Electric Resource Plan

Assessment of Existing Resources

for

Tri-State Generation and Transmission Association, Inc.

Submitted to:

Colorado Public Utilities Commission

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Compliance Table

Rule	Section
3605(c)(I)(A-E,J,K)	Owned and Leased Resources
3605(c)(I)(F-G,L)	Purchased Power Resources
3605(c)(I)(I)	Demand Side Management & Energy Efficiency
3605(c)(I)(C,H)	Projected Annual Emissions, Capacity Factors and Availability
3605(c)(II)	Benchmarking
3605(c)(III)	Ancillary Service Assessment

Background

Pursuant to Commission Decision No. C20-0304, in Proceeding No. 19R-0408E and Rule 3605 (a)(i) of the Colorado Public Utilities Commission's Rules Regulating Electric Utilities, Tri-State Generation and Transmission Association, Inc. (Tri-State) submits the following assessment of existing resources pursuant to paragraph 3605 (c) to the Public Utilities Commission of Colorado (Commission).

Summary

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 43 Utility Member systems located across four states, operating within multiple Balancing Authorities and served by multiple Transmission Providers. Additionally, Tri-State's load is dispersed in multiple states and between the Eastern Interconnection grid and the Western Interconnection grid. Tri-State's load in the Eastern Interconnection, which primarily includes loads in Nebraska along with a small amount of northeastern Colorado load, is served by an all requirements contract with Basin Electric Power Cooperative (BEPC). Resources for serving Tri-State load in the Western Interconnection, which includes loads in Wyoming, Nebraska, Colorado and New Mexico, are a combination of company owned resources and power purchase agreements.

Figure 1 below illustrates the geographic diversity of Tri-State's load and resources along with Tri-State Merchant[1]-owned transmission capacity and related transmission constraints. In the Western Interconnection, Tri-State Merchant is a network transmission customer of the following Transmission Providers:

- Tri-State Generation & Transmission Association (Tri-State Transmission)
- Public Service of Colorado (PSCo)
- Platte River Power Authority
- Western Area Power Administration (WAPA) Rocky Mountain Region Loveland Area Projects
- Black Hills Energy Colorado
- PacifiCorp

Additionally, Tri-State Merchant is a point-to-point transmission customer of many Transmission Providers in the Western Interconnection. Tri-State Merchant uses these network and point-to-point transmission rights within Western Electricity Coordinating Council (WECC) TOT capacity limits and other system constraints to schedule power from resources to loads on a day ahead and hourly basis to serve Utility Member system loads.

[1] Tri-State Merchant is the marketing arm of Tri-State Generation and Transmission Association that is responsible for planning and originations in regard to energy, capacity and transmission necessary to serve Utility Member system load along with related dispatch, scheduling and settlements activity.

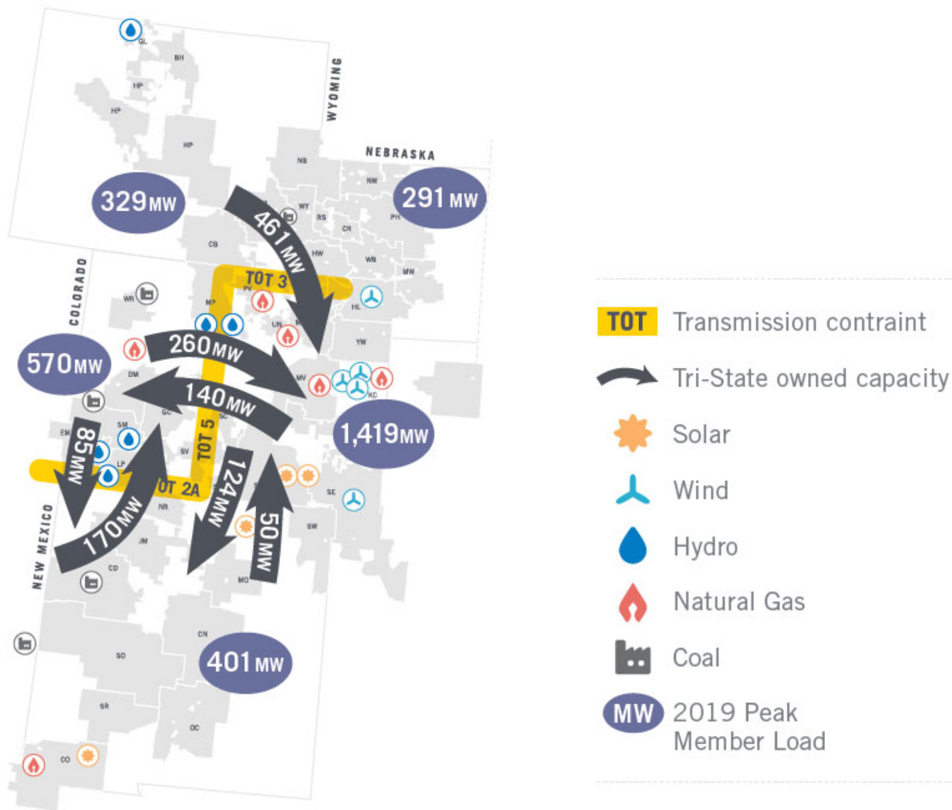

Figure 1 – Tri-State System Map

The following assessment describes existing resources both operational and contracted for at the time of this filing with appropriate detail as prescribed in 3605(c).

Assessment of Existing Resources

1. Owned & Leased Resources

Assessment Approach

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. Assessment excludes the following items, as Tri-State does not have any applicable resources in these categories:

- Thermal resources under contract (3605(c)(I)(A))
- Utility-owned energy storage resources (3605(c)(I)(A))
- Utility-owned thermal resources that are not in service at this time (3605(c)(I)(D))

The following assumptions and interpretations apply:

- Escalante is excluded, as it will be retired by December 31, 2020.
- Craig 1's useful life is identified as its announced retirement date. Original useful life was in the 2030s.

- Net Dependable Capacity for coal resources is the same MW value as Maximum Capacity. (3605(c)(I)(B))
- Net Dependable Capacity for gas resources varies by season and is identified by Summer and Winter Capacity MW values. Gas resources reach their maximum capacity level in the winter. (3605(c)(I)(B))
- Marginal heat rate is calculated as the average heat rate over the Resource Acquisition Period (RAP), which is identified as 2021 to 2030, for a typical dispatch.
- Fuel cost can be derived from provided heat rates for each resource and forward fuel curves for each fuel type. Tri-State does not utilize a forward fuel curve for oil, as our oil units are used for reliability events, not economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental; data will be refreshed as 2019 actuals are finalized and updated in the December 1, 2020, ERP filing.
- For Revenue Requirements where Tri-State has partial ownership in a resource, costs represent Tri-State's pro-rata share.
- There are no planned significant new investment or maintenance expenses. O&M and Capex costs are representative of necessary maintenance and improvements to maintain reliability of the resources. (3605(c)(I)(E))
- Annual capital expenses are an average of annual expenses over the Resource Planning Period of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Costs associated with the use of emissions control systems are not separately forecasted, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, Social Cost of Carbon is included in the revenue requirement tables for thermal resources, as Tri-State is aware of the requirement to consider this value in its assessment of resources and resulting dispatches in relation to the ERP process. The Social Cost of Carbon is calculated as the resource carbon emission rate of each unit in tons per MWh times $46.00/ton social cost of carbon.
- Tri-State's gas fleet consists of intermediate and peaking units, which are designed for cycling; therefore, no cycling or integration costs are identified for those resources. (3605(c)(I)(J))

Coal-Fueled Generation Resources

Craig Generating Station: Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Tri-State owns a 24% interest in Craig Units 1 and 2 (Yampa Project)[2], which have nameplate ratings of 427 MW and 410 MW, respectively; a 100% interest in Craig Unit 3, which has a capacity of 448 MW; and a 49% interest in the common facilities, which serve all three units. Tri-State is the operating agent for all three units and is responsible for the daily management, administration and maintenance of the facility. The non-fuel costs associated with operating Craig units 1 and 2 are divided on a pro-rata basis among all the participants[3]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to

[2] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[3] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.

retire Craig Unit 1 by December 31, 2025, as part of revisions to the Colorado regional haze State Implementation Plan. Tri-State has also announced that Craig Units 2 and 3 will be retired by 2030.

Laramie River Generating Station: The Laramie River Station (LRS) is a three-unit, 1,710 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[4], Tri-State has a 27.1% interest (464 MW) in LRS. For operational purposes, Tri-State receives energy only from LRS 2 and 3 due to their location in the Western Interconnection. LRS 1 is scheduled solely to the Eastern Interconnection and Tri-State does not receive energy from this resource. LRS is operated by BEPC.

Springerville Unit 3: Springerville Unit 3 is a 417 MW coal-fired electric generating unit that is part of the four-unit generation station located near Springerville, Arizona. One hundred percent of Unit 3 is leased by Tri-State. Tucson Electric Power (TEP) is the plant operator for the Springerville Generating Station.

Unit Characteristics

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Average Heat Rate *(btu/kWh)*	[redacted]					
Marginal Heat Rate *(btu/kWh)*						
Quick Start Capable *(Yes/No)*	No	No	No	No	No	No
Minimum Operating Level *(MW)*	31	31	130	94	94	109
Useful Life	12/31/2025	12/31/2039	12/31/2044	12/31/2041	12/31/2042	12/31/2066

Emission Rates

lbs. per MWH	CO_2	SO_2	NOx	PM	HG
Craig 1	2319	0.378	2.771	0.042	0.00001700
Craig 2	2350	0.345	0.672	0.047	0.00001400
Craig 3	2090	1.308	2.248	0.061	0.00007800
LRS 2	2203	1.101	2.331	0.095	0.00004110
LRS 3	2407	1.823	2.410	0.177	0.00004680
SPV3	2139	0.838	0.787	0.031	0.00001600

CO2, SO2, and NOx are lbs. per net MWh; PM and HG are lbs. per Gross MWh

Revenue Requirements

	Fixed O&M Annual *($000s)*	Variable O&M *($/MWH)*	CapEx Costs Annual *($000s)*	Social Cost of Carbon *($/MWh)*	Integration & Cycling Costs *($/MWh)*	Fuel Curve *(See Figure 2)*
Craig 1	[redacted]		~$500	$53.34	[redacted]	

[4] The Missouri Basin Power Project is the Laramie River Electric Generating Station and Transmission System located in Wyoming. Its participants include Tri-State, BEPC, the Western Minnesota Municipal Power Agency (Missouri River Energy Services), the Lincoln Electric System, and the Wyoming Municipal Power Agency.

Craig 2	[redacted]	~$500	$54.05	[redacted]
Craig 3	[redacted]	~$3,000	$48.07	[redacted]
LRS 2	[redacted]	~$1,500	$50.67	[redacted]
LRS 3	[redacted]	~$1,500	$55.36	[redacted]

Tri-State forward coal prices change annually. Figure 2 below shows the current coal forward curve inclusive of inflation. CRG (All-In), LRSG and SPV3 values are all inclusive costs of fuel. CRG (Inc) is the Craig coal cost as an incremental value.

[redacted]

Figure 2 – Coal Price Curve

Gas & Oil-Fueled Generation Resources

Below capacity ratings are composite annual MW rating.

<u>J.M. Shafer Generating Station:</u> J.M. Shafer is a 272 MW natural gas-fueled, combined-cycle power plant located north of Fort Lupton, Colorado. The facility is a wholly-owned Tri-State subsidiary, Thermo Cogeneration Partnership, L.P., and operated by Tri-State.

<u>Rifle Generating Station:</u> Rifle Station is an 81 MW, natural gas-fueled combined-cycle power plant located near Rifle, Colorado. The facility is wholly owned and operated by Tri-State.

<u>Limon Generating Station:</u> Limon Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Limon, Colorado. It is wholly owned and operated by Tri-State.

<u>Knutson Generating Station:</u> Knutson Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Brighton, Colorado. It is wholly owned and operated by Tri-State.

Pyramid Generating Station: Pyramid Station is a four-unit, 160 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Lordsburg, New Mexico. It is wholly owned and operated by Tri-State.

Burlington Generating Station: Burlington Station is a two-unit, 110 MW, oil-fired simple cycle combustion turbine facility located in Burlington, Colorado. It is wholly owned and operated by Tri-State.

Unit Characteristics

	JM Shafer	Rifle	Limon	Knutson	Pyramid	Burlington
Summer Capacity *(MW)*	272	72	67	67	40	48
Winter Capacity *(MW)*	272	84	74	74	40	60
Fuel type	NG	NG	NG/FO	NG/FO	NG/FO	FO
Average Heat Rate *(btu/kWh)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Marginal Heat Rate *(btu/kWh)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-[5]
Quick Start Capable *(Yes/No)*	No	No	Yes	No	Yes	Yes
Minimum Operating Level *(MW)*	41	22	40	40	25	25
Useful Life	12/31/2047	12/31/2028	12/31/2048	12/31/2048	12/31/2049	12/31/2037

NG = Natural Gas; FO = Fuel Oil

Emission Rates

lbs. per MWH	CO_2	SO_2	NOx	PM	HG
JM Shafer	981	0.008	0.747	0.080	n/a
Rifle	1206	0.001	2.611	0.239	n/a
Limon	1495	0.008	0.378	0.062	n/a
Knutson	1502	0.009	0.341	0.124	n/a
Pyramid	1240	0.012	1.223	0.070	n/a
Burlington	2149	0.194	12.383	0.158	n/a

CO2, SO2, and NOx are lbs. per net MWh; PM is lbs. per Gross MWh

Revenue Requirements

	Fixed O&M Annual *($000s)*	**Variable O&M** *($/MWH)*	**CapEx Costs Annual** *($000s)*	**Social Cost of Carbon** *($/MWh)*	**Fuel Curve** *(See Figure 3)*
JM Shafer	[redacted]	[redacted]	~$1,500	$22.56	[redacted]
Rifle	[redacted]	[redacted]	~$200	$27.74	[redacted]
Limon	[redacted]	[redacted]	~$275	$34.39	[redacted]
Knutson	[redacted]	[redacted]	~$400	$34.55	[redacted]
Pyramid	[redacted]	[redacted]	~$300	$28.52	[redacted]

[5] Burlington did not dispatch over the RAP

Burlington	[redacted]	~$450	$49.42	[redacted]

Tri-State forward gas prices change monthly. Figure 3 below shows the current gas forward curve without inflation. Additional transport costs apply.

[redacted]

Figure 3 – Forward Gas Curve

Third Party Assessment

In preparation for Tri-State's 2020 Colorado Electric Resource Plan (ERP) and Western Area Power Administration's Integrated Resource Plan (IRP) processes, Tri-State engaged Black & Veatch (B&V) to assist Tri-State with this assessment of existing resources. The above data reflects the outcome of that assessment where applicable. Specific areas of recommended change were as follows:

B&V Recommendation	Conclusion
Increase Burlington Heat Rate	Adjustment made to heat rate curve
Change Availability Factor of Combined Cycle resources to 90%	Tri-State will make accommodations in modeling to reflect these changes.
Change Availability Factor of Combustion Turbine dual fuel resources to 96%	Tri-State will make accommodations in modeling to reflect these changes.
Change Availability Factor of Combustion Turbine oil resources to 98%	Tri-State will make accommodations in modeling to reflect these changes.
Reduction in Rifle Fixed Costs	Rifle fixed costs are based on historical data. Tri-State will continue to monitor Rifle fixed costs and adjust as necessary.
Reduction to Burlington and Rifle NOx emission rate	Burlington and Rifle NOx emissions are based on historical data. There are conditions specific to these units that make

	their emissions rates higher than industry averages, so this will remain at the higher level.
Increase to Rifle and Shafer SO_2 emission rates	Rifle and Shafer SO_2 emission rates are based on historical data. Tri-State will continue to monitor SO_2 for these units and update as needed.
Decrease of availability factor and related increase in equivalent forced outage rate for all gas units	Tri-State is reviewing this feedback and will take into consideration current and expected operation of gas and oil units and modify as determined to be necessary.

The Black & Veatch evaluation detail can be found in Appendix A Black & Veatch Report on Review of Existing Resources.

2. Projected Annual Emissions, Capacity Factors and Availability:

This section contains representative scenario data for emissions, capacity factors and availability during the RAP.

Base Case Scenario (typical dispatch):

The following values are based on a "typical" dispatch plan representative of Tri-State's current operations and announced resource additions and retirements. Expansion plan resources are required to support this dispatch. Greenhouse gas reduction requirements in the state of Colorado are not reflected in these numbers. Tri-State anticipates that an appropriate greenhouse gas reduction strategy will be developed in conjunction with the presently ongoing proceedings of the Colorado Air Quality Control Commission and as part of the ERP process.[6]

The below calculated emissions are based on generation by resource from the plan and applicable emission rates as identified in the Owned & Leased Resources section above.

Projected CO_2 Emissions (000s of Short Tons)

CO_2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	829	829	829	829	477	0	0	0	0	0
Craig 2	941	947	841	896	495	552	623	569	0	0
Craig 3	3357	3779	3352	3164	1851	2339	2156	2414	2955	0
LRS 2	2116	1847	2104	1935	1826	2116	2106	1872	2021	2031
LRS 3	2246	2144	1986	1933	2280	2039	2283	2281	1955	2198
SPV3	2025	1697	1920	1824	2292	2486	2583	2538	2648	2709
JM Shafer	376	285	46	142	226	182	145	104	111	125
Rifle	1	0	16	0	0	0	0	0	0	0
Limon	10	5	116	5	16	4	1	0	0	0
Knutson	23	16	137	6	14	2	1	0	0	0
Pyramid	11	34	8	5	90	90	84	83	46	37
Burlington	0	0	0	0	0	0	0	0	0	0

[6] The retirement of Craig 2 at the end of 2028 as illustrated in this dispatch is one of several possible scenarios. The official retirement date for Craig 2 will be determined by agreement of the Yampa participants.

Projected SO_2 Emission (Short Tons)

SO_2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	135	135	135	135	78	0	0	0	0	0	0
Craig 2	138	139	123	132	73	81	91	84	0	0	0
Craig 3	2101	2365	2098	1980	1159	1464	1350	1511	1850	0	0
LRS 2	1058	923	1052	967	913	1058	1053	935	1010	1015	888
LRS 3	1701	1624	1504	1464	1727	1544	1729	1727	1480	1664	1664
SPV3	793	665	752	714	898	974	1012	994	1038	1061	956
JM Shafer	2.99	2.27	0.36	1.13	1.80	1.45	1.15	0.82	0.88	1.00	1.22
Rifle	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limon	0.05	0.03	0.62	0.02	0.09	0.02	0.01	0.00	0.00	0.00	0.00
Knutson	0.14	0.10	0.83	0.04	0.09	0.01	0.01	0.00	0.00	0.00	0.00
Pyramid	0.11	0.33	0.08	0.04	0.88	0.87	0.82	0.81	0.45	0.36	0.58
Burlington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Projected NOx Emissions (Short Tons)

NOx	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	990	990	991	991	570	0	0	0	0	0
Craig 2	269	271	240	256	142	158	178	163	0	0
Craig 3	3611	4064	3605	3404	1991	2516	2319	2596	3179	0
LRS 2	2239	1954	2226	2047	1932	2239	2228	1981	2138	2149
LRS 3	2249	2147	1989	1936	2283	2042	2286	2283	1957	2200
SPV3	745	624	706	671	843	915	950	934	974	997
JM Shafer	287	217	35	108	172	139	110	79	84	95
Rifle	3	0	34	0	0	0	0	0	0	0
Limon	2	1	29	1	4	1	0	0	0	0
Knutson	5	4	31	1	3	1	0	0	0	0
Pyramid	11	34	8	4	89	88	83	82	45	37
Burlington	0	0	0	0	0	0	0	0	0	0

Projected Particulate Matter Emissions (Short Tons)

PM	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	16	16	16	16	9	0	0	0	0	0
Craig 2	20	20	18	19	11	12	13	12	0	0
Craig 3	106	120	106	100	59	74	68	76	94	0
LRS 2	98	86	98	90	85	99	98	87	94	95
LRS 3	178	170	157	153	180	161	181	180	155	174
SPV3	32	26	30	28	36	39	40	39	41	42
JM Shafer	31	24	4	12	19	15	12	9	9	10

Rifle	0.26	0.00	3.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limon	0.42	0.21	4.99	0.20	0.71	0.15	0.05	0.00	0.00	0.00
Knutson	1.94	1.32	11.37	0.51	1.17	0.20	0.10	0.00	0.00	0.00
Pyramid	0.62	1.94	0.46	0.26	5.13	5.12	4.79	4.73	2.61	2.12
Burlington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Projected Mercury Emissions (Short Tons)

hg	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	0.007	0.007	0.007	0.007	0.004	0.000	0.000	0.000	0.000	0.000
Craig 2	0.006	0.006	0.005	0.006	0.003	0.004	0.004	0.004	0.000	0.000
Craig 3	0.135	0.152	0.135	0.127	0.074	0.094	0.087	0.097	0.119	0.000
LRS 2	0.042	0.037	0.042	0.039	0.037	0.042	0.042	0.038	0.041	0.041
LRS 3	0.047	0.045	0.042	0.040	0.048	0.043	0.048	0.048	0.041	0.046
SPV3	0.016	0.014	0.016	0.015	0.019	0.020	0.021	0.021	0.022	0.022
JM Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Projected Annual Capacity Factors

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	80%	80%	80%	80%	46%	0%	0%	0%	0%	0%
Craig 2	93%	94%	83%	89%	49%	55%	62%	56%	0%	0%
Craig 3	82%	92%	82%	77%	45%	57%	53%	59%	72%	0%
LRS 2	95%	82%	94%	86%	82%	95%	94%	84%	90%	91%
LRS 3	92%	88%	81%	79%	93%	83%	93%	93%	80%	90%
SPV3	52%	43%	49%	47%	59%	64%	66%	65%	68%	69%
JM Shafer	32%	24%	4%	12%	19%	16%	12%	9%	9%	11%
Rifle	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	1%	13%	1%	2%	0%	0%	0%	0%	0%
Knutson	3%	2%	15%	1%	2%	0%	0%	0%	0%	0%
Pyramid	1%	4%	1%	1%	10%	10%	10%	10%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Projected Availability Factors 2021 to 2030

For modeling purposes, availability factors are a result of modeled equivalent forced outage rates as well as planned outage hours. Tri-State assumes a 4% equivalent forced outage rate for all coal-fired generation. Historically, gas and oil resources are not assigned an equivalent forced outage rate due to their limited annual capacity factors. Tri-State is currently updating its models to reflect recommended equivalent forced outage rates as provided by Black & Veatch (Appendix A).

Applicable Scheduled Outage Plan over the RAP:

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Start Date	[redacted]					
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						

3. Purchased Power Resources

The following list provides summary information regarding current firm purchase power agreements in regards to capacity, energy and demand side resources. Tri-State does not have any wheeling or coordination agreements that provide capacity and energy.

Contract Purchases and Renewable Power Purchase Agreements differ from thermal resources in regards to applicable characteristics and costs. The format used below is intended to present the applicable data for these agreements as required in Rule 3605(c).

Contract Purchases:

Basin Contract Rate of Delivery (CROD) Western Interconnection: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year. Effective Date 1/16/1975; Renewed Date 10/1/2017; Contract Expires 12/31/2050.

Basin Electrically East: All Requirements Purchase Contract for Electrically East Loads, Effective Date 1/16/1975; Renewed Date 10/1/2017; Contract Expires 12/31/2050.

Colorado River Storage Project (CRSP) WAPA: 231 MW summer capacity, ~1424 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract. Effective Date 10/1/1989; Renewed Date 10/1/2017; Contract Expires 9/30/2057.

- Contracts TS-89-0005 and PL-89-0002 expire end of day, 9/30/2024. Contract TS-17-0128 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/1/2024 through end of day 9/30/2057.

Loveland Area Projects (LAP) WAPA: 353 MW summer capacity, ~900 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract, Effective Date 10/1/1989; Contract Expiration 9/30/2054.

- Contract TS-89-0002 expires end of day, 9/30/2024. Contract TS-14-0238 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/01/2024 through end of day, 9/30/2054.
- LAP contract includes rights to Mt. Elbert pump back storage 176 MW summer capacity with a 70% efficiency and prescribed generating and pumping hours. The Mt. Elbert contract capacity shares transmission with the LAP contract and the combination of usage cannot exceed the LAP contract max capacity in any hour.

Native American WAPA Allocations: Monthly (fixed schedule peaking) at 5 MW annually, ~28 GWh/year. Effective Date 10/1/2004; Expires 10/1/2024.

Central Valley Electric: ~1 MW capacity, ~5 GWh/year. Effective Date 12/05/1996; Contract Expires Evergreen

Additionally, Tri-State has several contracts under WSPP agreements that serve Utility Member system load associated with wind and solar facility station service for generators that are under contract and deliver energy to third party utilities but are located in a Tri-State Utility Member's service territory. These contracts are de minimis in nature (i.e., under 1 GWh in annual energy; 2 MW maximum demand).

Energy and Capacity Payments for Contract Purchases

The following rates are averaged over the RAP:

Resource	**Energy Rate** *($/MWh)*	**Demand Rate** *($/KW-month)*
Basin CROD Western Interconnection	[redacted]	
Basin Electrically East		
CRSP		
LAP		
Native American WAPA Allocations		
Central Valley Electric		

Renewable Power Purchase Agreements:

Cimarron (First Solar) Purchase: Facility located in northeastern New Mexico, 30 MW (Maximum Capacity), ~64 GWh/year. Effective Date 2/23/2009; COD 11/25/2010; Contract Expires 11/24/2035.

Kit Carson Wind Purchase: Facility located in eastern Colorado, 51 MW (Maximum Capacity), ~185 GWh/year. Effective Date 6/30/2009; COD 11/19/2010; Contract Expires 11/30/2030.

Colorado Highlands Wind Purchase: Facility located in northeastern Colorado, 94 MW (Maximum Capacity) 91 MW (Nameplate Capacity), ~369 GWh/year. Effective Date 2/28/2012; COD 12/6/2012; Contract Expires 12/31/2032.

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[7] Composite rate encompassing energy and demand components
[8] Composite rate encompassing energy and demand components

Carousel Wind Purchase: Facility located in eastern Colorado, 150 MW (Maximum Capacity), ~665 GWh/year. Effective Date 12/27/2013; COD 07/07/2016; Contract Expires 7/31/2041.

San Isabel Solar Purchase: Facility located in southern Colorado, 30 MW (Maximum Capacity), ~77 GWh/year. Effective Date 8/19/2015; COD 12/5/2016; Contract Expires 12/31/2041.

Alta Luna Solar Purchase: Facility located in southern New Mexico, 25 MW (Maximum Capacity), ~77 GWh/year. Effective Date 9/24/2015; COD 1/12/2017; Contract Expires 01/31/2042.

Twin Buttes II Wind Purchase: Facility located in southeastern Colorado, 75 MW (Maximum Capacity), ~302 GWh/year. Effective Date 6/1/2015; COD 12/28/2017, Contract Expires 12/31/2042.

Spanish Peaks Solar Purchase: Facility located in southern Colorado, 100 MW (Maximum Capacity), ~267 GWh/year. Effective Date 12/12/2018; Expected COD 11/01/2023, Contract Expires 11/30/2038*.

Crossing Trails Wind Purchase: Facility located in eastern Colorado, 104 MW (Maximum Capacity), ~439 GWh/year. Effective Date 2/5/2019; Expected COD 12/18/2020, Contract Expires 12/31/2035*.

Niyol Wind Purchase: Facility located in northeastern Colorado, 200 MW (Maximum Capacity), ~843 GWh/Year. Effective Date 12/18/2019; Expected COD 12/31/2021, Contract Expires 12/31/2041*.

Escalante Solar Purchase: Facility located in western New Mexico, 200 MW (Maximum Capacity), ~566 GWh/Year. Effective Date 12/10/2019; Expected COD 11/30/2023, Contract Expires 11/30/2040*.

Axial Basin Solar Purchase: Facility located in northwestern Colorado, 145 MW (Maximum Capacity), ~370 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Dolores Canyon Solar Purchase: Facility located in southwestern Colorado, 110 MW (Maximum Capacity), ~297 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Spanish Peaks II Solar Purchase: Facility located in southern Colorado, 40 MW (Maximum Capacity), ~107 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Coyote Gulch Solar Purchase: Facility located in southwestern Colorado, 120 MW (Maximum Capacity), ~331 GWh/Year. Effective Date 1/13/2020; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

All solar power purchase agreements are assumed to have declining annual energy at approximately 0.5% per year to reflect solar panel degradation

*Contract expiration calculated from expected COD

Small Power Producers (Hydropower) contracts are as follows:

Facility Name (Maximum Capacity)	Effective Date	Expiration	Location
Boulder Hydro (5MW) & Other Facilities (1.27 MW)	6/1/2018	5/31/2028	Colorado
Denver Water/Williams Fork (3.5 MW)	1/1/2007	12/31/2026	Colorado
Mancos/Jackson Gulch (0.26 MW)	9/1/1995	2/8/2035	Colorado
Vallecito/Ptarmigan (5.6 MW)	6/25/2004	6/24/2024	Colorado
Garland Canal (2.9 MW)	12/10/2014	12/31/2024	Wyoming

Tri-County Water/Ridgway (8 MW)	8/22/2012	9/30/2023	Colorado

Energy Payments for Renewable Power Purchase Agreements

The following rates are averaged over the RAP. Capacity rates are not applicable to our Renewable Power Purchase Agreements:

Resource	Energy Rate *($/MWh)*
Cimarron	[redacted]
Kit Carson	
Colorado Highlands	
Carousel	
San Isabel	
Alta Luna	
Twin Buttes II	
Spanish Peaks	
Crossing Trails	
Niyol	
Escalante	
Axial	
Dolores Canyon	
Spanish Peaks II	
Coyote Gulch	
Boulder Hydro & Other Facilities	
Denver Water/Williams Fork	
Mancos/Jackson Gulch	
Vallecito/Ptarmigan	
Garland Canal	
Tri-County Hydropower	

Contract Provisions – Modification of Capacity and Energy Purchased

The above contract purchases and renewable purchase power agreements are a combination of must take energy or take or pay energy. Limited ability to modify capacity or energy purchased under these contracts exists. The few exceptions are listed below:

- Annually LAP contract capacity and energy is adjusted by WAPA per the contract formula. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- At predetermined dates in the CRSP contract, WAPA will adjust capacity and energy as necessary up to the maximum 1% withdrawal limit for the resource pool. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.

- All utility scale renewable projects have a right of first refusal option with regard to facility expansion and exercise of such option when made available could result in additional capacity and energy.
- All utility scale renewable projects allow for Tri-State to take excess energy produced over and above expected contract energy as defined by each contract
- The majority of Tri-State's utility scale renewable contracts have a provision to modify energy without penalty under certain conditions through an allowable curtailment option. The allowable curtailment amount varies by contract but does not exceed 1% of annual contract energy.

Utility Member System Distributed Generation

Tri-State's wholesale power contract with each of its Utility Member systems and applicable Tri-State Board policies allow for and facilitate the development of local distributed generation projects in Tri-State Utility Members' service territories, including community solar projects. These renewable and distributed projects help to fulfill both Colorado and New Mexico RES/RPS requirements, as well as satisfy Utility Members' and consumers' interest in purchasing renewable power from locally-sited projects.

As of May 2020, 66 renewable or distribution generation projects, totaling 136 MW of capacity and capable of producing ~380 GWh/year are operating or under development. Approximately 85% of Utility Member system distributed generation is located in Colorado, and on a capacity basis, approximately 75% of the distributed generation in Colorado and New Mexico is solar. It is expected that the number of these projects will continue to grow as pricing for renewable resources continues to be attractive and Utility Members continue to show interest in supporting local renewable projects. These numbers are also expected to grow as a result of Tri-State's Board of Directors approving a new policy in 2019 that will facilitate the development of community solar projects throughout its Utility Members' service territories.

These resources are not owned by, or contracted to, Tri-State, but instead serve Utility Member system load directly, so Tri-State has not attempted to provide a detailed assessment of these generation projects.

4. Demand Side Management & Energy Efficiency

As reported in Tri-State's 2019 Annual Progress Report an ongoing part of Tri-State's Action Plan is the implementation of Demand Side Management (DSM) and Energy Efficiency (EE) programs. Options that have been evaluated include programs related to residential, small commercial, irrigation, large commercial and industrial programs. These offerings are continually refined based on effectiveness and member feedback. As a reminder, Tri-State does not have retail load and is reliant upon Utility Member system participation in DSM and EE program implementations.

<u>Current offerings for Demand Side Management include:</u>

- Demand Response (DR) related to air conditioning, water heating and irrigation
  - Four Utility Member systems currently have irrigation DR programs

- Energy shaping related to electric thermal storage and electric vehicle charging station
    - Eleven Utility Member systems use time of use rates for storage heater control
    - Several Utility Member systems are investigating or have implemented residential demand rates in an attempt to control/shift load during peak times

Tri-State's current A-40 rate structure provides Tri-State's Utility Member systems an incentive to control load during Tri-State's defined peak period. Tri-State's A-40 rate consists of energy, generation demand and transmission demand rates. Many Utility Member systems successfully use active load control methods during Tri-State's defined peak period to reduce their monthly demand usage and related demand charges.

Current offerings for Energy Efficiency include:

- Heat Pump Projects working with the Electric Power Research Institute (EPRI) and our Utility Member systems
- Rebates on education programs for training in Energy Auditing
- Irrigation program to educate Utility Member systems in regards to efficiency
- Incentives are offered in many areas such as residential and commercial lighting, appliances, air conditioning, motors, air and ground source heat pumps and assisting in energy efficient education and training

Year End 2019 Cumulative Energy Efficiency Results:

Category	Typical Measures	kW Savings	kWh Savings
Agriculutural	Irrigation Motors Variable Speed Drive Retrofits	13,080	21,902,726
C&I HVAC	Air Source and Ground Source Heat Pumps	7,275	9,263,112
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	25,434	91,528,578
C&I Motors	Variable Speed Drive Retrofits	3,968	8,199,393
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	83,891	57,344,907
Residential - Othe	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	51,488	23,905,259
Total		**185,136**	**212,143,975**

Energy Efficiency Rebate History

- 2014 - $2,131,637

- 2015 - $2,128,582
- 2016 - $2,078,582
- 2017 - $2,349,835
- 2018 - $3,338,435
- 2019 - $3,327,027
- 2020 Budget - $6,697,353

Additionally, in late 2019, Tri-State initiated a Demand Side Management (DSM) and Energy Efficiency (EE) Potential study with an outside consultant with the goal of receiving updated information in regard to achievable potential and cost savings in these areas for use in Tri-State's 2020 ERP process. Tri-State intends to leverage this study along with Utility Member systems input to evolve and expand its DSM and EE products and services in a manner that is beneficial to Tri-State and Utility Member systems. Key findings from this study include:

- Identifies significant cost effective opportunities for energy and demand savings for energy efficiency programs
- Identifies limited opportunities for DR programs, but long-term operation is key for cost effectiveness
- Distributed Energy Resource (DER) programs are not cost-effective except for larger systems in specific regions

The complete study is included as Appendix C to this report.

5. Benchmarking

For the purposes of the Rule 3605(c)(II) Benchmarking requirement, Tri-State engaged Black & Veatch to perform an analysis of cost and performance of existing owned and contracted resources as compared to generic resources. The scope of this benchmarking analysis was limited to the following:

- Thermal and renewable utility scale resources that are:
  - Commercially operational, and
  - Located in the state of Colorado, or
  - Located outside of the state of Colorado but capable of serving Colorado load at any time.

Alta Luna and Cimarron renewable resources located in New Mexico are included in the benchmarking process but have never been scheduled to Colorado load.

Resources excluded from the benchmarking process include:

- Federal hydro contracts of LAP and CRSP as these long term, cost-based contracts for delivery of firm, renewable, quasi-dispatchable power contracts with certain transmission and ancillary service benefits do not have a reasonable comparison within the generic resource pool.

- Basin Electrically East contract as it is a full requirements contract in the Eastern Interconnection and Tri-State's resource planning process is focused on expansion planning related to Western Interconnection resources.
- Basin CROD contract as it is a shaped contract purchase at specific delivery points in Nebraska and Colorado delivered from unspecified source(s) and does not have a reasonable comparison within the generic resource pool.
- Other small contract purchases, small hydro power producer contracts

Additionally, neither Basin contract has a means by which to terminate the contract early, which would seem to make results from a benchmarking process for these contracts unactionable.

The full methodology, results and insights from the Black & Veatch Benchmarking process are located in Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

6. Ancillary Service Assessment

Tri-State meets its ancillary service requirements through Network Integration Transmission Service Agreements and Balancing Authority Ancillary Service Agreements. In the Western Interconnection, Tri-State receives ancillary services from PacifiCorp, PSCo, Public Service of New Mexico and WAPA. As mentioned previously in this report, Tri-State's electrically east load is served via a full requirements contract with BEPC, which includes ancillary services.

The following is a list of the primary ancillary services required via applicable Open Access Transmission Tariffs and how Tri-State acquires these services including any applicability to Tri-State resources:

<u>Scheduling, System Control & Dispatch:</u> Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Tri-State Resources do not have any impact on or relation to this service.

<u>Reactive Supply & Voltage Control:</u> Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Tri-State's generating resources do not have any impact on or relation to this service. Tri-State does, however, have several applicable agreements with entities to partially self-supply reactive support via transmission system equipment in exchange for a reduced cost in service. Separately, Tri-State generation resources are required via NERC Reliability Standards to follow reactive power instructions from Transmission Operators and operate in automatic voltage control mode.

<u>Regulation and Frequency Response (includes load following capabilities):</u> Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Applicable Tri-State-owned or contracted resources and Utility Member system distributed resources nameplate capacity are, at times, a factor in determining regulation cost, but Tri-State does not have any obligation to regulate for its own load or resources. Tri-State does, however, have generating resources that have the capability to operate in Automatic Generation Control (AGC) mode and thereby provide regulation as a service for a cost.

Tri-State generating resources that are AGC capable include:

- Craig 1, 2, and 3
- LRS 2
- Springerville 3
- JM Shafer
- Knutson 1,2
- Limon 1,2
- Pyramid 1,2,3,4
- Burlington 1,2

Energy Imbalance Service: Tri-State currently pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the Western Energy Imbalance Service (WEIS) and the Western Energy Imbalance Market (WEIM). Upon entry, Tri-State will be able to participate with its resources located within the respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Operating Reserve Spinning Service: Tri-State self-provides spinning reserves through Southwest Reserve Sharing Group membership and via two sub-entity Reserve Sharing Group Agreements. Tri-State generating resources typically online and capable of carrying spinning reserves include:

- Craig 1
- Craig 2
- Craig 3
- LRS2
- LRS3
- Springerville 3
- JM Shafer

Due to recent changes in operating standards in the Western Interconnection, operating reserves may be fully served via non-spinning supplemental service rather than the previous requirement that operating reserves must include of a minimum of 50% spinning reserves.

Operating Reserve Supplemental Service:

Tri-State self-supplies spinning reserves through Southwest Reserve Sharing Group member and via two sub-entity Reserve Sharing Group Agreements. Tri-State generating resources with quick start capability to qualify for supplemental service include:

- Burlington 1,2
- Limon 1,2
- Pyramid 1,2,3,4

Generator Imbalance Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the WEIS and the WEIM. Upon entry, Tri-State will be able to participate with its resources located within each respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Flex Reserve Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. This service is calculated based on proportional wind capacity contribution within the footprint as is used by the Balancing Authority to cover the costs of ramping requirements related to wind intermittency.

Loss Supply Service: Tri-State either pays for this service monthly from appropriate Transmission Providers or Balancing Authorities or provides physical loss requirement depending on specific contractual arrangements.

Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this Assessment of Existing Resources and which Tri-State has designated as confidential information:

- Black & Veatch Benchmarking of Existing Resources
- Black & Veatch Evaluation of Existing Resources
- Unit level heat rates
- Scheduled Outage Plan (Maintenance)
- Fixed O&M Expenses
- Variable O&M Expenses
- Integration and Cycling Costs
- Fuel Curves (Gas and Coal)
- Contract/PPA Energy Rate
- Contract/PPA Capacity Rate
- Purchase Contracts and Renewable Power Purchase Agreements
- Any information protected by a confidentiality clause in a PPA

Highly Confidential Information

With respect to the confidential information identified above, Tri-State believes the following subset of information requires extraordinary protection as highly confidential information:

- Unit level heat rates
- Fixed O&M Expenses
- Variable O&M Expenses
- Integration and Cycling Costs
- Fuel Curves (Gas and Coal)
- Contract/PPA Energy Rate
- Contract/PPA Capacity Rate
- Purchase Contracts and Renewable Power Purchase Agreements
- Any information protected by a confidentiality clause in a PPA

Tri-State has filed with the Commission an appropriate motion seeking extraordinary protection of this highly confidential information. Tri-State may designate confidential or highly confidential, as appropriate, additional information included in its full Electric Resource Plan when it is filed on December 1, 2020.

Appendix A: Black & Veatch Report on Review of Existing Resources

PUBLIC

This entire document contains **HIGHLY CONFIDENTIAL** or **CONFIDENTIAL** information and is being submitted under seal pursuant to the Commission's rules governing the submission of confidential information (4 CCR 723-1-1100).

PROCEEDING NO. 20M-0218E

Party: Tri-State Generation and Transmission Association, Inc.

Date: June 1, 2020

Description: Black & Veatch Report on Review of Existing Resources

Following the conclusion of the Commission proceedings and any related court proceedings, Tri-State requests that the Commission and other parties destroy this information by shredding or returning the information to Tri-State's attorneys assigned to this case in accordance with Commission Rule 1101(a)(III)E.

Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

PUBLIC

This entire document contains **HIGHLY CONFIDENTIAL** or **CONFIDENTIAL** information and is being submitted under seal pursuant to the Commission's rules governing the submission of confidential information (4 CCR 723-1-1100).

PROCEEDING NO. 20M-0218E

Party: Tri-State Generation and Transmission Association, Inc.

Date: June 1, 2020

Description: Black & Veatch Report on Benchmarking of Existing Resources

Following the conclusion of the Commission proceedings and any related court proceedings, Tri-State requests that the Commission and other parties destroy this information by shredding or returning the information to Tri-State's attorneys assigned to this case in accordance with Commission Rule 1101(a)(III)E.

Appendix C: Mesa Point Energy & BrightLine Group - Tri-State Demand Side Management and Energy Efficiency Potential Study

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

FOR TRI-STATE GENERATION & TRANSMISSION

MAY 8, 2020

Prepared by: Mesa Point Energy & BrightLine Group

TRI-STATE GENERGATION & TRANSMISSION
DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

MAY 8, 2020

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EXECUTIVE SUMMARY

Project Overview

Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) performed a demand side management potential study in support of Tri-State Generation and Transmission's (Tri-State) resources planning initiatives. The study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). The Mesa Point Team assessed the available technical, economic, and achievable energy and demand savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State.

The study focuses on energy efficiency, DR, and DER *achievable* potential; it is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, the study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations inherent and unique to the cooperative utility structure where each member can choose which products and measures to offer.

This Executive Summary presents an overview of the analysis approach, key assumptions, and study findings and the main report report goes into more detail on methods, savings, and findings.

A separate electronic reporting tool serves as an appendix to the report. The tool provides the ability to view findings in greater detail by sector, end-use, and region.

Results by Resource: EE, DR, DER

There are significant opportunities for cost-effective EE and DR savings in the Tri-State service territory. Behind-the-meter DER resources hold significant technical potential but realize limited cost-effective potential based on the analysis framework used for the study.

Given the uncertainty associated with customer adoption of energy-saving technologies, the Mesa Point Team developed achievable scenarios based on four different incentive and program delivery spending levels – from low to maximum levels of program funding.

These scenarios were:

1. Low – assumes incentivizing 25% of incremental cost
2. Moderate – 50% incentive level
3. Aggressive – 75% incentive level
4. Maximum – 100% of incremental cost. Note that maximum funding was assumed to be limited to 100% of the incremental cost to install a measure.

Key findings from each of the three resources assessed, EE, DR, and DER, are summarized below.

Energy Efficiency (EE) Resource

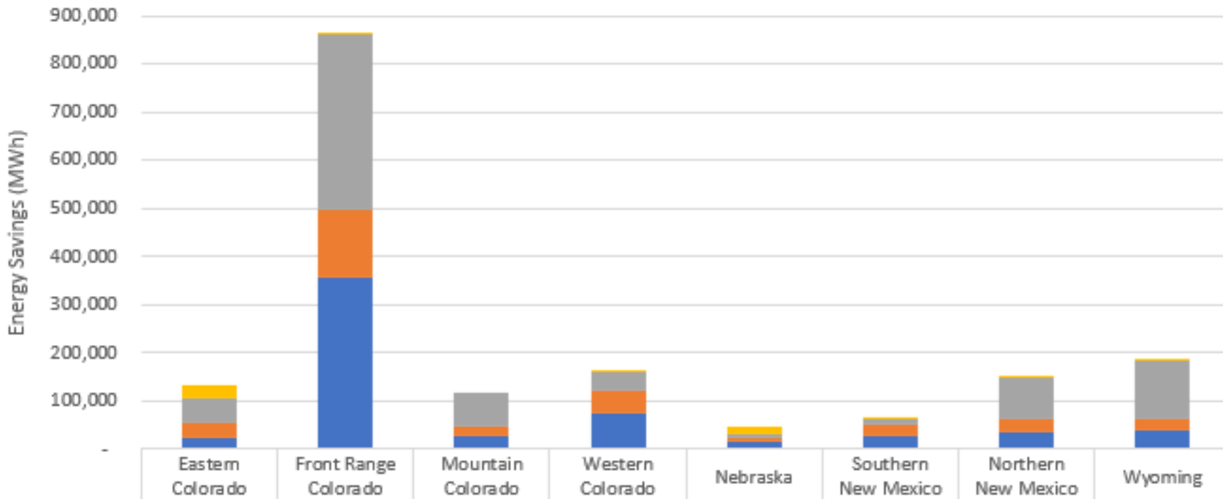
As summarized in Table ES-1, the Mesa Point Team found that the Achievable-moderate scenario would result in approximately 38 GWh (0.25% of sales) of energy efficiency saving in 2021 rising to 1,718 GWh (8.16% of sales) of savings through 2040.

Table ES-1. Portfolio Cumulative Energy Efficiency Savings by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Energy Savings (MWh)						
2021 (first year)	130,384	98,221	75,523	55,330	38,083	27,043
2025	1,293,033	928,122	539,750	393,656	266,309	179,222
2030	3,868,940	2,851,171	1,372,971	1,062,225	723,605	475,993
2040	9,081,432	6,956,507	2,876,487	2,354,365	1,718,357	1,193,109
% of Baseline Sales						
2021 (first year)	0.85%	0.64%	0.49%	0.36%	0.25%	0.18%
2025	7.88%	5.65%	3.29%	2.40%	1.62%	1.09%
2030	21.74%	16.02%	7.71%	5.97%	4.07%	2.67%
2040	43.14%	33.04%	13.66%	11.18%	8.16%	5.67%

Energy effiency savings potential breakdown shares similarities to energy load in terms of distribution by region and by sector (Figure ES-1 and Figure ES-5). Front Range Colorado has the largest cumulative energy savings potential with 860 GWh. Across all regions, the industrial customer sector has more than 744 GWh of cumulative energy savings potential, followed by the residential sector at just under 600 GWh.

Figure ES-1. 2040 Cumulative Energy Efficiency Savings Potential by Region by Customer Sector (Achievable-Moderate Scenario)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Western Colorado	Nebraska	Southern New Mexico	Northern New Mexico	Wyoming
Irrigation	29,895	68	-	220	16,315	3,631	2,735	270
Industrial	48,525	363,476	69,968	36,409	7,214	12,277	86,024	120,651
Commercial	32,506	142,190	19,629	49,150	9,063	23,289	29,223	21,334
Residential	23,366	354,282	27,962	72,760	13,675	28,489	33,310	40,453

Table ES-2 summarizes the key cumulative energy efficiency cost metrics across the portfolio at four time horizons under the Achievable-Moderate scenario, as well as 20-year averages across the full study time horizon. It is estimated that over the 20-year study horizon approximately 114 GWh of energy savings is achievable, on average, per year at a cost of $24.3 million for an acquisition cost of $212/MWh. Over the 20 year study horizon, and on a levelized basis, the cost to acquire all energy savings under the Achievable-Moderate scenario is $21.55/MWh.

Table ES-2. Portfolio Energy Efficiency Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	SUM OF ANNUAL PROGRAM COSTS ($)[1]	SUM OF FIRST YEAR MEASURE SAVINGS (MWH)	FINAL YEAR DEMAND SAVINGS (MW)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$6,957,787	38,083	5.28	$182.70	$15.25
2025	1.91	$54,155,251	279,461	9.91	$193.78	$17.41
2030	1.72	$164,148,094	797,374	17.25	$205.86	$20.18
2040	1.64	$486,794,842	2,290,399	23.11	$212.54	$21.55
20-year avg.	**1.64**	**$24,339,742**	**114,520**	13.89	**$212.54**	**$21.55**

Demand Response (DR) Resource

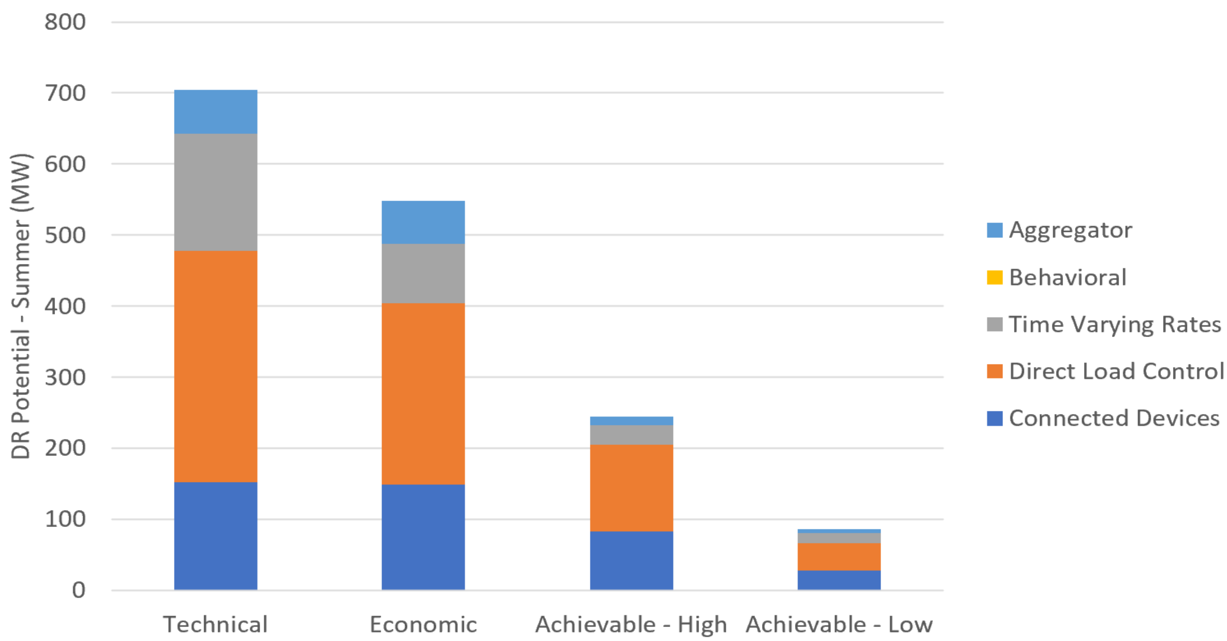
The study considered five different types of DR programs:

1. Aggregator – Capacity bidding programs managed by 3rd party aggregators
2. Behavioral – Personalized communication to customers requesting curtailed usage during peak events
3. Time varying rates – Customer retail electricity rates designed to shift usage by charging more during peak periods
4. Direct load control – Centralized remote control of customer equipment through installation of switches
5. Connected devices – Interaction with and control of internet-connected customer devices through web-based portals (e.g. Bring Your Own Thermostat programs)

Figure ES-2 shows the available DR potential across the portfolio by 2040 by program type. Connected device programs (primarily for Smart Thermostats) and Direct Load Control (DLC) (primarily for irrigation pumping) are the most significant program types.

[1] Includes administrative and incentive costs

Figure ES-2. Portfolio Demand Response Potential by Program Type (2040)



The DR analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. Because Tri-State does not control customer rates, implementing a CPP or TOU rate demand response programs would require a high level of collaboration with electric cooperatives.

Table ES-3 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cumulative total cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity until 2027.

Table ES-3. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)

MILESTONE YEAR	TRC RATIO	CUMULATIVE PROGRAM COST ($)	DR POTENTIAL (MW)
2021	0.02	$5,440,119	5
2025	0.09	$13,818,802	30
2030	0.60	$24,286,062	78
2040	1.16	$39,068,285	86

Distributed Energy Resource (DER)

The Team limited resources for the DER potential study to technologies that are behind-the-meter and owned by the customer; we did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040. We performed review and preliminary cost screens for other potential DER technologies such as combined heat and power and small wind but ultimately did not find these technologies applicable and/or cost effective.

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure ES-3 and Figure ES-4 below illustrate cumulative technically possible PV generation in 2040 compared to cumulative 2040 sales. It is interesting to note that in some areas of New Mexico solar power has the technical potential to produce more energy than is used. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency and relatively low consumption on average.

Figure ES-3. 2040 Technical Potential for Cumulative Residential PV Generation vs Sales by Region

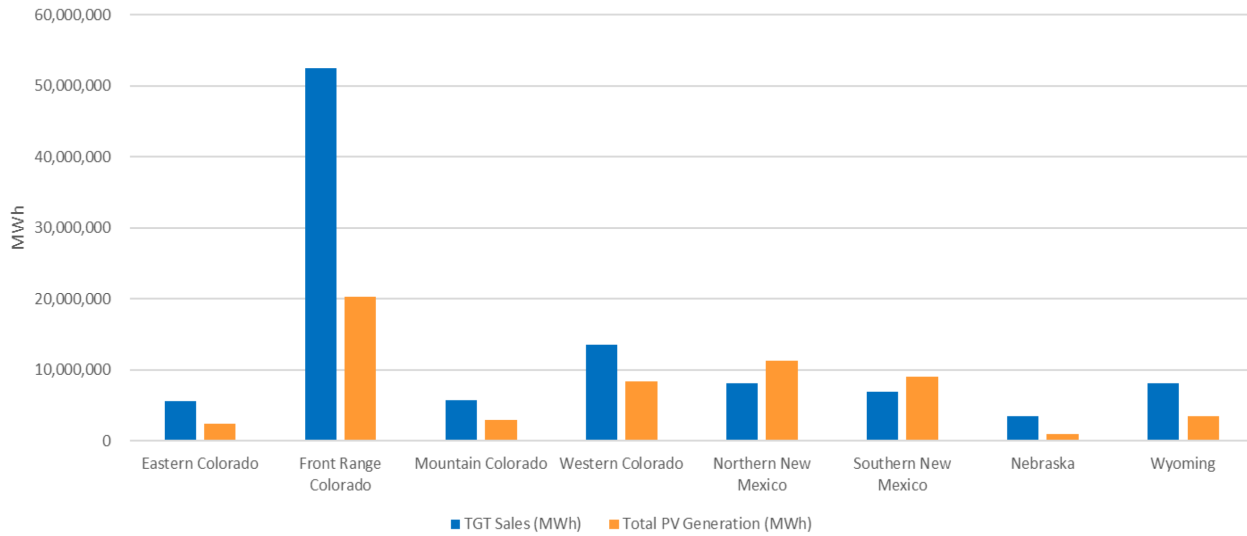
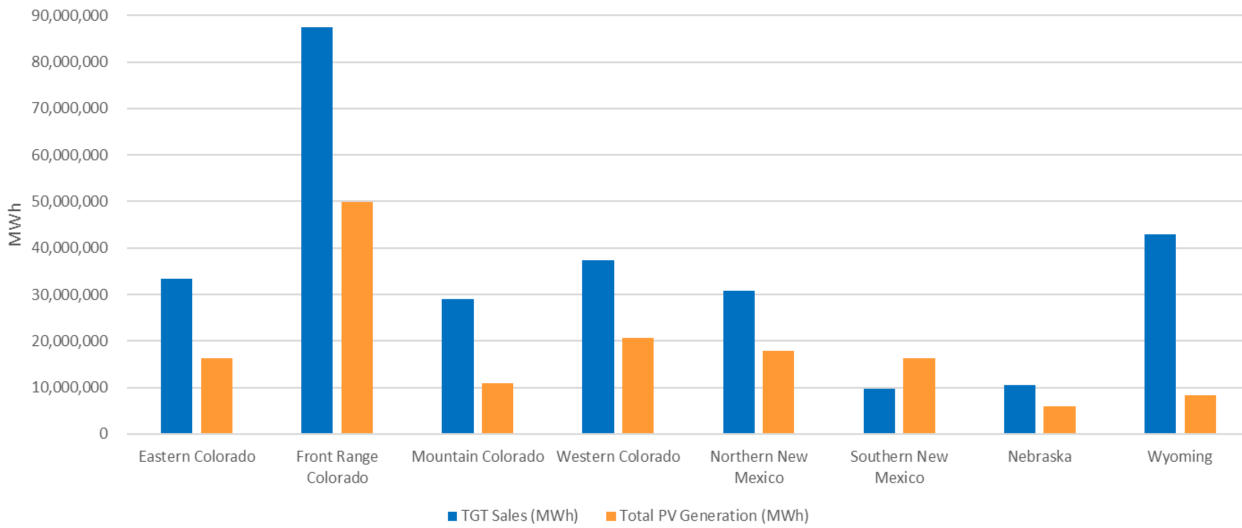
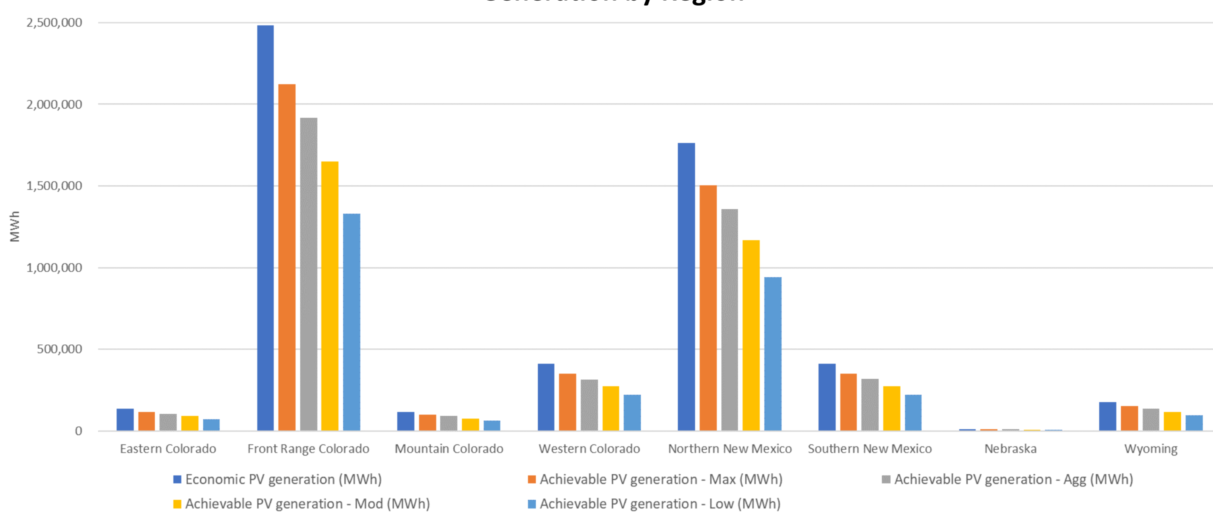


Figure ES-4. 2040 Technical Potential for Cumulative Non-Residential PV Generation vs Sales by Region



The results of the economic and achievable potential analysis are presented below in Figure ES-5. Only non-residential measures passed cost effectiveness, and those cost effective measures comprised just 9% of analyzed measure permutations. Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while this potential generation reflect the entire Tri-State territory, the cost effective scenario used in this analysis includes CO_2 emission benefits which are not applicable to regions outside of Colorado, as emissions are not a quantifiable benefit at the time of this report publication.

Figure ES-5. 2040 Cumulative Non-Residential Economic and Achievable Potential PV Energy Generation by Region



Results Summary

In summary, Tri-State and its member co-ops could save the following energy and dollars with the corresponding investment, on a levelized basis over the 20-year study period:

Table ES-7. DSM Investment Outlook through 2040 (Achievable-Moderate Scenario)

RESOURCE TYPE	RESULTS
EE	Average annual savings of 114,520 MWH/year and 14 MW at a levelized cost of $15.25/MWH (TRC = 1.64)
DR	86 MW of demand response potential by 2040 at a cumulative cost of $39M (TRC = 1.16)
DER	3,661,295 MWH and 50 MW potential by 2040 at a cumulative administrative cost of $183M (TRC = 1.04)

Market Characterization & Baseline Forecast Results

In order to develop the results presented above, the Team developed a detailed characterization of Tri-Stat's customer base. This section summarizes the market and baseline forecast characterization including Tri-State's energy usage by sector and end use (additional details about customer segment and end use breakdowns within each sector are provided in Section 3). Tri-State's forecasted 2021 electricity sales to member cooperatives is just over 15 TWh, estimated to grow to just over 20 TWh by 2040 (Figure ES-6). In the base year of the analysis industrial is the largest market sector at 44% of load, followed by the residential sector at 30% of load, commercial at 18% and finally irrigation at 8%. These sector load shares remain fairly steady during the study horizon. The distribution of energy load by customer sector varies among the eight regions modeled in this study – for example, Eastern Colorado has a large irrigation sector load share while Mountain Colorado has almost no irrigation energy load (Figure ES-7). Front Range Colorado is the largest region at 5 TWh of energy load; it also has the largest Residential load share.

Figure ES-6. Baseline Load Forecast by Sector by Milestone Year

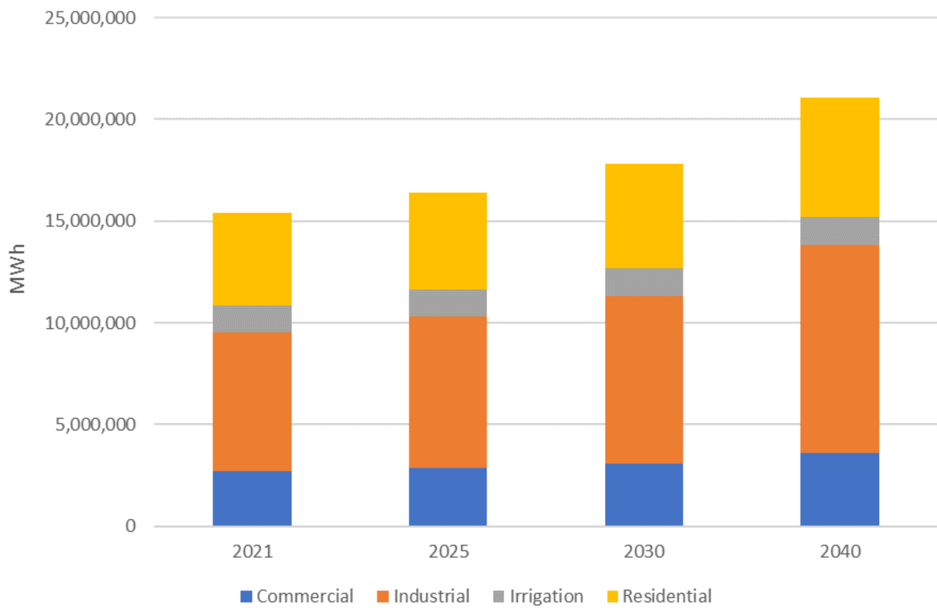
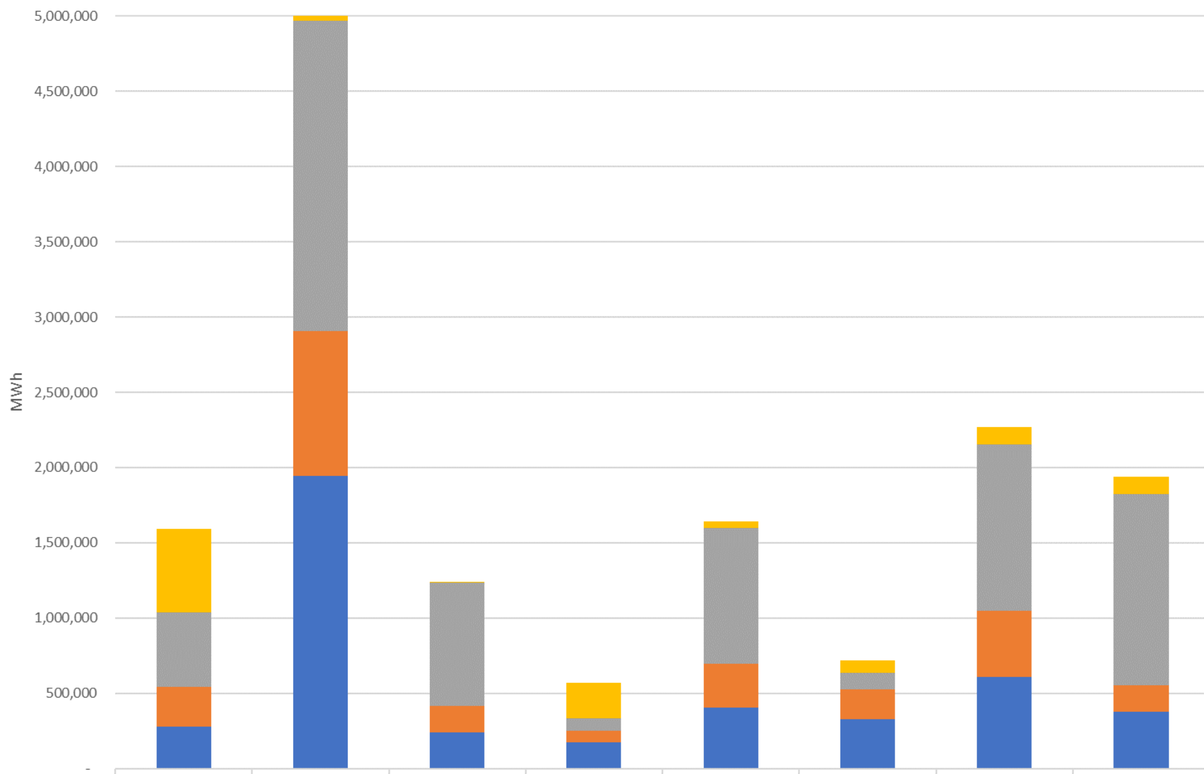


Figure ES-6. 2018 Baseline Energy Load by Customer Sector by Region



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	176,453	78,733	289,986	197,934	444,417	173,590
Residential	276,257	1,944,118	241,514	173,762	406,734	328,318	606,582	380,071

Study Approach and Methods

The study approach undertaken to develop the results presented above consists of three main tasks. These tasks are summarized below and discussed in more detail in Section 2 of this report. The tasks include:

- Customer Segmentation and Forecast Disaggregation
- Measure Impact Research
- Modeling and Data Analysis

Segmentation and forecast: For the market segmentation analysis, the Team collected relevant customer and forecast datasets from Tri-State to disaggregate customer energy load by region, sector, building/business type (i.e. segment), and end use for each year in the study's 20-year time horizon. This task identifies the available energy load within the various market and end use sectors available for conversion to higher efficiency or demand reduction technologies.

Measure impacts: With the market segemented and forecast disaggregated across the study horizon, the Team then characterized the universe of efficiency, demand response, and DER measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Each measure was assigned to the relevant resource, region(s), sector(s), segment(s), and end use(s) for modeling. Each measure permutation was screened for cost effectiveness according the Total Resource Cost (TRC) test with a passing threshold of 0.7 for EE measures (thus allowing some less cost-effective measures to be assessed so long as the portfolio remained above a TRC of 1.0) and a passing threshold of 1.0 for DR and DER resources.

Modeling and data analysis: The Mesa Point Team used industry-standard modeling approaches to estimate the technical, economic, and achievable potential and associated costs for EE, DR and DER resources. Specifically, a discrete model was developed for each resource and potential estimates were developed independent of one-another – for example, each resource used the same baseline disaggregated load forecast and energy efficiency improvements did not reduce the opportunity for demand response potential. The energy savings and associated costs of each resource was forecasted for a 20-year time horizon (2021 – 2040). Two to four achievable potential scenarios were developed for each resource so that varying levels of market opportunities could be assessed given variances in measure incentive levels and aggressiveness of program delivery. Outputs from each resource model were developed at high levels of resolution, showing annual energy savings, lifetimes, and costs for each measure permutation (by region, sector, segment, end use, and vintage) for each year of the study horizon.

1. INTRODUCTION

1.1. Background, Project Scope, and Objectives

Tri-State retained Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) to perform a demand side management study in support of the company's resources planning initiatives. The primary objective of this study is to assess the available technical, economic, and achievable energy savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State). Measures considered are limited to technologies that are behind-the-meter and owned by the end-user.

The potential study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). Tri-State will use the results of this market potential study to analyze and incorporate potential EE, DR and DER impacts at various levels of program investment over the planning horizon from 2021 to 2040.

The study focuses on energy efficiency, DR, and DER *achievable* potential. As discussed further in Section 2, the study is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, this report's conclusions and recommendations do not include program-specific recommendations; rather, the report focuses on identifying market opportunities and costs for EE, DR, and DER.

1.2. Achievable v. Planned Savings

This potential study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations to that potential.

Tri-State member cooperatives are responsible for implementing measures and programs on a voluntary basis. Tri-State does not have control over which measures its members choose to offer nor how the measures are bundled into program offerings. Some co-ops may choose not to offer incentive programs, or to incent only a subset of cost-effective measures.

The study only takes into consideration barriers on the market side and does not attempt to predict if and at what levels co-ops will choose to move forward with programs.

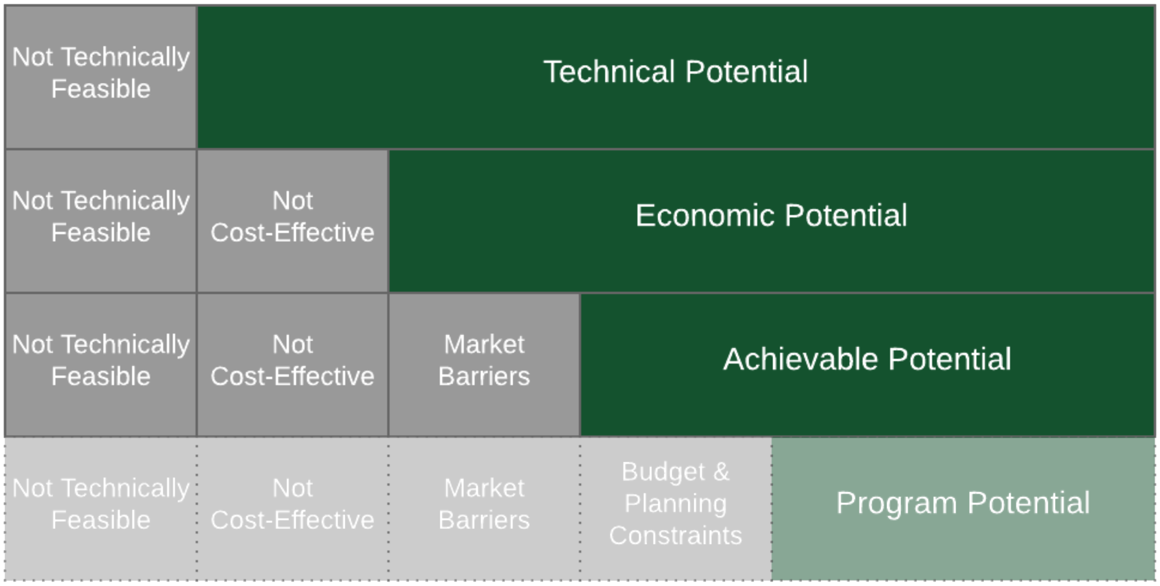
1.3. Study Approach Overview

In accordance with standard industry practice for DSM potential studies, this study considers measures from the perspective of theoretical maximum savings, and then accounts for barriers to estimate actual achievable savings.

Specifically, the study begins with *technical potential*, wherein all technically viable measures are included without regard to costs or other barriers. Knowing the technical potential, *economic potential* is assessed by estimating costs to implement measures, and then applying economic criteria to the measures. Finally, *achievable potential* is calculated by considering non-economic factors affecting DSM measure implementation. Not considered in the report are factors affecting *program potential*.

This analysis approach is based on standard perspectives of DSM resource potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE)[2] as illustrated in Figure 1.

Figure 1: Conceptual Overview of DSM Resource Potential Defintions



- **Technical Potential** is the theoretical maximum amount of energy and capacity that could be displaced by an efficient technology, regardless of cost and other barriers that may prevent the installation or adoption of a measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** is the amount of energy and capacity that could be reduced by measures that pass a cost-effectiveness test. This analysis used the Total Resource Cost (TRC) Test, which estimates the measure costs to both the utility and customer.
- **Achievable Potential** is the energy savings that can feasibly be achieved through program and policy interventions. Achievable potential takes into account barriers that hinder consumer adoption of energy efficiency measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time.
- **Program Potential** reflects the realistic quantity of energy savings the utility can realize through DSM programs during the horizon defined in the study. Potential delivered by programs is often less than achievable potential due to real-world constraints such as program budgets, effectiveness of outreach, and market delays. Program potential would also incorporate go-to-market considerations, such as practical limitations for Tri-State to deliver programs to

[2] The EPA National Action Plan for Energy Efficiency: http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf

customers through the rural electric cooperative members. As noted previously and as shown in Figure 1, this study does not address program potential.

1.4. Cost Effectiveness

At the core of DSM potential is the concept of cost-effectiveness. To assess cost effectiveness, the total cost of implementing measures is compared to the cost of business as usual with energy being provided to the baseline energy using equipment and behaviors. A DSM measure is considered cost effective if it is less costly than simply providing energy to baseline systems.

The California Standard Practice Manual (SPM) provides the methodology for estimating cost effectiveness of technologies, bundles, programs, or portfolios based on a series of tests representing the perspectives of the utility, customers, and societal stakeholders. "Low," Moderate ("Mod"), Aggressive ("Agg"), and Maximum ("Max") scenarios vary based on the assumptions for level of incentive, staffing, and marketing investment.

1.5. Presentation of Savings

This report represents savings in several different ways. For the most part, savings across years is presented as cumulative, but there are cases in which the savings may be presented in one of the other ways defined below. Following are the various methods for presenting savings:

- **Annual Incremental**: Energy savings acquired in the year in which measures are installed
- **Cumulative**: Total energy savings acquired over a given time horizon, accounting for measure decay (i.e. retired energy savings after an installed measure reaches the end of its useful life)
- **Sum of Annual Incremental**: Total energy savings acquired over a given time horizon, not accounting for measure decay

1.6. Organization of the Report and Related Deliverables

This report presents a summary of the analysis approach, key assumptions and study findings. Two separate electronic reporting tools serve as an appendices to the report. The tools provide the ability to view findings by sector, end-use, and region from both annual and hourly perspectives. The intent is for Tri-State and stakeholders to make use of both work products depending on the desired level of detail. Figure 2 summarizes the structure for the remainder of this report.

Figure 2. Summary of Report Structure

Section 2

- Describes the study approach and methods.

Section 3

- Discusses the team's efforts to disaggregate and analyze Tri-State's baseline forecast. That work serves as the foundation for the analysis and findings presented in the remainder of the report.

Sections 4-8

- Present sector-level findings for energy efficiency potential.

Section 9

- Presents findings for the demand response potential analysis.

Section 10

- Presents findings from the distributed energy resource (DER) potential analysis.

Section 11

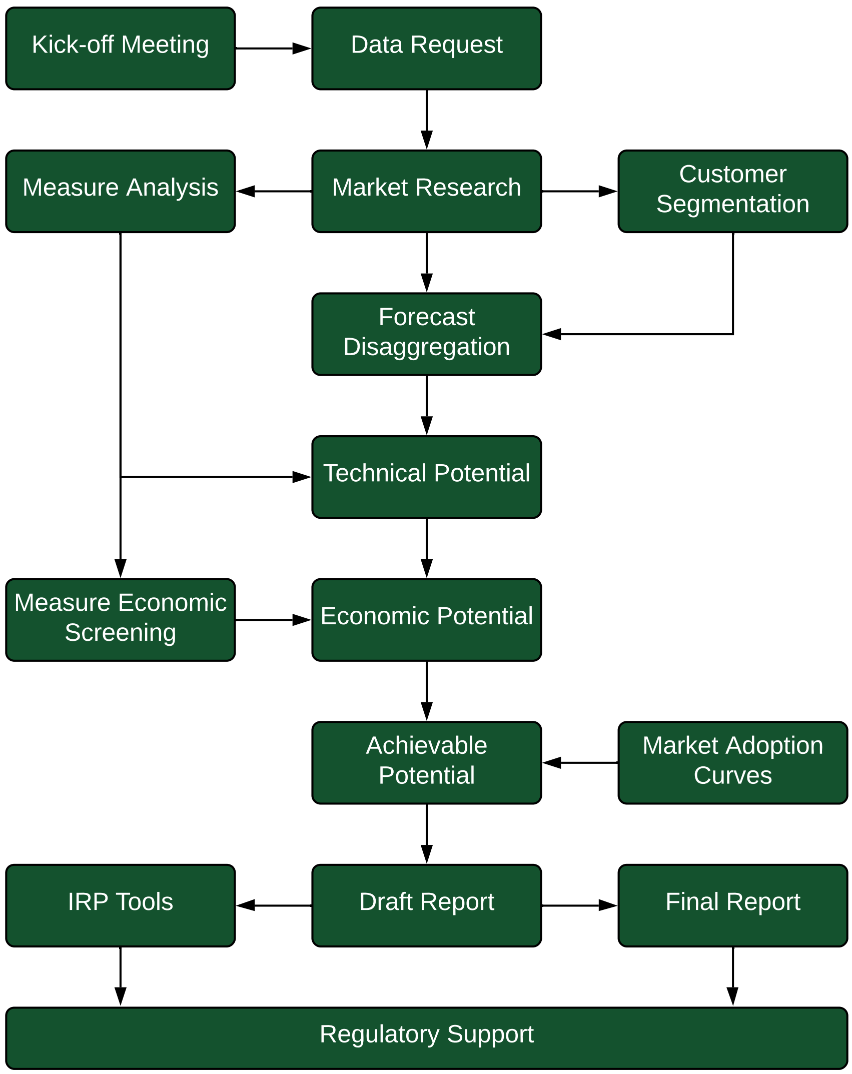
- Presents overall findings and recommendations.

2. STUDY APPROACH AND METHODS

2.1. Overview

The process shown in Figure 3 depicts the steps taken during a market potential study.

Figure 3. Approach for Demand Side Resource Potential Modeling



These steps generally apply to all three demand-side management (DSM) resources considered: energy efficiency, DR, and DER. Each step is described in detail in the sections that follow. Sections 2.2–2.4 generally apply across all three resources. Sections 2.5 and 2.6 provide additional detail for the approach and methods used for the DR and DER analyses.

2.2. Customer Segmentation and Forecast Disaggregation

An accurate assessment of achievable savings potential requires a thorough characterization of the baseline energy usage. This characterization involves the following steps:

- Determine the energy consumption per region, customer class and segment in baseline year.
- Disaggregate customer class loads into end-use loads, such as water heating.
- Analyze and calibrate data to 2018.
- Forecast the 20-year end-use energy consumption through 2040.

To complete these steps the Team relied on a large dataset consisting of:

- Information on Tri-State member cooperative customers
- Historical loads
- Market data including fuel shares, equipment saturations, and structural characteristics
- End-uses including energy use intensities and load shapes
- Measure characteristics including technologies, costs, life, and savings

These data were drawn from a combination of primary and secondary research. An overview of the steps involved in this process follows. The findings of the market characterization is presented in Section 3.

2.2.1. Customer Segmentation

To begin, the Team analyzed the portion of Tri-State's forecasted sales attributable to DSM-ineligible accounts. This included the share of the load that is served by re-sale customer or non-premise accounts. This portion of the load was removed from the load considered eligible for energy efficiency and demand reduction measures.

Next the Team determined energy and demand loads for the appropriate regions, sectors, market segments, vintages, and end-uses as follows:

- **Regions**: Sales for rural electric cooperatives were aggregated into regional definitions; including Front Range Colorado, Nebraska, North New Mexico, Wyoming, etc., as shown in Table 1.
- **Customer Sectors**: Residential, commercial, irrigation, and industrial (including agricultural)
- **Market Segments:**
  - **Commercial**: Typically based on major Commercial Buildings Energy Consumption Study (CBECS) business types.
  - **Industrial**: All major industrial segments in Tri-State service territory using NAICS classification from the Form 345 information.
  - **Residential and Irrigation**: No further segment-level breakdown

- **Vintages:** Existing and New Construction
- **End-uses:** Those shown by sector in Table 2

2.2.1.1. Primary Market Research

Primary market research guided customer segmentation. In 2012, Tri-State distributed a mail-in residential end-use survey requesting information on consumers' residence structure and energy consuming equipment type, age, fuel type, end-uses, and behavior. The survey yielded over 300 customer responses, with each cooperative providing a minimum confidence level of 90% with 10% precision for each surveyed technology at the cooperative level. This data was used to guide the disaggregation of the residential sector load.

The Team also used North American Industry Classification System (NAICS) data that provides business type data on large customers (greater than 250KW) and their associated energy consumption from the Rural Utilities Service (RUS) Form 345. Business type information for energy sales of non-residential customers less than 250KW was not available. Secondary research was necessary to estimate segmentation of business types for customers less than 250KW.

2.2.1.2. Secondary Market Research

The Team utilized secondary resources to complete the customer segmentation. Examples of these resources include the 2010 Tri-State System-Wide Electric Energy Efficiency Potential Study , United States Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS)[3], the EIA Commercial Buildings Energy Consumption Survey (CBECS)[4], 2016 NorthWestern Energy End-Use and Load Profile study[5], the 2015 Platte River Power DSM Potential Study, among other references.

2.2.2. Segmentation of Regions

To accurately characterize Tri-State's large geographic service territory, the Team segmented end-use load profiles and energy efficiency potential by region. Eight (8) regions were defined based on geographic location of the co-ops[6]. Segregating the co-ops by region, instead of producing one set of potential values for all of Tri-State's territory has several advantages:

- Energy efficiency measures more accurately match building codes in each region. For example, envelope construction requirements are different depending on climate zone.

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[3] *https://www.eia.gov/consumption/residential/*

[4] https://www.eia.gov/consumption/commercial/

[5] https://www.northwesternenthinkergy.com/docs/default-source/documents/etac/2017/nexant_energy_end_use_and_load_profile_study.pdf

[6] This report and the associated Reporting Tool, described in this report, utilize the regional breakdown characterized here. The Load Shape Tool, also described in this report, utilizes an adapted breakdown to accommodate for member coops that cross certain regional boundaries. This alternative breakdown of potential savings is to allow for more accurate output data for input into Tri-State's resource planning models. The adjustment reflects where coop service territory extends across eastern and western interconnects.

- Regional segmentation captures a higher resolution of equipment end-use saturation and energy intensity. For instance, direct expansion (DX) cooling in the residential sector has a higher saturation and energy intensity in southern New Mexico as compared to northern Wyoming.
- This segmenation accommodates regional cost variances for participant energy efficiency implementation or utility avoided costs.
- Barriers to achievable potential may be regionally specific.

Based on evaluation of climatic impacts, sector segmentation and end-uses, the Team developed the regional electric cooperative groups shown in Table 1.

Table 1: Tri-State Cooperative Regional Groups

EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO
Highline	Mountain View	Gunn County	Empire
K.C.	Poudre Valley	Mountain Parks	La Plata
Morgan County	San Isabel	White River	San Luis Valley
Southeast	United		San Miguel
Y-W			Sangre De Cristo
NEBRASKA	SOUTHERN NEW MEXICO	NORTHERN NEW MEXICO	WYOMING
Chimney Rock	Central NM	Cont. Divide	Big Horn
Midwest	Columbus	Jemez Mtns	Carbon
Northwest	Otero County	Mor San Miguel	Garland
Panhandle	Sierra	North. Rio Arriba	High Plains
Roosevelt	Socorro	Southwestern	High West
Wheat Belt		Springer	Niobrara
			Wheatland
			Wyrulec

2.3. End-Use Load Classification

To further disaggregate the load the Team established end-use loads within each sector.[7] Table 2 presents a summary of those end-uses.

[7] The irrigation sector is solely composed of the motor end-use.

Table 2: End-Uses for Each Tri-State Sector

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
Central Air Conditioning	Cooking	Lighting
Central Heating	Cooling	HVAC
Clothes Washer	Heat Pump	Motors
Dishwasher	HVAC Aux	Pumps
Electric Cooking	Lighting	Process Heat
Electric Dryer	Plug Load	Process Cool
Freezer	Refrigeration	Pumps
Exterior Plug Load	Space Heating	
HVAC Aux	Water Heating	
Heat Pump		
Lighting		
Plug Load		
Refrigerator		
Second Refrigerator		
Room AC		
Electric Water Heater		

The primary regional inputs needed to model each end-use were the total premise count, fuel shares, end-use Unit Energy Consumption (UEC), and saturation. Expected improvements in building energy code requirements and other general trends were incorporated into the UECs based on data found in the U.S. Energy Information Administration's forecasts. In general these trends showed a decrease in all end-use UECs with the exception of plug loads, which showed an increasing trend.

2.3.1.Codes and Standards

There is uncertainty about future federal standard updates and enforcement. While the study considers current codes and standards, the analysis is not intended to predict how or when energy codes and standards will change over time. As a result, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

The primary adjustment made in the Team's methodology impacts residential screw-in lighting. Based on the current Department of Energy final rule that did not trigger the Energy Independence and Security Act (EISA) backstop, the potential analysis does not model Tier II EISA efficiency requirements. However, the study does model the transitioning screw-based lighting market that is rapidly being saturated with LED technology. The Team modeled this market transition by limiting the future potential for residential lighting starting in 2027. The analysis assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the latter analysis period.

Although not exhaustive, the following list outlines additional key standards the Team considered:

- The baseline efficiency for air source heat pumps (ASHP) is anticipated to improve to 15 SEER/8.8 HSPF.
- The baseline efficiency for split system central AC systems is anticipated to improve to 14 SEER in 2023.
- In July 2019, the DOE makes new standards effective for more efficient furnace fan/motors. The standards are expected to improve the efficiency by approximately 45% over the current baselines. The new standard will create a shift to electronically commutated motors (ECMs).

2.4. Energy Efficiency Potential Modeling

Drawing on outcomes from of the disaggregated the Team modeled first technical, then economic, and finally achievable energy savings potential. Those steps are described in the following sections.

2.4.1.Estimate Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility of measures. The model applies the measure-level inputs to the disaggregated baseline sales forecast to estimate technical savings and demand reduction potential over the planning horizon.

As an example, the core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 1.

Equation 1. Core Equation for Residential Sector Technical Potential

Technical Potential of Efficient Measures = Total Number of Households + Base Case Equipment Energy Use Intensity (kWh/unit) + Saturation Share + Remaining Factor + Applicability Factor + Savings Factor

Where:

Total Number of Households = *Count of customer households in the subject region.*

Base Case Equipment Energy Use Intensity *= the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case* *equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.*

Saturation Share = *the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.*

Remaining Factor = *the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.*

Applicability Factor = *the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective—i.e., it may not be possible to install a heat pump water heater in all homes due to space constraints.*

Savings Factor = *the percentage reduction in electricity consumption resulting from the application of the efficient technology*.

2.4.1.1. Measure Definitions

Once the baseline forecast is disaggregated, the next step to assessing technical market potential is to accurately detail the universe of efficiency measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Additionally, our Team compiled all measures available from such sources as the Pacific NorthWest Regional Technical Forum (RTF), Xcel Energy's Demand Side Management Plan, and technical reference manuals (TRMs) from jurisdictions like the states of New Mexico, Pennsylvania, and Minnesota. The Team also leveraged measure data it has characterized in similar studies. From these regionally relevant databases, the Team selected measures that are commonly available, based on well-understood technology, and applicable to the buildings and end-uses in Tri-State's service territory. The Team also considered measures that show promise for future viability but have not yet gained a foothold in the market.

Energy efficiency measures are characterized in three main vintages:

- **Replace on Burnout:** As equipment replacements are made normally in the market when a piece of equipment is at the end of its effective useful life (also referred to as "turnover").
- **Retrofit:** At any time in the life of the equipment or building (referred to as "early-retirement").
- **New:** When a new home or building is constructed.

Upon finalizing the energy efficiency measure list, the Team collected data on energy savings, costs, lifetime, and applicability to determine potential measure impacts. This work involves a multi-step process described here.

Step 1: Define market classifications for application of measures

The Team established market classifications as a framework for documenting applicability of each measure. These classifications were based on factors including region, fuel type, sector, market segment, and end-use as defined in the disaggregated forecast (Section 2.2). Additionally, the Team further defined permutations for each measure based on the following parameters:

- **Climate Zone:** This measure research includes savings estimates for weather-dependent measures specific to ASHRAE climate zones 4 through climate zone 6
- **Measure Type:** Equipment vs. Non-equipment
- **Vintage:**
    - **Equipment** – Turnover, Retrofit, New
    - **Non**-equipment – Existing, New

Step 2: Screen sectors, segments, and end-uses for eligibility

The Team screened market segments and end-uses for applicability of specific energy efficiency measures. For example, certain commercial end-uses, such as cooking, may not be appropriate for segments such as offices and warehouses and therefore were analyzed only in limited market segments.

Step 3: Develop base case impacts and costs

The Team determined base case equipment and practices for each of the energy efficiency measures on the final list, and developed a description and rationale for each. This included all base case assumptions and data, such as state building codes (the 2012 International Energy Conservation Code (IECC) in most cases) and federal standards. Base case assumptions included projected future adjustments, such as upcoming federal standards.

Step 4: Develop energy efficiency measure impacts and costs

The Team developed a description of all energy efficiency (or "change case") measure equipment and practices, including all measure energy savings assumptions and calculation parameters, such as equivalent full load hours (EFLH). For each measure, the Team estimated energy savings as a percentage of base equipment and/or end-use consumption.

In addition to energy savings, the Team collected incremental measure costs pertinent to Tri-State's service territory from appropriate TRM references and internet retailer data and researched measure life drawing on TRM documentation.

2.4.1.2. Screw-in Lighting

The Team reviewed the residential, commercial, and industrial lighting measures and lighting end-use assumptions to incorporate recent changes to the lighting market. This included reviewing and updating savings, measure cost, saturation, and expected useful life assumptions for each lighting measure. Based on federal policy projections, the Team made the assumption that the EISA "backstop" would not be enacted beginning in 2020. Additionally, the Team characterized the lighting market to transform primarily to an LED baseline for screw-in lighting by the end of the decade.

2.4.2. Estimate Economic Potential

Economic potential represents the savings possible given full adoption of all cost-effective efficiency measures. For this study, the Team utilized the Total Resource Cost (TRC), which is commonly considered the preferred test to assess measure benefits and costs from the perspective of the utility and society as a whole. Equation 2 presents the TRC ratio equation.

The benefits in the TRC test are the net present value of the lifetime avoided energy and capacity costs. The costs in this test are the net present value incremental measure costs.

Equation 2. TRC Ratio

$$\textbf{TRC Ratio} = \textbf{NPV}(\textbf{Avoided Costs})/\textbf{NPV}(\textbf{Incremental Measure Costs})$$

Where*:*

$$\text{Avoided Cost} = \text{NPV}\left(\sum_{\text{year}=1}^{\text{measure life}}\left(\sum_{\text{i}=0}^{\text{i}=8760}(\text{impact}_\text{i} \times \text{avoided cost}_\text{i})\right)\right)$$

The **benefits** include the net present value of the energy and capacity saved by the measures along with any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy and capacity were obtained from Tri-State and represent their most recent forecast of avoided electric benefits. The avoided costs are calculated by applying end-use-specific annual hourly load shapes to measure savings impacts and determine the time-differentiated value of energy and capacity benefits. The annual hourly load shapes were developed from industry-specific energy load profiles, and a peak definition (noon – 22nd hour in weekday summer months) was provided by Tri-State to estimate coincident peak demand.

To accurately value avoided energy savings for Tri-State, the expected losses were estimated from the customers' meters to Tri-State's generation source. These losses were calculated for each climate zone, and reflected the losses from the customer to the co-op and the losses from the co-op to Tri-State. In addition to line losses, a discount rate of 5% was applied to value future avoided costs.

The **costs** are the net present value of all costs to implement those measures. These costs include full incremental costs (both utility and participant contributions), but no incentive payments that offset incremental costs to customers and no lost revenues. The full incremental costs include single upfront costs and operational & maintenance costs where applicable. Incentives are not included, because they are transaction between the utility and customer, thus the costs and benefits negate each other. While non-incentive costs were not included in the measure-level screening of electric energy efficiency potential, they were included in further assessments of potential at the achievable potential level described below.

Additionally the social cost of carbon at $46/ton of carbon dioxide (CO_2) was incorporated as an avoided benefit in the TRC calculations. This value was escalated annually over the study time horizon based on figures provided by Tri-State.

The measure screen from technical potential to economic potential utilized a cost-effectiveness hurdle of 0.7 in order that the sector level TRC test would be closer to 1.0. This reduction in the screening threshold permits non cost-effective measures into the portfolio so that a potential program intervention is more well-rounded and can include a limited number of non-cost-effective measures. However, the forecasted sector portfolio must have an estimated TRC greater than 1.0 when program administrative costs are included.

2.4.3.Estimate Achievable Potential

Finally, the assessment of realistically achievable energy efficiency potential required estimating, among other parameters, the rate at which cost-effective measures can be adopted over time. The Team incorporated individually developed sets of market penetration curves corresponding to implementation scenarios to account for the fact that program implementation scenarios have a direct influence over such market penetration rates. These scenarios were correlated to differing levels of urgency in program implementation, tolerance for rate impacts, macroeconomic conditions, and other situations.

The following are important components in determining achievable potential:

- **Benchmarking.** The amount of savings expected to be achievable through DSM programs will be informed by the experience of utilities across the region and nation.
- **Customers' willingness to participate.** The likelihood that customers will participate in energy efficiency programs is a function of several factors, most notably incentive level.
- **Uncertainty.** Planning requirements often necessitate a point-estimate of potential, however, this is not an accurate reflection of the reality of DSM programs. We prefer to think of achievable potential as a range, or probability distribution, where the point-estimate is the most likely outcome. This distribution defines the lower and upper bounds of expected savings, as well as the most likely value.

Achievable potential energy efficiency impacts were evaluated based on four incentive scenarios as a function of the incremental costs of efficiency measures:

- 25% "Low"
- 50% Moderate ("Mod")
- 75% Aggressive ("Agg")
- 100% Maximum ("Max")

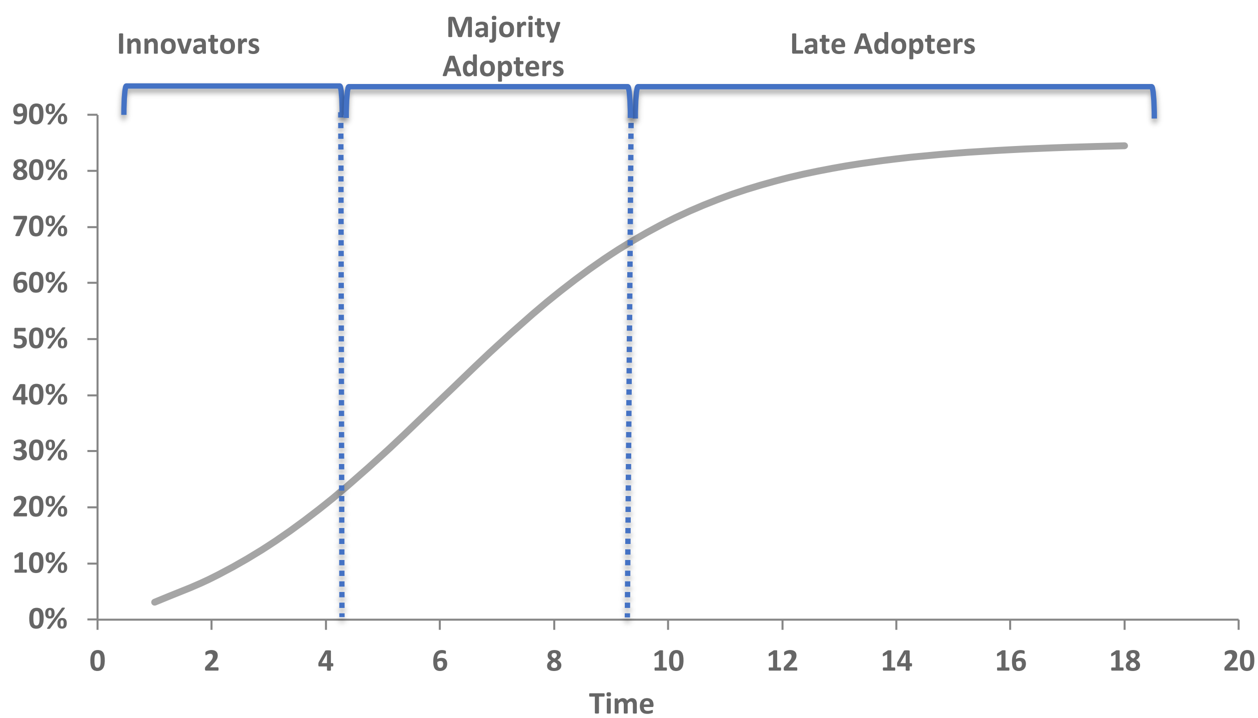
For instance, the moderate scenario approximates the market adoption achievable by incentivizing 50% of the incremental cost of the measure. Results are presented from the perspective of the Achievable Moderate scenario unless otherwise specified. This scenario represents a reasonable progression from Tri-State's current program offerings.

2.4.3.1. Market Adoption Rates

In order to characterize the rate of market adoption for each of the specified scenarios, the Team developed a quantitative approach based on a Bass Diffusion Model. This method relies on scientific theory and historic program participation data based on Tri-State experience and other DSM programs in North America.

The Bass Diffusion Model is a mathematical description of how the rate of product diffusion in a market changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of forecasting future adoption rates is illustrated in Figure 4.

Figure 4: Typical Product Diffusion in the Marketplace



The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters.

- Initial Year Measure Adoption
  - First year adoption levels were informed by recent Tri-State historical performance where possible.
- Long-Term Market Adoption Rates
  - The final adoption scores that resulted from willingness to pay surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario.
- Adoption Curve Shape
  - Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B.

Unique end-use adoption curves were developed based on the following three parameters:

- **Customer Sector:** Residential, Commercial, and Industrial
- **End-Use**: Lighting, Motors, etc.
- **Incentive Level based on Achievable Scenario**: 25%, 50%, etc.

2.4.3.2. Program Costs

Finally, to capture the full cost of achievable energy efficiency potential, the Team added program non-incentive costs in the overall assessment of cost-effectiveness. Non-incentive program cost categories included: (1) Administration, (2) Marketing, (3) Technical, and (4) Measurement & Verification and Planning. Program non-incentive costs were calculated on a gross $ per first-year kWh saved. Non-incentive costs were developed for each program by sector. The included program cost assumptions are shown in Table 3.

Table 3: Summary of Non-Incentive Program Costs ($/kWh)

SECTOR	ACHIEVABLE LOW	ACHIEVABLE MOD	ACHIEVABLE AGG
Residential	$0.100	$0.115	$0.150
Commercial	$0.050	$0.058	$0.075
Industrial	$0.100	$0.115	$0.150
Irrigation	$0.050	$0.058	$0.075

2.4.4. Data Analysis and Reporting Tool

A set of dynamic analysis tools were developed to provide Tri-State staff access to the data outputs from the modeling efforts. These consist of a Reporting Tool and a Load Shape Tool specifically created for this project. The Reporting Tool summarizes and illustrates the savings potential and associated costs by sector, year, and scenario enabling the user to select results for a specific region or for the entire service territory. The results are depicted in tabular form and in associated charts that update dynamically based on the selected region.

The Load Shape Tool was developed to convert the model's annual energy savings and cost outputs into 8760 hourly load profiles for direct input into Tri-State's ERP planning tool. The tool bundles and maps measures to associated 8760 hourly load profiles to illustrate at what hours during the day and year energy savings are likely to be incurred for each bundle of measures. The tool also shows the associated levelized cost of each bundle of measures on an 8760-hourly basis. The data is represented by sector, interconnect region, scenario, and load shape bundle. This tool will allow Tri-State to compare energy efficiency resource savings and levelized costs and compare them with other supply-side and demand-side resources during its ERP development process.

2.5. Demand Response Potential Assessment

Demand response refers to the reduction of electric demand by way of altering the operation of some piece of technology or equipment. Demand response programs take several forms, but most rely on direct control of energy-using equipment via communication infrastructure like radio or WiFi or the change in customer behavior from time-based rates.

There are a few important differences between the assessment of demand response programs and other demand-side management options, such as energy efficiency. First, demand response programs require active, ongoing participation by customers. Second, unlike energy efficiency programs, demand response is designed to shift load from peak periods of energy use to non-peak periods, which can affect the availability of service to the customer. These programs use independent concepts and technologies and not ‘upgrades’ in the sense that energy efficiency measures are upgrades from some similar baseline option. These programs use independent concepts or technologies and are not ‘upgrades’ in the sense that energy efficiency measures are upgrades from similar baseline options. Thus, demand response technologies have no incremental cost. Finally, demand response depends on a customer’s willingness to participate in individual events. This willingness to participate is a function of program design, which includes the number of events, incentive levels, the stipulation of mandatory or voluntary participation, and the existence of penalties for non-compliance. Hence, estimating demand response potential involves in a number of steps. The final potential number is a product of the base peak demand, eligibility rates, technical load impact rates, program participation rates, and event participation rates.

2.5.1. Estimate Peak Demand

Coincident peak demand data was available for each of the eight regions in the Tri-State system. This system-level peak demand was divided to estimate the contributions from each sector (residential, irrigation, commercial, and industrial) by using sector energy use during the peak month relative to the system energy use during the same time period. Per premise demand estimates were generated by dividing by the number of premises in each sector.

2.5.2. Apply Eligibility Rates

Eligibility rates customized to each program were applied to the base peak demand to determine the peak load eligible to participate. For example, a Direct Load Control (DLC) program capturing residential central HVAC load will require premises to have central air conditioners, while a Smart Thermostat DR program would additionally require the residence to have broadband service and a WIFI network. Irrigation load reduction is generally limited to customers with pumping power greater than 75 horsepower. Commercial and industrial customers in a capacity bidding program typically need to have a peak demand of greater than 250 kW.

2.5.3. Estimate Technical DR Potential

Technical potential for demand response is the theoretical maximum level of peak demand that could be curtailed through DR programs. This scenario disregards non-engineering constraints such as cost-effectiveness and willingness of end-users to enroll. All eligible customers are modelled as if enrolled in one or more DR programs and participating in DR events.

In the Technical Potential scenario, care must be taken to avoid double-counting participation in programs that affect the same end-uses. For example, a customer cannot be modelled as curtailing its HVAC load in both a DLC program and a rate program during the same event. We applied a hierarchy of demand response programs for each sector based on Tri-State's unique market position, as shown in Table 4.

Table 4. Demand Response Programs Applied by Sector

RESIDENTIAL	AGRICULTURAL	COMMERCIAL	INDUSTRIAL
Smart Devices	Direct Load Control	Capacity Bidding	Capacity Bidding
Behavioral	Time Varying Rates	Smart Devices	Time Varying Rates
Direct Load Control		Direct Load Control	
Time Varying Rates		Time Varying Rates	

2.5.4. Estimate Economic DR Potential

Economic potential is a subset of technical potential that is economically cost-effective. A full cost-benefit analysis was conducted for each DR program incorporating Tri-state's avoided energy and capacity costs, program start-up costs, on-going administrative costs, equipment costs for the program and the participant, and discount rates.

Resource acquisition costs fall into one of two categories. Fixed costs include program start-up, infrastructure, maintenance, administration, and data acquisition. Variable costs include hardware costs, which vary by the number of customers, and incentive costs, which can vary by number of customers or kW reduced.

Fixed and variable costs were estimated for each program type according to comparable programs implemented by other utilities or other potential studies. In cases where published cost information could not be found, the Team used assumptions based on other comparable program data points. The Team also incorporated a multiplier of 8 into start-up costs and administration costs, to represent the complexity of managing a program with multiple co-op partners. This analysis assumes a cost of $640,000 or more to start a demand response program. Lower costs were incorporated for time-vary rates programs - $100,000 for start-up and $23,000 per year for administration. Lower costs were also assumed for some commercial programs where commercial participation could be assumed as an addition to an existing residential program. All programs were assumed to require an annual evaluation at a cost of $50,000. Average hardware, communication, and incentive levels were estimated based on published values from other utilities or studies.

Program cost assumptions are summarized in Table 5.

Table 5. Demand Response Program Cost Assumptions

SECTOR	PROGRAM	START-UP	ADMIN	EVAL	MARKETING	EQUIP
Residential	Smart Tstat	$640k	$538k/yr	$50k/yr	$50/signup	$0
	Smart Water Heater	$665k	$543k/yr	$50k/yr	$50/signup	$175
	DLC Central AC	$665k	$543k/yr	$50k/yr	$50/signup	$225
	DLC Room AC	$665k	$543k/yr	$50k/yr	$20/signup	$50
	DLC Pool Pump	$665k	$543k/yr	$50k/yr	$20/signup	$200
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Behavioral	$640k	$7/meter	$50k/yr	$0	$0
Irrig-ation	DLC	$665k	$862k/yr	$50k/yr	$63/premise	$500
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
Commer-cial	Capacity Bidding	$640k	$184k/yr	$50k/yr	$50/premise	$0
	Smart Tstat	$128k	$107k/yr	$50k/yr	$50/signup	$0
	DLC Water Heater	$128k	$107k/yr	$50k/yr	$50/signup	$175
	DLC Room AC	$665k	$543k/yr	$50k/yr	$20/signup	$50
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
Indust-rial	Capacity Bidding	$640k	$184k/yr	$50k/yr	$50/premise	$0
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200

2.5.5.Estimate Achievable DR Potential

The Team applied program participation rates to economic potential to incorporate each sector's willingness to participate in demand response programs. This participation rate is expressed as a percentage of eligible customers. As it takes some time for a utility to fully implement a demand response program, program participation rates are assumed to reach a mature participation rate after 10 years.

Combining economic potential with program and event participation rates yields "achievable potential," or the load that can reasonably be reduced during any one event for a certain program. The Team modeled two achievable potential scenarios for demand response to illustrate the impacts of varying incentive levels to drive program participation. Adoption for both scenarios were selected based on achieved participation rates from similar program types in other jurisdictions.

- 'High' scenario represents best-in-class participation for programs with non-mandantory (opt-in) enrollment
- 'Low' scenario represent more typical or 'average' participation rates from the body of similar programs.

Steady-state participation rates are summarized in Table 6 for each achievable scenario.

Table 6. Demand Response Program Achievable Scenario Participation Rates

SECTOR	PROGRAM	ACHIEVABLE HIGH	ACHIEVABLE LOW
Residential	Smart Tstat	59%	20%
	Smart Water Heater	59%	20%
Irrigation	DLC	48%	15%
	CPP no tech	18%	8%
Commercial	Capacity Bidding	20%	10%
	Smart Tstat	20%	8%
	CPP no tech	18%	8%
Industrial	Capacity Bidding	20%	10%
	CPP no tech	18%	8%

The results of the approach described in this section are presented in Section 9.

2.6. Behind-the-Meter Distributed Energy Resource Potential Assessment[8]

For the purposes of this report, distributed energy resources is defined as equipment installed at customer premises behind-the-meter that generates electricity. This study reviewed the potential for end users of Tri-State's electricity to install and operate these types of resources.

The DER potential study followed the same method as energy efficiency potential in that the DER assessment reviews the opportunity for technical, economic, and achievable potential. The analysis limited resources for this potential assessment study to technologies that are behind-the-meter and owned by the customer. The analysis did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040, because it was the most probable technology to be cost effective and applicable to Tri-State's territory. We performed review and preliminary cost screens for potential DER technologies such as combined heat and power and small wind but did not find these technologies to be applicable and/or cost-effective.

2.6.1. Estimate Technical DER Potential

The technical potential of a DER is the amount of energy that can be generated at a customer's site behind the meter.

Photovoltaic systems utilize solar panels, a packaged collection of photovoltaic cells, to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter(s), a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted and face south-west, south, and/or, south-east.

The study analyzed the potential associated with roof-mounted systems installed on residential and non-residential sector buildings. For the non-residential sector, the analysis estimated potential for ground mounted (or covered parking) systems for a few specific business types such as municipal

[8] Actual results for DER analysis are not included in this draft report pending gathering of additional information

facilities, parking enclosures, and some manufacturing facilities. The analysis also included battery storage as an additional configuration with each solar PV system type. This study did not explore the market potential associated utility-scale solar PV installations.

The approach to estimating technical potential required calculating the total square footage of suitable rooftop area within Tri-State's territory and calculating solar PV system generation based on building and regional characteristics. Technical potential is computed using Equation 3.

Equation 3: Solar PV Technical Potential Calculation

$$\textbf{\textit{PV Technical Potential}} = \Sigma(\textbf{\textit{Suitable Rooftop Square Footage}} \times \textbf{\textit{PV System Generation per Sq. Ft.}})$$

The two key parameters in Equation 3 were estimated based on multiple data sources relevant to Tri-State's territory. A discussion of methods for defining these parameters follows.

The Team estimated total rooftop square footage using the forecast disaggregation analysis to characterize the existing and new residential and non-residential building stocks. The building stocks were characterized based on relevant parameters such as number of facilities, average number of floors, average premise consumption, and premise EUI by region. The Team used these parameters to estimate the total rooftop square footage for each Tri-State region.

To estimate the fraction of the total roof area that is suitable for rooftop solar PV, the Team relied on research completed by the National Renewable Energy Laboratory (NREL). NREL has developed estimates of the portion of total rooftops across the country that are suitable for solar PV based on analysis of LIDAR data. NREL criteria for suitable roof area include:

- **Contiguous rooftop area size:** Rooftops with fewer than 10 square meters of contiguous roof area excluded.
- **Rooftop orientation (tilt and azimuth):** Northeast through northwest orientation and roof pitches greater than 60 degrees excluded.
- **Shading:** Roof areas that had a minimum solar exposure of less than 80% relative to an unshaded roof were excluded.

Based on NREL's data, the Team was able to apply unique suitability factors to estimate the total square footage of suitable rooftop for residential and non-residential buildings for each Tri-State region. The Team further adjusted the total suitable rooftop square footage by accounting for existing systems. Data on existing systems was captured from Google's Project Sunroof and applied to the NREL suitability factors.

The second key parameter – PV system generation – was estimated by developing standardized solar PV system configurations. These included system sizes for residential premises ranging from 3 to 20 kW (DC) and 10 to 2,000 kW (DC) for non-residential premises. Additionally, the Team selected battery system sizes for each solar PV system size to dispatch energy for 2-4 hours during low and/or non-generation time periods.

The Team relied on NREL's PVWatts[9] (Version 6) and System Advisor Model (SAM)[10] tools to estimate system generation for both residential and non-residential sited systems. These tools model PV power density based on site specific data from NREL's LIDAR-based NSRDB to estimate total solar irradiance in conjunction with PV system specifications. The PV system simulations were generated for various cities within each Tri-State region. The Team based assumptions for PV system azimuth on rooftop orientation data sourced from Google's Project Sunroof. For the analysis the following assumptions are summarized in Table 7.

Table 7: Key Assumptions in Solar PV Analysis

PARAMETER	ASSUMPTIONS
Residential System Sizes (Nominal DC Capacity)	3 kW, 5 kW, 7.5 kW, 10 kW, 15 kW, 20 kW
Non-Residential System Sizes (Nominal DC Capacity)	10 kW, 15 kW, 20 kW, 25 kW, 50 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, 2,000 kW
System losses	14.1%
Tilt	By region
Azimuth:	By region
DC to AC size ratio	1.2
Inverter efficiency	96% (micro-inverter)
Battery Round-Trip Efficiency	85%
Technology Useful Life	20 years

Based on the simulations and resulting capacity factors for residential and non-residential buildings for each Tri-State region, we applied the capacity factor to the system size and multiplied by 8,760 to estimate annual electricity generation. These system generation values were used to calculate total energy generation per square foot of rooftop and extrapolated based on the total suitable rooftop square footage to estimate overall all technical potential.

2.6.2.Estimate Economic DER Potential

As discussed in Section 2, economic potential represents the savings possible given full adoption of all cost-effective efficiency measures according to the Total Resource Cost (TRC) test or other commonly used tests. For the cost effectiveness analysis on solar PV, the Team set a TRC hurdle of 1.0[11]. To estimate economic potential for solar PV, we gathered pertinent data on system costs along with calculated generation benefits to use in the benefit-cost analysis which we conducted at the system measure level. The Team screened solar PV measures with an assumed program administration cost of $0.05 per kWh generated.

9 PVWatts estimates solar PV energy production and costs. Developed by the National Renewable Energy Laboratory. (NREL) *http://pvwatts.nrel.gov/*

10 SAM estimates houlry solar PV energy production and costs with more detailed inputs and outputs than PVwatts. Developed by the National Renewable Energy Laboratory. (NREL) *http:// https://sam.nrel.gov/*

11 The TRC hurdle is higher than the hurdle used for the energy efficiency study as the solar PV systems have a much more homogenous benefit-cost profile relative to the portfolio of diverse energy efficiency measures that when combined elevated the overall TRC ratio for the portfolio.

The Team relied on multiple data sources to determine the solar PV system costs for the system sizes and configurations mentioned above. We assessed system component costs based on data included in the National Renewable Energy Laboratory's (NREL) Q1 2018 Benchmarking report[12] which provided detailed cost information on modules, inverters (by technology), structural and electrical balance of system, supply chain, permitting-inspection-interconnection, marketing, overhead, and profit. We adjusted cost parameters from a national level to Tri-State region-specific values by using various market data provided by Energy Sage[13] for residential cost estimates and the Lawrence Berkeley National Laboratory Tracking the Sun[14] data for non-residential cost estimates. This analysis produced an estimated installation cost per watt installed which we applied to various system sizes to estimate total installed cost. Additionally, the Team included O&M costs that scale with system size. Finally, we assumed the impact of the federal investment tax credit (ITC) to follow the existing schedule at the time of this report which equates to a 10% tax credit for commercial systems by 2022 and a 0% tax credit for residential systems by 2022.

In addition to modeling solar PV system costs, the Team estimated cost impacts for solar PV systems coupled with battery storage. Because these systems are far less prevalent in both residential and non-residential systems at the time of reporting, fewer published data on battery costs, balance of system costs, and maintenance were available. Moreover, the battery capacity is also variable based on the service need. Ultimately, multiple data sources were used to assume an overall capital cost per kWh based on a 3- or 4-hour battery for various measure permutations. O&M costs were largely defined by a ten-year amortized battery replacement cost.

Table 8: Average Solar PV Installation Cost

SECTOR	SYSTEM COST ($/ DC W)[1]
Residential	$3.22
Residential (Battery)	$4.88
Non-Residential (<250 kW)	$2.73
Non-Residential (<250 kW w/ Battery)	$3.52
Non-Residential (≥250 kW)	$1.50
Non-Residential (≥250 kW w/ Battery)	$1.87
Operations & Maintenance	$10-$15/kw/yr
Operations & Maintenance w/Battery	$24-$76/kw/yr

[1]Costs reflect impact of federal investment tax credit and are averages across regions. Analysis uses region-specific costs.

[12] Fu, R, et. al., U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. NREL, November 2018.

[13] Energysage Solar Marketplace Intel Report, H2 2018 – H1 2019.

[14] Barbose, G. and Darghouth, N., Tracking the Sun. Lawrence Berkeley National Laboratory. October 2019.

2.6.3. Estimate Achievable DER Potential

The approach to assessing achievable potential for solar PV follows the same logic and methods as outlined in Section 0. Similar to the energy efficiency analysis, the Team defined adoption curves based on a Bass diffusion model. The data informing the adoption curves were based on two key parameter inputs:

- Maximum estimated number of buildings suitable for solar
- Adoption rates based on customer willingness to participate

The Team estimated the first parameter based on the count of buildings suitable for solar PV measures. For example, if a 7.5 kW solar PV measure passed cost effectiveness, the total count of applicable buildings is defined as residential buildings that do not consume more than the total annual generation of the PV system and have sufficient rooftop area to support a system of that size. The second parameter of customer adoption is based on secondary data collected from the Midwest that surveyed residential and non-residential customers' willingness to install solar PV on their home or facility with varying incentive levels. Residential customers were asked their willingness to install based rebate values that covered a percent of the total system cost while non-residential customers were asked their willingness to install based on number of years of payback. With these parameters defined, the Team developed Bass diffusion curves to approximate adoption at various incentive levels. Innovation and imitation coefficients were defined based on state-specific research conducted by NREL[15].

3. MARKET CHARACTERIZATION & BASELINE FORECAST FINDINGS

3.1. Overview

As outlined in Section 2, the analysis of theoretically achievable savings potential requires an accurate characterization of the baseline energy usage and customer characterization. This section summarizes the market and end-use characterization including Tri-State's energy usage by sector, region, and end-use. Tri-State's 2018 electricity sales to member cooperative customers were found to be 14,974 GWh with distribution of sales by customer sector shown in Figure 5, sales by region in Figure 6, and finally with detail conjoined by customer sector and region included in Figure 7.

[15] Sigrin, B, et. al. The Distributed Generation Market Demand Model (dGen): Documentation. National Renewable Energy Laboratory. February 2016.

Figure 5. 2018 Energy Sales by Customer Sector

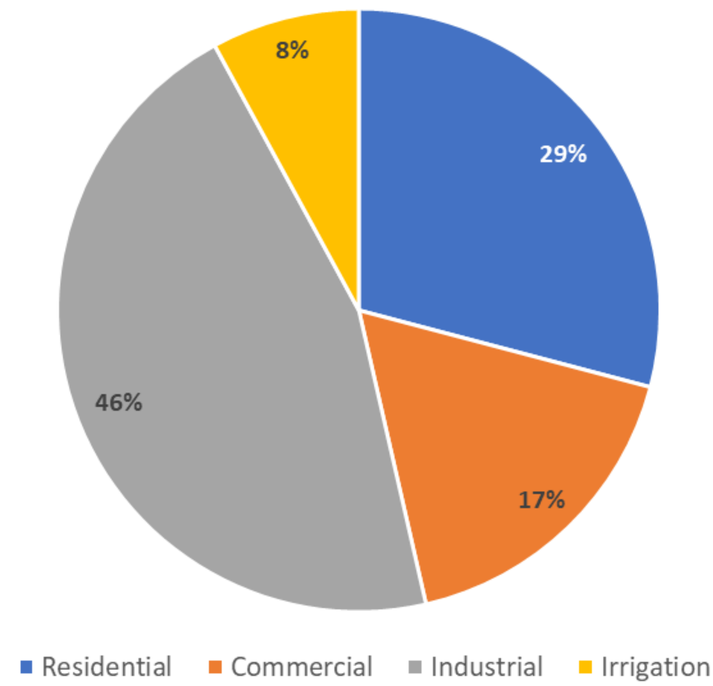


Figure 6. 2018 Energy Sales by Region

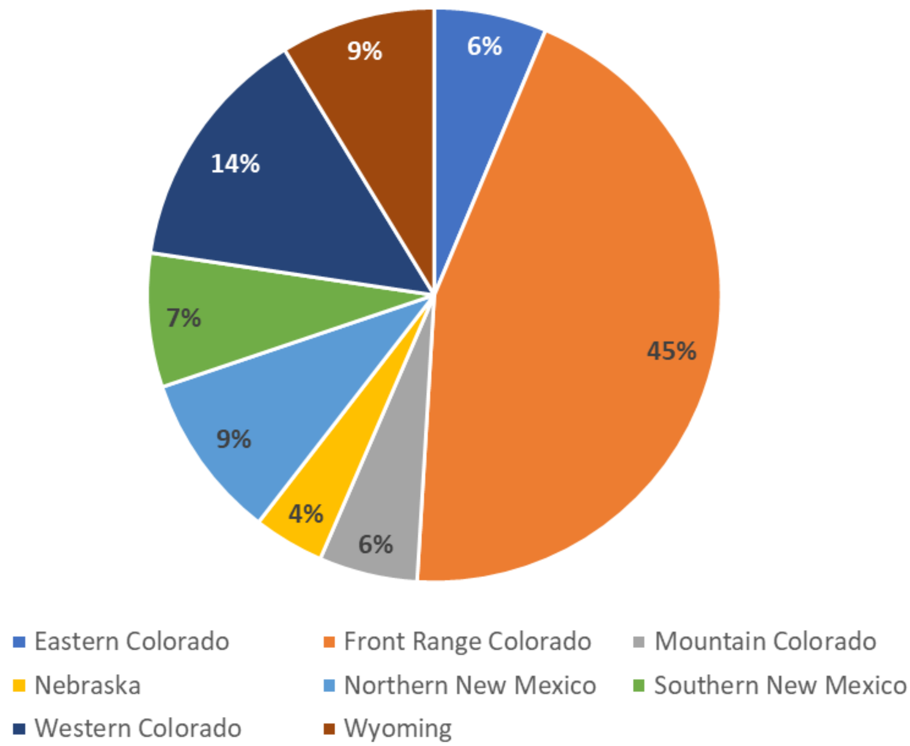
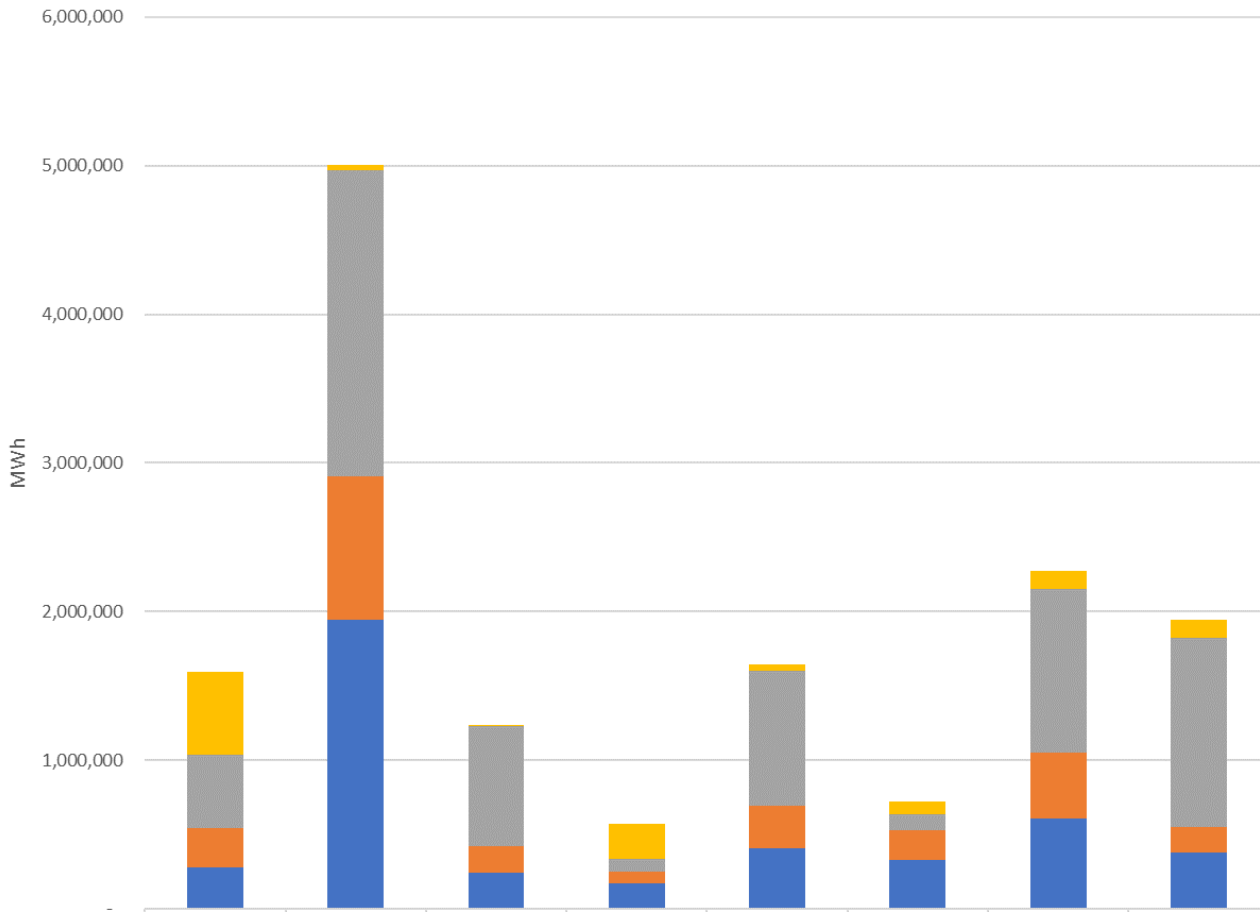


Figure 7. 2018 Energy Sales by Customer Sector and Region



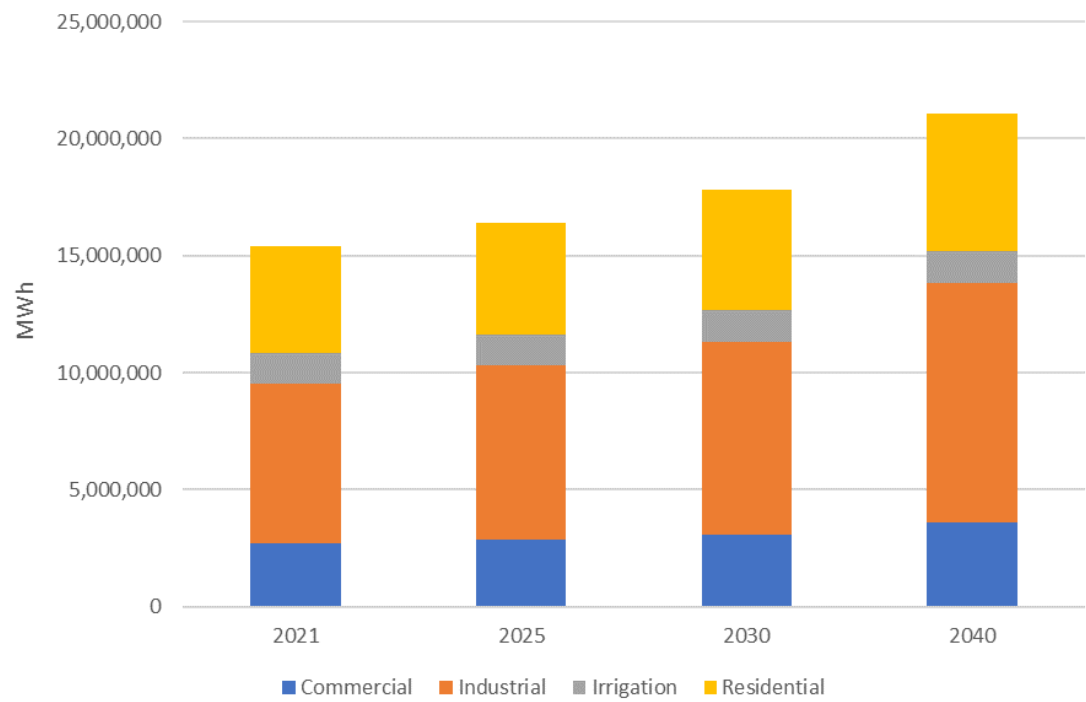
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	176,453	78,733	289,986	197,934	444,417	173,590
Residential	276,257	1,944,118	241,514	173,762	406,734	328,318	606,582	380,071

The industrial sector comprises a very large share of the energy load (46%). Energy use in this sector is predominately focused around the oil, gas, and mining industries, as described further in section 4.3. Conversely, the commercial sector share, at 17%, is lower than other electric utilities that serve metropolitan communities and typically have a commercial sector share closer to 40 to 50% of all energy sales. Tri-State's relatively low commercial sector values reflect the fact that many of the member cooperatives do not serve the city and town customers within their service territories. Municipal electric utilities are common for many rural towns within western Nebraska, eastern Colorado, and most of Wyoming. Eastern Colorado and Nebraska regions have significant shares of their overall electricity sales in the irrigation sector.

Figure 8 presents the baseline load forecast at key milestone points during the analysis period. The industrial sector will see the largest amount of load growth, increasing by approximately 50% by 2040.

Commercial and residential sector load will each increase by approximately one-third. The load growth estimate for the irrigation sector is negligible.

Figure 8. Baseline Load Forecast by Sector by Milestone Year

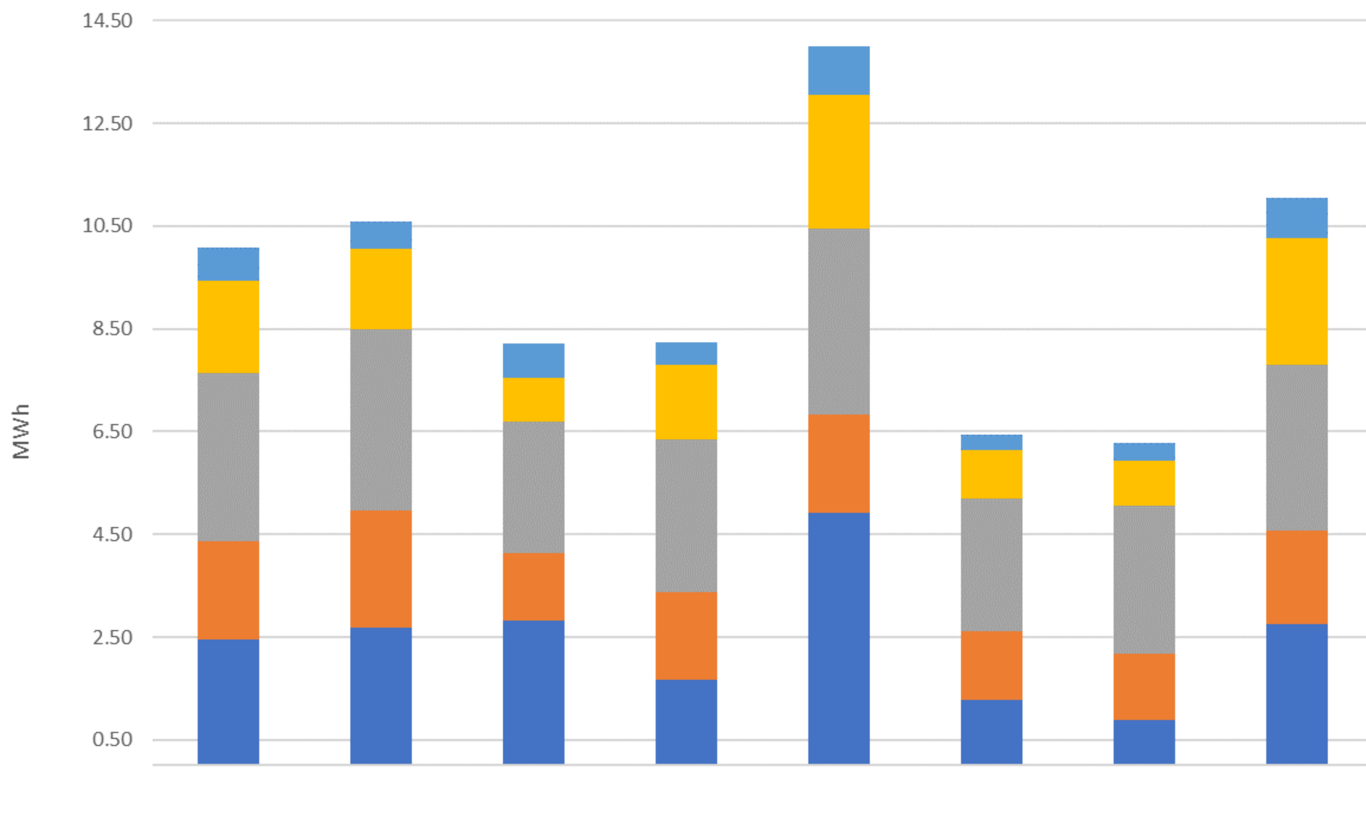


3.2. Residential End-Uses and Loads

The residential sector is responsible for 4,357 GWh of electric consumption, includes approximately 470,000 unique residential dwellings and accounts for 29% of Tri-State's total electricity sales. Average per dwelling energy usage was in line with an annual consumption of 9,260 kWh per home. Based on the limited information available to segment single-family, multi-family, and/or manufactured homes energy use or equipment saturations, it was determined that the existing residential sector should be analyzed in its entirety with no sub-sectors analyzed.

There are notable variations in average home size, average annual energy consumption, and equipment saturations across the different regions as shown in Figure 9.

Figure 9. Average Annual End-Use Consumption per Residence by Region (2018)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Western Colorado	Nebraska	Southern New Mexico	Northern New Mexico	Wyoming
Water Heat	653	540	668	444	955	298	334	785
Plug Load	1,786	1,569	865	1,441	2,590	948	887	2,478
Appliances	3,279	3,527	2,557	2,972	3,621	2,564	2,868	3,225
Lighting	1,919	2,280	1,308	1,718	1,909	1,356	1,290	1,810
HVAC	2,443	2,674	2,818	1,662	4,928	1,269	890	2,757

The Team utilized the 2012 Tri-State residential end-use survey to compile end-use saturations and average residential premise square footage as in Table 9.

Table 9: Tri-State End-Use Saturations per Region

END-USE	EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO	NEBRASKA	SOUTHERN NEW MEXICO	NORTHERN NEW MEXICO	WYOMING
Central Heating	13.2%	16.0%	22.7%	15.6%	25.5%	8.4%	6.3%	15.4%
HVAC Aux	67.9%	91.7%	78.3%	78.6%	72.6%	57.5%	39.4%	71.8%
Room AC	18.1%	6.9%	1.8%	5.8%	23.3%	11.3%	11.8%	16.1%
Evap Cooler	12.2%	10.2%	1.6%	17.3%	10.2%	33.4%	10.2%	12.2%
Central Air	44.8%	49.9%	1.4%	7.4%	44.6%	19.7%	12.5%	26.3%
Heat Pump	4.2%	3.9%	0.2%	1.2%	14.4%	2.6%	2.6%	2.0%
Interior Lighting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Exterior Lighting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Electric Cooking	56.4%	70.2%	65.8%	54.1%	71.3%	38.8%	71.0%	64.6%
Washer	81.1%	94.0%	79.8%	89.5%	89.6%	82.3%	76.8%	86.2%
Electric Dryer	75.3%	83.7%	67.5%	69.5%	85.6%	67.7%	61.3%	80.8%
Dish Washer	67.9%	91.7%	78.3%	78.6%	72.6%	57.5%	39.4%	71.8%
Electric Water Heater	29.7%	20.3%	40.9%	31.4%	53.7%	25.7%	25.8%	44.7%
Refrigerator	84.5%	96.1%	93.3%	94.3%	91.1%	90.6%	91.5%	89.1%
Second Refrig	23.4%	24.5%	14.1%	14.8%	27.5%	16.6%	14.6%	21.8%
Freezer	69.1%	62.6%	40.6%	54.3%	77.0%	53.6%	58.5%	72.0%
Exterior Plug Loads	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Plug Loads	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The saturations of ‘plug loads’ and ‘lighting’ are both 100% by definition. Therefore, the contribution of these end-uses to the overall energy usage is driven by the unit energy consumption (UEC) and by the prevalence of certain equipment within the end-use category.

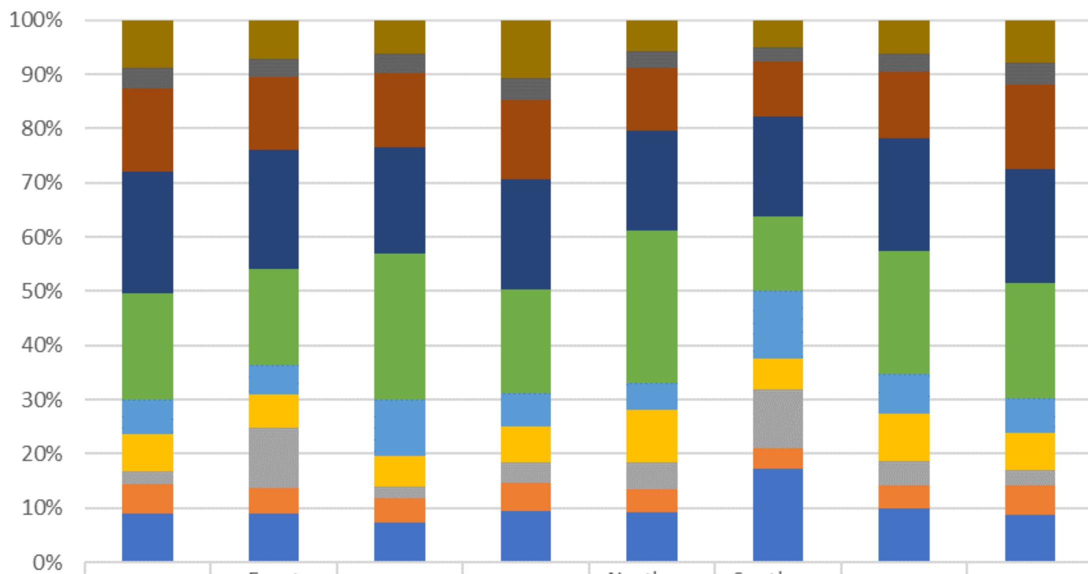
The analysis finds lower appliance saturations and smaller premise square footage for the New Mexico region residences. As expected, there is a higher prevalence of electric space and water heating in the colder climates of mountain Colorado, Nebraska, and Wyoming due to the lack of available natural gas in the rural environment.

3.3. Commercial End-Uses and Loads

The commercial sector is responsible for 2,594 GWh of electric consumption, which accounts for 17% of Tri-State's total electricity sales. In general, the commercial sector covers a large spectrum of customers, usually smaller in size as compared to the remainder of the non-residential customers, with 71% having a peak demand less than 250 kW.

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct commercial business types. Assumptions largely based on secondary data used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

Figure 10. Commercial Sector Energy Shares by Business Segment and Region (2018)

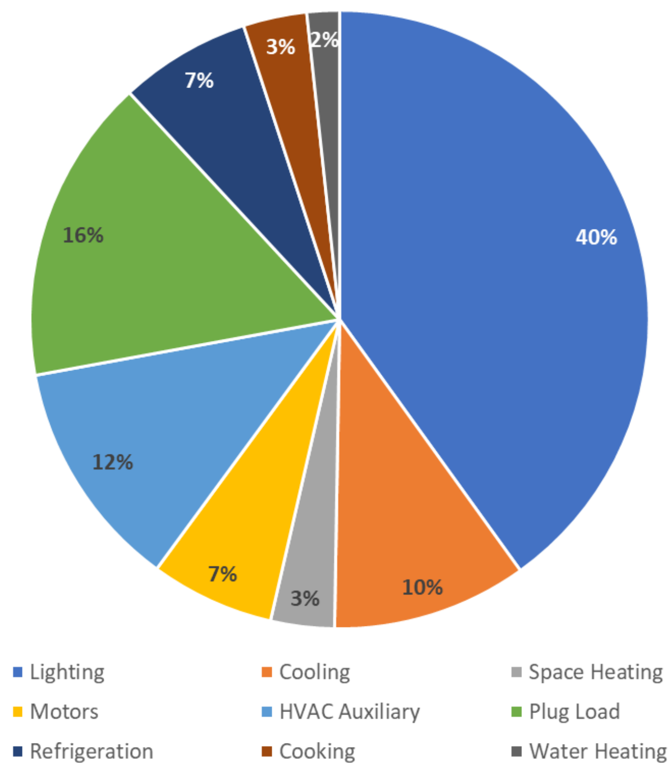


	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Warehouse	9%	7%	6%	11%	6%	5%	6%	8%
Restaurant	4%	3%	3%	4%	3%	3%	3%	4%
Office	15%	13%	14%	15%	12%	10%	12%	15%
Retail	22%	22%	20%	20%	18%	18%	21%	21%
Miscellaneous	20%	18%	27%	19%	28%	14%	23%	21%
Lodging	6%	6%	10%	6%	5%	13%	7%	6%
Health	7%	6%	6%	7%	10%	5%	9%	7%
Government	2%	11%	2%	4%	5%	11%	4%	3%
Grocery	5%	5%	5%	5%	4%	4%	4%	6%
Education	9%	9%	7%	9%	9%	17%	10%	9%

The Team next identified the appropriate energy usage intensity (EUI), or end-use energy consumption per square foot, for each end-use studied. These EUIs were calculated based on other applicable regional commercial end-use studies, such as those found in Wyoming, Montana, Utah, Colorado, New Mexico, and Iowa. Figure 11 summarizes the energy consumption for each end-use.

Lighting makes up forty-five percent of the total electricity consumption, which is attributable to the fact that this end-use is common in all sub-sectors and does not have any seasonal operation. Lighting is followed by HVAC Auxiliary which included fans, pumps, motors, and electronics used to move or control HVAC air and water systems.

Figure 11. Commercial Energy End-Use Consumption Shares

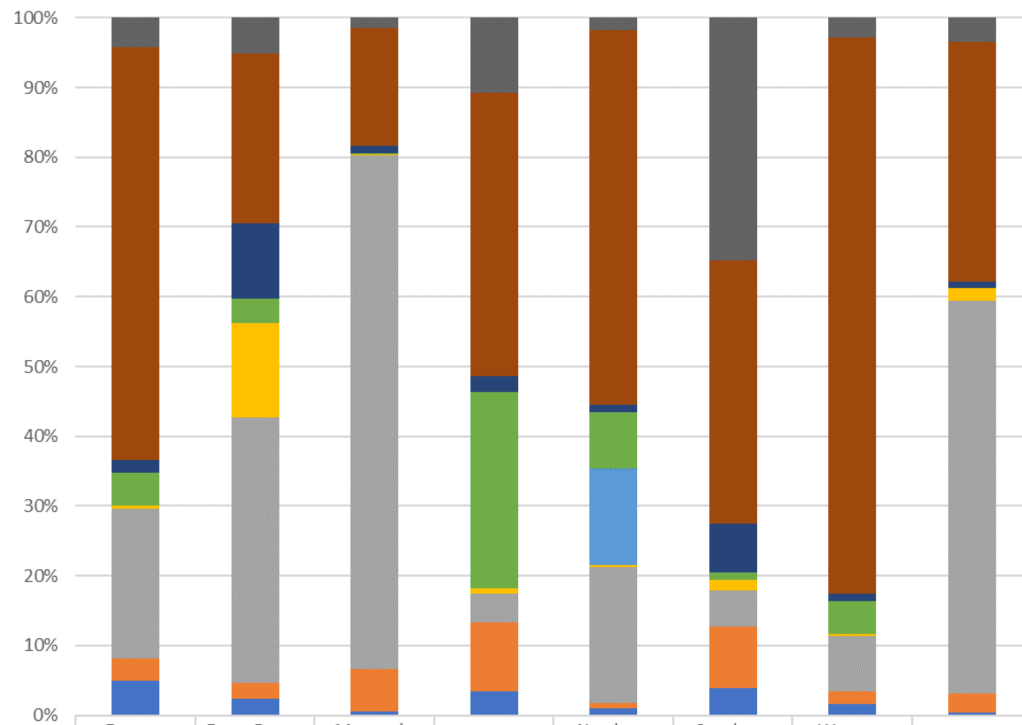


3.4. Industrial End-Uses and Loads

Industrial is the largest sector, accounting for 6,834 GWh of electric consumption and 46% of Tri-State's total electricity sales. In general, Tri-State's industrial sector is unique since approximately 77% of the sector's consumption is from the oil and gas industry and less than 15% is from manufacturing industries (Figure 12).

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct industrial business types. Assumptions used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

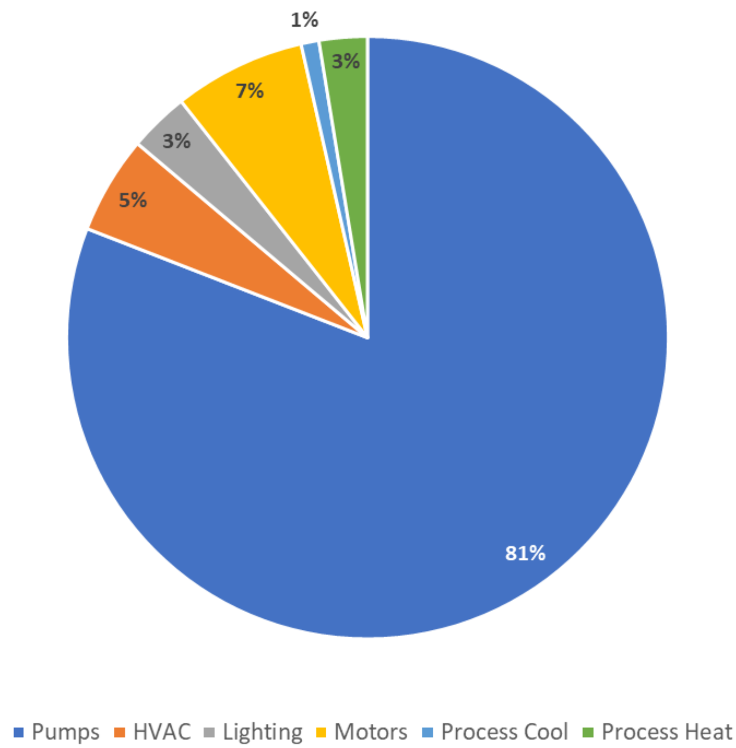
Figure 12. Industrial Sector Energy Shares by Business Segment and Region (2018)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
TCU	4%	5%	1%	11%	2%	35%	3%	4%
Pipeline Transportation	59%	24%	17%	41%	54%	38%	80%	34%
Mfg - Misc.	2%	11%	1%	2%	1%	7%	1%	1%
Mfg - Chemical	5%	3%	0%	28%	8%	1%	5%	0%
Mfg - Paper	0%	0%	0%	0%	14%	0%	0%	0%
Mfg - Nonmetallic Mineral Product	0%	13%	0%	1%	0%	2%	0%	2%
Liquid Mining (Oil, Gas, and Carbon Dioxide)	22%	38%	74%	4%	19%	5%	8%	56%
Mining	3%	2%	6%	10%	1%	9%	2%	3%
Agriculture	5%	2%	1%	3%	1%	4%	2%	0%

The Team identified the appropriate energy usage fraction for each industrial end-use studied. These energy end-use shares were calculated based on other applicable regional and national industrial end-use studies (Figure 13).

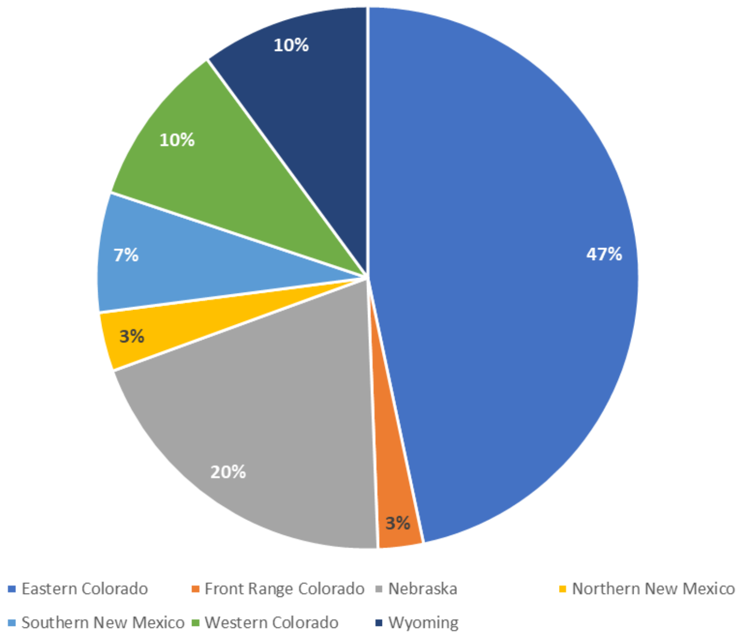
Figure 13. Industrial Sector Energy Shares by End-Use



3.5. Irrigation End-Uses and Loads

Figure 14 summarizes the irrigation energy consumption share for each region analyzed. Eastern Colorado has the largest share of irrigation energy consumption by a wide margin and is followed by the Nebraska region. The Mountain Colorado region has a negligible market share of irrigation sales and is not shown for clarity.

Figure 14: Irrigation Energy Shares by Region



Irrigation energy usage is entirely attributable to electric motors. These motors serve several different purposes, including well lift pumps, supplemental pressure boost pumps, drive motors for center pivots, and gate motors. Based on the Team's experience and research, it was determined that the major application for irrigation electricity is well lift pumps and supplemental pressure boost pumps; consequently, analyses and measures were developed for these end-uses.

3.6. Peak Demand Characterization

This section summarizes the market and end-use characterization of Tri-State's summer peak demand by sector and region. Tri-State's 2018 coincident peak demand used by member cooperatives was 2,887 MW, observed during the month of July. Figure 15 shows the distribution of the coincident peak demand by region. Energy sales by sector were used to estimate coincident peak demand allocation by sector, as described in Section 3. Figure 16 shows the results of this estimation for the Tri-State system as a whole and Figure 17 presents results by region. Notable contributors to the coincident peak demand are the residential and industrial sectors in the Front Range region, as well as the irrigation sector in Eastern Colorado and Nebraska.

Figure 15. 2018 Coincident Peak Demand by Region

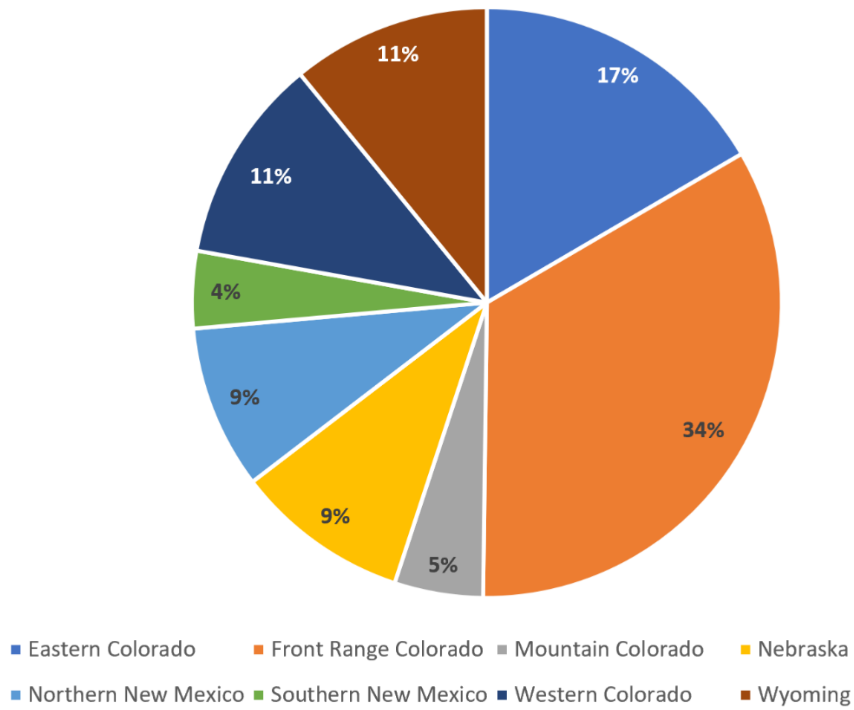


Figure 16. 2018 Coincident Peak Demand by Sector

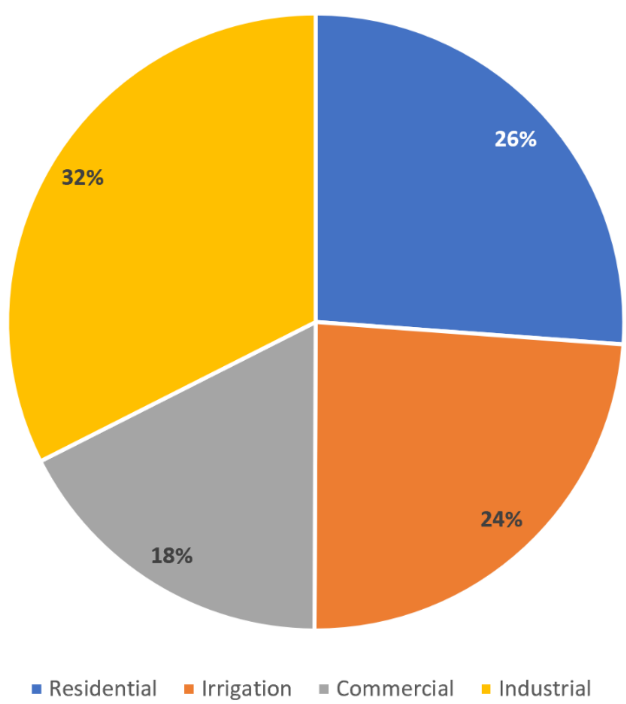
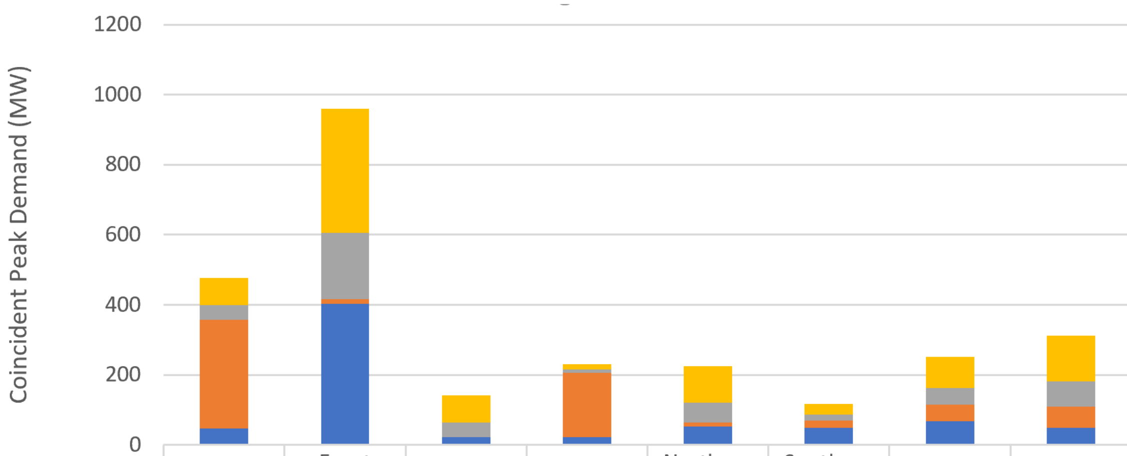


Figure 17. 2018 Coincident Peak Demand by Sector and Region

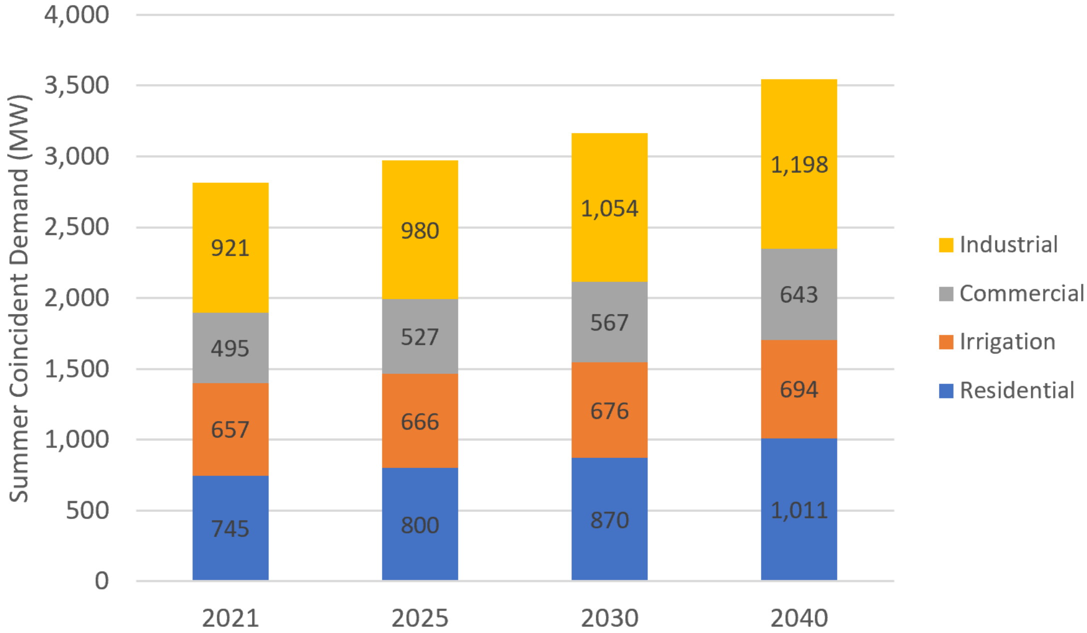


	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Industrial	78	354	78	15	106	30	89	131
Commercial	42	190	42	8	57	16	48	71
Irrigation	309	14	0	185	11	22	46	61
Residential	47	402	21	22	52	48	68	49

Residential Irrigation Commercial Industrial

Figure 18 presents the baseline demand forecast at key milestone points during the analysis period. Industrial, commercial, and residential sectors will increase by about 30%. The irrigation sector's coincident peak is not expected to increase significantly.

Figure 18. Baseline Demand Forecast by Sector by Milestone Year



4. PORTFOLIO LEVEL ENERGY EFFICIENCY POTENTIAL

4.1. Overview

The analysis finds that at the portfolio level Tri-State can achieve an average annual savings of 115 GWh from a collection of energy efficiency measures at an average annual cost of $24.3 million during the 20-year time horizon. This includes incentives and administrative costs and equates to an acquisition cost of $0.22/kWh which is in line with industry benchmarks.

4.2. Detailed Results

Table 10 presents portfolio-level energy efficiency savings potential by time horizon and Figure 19 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 38,083 MWh of savings potential in 2021 rising to 1,718,357 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive) could increase cumulative savings potential by approximately 40%. The maximum achievable scenario increases savings potential by approximately 25% over the aggressive scenario, resulting in cumulative savings of approximately 2,876,487 GWh. First-year savings potential for the Achievable-Moderate scenario represents an increase of approximately 19% over Tri-State's 2018 energy efficiency program performance.

Table 10 Cumulative Savings Potential (MWh) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	130,384	98,221	75,523	55,330	38,083	27,043

2025	1,293,033	928,122	539,750	393,656	266,309	179,222
2030	3,868,940	2,851,171	1,372,971	1,062,225	723,605	475,993
2040	9,081,432	6,956,507	2,876,487	2,354,365	1,718,357	1,193,109

Figure 19. Portfolio Energy Efficiency Savings Potential by Scenario by Year

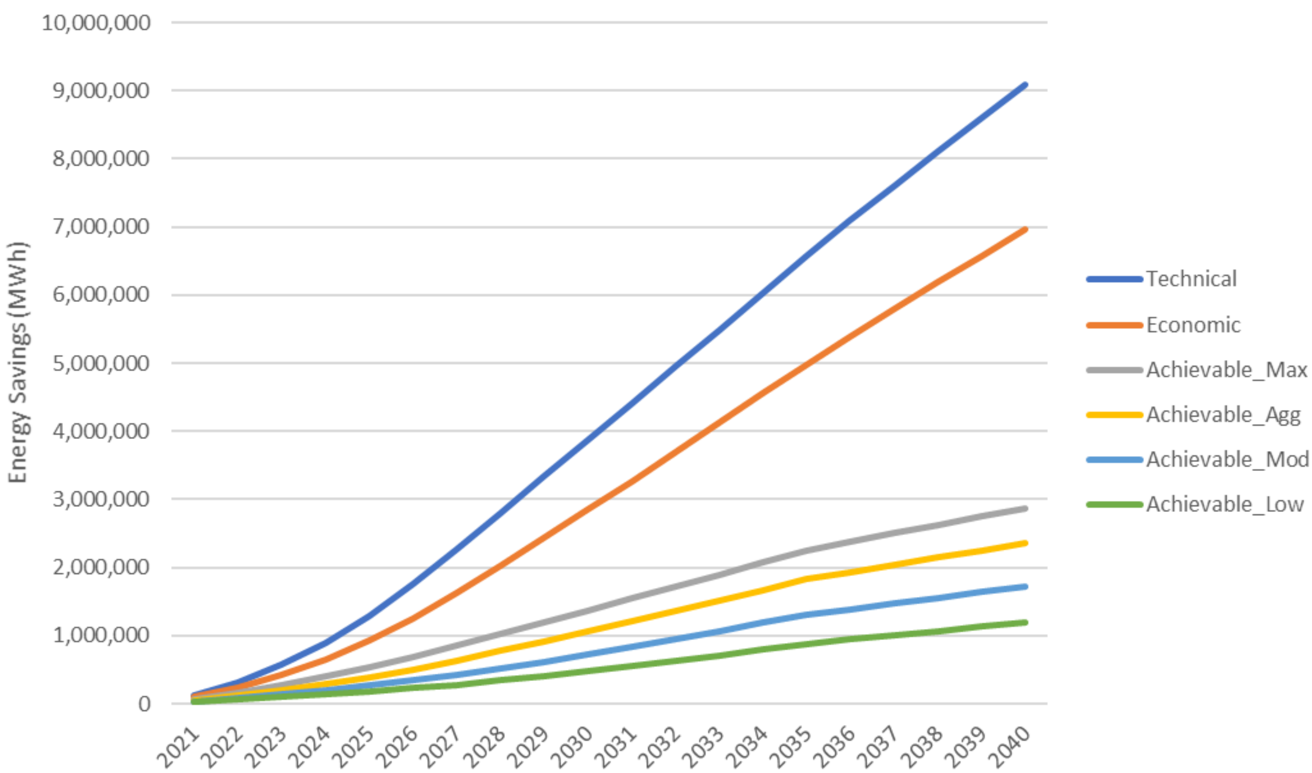


Table 11. shows the impacts of cumulative savings potential on Tri-State's baseline energy consumption forecast. The cumulative savings associated with the Achievable Moderate scenario would decrease Tri-State's baseline forecast consumption by approximately 0.25% in 2021. The reduction in baseline energy consumption would grow to 1.62% by 2025 and ultimately 8% through 2040. The range of potential reduction in baseline consumption across the achievable scenarios spans from 5.7% (Achievable-Low) to 13.7% (Achievable-Max) by 2040.

Table 11. Portfolio Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.85%	0.64%	0.49%	0.36%	0.25%	0.18%
2025	7.88%	5.65%	3.29%	2.40%	1.62%	1.09%

2030	21.74%	16.02%	7.71%	5.97%	4.07%	2.67%
2040	43.14%	33.04%	13.66%	11.18%	8.16%	5.67%

Figure 20 shows the impact of the modeled scenarios on the baseline forecast. The Achievable-Max scenario would reduce Tri-State's overall load growth significantly, though Tri-State's load will continue a steady growth trajectory under all Achievable scenarios.

Figure 20. Impact of Portfolio Energy Efficiency Savings on Baseline Forecast by Scenario by Year

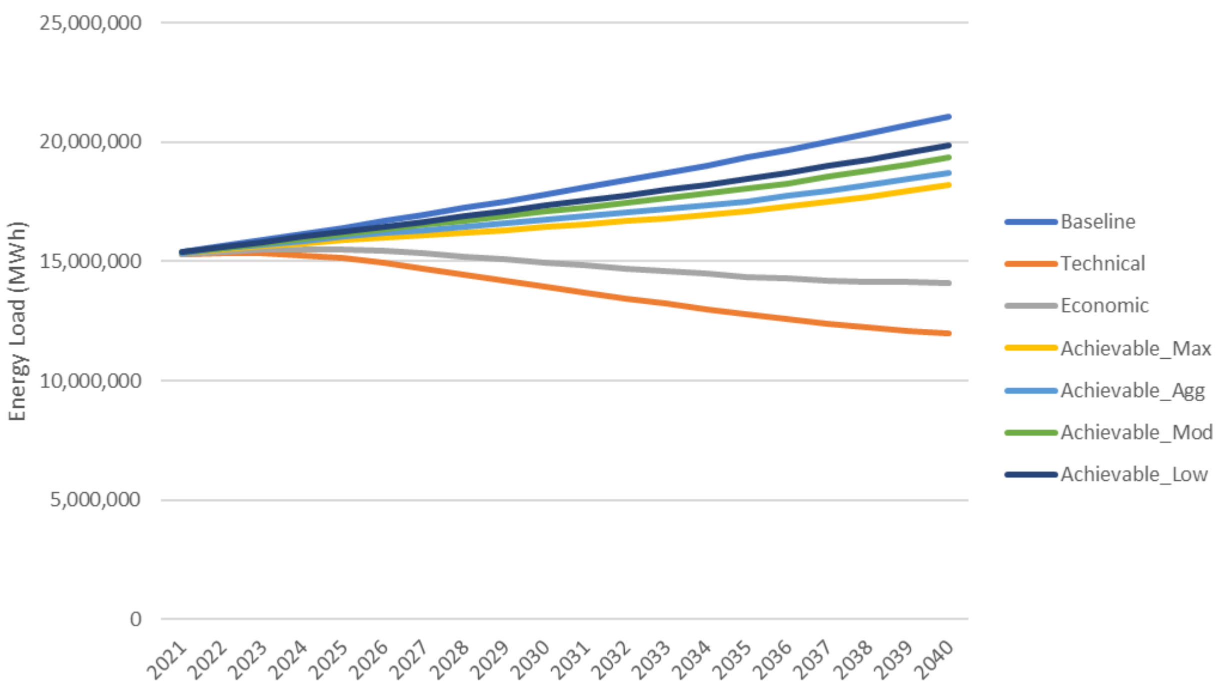
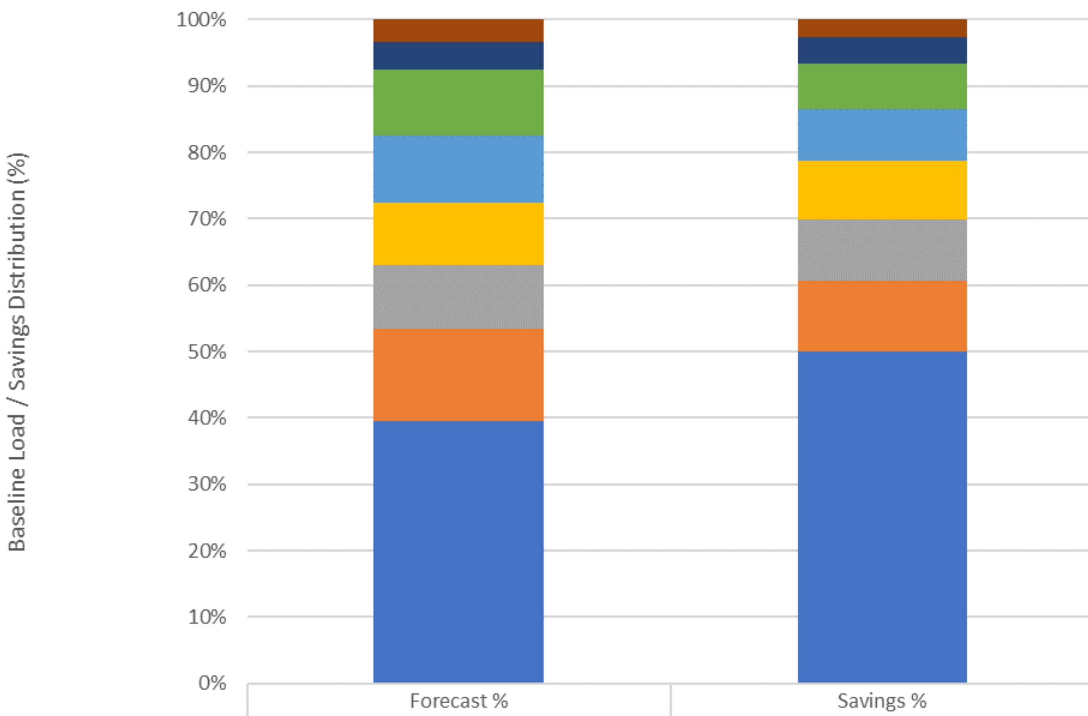


Figure 21 and Table 12 present energy savings potential by region. Front Range Colorado represents the largest share making up half the total. The other regions within Colorado account for nearly one quarter of the remaining savings potential. The two regions within New Mexico together comprise approximately 13% of total savings potential, while Wyoming accounts for approximately 10% of the total. Nebraska's savings potential is much smaller at just 2.7% of the total. This savings potential is generally aligned with the distribution of forecast energy load by region. However, Front Range Colorado's share of energy savings (50%) is larger than its share of forecast baseline energy consumption (39.5%) by a notable margin.

Figure 21. Baseline Forecast and Portfolio Energy Efficiency Savings by Region



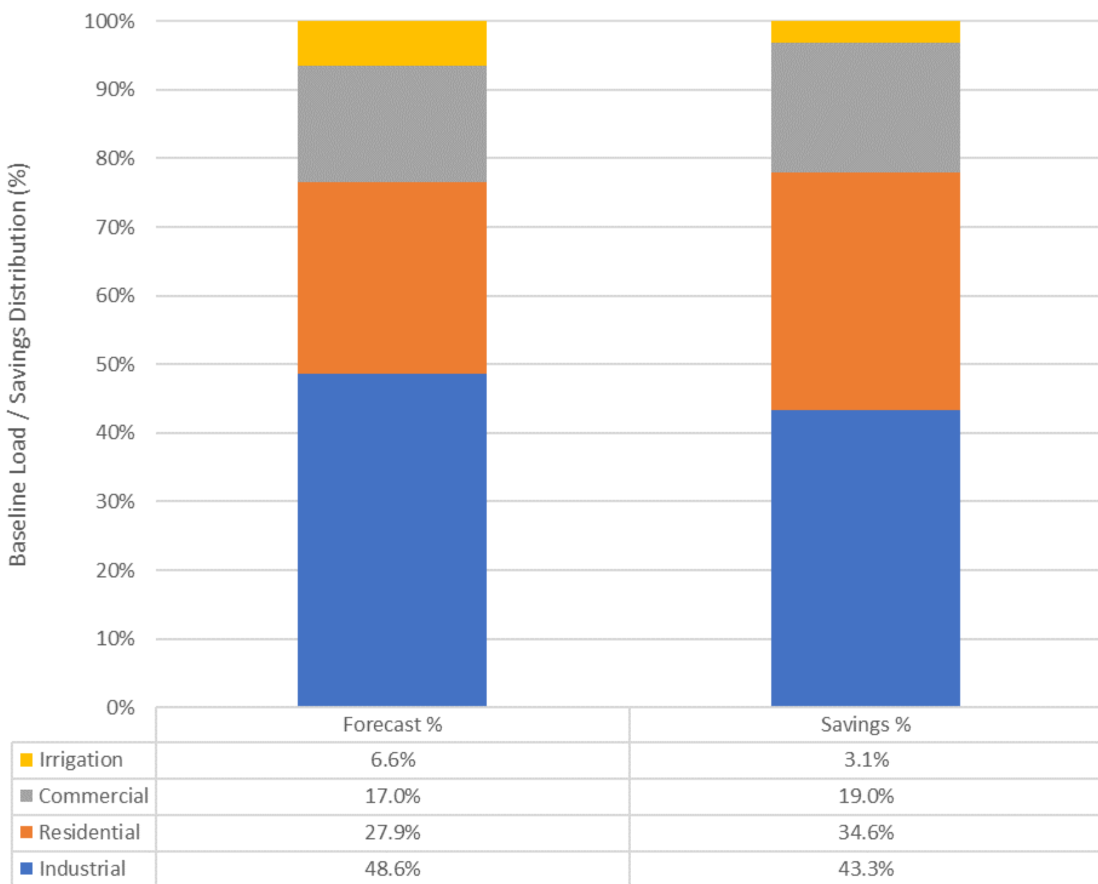
	Forecast %	Savings %
Nebraska	3.4%	2.7%
Southern New Mexico	4.1%	3.9%
Mountain Colorado	9.8%	6.8%
Eastern Colorado	10.2%	7.8%
Northern New Mexico	9.5%	8.8%
Western Colorado	9.6%	9.2%
Wyoming	13.9%	10.6%
Front Range Colorado	39.5%	50.0%

Table 12. Cumulative Savings Potential by Region, Achievable-Moderate Scenario (2040)

STATE / SUB-REGION	POTENTIAL SAVINGS (MWH)
Colorado	1,270,405
Front Range	*860,016*
Western	*158,539*
Mountain	*117,559*
Eastern	*134,292*
Wyoming	182,708
New Mexico	218,977
Northern	*151,292*
Southern	*67,685*
Nebraska	46,267
Total	**1,718,357**

As shown in Figure 22 the industrial and residential sectors represent the largest opportunity for savings. The industrial sector comprises 43% of the total savings potential and its share of the baseline forecast consumption is slightly higher at 49%. This sector's oil and gas-related energy consumption is exceptionally high, and motor-related efficiency improvements can go a long way toward reducing that load, as discussed further in Section 7. The residential sector makes up 35% of the total savings potential, and a slightly smaller portion of the baseline forecast consumption at 28%. Numerous measures are available to reduce residential energy load, with the most substantial savings coming from lighting and central heating, as discussed further in Section 5. The commercial sector also holds substantial potential energy savings at 19% of the total, which is generally in line with its share of the baseline forecast energy consumption. Heavy use of energy for lighting coupled with the availability of numerous lighting efficiency-related measures account for this sector's substantial share of savings potential. The irrigation sector contributes substantially less, both in terms of overall savings potential and in terms of its share of baseline forecast load.

Figure 22. Energy Efficiency Savings Potential by Sector (2040)



The portfolio of energy efficiency measures can achieve a cumulative demand savings of 23 MW by 2040 (Table 13.) under the Achievable-Moderate scenario. The industrial sector accounts for the largest share of demand savings, followed by the residential sector.

Table 13. Portfolio Cumulative Demand Savings Potential by Sector by Year (MW)

MILESTONE YEAR	INDUSTRIAL	RESIDENTIAL	COMMERCIAL	IRRIGATION	**TOTAL**
2021 (first year)	1.8	2.1	1.1	0.12	**5.3**
2025	3.7	3.5	2.3	0.37	**9.9**
2030	6.7	5.8	3.7	1.1	**17.2**
2040	10.3	6.2	4.5	2.1	**23.1**

Table 14 presents cumulative and average annual cost, savings and TRC metrics associated with the Achievable-Moderate scenario. As shown, in the first year Tri-State can achieve 38,083 MWh of energy savings at a cost of approximately $7 million, or $183/MWh. As programs expand and become more established annual costs and savings increase substantially to reach a cumulative program expenditure of nearly $500 million by 2040 and savings of approximately 2,290,400 MWh. The 20-year average annual program costs are approximately $24.3 million and savings are 114,520 MWh.

Table 14. Portfolio Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM OF FIRST-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$6,957,787	38,083	$182.70	$15.25
2025	1.91	$54,155,251	279,461	$193.78	$17.41
2030	1.72	$164,148,094	797,374	$205.86	$20.18
2040	1.64	$486,794,842	2,290,399	$212.54	$21.55
20-year avg.	1.64	$24,339,742	114,520	$212.54	$21.55

5. RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

5.1. Overview

The residential sector accounts for just under one-third of the total baseline forecast energy load, and 35% of energy savings potential. Cumulative savings potential for this sector is approximately 5,880 GWh through 2040 (Achievable-Moderate scenario) with lighting efficiency improvements making up over half the total energy savings potential. Central heating improvements comprise almost one-sixth of the residential sector savings potential.

Notable assumptions for the residential sector analysis include: 1) the speed with which lighting market transformation will occur, and 2) the timing of the roll-out and accrual of demand impacts associated with Home Energy Reports (HERs). With regard to lighting, research indicates that LED lamps will become standard technology within 10 years despite delays in implementing lighting efficiency standards under the Energy Independence and Security Act (EISA) of 2007. Lighting measures commonly account for the largest share of savings for residential energy efficiency programs. However, since residential lighting market transformation is well underway, savings from lighting measures are limited for the second half of the evaluation period.

For the home energy reports measure (HER) the analysis assumes a seven-year implementation delay in order to capture demand benefits associated with this measure. This is because Tri-State is not capacity constrained during this period and avoided cost of capacity benefits do not apply. The addition of demand benefits along with energy savings benefits allows the HERs measure to achieve cost effectiveness for various measure permutations in varying regions.

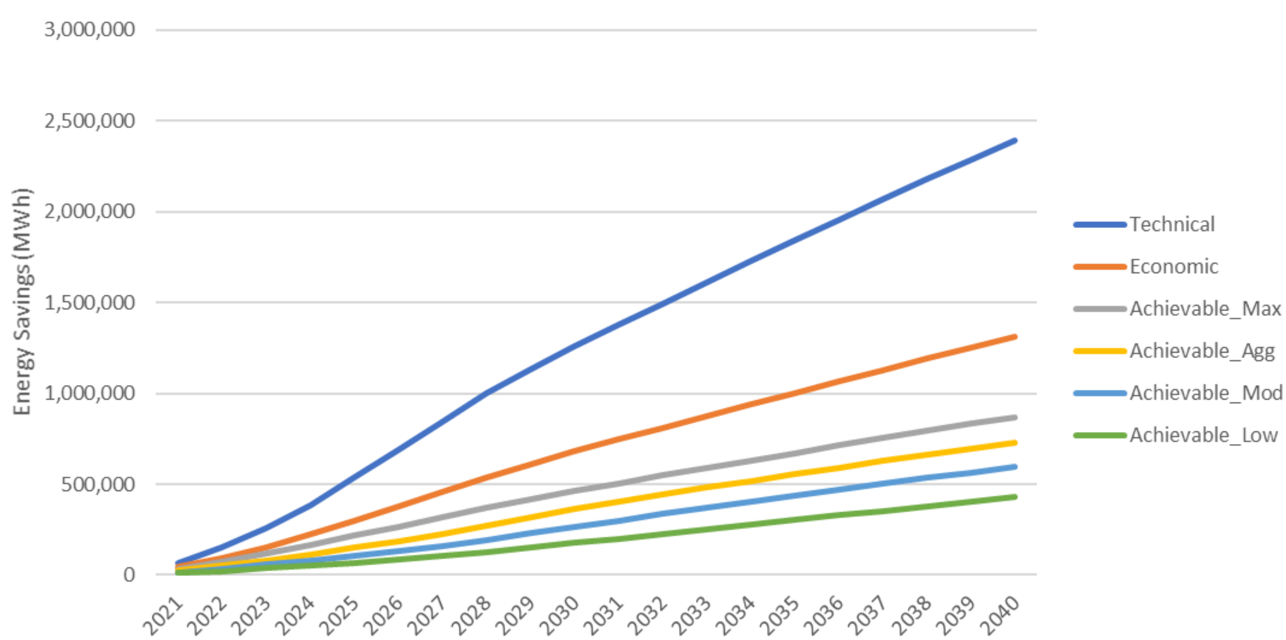
5.2. Detailed Results

Table 15 presents cumulative savings potential for the residential sector by scenario at various milestones in the analysis period and Figure 23 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14,649 MWh of savings potential in 2021 rising to 594,298 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 22%. The maximum achievable scenario estimates savings potential approximately 46% higher than the aggressive scenario, equating to cumulative savings of approximately 870,669 MWh through 2040.

Table 15. Cumulative Residential Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	63,817	42,581	34,166	22,384	14,649	9,539
2025	532,961	299,459	214,988	149,245	104,278	68,016
2030	1,257,012	679,699	461,040	361,598	263,762	175,118
2040	2,395,940	1,313,384	870,669	726,771	594,298	427,615

Figure 23. Residential Energy Efficiency Savings Potential by Scenario by Year



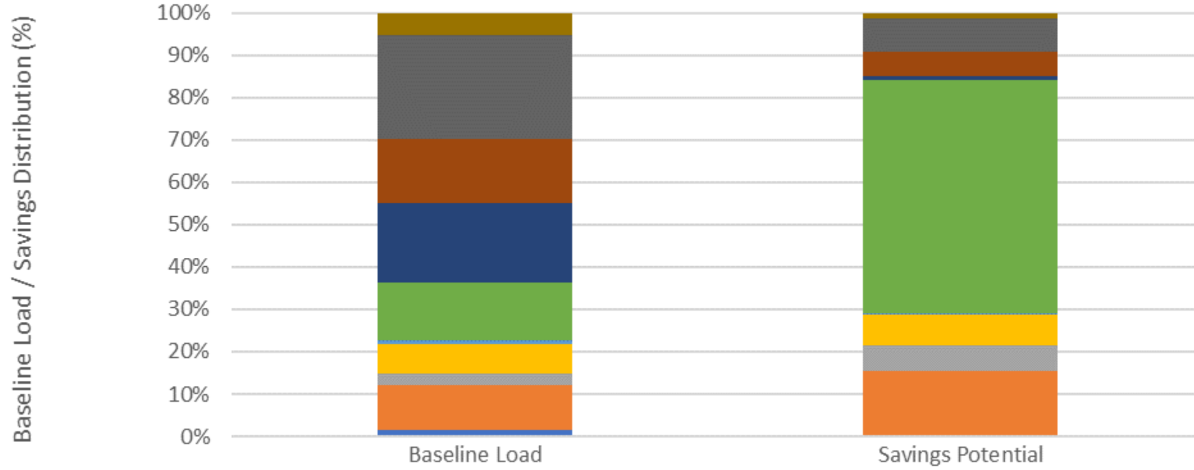
The cumulative residential savings potential under the Achievable-Moderate scenario equates to 9.1% of the residential baseline load forecast for 2040 (see Table 16.). The maximum achievable savings would equate to 16.2% of the forecast energy load for this sector.

Table 16. Residential Savings Potential as % of Baseline Forecast by Scenario by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1.10%	0.75%	0.57%	0.45%	0.32%	0.24%
2025	12.48%	8.63%	4.36%	3.36%	2.25%	1.54%
2030	38.13%	26.76%	10.02%	8.03%	5.53%	3.74%
2040	76.33%	53.93%	16.19%	13.21%	9.14%	6.54%

As shown in Figure 24, lighting accounts for the greatest share of energy savings potential at 55% of the total followed by central heating at approximately 15% of total savings. Plug loads, central air, HVAC auxiliary, and refrigerator/freezer end-uses combined comprise over a quarter of savings potential.

Figure 24. Residential Baseline Energy Load and Cumulative Energy Efficiency Savings Potential by End-Use (2040)



	Baseline Load	Savings Potential
Electric Water Heater	5.4%	1.3%
Plug Loads	24.5%	7.8%
Refirgerator/Freezer	14.9%	5.7%
Appliances	18.9%	1.1%
Lighting	13.6%	55.1%
Zonal Air	1.0%	0.2%
Central Air	6.8%	7.2%
HVAC Aux	2.9%	6.1%
Central Heating	10.4%	15.4%
Heat Pump	1.7%	0.1%

Table 17 presents cumulative residential demand savings by end-use by milestone year. High efficiency lighting is by far the greatest contributor to demand savings from residential energy efficiency measures producing 2,722 kW of cumulative demand savings through 2040. Additional measures with relatively large volumes of demand savings include plug loads and central air.

Table 17. Residential Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	HEAT PUMP	CENTRAL HEATING	HVAC AUX	CENTRAL AIR	ZONAL AIR	LIGHTING	APPLIANCES	REFRIG-ERATOR / FREEZER	PLUG LOADS	ELECTRIC WH	TOTAL
2021	0.0002	0.0053	0.0122	0.0951	0.0	1.8303	0.0080	0.0605	0.1238	0.0100	**2.1454**
2025	0.0008	0.0203	0.0538	0.3813	0.0	2.4448	0.0296	0.1921	0.3284	0.0408	**3.4921**
2030	0.0031	0.0505	0.1460	1.5397	0.0806	2.9055	0.0990	0.3152	0.5296	0.1378	**5.8072**

2040	0.0037	0.0440	0.2012	1.7245	0.0829	2.7220	0.1116	0.3383	0.7502	0.1771	**6.1554**

Table 18. presents cumulative program cost metrics by milestone year. As shown, first-year program costs are approximately $3.0 million, rising to a 20-year average annual cost of approximately $8.9 millon. Acquisition costs rise from $206/MWh in 2021 to $251/MWh in 2040. A change in lighting market measures available during the analysis period drives this increase in acquisition costs, as LEDs become the market baseline within ten years. The decline in highly cost-effective lighting measures also has a downward effect on the TRC ratio, as it decreases from 2.15 in 2021 to 1.36 in 2040.

Table 18. Cumulative Residential Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.15	$ 3,013,704	14,649	$ 205.72	$ 14.90
2025	1.84	$ 23,693,929	104,884	$ 225.91	$ 18.61
2030	1.50	$ 68,913,983	280,300	$ 245.86	$ 23.95
2040	1.36	$ 177,217,648	705,466	$ 251.21	$ 26.52
20-year avg.	1.36	$ 8,860,882	35,273	$ 251.21	$ 26.52

6. COMMERCIAL ENERGY EFFICIENCY POTENTIAL

6.1. Overview

The commercial sector accounts for 17% of the total baseline forecast energy load, and 19% of cumulative energy savings potential in 2040. Cumulative savings potential for this sector is approximately 326 GWh through 2040 (Achievable-Moderate scenario) with lighting measures making up 74% of the total energy savings potential. Other end-uses comprising a notable share of savings potential include refrigeration, motors and plug load at 7.5%, 5% and 4% of savings respectively. The retail segment holds the largest opportunity for savings at roughly 27% of the cumulative savings potential in 2040.

6.2. Detailed Results

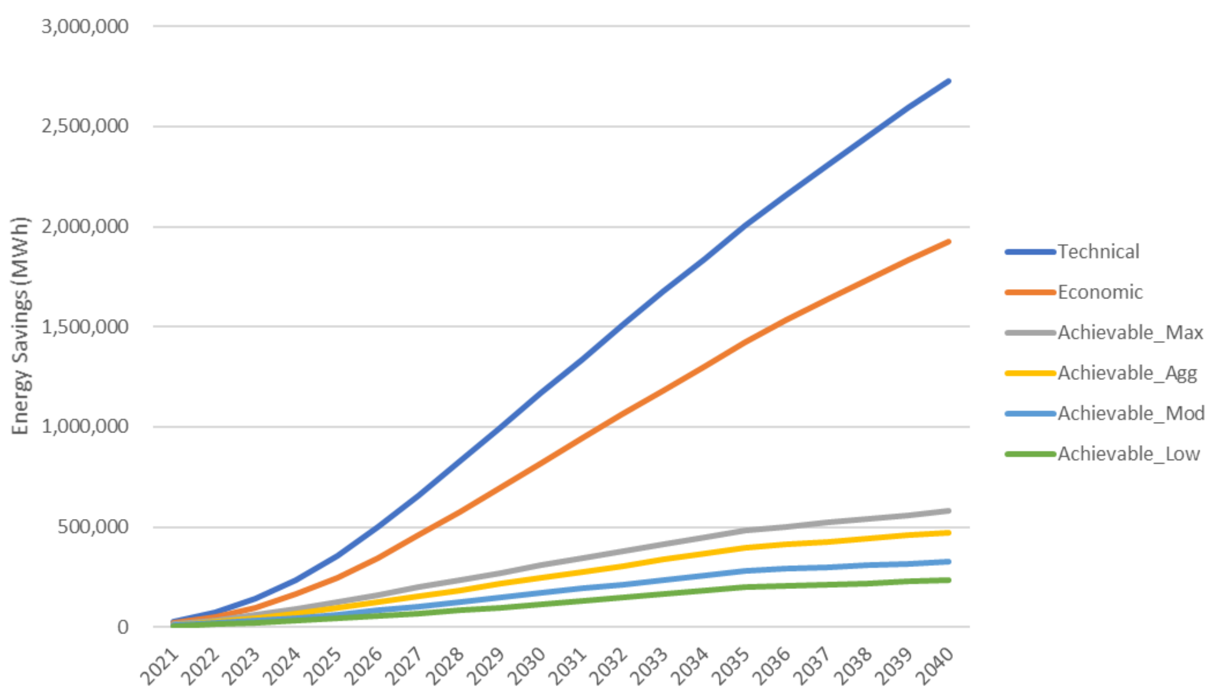
Table 19. presents cumulative savings potential for the commercial sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 8.6 GWh of savings potential in 2021 rising to approximately 326 GWh of cumulative savings potential through 2040. Pursuing an aggressive program-delivery approach (Achievable-Aggressive scenario) could increase cumulative savings potential

by approximately 45% to 472 GWh. A less aggressive program delivery approach (Achievable-Low scenario) would reduce savings by approximately 30% relative to the Achievable-Moderatemoderate scenario.

Table 19. Cumulative Commercial Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	29,723	20,331	15,375	12,230	8,626	6,372
2025	356,164	246,342	124,400	95,929	64,202	43,820
2030	1,167,833	819,729	307,053	245,955	169,298	114,633
2040	2,726,737	1,926,747	578,473	472,062	326,383	233,706

Figure 25. Commercial Cumulative Energy Efficiency Savings Potential by Sector by Year



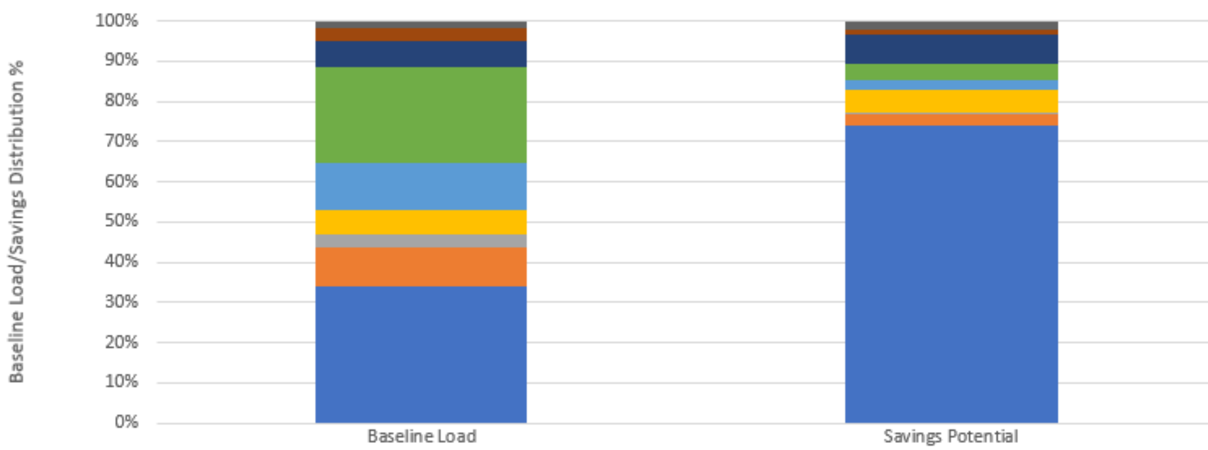
The cumulative commercial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.32% of commercial baseline sales in 2021, a 2.25% reduction by 2025 and a 9.14% reduction by 2040 (see Table 20.). The Mesa Point Energy Team esimates a range in reduction of baseline energy sales for the achievable scenarios from 6.5% (Achievable-Low) to 16.2% (Achievable-Max) by 2040.

Table 20. Commercial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1.10%	0.75%	0.57%	0.45%	0.32%	0.24%
2025	12.48%	8.63%	4.36%	3.36%	2.25%	1.54%
2030	38.13%	26.76%	10.02%	8.03%	5.53%	3.74%
2040	76.33%	53.93%	16.19%	13.21%	9.14%	6.54%

As shown in Figure 26 lighting makes up a large majority of the commercial sector's energy savings potential at 74%, a significant increase in its baseline load share. Refrigeration, motors and plug loads comprise most of the remaining savings potential for this sector at 7.5%, 5.5% and 4% respectively.

Figure 26. Commercial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)



	Baseline Load	Savings Potential
Water Heating	1.6%	2.1%
Cooking	3.2%	1.2%
Refrigeration	6.6%	7.5%
Plug Load	24.0%	3.9%
HVAC Auxiliary	11.5%	2.5%
Motors	6.3%	5.5%
Space Heating	3.2%	0.7%
Cooling	9.7%	2.6%
Lighting	33.8%	74.0%

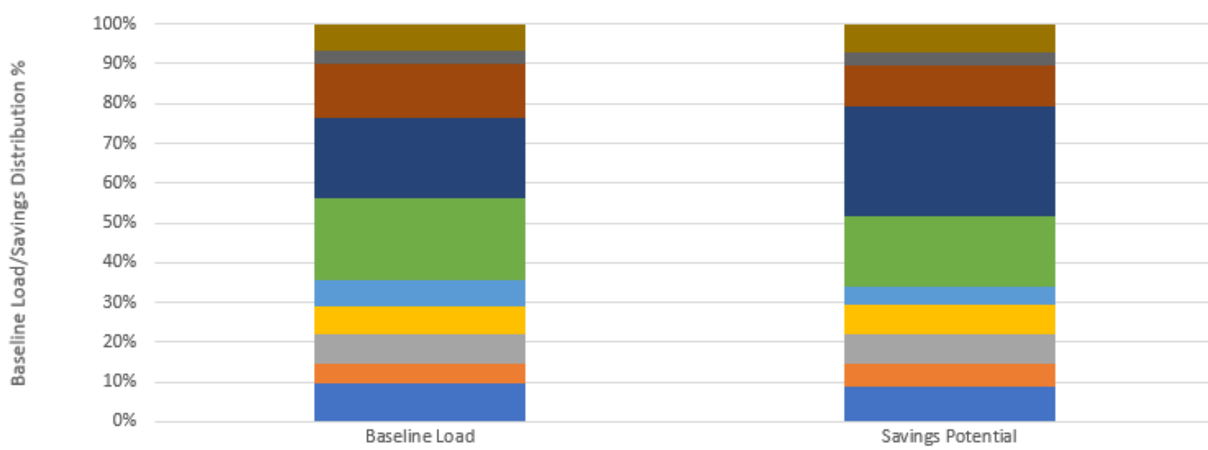
Table 21 presents cumulative commercial demand reductions by end-use by milestone year. Lighting accounts for nearly 55% of demand savings from commercial energy efficiency measures, producing almost 2,500 kW of demand reductions by 2040. Relative to their energy savings, the Cooling and HVAC Auxillary end-uses provide a large demand reduction opportunity at 430 kW and 424 kW respectively.

Table 21. Commercial Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	LIGHTING	COOLING	HEATING	MOTORS	HVAC AUX	PLUG LOAD	REFRIGER-ATION	COOKING	DHW	TOTAL
2021 (first year)	0.763	0.054	0.001	0.0251	0.054	0.102	0.108	0.011	0.014	**1.133**
2025	1.526	0.147	0.002	0.0693	0.145	0.161	0.230	0.025	0.039	**2.344**
2030	2.171	0.310	0.004	0.1529	0.305	0.233	0.353	0.041	0.082	**3.653**
2040	2.476	0.430	0.006	0.2206	0.424	0.357	0.434	0.053	0.116	**4.517**

Figure 27 presents baseline energy load and cumulative savings by commercial market segment through 2040. The savings potential for each segment is generally similar to its share of total baseline energy load. The retail segment has the largest share of 2040 cumulative savings potential (27.4%), an increase of just over 7% of its baseline energy load share. This is a result of the large lighting load share in retail buildings. The Miscellaneous and Office segments comprise the next largest opportunities at 17.7% and 10.4% of cumulative savings potential respectively.

Figure 27. Commercial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)



	Baseline Load	Savings Potential
Warehouse	6.7%	7.1%
Restaurant	3.3%	3.4%
Office	13.5%	10.4%
Retail	20.3%	27.4%
Miscellaneous	20.3%	17.7%
Lodging	6.7%	4.8%
Health	7.1%	7.2%
Government	7.5%	7.5%
Grocery	4.7%	5.5%
Education	9.7%	9.0%

Table 22. summarizes cumulative commercial program cost metrics by milestone year. As shown, first-year program costs are approximately $1.4 million, rising to a 20-year average annual cost of roughly $4.1 millon. Acquisition costs start at $159/MWh during the first year of analysis and see a gradual increase through 2040. The TRC ratio remains solid for the commercial sector starting at 2.11 in 2021 and decreasing modestly to 1.93 in 2040.

Table 22. Commercial Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.11	$ 1,367,761	8,626	$ 158.57	$ 18.87
2025	2.07	$ 10,437,397	64,743	$ 161.21	$19.27
2030	2.01	$ 30,065,223	181,191	$ 165.93	$ 20.13
2040	1.93	$ 82,522,317	481,235	$ 171.48	$ 21.24
20-year avg.	1.93	$ 4,126,116	24,062	$ 171.48	$ 21.24

7. INDUSTRIAL ENERGY EFFICIENCY POTENTIAL

7.1. Overview

The industrial sector makes up roughly one-half of Tri-State's total baseline forecast energy load, and 43% of potential energy savings. Cumulative savings potential for this sector is approximately 745 GWh through 2040 (Achievable-Moderate scenario) with pump-related savings accounting for a majority of potential savings at 58%. Efficiency measures for the oil and gas segment of the market comprise nearly 55% of potential savings for this sector. Manufacturing-related efficiency opportunities account for most of the remaining energy savings potential.

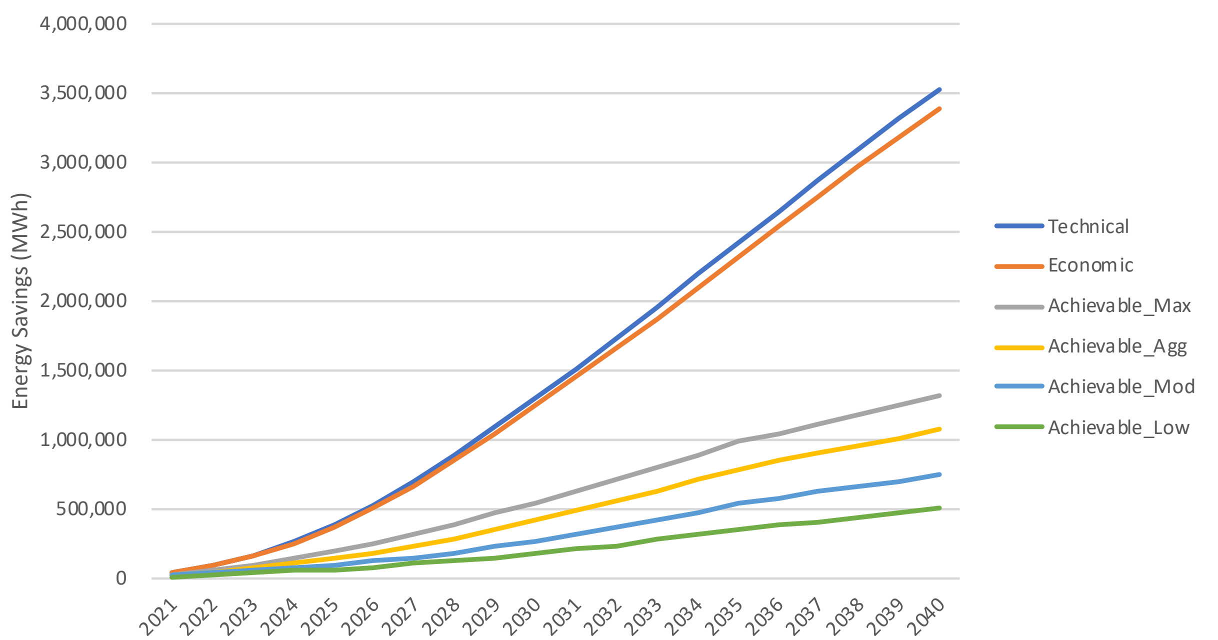
7.2. Detailed Results

Table 23 presents cumulative savings potential for the industrial sector by scenario at various milestones in the analysis period and Figure 28 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14 GWh of savings potential in 2021 rising to approximately 745 GWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 43%. Savings potential increases by an additional 22% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 1,308 GWh through 2040.

Table 23. Cumulative Industrial Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	35,303	34,181	24,956	19,902	14,224	10,678
2025	378,791	363,954	186,953	139,453	92,325	63,777
2030	1,294,201	1,240,358	544,166	414,383	268,351	173,960
2040	3,523,534	3,381,672	1,307,552	1,066,805	744,543	502,719

Figure 28. Industrial Energy Efficiency Savings Potential by Scenario by Year



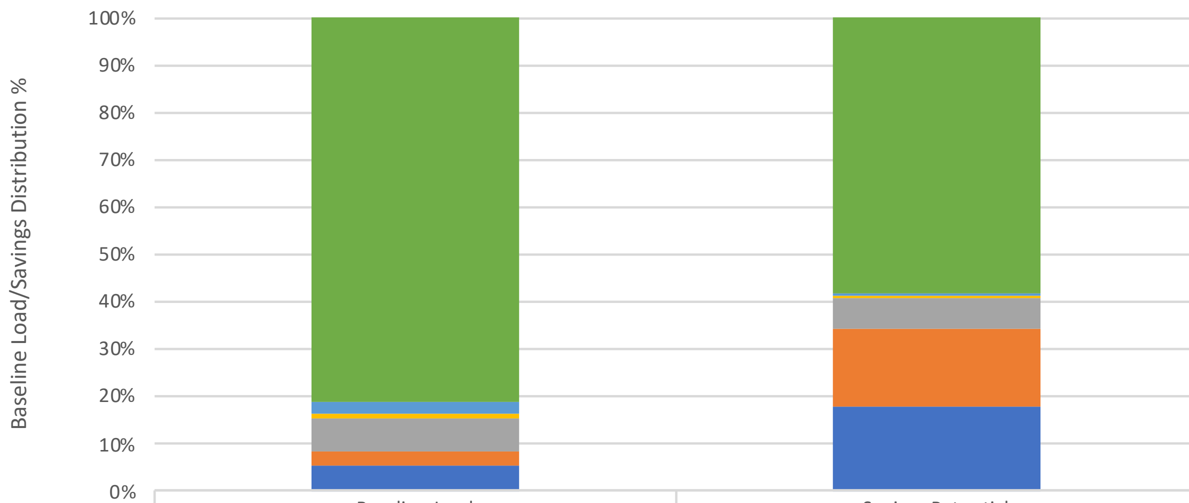
The cumulative industrial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.21% of industrial baseline sales in 2021, a 1.24% reduction by 2025 and a 7.28% reduction by 2040 (see Table 24.). The analysis estimates a range in reduction of baseline energy sales for the achievable scenarios from 4.9% (Achievable-Low) to 12.8% (Achievable-Max) by 2040.

Table 24. Industrial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.52%	0.50%	0.36%	0.29%	0.21%	0.16%
2025	5.09%	4.89%	2.51%	1.87%	1.24%	0.86%
2030	15.66%	15.01%	6.58%	5.01%	3.25%	2.10%
2040	34.44%	33.05%	12.78%	10.43%	7.28%	4.91%

As shown in Figure 29 efficient pumps and related measures hold by far the greatest energy savings potential for the industrial sector, accounting for nearly 60% of the total. This is in part due to the fact that pumps account for such a large portion of the industrial sector's forecast baseline energy load (81%). Lighting and HVAC also hold substantial energy savings potential for this sector at 17% and 18% of the total, respectively.

Figure 29. Industrial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)



	Baseline Load	Savings Potential
Pumps	81.0%	58.0%
Process Heat	2.6%	0.5%
Process Cool	1.0%	0.5%
Motors	6.8%	6.7%
Lighting	3.3%	16.6%
HVAC	5.3%	17.7%

Table 25. presents cumulative industrial demand savings by end-use by milestone year. As with energy savings potential, pumps are also the leader in terms of demand savings potential. Pump-related

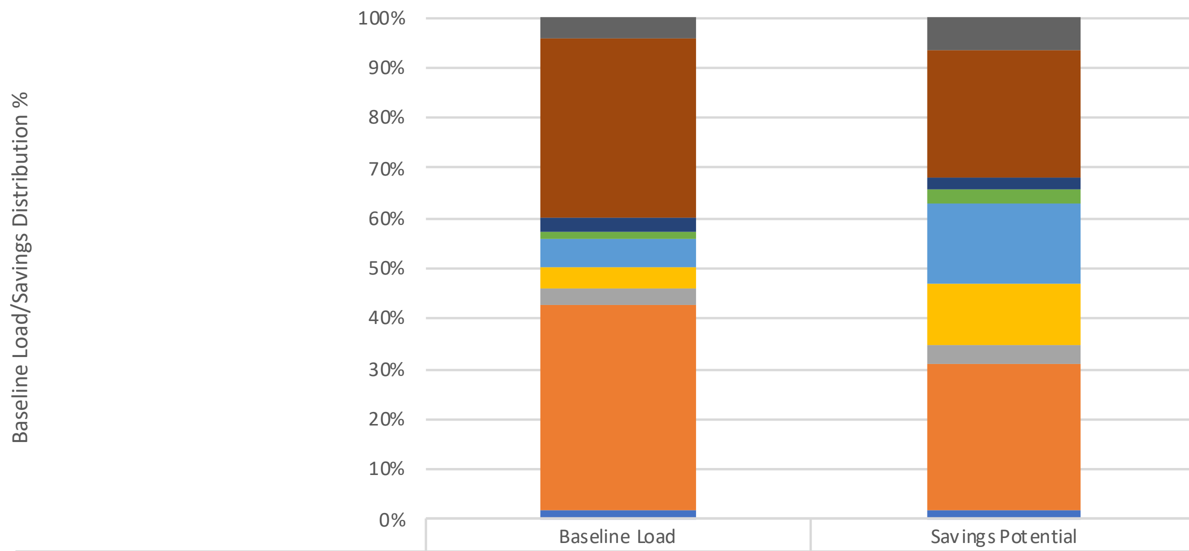
measures contribute nearly 6.6 MW of cumulative demand savings potential. Lighting efficiency measures have the potential to decrease demand by almost 1.3 MW and HVAC by nearly 1.7 MW.

Table 25. Industrial Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	HVAC	LIGHTING	MOTORS	PROCESS COOL	PROCESS HEAT	PUMPS	TOTAL
2021 (first year)	0.165	0.201	0.132	0.008	0.008	1.364	**1.878**
2025	0.469	0.496	0.242	0.022	0.020	2.456	**3.705**
2030	1.076	0.898	0.424	0.047	0.037	4.187	**6.669**
2040	1.686	1.258	0.672	0.070	0.052	6.597	**10.335**

Figure 30 shows that liquid mining and pipeline transportation are the two segments of the industrial sector that account for the most energy savings potential, at more than one-quarter of the total for each segement. Together, these two segments account for approximately 55% of the savings potential. Manufacturing-related segments (i.e., non-metallic mineral products, chemical, paper and other manufacturing segments) together make up over one-third of the total energy savings potential.

Figure 30. Industrial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)



	Baseline Load	Savings Potential
TCU	4.2%	6.6%
Pipeline Transportation (Oil, Gas, and CO2)	35.6%	25.5%
Mining	3.0%	2.0%
Mfg - Paper	1.6%	3.2%
Mfg - Nonmetallic Mineral Product	5.3%	15.9%
Mfg - Misc.	4.6%	12.1%
Mfg - Chemical	3.2%	3.9%
Liquid Mining (Oil, Gas, and Carbon Dioxide)	40.8%	29.2%
Agriculture	1.8%	1.7%

Table 26. summarizes cumulative industrial program cost metrics by milestone year. As shown, first-year program costs are approximately $2.4 million, rising to a 20-year average annual cost of roughly $9.6 millon. Acquisition costs start at $168/MWh during the first year of analysis and see only a slight increase through 2040. The TRC ratio remains solid for the industrial sector starting at 2.08 in 2021 and decreasing modestly to 1.92 in 2040.

Table 26. Industrial Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$2,391,009	14,224	$168.09	$11.67
2025	2.02	$18,273,240	104,319	$175.17	$12.80
2030	1.96	$57,536,744	311,837	$184.51	$14.14

2040	1.92	$192,026,153	993,332	$193.32	$15.25
20-year avg.	1.92	$9,601,308	**49,667**	**$193.32**	**$15.25**

8. IRRIGATION EFFICIENCY POTENTIAL

8.1. Overview

Irrigation accounts for a small fraction of energy consumption and savings potential; it represents approximately 8% of Tri-State's total baseline energy load, and 3% of potential energy savings. Cumulative savings potential for this sector is approximately 53,134 MWh through 2040 (Achievable-Moderate scenario). Measures with notable savings potential include high efficiency motors, motor VFDs and base boot gasket improvements, making up approximately 63%, 18% and 17% of total savings potential respectively.

8.2. Detailed Results

Table 27 presents cumulative savings potential for the irrigation sector by scenario at various milestones in the analysis period and Figure 31 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 584 MWh of savings potential in 2021 rising to approximately 53,134 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 70%. Savings potential increases by an additionad 39% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 119,793 MWh through 2040.

Table 27. Cumulative Irrigation Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1,541	1,128	1,026	814	584	454
2025	25,117	18,368	13,409	9,028	5,504	3,609
2030	149,894	111,385	60,712	40,289	22,193	12,282
2040	435,221	334,704	119,793	88,727	53,134	29,070

Figure 31. Irrigation Energy Efficiency Savings Potential by Scenario by Year

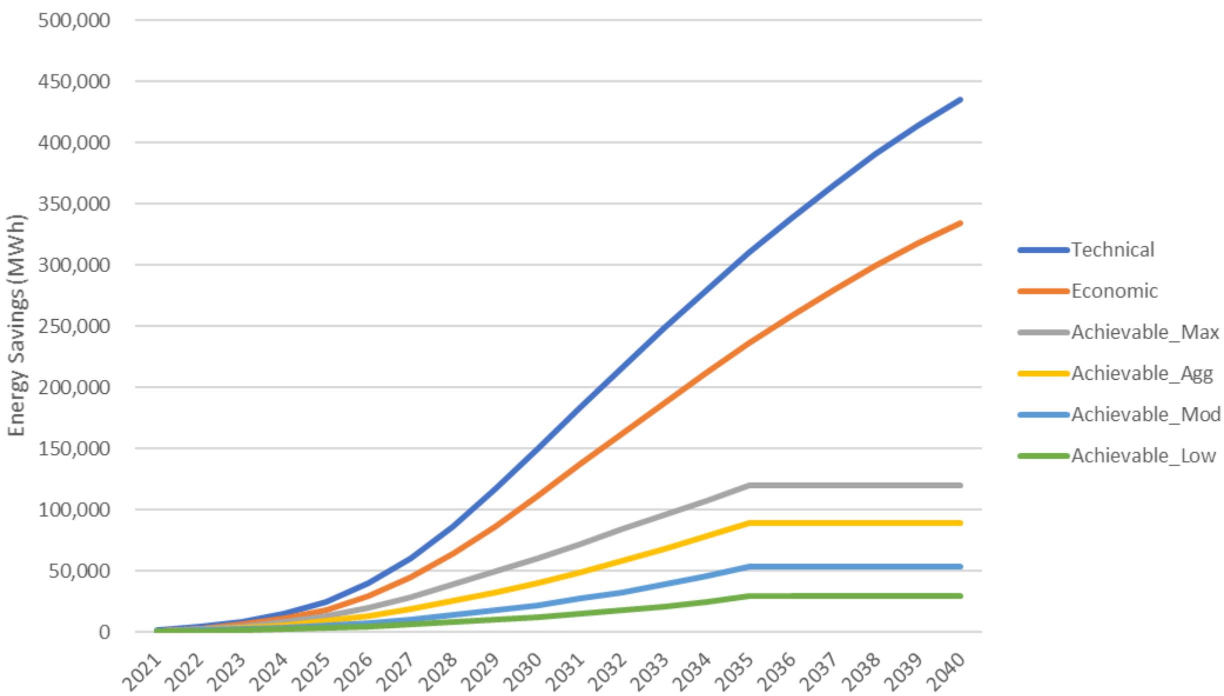


Table 28. shows the percentage impact of cumulative irrigation savings on the baseline forecast by scenario for each milestone year. Under the Achievable-Moderate scenario irrigation measures have the potential to reduce baseline load by nearly 4%. The maximum achievable scenario would more than double those savings to reduce baseline load by approximately 9%.

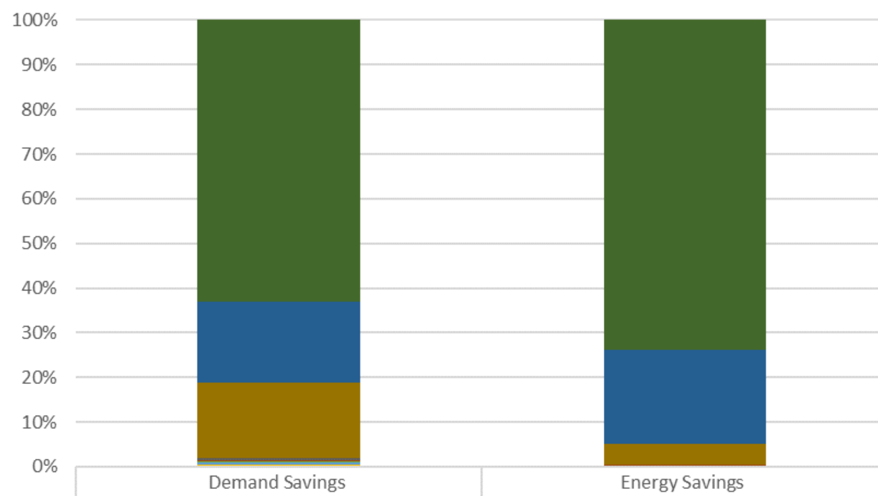
Eastern Colorado accounts for approximately half the irrigation savings potential, followed by Nebraska at approximately 30% of the total. Northern and Southern New Mexico together account for approximately 12% of total irrigation savings potential with the remaining regions making up a nominal share of total irrigation savings potential.

Table 28. Irrigation Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.12%	0.09%	0.08%	0.06%	0.04%	0.03%
2025	1.90%	1.39%	1.01%	0.68%	0.42%	0.27%
2030	11.17%	8.30%	4.52%	3.00%	1.65%	0.91%
2040	31.51%	24.23%	8.67%	6.42%	3.85%	2.10%

Figure 32 shows the range of measures examined as part of the analysis, as well as the share of total demand and energy savings each measure represents. High efficiency motors comprise by far the largest share of savings at 63% of demand and approximately 74% of energy savings. Motor VFDs and base boot gaskets also represent notable savings opportunities. Other measures, like upgrades to Low Elevation Spray Application (LESA) and Low Energy Precision Application (LEPA) and scheduling-related measures may hold potential for improving customer satisfaction, as they can reduce water use and improve crop yields. However, LESA and LEPA are not found to provide substantial energy savings, and the analysis Team did not explore scheduling-related measures as part of this analysis.

Figure 32. Irrigation Cumulative Demand and Energy Savings by Measure (2040)



	Demand Savings	Energy Savings
HE Motor	63.07%	73.81%
Motor VFD	18.02%	21.18%
Base boot gasket	16.91%	4.52%
Cut and press repair	0.43%	0.12%
Hub gasket	0.25%	0.11%
Upgrade from high pressure to LESA/LEPA/MDI	0.22%	0.10%
Upgrade from high pressure to MESA	0.20%	0.09%
Sprinkler package replacement, high pressure	0.41%	0.03%
Nozzle replacement	0.24%	0.02%
Gaskets	0.15%	0.02%
Drains	0.08%	0.01%
Sprinkler package replacement, MESA	0.02%	0.00%

Table 29. presents cumulative and average annual costs, savings and TRC metrics associated with the Achievable-Moderate scenario for irrigation efficiency measures. As shown, in the first year Tri-State can achieve approximately 584 MWh of energy savings at a cost of approximately $185,313, or a levelized cost of $47.49/MWh. As programs expand and become more established annual costs and savings increase substantially. The 20-year average annual program costs are approximately $1.75 million and savings are 5,518 MWh.

Table 29. Irrigation Cumulative Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM OF 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	0.99	$185,313	584	$317.40	$47.49
2025	0.99	$1,750,685	5,516	$317.39	$47.50
2030	0.99	$7,632,143	24,046	$317.40	$47.51
2040	0.99	$35,028,723	110,365	$317.39	$47.53
20-year avg.	**0.99**	$1,751,436	5,518	$317.39	$47.53

9. DEMAND RESPONSE POTENTIAL STUDY

9.1. Overview

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year analysis time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory.

Table 30 presents portfolio-level demand response potential by time horizon. As Tri-State does not currently offer demand response programs, each scenario ramps from zero and then plateaus when the program achieves maturity. The Achievable-Low scenario estimates 86 MW of cumulative summer demand response potential in 2040. Achieving more aggressive participation rates through increased marketing and incentive costs could yield an estimated 245 MW of potential (Achievable-High scenario).

Table 30. Cumulative Demand Response Potential (MW) By Scenario By Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE HIGH	ACHIEVABLE LOW
2021	46	30	12	5
2025	297	196	85	30
2030	647	500	222	78
2040	704	548	245	86

Figure 33. Portfolio Demand Response Potential by Scenario by Year

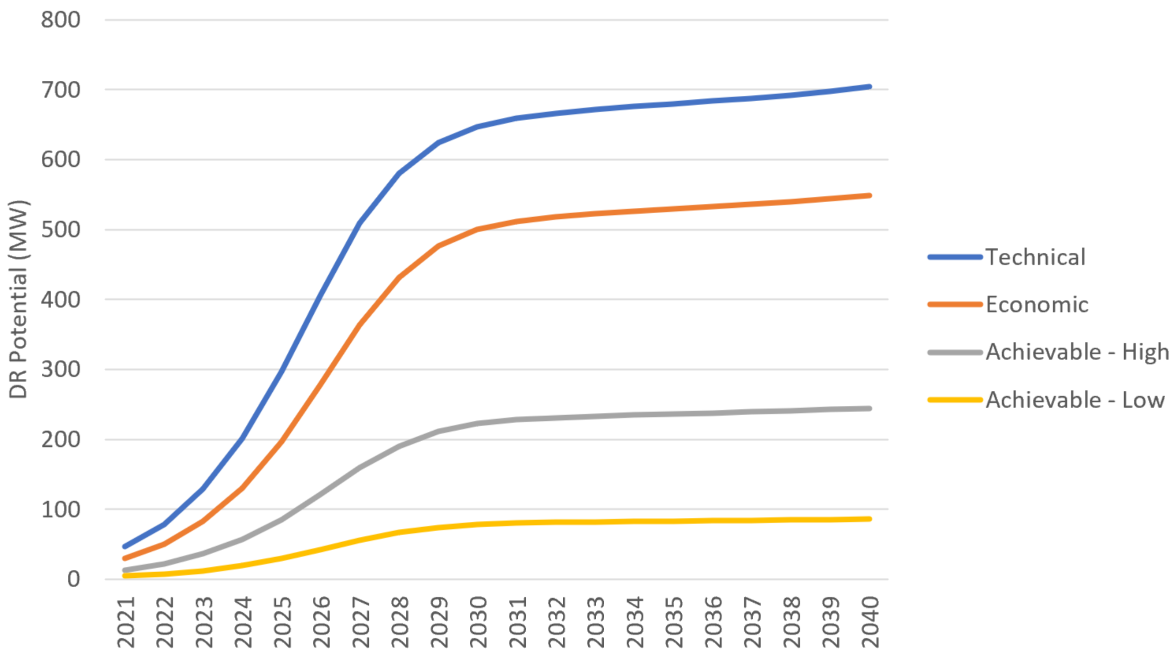


Table 31. shows the impacts of demand response potential relative to Tri-State's baseline demand forecast. The Achievable-High and -Low scenarios represent about 6.90% and 2.43% of forecasted coincident demand in 2040 respectively.

Table 31. Portfolio Demand Response Potential as % of Baseline Forecast by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE HIGH	ACHIEVABLE LOW
2021	1.65%	1.07%	0.48%	0.16%
2025	9.99%	6.61%	2.87%	1.00%
2030	20.43%	15.79%	7.03%	2.47%
2040	19.85%	15.46%	6.90%	2.43%

Figure 34 and Figure 35 show contributions to the portfolio-level demand response potential by sector and by program type respectively. In each scenario, the largest contributors to the demand response potential are the residential and irrigation sectors. Connected device programs, primarily Smart Thermostat programs, and Direct Load Control (DLC), primarily for irrigation pumping, are the most significant program types.

This analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. As Tri-State does not control customer rates, implementing this type of demand response program would require a high level of collaboration with electric cooperatives.

Figure 34. Portfolio Demand Response Potential by Sector (2040)

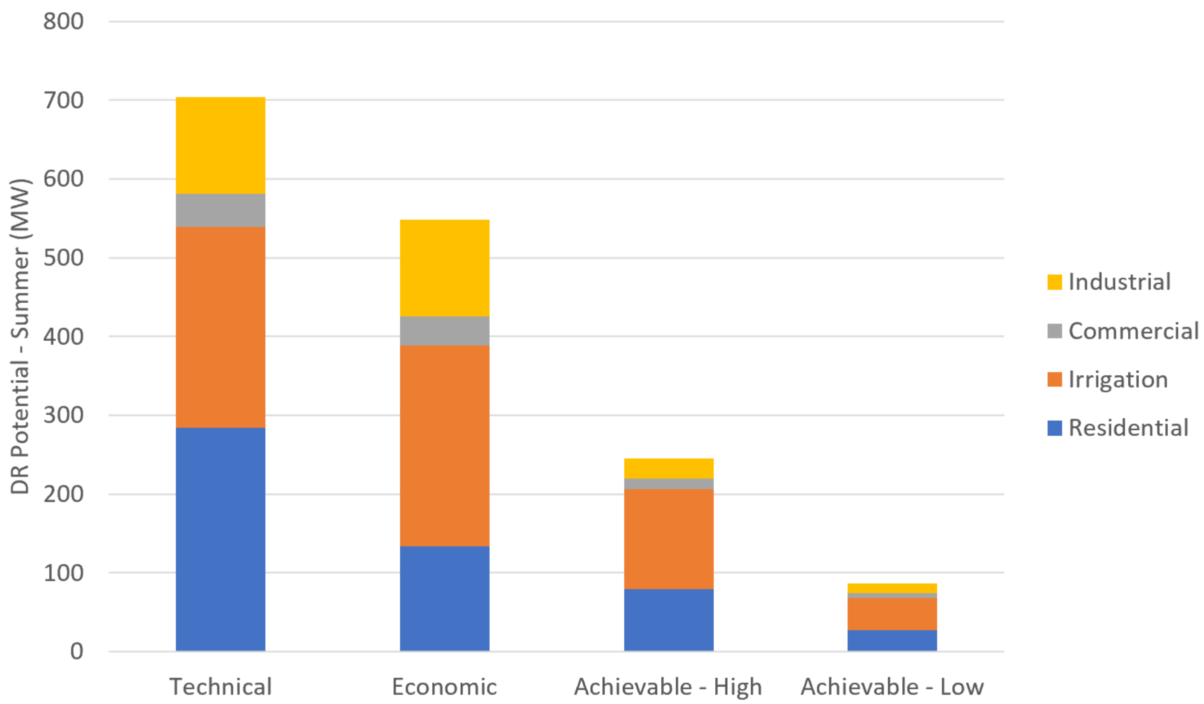
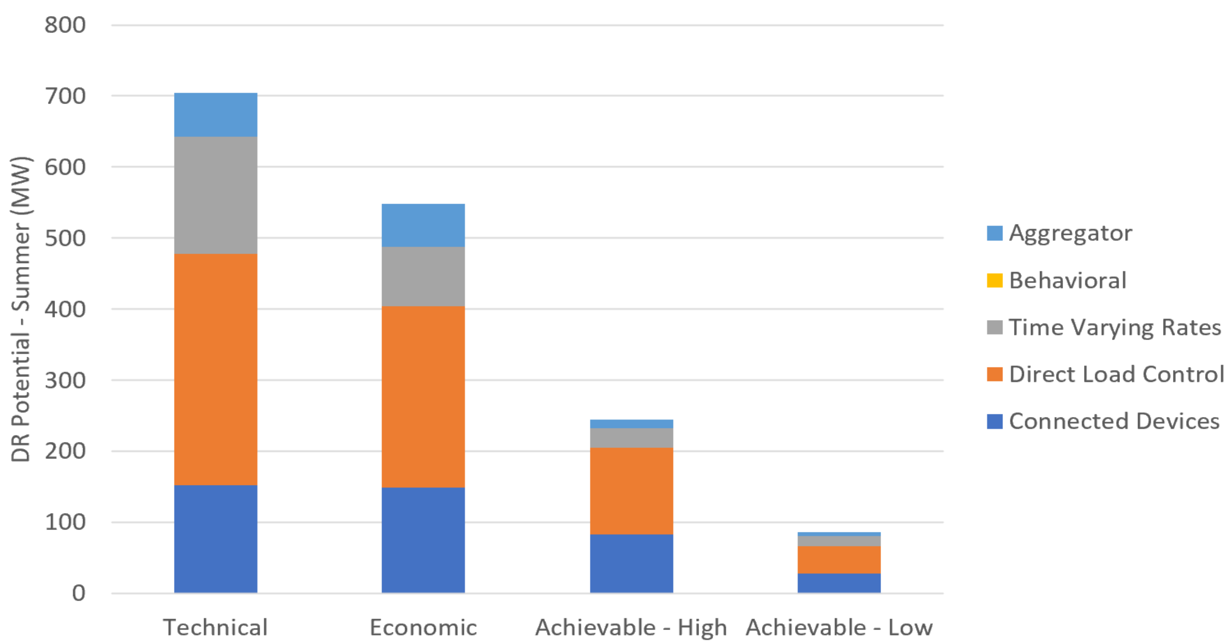


Figure 35. Portfolio Demand Response Potential by Program Type (2040)[16]



[16] Behavioral value is too small to observe.

Table 32 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity for 2021 through 2026 with an increase in 2027.

Table 32. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)

MILESTONE YEAR	TRC RATIO	CUMULATIVE PROGRAM COST ($)	DR POTENTIAL (MW)
2021	0.02	$5,440,119	5
2025	0.09	$13,818,802	30
2030	0.60	$24,286,062	78
2040	1.16	$39,068,285	86

9.2. Residential Sector Demand Response Potential

Figure 36 shows how demand response potential for residential sector programs grows over the study horizon as program participation increases. Figure 37 shows the contribution from each modeled demand response program for the four considered scenarios in 2040. Two programs were cost effective and thus included in the economic and achievable scenarios – Smart Thermostats and Smart Water Heaters. In the Achievable scenarios, Smart Thermostats achieve the largest share of the demand response potential.

Traditional DLC programs are not cost effective given their higher switch and controller hardware costs. The analysis shows that demand response for residential HVAC unit loads could be more cost effectively managed with a Bring-Your-Own-Thermostat program format utilizing customer-purchased smart thermostat devices. This finding aligns with a nationally observable trend away from the older DLC technology and pager network communications protocols towards programs that use customer-purchased devices and device internet access for communication.

Although a less mature program model, Smart Water heater programs are also increasing in popularity in many jurisdictions nationwide. Some versions of these programs similarly use internet-based communications and would be the most cost effective for Tri-State. Water heaters with built-in grid connection technology are also becoming more widely available, thus eliminating the need for installation of a separate device. As this technology matures, Tri-State could likely develop a successful demand response program to control residential water heaters during peak periods.

Figure 36. Residential Sector Demand Response Potential by Scenario by Year

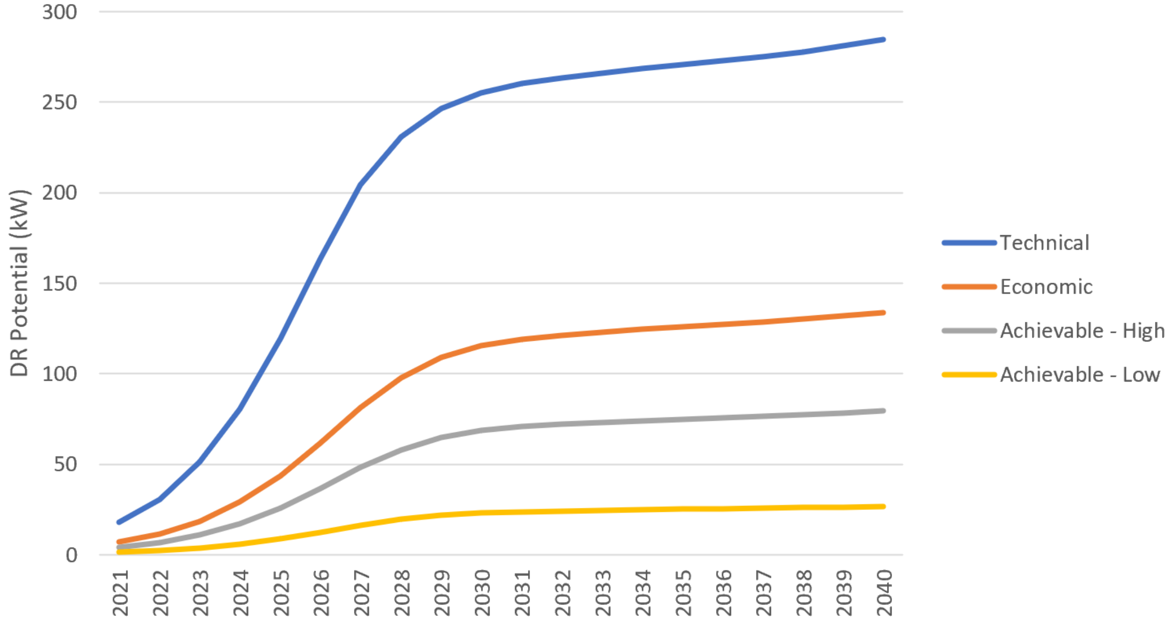
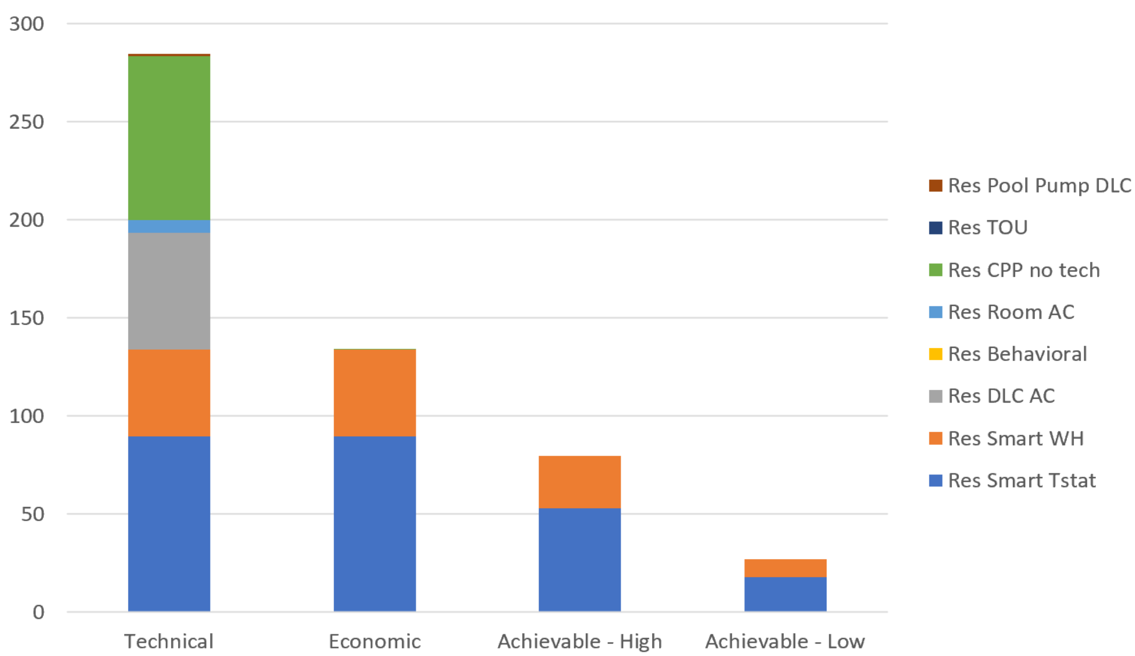


Figure 37. Residential Sector Demand Response Potential by Program (2040)



9.3. Irrigation Sector Demand Response Potential

Figure 38 shows how demand response potential for the irrigation sector programs grows over the study horizon as program participation increases. Figure 39 shows the each modeled demand response program's contribution to the four considered scenarios in 2040. Two programs were cost effective and therefore included in the economic and achievable scenarios – Direct Load Control and Critical Peak Pricing without Enabling Technology. In the Achievable scenarios, Direct Load Control achieves the largest share of the demand response potential.

Successful irrigation DLC programs are currently operational in regions similar to portions of Tri-State's territory, such as Idaho Power's Irrigation Peak Rewards program. That program is designed to target only customers with pumping demand greater than 75 horsepower, thereby focusing economic resources for maximum demand reduction. This analysis included eligibility rates for each region in Tri-State's territory to estimate the regional prevalence of large irrigation pumps. Mountain Colorado, for example, has a 0% eligibility rate because of presumed reliance on lower horsepower pumps for horizontal pumping.

Figure 38. Irrigation Sector Demand Response Potential by Scenario by Year

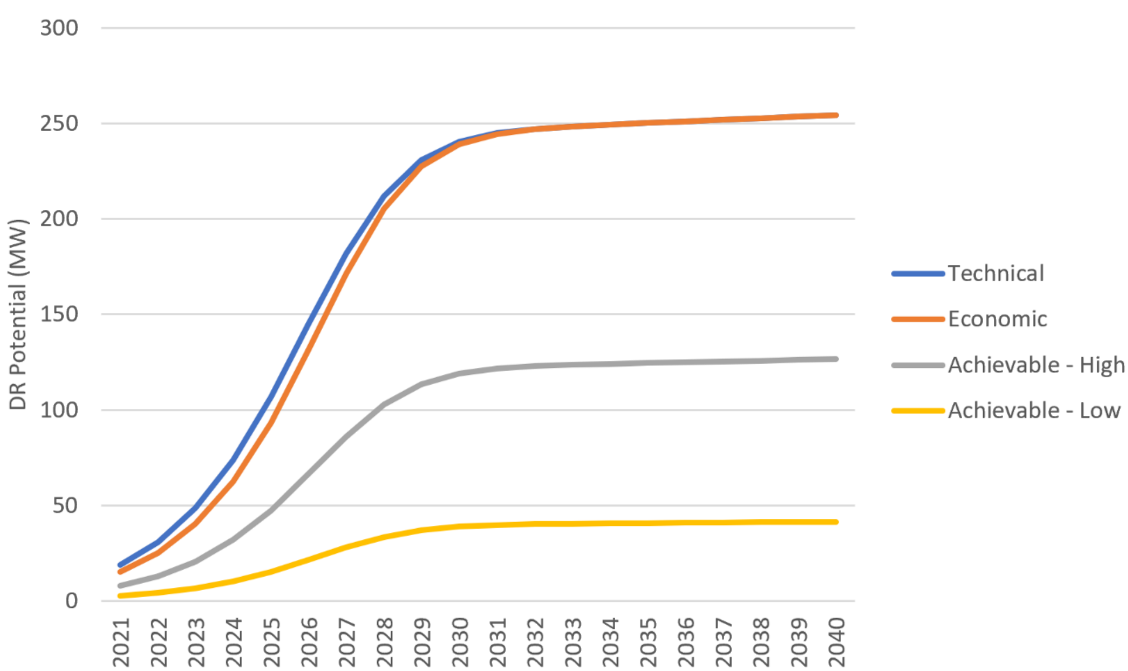
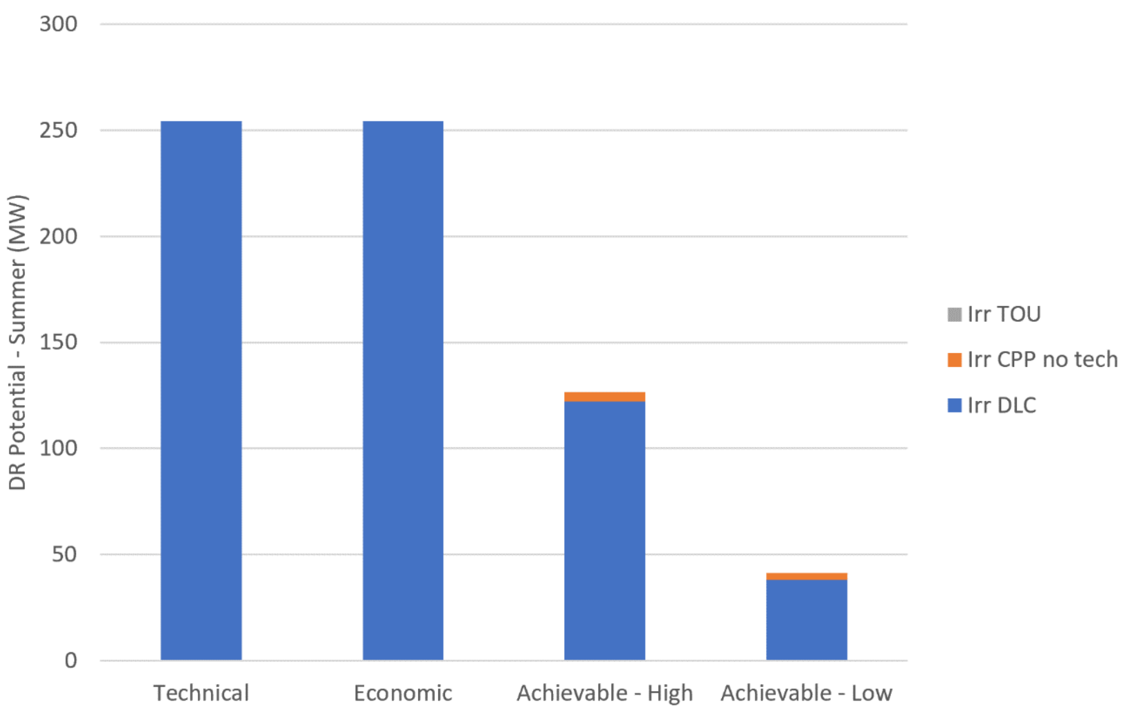


Figure 39. Irrigation Sector Demand Response Potential by Program (2040)



9.4. Commercial Sector Demand Response Potential

Figure 40 shows how demand response potential for irrigation sector programs grows over the study horizon as program participation increases. Figure 41 shows each modeled demand response program's contribution to the four considered scenarios in 2040. Three programs were cost effective and therefore included in the economic and achievable scenarios – Demand Bidding, Smart Thermostats, and Critical Peak Pricing without Enabling Technology. The Smart Thermostats program option was modelled as an extension of the residential Smart Thermostats program and assuming the residential program sector carries a majority of program set-up and administration costs.

Capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. Third-party aggregators often manage these types of programs; thefore, this could be a strategy to overcome Tri-State's lack of direct access to end-users.

Figure 40. Commercial Sector Demand Response Potential by Scenario by Year

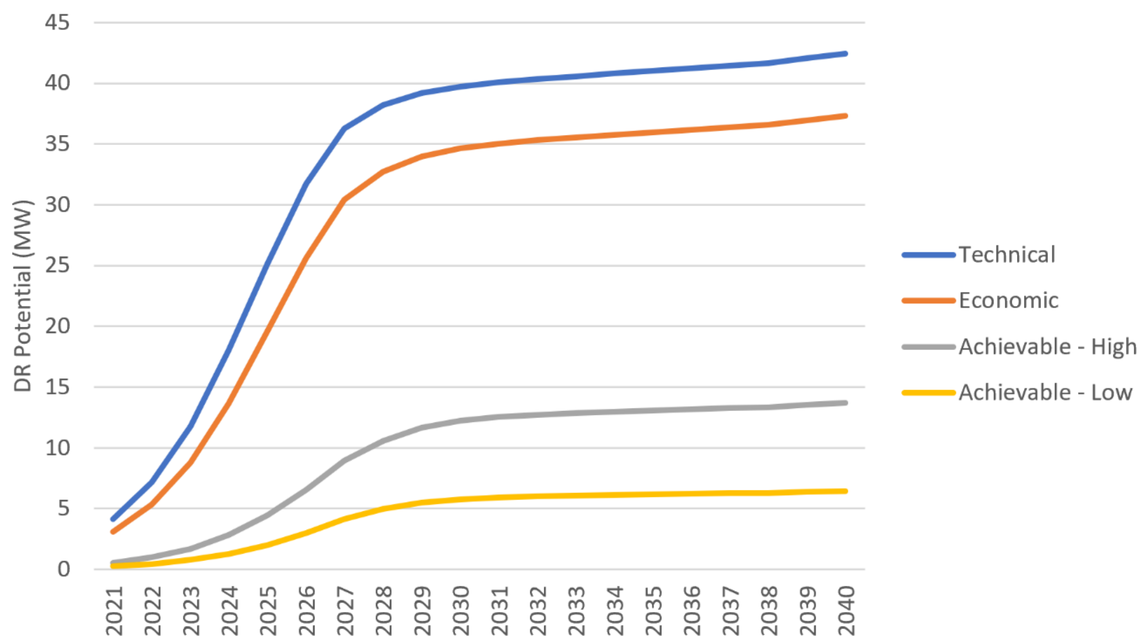
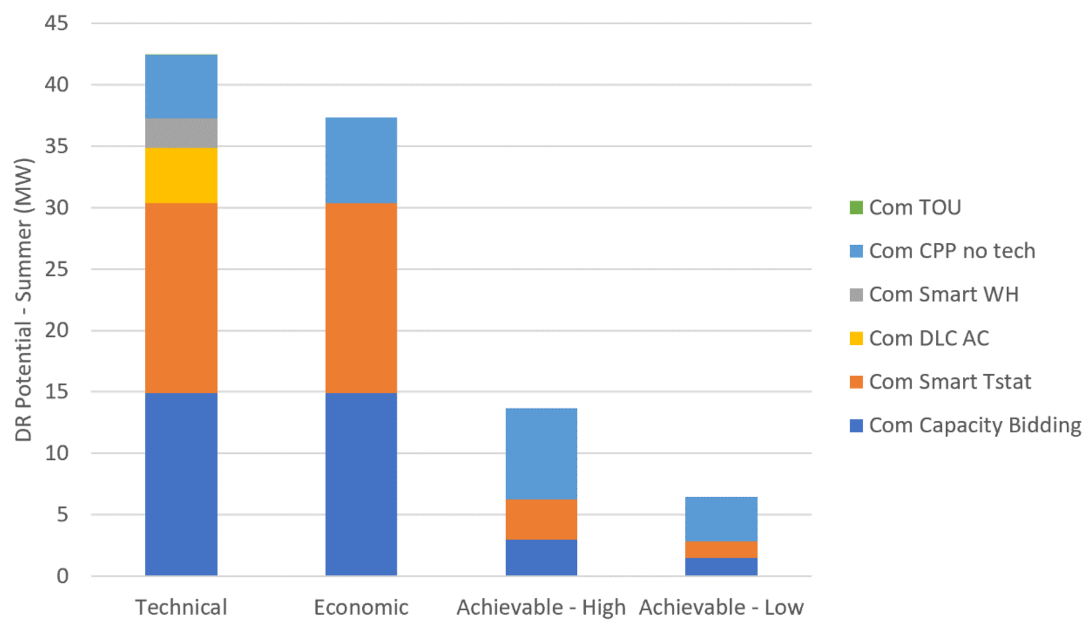


Figure 41. Commercial Sector Demand Response Potential by Program (2040)



9.5. Industrial Sector Demand Response Potential

Figure 42 shows how demand response potential for industrial sector programs grows over the study horizon as program participation increases. Figure 43 shows each modeled demand response program's contribution to the four considered scenarios in 2040. Two programs are cost effective and therefore included in the economic and achievable scenarios – Capacity Bidding and Critical Peak Pricing without Enabling Technology.

As in the commercial sector, capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. These types of programs are often managed by third-party aggregators, and thus could be a strategy to overcome Tri-State's lack of direct access to end-users.

Figure 42. Industrial Sector Demand Response Potential by Scenario by Year

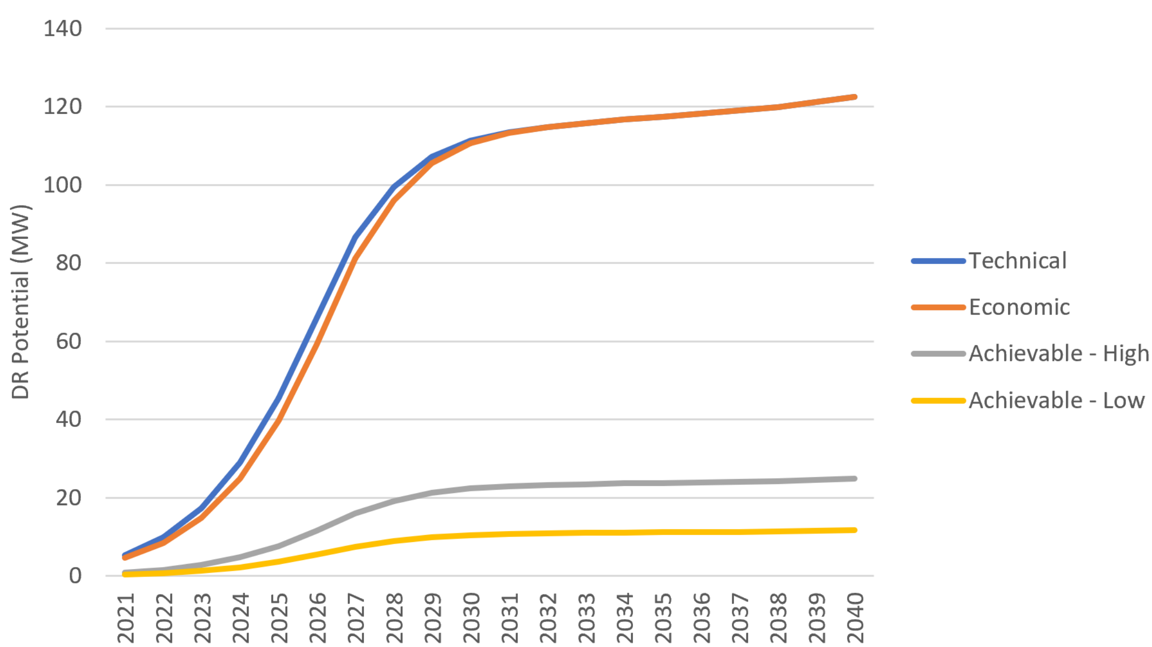
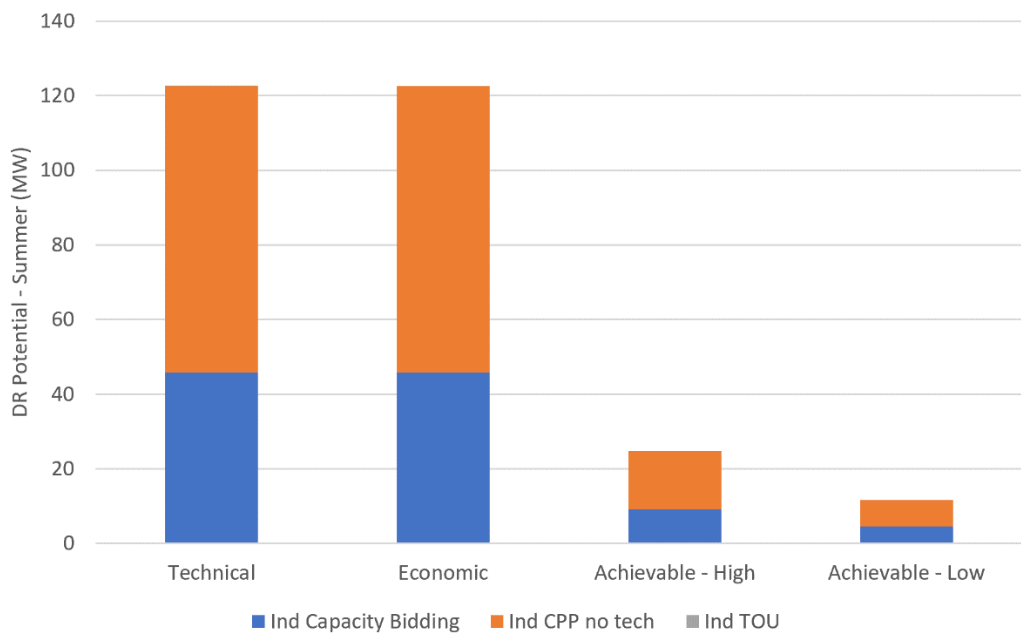


Figure 43. Industrial Sector Demand Response Potential by Program (2040)



10. BEHIND-THE-METER DISTRIBUTED ENERGY RESOURCE POTENTIAL STUDY FINDINGS

10.1. Overview

As discussed in Section 3, the Team assessed rooftop solar PV potential for the residential and non-residential sectors. The technical potential analysis considered the total rooftop area suitable for solar PV within Tri-State's territory and extrapolated potential solar generation based on solar system power density per square foot for each Tri-State region. The Team subsequently screened systems for cost effectiveness and adjusted potential accordingly followed by further adjustments using adoption curves to represent achievable potential.

The Team found no systems to be cost effective for the residential sector under any TRC scenario analyzed. The highest TRC ratio achieved under the residential sector was 0.45 which reflects capacity and CO_2 emissions benefits.

The non-residential sector's very large PV systems are marginally cost effective for specific scenarios. Of these scenarios, the Team found the presence of CO_2 emissions benefits to be crucial as no PV system analyzed surpassed a TRC of 1.0 without inclusion of these benefits.

10.2. Detailed Results

Table 33 and Table 34 summarize the solar PV cumulative annual potential estimated generation for the residential and non-residential sectors, respectively. Electric demand impacts are presented for each sector in Table 35 and Table 36. While technical potential represents 100% adoption for each year, economic and achievable potential reflect applied adoption rates across the study time horizon.

Table 33. Cumulative Residential Generation Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE _MAX	ACHIEVABLE _AGG	ACHIEVABLE _MOD	ACHIEVABLE _LOW
2021 (first year)	2,548,130	0	0	0	0	0
2025	13,139,699	0	0	0	0	0
2030	27,290,122	0	0	0	0	0
2040	58,657,889	0	0	0	0	0

Table 34. Cumulative Non-Residential Generation Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	6,417,504	10,322	10,310	10,300	10,284	10,256
2025	33,037,716	141,370	139,829	138,809	137,108	134,198
2030	68,427,022	1,011,060	951,078	911,778	851,923	764,606
2040	146,160,272	5,512,777	4,705,933	4,254,001	3,661,295	2,952,911

The demand impacts presented in Table 35 and Table 36 reflect technical capacity based on operational capacity (based on installed nameplate) and coincident peak capacity. Economic and achievable scenarios reflect coincident peak capacity benefits.

Table 35. Summary of Residential Solar PV Electric Demand Market Potential (MW)

MILESTONE YEAR	TECHNICAL DC CAPACITY	TECHNICAL PEAK CAPACITY	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1,644	400	0	0	0	0	0
2025	1,747	425	0	0	0	0	0
2030	1,878	457	0	0	0	0	0
2040	2,141	521	0	0	0	0	0

Table 36. Summary of Non-Residential Solar PV Electric Demand Market Potential (MW)

MILESTONE YEAR	TECHNICAL DC CAPACITY	TECHNICAL PEAK CAPACITY	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	4,139	1,106	2	2	2	2	2
2025	4,384	1,172	9	9	9	9	9
2030	4,686	1,252	49	45	42	37	31
2040	5,281	1,411	83	69	61	50	39

The cumulative residential generation potential under the technical scenario equates to 57% of the cumulative residential baseline load sales forecast for 2040 (see Table 37). Similarly, the non-residential cumulative generation represents 52% of the cumulative residential baseline load forecast for 2040 (see Table 38). Non-residential economic potential equates to 2.0% of the cumulative residential baseline load forecast for 2040 and ranges from 1.7% to 1.1% under the achievable potential scenarios.

Table 37. Cumulative Residential Generation Potential as % of Baseline Forecast Sales by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	56.1%	0	0	0	0	0
2025	56.3%	0	0	0	0	0
2030	56.4%	0	0	0	0	0
2040	56.5%	0	0	0	0	0

Table 38. Cumulative Non-Residential Generation Potential as % of Baseline Forecast Sales by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	53.9%	0.1%	0.1%	0.1%	0.1%	0.1%
2025	53.4%	0.2%	0.2%	0.2%	0.2%	0.2%
2030	53.1%	0.8%	0.7%	0.7%	0.7%	0.6%
2040	52.0%	2.0%	1.7%	1.5%	1.3%	1.1%

10.3. Technical DER Potential Findings

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure 44 and Figure 45 below illustrate cumulative PV generation in 2040 compared to cumulative 2040 sales. For both the residential and non-residential sectors, PV generation is well below total sales for each region with the exception of Northern New Mexico (for residential) and Southern New Mexico. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency, a relatively high number of buildings, and relatively low energy consumption on average.

Figure 44. 2040 Cumulative Residential PV Generation vs Sales by Region

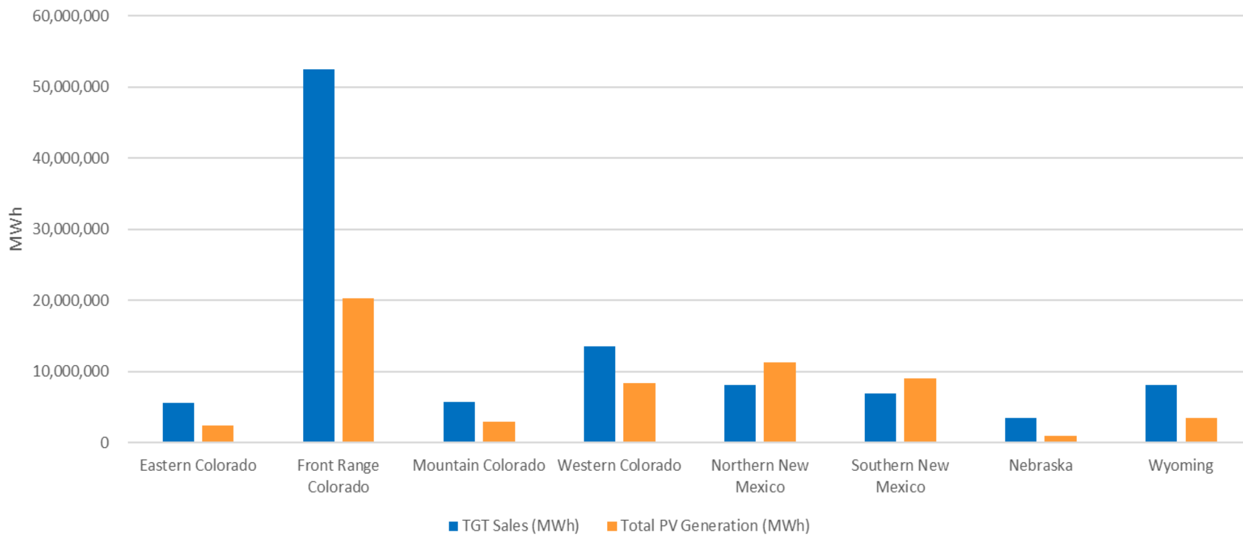
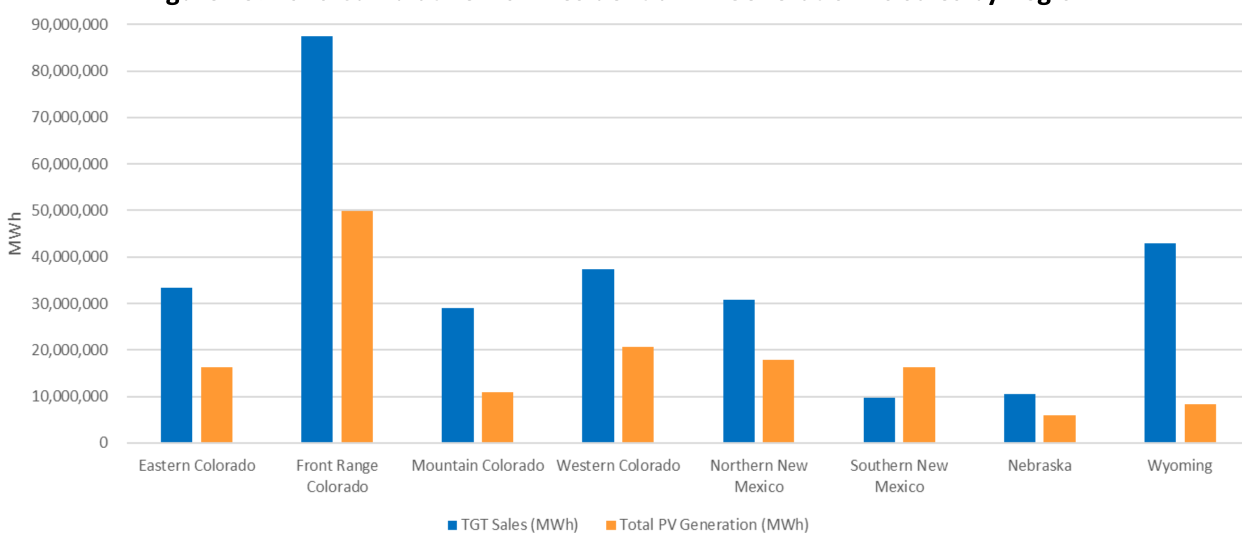


Figure 45. 2040 Cumulative Non-Residential PV Generation vs Sales by Region



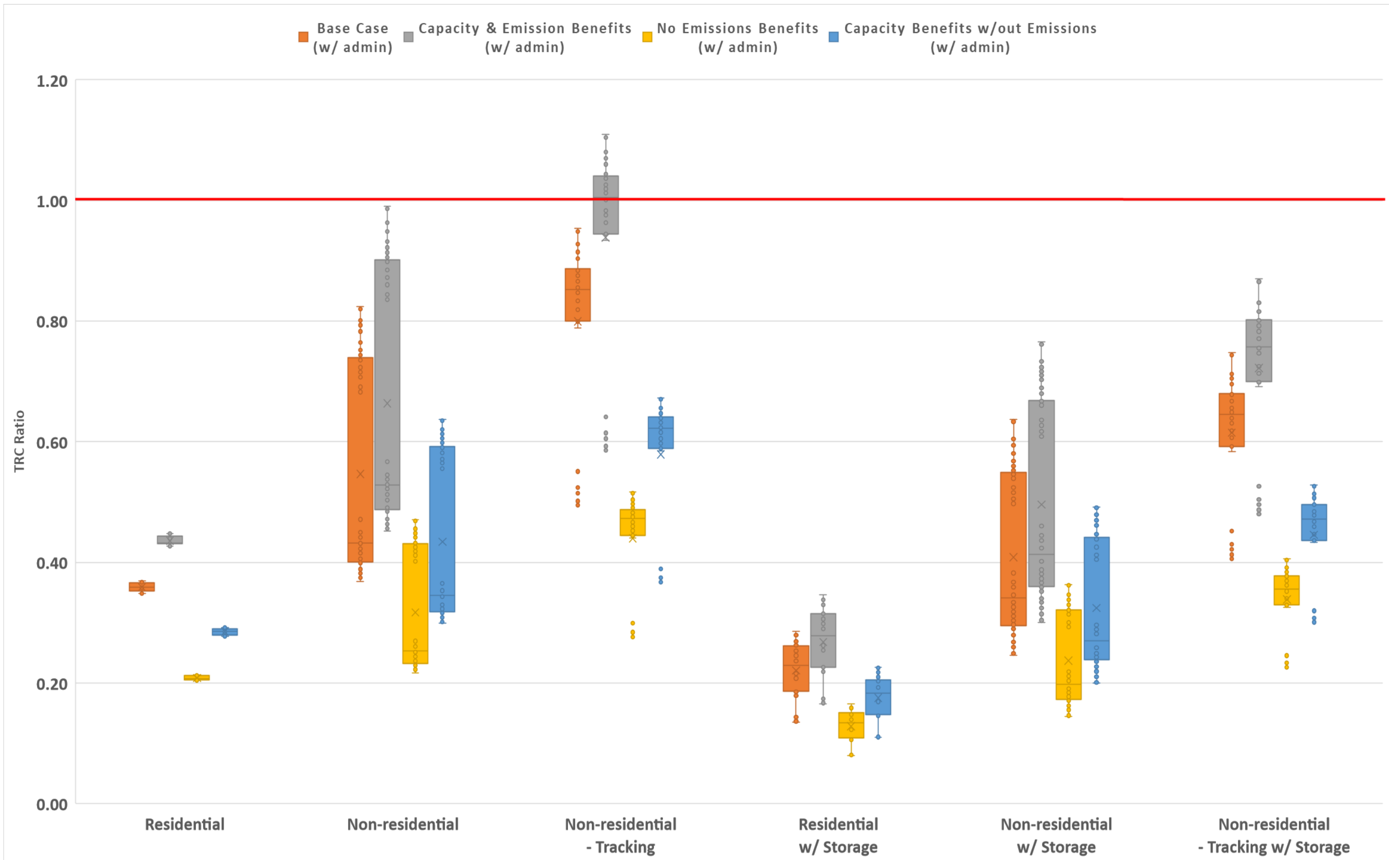
10.4. Economic and Achievable DER Potential Findings

The Team screened economic potential using a TRC hurdle of 1.0 with the inclusion of CO_2 emission benefits based on the social cost of carbon of $46/ton and administrative costs of $0.05/kWh. However, to understand the sensitivity of various benefit parameters, the team modeled cost effectiveness for multiple scenarios that included various combinations of benefits. Scenarios reviewed included:

- Base case
    - Inclusive of CO_2 emission reduction benefits
- Capacity and emission benefits
    - Base case inclusive of benefits resulting from reduced capacity needs
    - Inclusive of CO_2 emission reduction benefits
- No emissions benefits
    - Base case exclusive of CO_2 emission reduction benefits
- Capacity benefits without emissions benefits
    - Base case inclusive of benefits resulting from reduced capacity needs
    - Exclusive of CO_2 emission reduction benefits

Figure 46 illustrates the results and sensitivities of the solar PV cost effectiveness under each of these scenarios for various categories of solar PV systems included in the potential study. Only one scenario yields TRC ratios that exceed 1.0 – non-residential tracking systems assuming the presence of capacity and CO_2 emission benefits benefits. Also noted is any scenario excluding CO_2 emission benefits results in all solar system configurations analyzed to fail pass cost effectiveness.

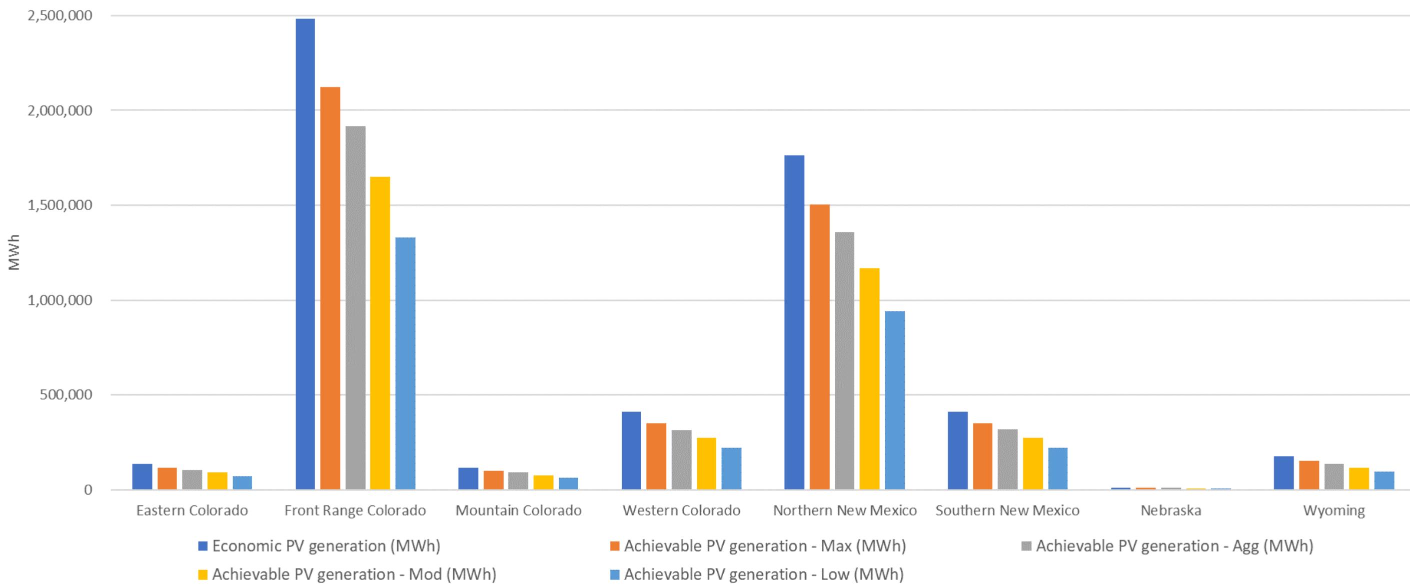
Figure 46. Solar PV TRC Ratios - Multiple Scenarios



Based on the cost effectiveness analysis, the Team modeled economic and achievable potential based on the sole cost effective scenario – non-residential tracking solar systems with capacity and emission benefits. Twenty two solar PV system configurations (9% of all tested measure permutations) passed cost effectiveness including tracking systems varying in size from 250 kW to 2000 kW system capacity. These passing measures have an average TRC of 1.04. This scenario, however, is not applicable throughout the Tri-State territory insofar as capacity constraints are not expected until 2027 (and therefore capacity benefits would not be realized until that time) and carbon benefits are only applicable to Colorado regions (at the time of report publication). Regardless, for the purposes of this report, the Team opted to model economic and achievable potential for all regions in order to inform Tri-State of how solar adoption may occur throughout its territory.

The results of the economic and achievable potential are presented below in Figure 47. Economic and achievable potential is limited due to the small number of solar systems that pass cost effectiveness and due to the physical requirements of these systems – tracking systems are considered ground-mounted for this analysis and therefore are only applicable to sites that are expected to have sufficient land space to host these systems and the system does not generate more energy than the site consumes. Based on these constraints, the team estimated 66 eligible sites across Tri-State's territory for the economic scenario. The number of eligible systems decreases for each achievable potential scenario as solar system payback time increases.

Figure 47. 2040 Cumulative Non-Residential Economic and Achievable Potential by Region



As illustrated in Figure 47, the highest concentration of eligible sites, and thereby the highest potential, are in the Front Range and Northern New Mexico regions. However, as noted earlier, carbon emission benefits at the time of this report publication are not currently a quantifiable benefit in New Mexico, Wyoming, or Nebraska and therefore this reported economic and achievable potential should be considered with that perspective.

11.KEY FINDINGS

At present Tri-State and its member cooperatives deliver some energy efficiency and DR programs, and no DER programs, to their customers. Even with low avoided energy cost benefits for DSM programs within Tri-State's service territory this study identifies significant cost-effective opportunities for energy and demand savings for energy efficiency programs. There are also opportunities for DR programs, but in some cases those program require long term operation to provide cost-effectiveness. DER programs are generally not cost-effective except for larger systems in specific regions. Key findings and observations related to each of these resources is summarized below. It should be noted that the results of this study and the findings presented here are uncertain to a degree and are sensitive customer adoption of DSM intervetions. Furthermore, the dynamic relationship between Tri-State and the member co-ops presents instrinsic challenges to the seamless implementation of DSM programs. These variables should be take into account when considering the results of this study.

11.1. Energy Efficiency

In 2018, Tri-State cooperative members acquired roughly 30 GWh of energy efficiency savings (~0.2% of baseline energy load)[17]. This suggests that Tri-State's members are currently operating programs somewhere between the Achievable-Low and Achievable-Moderate scenarios, which identified energy savings of 27 GWh and 38 GWh respectively in 2021. With coordinated efforts among cooperative members the long-term market opportunity for cost-effective energy efficiency savings in the region served by Tri-State is considerably higher; the average annual savings potential is 115 GWh over the study's 20-year time horizon for the Achievable-Moderate scenario. Additional key findings within the energy efficiency assessment include:

- 20-year average annual energy savings are just under 115 GWh (0.66% of baseline energy load) at a total program cost of $24M per year ($212/MWh acquired).
- 20-year levelized cost of energy to acquire all energy savings is $21.55/MWh.
- While the industrial sector represents the largest market opportunity (43% of 20-year potential), the residential sector represents the biggest opportunity (35% of potential) compared to its load share (28% of load).
- The commercial sector holds the most cost-effective savings opportunities with a TRC of 1.93 and average 20-year acquisition cost of $171/MWh.
- Pumps (primarily within the industrial sector) represent the largest end-use opportunity across the portfolio at 25% of 20-year cumulative energy savings – much of this opportunity resides with several large Liquid Mining and Pipeline Transportation customers.
- Even with rapid market transformation to LEDs for A-lamp bulbs, there is still considerable savings opportunities in the commercial lighting (21% of potential) and Residential lighting (19% of potential) end-uses – these end-uses are also among the most cost effective with acquisition costs of $150/MWh and $200/MWh respectively.

[17] Tri-State Generation and Transmission, Inc. 2018 Annual Report. (p. 12).

- HVAC measures account for 18% of savings potential – though are relatively expensive with an average acquisition cost of roughly $275/MWh.
- With zero capacity benefits in the first seven years, Home Energy Reports did not pass the study's TRC cost-effectiveness screen until 2028; after which the measure becomes a major opportunity contributing to almost 6% of portfolio savings potential.
- High/medium bay linear lamp and fixture conversions to LED technology represents more than 60% of cumulative energy savings potential in the commercial sector by 2040.
- Non-EISA compliant light bulbs contribute more than 45% to cumulative energy savings potential by 2040 in the residential sector.
- Upgrading existing air source heat pumps to higher efficiency models represent more than 6% of cumulative energy savings potential by 2040 in the residential sector.

11.2. Demand Response

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory. Additional key findings from the demand response potential analysis include:

- High levels of investment in marketing and incentives could yield up to 245 MW of potential (Achievable-High scenario).
- Potential reduction in portfolio-level baseline forecast demand ranges from 2.4% (Achievable-Low) to 6.9% (Achievable-High).
- The residential and irrigation sectors hold the greatest potential for demand response program savings.
- In general, the Direct Load Control program model holds the greatest potential for savings. Among the two Achievable scenarios the most promising program models within each each sector are:
    - Residential: Smart Thermostats and Smart Water Heaters
    - Commercial sector: Critical Peak Pricing and Smart Thermostats
    - Industrial: Critical Peak Pricing
    - Irrigation: Direct Load Control

11.3. Behind-The-Meter Distributed Generation

We analyzed potential for rooftop solar PV across Tri-State's territory for both the residential and non-residential sectors. Ultimately we found rooftop solar PV to not be cost effective for the residential sector. The non-residential sector is cost effective for very large ground-mounted tracking solar arrays when including key benefits of capacity and emission benefits. Additional findings from the distributed energy resource potential analysis include:

- Technical potential solar generation for both residential and non-residential sectors can equate to just over half of total sales.
- No residential solar PV measures pass cost effectiveness under any benefit-cost scenario analyzed in the study.
- The sole cost effective scenario includes both capacity benefits and CO_2 emissions benefits. Just 9% of analyzed measure permutations pass this cost effectiveness scenario and are characterized as non-residential ground-mounted tracking systems varying from 250 kW to 2000 kW system capacity. These system measures have an average TRC of 1.04.
- Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while these potential savings reflect the entire Tri-State territory, the sole cost effective scenario is not applicable to regions outside of Colorado as emissions are not a quantifiable benefit at the time of this report publication.