



**Mayor**  
Nanette Billings

**City Manager**  
Kaden C. DeMille

**Power Board**  
Mac J. Hall, Chair  
Dave Imlay, Vice Chair  
David Hirschi  
Colt Stratton  
Kerry Prince  
Mark Maag

## Power Board Meeting Agenda

7/2/2025

3:00 PM

Power Department Meeting Room – 526 W 600 N

Notice is hereby given that the Power Board will hold a Regular Meeting in the Power Department Meeting room located at 526 W 600 N, Hurricane, UT. A silent roll call will be taken, along with the Pledge of Allegiance and prayer by invitation.

### AGENDA

1. Pledge of Allegiance
2. Prayer
3. Approval of minutes from June 2025

### STAFF REPORTS

Mike Johns/Power Director  
Brian Anderson/Transmission & Distribution Superintendent  
Mike Ramirez/Service Superintendent  
Jared Ross/Substation & Generation Foreman

### OLD BUSINESS

1. Discussion regarding **Transformer Capacity Sales Proposal** – Mike Johns

### NEW BUSINESS

1. Discussion regarding **Impact Fee Analysis & Capital Facilities Plan Amendment** – Mike Johns
2. Discussion regarding **Approved Contractor List qualifications** – Mike Johns
3. UAMPS Updates
4. **Closed Meeting pursuant to Utah Code Section 52-4-205, upon request**

### ADJOURNMENT

The above notice was posted to the Hurricane City website, the Utah State Public Notice Website, and at the following locations:

1. Hurricane City Office – 147 North 870 West, Hurricane, UT
2. US Post Office – 1075 West 100 North, Hurricane, UT
3. Washington County Library (Hurricane Branch) – 36 South 300 West, Hurricane, UT





# HURRICANE CITY

## UTAH

### Mayor

Nanette Billings

### City Manager

Kaden C. DeMille

### Power Board

Mac J. Hall, Chair  
Dave Imlay, Vice Chair  
David Hirschi  
Colt Stratton  
Kerry Prince  
Mark Maag

1 The Hurricane City Power Board met on June 11, 2025, at 3:00 p.m. at the Clifton Wilson Substation located at 526 W  
2 600 N.

3  
4 In attendance were Mac Hall, Dave Imlay (by phone), Colt Stratton, Kerry Prince, Mike Johns, Brian Anderson, Mike  
5 Ramirez, Jared Ross, Dayton Hall, Kaden DeMille, Mike Vercimak, Weston Walker, Fred Resch, and Bruce  
6 Zimmerman.

7  
8 Mac Hall welcomed everyone to the meeting. Colt Stratton led the Pledge of Allegiance and Kerry Prince offered the  
9 prayer. Colt Stratton made a motion to approve minutes from the March 2025, April 2025, and May 2025 meetings.  
10 Kerry Prince seconded the motion. Motion passed unanimously.

11  
12 **Mike Johns:** Mike Johns reminded the board about the UAMPS Member Conference in August. Registration is open  
13 and if any assistance is needed reach out to Crystal Wright.

14  
15 **Brian Anderson:** Brian Anderson reported they've been working on Capacity Project 2.0 Phase 3 which is the section  
16 along 1100 West from 2300 South to 3000 South. Most of the poles have been set and they're waiting for an  
17 easement for the pole right on 3000 South. He has lost one crew member almost full-time due to Blue Stake locates  
18 which has been difficult. Mike Vercimak stated they're trying to fill that Locator position.

19  
20 **Mike Ramirez:** Mike Ramirez stated we've had some conflicts to work out for the 100 North project. There was a  
21 pole that ended up right in the middle of the sidewalk and they had to move it back about three feet. They will tackle  
22 any additional problems as they come up during that project. We completed phase 2 of the Balance of Nature project  
23 along Old Hwy 91. Phase 1 was to cut in the switch on the west side of the road. Phase 2 is a 6-inch conduit that was  
24 bored underneath the highway, and our crews set and energized another switch on the east side of the road. There  
25 will be one more phase as soon as the contract is worked out for capacity on Old Hwy 91. We officially received  
26 notification from the Department of Energy (DOE) that we were granted approval for our Grid Reliance Grant. We  
27 should receive contracts for that grant within five weeks.

28  
29 **Jared Ross:** Jared Ross reported they've been changing out the old relay controls at Anticline Substation (AC). We had  
30 a quality problem with the refurbished regulators we ordered from Solomon. These were different than what we had  
31 ordered. We went to install them, and they were substandard. We loaded them back up to ship back for them to  
32 bring up to standard. That has halted the transformer changeout at AC. When they come back, we will get them  
33 installed. We have ordered the transformer for the Sky Mountain substation. It should be here Fall 2026. We are  
34 working with ICPE to update our transformer specs to include 69/138KV dual voltage. Generation run has started and  
35 there have been some transformers needing to be changed and other maintenance items which happen at the  
36 beginning of each run season. The schedule has been shifted for the entire Substation Crew to cover the generation  
37 run with minimal overtime needs. There was a warranty repair needed on the dump truck and it had to be taken to  
38 Salt Lake City to have that completed.

39



40 **Update regarding the Impact Fee Analysis & Capital Facilities Plan Draft:** Mike Johns reported that the Impact Fee  
41 Analysis & Capital Facilities Plan Draft was approved. There will likely be an amendment coming soon to take care of  
42 items identified as necessary which were not included in the original draft; however, it was necessary to get that  
43 approved while we work on that amendment.  
44

45 **Update regarding AMI Metering:** Mike Ramirez provided the update and stated that we have worked with Eaton to  
46 enter the contract stage of this project. Eaton has stated that it's roughly 6-8 months after contract signatures before  
47 we would likely be setting any AMI meters. That interim provides time for software integration, installation of  
48 metering equipment needed, and training needed to be successful. We have received a contract template, but there  
49 were some things presented during Eaton's presentation that were not included in that template. We are working on  
50 the contract with them. We will need to revise our fee schedule to include the increased cost of those AMI meters.  
51 This is done through resolution.  
52

53 **Consideration and possible recommendation to the City Council on a Development and Power Line Extension**  
54 **Agreement for Black Ridge:** Mike Johns stated Wasatch Commercial Builders intended to be here in person to  
55 present this item but was unable to make it. They submitted a letter to the board which was passed out. Dayton Hall  
56 gave a brief overview of the original approved Development Agreement with the project formerly known as Colina  
57 Tinta. The project is located at the end of 1760 West on top of the hill and heads south. The agreement stated they  
58 would provide transmission power for almost 1900 units approved originally. However, the understanding was that  
59 distribution lines would be utilized at the cost of the developer to service that project. The original Colina Tinta  
60 project owners eventually lost that property and it was tied up in litigation for a significant time. The new owners  
61 were informed of the obligation in the original development agreement. The arrangement that has been negotiated  
62 and up for approval is that the developers will run a distribution line from the Sky Mountain Substation, south along  
63 2260 West, across SR-9, and south along Rlington Parkway to serve their project. That initial distribution line will  
64 provide power supply for approximately 1000 units. To go beyond that number of units, they will need to find a way  
65 to bring another distribution line from the Three Falls Substation to provide the power supply for their remaining  
66 units. In the clarified agreement there is a table providing a timeline for the improvements needed. Colt Stratton  
67 stated there is no Sky Mountain Substation currently. How will we be able to approve the distribution line connecting  
68 to that substation if they are prepared to complete that line prior to our construction of the substation? Mike  
69 Vercimak stated that the Sky Mountain Substation is currently our highest priority. Mike Johns replied that the  
70 substation transformer should be arriving in Fall 2026, and we are hopeful it can be completed 18 months to two  
71 years from now. Dayton Hall asked if it is a requirement to have the substation built to supply capacity for the  
72 remaining homes. Brian Anderson explained some ways we could work around that to provide power temporarily  
73 until the substation is built. We are just needing them to fulfill their obligation according to the agreement to provide  
74 the lines to supply their own power need. Mac Hall asked Colt Stratton if that satisfied his question. He stated it did.  
75 Dave Imlay made a motion to recommend approval of the development and power line extension agreement to the  
76 City Council. Colt Stratton seconded the motion. Motion passed unanimously.  
77

78 **Discussion and possible recommendation to the City Council on a UAMPS Central St George Project Resolution:**  
79 Mike Johns presented this item and the changes being made are to Exhibit C of the original transmission agreement.  
80 It increases the overall transmission infrastructure in Southern Utah. Anytime changes are made to any part of the  
81 agreement, or to the bond cap, it requires governing body approval. He described an overview of some of the  
82 infrastructure upgrades being included in the new exhibit. He stated the new bond cap will increase to \$100 million.  
83 He explained the bonds will get broken down into two series. We have been given the option to pay our portion of  
84 the funding up front or we participate in the bonding process. He went over what it would look like if we chose to  
85 participate in the bond. We are vested about 14.62% in this project and he showed what that percentage looks like in  
86 relation to the overall project. The resolution that is needed details the overall transmission upgrades being included

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87 in Exhibit C as well as our decision of whether to pay our portion up front or participate in the bond. Dave Imlay  
88 stated he would defer to Kaden DeMille since he understands the financial aspect more, but his feeling is to  
89 participate in the bonding process so we can keep our cash flow for our own more immediate needs. Mac Hall stated  
90 that after reviewing his old notes, his understanding was that PacifiCorp was responsible financially for anything  
91 dealing with the 345KV line from Central to and including the St George Substation. He stated that the change would  
92 have been to Exhibit C, but it would have been in the 2006-2007 timeframe. Dave Imlay stated that had been a heavy  
93 topic during his time as well, but if it's not being mentioned in any of the meetings currently then we may have lost  
94 that battle. Mike Johns stated those topics weren't discussed in the meetings. Our 14.62% portion to pay this up  
95 front would be in the \$2 million range. Kaden DeMille asked what the interest rate is. Mike Johns replied around  
96 5.15%. Kaden DeMille said that unless we want to draw down on our reserves, that is a great interest rate. He would  
97 suggest participating in the bond. Colt Stratton made a motion to the City Council to recommend approval of the  
98 UAMPS Central St George Project Resolution with the option to participate in the financing through UAMPS. Dave  
99 Imlay seconded the motion. Motion passed unanimously.

100  
101 **Discussion regarding Transformer Capacity Sales Proposal:** Mike Johns stated we have major infrastructure needs  
102 and an issue with not having the impact fees available to handle the projects as soon as they are needed. He  
103 presented an idea to generate more money up front as opposed to waiting through the impact fee process to collect  
104 those funds. This concept would sell transformer capacity to developments based on how much capacity is needed  
105 for their projects up front. He described using the cost of various transformer sizes compared to the capacity needed  
106 for individual developments to break down how much of that transformer cost would be due to their project. This  
107 would require us to pull the costs of substation transformers out of the impact fees since they currently are included.  
108 Dayton Hall summarized that our impact fee is currently calculated to include transmission, substation, and  
109 generation. We do not include distribution costs. What is being proposed is to remove the cost of the transformers in  
110 the substation portion of those fees. That would effectively lower the overall impact fee. Developers would then  
111 have to build their distribution lines like they do currently, and in addition pay their proportionate share of the  
112 substation transformer needs for their project. This will result in more money coming in earlier so we can be more  
113 proactive in building the infrastructure needed. Colt Stratton asked if we would put in any smaller than 20MVA  
114 transformers in our substations. His concern is that we're proposing to charge for a transformer size we wouldn't  
115 install thereby inflating the overall transformer cost to the developers. A 5MVA proportionate share of a 20MVA  
116 transformer is less than paying for a 5MVA transformer itself. As a developer, he's going to fight to only pay for his  
117 cost of the 20MVA proportionate share which doesn't gain us any ground financially, other than potentially getting  
118 the money sooner. Dave Imlay stated he feels like this opens a can of worms. He agrees that we haven't collected the  
119 impact fees we need for the development that has come. It's not the developers' fault we didn't update our impact  
120 fees soon enough. He feels like the impact fees are built to handle various scenarios already, and if we need to install  
121 infrastructure sooner than impact fee money is received, we should bond for those projects and use incoming impact  
122 fee money to pay off those bonds. Mike Johns stated one advantage to this proposal is the developers are more  
123 invested in their projects up front with the requirement to participate in the capacity purchase for their project. Mac  
124 Hall stated it's a new idea and it's worth continuing to investigate. Mike Johns stated he has concerns about our  
125 reliability and redundancy based on our current infrastructure assets. The fix includes major infrastructure upgrades.  
126 He's trying to find a financial solution to alleviate some of those concerns. He explained an actual issue with a  
127 developer that has come in and there is no way to provide them with the capacity they need. Their option is to pay  
128 the money to build an entire substation or wait until someone else does it for them. It pushes their development  
129 basically to non-existence. He's trying to find solutions to these kinds of problems.

130  
131 **UAMPS Updates:** Mike Johns stated there are no further updates needed to share.

132  
133 Meeting adjourned at 4:04 p.m. The next Power Board meeting is scheduled for July 2, 2025, at 3:00 p.m.

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**BUDGET**

## AVERAGE YEARLY POWER PRICES

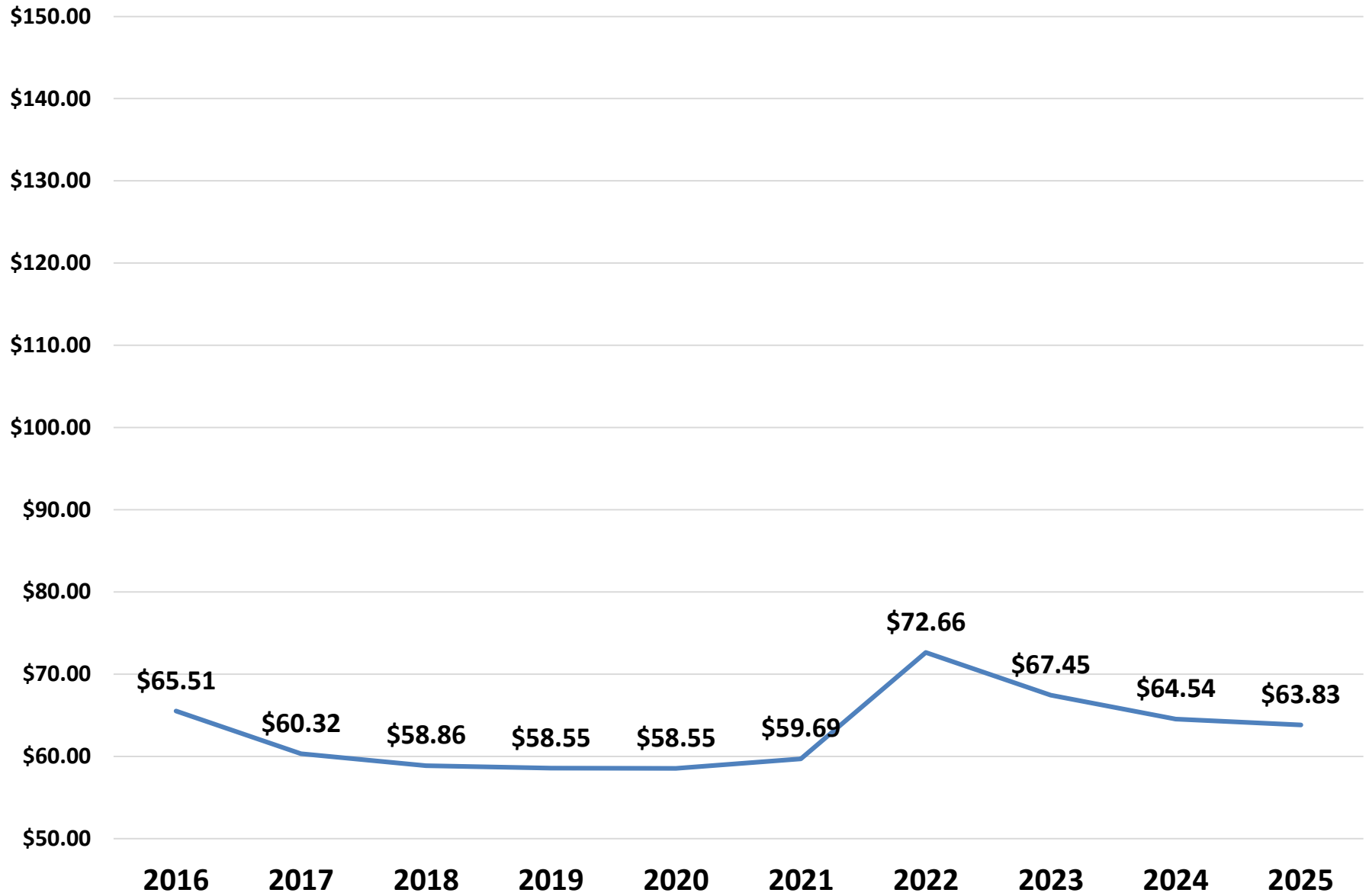
24-25 bdgt amount (thru Apr 2025) **\$72.17**  
 BDGT Year to Date **\$71.80**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
<i>Jan</i>	\$57.87	\$59.07	\$60.62	\$59.75	\$57.76	\$60.14	\$68.25	\$132.44	\$80.85	\$73.22
<i>Feb</i>	\$62.38	\$63.04	\$60.96	\$67.00	\$60.67	\$63.19	\$70.88	\$83.72	\$71.23	\$74.69
<i>Mar</i>	\$61.77	\$60.99	\$60.09	\$65.17	\$64.67	\$63.64	\$67.28	\$87.92	\$70.62	\$77.46
<i>Apr</i>	\$59.71	\$59.49	\$55.02	\$55.44	\$55.92	\$61.86	\$82.63	\$75.32	\$70.32	\$76.49
<i>May</i>	\$65.51	\$60.32	\$58.86	\$58.55	\$58.55	\$59.69	\$72.66	\$67.45	\$64.54	\$63.83
<i>June</i>	\$65.51	\$58.54	\$52.17	\$55.30	\$53.44	\$86.91	\$77.60	\$69.52	\$63.88	
<i>Jul</i>	\$56.95	\$58.29	\$67.87	\$54.29	\$55.98	\$81.04	\$85.31	\$90.48	\$70.51	
<i>Aug</i>	\$57.67	\$59.00	\$66.55	\$54.58	\$78.40	\$72.03	\$96.60	\$84.39	\$67.05	
<i>Sep</i>	\$56.97	\$62.36	\$55.00	\$54.34	\$64.93	\$82.38	\$127.29	\$83.74	\$66.46	
<i>Oct</i>	\$59.23	\$59.79	\$59.36	\$59.70	\$62.82	\$75.92	\$83.45	\$83.77	\$75.82	
<i>Nov</i>	\$64.18	\$62.14	\$64.60	\$63.80	\$63.60	\$70.47	\$96.34	\$73.03	\$85.85	
<i>Dec</i>	\$61.51	\$58.80	\$61.61	\$58.55	\$60.33	\$70.07	\$161.27	\$71.99	\$68.50	
<i>Yr Avg</i>	\$60.64	\$60.15	\$60.23	\$58.87	\$61.42	\$70.61	\$90.80	\$83.65	\$71.30	\$73.14
<i>Weighted Avg</i>	\$59.55	\$59.90	\$60.56	\$58.11	\$61.98	\$72.46	\$92.09	\$84.16	\$70.50	<b>\$72.65</b>

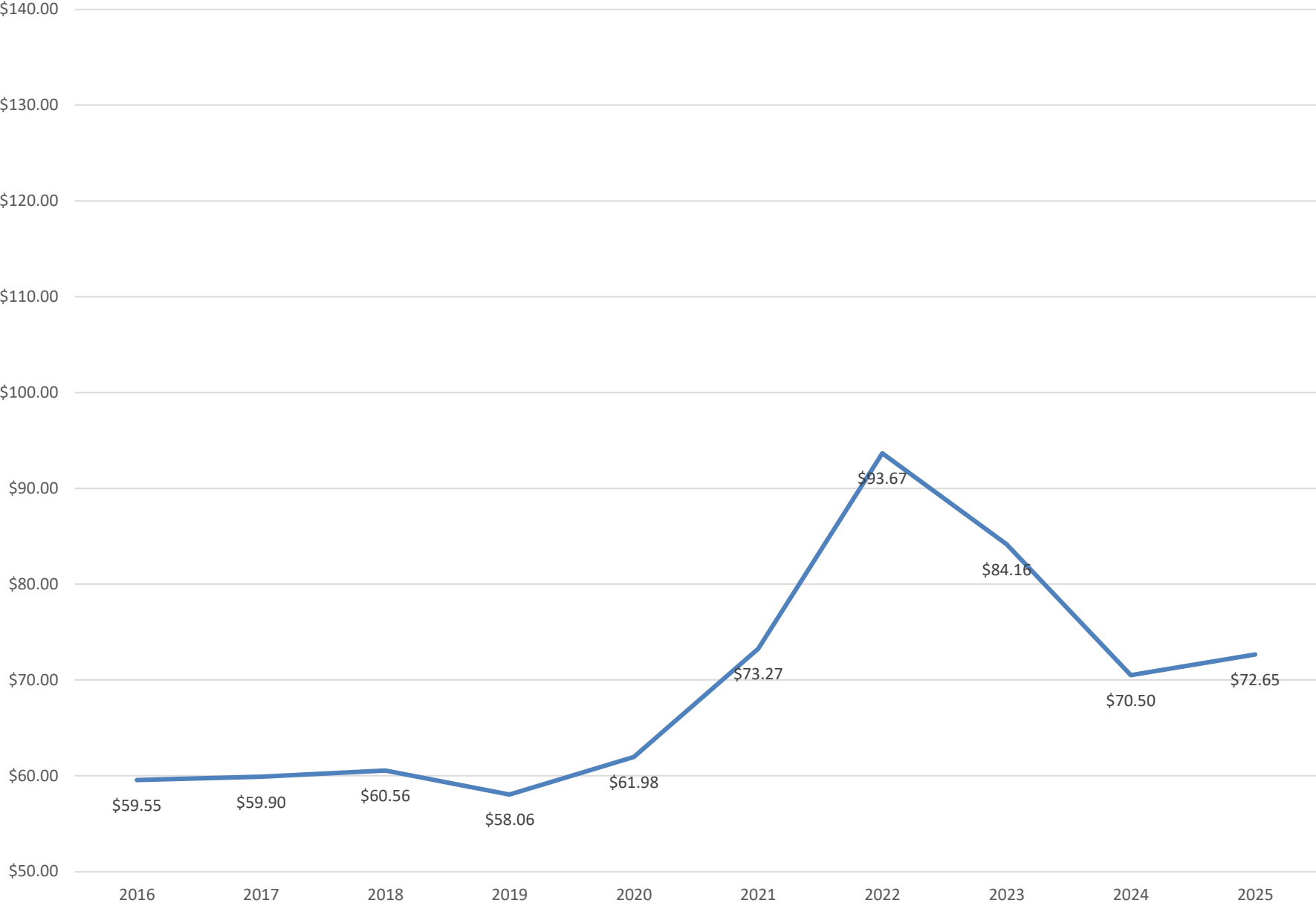
**Cy to  
Date**

*These figures capture the total cost of power to the power department.  
 The power department uses costs only associated with the purchasing  
 and generation of power and includes debt payments and interest*

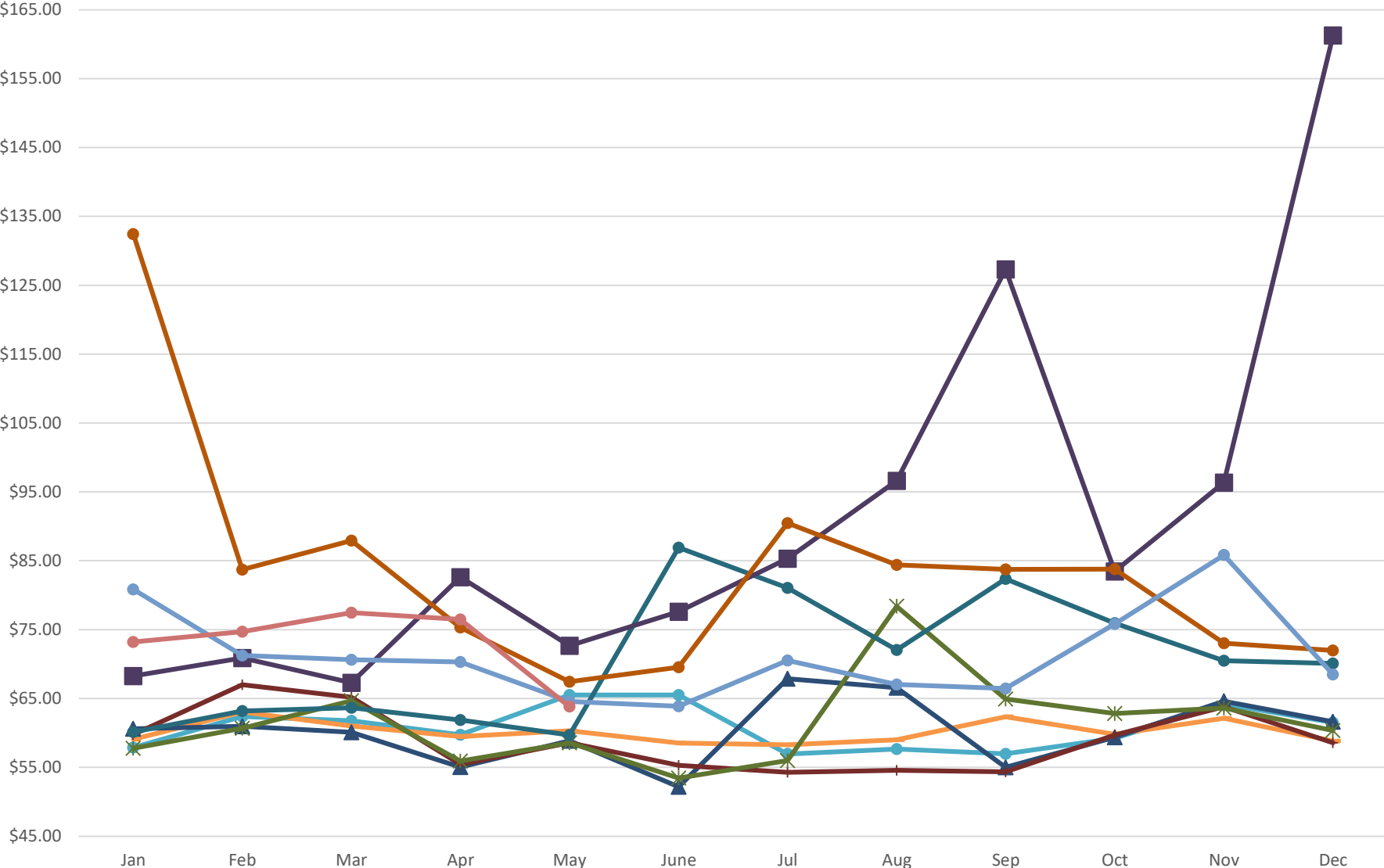
# May



### Weighted Average



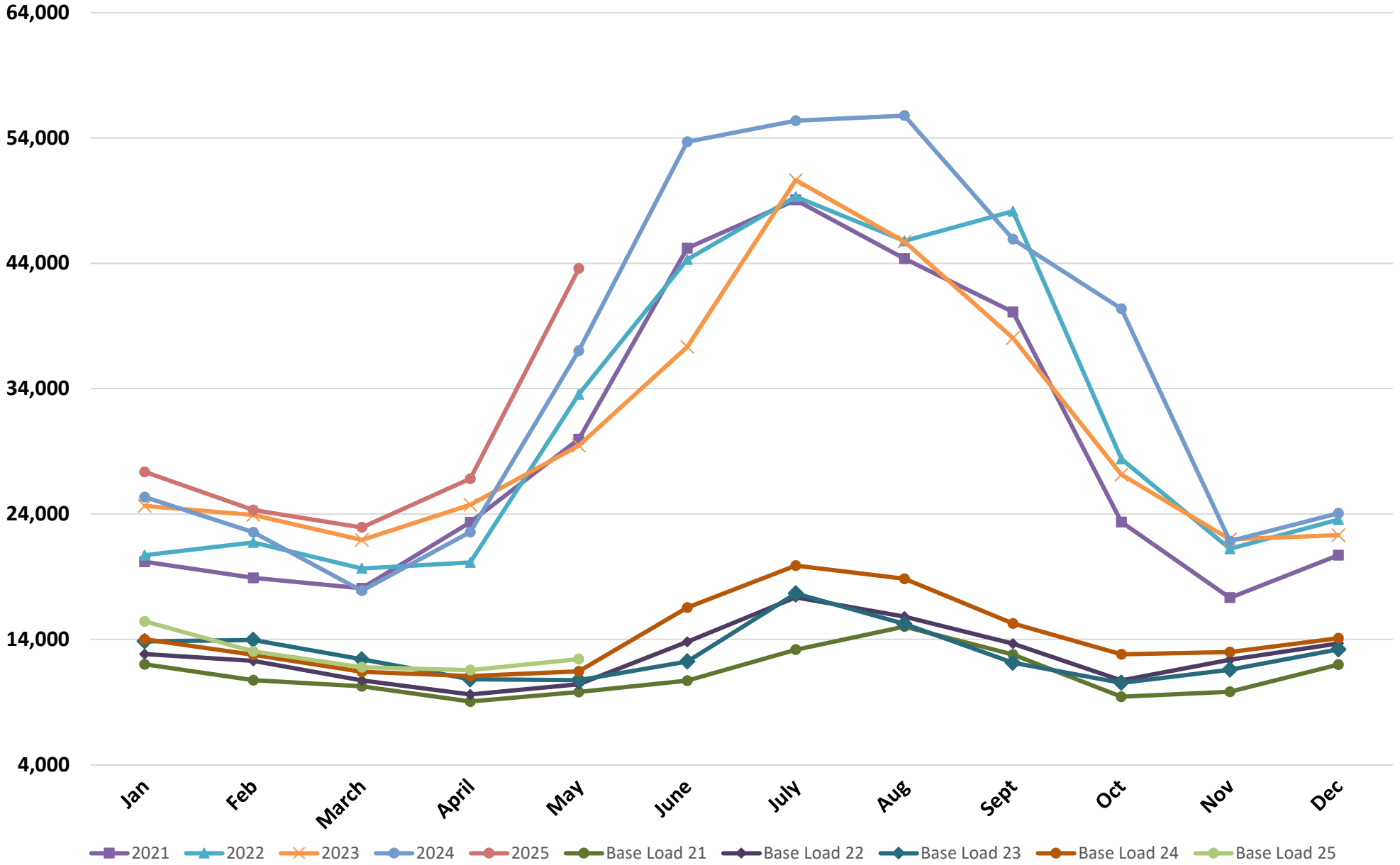
Avg Monthly Price



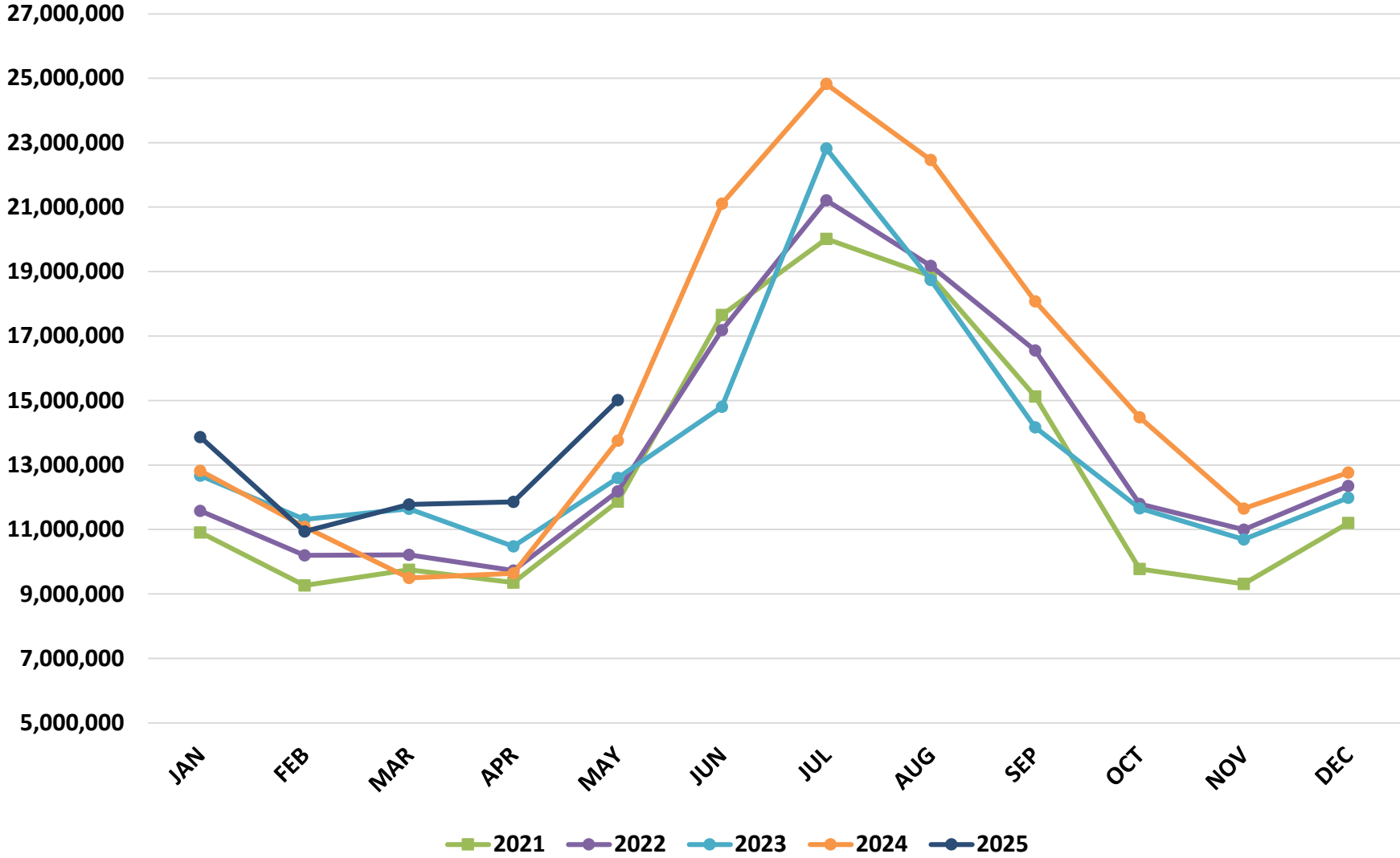
● 2016 ● 2017 ▲ 2018 + 2019 \* 2020 ● 2021 ■ 2022 ● 2023 ● 2024 ● 2025



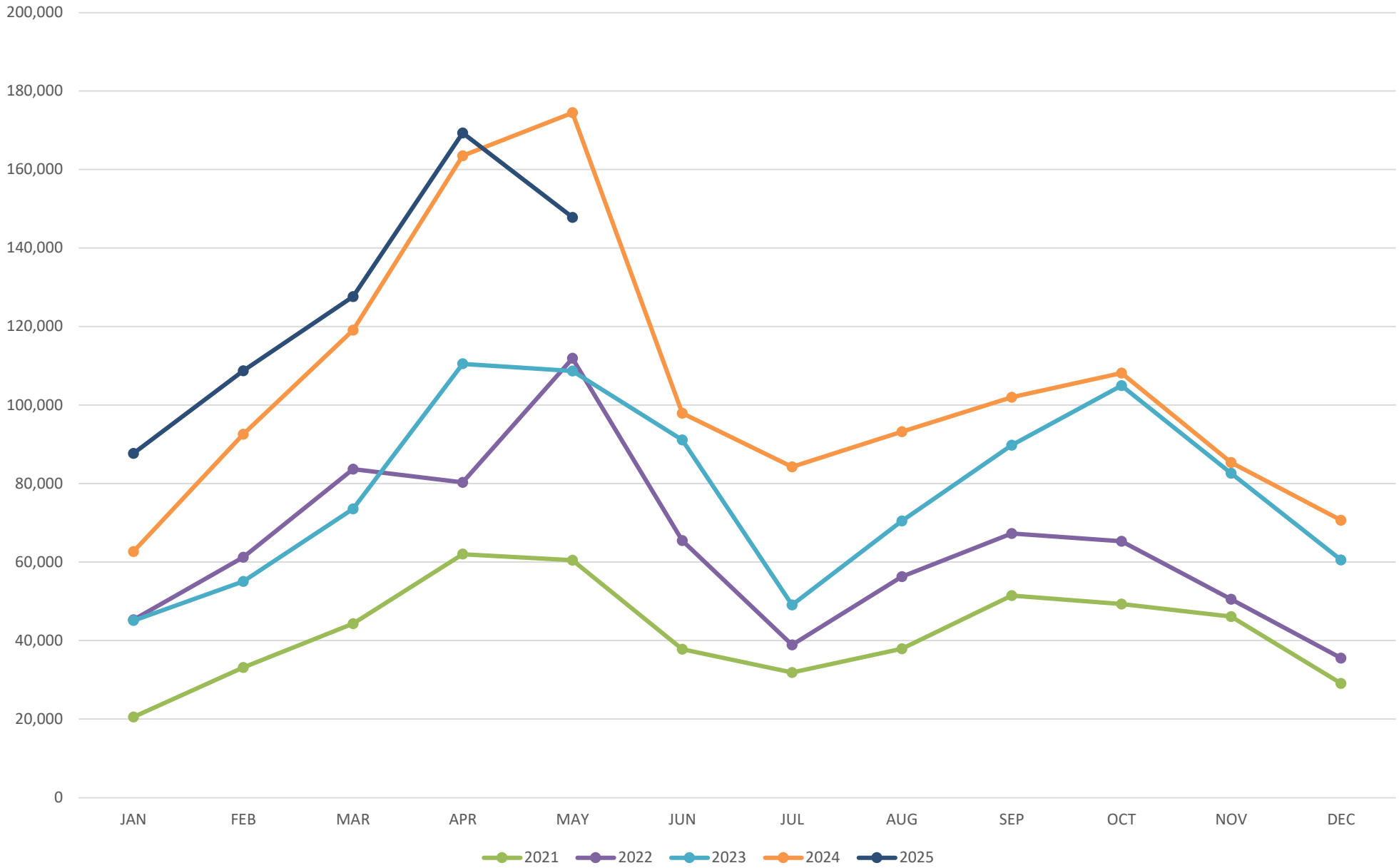
### 2021 - 2025 KW LOAD



### 2021 - 2025 KWH LOAD



### Solar Kwh



**EXISTING  
APPROVED  
IMPACT FEES**



# Hurricane City

## Electrical Transmission and Substation Impact Fee Facility Plan

May 2025  
Rev 2



**Intermountain Consumer  
Professional Engineers, Inc.**  
1145 East South Union Avenue  
Midvale, Utah 84047  
(801) 255-1111

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# SECTION I GENERAL

## Introduction

Intermountain Consumer Professional Engineers, Inc. (“ICPE”) performed studies and analyses for Hurricane City to update their Electrical Power Capital Facilities Plan and Impact Fee Facilities Plan.

ICPE utilized load predictions in the studies that were developed using recent load data provided by Hurricane City and load trends observed in Hurricane City over the past several years. The future loads used in the studies are predictions and do not reflect actual values which prevents ICPE from guaranteeing or assuring that the recommendations reflect actual events that will occur in the future. However, it is believed that all predictions and observations used in the study are reasonable and appropriate for the purpose of the Capital Facilities Plan and Impact Fee Facilities Plan.

## Impact Fees - General

Impact fees are generally used by cities to fund infrastructure projects necessary to provide services to new developments within the city’s boundary. The new development should bear the additional or incremental capital cost for the services, existing residents who do not benefit from the new development should not bear the costs for services to the new development. Impact fees are not intended for operating expenses or for corrections to existing deficiencies in the services presently being provided by a city. Impact fees are based on anticipated new load increase to the electrical system due to the new developments. The improvements outlined in the plans are required to maintain the present level of service to both new and existing customers.

## Impact Fees - Utah

In Utah, impact fees are governed by state statute, specifically U.C.A. 1953 § 11-36a-102. The Statute requires that each governmental agency that imposes an impact fee shall (1) prepare an Impact Fee Facilities Plan (§ 11-36a-301), (2) perform an Impact Fee Analysis (§ 11-36a-303), (3) calculate the Impact Fee(s) (§ 11-36a-305) and (4) certify the Impact Fee Facilities Plan (§ 11-36a-306).

As stated in the Statute, the “Impact Fee Facilities Plan (“IFFP”) shall identify (a) demands placed upon existing public facilities by new development activity; and (b) the proposed means by which the political subdivision will meet those demands.” The IFFP shall also consider all revenue sources,

including impact fees, used to finance impacts on system improvements. This report incorporates the most recent Hurricane City Capital Facilities Plan (“CFP”), dated August 2024. In general, the CFP outlines all projects necessary to maintain electrical service to existing customers and the IFFP outlines fees for the improvements necessary to provide service to new developments and customers. Projects identified in the CFP may be due to the correction of an existing deficiency or improvement necessary to maintain reliability and are not included in the IFFP.

The Utah Statute requires the governmental agency that imposes an impact fee to perform an analysis of the impact fee and document the results. The agency is also required to provide a summary document of the analysis that can be understood by a layman. The estimated impacts on the existing electrical system due to the new development are to be included in the Impact Fee Analysis (IFA) along with the costs associated with addressing the impacts. The IFA is also required to include the costs of existing capacity that will be recouped.

Impact Fee calculations may include the following:

- (a) The construction cost.
- (b) The cost of acquiring land and material.
- (c) The cost for planning, surveying, and engineering fees for services provided to design the construction.
- (d) Debt service charges, if the impact fees are used to pay the principal and interest on bonds or other obligations to finance the costs of the construction.

Impact Fee calculations are to be based on local industry standard material and labor estimates. The assumptions used to develop the estimates are to be included in the IFA. The IFFP and the IFA area to be certified by the person or entity that prepared the documents.

## Hurricane City



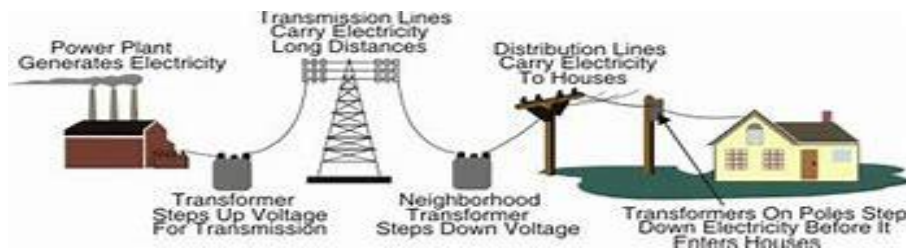
Hurricane City is located in southwest Utah in Washington County, approximately 140 miles northeast of Las Vegas, NV. According to the US Census, the land area is 31.5 square miles and the estimated population in 2022 was about 20,609 persons. The median resident age is 43.3 years, the average household size is 2.87 persons, and the median household income is about \$64,182.

Hurricane can best be described as a suburban community since many of its resident’s commute to work in the City of St. George other nearby business areas. Hurricane, as well as the surrounding area has a rapidly growing population.

# Electricity Supply

## General

Figure 1 illustrates the three basic components of an electrical system, an electric generator that creates the electricity, a transmission system that carries the electricity to the distribution system; and the distribution system that delivers the electricity to the customer.



**Figure 1**

### **Illustration of a Typical Power Delivery System**

## Electricity Generation

Electricity is produced by a generator that is powered by a fuel source. The generator can be a steam, hydro, turbine, diesel engine, wind, solar or geothermal. The generated electricity is provided to a utility through purchased power agreements, which can be a firm power agreement (long-term and short-term); unit power (a portion of a specific generating unit) and non-firm (usually short-term). The type and amount of each generating resource that is used by a utility to meet the electrical demand depends on the amount and duration of the demand, the availability of the generating units and the cost of the electricity from the generating units. To meet the hourly demand for electricity, each available generating resource is evaluated according to its availability, capacity and operating cost and then dispatched accordingly to meet the demand for electricity in each hour of the day.

The utility's peak demand is the highest demand for electricity in any one hour. It is during these peak hours that a utility will use multiple generating resources including its own generating resources.

## **Electricity Transmission**

The electricity leaving the generator is stepped up to a higher voltage by a transformer and delivered to the transmission system. The transmission system consists of transmission power poles or towers, conductors, substations and other equipment necessary to deliver electricity from the generators to the utility.

Transmission of electricity to Hurricane City is through the Utah Associated Municipal Power Systems (UAMPS) transmission system. UAMPS receives electricity through Rocky Mountain Power's transmission system.

## **Electricity Distribution**

Electricity distribution is the final stage in the delivery of electricity to customers. An electricity distribution system receives electricity from the transmission system and delivers it to consumers. A typical electric distribution system includes medium-voltage (138kV, 69 kV & 12.47 kV) power lines, substations, transformers, service drops and metering. The distribution system begins where the voltage is stepped down through transformer(s) and ends at the secondary service point at the customer's meter. Distribution circuits begin at the low-voltage side of the transformer located in the City's substation. Conductors for the distribution delivery system are either located overhead on utility poles or buried underground.

Most electric customers are connected to a pole mounted or pad mounted transformer that reduces the distribution voltage to the low voltage used by customers. Each customer has an electrical service connection and a meter.

# SECTION II CAPITAL FACILITIES PLAN AND IMPACT FEE FACILITIES PLAN

## General

The Impact Fee Facilities Plan identifies the additional electrical load placed on an existing electrical system by new developments, identifies additions or modifications to the existing electrical system necessary to meet the increased load and provides costs for the system additions or modifications. The Plan will enable the utility to determine how they will fund the projects necessary to meet the load increase to the system.

The following summarizes the results of the Capital Facilities Plan Update that was completed in August 2024 where load increases were identified, projects were proposed to meet the load increase and costs were provided for the proposed projects.

## Historical Population and Load Growth

According to the U.S. Census Bureau, the Hurricane City's population in 2020 was approximately 20,609. The population grew to 25,209 by 2024 for an approximate 22.3% increase in population over four years. The following table is a summary of the population growth since 1960.

**Table 2-1  
Hurricane City Historical Population**

Historical population		
Census	Pop.	%±
1960	1,251	
1970	1,408	12.5%
1980	2,660	88.9%
1990	4,014	50.9%
2000	8,560	113.3%
2010	13,748	60.6%
2014	15,032	9.3%
2020	20,609	37.1%
Est 2024	25,209	22.3%

Hurricane City experienced a high growth rate between 1980 and 1990 and between 1990 and 2010. However, the electrical load during these periods did not increase as significantly as the population. The annual historical load growth since 1987 is shown in Table 2-2.

**Table 2-2**  
**Hurricane City**  
**Electrical Load History**

Year	PEAK kW	
	Summer Peak	% Growth (Summer)
1991	5,544	
1992	6,497	17.19%
1993	6,675	2.74%
1994	8,267	23.85%
1995	9,364	13.27%
1996	11,467	22.46%
1997	11,632	1.44%
1998	13,101	12.63%
1999	13,836	5.61%
2000	16,200	17.09%
2001	15,600	-3.70%
2002	18,200	16.67%
2003	19,700	8.24%
2004	21,200	7.61%
2005	25,700	21.23%
2006	27,800	8.17%
2007	31,300	12.59%
2008	29,300	-6.39%
2009	31,243	6.63%
2010	31,315	0.23%
2011	31,435	0.38%
2012	32,870	4.56%
2013	33,731	2.62%
2014	31,502	-6.61%
2015	34,228	8.65%
2016	37,411	9.30%
2017	37,527	0.31%
2018	38,483	2.55%
2019	39,148	1.73%
2020	44,416	13.46%
2021	49,060	10.46%
2022	49,314	0.52%
2023	50,635	2.68%

# Electric Infrastructure and Future Needs

## Transmission

Hurricane City Power is served by PacifiCorp's Purgatory Flat Transmission Substation with two radial 69kV lines, one line feeds Anticline substation and the other line feeds the other three 69kV substations. The radial 69kV line interconnects Hurricane City Power's four Distribution substations. Future Substation 1, Future Substation 2, and Three Falls Substation are planned to be fed by a 138 kV line originating at Purgatory Flat. Sky Mountain Substation is planned to be fed by the 69 kV line originating at Purgatory Flat.

In the 5-year planning horizon the new proposed Future Substation 1 will need a new 138 kV transmission line to provide power to the substation. This new 138kV transmission line would feed the new substation from the existing Purgatory Substation. The proposed 138kV line would be served by the 138kV bus of the Purgatory Substation. The line would be approximately 8.1 miles of single circuit 1272 ACSR conductor. Future Substation 1 would also need to be designed to allow for two transmission lines. The 138kV line needs to be extended to the Three Falls Substation from Future Substation 1. This line is necessary to provide power to the proposed second bay of Three Falls. This 138 kV would be approximately 4.6 miles of single circuit 1272 ACSR conductor. Three Falls was designed in a ring bus configuration to accommodate the building of this line.

In the 10-year planning horizon, Sky Mountain Substation will need to get power from the existing 69kV line that runs along 600 North, this line will be approximately 200 ft of 795 ACSR single circuit conductor. Future Substation 2 will need to get power from the existing 138kV line that runs along 600 North, this line will be approximately 400 ft of 1272 ACSR single circuit conductor. A new 138 kV transmission line is proposed that will make a connection between the existing 138kV line and the proposed line that will feed Future Substation 1, this line is necessary to build before Three Falls Substation is upgraded to a 138 kV substation. This 138 kV line would be approximately .9 miles of single circuit 1272 ACSR conductor. The existing 1/0 ACSR 69 kV transmission line that provides power to Three Falls Substation will need to be upgraded to accommodate the upgraded substation equipment and new bay. This new line will connect to the existing 138kV line along 600 North and will be approximately 1.9 miles of 1272 ACSR single circuit conductor.

## Substations

Hurricane City Power system currently has four power distribution substations: Anticline Substation, Brentwood Substation, Clifton Wilson Substation, and Three Falls Substation. It is noted that during the time of this study Three Falls Substation was under construction but was not yet operating. So, the peak loading for Three Falls Substation was estimated.

In the 5-year planning horizon Anticline T1 will need to be upgraded to a 20 MVA transformer to meet growth requirements in the area. The Bay 1 voltage regulators will also need to be upgraded. Due to the projected growth in the area that Anticline Substation serves it will be necessary to have both bays of Anticline substation feeding load. The addition of one substation (Future Substation 1) will be necessary to meet growth requirements and to maintain the required current level of service. The location of Future Substation 1 should be in the general vicinity of 2700 South, east of Highway 7.

In the 10-year planning horizon the addition of Sky Mountain will be necessary to meet the estimated growth. The location of Sky Mountain is approximately 600 North and 2200 West. It will be necessary to install the second bay in Three Falls Substation to help take the load off Clifton Wilson and to help back up Future Substation 1. Sky Mountain Substation helps take load off Clifton Wilson and Brentwood Substations and helps provide backup of those substations during N-1 conditions. Three Falls substation should be upgraded from 69kV to 138kV. This is necessary to complete the 138kV loop for redundancy during N-1 conditions. Future Substation 2 will be a 138kV-69kV substation and will provide a second 69kV source for the 69kV substations during the loss of the 69kV line from Purgatory. The location of Future Substation 2 should be approximately 600 North in between Sky Mountain and Clifton Wilson.

## Level of Service Standards

Consistent with current practice and level of service, Hurricane City plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions must remain below their ONAN/ONFA/ONFA 55-degree rating.
- Dual bay substations loading shall not exceed 75% of combined ONAN/ONFA/ONFA 55-degree MVA rating of power transformers.
- The system must be able to adequately serve load under single contingency (N-1) situations, where “N” is a power system element such as a transformer or line.
- The system switching required under an N-1 contingency should remain as simplified as possible to ensure that switching orders do not become unnecessarily complex.
- Distribution circuit loading criteria must remain below 90% of its maximum current rating.
- Transmission circuit voltage must remain between 95% and 105% of its nominal value.
- Distribution circuit voltage must remain between 98% and 105% (at loads) of its nominal value.
- Distribution circuit mains must be able to serve additional load under N-1 contingencies.

The above criteria were used to determine Hurricane City’s facility needs based on the amount of load (i.e., demand) placed on the existing system over the study planning horizon.

## Demands Placed on Existing Facilities

Electrical demand loads on a system are measured in kilowatts (kW) or kilovolt-amperes (kVA) and are indicated as either coincident-peak (“CP”) demand or non-coincident peak (“NCP”) demand. The system CP demand is the maximum demand for the entire system measured at a point in time where the sum of all demands on the system is the highest for the system as a whole. The NCP demand is the sum of the maximum demands of individual customers or customer classes such as residential, commercial, industrial, measured for a period of time. The CP demand represents the combined loads across all customer classes measured at the system level where the NCP demand represents the total demand the system would be subject to if all customer classes peaked at the same time. The CP demand is usually lower than the NCP demand. For Impact Fees, CP represents the demand placed on the existing system as a whole, while NCP reflects the maximum demand placed on local facilities by individual customer classes. The CP demand is normally the demand that a utility plans for when sizing facilities that will be used to meet future growth on the system. However, each individual piece of equipment must be able to support its own individual peak demand even if that demand does not occur at the same time as the system’s CP.

Hurricane City’s projected CP demand between 2024 and 2033 are shown in Table 2-3. The System CP Demands for the planning period (2024 – 2033) were developed by ICPE.

**Table 2-3  
Summary of CP Demands  
For the Period 2023 through 2033**

Description	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total System CP Demands (kW)	54,686	59,061	63,786	68,888	74,399	77,375	80,470	83,689	87,037	90,518

## System Modeling for the CFP/IFFP

The recent CFP completed contains results of load flow analysis of the Hurricane City electrical system. The system load flows provide insight on substation transformer loading and system voltage drop. The study includes analyzing N-1 outage conditions. An N-1 outage condition is the loss of a major system component such as loss of a substation transformer or loss of a main line section. The existing substations that were studied include Anticline, Brentwood, Clifton Wilson, and Three Falls. The CFP study is primarily focused on Transmission (69kV or greater) and Substation requirements.

To perform load flow analysis a system computer model was developed. System model development and analysis were performed on SKM Power Tools. System modeling data was developed from data provided by Hurricane City. System load was modeled based on 2023 peak values since they were available at the time. Circuit models are based on the assumption that provided circuit maps and data (conductor sizes, circuit configurations, line lengths, etc.) are reflective of actual field conditions.

## Model Results

The following System Improvement Summary from the CFP details the anticipated projects and estimated expenditures necessary to sustain the projected growth rate for Hurricane City's electrical system for the next 10 years. There is greater confidence in projecting requirements for 2 to 3 years than there is for a 10-year or longer outlook. However, it is necessary to forecast future projects due to the magnitude (and cost) of the modifications necessary. Substation and transmission line projects can take significant time from start to finish due to material lead times and permitting requirements. Substation and transmission line requirements need to be addressed to meet future needs of the city in a timely fashion.

The proposed projects will provide a method for Hurricane City to plan and budget for the facilities necessary to serve the anticipated electrical load growth. Existing electrical facilities as well as new facilities will be used to meet projected load levels. Table 2-4 is a summary of the recommended projects, timing and costs. Detailed cost estimates for the various projects can be found in the appendix of the CFP. Costs shown are based on present 2024 project material and labor pricing.

**Table 2-4**  
**Summary of CFP Improvement Projects**  
**For the Period 2024 through 2033\***

Project Number	Description	Project Estimated Cost (\$) **	Estimated Timeframe	IFFP Percentage	Adjusted Project Cost
1	Replace Anticline T1	1,943,675.00	2025	73.3%	1,424,713.78
2	New 138kV line from Purgatory to Future Sub 1	6,404,366.00	2025-2027	73.3%	4,694,400.28
3	New Future Substation 1	7,690,408.00	2027	73.3%	5,637,069.06
4	New 138kV line from Future Sub 1 to Three Falls	3,100,207.00	2027-2028	73.3%	2,272,451.73
5	Three Falls Substation Bay 2	3,728,421.00	2029	73.3%	2,732,932.59
6	New 69kV line to Sky Mountain	200,805.00	2029	73.3%	147,190.07
7	New Sky Mountain Substation	5,503,354.00	2030	73.3%	4,033,958.48
8	New 138kV line to 600 North	685,450.00	2031	73.3%	502,434.85
9	New 138kV line from 600 North to Three Falls	1,339,409.00	2032	28.5%	381,731.57
10	Three Falls substation Bay 1 Upgrade	2,119,390.00	2032	28.5%	604,026.15
11	New 138kV line to Future Substation 2	210,848.00	2033	28.5%	60,091.68
12	New 138kV-69kV Future Substation 2	7,195,069.00	2033	28.5%	2,050,594.67
	<b>TOTAL</b>	<b>40,121,402.00</b>			<b>24,541,594.90</b>

\* Note: Project timing will vary based on actual load growth amount and location.

\*\* Values have been rounded.

## **IFFP Capital Projects and Costs**

As previously mentioned, the costs for the above projects are estimated in 2024 dollars. As with most capital facilities plans, the majority of these projects are scheduled to occur in the earlier planning windows. However, growth in demand on the system generally happens in “groups” or “lumps” according to actual commercial and residential development. Actual load growth may be sooner or later than shown based on current economic and development levels. Projects shown in the IFFP may be delayed or accelerated based on actual load growth locations and timing.

## Certification of the IFFP

I certify that the attached Impact Fee Facilities Plan:

1. includes only the costs of public facilities that are:
  - a. allowed under the Impact Fees Act; and
  - b. actually incurred; or
  - c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
  - a. costs of operation and maintenance of public facilities;
  - b. costs for qualifying public facilities that will raise the level of service for facilities, through impact fees, above the level of service that is supported by existing residents;
  - c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;

### CERTIFIED BY:

Signature: Mac Fillingim

Name: Mac Fillingim

Title: ICPE, Senior Engineer

Date: August 2024



PUBLIC  
FINANCE  
ADVISORS



# HURRICANE UTAH

MAY 2025

IMPACT FEE ANALYSIS (IFA)

ELECTRICAL TRANSMISSION AND  
SUBSTATIONS

PREPARED BY:

**LRB PUBLIC FINANCE ADVISORS**

FORMERLY LEWIS YOUNG ROBERTSON & BURNINGHAM INC.

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# IMPACT FEE CERTIFICATION

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## IFA CERTIFICATION

LRB Public Finance Advisors certifies that the attached impact fee analysis:

1. includes only the costs of public facilities that are:
  - a. allowed under the Impact Fees Act; and
  - b. actually incurred; or
  - c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
  - a. costs of operation and maintenance of public facilities;
  - b. costs for qualifying public facilities that will raise the level of service for the facilities, through impact fees, above the level of service that is supported by existing residents;
  - c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;
3. offsets costs with grants or other alternate sources of payment; and,
4. complies in each and every relevant respect with the Impact Fees Act.

## **LRB Public Finance Advisors makes this certification with the following caveats:**

1. All of the recommendations for implementations of the IFFP made in the IFFP documents or in the IFA documents are followed by City Staff and elected officials.
2. If all or a portion of the IFFP or IFA are modified or amended, this certification is no longer valid.
3. All information provided to LRB is assumed to be correct, complete, and accurate. This includes information provided by the City as well as outside sources.

LRB PUBLIC FINANCE ADVISORS



## DEFINITIONS

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The following acronyms or abbreviations are used in this document:

<b>IFA:</b>	Impact Fee Analysis
<b>IFFP:</b>	Impact Fee Facilities Plan
<b>kVA:</b>	Kilo-volt-amperes
<b>kW:</b>	Kilowatt
<b>LOS:</b>	Level of Service
<b>LRB:</b>	LRB Public Finance Advisors (Formerly Lewis Young Robertson & Burningham, Inc.)
<b>M:</b>	Million
<b>MW:</b>	Megawatt



## SECTION 1: EXECUTIVE SUMMARY

The purpose of the electrical transmission and substation Impact Fee Analysis (“IFA”) is to fulfill the requirements established in Utah Code Title 11 Chapter 36a, the “Impact Fees Act”, and assist Hurricane City (the City) in financing and constructing necessary capital improvements for future growth. This document will address the appropriate impact fees the City may charge to new growth to maintain the level of service (LOS) as defined in the Impact Fee Facilities Plan, dated May 2025.

- **Impact Fee Service Areas:** The impact fees identified in this document will be assessed within the proposed Service Area, as discussed in **SECTION 3**.
- **Demand Analysis:** A total of 39,883 additional kilowatts (kW) of demand will be generated within the current Service Area in the IFFP planning horizon. See **SECTION 3** for details regarding growth in kW.
- **Level of Service:** The LOS is based on loading to the base rating on substation transformers and system voltage criteria. **Section 3** provides the LOS information used in this analysis. New facilities are designed to maintain the diversified kW LOS.
- **Excess Capacity:** This analysis focuses on the construction of new facilities and does not include a buy-in related to excess capacity within the current system.
- **Capital Facilities Analysis:** The IFFP has identified the growth-related projects needed within the next ten years. The total construction cost related to growth is **\$29M**, based on an inflation rate of four percent annually.
- **Financing of Future Facilities:** This analysis assumes the City will not utilize bond financing to fund future infrastructure.

### SUMMARY OF PROPOSED IMPACT FEES

The impact fees proposed in this analysis will be assessed within the Service Area. The tables below illustrate the calculated impact fee for electric transmission and substation facilities.

**TABLE 1.1: ILLUSTRATION OF COST PER NEW kW**

	TOTAL COSTS	% GROWTH RELATED AND IMPACT FEE FUNDED	GROWTH RELATED & CITY FUNDED COSTS	GROWTH RELATED kW	COST PER NEW kW
Future System Improvements	\$49,006,901	59%	\$29,079,067	39,883	\$729.11
Professional Expense	\$73,925	65%	\$47,900	26,740	\$1.79
Interest Credit	(\$128,000)	100%	(\$128,000)	39,883	(\$3.21)
<b>TOTALS:</b>	<b>\$48,952,826</b>		<b>\$28,998,968</b>		<b>\$727.69</b>

Professional expense is based on the cost to complete the IFFP and IFA.



**TABLE 1.2: ILLUSTRATION OF IMPACT FEE BY PANEL SIZE**

PANEL RATING	LINE-TO-LINE VOLTAGE	100% PANEL KVA	AVG PANEL LOADING	AVG PEAK DEMAND @ PANEL (KVA)	POWER FACTOR	ESTIMATED DIVERSIFIED KW	PROPOSED FEE	EXISTING FEE	% CHANGE
<b>Residential (120/240, 1 phase)</b>									
125	240	30	12.50%	3.75	95%	3.56	\$2,592	\$1,622	60%
200	240	48	12.50%	6.00	95%	5.70	\$4,148	\$2,595	60%
400	240	96	12.85%	12.34	95%	11.72	\$8,528	\$5,190	64%
600	240	144	12.85%	18.50	95%	17.58	\$12,792	\$7,785	64%
<b>Commercial (120/240, 1 phase)</b>									
200	240	48	25.00%	12.00	90%	10.80	\$7,859	\$4,902	60%
400	240	96	25.00%	24.00	90%	21.60	\$15,718	\$9,803	60%
600	240	144	25.00%	36.00	90%	32.40	\$23,577	\$14,705	60%
800	240	192	25.00%	48.00	90%	43.20	\$31,436	\$19,607	60%
<b>Commercial (120/208, 3 phase)</b>									
200	208	72	25.00%	18.01	90%	16.21	\$11,797	\$7,358	60%
400	208	144	25.00%	36.03	90%	32.42	\$23,595	\$14,715	60%
600	208	216	25.00%	54.04	90%	48.64	\$35,392	\$22,073	60%
800	208	288	25.00%	72.05	90%	64.85	\$47,189	\$29,431	60%
1,000	208	360	25.00%	90.07	90%	81.06	\$58,987	\$36,788	60%
1,200	208	432	25.00%	108.08	90%	97.27	\$70,784	\$44,146	60%
1,600	208	576	25.00%	144.11	90%	129.70	\$94,378	\$58,861	60%
1,800	208	648	25.00%	162.12	90%	145.91	\$106,176	\$66,219	60%
2,000	208	721	25.00%	180.13	90%	162.12	\$117,973	\$73,577	60%
2,500	208	901	25.00%	225.17	90%	202.65	\$147,466	\$91,971	60%
3,000	208	1,081	25.00%	270.20	90%	243.18	\$176,960	\$110,365	60%
<b>Commercial (277/480, 3 phase)</b>									
200	480	166	25.00%	41.57	90%	37.41	\$27,225	\$16,979	60%
400	480	333	25.00%	83.14	90%	74.82	\$54,449	\$33,958	60%
600	480	499	25.00%	124.71	90%	112.24	\$81,674	\$50,938	60%
800	480	665	25.00%	166.28	90%	149.65	\$108,898	\$67,917	60%
1,000	480	831	25.00%	207.85	90%	187.06	\$136,123	\$84,896	60%
1,200	480	998	25.00%	249.42	90%	224.47	\$163,347	\$101,875	60%
1,600	480	1,330	25.00%	332.55	90%	299.30	\$217,796	\$135,834	60%
1,800	480	1,496	25.00%	374.12	90%	336.71	\$245,021	\$152,813	60%
2,000	480	1,663	25.00%	415.69	90%	374.12	\$272,246	\$169,792	60%
2,500	480	2,078	25.00%	519.62	90%	467.65	\$340,307	\$212,241	60%
3,000	480	2,494	25.00%	623.54	90%	561.18	\$408,368	\$254,689	60%

A detailed explanation of the increase in the proposed impact fee is in **Section 6** of this report.

**NON-STANDARD IMPACT FEES**

The proposed fees are based upon growth in kW. The City reserves the right under the Impact Fees Act to assess an adjusted fee that more closely matches the true impact that the land use will have upon public facilities.<sup>1</sup> A developer may submit studies and data for a particular development and request an adjustment. This adjustment could result in a higher or lower impact fee if the City

<sup>1</sup> UC 11-36a-402(1)(c)



determines that a particular user may create a different impact than what is standard for its land use. The following formulas will help determine the non-standard impact fee.

**Estimated Diversified kW Usage \* \$727.69**

The formula for a non-standard impact fee should be included in the impact fee enactment (by resolution or ordinance). In addition, the impact fee enactment should contain the following elements:

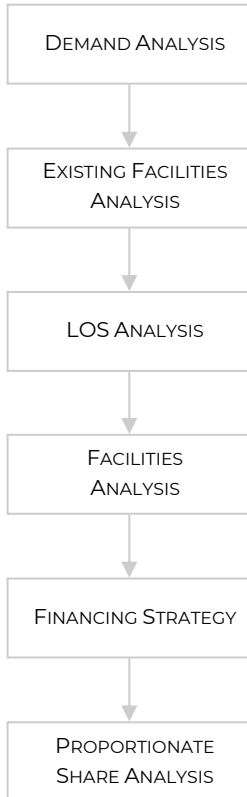
- A provision establishing one or more service areas within which the local political subdivision or private entity calculates and imposes impact fees for various land use categories.
- A schedule of impact fees for each type of development activity that specifies the amount of the impact fee to be imposed for each type of system improvement or the formula that the local political subdivision or private entity will use to calculate each impact fee.
- A provision authorizing the local political subdivision or private entity to adjust the standard impact fee at the time the fee is charged to:
  - Respond to unusual circumstances in specific cases or a request for a prompt and individualized impact fee review for the development activity of the state, a school district, or a charter school and an offset or credit for a public facility for which an impact fee has been or will be collected.
  - Ensure that the impact fees are imposed fairly.
- A provision governing calculation of the amount of the impact fee to be imposed on a particular development that permits adjustment of the amount of the impact fee based upon studies and data submitted by the developer.
- A provision that allows a developer, including a school district or a charter school, to receive a credit against or proportionate reimbursement of an impact fee if the developer:
  - Dedicates land for a system improvement.
  - Builds and dedicates some or all of a system improvement.
  - Dedicates a public facility that the local political subdivision or private entity and the developer agree will reduce the need for a system improvement.
- A provision that requires a credit against impact fees for any dedication of land for, improvement to, or new construction of, any system improvements provided by the developer if the facilities:
  - Are system improvements; or,
  - Dedicated to the public and offset the need for an identified system improvement.

Other provisions of the impact fee enactment may include exemption of fees for development activity attributable to low-income housing, the state, a school district, or a charter school. Exemptions may also include other development activities with a broad public purpose. If an exemption is provided, the entity should establish one or more sources of funds other than impact fees to pay for that development activity. The impact fee exemption for development activity attributable to a school district or charter school should be applied equally to either scenario.



## SECTION 2: GENERAL IMPACT FEE METHODOLOGY

FIGURE 2.1: IMPACT FEE METHODOLOGY



The purpose of this study is to fulfill the requirements of the Impact Fees Act regarding the establishment of an IFFP and IFA. The IFFP identifies the demands placed upon the City's existing facilities by future development and evaluates how these demands will be met by the City. The IFFP is also intended to outline the improvements, which are intended to be funded by impact fees. The purpose of IFA is to allocate the cost of the new facilities and any excess capacity to new development, while ensuring that all methods of financing are considered. The Impact Fee Act requires that the IFFP and IFA consider the historic level of service provided to existing development and ensure that the proposed impact fees maintain the existing level of service. The following elements are important considerations when completing an IFFP and IFA.

### DEMAND ANALYSIS

The demand analysis serves as the foundation for the IFFP and IFA. This element focuses on a specific demand unit related to each public service – the existing demand on public facilities and the future demand as a result of new development that will affect system facilities.

### EXISTING FACILITY INVENTORY

In order to quantify the demands placed upon existing public facilities by new development activity, to the extent possible the IFFP provides an inventory of the City's existing system facilities. The inventory valuation should include the original construction cost and estimated useful life of each facility. The inventory of existing facilities is important to determine the excess capacity of existing facilities and the utilization of excess capacity by new development.

### LEVEL OF SERVICE ANALYSIS

"Level of service" or LOS means the defined performance standard or unit of demand for each capital component of a public facility within a service area. Through the inventory of existing facilities, combined with the growth assumptions, this analysis identifies the existing LOS that is provided to a community's existing residents and ensures that future facilities maintain these standards.

### EXCESS CAPACITY AND FUTURE CAPITAL FACILITIES ANALYSIS

The demand analysis, existing facility inventory and LOS analysis allow for the development of a list of capital projects necessary to serve new growth and to maintain the existing system. This list includes any excess capacity of existing facilities as well as future system improvements necessary to maintain the LOS. Any excess capacity identified within existing facilities can be apportioned to new development. Any demand generated from new development that overburdens the existing system beyond the existing capacity justifies the construction of new facilities.



### **FINANCING STRATEGY**

This analysis must also include a consideration of all revenue sources, including impact fees, future debt costs, alternative funding sources and the dedication of system improvements, which may be used to finance system improvements.<sup>2</sup> In conjunction with this revenue analysis, there must be a determination that impact fees are necessary to achieve an equitable allocation of the costs of the new facilities between the new and existing users.<sup>3</sup>

### **PROPORTIONATE SHARE ANALYSIS**

The written impact fee analysis is required under the Impact Fees Act and must identify the impacts placed on the facilities by development activity and how these impacts are reasonably related to the new development. The written impact fee analysis must include a proportionate share analysis, clearly detailing each cost component and the methodology used to calculate each impact fee. A local political subdivision or private entity may only impose impact fees on development activities when its plan for financing system improvements establishes that impact fees are necessary to achieve an equitable allocation of the costs borne in the past and to be borne in the future (UCA 11-36a-302).

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<sup>2</sup> 11-36a-302(2)

<sup>3</sup> 11-36a-302(3)

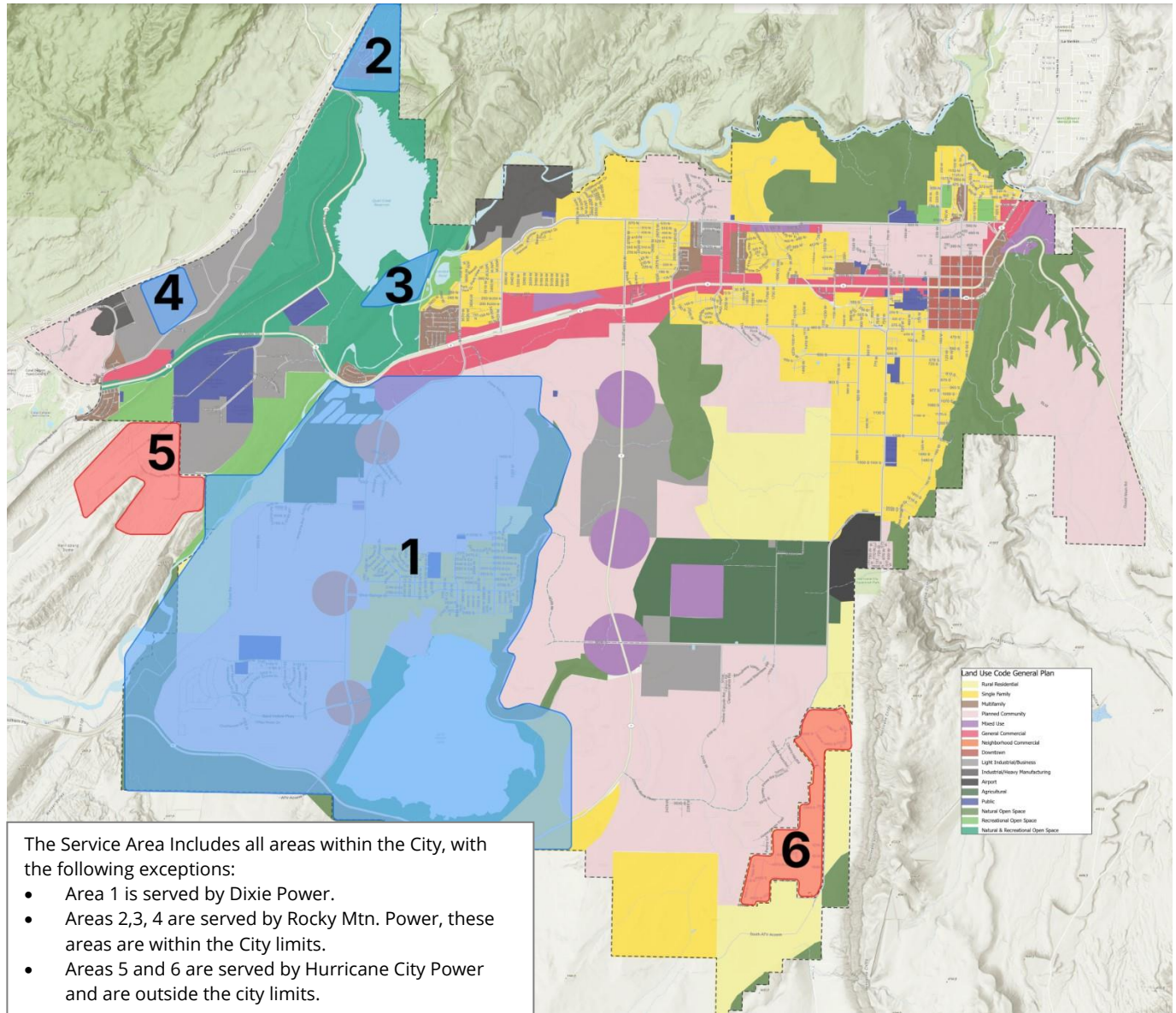


# SECTION 3: SERVICE AREA, DEMAND, AND LOS

## SERVICE AREA

Utah Code requires the impact fee enactment to establish one or more service areas within which impact fees will be imposed.<sup>4</sup> This document identifies the necessary future system improvements for the Service Area that will maintain the existing LOS into the future. According to the 2025 IFFP, the Service Area includes areas within the City boundary as shown in **Figure 3.1**.

**FIGURE 3.1: POWER SERVICE AREA**



<sup>4</sup> UC 11-36a-402(1)(a)



## DEMAND

The City's electrical system requires expansion to maintain the existing LOS as new growth and development activity occurs within the Service Area. To accurately determine the portion of the costs of future capital infrastructure that should be included in the impact fees, this analysis projects the future growth in megawatts (MW) and kilowatts (kW). The demand unit used in the calculation of the electrical impact fees is the estimated MW and kW at a power factor of 95 percent for residential and 90 percent for commercial.<sup>5</sup> **TABLE 3.1** summarizes the projected annual increase in kW within the Service Area.

**TABLE 3.1: PROJECTED DEMAND**

DESCRIPTION	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total System CP Demands (kW)	50,635	54,686	59,061	63,786	68,888	74,399	77,375	80,470	83,689	87,037	90,518
<b>Ten Year Demand</b>	<b>39,883</b>										

It is anticipated that new growth will have an impact on the City's existing services. Electrical facilities will need to be expanded to maintain the existing LOS. The IFFP, in conjunction with the impact fee analysis, are designed to accurately assess the true impact of a particular user upon the City's infrastructure.

## LEVEL OF SERVICE STANDARDS

Impact fees cannot be used to finance an increase in the LOS to current or future users of capital improvements. Therefore, it is important to identify the LOS within the Service Area to ensure that the new capacities of projects financed through impact fees do not exceed the established standard. According to the most recent IFFP, the City plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions must remain below their ONAN/ONFA/ONFA 55-degree rating.
- Dual bay substations loading shall not exceed 75% of combined ONAN/ONFA/ONFA 55-degree MVA rating of power transformers.
- The system must be able to adequately serve load under single contingency (N-1) situations, where "N" is a power system element such as a transformer or line.
- The system switching required under an N-1 contingency should remain as simplified as possible to ensure that switching orders do not become unnecessarily complex.
- Distribution circuit loading criteria must remain below 90% of its maximum current rating.
- Transmission circuit voltage must remain between 95% and 105% of its nominal value.
- Distribution circuit voltage must remain between 98% and 105% (at loads) of its nominal value.
- Distribution circuit mains must be able to serve additional load under N-1 contingencies.

The above criteria were used to determine Hurricane City's facility needs based on the amount of load (i.e., demand) placed on the existing system over the study planning horizon.

<sup>5</sup> Power factor (p.f.) is the ratio of working power, measured in kilowatts (kW), to apparent power, measured in kilovolt amperes (kVA). The power factor of the present system is acceptable, above 0.95. The system power factor is primarily influenced by the types and level of loads on the system and the amount of shunt capacitors installed in the system.



## SECTION 4: EXISTING FACILITIES & EXCESS CAPACITY

This section is intended to summarize the existing public facilities related to electric transmission and substation infrastructure. The IFFP indicates the City is served by PacifiCorp's Purgatory Flat Transmission Substation with two radial 69kV lines, one line feeds Anticline substation and the other line feeds the other three 69kV substations. The radial 69kV line interconnects Hurricane City's four Distribution substations. Hurricane City's electrical system currently has four power distribution substations: Anticline Substation, Brentwood Substation, Clifton Wilson Substation, and Three Falls Substation. It is noted that during the time of this study Three Falls Substation was under construction but was not yet operating. So, the peak loading for Three Falls Substation was estimated.<sup>6</sup>

### VALUE OF EXISTING INFRASTRUCTURE

Based upon data provided by the City using the electric utility depreciation schedule, the existing system is valued at approximately \$42M, based on original cost as shown in **TABLE 4.1**. Generation is excluded from the calculation of buy-in. Project improvements and non-eligible values are excluded from the analysis.

**TABLE 4.1: VALUE OF EXISTING SYSTEM**

<b>Total System Value</b>	\$42,235,807
Eligible Distribution/Transmission	\$4,951,860
Eligible Substations	\$8,240,115
<b>Subtotal of Eligible Value</b>	<b>\$13,191,976</b>
Estimate of Buildout Demand	140,000
IFFP Demand	39,883
<b>% of Total</b>	<b>28%</b>

### EXCESS CAPACITY

The City maintains a network of transmission and distribution infrastructure. **TABLE 4.1** illustrates the value of the system on the proportion that would be assigned to new development, assuming the system benefits all users through buildout. However, this analysis excludes the excess capacity buy-in and instead determines the impact fees to construct only of the electrical projects that are necessary for the next ten years. A percentage of each project will be paid for by impact fees collected after the 10-year period.

### MANNER OF FINANCING EXISTING INFRASTRUCTURE

The City has funded its existing capital infrastructure through a combination of different revenue sources, including user fee revenues, service fees, and impact fees. Therefore, the City's existing LOS standards have been funded by the City's existing residents. The City does not foresee receiving revenues from other entities (i.e., grants, federal or state funds, other contributions, etc.) to fund new facilities.

<sup>6</sup> IFFP p.7. This station is now in operation.



## SECTION 5: CAPITAL FACILITY ANALYSIS

The capital project and engineering data, planning analysis, and other information related to future capital needs can be found in the 2025 IFFP. The accuracy and correctness of this plan is contingent upon the accuracy of the data and assumptions. Any deviations or changes in the assumptions due to changes in the economy or other relevant information used by the City for this study may cause this plan to be inaccurate and may require modification to this analysis to ensure accuracy.

### SUMMARY OF FUTURE CAPITAL FACILITIES

Based upon the projected increase in kW and demand on the system, the City has identified the future capital projects that must be constructed over the next ten years to serve future development. The costs of these projects are summarized in **TABLE 5.1**. The percentage of the total cost that is attributable to growth is based upon the ratio of the capacity available for meeting future growth in the 10-year IFFP demand period to the total capacity provided by the project. All the projects listed in the table below have a life expectancy of more than 10 years.

**TABLE 5.1: SUMMARY OF FUTURE CAPITAL PROJECT COSTS**

Project & Title	Opinion of Cost	Year	Const. Year Cost	% to IFFP Demand	Cost to Growth
Replace Anticline T1	\$1,943,675	2025	\$2,021,422	73.3%	\$1,481,702
New Future Substation 1	\$7,690,408	2027	\$8,650,663		\$6,340,936
Three Falls Substation Bay 2	\$3,728,421	2029	\$4,536,194		\$3,325,030
New Sky Mountain Substation	\$5,503,354	2030	\$6,963,498		\$5,104,244
Three Falls substation Bay 1 Upgrade	\$2,119,390	2032	\$2,900,532	28.5%	\$826,651
New 138kV-69kV Future Substation 2	\$7,195,069	2033	\$10,240,827	28.5%	\$2,918,636
New 138kV line from Purgatory to Future Sub 1	\$6,404,366	2026	\$6,926,962	73.3%	\$5,077,463
New 138kV line from Future Sub 1 to Three Falls	\$3,100,207	2027	\$3,487,311	73.3%	\$2,556,199
New 69kV line to Sky Mountain	\$200,805	2029	\$244,310	73.3%	\$179,079
New 138kV line to 600 North	\$685,450	2031	\$902,005	73.3%	\$661,170
New 138kV line from 600 North to Three Falls	\$1,339,409	2032	\$1,833,074	28.5%	\$522,426
New 138kV line to Future Substation 2	\$210,848	2033	\$300,102	28.5%	\$85,529
<b>Total</b>	<b>\$40,121,402</b>		<b>\$49,006,901</b>		<b>\$29,079,067</b>

According to the 2025 IFFP, the “% to IFFP Demand” percentage was calculated from the ratio of the total estimated growth and the added electrical capacity of the new projects. The electrical capacity of the new substations was determined by using 75% of the 55°C transformer rating which is what each transformer is allowed to be loaded to meet the Level of Service Standard. The total additional capacity added by the proposed substation projects to the system is 54.4 MW. The total estimated growth is 39.883 MW. The corresponding ratio for this approach is 73.3%. Therefore, it is proposed to apply 73.3% of the respective cost of these projects to the impact fees. The other 26.7% of the cost of these projects will be assumed to be captured by impact fees beyond the 10-year window of this current study. The % allocation of the remaining projects were based on a system-wide benefit, with the projects serving existing and future development. Thus the projects are spread across the combined system demand, with the IFFP demand comprising 28.5% of the total.

The projected resource needs for the next several years are detailed in the following paragraphs. The estimated costs of future capital projects are based on historical experience with the system and projected growth patterns for the system.



## SYSTEM VS. PROJECT IMPROVEMENTS

System improvements are defined as existing and future public facilities that are intended to provide services to service areas within the community at large.<sup>7</sup> Project improvements are improvements and facilities that are planned and designed to provide service for a specific development (resulting from a development activity) and considered necessary for the use and convenience of the occupants or users of that development.<sup>8</sup> The Impact Fee Analysis may only include the costs of impacts on system improvements related to new growth within the proportionate share analysis. However, impact fees will be used for the substations, etc. since these are considered system improvements.

## FUNDING OF FUTURE FACILITIES

Future facilities are generally funded using the following resources:

### UTILITY RATE REVENUES

Utility rate revenues serve as the primary funding mechanism within enterprise funds. Rates are established to ensure appropriate coverage of all operations and maintenance expenses, debt service coverage, and capital project needs not related to growth.

### GRANTS AND DONATIONS

The City does not anticipate receiving grants or donations to fund improvements currently contemplated in this IFFP. However, the impact fees will be adjusted if grants become available to reflect the grant monies received. A donor may be entitled to reimbursement for the value of the system improvements funded through impact fees if donations are made by new development. **SECTION 6** further addresses proposed credits available to development.

### IMPACT FEE REVENUES

Impact fees are charged to ensure that new growth pays its proportionate share of the costs for the development of public infrastructure. Impact fee revenues can also be attributed to the future expansion of public infrastructure if the revenues are used to maintain an existing level of service. Increases to an existing level of service cannot be funded with impact fee revenues. Impact fee revenues are generally considered non-operating revenues and help offset future capital costs.

### DEBT FINANCING

In the event the City has not accumulated sufficient impact fees to pay for the construction of time sensitive or urgent capital projects needed to accommodate new growth, the City must look to revenue sources other than impact fees for funding. The Impact Fees Act allows for the costs related to the financing of future capital projects to be legally included in the impact fee. This allows the City to finance and quickly construct infrastructure for new development and reimburse itself later from impact fee revenues for the costs of issuing debt. Debt financing costs are not included in this analysis.

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<sup>7</sup> 11-36a-102(20)

<sup>8</sup> 11-36a102(13)



### **EQUITY OF IMPACT FEES**

Impact fees are intended to cover the costs of system improvements (infrastructure) that relate to future growth. The impact fee calculations are structured for impact fees to fund 100 percent of the growth-related facilities identified in the proportionate share analysis as presented in the impact fee analysis. Even so, there may be years when actual impact fee revenues cannot cover the annual growth-related expenses. In those years, growth-related projects may be delayed, or other revenues such as general utility rate revenues may be borrowed to make up any annual deficits. Any borrowed funds are to be repaid in their entirety through subsequent impact fees.

### **NECESSITY OF IMPACT FEES**

An entity may only impose impact fees on development activity if the entity's plan for financing system improvements establishes that impact fees are necessary to achieve parity between existing and new development. This analysis has identified the improvements to public facilities and the funding mechanisms to complete the suggested improvements. Impact fees are identified as a necessary funding mechanism to help offset the costs of new capital improvements related to new growth. In addition, alternative funding mechanisms have been identified to help offset the cost of future capital improvements.



## SECTION 6: ELECTRICAL IMPACT FEE CALCULATION

The calculation of impact fees relies upon the information contained in this analysis. Impact fees are calculated based on many variables centered on proportionality and LOS. The following paragraph briefly discusses the methodology for calculating impact fees. Impact fees can be calculated using a specific set of costs specified for future development. The improvements are identified in the IFFP as growth-related projects. The total project costs are divided by the total demand units the projects are designed to serve. Under this methodology, it is important to identify the existing LOS and determine any excess capacity in existing facilities that could serve new growth.

### IMPACT FEE CALCULATION

Based on the growth-related projects, as well as the applicable buy-in fee, the cost per new kW is shown in **TABLE 6.1**.

**TABLE 6.1: ESTIMATE OF IMPACT FEE COST PER KW**

	TOTAL COSTS	% GROWTH RELATED AND IMPACT FEE FUNDED	GROWTH RELATED & CITY FUNDED COSTS	GROWTH RELATED KW	COST PER NEW KW
Future System Improvements	\$49,006,901	59%	\$29,079,067	39,883	\$729.11
Professional Expense	\$73,925	65%	\$47,900	26,740	\$1.79
Interest Credit	(\$128,000)	100%	(\$128,000)	39,883	(\$3.21)
<b>TOTALS:</b>	<b>\$48,952,826</b>		<b>\$28,998,968</b>		<b>\$727.69</b>

Professional expense is based on the cost to complete the IFFP and IFA.

The fee per kW is then applied to the general usage statistics for residential and commercial users, as shown in **Table 6.2**. The higher impact fee base cost per kW in this analysis comes from the type of proposed projects in this analysis, the higher cost of system components and the increased costs construction labor since the last analysis was done.

**TABLE 6.2: ILLUSTRATION OF IMPACT FEE BY PANEL RATING**

PANEL RATING	LINE-TO-LINE VOLTAGE	100% PANEL KVA	AVG PANEL LOADING	AVG PEAK DEMAND @ PANEL (KVA)	POWER FACTOR	ESTIMATED DIVERSIFIED KW	PROPOSED FEE	EXISTING FEE	% CHANGE
<b>Residential (120/240, 1 phase)</b>									
125	240	30	12.50%	3.75	95%	3.56	\$2,592	\$1,622	60%
200	240	48	12.50%	6.00	95%	5.70	\$4,148	\$2,595	60%
400	240	96	12.85%	12.34	95%	11.72	\$8,528	\$5,190	64%
600	240	144	12.85%	18.50	95%	17.58	\$12,792	\$7,785	64%
<b>Commercial (120/240, 1 phase)</b>									
200	240	48	25.00%	12.00	90%	10.80	\$7,859	\$4,902	60%
400	240	96	25.00%	24.00	90%	21.60	\$15,718	\$9,803	60%
600	240	144	25.00%	36.00	90%	32.40	\$23,577	\$14,705	60%
800	240	192	25.00%	48.00	90%	43.20	\$31,436	\$19,607	60%
<b>Commercial (120/208, 3 phase)</b>									
200	208	72	25.00%	18.01	90%	16.21	\$11,797	\$7,358	60%
400	208	144	25.00%	36.03	90%	32.42	\$23,595	\$14,715	60%
600	208	216	25.00%	54.04	90%	48.64	\$35,392	\$22,073	60%



PANEL RATING	LINE-TO-LINE VOLTAGE	100% PANEL KVA	AVG PANEL LOADING	AVG PEAK DEMAND @ PANEL (kVA)	POWER FACTOR	ESTIMATED DIVERSIFIED kW	PROPOSED FEE	EXISTING FEE	% CHANGE
800	208	288	25.00%	72.05	90%	64.85	\$47,189	\$29,431	60%
1,000	208	360	25.00%	90.07	90%	81.06	\$58,987	\$36,788	60%
1,200	208	432	25.00%	108.08	90%	97.27	\$70,784	\$44,146	60%
1,600	208	576	25.00%	144.11	90%	129.70	\$94,378	\$58,861	60%
1,800	208	648	25.00%	162.12	90%	145.91	\$106,176	\$66,219	60%
2,000	208	721	25.00%	180.13	90%	162.12	\$117,973	\$73,577	60%
2,500	208	901	25.00%	225.17	90%	202.65	\$147,466	\$91,971	60%
3,000	208	1,081	25.00%	270.20	90%	243.18	\$176,960	\$110,365	60%
<b>Commercial (277/480, 3 phase)</b>									
200	480	166	25.00%	41.57	90%	37.41	\$27,225	\$16,979	60%
400	480	333	25.00%	83.14	90%	74.82	\$54,449	\$33,958	60%
600	480	499	25.00%	124.71	90%	112.24	\$81,674	\$50,938	60%
800	480	665	25.00%	166.28	90%	149.65	\$108,898	\$67,917	60%
1,000	480	831	25.00%	207.85	90%	187.06	\$136,123	\$84,896	60%
1,200	480	998	25.00%	249.42	90%	224.47	\$163,347	\$101,875	60%
1,600	480	1,330	25.00%	332.55	90%	299.30	\$217,796	\$135,834	60%
1,800	480	1,496	25.00%	374.12	90%	336.71	\$245,021	\$152,813	60%
2,000	480	1,663	25.00%	415.69	90%	374.12	\$272,246	\$169,792	60%
2,500	480	2,078	25.00%	519.62	90%	467.65	\$340,307	\$212,241	60%
3,000	480	2,494	25.00%	623.54	90%	561.18	\$408,368	\$254,689	60%

**NON-STANDARD IMPACT FEES**

The proposed fees are based upon growth in kW. The City reserves the right under the Impact Fees Act to assess an adjusted fee that more closely matches the true impact that the land use will have upon public facilities.<sup>9</sup> A developer may submit studies and data for a particular development and request an adjustment. This adjustment could result in a higher or lower impact fee if the City determines that a particular user may create a different impact than what is standard for its land use.

**Estimated Diversified kW Usage \* \$727.69**

<sup>9</sup> UC 11-36a-402(1)(c)



### CALCULATION OF IMPACT FEE INTEREST CREDIT

This analysis calculates projected interest earnings and applies a credit in the fee calculation. The table below illustrates that the proposed impact fee revenue collections compared to impact fee expense, with interest credit applied.

**TABLE 6.3: IMPACT FEE INTEREST CALCULATION**

YEAR	KW	NEW KW	FEE PER KW	PROJECTED REVENUE	PROJECTED EXPENSE	PROJECTED BUY-IN EXPENSE	NET	CUMULATIVE	INTEREST EARNED
2023	50,635								
2024	54,686	4,051	\$728	\$2,947,872	\$0	\$0	\$2,947,872	\$2,947,872	\$29,479
2025	59,061	4,375	\$728	\$3,183,644	(\$1,481,702)	\$0	\$1,701,941	\$4,649,814	\$46,498
2026	63,786	4,725	\$728	\$3,438,335	(\$5,077,463)	\$0	(\$1,639,128)	\$3,057,184	\$30,572
2027	68,888	5,102	\$728	\$3,712,674	(\$8,897,135)	\$0	(\$5,184,461)	(\$2,096,705)	(\$20,967)
2028	74,399	5,511	\$728	\$4,010,300	\$0	\$0	\$4,010,300	\$1,892,627	\$18,926
2029	77,375	2,976	\$728	\$2,165,605	(\$3,504,110)	\$0	(\$1,338,504)	\$573,049	\$5,730
2030	80,470	3,095	\$728	\$2,252,201	(\$5,104,244)	\$0	(\$2,852,044)	(\$2,273,264)	(\$22,733)
2031	83,689	3,219	\$728	\$2,342,434	(\$661,170)	\$0	\$1,681,264	(\$614,733)	(\$6,147)
2032	87,037	3,348	\$728	\$2,436,306	(\$1,349,077)	\$0	\$1,087,229	\$466,349	\$4,663
2033	90,518	3,481	\$728	\$2,533,089	(\$3,004,165)	\$0	(\$471,076)	(\$64)	(\$1)
<b>Total</b>				<b>\$29,022,460</b>	<b>(\$29,079,067)</b>	<b>\$0</b>			

Assumes interest earnings based on one percent interest rate.

### CONSIDERATION OF ALL REVENUE SOURCES

The Impact Fees Act requires the proportionate share analysis to demonstrate that impact fees paid by new development are the most equitable method of funding growth-related infrastructure. See **SECTION 5** for further discussion regarding the consideration of revenue sources.

### EXPENDITURE OF IMPACT FEES

Legislation requires that impact fees should be spent or encumbered within six years after each impact fee is paid. Impact fees collected in the next five to six years should be spent or encumbered on only those projects outlined in the IFFP as growth-related costs to maintain the LOS or to reimburse existing development for excess capacity used. The existing impact fee fund balance is included in this analysis and will be spent on the projects that are shown here that were identified in the prior Impact Fee Facilities Plan (also included in this analysis).

### PROPOSED CREDITS OWED TO DEVELOPMENT

Credits may be applied to developers who have constructed and donated system facilities to the City that are included in the IFFP in-lieu of impact fees. Credits for system improvements may be available to developers up to, but not exceeding, the amount commensurate with the LOS identified within this IFA. Credits will not be given for the amount by which system improvements exceed the LOS identified within this IFA. This situation does not apply to developer exactions or improvements required to offset density or as a condition of development. Any project that a developer funds must be included in the IFFP, if a credit is to be issued.



In the situation that a developer chooses to construct system facilities found in the IFFP in-lieu of impact fees, the decision must be made through negotiation with the developer and the City on a case-by-case basis.

**GROWTH-DRIVEN EXTRAORDINARY COSTS**

The City does not anticipate any extraordinary costs necessary to provide services to future development.

**SUMMARY OF TIME PRICE DIFFERENTIAL**

The Impact Fees Act allows for the inclusion of a time price differential to ensure that the future value of costs incurred at a later date are accurately calculated to include the costs of construction inflation. A four percent annual construction inflation adjustment is applied to projects completed after 2023 (the base year cost estimate).



**EXISTING  
TABLE OF PROJECTS  
PLUS MAP OF  
ADDITIONAL NEEDS  
IDENTIFIED**

**TABLE 5.1: SUMMARY OF FUTURE CAPITAL PROJECT COSTS**

Project & Title	Opinion of Cost	Year	Const. Year Cost	% to IFFP Demand	Cost to Growth
Replace Anticline T1	\$1,943,675	2025	\$2,021,422	73.3%	\$1,481,702
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<b>Total</b>	<b>\$40,121,402</b>		<b>\$49,006,901</b>		<b>\$29,079,067</b>

According to the 2025 IFFP, the “% to IFFP Demand” percentage was calculated from the ratio of the total estimated growth and the added electrical capacity of the new projects. The electrical capacity of the new substations was determined by using 75% of the 55°C transformer rating which is what each transformer is allowed to be loaded to meet the Level of Service Standard. The total additional capacity added by the proposed substation projects to the system is 54.4 MW. The total estimated growth is 39.883 MW. The corresponding ratio for this approach is 73.3%. Therefore, it is proposed to apply 73.3% of the respective cost of these projects to the impact fees. The other 26.7% of the cost of these projects will be assumed to be captured by impact fees beyond the 10-year window of this current study. The % allocation of the remaining projects were based on a system-wide benefit, with the projects serving existing and future development. Thus the projects are spread across the combined system demand, with the IFFP demand comprising 28.5% of the total.



Brentwood  
**H**

Sky Mountain  
**H**

69 KV to  
138 KV Sub  
**H**

Clifton-Wilson  
**H R**

Existing 69 KV  
UAMPs Line

SR-9

600 north

Anticline  
**H**

138/69kv Dual  
Circuits this section

138KV

Shadow Ridge  
**R**

Three Falls  
**H**

Purgatory  
**R**

SR-7

Dixie  
Springs #51  
**D**

1100 west

3000 south

**H**

**CONTRACTOR PRE-QUALIFICATION FORM**

This form is to be completed by electrical contractor/contractor prior to being allowed to take Hurricane City Power's pre-qualification test to become approved to work on and install 15KV high voltage cable and subdivisions electrical systems. This information will be used by Hurricane Power to determine contractors experience and knowledge of working on 15KV high voltage cable and installing electrical systems in subdivisions. Hurricane City will use the information given on this form to decide eligibility of whether the contractor will be allowed to proceed to become a Hurricane City Power approved contractor.

Company Name:

Phone Number:

Permanent Address:

Owner of Company:

Phone Number:

Company's Years in Business:

Company Representative that will be taking test:

Title & Position of Representative:

Phone Number:

Number of Employees:

Utah State License #:

Date of Expiration:

Include photo copy of card and if not stated on card include what type of Card it is. (Required S-200)

Contractor shall have a minimum of three years experience working on and installing 15 KV high voltage cables and subdivision electrical systems. Include on separate sheets, if needed, documentation of such experience. Include jobs completed, where they are located, developers name and phone numbers, size of the project, three phase or single phase system and any other information that may be deemed useful to determine eligibility on being qualified to work on Hurricane Power System.

List of Company's equipment that is used for pulling and installing high voltage electrical cables and equipment:

Hurricane Power will provide a classroom instruction for the contractor's crew supervisors, foremen or other key personnel that may be running jobs after the contractor has been approved and successfully passed all pre-qualification requirements. This class will be to familiarize the contractor and contractor employees on what Hurricane Power expects to see as far as quality of work and standard practices. After taking this class the contractor employees will receive a different card, authorizing them to supervise jobs for the contractor. Hurricane Power will require that one qualified card holder be present on job site at all times. This includes all aspects of the electrical system. (Including trenching and piping) Please include a list of all names of key personnel that would be taking this class. Include names, title/position, number of years with the company and any other work history that may be deemed useful. Attach other sheets as necessary.

Person Completing This Form: \_\_\_\_\_ Title: \_\_\_\_\_  
Signature: \_\_\_\_\_ Date: \_\_\_\_/\_\_\_\_/\_\_\_\_

## **Hurricane City Contractor Pre-qualification Requirements**

1. Contractor must have a S-200 license in the State of Utah and have a minimum of three years documented experience of working on and installing 15KV high voltage cables and subdivision electrical systems.
2. The City of Hurricane Reserves the right to disqualify any contractor that does not fully comply with its codes and specifications, or due to poor workmanship.
3. All pre-qualified contractors shall provide a minimum of one pre-qualified employee on a job site at all times. This is for all aspects of installing any part of the electrical system in a subdivision or for primary equipment and/or wire. This includes all trenching and piping.
4. Pre-qualification testing will be held only at specific times of the year. It is the responsibility of the contractor to contact Hurricane Power to be added to the next test date. In time, the test date will be posted on Hurricane City's website at [www.cityofhurricane.com](http://www.cityofhurricane.com).
5. All contractors that are successfully approved must complete an information form prior to starting any project in the City of Hurricane. The form is available at Hurricane's Power Department office.
6. All contractors will be required to re-submit pre-qualification forms every two years. This may include re-testing if there have been any problems with the contractor not following Hurricane Power Specifications or due to poor workmanship. Any contractors that have not worked on Hurricane City's Power system for two years will be required to go thru the full pre-qualification process again.
7. All contractors pulling wire into a hot piece of equipment are required to schedule with Hurricane Power. Contractor crews shall have equipment set up and ready to pull wire at the scheduled time. If contractor is not set up and ready to start at the scheduled time, Hurricane's Power crew may leave the job site and the contractor will have to re-schedule the wire pull. The contractor may get charged for a second time by Hurricane Power.
8. Hurricane City Power may periodically schedule mandatory training for all pre-qualified contractors and key personnel card holders. Failure to attend these classes may result in disqualification of the contractor's pre-qualified status from Hurricane City.

If our company is pre-qualified and approved, I agree to follow Hurricane Power Specifications. I certify that I meet all pre-qualification requirements and that the information is true and accurate to the best of my knowledge.

Name of Company: \_\_\_\_\_

Name of Company Representative: \_\_\_\_\_

Signature of Company Representative: \_\_\_\_\_

Date: \_\_\_\_/\_\_\_\_/\_\_\_\_

# All Requirements Investigation—June 2025

# Agenda

Review All Requirements  
Contract Key Terms

Guiding Principles for All  
Requirements

Next Steps

# All Reqs Contract Key Terms

25-year term (term should be relatively long to coincide with life of generating assets to be procured (~25+ years))

- Member can buyout earlier ( 5 year notice) but resource procured under all requirements project stay with all requirements project

UAMPS will provide all power supply needs of the member except for **excluded resources**

- Once existing UAMPS resources terminate, procurement responsibility for those resources shifts to UAMPS

New large loads in member territories—agreement by ALL UAMPS members

Member coordination on net metering, energy efficiency, and demand response (necessary for UAMPS to better understand member load)

# All Reqs Contract Key Terms....

**Rate Schedule:** Annual rate schedule based on procured or to be procured w/in budget year all requirements resources and forecast member load

**Treatment of Existing UAMPS Resources:** Existing resources already procured by AR members will be excluded from the rate schedule and invoiced separately via the project based billing structure

# All Reqs Contract Key Terms....

**Voting:** Each AR member shall have one unweighted vote.

- Ability to call for an weighted vote
- AR members votes are weighted based on member forecasted demand (accounting for member's forecasted demand minus member's excluded and existing resources)

**Payment obligations** by a member will be take-or-pay similar to Power Sales Contracts with similar covenants being agreed to by the member

# Guiding Principles in Designing All Requirements Project

All UAMPS Members (All-Requirements & Project-Based) must be treated equitably (governance and operations must not discriminate against one type of UAMPS member over the other).

Members will not have identical perspectives; all-requirements members will need to meet in the middle.

Members will not have the ability to jump in and out of all-requirements unless a “light” version is pursued.

The goal is to make resource procurement by the member an easier, more streamlined process.

It will be up to the members the degree to which “give and take” will be equalized amongst members.

# Next Steps

1

Circulate High Level Talking Points for Governing Bodies

2

High Level Presentation during UAMPS Member Conference

3

Continue Investigation— Focus on Credit Rating (low cost and relative lower effort as compared to drafting contracts; outcome of credit rating analysis will inform contracting structure)

# Project Operations Reports

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JUNE 2025

# UAMPS Summary for May 2025

**River Substation** – Completed monthly Substation and SCADA checks.

**Lower Skyline Substation** – Completed monthly Substation and SCADA checks.

**Millcreek Substation** – Completed monthly Substation and SCADA checks. Completed checks on GCB-022 and GCB- 008.

**Snow Canyon Substation** – Completed checks on breaker GCB-009. Checked SC-367 and capacitor bank.

**Red Hills Substation** – Checked RH – 204 and capacitor bank.

**Hillside Substation** – Checked HS-464 and capacitor bank.

**East Ridge Substation** – Checked ER – 444 and capacitor bank.

**Purgatory Flat 69 kV lines** – Monthly line patrol.

**Fire Call Outs** - None

**Notes:**

# MEMORANDUM

TO: Hunter Project Chairman

FROM: UAMPS Staff

DATE: June 13, 2025

SUBJECT: May 2025 Operations Report

Hunter was restricted for 130 hours for mill overhauls. The equivalent availability was 96% for the month. Budgeted fuel price is \$36.09 per MWh.

Hunter energy breakdown:

Schedule for Participant Load	10,194	MWh
Schedule for Pool	3,467	MWh
Fuel Replacement for Participants	12,498	MWh

The web file portal contains a summary of fuel and plant statistics for the previous twelve months.

# HUNTER PROEJCT

- To approve the Hunter Project being bid and scheduled into EDAM as a unified project, as presented and discussed.

# MEMORANDUM

TO: Nebo Project Chairman  
FROM: UAMPS Staff  
DATE: June 13, 2025  
SUBJECT: May 2025 Operations Report

Nebo energy breakdown:

Generation for Participant Load	64,095	MWh
Generation for Off-System Sales	9	MWh
Generation for Pool	13,432	MWh
Fuel Replacement for Participants	2,115	MWh

Nebo burned 659,055 MMBtu of locked gas. The equivalent average Index price was \$2.23/MMBtu.

The cost of the Locked gas / price differential compared to Index priced gas was \$731,800.

Nebo sales margins:

Off-System Sales	\$200
Pool Sales	<u>\$145,000</u>

# NEBO PROJECT

- Approve Option #1 – UDOT Transmission Outside Engineering Services Reimbursement Agreement as presented. (*Carryover item from May 2025 Committee Meeting*).
- Approve the Nebo Project being bid and scheduled into EDAM as a unified project for a 6-month period, after go live date, at which time the Committee will re-evaluate the bidding strategy.
- Approve the Spanish Fork Pole Replacement & Easement Release as presented.

# MEMORANDUM

TO: Firm Power Supply Project Chairman

FROM: UAMPS Staff

DATE: June 13, 2025

SUBJECT: May 2025 Operations Report

UAMPS' output from the Pleasant Valley Wind resource was 2,399 MWh. Peak share of output was 12.6 MW. Capacity factor was 21%.

Red Mesa Solar generated 21,069 MWh for UAMPS. Peak UAMPS output was 66 MW. Capacity factor was 43%.

Steel A Solar generated 11,774 MWh. Peak output was 40.3 MW. Capacity factor was 40%.

Steel B Solar generated 11,235 MWh. Peak output was 40.0 MW. Capacity factor was 38%.

90 MWh were scheduled from the Patua resource.

39,480 MWh were scheduled per the 5-Year group purchase at an average price of \$23.04/MWh.

8,928 MWh were scheduled per various member purchases.

14,215 MWh were scheduled from the Sunnyside resource. Peak schedule was 29 MW. Capacity factor was 66%.

# Pool Memorandum

**To:** Pool Project Chairman

**From:** Kelton Andersen

**Date:** June 13, 2025

**RE:** [UAMPS May 2025 Pool Operations Report](#)

- [Unplanned pool energy for May 2025 was 84,387 MWh](#)
- [The average Unplanned pool energy price was \\$30.1/MWh](#)
- [All-In pool energy for May 2025 was 845 MWh](#)
- [The average All-In pool energy price was \\$34/MWh](#)
- [UAMPS May 2025 load peak was 1035 MW, a 22.9% increase over last year](#)
- [UAMPS May 2025 energy load was 431,156 MWh, a 7.9% increase over last year](#)

# POOL PROJECT

- Approve Budget Amendment #1 - a decrease to the FY2026 transmission rate of \$0.25 per MWh, or \$1.04M in total, which reflects a decrease to the Network Transmission Rate, as presented.
- Approve the UAMPS PCC2 Marketing Agreement CEC Mercuria Contract, as presented.

# POWER COUNTY POWER PROJECT

- Approve a Resolution relating to the Power County Power Project; authorizing and delegating authority to the Project Management Committee to establish a maximum target price for cost of energy and dates to determine the cost of energy, and related matters, as presented.

# MILLARD COUNTY POWER

- Approve moving forward with Option 2 – Millard County Power Project to roll the total study project costs of \$207,357 into the MCPP financing allowing the study revenues of \$535,800 to be returned to the participating Members as presented. (*Carryover item from May 2025 Committee Meeting*)
- Approve a Resolution relating to the Millard County Power Project; Establishing maximum target price for Cost of Energy and establishing dates to determine the target price based on Project development milestones; and related matters, as presented.
- Approve a Resolution relating to the Millard County Power Project; Delegating Authority to the Project Management Committee to approve purchase orders for long lead materials; and related matters, as presented.

# MEMORANDUM

TO: CRSP Project Chairman

FROM: UAMPS Staff

DATE: June 13, 2025

SUBJECT: May 2025 Operations Report

UAMPS scheduled the CRSP resource at 63% capacity factor with a 40 MW maximum. Energy totaled 18,842 MWh. The average energy plus capacity price is \$38.1 per MWh.

UAMPS scheduled	0	MWh for Provo River
UAMPS scheduled	1,189	MWh for Olmsted

# MEMORANDUM

TO: IPP Project Chairman

FROM: UAMPS Staff

DATE: June 13, 2025

SUBJECT: May 2025 Operations Report

UAMPS scheduled IPP at minimum MW most of the month due to limited coal supply, with ramping to the maximum available on some peak hours. There was one coal unit online all month. UAMPS has a summer callback of 73 MW of coal capacity; half of that with one unit online. There has been some testing of the new gas units, but UAMPS is not taking any MW of the test energy. The IPP project scheduled 10,228 MWh of energy during the month. The ~~equivalent availability~~ capacity factor was 19%.

# CENTRAL ST. GEORGE

- To approve the Settlement Agreement, subject to approval of the easement alignment, as presented. (Carryover item from May 2025 Committee Meeting)

# MEMORANDUM

TO: Natural Gas Project Chairman

FROM: UAMPS Staff

DATE: June 13, 2025

SUBJECT: May 2025 Operations Report

UAMPS scheduled 684,875 MMBtu through the Natural Gas Project during the month.

Natural Gas Scheduled:

Nebo Gas	659,055	MMBtu
Hurricane Gas	0	MMBtu
Plumas Gas	21,700	MMBtu
Santa Clara Gas	1,960	MMBtu
Springville Gas	1,060	MMBtu
Washington Gas	1,100	MMBtu

# MEMORANDUM

TO: Horse Butte Wind Project Chairman

FROM: UAMPS Staff

DATE: June 13, 2025

SUBJECT: May 2025 Operations Report

Horse Butte Wind generated 9,885 MWh. Peak output was 54.5 MW. Capacity factor was 23%.

# Board of Directors


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Rachel Stanford

# PacifiCorp Weather Station Website



- WRF – Weather Research Forecast
- EC – European model
- NBM – National Blend Model
- HRRR – High-Resolution Rapid Refresh


**WEATHER AWARENESS SYSTEM**
All Stations
Map

Filter by State 
 Region 
 Company 
 Service Area 
 Station Type

Station	Region	Wind	Gust ▲	Direction	Temp	Humidity
I80 - Halleck Ridge	WY - Southeast	17 mph	34 mph	W	61°F	50%
I-15 at Beaver	UT - Southwest	23 mph	31 mph	N	78°F	12%
Red Butte	UT - Southwest	20 mph	30 mph	NNE	81°F	13%
Point of the Mountain (I-15 Alpine)	UT - Wasatch Front/West Desert	15 mph	29 mph	NE	78°F	27%
Cedar Fort	UT - Wasatch Front/West Desert	15 mph	29 mph	N	79°F	18%
MWSUT2 Big Mountain	UT - Southwest	18 mph	29 mph	NNE	70°F	18%
Mws Ut4 Nephiwest	UT - Southwest	19 mph	28 mph	NE	74°F	24%
Pilot Hill	WY - Southeast	15 mph	27 mph	E	56°F	74%

**CURRENT CONDITIONS**

**TOP GUSTS**

- I80 - Halleck Ridge 34 mph
- I-15 at Beaver 31 mph
- Red Butte 30 mph
- MWSUT2 Big Mountain 29 mph
- Point of the Mountain 29 mph

**TOP NOTEWORTHY GUSTS**

- McCammom Interchange I-15 24 mph
- Spring City East 26 mph
- Border Summit 23 mph



# EDAM WORKSHOP

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June 17, 2025

# Training Topics

- CAISO and PacifiCorp policy update
- What are the new market principles under EDAM?
- What is Resource Sufficiency Evaluation
  - What does the Pool look like under EDAM?
- How to best utilize UAMPS portfolio under EDAM?
- What changes are needed to scheduling protocols to meet EDAM scheduling timeline?
- What does billing look like under EDAM



# Policy Update

- **CAISO has the overall EDAM tariff requirement**
  - December 20, 2023 FERC approved the majority of the EDAM tariff
  - June 11, 2024 FERC approved the EDAM Access Charge
- **A Balancing Area Authority (BAA) must have FERC approve updates to their own tariff to participate in EDAM**
  - April 2024 PacifiCorp signed an EDAM Implementation Agreement
  - January 16, 2025 PacifiCorp filed a revised tariff revision to implement EDAM with a two-step congestion revenue allocation approach
  - Significant protests filed with FERC, including UAMPS
    - Focused on congestion allocation and Resource Sufficiency Evaluation (RSE)

# Policy Approach (cont.)

- **Questions on congestion allocation spurred an accelerated stakeholder process at the CAISO**
  - The final draft proposal is not optimal but provides a path forward
- **CAISO has not yet provided EDAM business practice manuals for review**
- **PacifiCorp is waiting for FERC response to PacifiCorp's response on FERC's deficiency letter**
  - Several entities continuing to file comments
  - Anticipate FERC response in June
  - Will likely provide additional clarity on congestion revenue allocation and Resource Sufficiency Evaluation

# EDAM ELEMENTS

Asset  
Registration

Resource  
Sufficiency  
Evaluation

Resource  
Participation

Load  
Participation

Transmission

Congestion  
Allocation

Settlements

# EDAM Platform

- **EDAM concept is that an analysis is made of resources in participating balancing area authorities**
  - Based upon transmission availability, losses, and resource bids, the most economic dispatch of resources is selected
  - In some cases, resources must run via a self schedule (take-or-pay PPAs, non-dispatchable resource)
- **UAMPS must ensure resource adequacy to serve its load and imbalance reserves**
  - PacifiCorp will impose a fine to UAMPS for not meeting Resource Sufficiency requirements which would get sub-allocated to the members
  - UAMPS position is that resources will be acquired on a day-ahead basis at the latest – members who are not resource sufficient will pay for the day-ahead purchase, similar to the pool today

# EDAM Platform (cont.)

- **UAMPS' resources, loads, and transmission are all submitted to the market**
  - Resources can be self-scheduled or bid
- **EDAM will economically dispatch the generation fleet to serve all load, not individual generation to individual loads**
  - Members save money whenever a cheaper resource serves their load
  - Members make money anytime their resources are dispatched above their bid to serve load
- **Congestion separates prices between generation and load**
  - Ideally a portion of congestion revenue flows back to UAMPS members – this is the subject of UAMPS concerns in CAISO and PacifiCorp tariffs

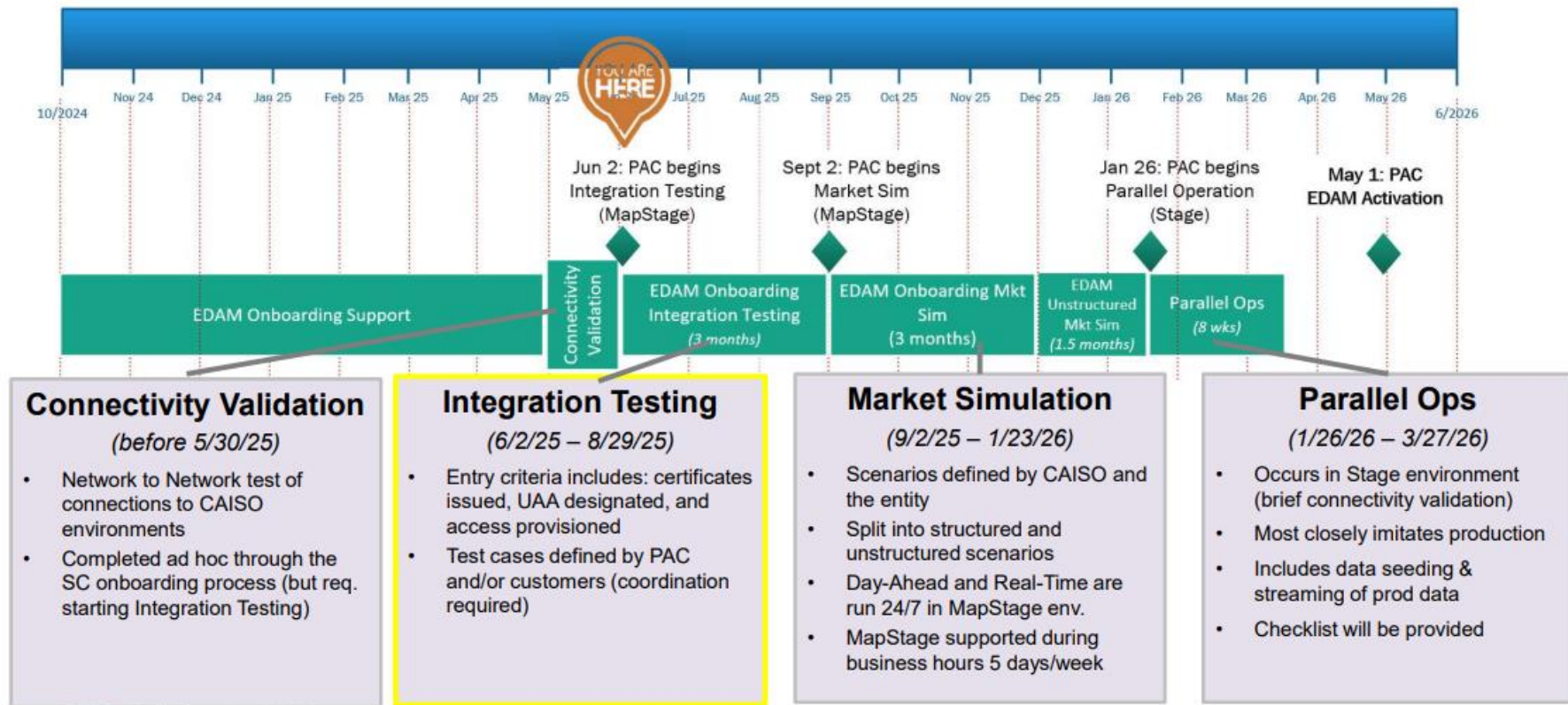
# EDAM Operations / Settlements

- Day Ahead
  - Submit schedules for resources and load EVERY day
    - WECC scheduling calendar no longer applies for EDAM Operations
  - **Resource Sufficiency Evaluation**
- Market Day
  - Generation is paid **the Locational Marginal Price (LMP)**
  - Load is charged the **External Load Aggregation Point (ELAP)** price
- Settlements
  - Multiple **Settlements** per day
  - Shadow settlements validate settlements from CAISO
  - Billed every seven (7) days – UAMPS planning to utilize lines of credit between CAISO/PAC invoicing and the UAMPS member invoicing



# PAC/CAISO EDAM Onboarding and Testing

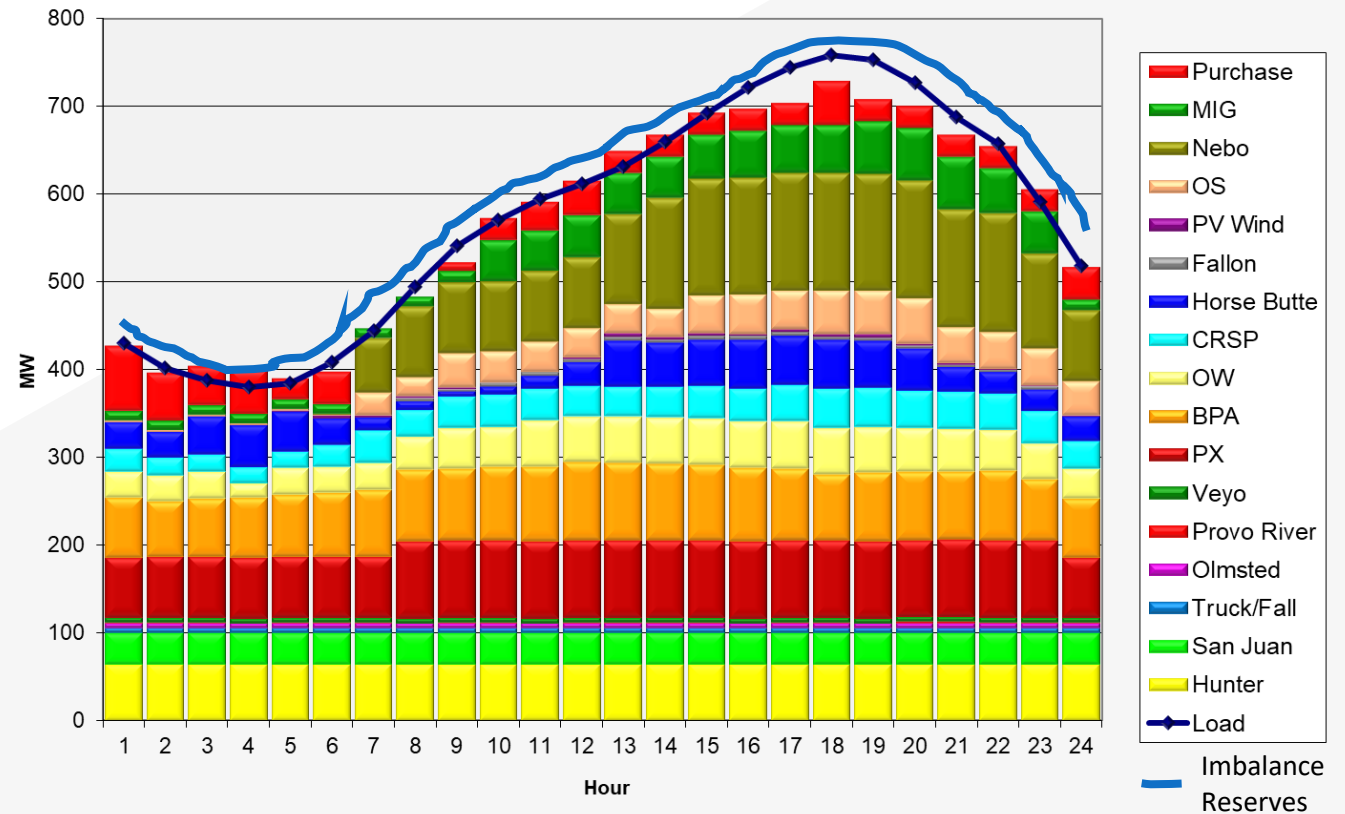
## EDAM Onboarding Timeline Review



# Resource Sufficiency Evaluation

- UAMPS will need to offer in enough resources day-ahead to meet load and imbalance reserves
- Imbalance Reserves are based on historical uncertainty between day-ahead and real-time

UAMPS Load and Resources - May 18, 2021



# Resource Sufficiency Evaluation Formula

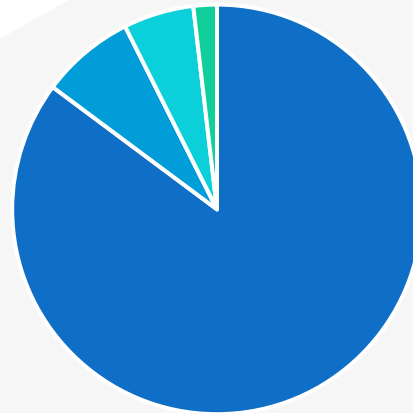
$$\text{Resource Sufficiency Evaluation} = \text{Day-Ahead Expected Load Forecast} + \text{Imbalance Reserves} + \text{Ancillary Services}$$

- Resource Sufficiency Evaluation:
  - Balancing Authority level test - PacifiCorp is responsible for passing
  - Evaluates sufficiency across 24-hour horizon
  - PacifiCorp will sub-allocate requirements to LSEs within their balancing area
    - Sub-allocation will be based upon UAMPS 3-year average pro rata share of the balancing area authority load
    - In some cases, the requirement could be larger than UAMPS forecasted load for the following day
- Load Forecast: load and variable energy resource forecasts are either created by CAISO or submitted by PacifiCorp (on behalf of UAMPS)
- Imbalance Reserves: requirement is based on the historical uncertainty between day-ahead and real-time – UAMPS may be sub-allocated a portion of PacifiCorp’s imbalance reserves requirement
- Ancillary Services: purchased from PacifiCorp

# Resource Sufficiency Evaluation Allocation


- Resource Sufficiency Evaluation Requirement:
  - Resource Sufficiency Evaluation requirements are governed by the UAMPS SQMD load calculation
  - PacifiCorp position - only resources in the CAISO full network model qualify to show resource sufficiency
  - Resources not in the full network model reflect as negative load, reducing the load requirement
  - Currently working on questions for PacifiCorp regarding qualifying resources
  - UAMPS plan is to have an allocation for member resource sufficiency similar to the PacifiCorp requirement of UAMPS
    - Member loads over the last 3 years will be used to allocate the resource sufficiency requirement that UAMPS is given

Sub-allocation of Resource Requirement



■ PacifiCorp ■ UMPA/Deseret ■ UAMPS ■ Member A

# Resource Participation



All resources in PAC's network model must participate in EDAM  
Smaller or grandfathered behind the meter resources are considered negative load

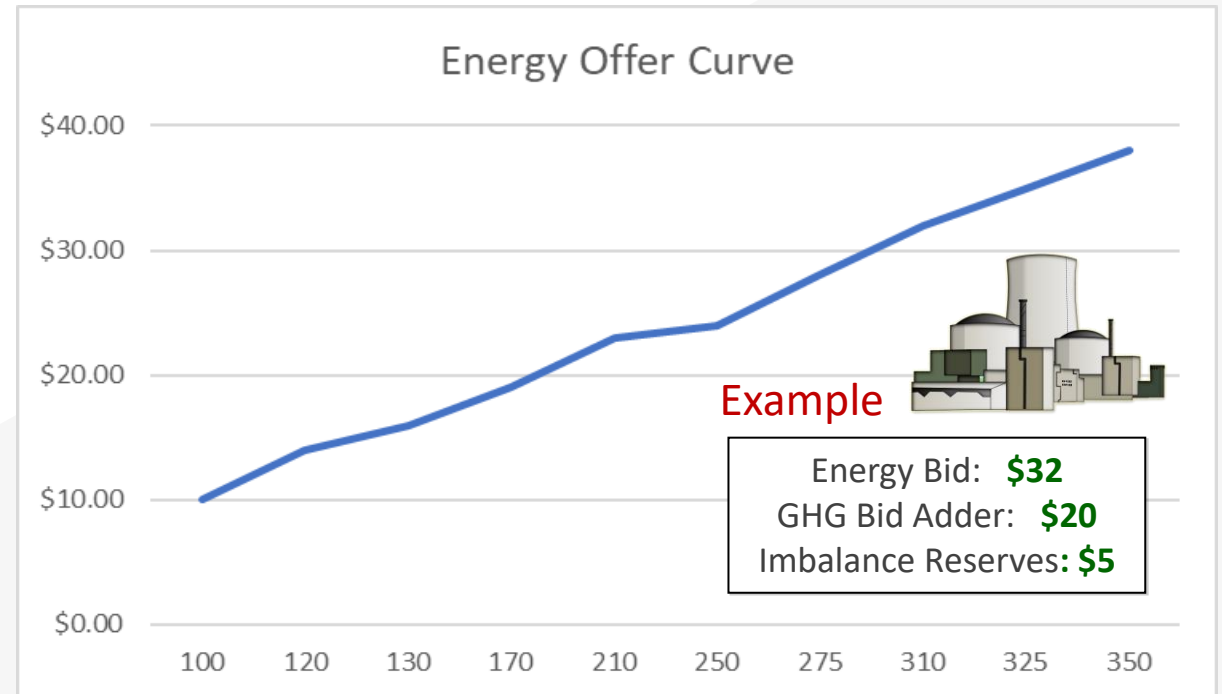
Requires a Scheduling Coordinator  
TEA will be UAMPS Scheduling Coordinator

Bidding means you receive a dispatch target and are required to follow instructions  
Self-scheduled resources must follow their schedule or get charged imbalance

Operational control of the resources remains with UAMPS and its members

# Resource Participation

- Economic offers or self-schedules (price-taker) for all UAMPS resources will be submitted to the CAISO
  - Before 10am day-ahead for 24 hours of the next operating day
  - Before 75 min for the next operating hour
- Offers are submitted for:
  - Energy
  - Flexibility products



PRICE	\$10.00	\$14.00	\$16.00	\$19.00	\$23.00	\$24.00	\$28.00	\$32.00	\$35.00	\$38.00
MW	100	120	130	170	210	250	275	310	325	350

# UAMPS Portfolio Participation at Go-live

## Self-Schedule

- CRSP & WRP (*TBD*)
  - Project and non-Project Participants
- IPP (*TBD*)
- MIGs (none bidding at go-live)
- Veyo
- Red Mesa
- Steel Solar 1A & 1B
- Horse Butte Wind
- Sunnyside
- Bilateral Market Purchases

## Bid

- Nebo (*recommendation*)
- Hunter (*recommendation, pending outcome of allocator discussion with PacifiCorp*)

# Nebo and Hunter

- UAMPS staff recommends Nebo and Hunter each participate as a single bid-in resource
  - Both units will have a blend of self-scheduling for contract purposes and economic bids
    - Minimum Nebo operations for prepay gas
    - Hunter minimum will need to be scheduled
- Most economic solution will be the same for all members
  - Resource participates as a whole
    - Resource allocation of cost and awards is split by ownership entitlement
- Other options introduce economic risk and settlement issues

# CRSP

- **CRSP scheduling still needs to be worked out**
  - Transition to SPP RTO expansion is affecting WAPA product offering for future, specifically WRP
  - UAMPS has initiated meetings with WAPA, however more are in the works
- WAPA is preparing not only for EDAM but for SPP RTO Market expansion
  - WAPA will no longer offer hourly WRP (but still available day ahead)
  - WRP may cost more due to the structure of the RTO
  - UAMPS investigating use of the WAPA Transmission for Non-WAPA bilateral purchases up to available CROD
    - Logistics - transmission identifier, point of receipt (Glen Canyon or Vernal)
- Annual Hydro Power
  - No Changes
  - Current changes need to be made 3 days in advance



# IPP

- IPP Participation will likely come with LADWP's entry into EDAM
- IPP is in LADWP's Balancing Area
  - It will be treated as import daily into PACE's system
  - UAMPS developing strategy for optimization to present to members
    - Gas, energy, and capacity benefit
- IPP participation under the current model would require a pseudo-tie between PAC and LADWP
  - Timing for this event to take place is 18 months from pencils down on the agreement
- LADWP is currently planning on entering the EDAM market in 2027
  - Members' share of IPP will be participating in the market when LADWP goes live
  - Strategic decisions in the future to take advantage of the members' full entitlement shares



## EXAMPLE 1: NEBO

### UAMPS' cost to run NEBO is \$40/MWh for HE13 and HE19.

- **HE13:** There is oversupply solar from California during HE13 that sets the marginal price at **\$5/MWh**.
  - UAMPS load pays **\$5/MWh** for every MW of load.
  - NEBO didn't get dispatched. UAMPS **saved \$35** for every MW NEBO didn't run.
- **HE19:** As the sun goes down in California, the load gets served by higher priced resources and the price reaches **\$55/MWh**.
  - UAMPS load pays **\$55/MWh**.
  - NEBO gets dispatched and gets paid **\$55/MWh**. UAMPS **made \$15/MWh** for every MW NEBO ran surplus to UAMPS load needs.

## EXAMPLE 2A: PPA External to PAC

UAMPS pays \$50/MWh for a PPA  
outside the PAC BA bilaterally.

- The PPA self-schedules for HE10 and the price at the PAC interface is **\$30/MWh**. UAMPS gets paid **\$30/MWh**.
- There is no congestion between the PPA and UAMPS load so the UAMPS load price is **\$30/MWh**. UAMPS pays **\$30/MWh** for its load.
- UAMPS paid **\$80/MWh** (**\$50/MWh** for the PPA and **\$30/MWh** for its load) and got paid **\$30/MWh** (for the PPA in the market), netting the original **\$50/MWh** it paid to the PPA.

## EXAMPLE 2B: PPA External to PAC

- The PPA self-schedules for HE10 and the price at the PAC interface is **\$30/MWh**. UAMPS gets paid **\$30/MWh**.
- There is congestion between the PPA and UAMPS load so the UAMPS load price is **\$40/MWh**. UAMPS pays **\$40/MWh** for its load.
- Let's say UAMPS doesn't get paid congestion revenue based on PAC's rules.
- UAMPS paid **\$90/MWh** (**\$50/MWh** for the PPA and **\$40/MWh** for its load) and got paid **\$30/MWh** (for the PPA in the market), netting **\$60/MWh**.

# Direct Load Participation Example

## LOAD

UAMPS Load is 500 MW for HE 9

- UAMPS buys 450 MW of its load Day-Ahead at \$100
  - $450 \text{ MW} \times \$100/\text{MWh} = \$45,000$
- UAMPS buys remaining 50 MW load in Real-Time at \$90
  - $50 \text{ MW} \times \$90/\text{MWh} = \$4,500$
- **UAMPS paid \$49,500 for its load.**
  - Saved \$10/MWh for 50 MW = **\$500**

## RESOURCES

UAMPS Resources get dispatched for 500 MW Day-Ahead

- The Day-Ahead clearing price is \$100
- No additional dispatch of resources in real-time
- **UAMPS resources get paid \$50,000**

# Members Scheduling Timeline

- Utilize current Member Portal
- UAMPS will continue status-quo scheduling on behalf of some members
- Sunset and revise current Pooling Appendices to meet new EDAM timeline

# Members Scheduling Timeline (cont.)

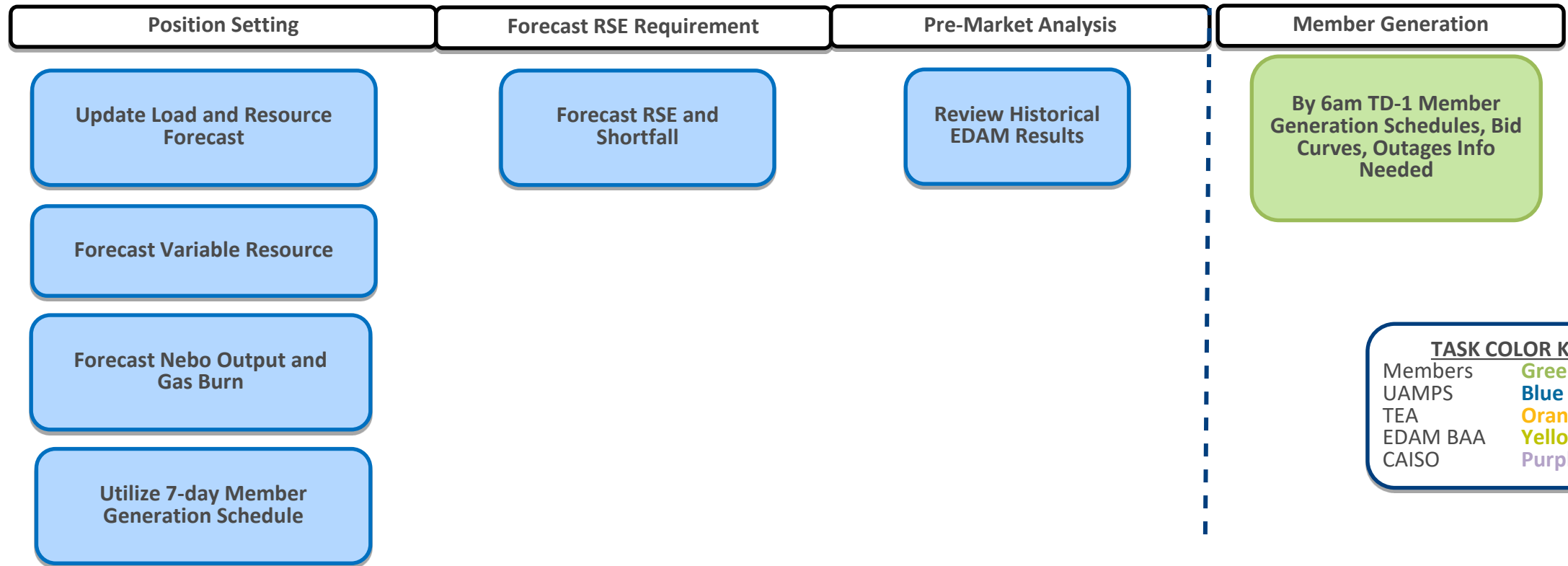
## Current Appendix Timeline

- Longer than 1-month transactions
  - By 10 am, 7 business days prior to the beginning of the month
- Monthly transactions
  - By 10 am, 7 days prior to the scheduling day
- Day-ahead transactions
  - Changes by 9 am 2 business days prior to the day transacted and 3 business days for CRSP
- Hourly transactions
  - 2 hours prior to the scheduling hour

## EDAM Timeline

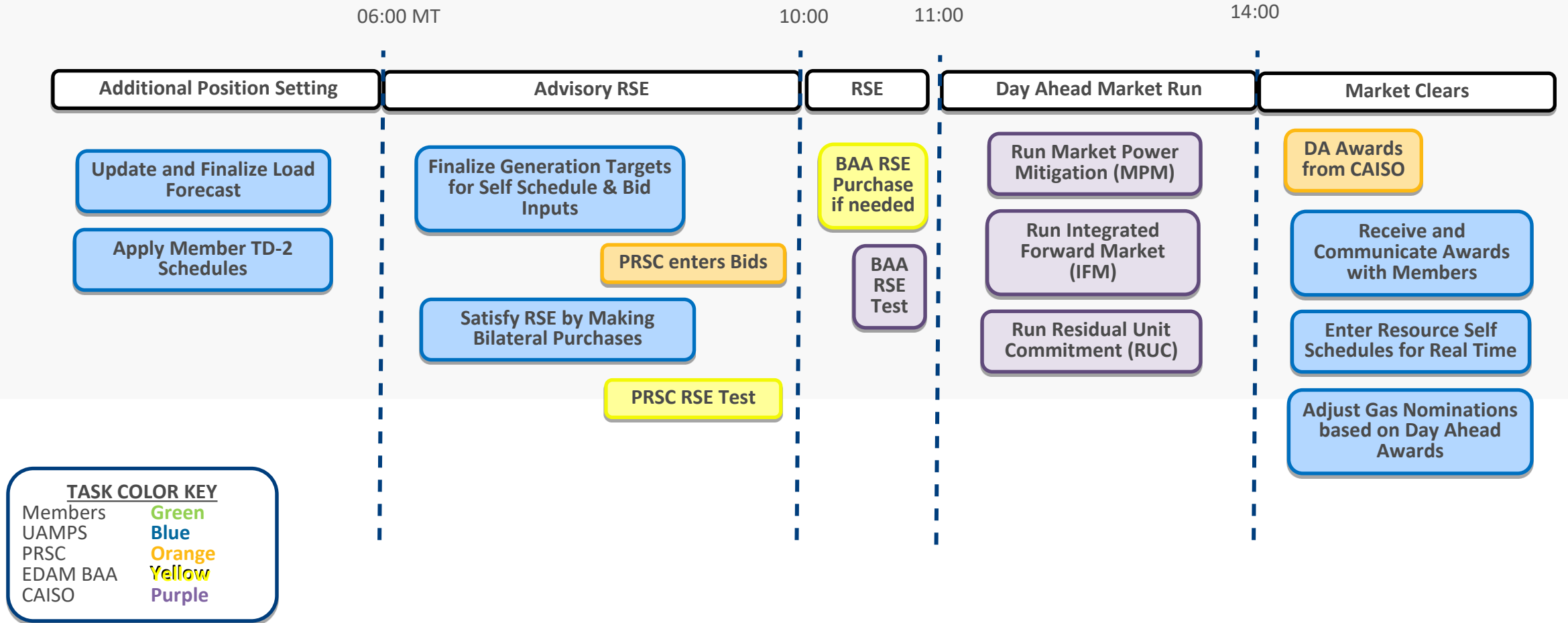
- Longer than 1-month transactions
  - By 10 am, 7 business days prior to the beginning of the month
- Monthly transactions
  - By 10 am, 7 days prior to the scheduling day
- Day-ahead transactions
  - **Changes by 6 am 2 business days prior to the day transacted and 3 business days for CRSP**
- Hourly transactions
  - **No longer applicable**

18:00

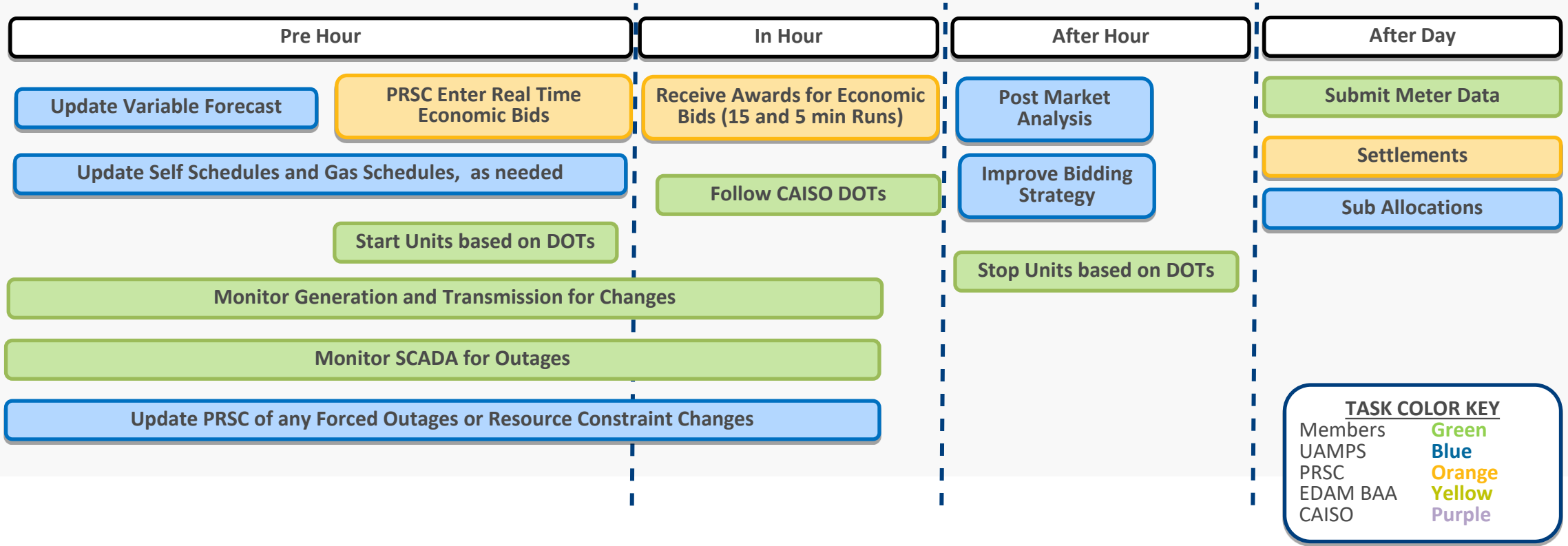


**TASK COLOR KEY**

Members	Green
UAMPS	Blue
TEA	Orange
EDAM BAA	Yellow
CAISO	Purple



Hourly Real Time (TD)



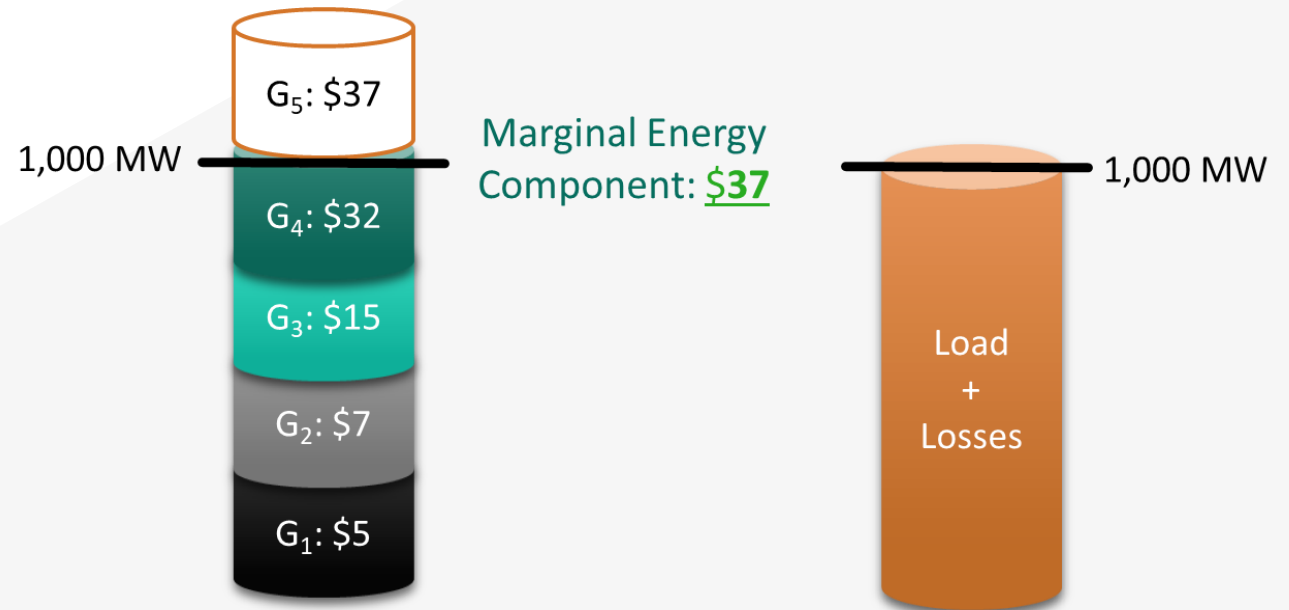


- Locational marginal prices (LMPs) are calculated for every price node
- Generators get paid at the generation bus LMP
- Loads pay at load bus LMP

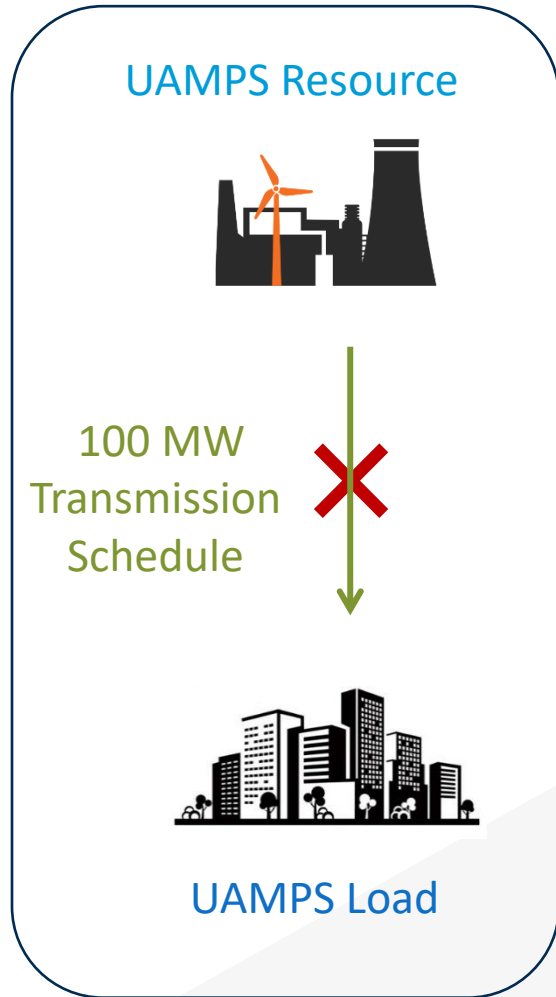
# Locational Market Prices



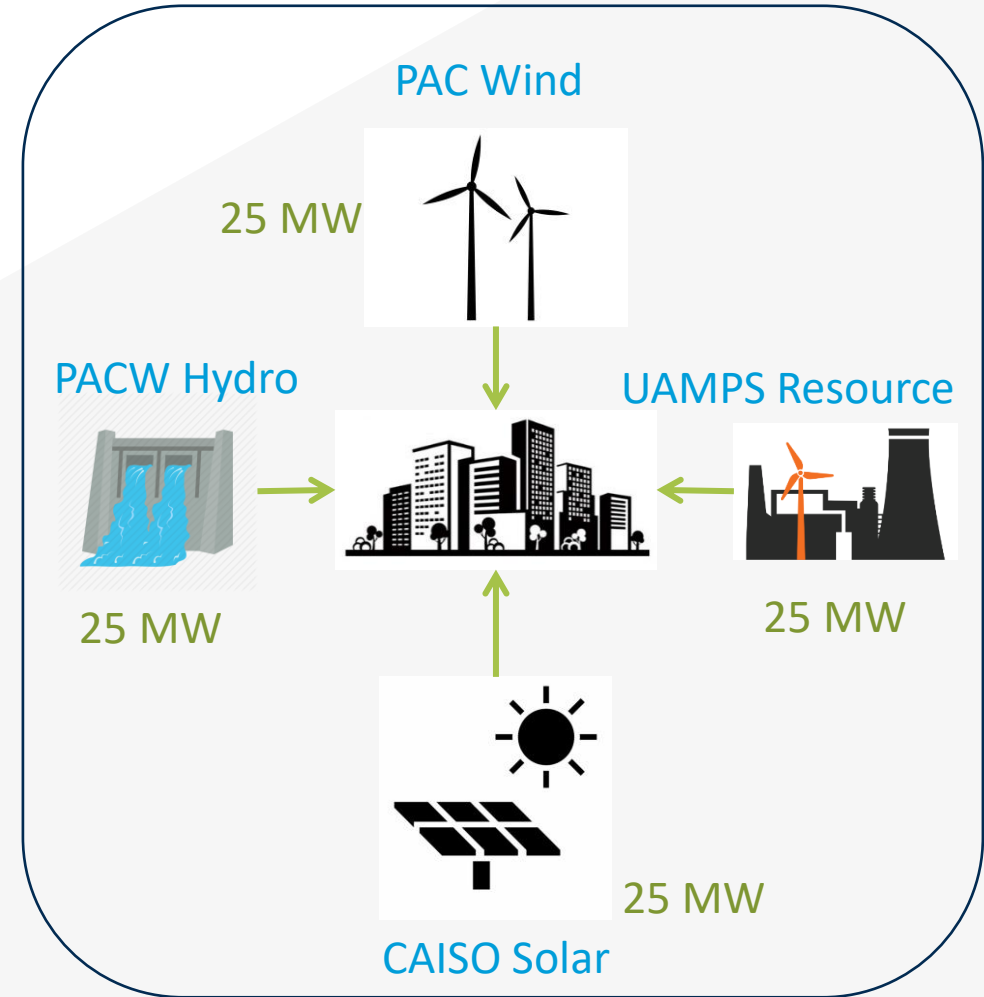
- Represents marginal cost of Energy
- Marginal Energy Price is same for all price nodes
- Price differences between nodes reflect the cost of losses and congestion



# Transmission



- UAMPS will no longer schedule generation to its PACE load on its transmission rights
- UAMPS' transmission rights internal to the PacifiCorp BA get made available to EDAM (some exclusions)
- EDAM will economically dispatch the generation fleet to serve all load, not individual generation to individual loads



# Congestion Revenue



- All transmission rights are made available to the market
- Transmission congestion occurs when the lowest-priced energy can't reach areas of high load, causing price separation
- The price difference between nodes is considered congestion revenue

# Congestion Allocation

- EDAM is not an RTO – PacifiCorp will maintain its Transmission Service Provider function
- Congestion revenues are still collected by CAISO as a function of least-cost dispatch
- CAISO must remain revenue neutral and therefore will distribute congestion revenues to PacifiCorp, who will determine how to sub-allocate them to UAMPS
- It will be important that PacifiCorp sub-allocates congestion revenues in a manner that allows UAMPS to hedge their congestion exposure

# TSOA

- Investigating different congestion revenue impacts, depending upon firm/non-firm transmission
- Identifying potential changes in the TSOA to help ensure the return of congestion revenue
- Completing comparison analysis to understand EDAM tariff requirements with our current TSOA rights

# Working Capital Requirements

- As a result of more frequent billing (weekly) from the CAISO, UAMPS staff is reviewing working capital requirements
- Parallel operations early next year will provide insight into the anticipated invoice amounts
- UAMPS will adjust lines of credit accordingly to account for anticipated swings in invoicing
- Rate stabilization accounts (similar to the EIM account) may be necessary, depending upon the magnitude of swings in the invoices

# Settlements

- Current plan is to continue member invoices by project as is done today
- There will be an additional line item to identify the net EDAM impact
- Additional supporting documentation (e.g. Excel file) will provide the breakdown of the EDAM and PacifiCorp charges