(190,784.56)
	Life	(24,754.39)

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

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%

Power Cost and Economic Parameters	
Summer Capacity ($/kW-season)	12.00
Winter Capacity ($/kW-season)	-
Avoided Energy Cost ($/MWh)	42.00
Rate Escalation (%/yr)	3.00%
Measure Life	30
Discount Rate	4.50%

Estimated Applicability	Amount
Estimated Industrial Customers	99
Estimated Application 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) ($)	Present Value ($)
2022	750	750	37,500	12.00	-	52.30	10,961.25	62,500.00	12,250.00	(63,788.75)	(63,788.75)
2023	750	750	37,500	12.36	-	54.20	11,302.50	-	12,556.25	(1,253.75)	(1,199.76)
2024	750	750	37,500	12.73	-	55.70	11,636.85	-	12,870.16	(1,233.31)	(1,129.38)
2025	750	750	37,500	13.11	-	57.00	11,972.04	-	13,191.91	(1,219.87)	(1,068.97)
2026	750	750	37,500	13.51	-	61.00	12,417.08	-	13,521.71	(1,104.63)	(926.30)
2027	750	750	37,500	13.91	-	63.00	12,795.97	-	13,859.75	(1,063.78)	(853.63)
2028	750	750	37,500	14.33	-	65.00	13,183.97	-	14,206.24	(1,022.27)	(785.00)
2029	750	750	37,500	14.76	-	45.00	12,756.36	-	14,561.40	(1,805.04)	(1,326.39)
2030	750	750	37,500	15.20	-	46.35	13,139.06	-	14,925.44	(1,786.38)	(1,256.16)
2031	750	750	37,500	15.66	-	47.74	13,533.23	-	15,298.57	(1,765.34)	(1,187.91)
2032	750	750	37,500	16.13	-	49.17	13,939.22	-	15,681.04	(1,741.81)	(1,121.60)
2033	750	750	37,500	16.61	-	50.65	14,357.40	-	16,073.06	(1,715.66)	(1,057.19)
2034	750	750	37,500	17.11	-	52.17	14,788.12	-	16,474.89	(1,686.77)	(994.62)
2035	750	750	37,500	17.62	-	53.73	15,231.77	-	16,886.76	(1,654.99)	(933.87)
2036	750	750	37,500	18.15	-	55.34	15,688.72	-	17,308.93	(1,620.21)	(874.87)
2037	750	750	37,500	18.70	-	57.00	16,159.38	-	17,741.65	(1,582.27)	(817.59)
2038	750	750	37,500	19.26	-	58.71	16,644.16	-	18,185.19	(1,541.03)	(761.99)
2039	750	750	37,500	19.83	-	60.48	17,143.49	-	18,639.82	(1,496.34)	(708.03)
2040	750	750	37,500	20.43	-	62.29	17,657.79	-	19,105.82	(1,448.03)	(655.67)
2041	750	750	37,500	21.04	-	64.16	18,187.53	-	19,583.46	(1,395.94)	(604.86)
2042	750	750	37,500	21.67	-	66.08	18,733.15	-	20,073.05	(1,339.90)	(555.58)
2043	750	750	37,500	22.32	-	68.07	19,295.15	-	20,574.88	(1,279.73)	(507.78)
2044	750	750	37,500	22.99	-	70.11	19,874.00	-	21,089.25	(1,215.25)	(461.43)
2045	750	750	37,500	23.68	-	72.21	20,470.22	-	21,616.48	(1,146.26)	(416.49)
2046	750	750	37,500	24.39	-	74.38	21,084.33	-	22,156.89	(1,072.57)	(372.93)
2047	750	750	37,500	25.13	-	76.61	21,716.86	-	22,710.82	(993.96)	(330.72)
2048	750	750	37,500	25.88	-	78.91	22,368.36	-	23,278.59	(910.22)	(289.82)
2049	750	750	37,500	26.66	-	81.28	23,039.41	-	23,860.55	(821.14)	(250.19)
2050	750	750	37,500	27.46	-	83.71	23,730.60	-	24,457.06	(726.47)	(211.82)
2051	750	750	37,500	28.28	-	86.22	24,442.51	-	25,068.49	(625.98)	(174.66)

NPV in 2022 $		
	Five Year	(68,113.15)
	Ten Year	(73,522.24)
	Life	(85,623.96)

Appendix B – Public Notices, Agendas, Resolution

Arkansas River Power Authority

BUSINESS OPERATIONS – December 2021

Integrated Resource Plan (IRP): The Arkansas River Power Authority is in the process of preparing an 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. The IRP must be submitted to WAPA by July 1, 2022.

One of the requirements of EPAMP is to provide opportunity for public participation. ARPA will accept written and verbal comments from affected retail customers of the six ARPA communities at its February 24, 2022 meeting and for a thirty working day period following the February 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 on May 26, 2022.

Interested parties may provide written comments directly to ARPA outside of the listed public meeting 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

ARPA Board Approves Power Sales Agreement with Guzman Energy, LLC: The Board of Directors of the Arkansas River Power Authority approved a resolution to enter into a Power Sales Agreement with Guzman Energy, LLC, headquartered in Denver, CO. The Agreement which is for the purchase and sale of electricity and related support functions begins February 1, 2025 and extends through 2043. Guzman Energy will provide power supply, scheduling, and transmission services to the Authority. With this Agreement comes predictable, fixed wholesale power pricing that ARPA believes will result in lower wholesale power rates for its member communities.

ARPA Board Adopts 2022 Budget: At its December meeting the ARPA Board of Directors approved its operating budget for 2022 in the amount of $24,858,361. Rates will remain unchanged and stable for the 2022 budget which includes:

- Revenues of approximately $30.46 million
- Power supply expense of approximately $14 million
- Transmission expense of approximately $3.5 million
- A&G expense of approximately $1.3 million
- Debt Service expense of $8.3 million

Summary of October 2021 Financial and Operating Statements: During the month of October, revenue from power sales were 4.7% less than budget and total cost of goods sold were under budget by 10%. Net Operating revenue for the month was $440,512. Year to Date revenues from power sales are just under budget (0.4%) and cost of goods sold are 3.1% under budget. Net Operating revenues YTD are $5 million. Member Energy sales were 5.3% less than budget in October and 4.5% less when compared to October 2020.

Operating Committee Reviews Distributed Generation (DG) Policy: The ARPA Operating Committee reviewed ARPA's DG Policy at its meeting in November. The focus of the meeting dealt with the reporting requirements and compensation method related to residential and commercial solar installations in the member's communities. The Committee will discuss the policy in further detail at its February meeting.

Next ARPA Meeting: The next regularly scheduled meeting of the ARPA Board of Directors is Thursday, February 24, 2022. The meeting will be held in La Junta at the Otero Junior College Student Center, 2001 San Juan. The meeting notice and agenda will be posted on ARPA's website (arpapower.org) under Public Notices and will also be posted in a designated location in each of the member cities at least 24 hours in advance of the meeting. ARPA board meetings are open to the public.

Arkansas River Power Authority

BUSINESS OPERATIONS – March 2022

Integrated Resource Plan (IRP): 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. ARPA will be accepting written and verbal comments from affected retail customers of the six ARPA communities through March 28, 2022. 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 on May 26, 2022. Interested parties may provide written comments directly to ARPA 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

ARPA Board College Scholarship Funding: The Arkansas River Power Authority Board of Directors established the College Scholarship Program in 2000. The Program is administered through our member municipalities of Holly, La Junta, Lamar, Las Animas, Springfield and Trinidad, Colorado. The scholarship is awarded to one high school senior in *each member municipality*. Currently, the total scholarship award is $1,000 funded equally between ARPA and the member municipality. Application forms, scholarship requirements, and eligibility criteria are available either through the counseling offices of the member high schools or at the local office of the electric utility. To be eligible, a student must reside with a family that receives electric service from one of the ARPA member municipalities.

Summary of January 2022 Financial and Operating Statements: During the month of January, revenue from power sales were 2.4% less than budget and total cost of goods sold were right on budget. Net Revenue for the month was $294,110. Member Energy sales were 1% less than budget in January but 2.6% better when compared to January 2021.

Town of Holly Trustees Appoints New Representative to the ARPA Board of Directors: Blaine Ice, a Trustee for the Town of Holly since April 2020, was appointed to the ARPA Board of Directors beginning January 1, 2022. Mr. Ice replaces outgoing Board Member Calvin Melcher who represented the Town of Holly on the ARPA Board from February 2019 through December 31, 2021. We wish to thank Calvin Melcher for his past service on the Board of Directors.

ARPA Holds Special Election for Vice President: At the February meeting the Board of Directors held a special election and elected Ron Clodfelter (Las Animas) to the office of Vice President. Other officers include P. Lorenz Sutherland (Pres., La Junta), Gary Cranson, (Treas., La Junta), and staff member Arvenia Morris serves as Secretary. The officers will hold office until the next annual election in May.

ARPA Board Receives Report on Financial Compliance: Aarin Ritter, Finance Manager for ARPA provided the annual Financial Compliance Report to the ARPA Board at its February meeting. Ms. Ritter reported that the Authority is in full compliance with its Bond Covenants including fully funding its Bond Accounts, meeting its Debt Service Coverage Ratio, and the posting of its ongoing financial disclosures, including the quarterly financial reports, on the Municipal Securities Rulemaking Board website- EMMA. ARPA's financial disclosures can be found at https://dataport.emma.msrb.org.

Next ARPA Meeting: The next regularly scheduled meeting of the ARPA Board of Directors is Thursday, May 26, 2022. The meeting will be held in La Junta at the Otero Junior College Student Center, 2001 San Juan. The meeting notice and agenda will be posted on ARPA's website (arpapower.org) under Public Notices and will also be posted in a designated location in each of the member cities at least 24 hours in advance of the meeting. ARPA board meetings are open to the public.

PUBLIC NOTICE

A meeting of the Arkansas River Power Authority (ARPA) Board of Directors will be held on Thursday, February 24, 2022, at 10:00 AM at the Otero Junior College Student Center, 2001 San Juan, La Junta, CO. The agenda will include a scheduled hearing at 11:50 AM 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. The agenda is also posted on the ARPA website (arpapower.org/agendas/) at least 24 hours prior to 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.

BOARD OF DIRECTORS MEETING AGENDA
Thursday, February 24, 2022, **10:00 AM**
Otero Junior College Student Center
2001 San Juan
La Junta, CO 81050

Board Members:

Holly:	Blaine Ice	*Springfield:*	Darwin Hansen
	Mike Tanner		Jay Suhler
La Junta:	Gary Cranson, Treasurer	*Trinidad:*	
	Lorenz Sutherland, President*		Carlos Lopez
Lamar:	Houssin Hourieh		
	Roger Stagner	*Executive Committee Members	
Las Animas:	Ron Clodfelter*	Arvenia Morris, Secretary	
	Richard Stwalley		

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 Minutes of the December 2, 2021 Regular Meeting
4. Public Comment – Members of the general public must limit their comments to three (3) minutes each, unless otherwise authorized by the ARPA Board President, or presiding officer
5. Executive Session CRS § 24-6-402 (4)(b) and (e)
    a. Power Supply Contract Negotiations
6. Consider Filling the Vacant Officer Position
7. Financial Report and Approval of Outstanding Bills
    a. 2021 4th Quarter Financial Review
    b. January 2022 Financial Statement
    c. Financial Modeling 2022-2027
    d. Financial Compliance Report
8. Operating Report
    a. Wind Report
9. Operating Committee Report
    a. Proposed Modifications to the Distributed Generation Policy
10. Update Banking Authorization Cards – Action Item
11. Integrated Resource Plan – Public Comments (11:50 AM)
12. General Manager Report
    a. Update on Tri-State Transmission Rate Filing
    b. Billing Dispute with PSCo
    c. Miscellaneous
13. New Business
    a. Consider Approval of First Amendment to Amended and Restated GM Employment Agreement
    b. Consider Agreement for Sale of Renewable Energy Certificates
14. Unfinished Business
15. Planning and Communication
    a. ARPA Scholarship Program
    b. APPA National Conference- June 10-15
16. Member Cities Reports
17. Next Meeting Date: May 26, 2022, in La Junta at Otero Junior College Student Center
18. Adjourn

PUBLIC NOTICE

A meeting of the Arkansas River Power Authority (ARPA) Operating Committee will be held on Thursday, May 19, 2022, at 9:30 AM, at the City of Las Animas City Council Chambers.

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. ARPA Operating Committee meetings are open to the public.

A proposed agenda for the meeting will be posted on the ARPA website (arpapower.org/agendas/) at least 24 hours prior to 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.

Operating Committee Meeting Agenda
May 19, 2022, **9:30 AM**
Las Animas City Council Chambers
532 Carson
Las Animas, CO 81054

Operating Committee Members:

Holly:	Vacant	*Las Animas:*	Ron Clodfelter
La Junta:	Bill Jackson	*Springfield:*	Heath Piper
Lamar:	Houssin Hourieh	*Trinidad:*	Vacant

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

1. Call to Order

2. Approval of Agenda

3. Approval of Minutes
   a. February 8, 2022

4. Renewable Distributed Generation Policy
   a. Consider Modifications to DG Policy

5. Power Supply Discussion
   a. Update on Renewable Projects
      i. Review of Renewable Project Development Checklist
      ii. Review of New Load Development Checklist

6. Discussion on Rate Studies

7. Miscellaneous
   a. Integrated Resource Plan (IRP)
   b. Discussion on Supply Chain Issues
   c. Poletop and Bucket Truck Rescue Safety Training – June 21

8. Review Bids for Equipment Testing 2022-2024

9. Member Utility Reports
   a. Summer Loads/Resources
   b. Sales and Operations

10. Next Meeting Date

11. Adjourn

PUBLIC NOTICE

A meeting of the Arkansas River Power Authority (ARPA) Board of Directors will be held on Thursday, May 26, 2022, at 10:00 AM at the Otero Junior College Student Center, 2001 San Juan, La Junta, CO.

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. The agenda is also posted on the ARPA website (arpapower.org/agendas/) at least 24 hours prior to 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.

BOARD OF DIRECTORS MEETING AGENDA
Thursday, May 26, 2022, **10:00 AM**
Otero Junior College Student Center
2001 San Juan
La Junta, CO 81050

Board Members:

Holly:	Blaine Ice	*Springfield:*	(vacancy)
	Mike Tanner		Jay Suhler
La Junta:	Gary Cranson, Treasurer	*Trinidad:*	(vacancy)
	Lorenz Sutherland, President*		Carlos Lopez
Lamar:	Houssin Hourieh		
	Roger Stagner	*Executive Committee Members	
Las Animas:	Ron Clodfelter, Vice President*	Arvenia Morris, Secretary	
	Richard Stwalley		

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 Minutes of the February 24, 2022 Regular Meeting
4. Public Comment – Members of the general public must limit their comments to three (3) minutes each, unless otherwise authorized by the ARPA Board President, or presiding officer
5. Executive Session CRS § 24-6-402 (4)(b)(e) and (f)
    a. General Manager's Contract Review
    b. Power Supply Contract Negotiations
6. Financial Report and Approval of Outstanding Bills
    a. 2022 1st Quarter Financial Review
    b. April 2022 Financial Statement
    c. Projected Year End Financials
7. Presentation of the 2021 Audited Financial Statements (time TBD)
    a. Resolution No. __-22
8. Operating Report
    a. Wind Report
9. Operating Committee Report
10. 2022 Integrated Resource Plan
    a. Resolution No. __-22
11. General Manager Report
    a. Update on Tri-State Transmission Rate Filing
    b. Billing Dispute with PSCo
    c. Update on WAPA Activities
    d. Miscellaneous
12. New Business
    a. Consider Approval of Environmental Attributes Management Agreement
    b. Consider Adopting Revised Renewable Distributed Generation Policy (Board of Directors Policy No. 4)
    c. Consider General Manager's Contract Extension
13. Unfinished Business
14. Planning and Communication
    a. ARPA Scholarship Program
    b. APPA National Conference- June 10-15
15. Member Cities Reports
16. Next Meeting Date: August 25, 2022, in La Junta at Otero Junior College Student Center
17. Adjourn

RESOLUTION NO. 02 - 22

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 chief purpose of the Arkansas River Power Authority (ARPA or "Authority"), an intergovernmental entity and political subdivision of the State of Colorado, is to provide the wholesale electric requirements of its member municipalities, each of whom furnish retail electric service in their local communities. ARPA's members are the Colorado municipalities of Holly, Lamar, La Junta, Las Animas, Springfield and Trinidad.

WHEREAS, the 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 Colorado River Storage Projects. 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.

WHEREAS, ARPA has prepared its sixth IRP ("2022 IRP") since the enactment of the EPAct in compliance with Western's implementing rules.

WHEREAS, the 2022 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.

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.

WHEREAS, ARPA entered into a contract with a consulting firm to draft the 2022 IRP which was presented to the public and the Authority's Board of Directors at their meeting on February 24, 2022.

WHEREAS, A final draft of the 2022 IRP was provided to the Authority's Board of Directors at their meeting on May 26, 2022 for review, final comment and approval.

WHEREAS, the Board of Directors of the Authority, now being fully briefed on the proposed 2022 IRP and being fully advised, hereby takes the following action:

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 26, 2022, is hereby approved.

2. The 2022 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 2022 IRP.

4. The Board of Directors reserves the right to modify the 2022 IRP to take into account changed circumstances and operational and economic considerations.

Approved by the Board of Directors on this 26th day of May 2022.

P. Lorenz Sutherland
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. 02- 22 adopted by the Board of Directors of the Arkansas River Power Authority at a regularly scheduled meeting on May 26, 2022, at which a quorum of the Board was present and voting.

(SEAL)

Arvenia L. Morris