Power Board Meeting Agenda

8/6/2025

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 July 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
2. Update regarding **Impact Fee Analysis & Capital Facilities Plan Amendment –** Mike Johns

NEW BUSINESS

1. Discussion and possible recommendation to the City Council regarding **Updated Power Connection Fee Schedule –** Mike Johns
2. Discussion and possible recommendation to the City Council regarding **Analog Meter Rate –** Mike Johns
3. Discussion and possible recommendation regarding **AMI Metering Opt-Out –** Mike Johns
4. UAMPS Updates
5. **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

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

In attendance were Mac Hall, Dave Imlay, Colt Stratton, Kerry Prince, Mark Maag, Mike Johns, Brian Anderson, Mike Ramirez, Jared Ross, Nanette Billings, Dayton Hall, Kaden DeMille, Mike Vercimak, Weston Walker, Fred Resch, Bruce Zimmerman and Crystal Wright.

Mac Hall welcomed everyone to the meeting. Mark Maag led the Pledge of Allegiance and Mac Hall offered the prayer. Mac Hall made a motion to approve minutes from the June 2025 meeting. Dave Imlay seconded the motion. Motion passed unanimously.

Mike Johns: Mike Johns mentioned we are looking to hire an Electrical Engineer. We are still working out the details, but it is something we are looking forward to. He reminded the board about the UAMPS Member Conference in August. Registration is open and if any assistance is needed or to make travel arrangements please reach out to Crystal Wright.

Brian Anderson: Brian Anderson reported that the Line Crew has continued working along 1100 West. We are approximately two-thirds of the way done with setting the poles. We have continued doing Blue Stake locates. Mike Vercimak provided an update that we have hired a new Locator who will start next Monday. The Line and Service Crews have continued to work together to do terminations for subdivisions. Mayor Nanette Billings asked when the wire will be strung on the poles along 1100 West. Brian Anderson reported we are still waiting for one easement for one pole location and there has been progress. Once that easement is signed, we can set that last pole. We will string wire from 2300 South to 3000 South. This portion is part of the Capacity 2.0 project so that will be completed right away. He hesitates to give a timeframe deadline for the remainder because our crews will be switching to 2800 West which takes priority over 1100 West as soon as we can get the drilling done for the foundation poles.

Mike Ramirez: Mike Ramirez provided a quick update on some of those projects that the crews combined to terminate. We just completed the next phase of the Quail Creek Industrial Park project and then will be heading over to work on terminations for Liberty Village. He reported on the 3M Training that Kyle Fenn & Jordan Steglich attended in Austin, TX. 3M is the company that makes a lot of the rubber goods we use including our termination kits. They had class time learning about the science of the products in addition to hands-on testing sessions with actual products. Dave Imlay asked how many terminations we've had fail. Mike Ramirez stated only a few over the course of his career with Hurricane Power. Mike Ramirez emphasized it says a lot about the quality of the work our guys have done. He provided an update on the AMI Metering Project. We've been working on the contract. We sent it back with our revisions on June 20th. We're ready to move forward as soon as we receive that contract back. There were Caselle billing updates that were needed as well that will help the utility office out with both power and water reads and billing. He anticipates the AMI contract will be signed before the next board meeting.

Jared Ross: Jared Ross reported on the starter failure on Gen 4. He got that fixed and then Gen 5 had a bigger failure. Gen 5 dropped some valves which caused more damage to the rest of the engine. He described in detail the damage

526 West 600 North • Hurricane, Utah • 84737
Phone (435) 635-5536 • Fax (435) 635-4127 • www.cityofhurricane.com

that occurred and that we are waiting for the parts to fix it. Each generator has over 10,000 hours of run-time so we are working on rebuilding one engine each budget year and can hopefully get through all of them before experiencing any more major failures. He explained we received specs for a 69/138KV dual voltage transformer. We have taken those specs and gone out to bid for a transformer. We are hoping to have bids back by the end of July. We are also looking into making changes to the Sky Mountain Substation design. We are looking at pricing comparisons between prefab buildings versus brick-and-mortar buildings in addition to changing the distribution bussing configuration. Mike Johns stated it may not be much of a cost difference over our current configuration, but he explained the advantages this configuration has. He explained the Survalent training course that Brent George took online. We have a new SCADA server and operating software that will be updated on July 25th. Our SCADA system is still operating well but hasn't really been maintained since Scott Hughes left the substation division. Brent George has stepped up and expressed interest and we are training him to be our SCADA Tech.

Discussion regarding Transformer Capacity Sales Proposal: Mike Johns explained the benefits to both development and the City of this proposal. He understands it is a new idea and would like to keep discussions going. He feels it is something that could be implemented to provide a solution to lack of revenue to purchase major substation transformers. Currently we face an issue with not having the infrastructure needed to expand and develop as fast as growth is happening in addition to not having enough impact fee money collected to purchase major infrastructure materials in advance of the growth. An additional challenge we face is not having spare infrastructure on hand, or quickly being available, for a large equipment failure. Advantages to implementing this proposal include: pulling the cost of substation transformers out of impact fees, adding revenue on the front side of development which would allow us to purchase infrastructure to have on hand to be prepared to move more quickly when infrastructure is needed to be installed, and providing extra revenue to purchase transformers, regulators, and other large infrastructure items to have on hand in the event of a major equipment failure. Dave Imlay stated he likes the concept. He used a specific example to explain a concern. We previously had a large industrial customer come in telling us they would need 6MW for their project. They only used 2MW maximum at completion. He asked how that would work in this instance? Would the full 6MW need to be reserved because that specific customer paid for it? Do we allow the customer to sell off the extra power they didn't end up needing? Do we have to hold that 6MW capacity for that customer forever? Mike Johns explained we would reserve the capacity paid for and would build some flexibility in the construction of our substations by making them each a dual bay substation. Mac Hall asked if it's possible to write the impact fee so you can provide an option for either paying for transformer capacity in addition to an impact fee without the transformer included for large developers, or paying the normal impact fee, with the transformer included, for single homes or smaller developments? Mike Johns stated he hasn't thought about that option, but we could put our heads together to see if that's possible. Colt Stratton asked how we would guarantee that money pulled out of impact fees for transformers is still used in accordance with the laws regulating the use of impact fee money. How does that happen if it's removed from the impact fee? Kaden DeMille stated that it probably wouldn't fall under the same rules as impact fees if it was pulled out but agreed it should be used for the purchase of the items it was intended for. He explained he would like to utilize a separate account to track that money and have it earmarked for that specific purpose. Without it being contained within the impact fees it wouldn't be subject to the same regulations that impact fees are. Mac Hall stated this may provide incentive to developers to fine tune the amount of capacity they're asking for in their developments. Crystal Wright asked if it could potentially work the other way, meaning developers would minimize their power needs to pay less up front and then ask for extra capacity afterward. Mike Johns stated they would have to pay for the extra when they needed it anyway so there would still be the expense. Dayton Hall stated there have been developments who understated their power needs. Property changed hands and three owners built their homes. When the fourth lot owner came in to build, they were required to pay for power upgrades before they could proceed. It's not an exact reference because this example deals with distribution infrastructure, but the same concept could happen on a larger scale with the developer for substation capacity. There was a long discussion about potential scenarios. Colt Stratton stated if you are now going to require it to be stated in the preliminary plat that it will require a change to our standards. Mike Johns agreed there would be modifications to standards needed. Mac Hall asked how revenue-neutral we determined this would be. Would it cost the developer more or less? Mike Johns stated that in a general sense it would cost the developer more. Dave Imlay stated he likes the idea, but he's concerned about any repercussions in charging more than our impact fee study states is the actual impact with the transformers included. Dayton Hall provided context that we have 4-6 substations needing to be built in the short term. There is not currently money available to build them and would require bonding for construction. We have told several developers the City does not have the financial ability to construct the substations needed for their development immediately, and they are frustrated with the wait because they are ready to move forward with their developments. This wait is both financial as well as due to long lead times for ordering and receiving substation infrastructure equipment. We've invited them to pay money to build the substations and any transmission lines needed. These are all impact fee eligible under the current fee structure. If they pay that money up front, we will give them vouchers through a reimbursement agreement and they will not pay an impact fee until they reach the dollar amount of that agreement. That is how the current structure is set up with our impact fees and current ordinances. Mike Vercimak stated the City has operated with the premise that if a new development needs service where we don't currently have service, they can choose to bring it in themselves or wait for the City to build the infrastructure and connect when it gets to them. He doesn't believe there's a mechanism to force the City to bring the service. He would like more discussion to get additional analysis about this new idea. He would like to see clarification between how this situation interfaces with impact fees. Colt Stratton asked about what happens if a developer has paid more than the impact fee vouchers needed for their development? Would they get a reimbursement from the City? Additionally, what happens if a development comes in and pays for their proportionate share of the transformer, but nobody else comes in to pay for the remainder of what is needed to build the complete substation? Would we be required to provide the developer with the capacity they paid for, when we still don't have the money for the full buildout? Dayton Hall summarized if a developer pays money, there will be expectations that will need to be managed contractually, and he agrees. Mac Hall summed up the conversation with a consensus that this may be a good way to proceed, with some details that need to be clarified. Mike Johns stated he thinks we can iron out some details and present something a little more formal.

Discussion regarding Impact Fee Analysis & Capital Facilities Plan Amendment: Mike Johns explained that the current Impact Fee Analysis was very recently approved, however, there are already needs identified that need to be considered through an amendment. We needed to get the existing impact fees approved while we worked on getting those new needs added as a revision for an amendment. The two big items include two additional substations that are needed, one by the new proposed Zion Regional Medical Center with the other proposed near 1100 West 3000 South. He also identified an upgrade to a 138KV line from Purgatory up to the new 69/138KV substation. He is attempting to have that section included as part of the UAMPS Central-St. George project. Dave Imlay stated that may open intense discussion at that meeting with that proposal based on the history of that project. Mayor Nanette Billings asked if the Medical Center project is unable to move forward until the amendment is complete. Mike Vercimak stated that bonding for the full project would be prudent. Mike Johns stated we need to get these amendments approved through the Impact Fee Study because we cannot issue any impact fee vouchers until it is officially impact fee eligible. We are planning on looking at impact fee studies on an annual basis moving forward. Mayor Nanette Billings asked if the completed study would need to be presented to the Power Board once it is complete before coming before the City Council. Dayton Hall confirmed the correct process is to present it to the Power Board for a recommendation before bringing it to the City Council.

Discussion regarding Approved Contractor List Qualifications: Mike Johns showed the approved contractor list. We had a resident attempt to contact every contractor on our list. She provided feedback that the process was miserable. She only received 3-4 responses back in total. In response, we will be sending out a notification to every contractor on our list. Our contractor list requirements state they are supposed to resubmit forms every two years and re-test if they haven't done any work within the previous two years. We are going to enforce the requirements for updates that already exist in our policy to bring our contractor list current. There's some other language that needs cleaned up in that policy section and we will be conducting annual contractor training that will be mandatory for them to attend to remain on this list each year.

UAMPS Updates: Mike Johns reported he already talked about adding the 138KV upgrade into the Central-St. George Project. Dave Imlay stated that we pay for each one of the Exhibit C items by percentage of load by user. Our load for that section of line would be close to 100%, so we may end up paying for most of the project itself anyway, but it would put the bonding on the UAMPS books instead of ours. Mike Johns also stated that because it is included in that project, UAMPS would facilitate the project including handling the engineering, design, and building.

Dave Imlay asked about our generation. He talked to a councilman in another city, and they explained a restriction by PacifiCorp for them only being able to generate 3MW. He wasn't sure if our grandfathered status provided us with the ability to generate everything we have or if we were subject to any restriction. Mike Johns and Crystal Wright stated we have not received any notification of restriction, and we are generating using our full generation capability.

Meeting adjourned at 4:40 p.m. The next Power Board meeting is scheduled for August 6, 2025, at 3:00 p.m.

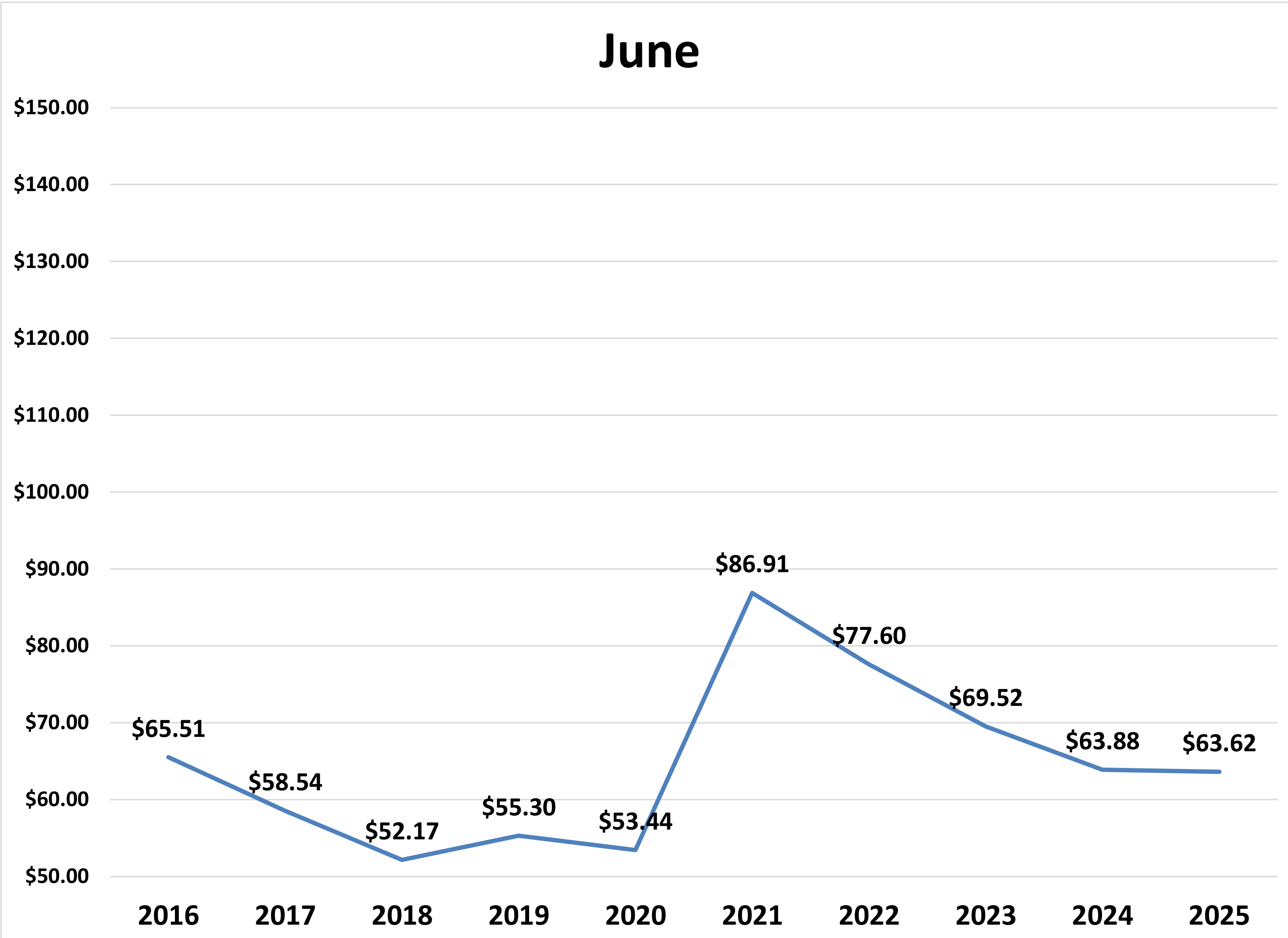
BUDGET

AVERAGE YEARLY POWER PRICES

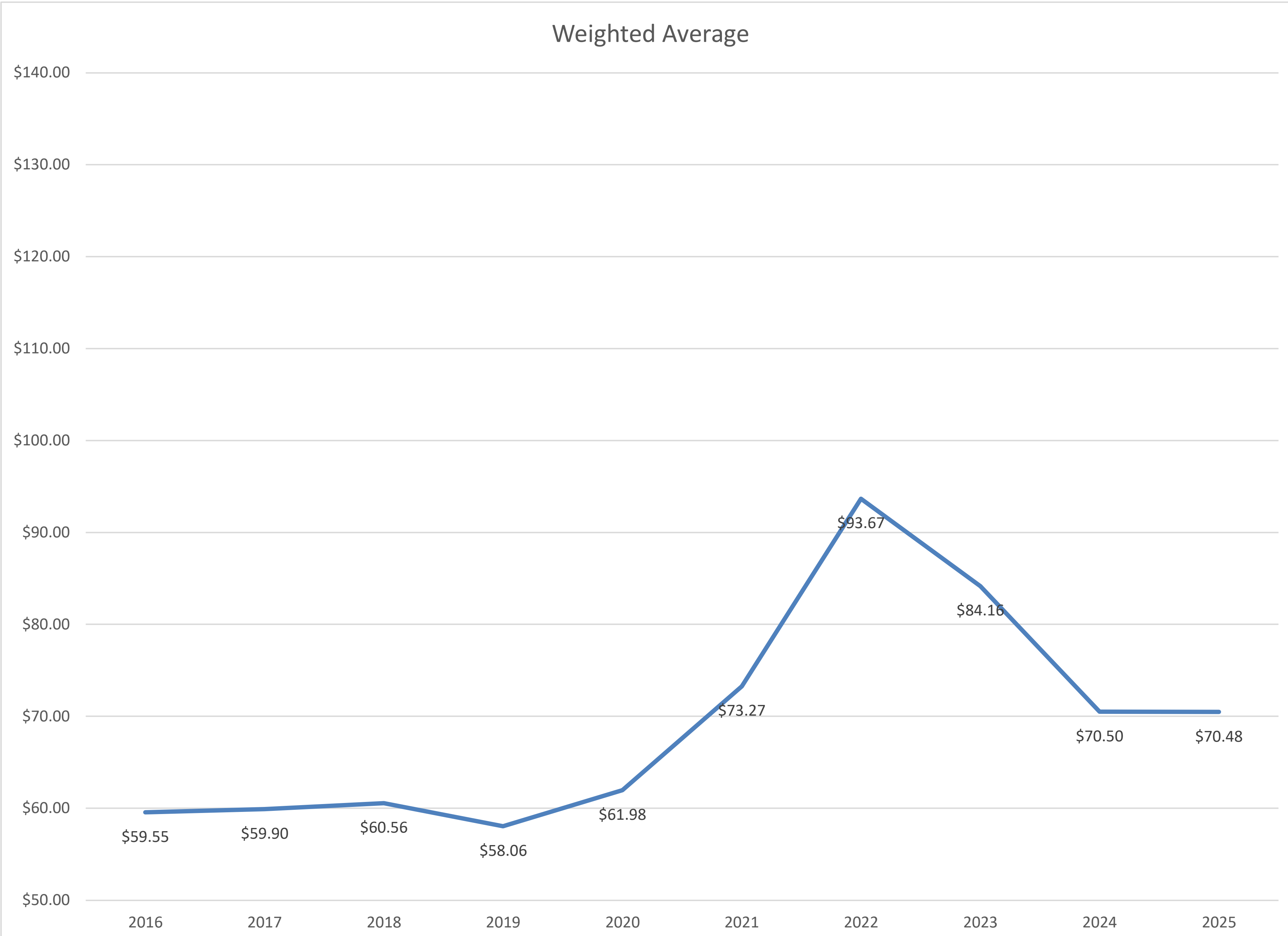
	24-25 bdgt amount (thru June 2025)	**$70.65**
	BDGT Year to Date	**$70.92**

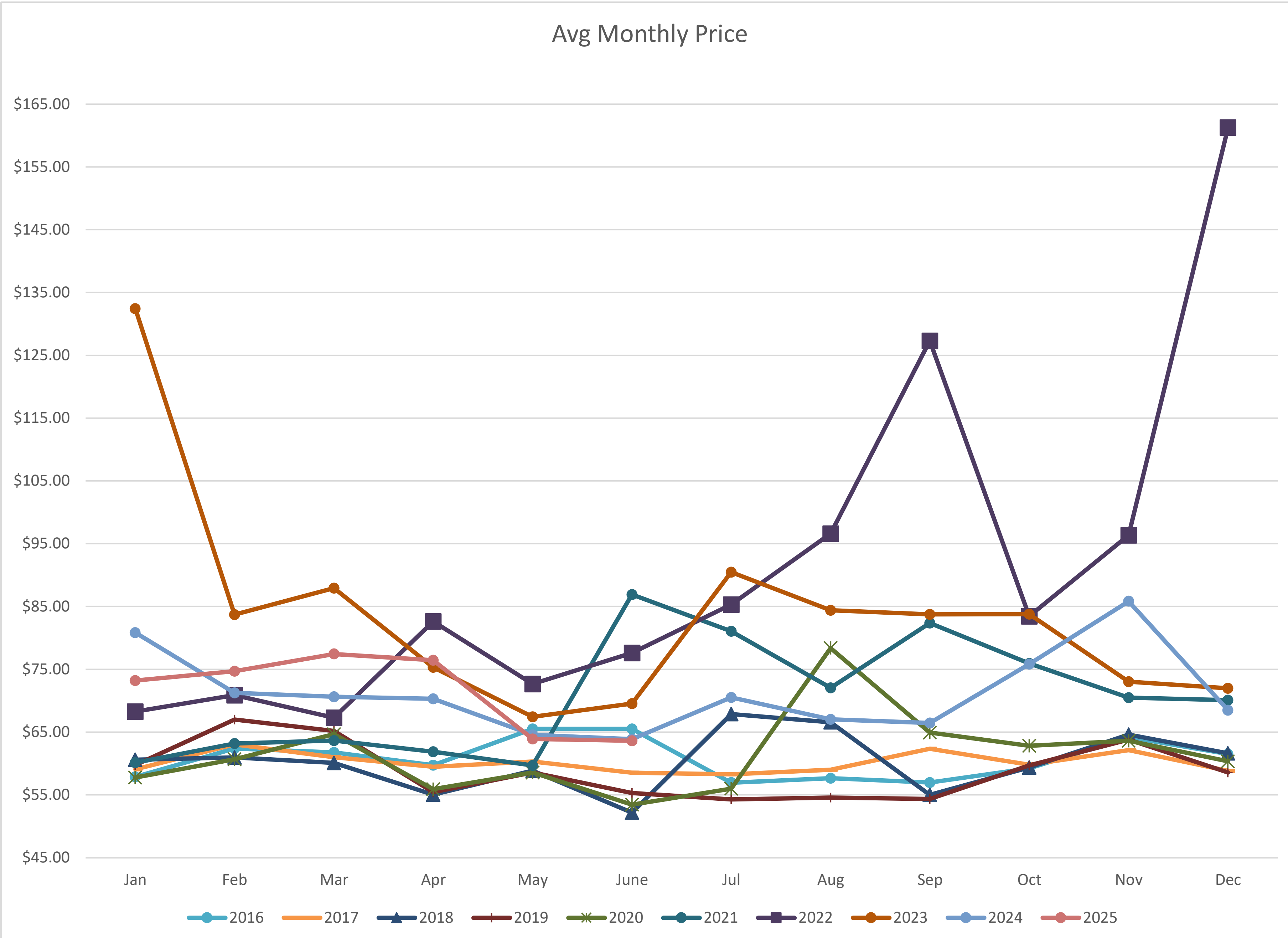
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	$57.87	$59.07	$60.62	$59.75	$57.76	$60.14	$68.25	$132.44	$80.85	$73.20
Feb	$62.38	$63.04	$60.96	$67.00	$60.67	$63.19	$70.88	$83.72	$71.23	$74.69
Mar	$61.77	$60.99	$60.09	$65.17	$64.67	$63.64	$67.28	$87.92	$70.62	$77.45
Apr	$59.71	$59.49	$55.02	$55.44	$55.92	$61.86	$82.63	$75.32	$70.32	$76.44
May	$65.51	$60.32	$58.86	$58.55	$58.55	$59.69	$72.66	$67.45	$64.54	$63.90
June	$65.51	$58.54	$52.17	$55.30	$53.44	$86.91	$77.60	$69.52	$63.88	$63.62
Jul	$56.95	$58.29	$67.87	$54.29	$55.98	$81.04	$85.31	$90.48	$70.51	
Aug	$57.67	$59.00	$66.55	$54.58	$78.40	$72.03	$96.60	$84.39	$67.05	
Sep	$56.97	$62.36	$55.00	$54.34	$64.93	$82.38	$127.29	$83.74	$66.46	
Oct	$59.23	$59.79	$59.36	$59.70	$62.82	$75.92	$83.45	$83.77	$75.82	
Nov	$64.18	$62.14	$64.60	$63.80	$63.60	$70.47	$96.34	$73.03	$85.85	
Dec	$61.51	$58.80	$61.61	$58.55	$60.33	$70.07	$161.27	$71.99	$68.50	
Yr Avg	$60.64	$60.15	$60.23	$58.87	$61.42	$70.61	$90.80	$83.65	$71.30	$71.55
Weighted Avg	$59.55	$59.90	$60.56	$58.11	$61.98	$72.46	$92.09	$84.16	$70.50	$70.48
										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

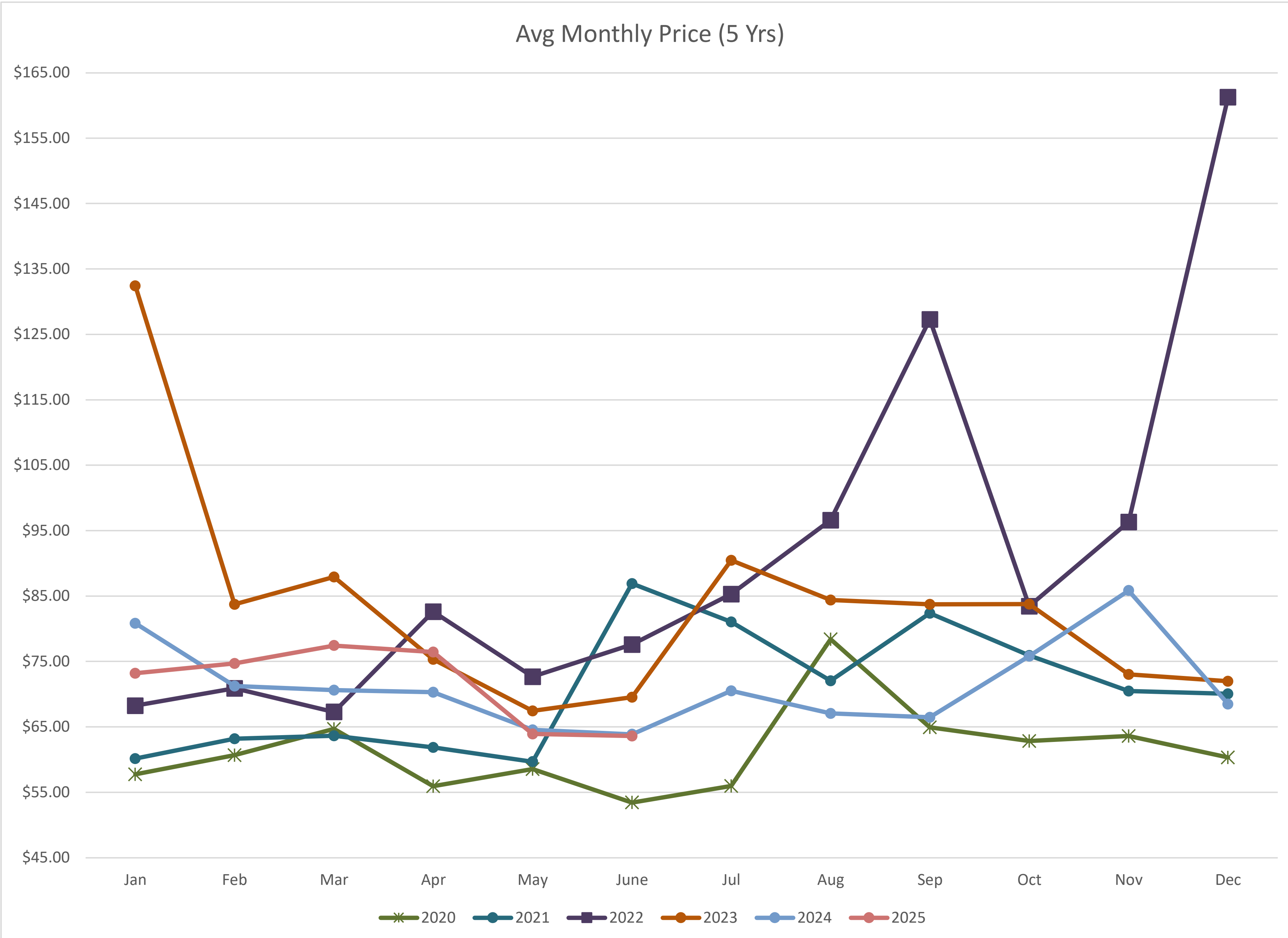


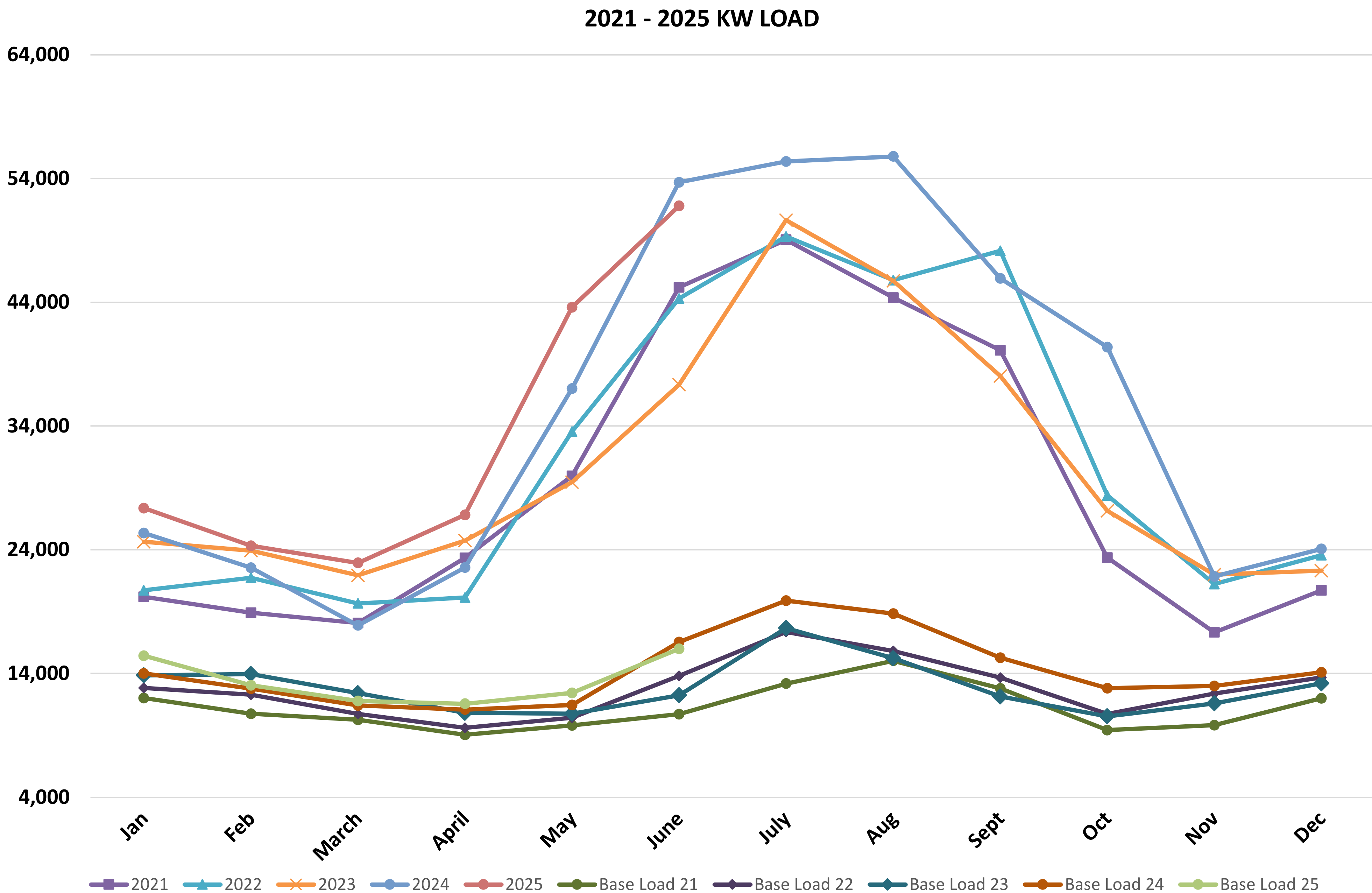
June
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$65.51
$58.54
$52.17
$55.30
$53.44
$86.91
$77.60
$69.52
$63.88
$63.62
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

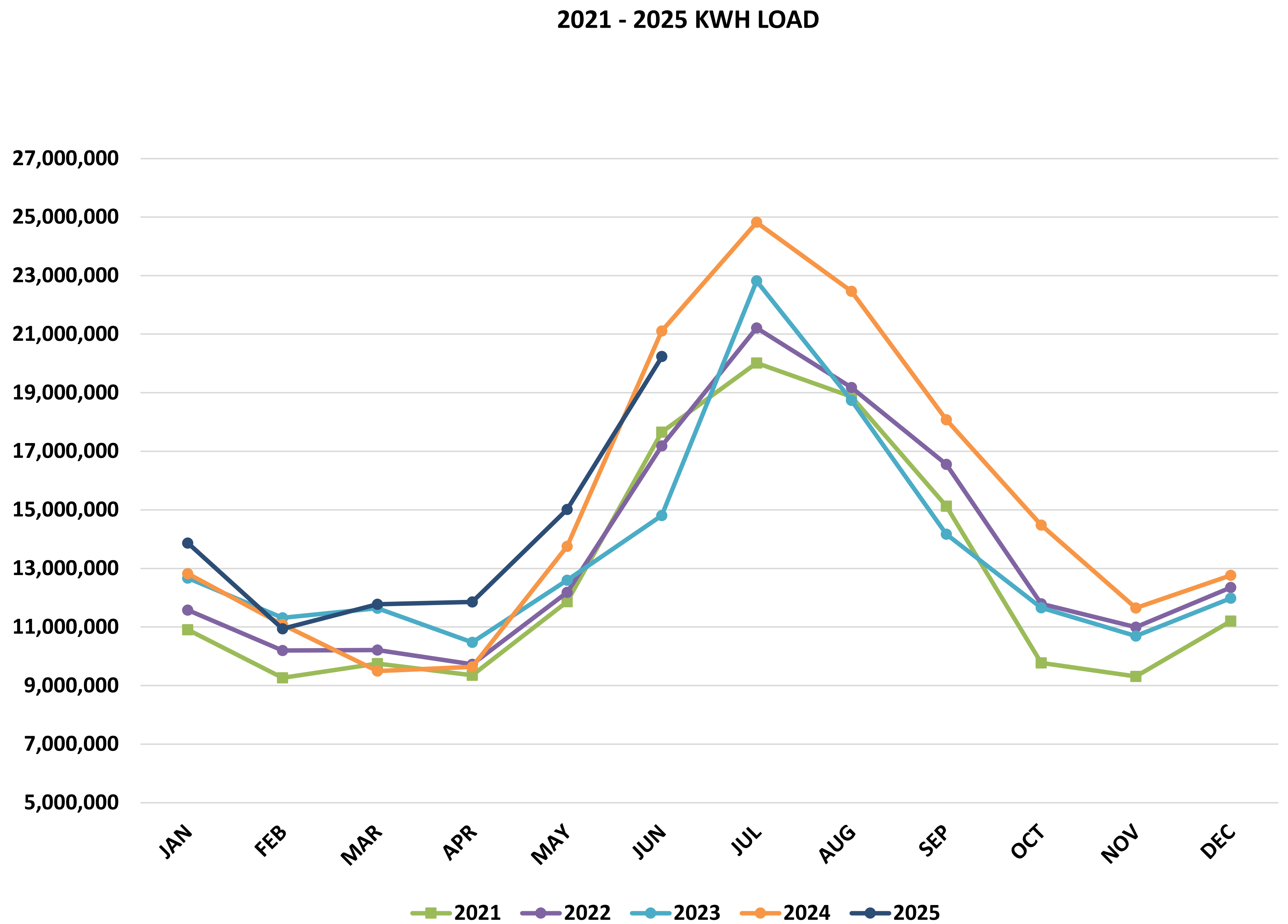

Weighted Average
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$59.55
$59.90
$60.56
$58.06
$61.98
$73.27
$93.67
$84.16
$70.50
$70.48
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

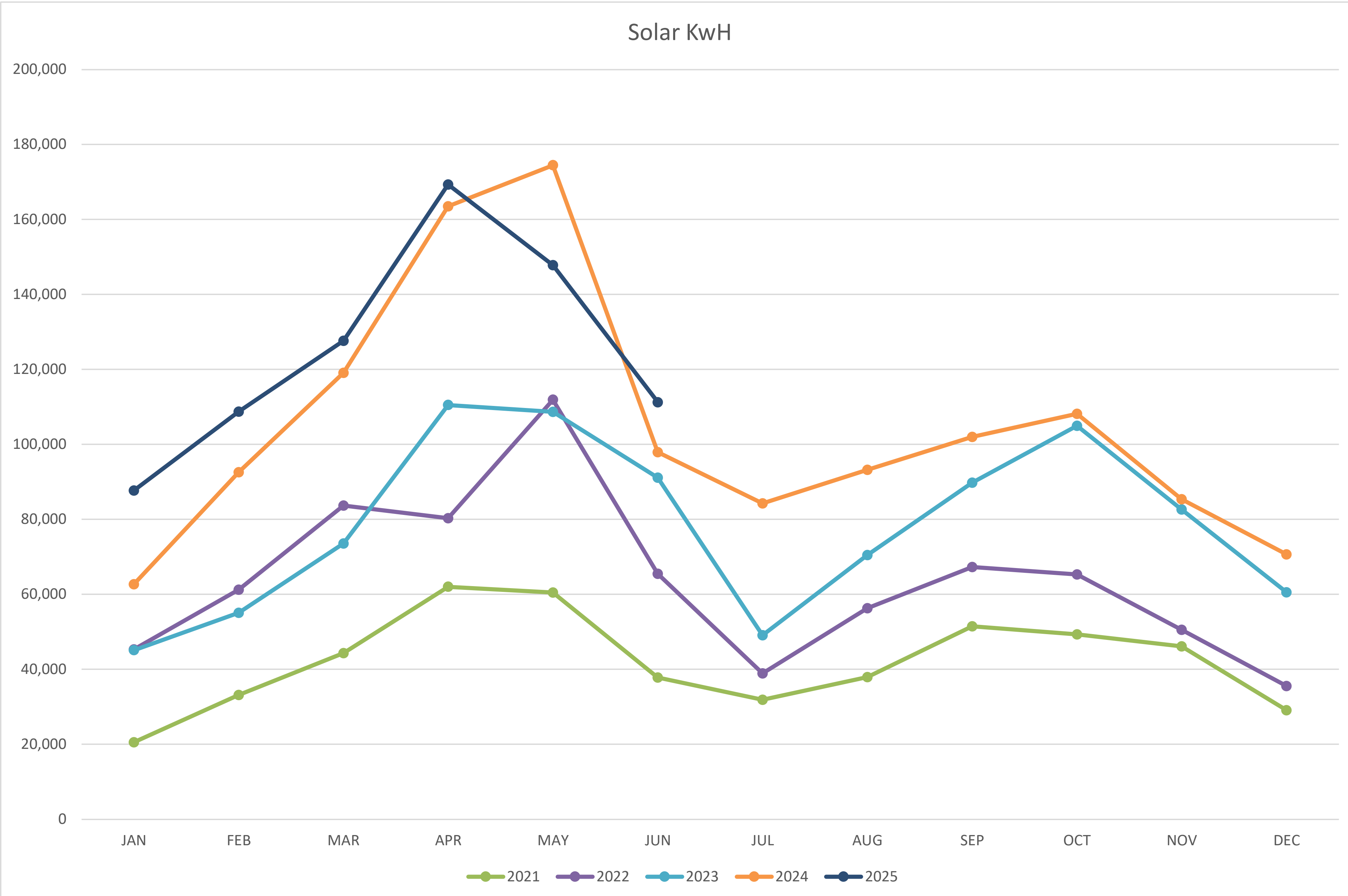


Avg Monthly Price
$165.00
$155.00
$145.00
$135.00
$125.00
$115.00
$105.00
$95.00
$85.00
$75.00
$65.00
$55.00
$45.00
Jan
Feb
Mar
Apr
May
June
Jul
Aug
Sep
Oct
Nov
Dec
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025


Avg Monthly Price (5 Yrs)
$165.00
$155.00
$145.00
$135.00
$125.00
$115.00
$105.00
$95.00
$85.00
$75.00
$65.00
$55.00
$45.00
Jan
Feb
Mar
Apr
May
June
Jul
Aug
Sep
Oct
Nov
Dec
2020
2021
2022
2023
2024
2025


2021 - 2025 KW LOAD
64,000
54,000
44,000
34,000
24,000
14,000
4,000
Jan
Feb
March
April
May
June
July
Aug
Sept
Oct
Nov
Dec
2021
2022
2023
2024
2025
Base Load 21
Base Load 22
Base Load 23
Base Load 24
Base Load 25


2021 - 2025 KWH LOAD
27,000,000
25,000,000
23,000,000
21,000,000
19,000,000
17,000,000
15,000,000
13,000,000
11,000,000
9,000,000
7,000,000
5,000,000
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2021
2022
2023
2024
2025



Solar KwH
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2021
2022
2023
2024
2025

TRANSFORMER CAPACITY SALES PROPOSAL

Discussion regarding Transformer Capacity Sales Proposal

Overall Goals of the project:

- *Limit impact fee increasements toward the general public*
- *Push more of the cost on developers and have less impact on local citizens*
- *Be able to develop our system more efficiently to facilitate a healthy growth rate and be able to allow developers to complete their projects faster with less delays from the Power Department*
- *Be able to procure additional resources and assets to limit outage durations and be better prepared in emergency or blackout conditions*
- *Help limit the City's risks associated with bonding*

The Plan:

Create an ordinance that charges an upfront cost on new developments. The cost is determined by the amount of power required and is based on the sales cost of the substation power transformer.

For example, if the new development requires 5 MVA of power then the fee would be equal to the cost of a 5 MVA power transformer; if the new development requires 10 MVA of power then the fee would be equal to the cost of a 10 MVA transformer etc…

How this approach accomplishes the above goals:

Limit impact fee increasements toward the general public:

- This plan would eliminate the cost of the substation power transformer from the impact fee study.
- Power transformers are the most expensive asset in the substation. Hurricane City currently has plans to install 4 new substations as part of its capital infrastructure. In addition to new substations, there are plans to add new transformers to existing substations.

- By removing transformers from the impact study, it could significantly reduce the overall cost on impact fee related projects and help reduce the inevitable increases in impact fees.

Push more of the cost on future developers and have less impact on local citizens:

- Implementing this fee through a city ordinance toward the developer during the planning process.
- The fee will be implemented at a fair and honest cost proportional to the power required for their individual development.
- If a developer wanted to build a substation to supply power to their development, this would be equal to the cost of the transformer required to do so.
- This approach pays for the power transformer upfront without implementing these costs on the impact fee study.

Be able to develop our system more efficiently to facilitate a healthy growth rate and be able to allow developers to complete their projects faster with less delays from the Power Department:

- Because these fees are charged up front, it allows us flexibility to get large assets and equipment with long lead times ordered for new infrastructure a lot more quickly and in a much more efficient manner.
- Larger assets, particularly in substations, have extremely long lead times. Power transformers in particular can extend longer than a year’s time. This has been very frustrating for developers because it prevents them from being able to start projects and delays their ability to see a profit back on their investments.
- Extra funds from this plan will allow the City to purchase some of these assets in advance and have them on hand prior to new developments starting. Then it can be ordered as we use them. We would basically be one step ahead of the procurement process.
- This is a huge benefit to the developers. So far it has been my experience that this has been one of the most frustrating aspects coming from developers.

Be able to procure additional resources and assets to limit outage durations and be better prepared in emergency or blackout conditions:

- Currently the majority of Hurricane City is fed with a single radial 69KV transmission feed. We do not currently have backup assets (Transformers, Regulators).
- In the event of a transformer or main substation asset failure, we do not have the ability to effectively restore power or to be as reliable as we need to be.
- Having these extra funds would eventually allow us to not only to get these assets in advance for development reasons, but to also have them as backup assets to our existing system.
- We do our best to make plans in advance to address emergency concerns, but this particular event would be devastating.
- This plan would allow for extra funds to be able to purchase and have some equipment on hand. And allow us to continue to develop emergency plans and policies for the most efficient power restoration.

Help limit the City's risks associated with bonding:

- The City could bond for this infrastructure. However, if for some reason building slows, we wouldn't have the impact fees coming in to make the bond payments.

Primary Concerns:

- Developers want to pay the fee based on the proportionate share of the 20MVA transformer, and not the cost of 5 MVA transformer (assuming the development requires 5 MVA of capacitance)

    - *The purpose of charging the 5MVA transformer is to create additional revenue that would allow the city to acquire additional or spare assets*
    - *If the developer wanted to construct the substation to supply power to their development only, they would pay for and install the 5MVA transformer*

- What fee would be required if an in-between amount of power is needed? For example, if the development needed 3.5 MVA.

    - *Similar to the distribution system, the fee will be set to the smallest nominal size transformer that would be required to supply power to the development if the substation being built was to only supply power to that development.*

    - *In the example above there is not a 3.5 MVA transformer, the most cost-effective transformer that would be required in this application would be a 5 MVA transformer*

- What size of development would be subject to the fee?

    - *We are still working through this one. The smallest nominal transformer for this study is a 2 MVA power transformer.*
    - *We are thinking that anything in excess of 1 MVA would qualify*
    - *One of the primary purposes of this plan is to reduce the costs for the general public. We want to gear this plan towards larger developments.*
    - ***Any additional thoughts or ideas are welcome***

- Would existing developments be subject to the fee?

    - *Developments not currently under contract would be subject*
    - *Developments with expired contracts would be subject*
    - *I will get with Dayton to work all the way through this one*

Notes:

- Nominal transformer sizes: 2 MVA, 5 MVA, 7.5 MVA, 10 MVA, and 20 MVA.
- ICPE is working with their procurement team to establish the cost of these different size transformers

Final thoughts:

- What impact fees are developers subject to?
    - If developers sell off land after development has been approved?
    - Or just when building permits are pulled

Updated
Power Connection Fee Schedule

Proposed Update for Existing Connection Costs					
	Now	***New***	**Labor**	**Equipment**	**Material**
Hook-up Costs					
Single Phase Metering (200 amp and below)	**$237.00**	*$418.00*	$181.72	$38.50	$196.90
Single Phase Non C.T. Metering (above 200 amp, up to 400 amp)	**$425.00**	*$440.00*	$181.72	$38.50	$218.90
Three Phase Non C.T. Metering (under 400 amps)	**$544.00**	*$783.00*	$90.86	$38.50	$653.40
Three Phase with C.T. Metering (over 400 amps)	**$1,524.00**	*$1,833.00*	$272.58	$77.00	$1,482.55
Developing Underground Connection Point from Overhead to Underground					
Single Phase Secondary	**$1,679.00**	*$1,701.00*	$290.75	$116.16	$1,293.95
4/0 Riser	**$874.00**	*$888.00*	$363.44	$132.00	$391.74
350 MCM Riser	**$842.00**	*$855.00*	$363.44	$132.00	$359.18
500 MCM Riser	**$977.00**	*$990.00*	$363.44	$176.00	$450.25
Primary Single-Phase Riser					
1/0 Primary Riser	**$1,604.00**	*$1,449.00*	$408.87	$176.00	$863.27
Primary Three-Phase Riser					
1/0 Primary Riser	**$3,027.00**	*$3,052.00*	$817.74	$264.00	$1,969.44
4/0 Primary Riser	**$3,027.00**	*$3,052.00*	$817.74	$264.00	$1,969.44
500 Primary Riser	**$5,217.00**	*$5,374.00*	$1,272.04	$396.00	$3,705.76
750 Primary Riser	**$5,217.00**	*$5,374.00*	$1,272.04	$396.00	$3,705.76
Other Connection Costs					
Switch Grounding	**$651.00**	*$668.00*	$272.58	$77.00	$317.57
Connect into Developers Switch Fuse Bay	**$1,232.00**	*$1,260.00*	$545.16	$77.00	$637.40
Connect into Developers Solid Blade Bay	**$646.00**	*$658.00*	$545.16	$77.00	$35.31
Connect into Existing Switch per Bay	**$8,999.00**	*$13,423.00*	$772.31	$324.50	$12,325.81
Connect into an Existing Vault per KVA	**$6.50**	*$6.50*	-	-	-
Elbow Termination	**$126.00**	*$130.00*	$90.86	$38.50	-

Resolution 2025-XX

RESOLUTION

A RESOLUTION OF THE CITY COUNCIL OF HURRICANE, UTAH, AMENDING THE CONNECTION COST SCHEDULE FOR THE HURRICANE POWER DEPARTMENT

WHEREAS, the Hurricane City Council is authorized by Section 10-3-717 of the Utah Code and Section 1-5-6-G.1. of the Hurricane City Code to establish fees for municipal services; and

WHEREAS, said City Council desires to amend the connection cost schedule for Hurricane Power Department Services, and

WHEREAS, said City Council deems it necessary and desirable for the preservation and protection of the health, safety, and welfare of the residents of Hurricane, Utah,

BE IT HEREBY RESOLVED by the City Council of Hurricane, Utah as follows:

1. Approval and Adoption of the Connection Cost Schedule. The costs contained in the Hurricane Power Department are attached hereto as Exhibit "A" and incorporated herein as if fully set forth are hereby approved and adopted. The Power Department shall charge the costs set forth in Exhibit A.

PASSED AND APPROVED THIS 7th day of August, 2025.

____
Nanette Billings, Mayor

ATTEST:

____
Cindy Beteag, Recorder

The foregoing Resolution was presented at a regular meeting of the Hurricane City Council held at the Hurricane City Office Building on the 7th day of August, 2025. Whereupon a motion to adopt and approve said Resolution was made by ___________________________ and seconded by ____________________________. A roll call vote was then taken with the following results:

	Yea	Nay	Abstain	Absent
David Hirschi	___	___	___	___
Kevin Thomas	___	___	___	___
Clark Fawcett	___	___	___	___
Drew Ellerman	___	___	___	___
Joseph Prete	___	___	___	___

____
Cindy Beteag, Recorder

Exhibit A

CONNECTION FEES Pending Approval 8/7/25

Hookup Fees	
Single Phase Metering (200 Amp and below)	$418.00
Single Phase Non C.T. Metering (above 200 Amp, up to 400 Amp)	$440.00
Three Phase Non C.T. Metering (under 400 Amps)	$783.00
Three Phase with C.T. Metering (over 400 Amps)	$1,833.00
Developing Underground Connection Point from Overhead to Underground	
Single Phase Secondary	$1,701.00
Secondary Riser	
4/0 Riser	$888.00
350 MCM Riser	$855.00
500 MCM Riser	$990.00
Primary Single-Phase Riser	
1/0 Primary Riser	$1,449.00
Primary Three-Phase Riser	
1/0 Primary Riser	$3,052.00
4/0 Primary Riser	$3,052.00
500 Primary Riser	$5,374.00
750 Primary Riser	$5,374.00
Other Connection Fees	
Switch Grounding Fee	$668.00
Connect into Developers Switch Fuse Bay	$1,260.00
Connect into Developers Solid Blade Bay	$658.00
Connect into Existing Switch per Bay	$13,423.00
Connect into an Existing Vault per KVA	$6.50
Elbow Termination Fee	$130.00
Design & Review Fees	Contact Power Dept

ELECTRIC RATES April 1, 2023

Residential		
Base Charge		$20.00
Usage		
1-800 KWH		$.08946/KWH
801-2000 KWH		$.10222/KWH
2001+ KWH		$.11485/KWH
Small Commercial		
Base Charge-Single Phase		$19.00
Base Charge-Three Phase		$24.50
Usage		
1-800 KWH		$.10302/KWH
801+ KWH		$.10880/KWH
Demand Charge		
Over 50 KW		$8.50/KW
Large Commercial		
Base Charge		$320.00
Usage		
All KWH		$.06658/KWH
Demand Charge		
All KWH		$9.10/KW
SOLAR FEES AND RATES April 1, 2023		
Application Review Fee (1st Review)		$200.00
Each Additional Review		
Bi-Directional Meter Fee		
Single Phase Basic Base Rate	6kW AC or Less	$30.00
Single Phase Large Base Rate	12 kW AC or Less	$40.00
Three Phase Basic Base Rate	12 kW AC or Less	$90.00

*See Grid-Tied Policy for additional base rates and application review details

IMPACT FEE SCHEDULE Approved May 15, 2025 (Effective August 13, 2025)

*Impact Fee=Base Impact Fee ($ per kW) $727.69

Service Amps	120/240 Single Phase	Commercial 120/240 Single Phase	Commercial Industrial 120/208 Three Phase	Commercial Industrial 240/480 Three Phase	Commercial Industrial 277/480 Three Phase
125	$2,592	NA	NA	NA	NA
200	$4,148	$7,859	$11,797	$27,225	$27,225
400	$8,528	$15,718	$23,595	$54,449	$54,449
600	$12,792	$23,577	$35,392	$81,674	$81,674
800	NA	$31,436	$47,189	$108,898	$108,898
1000	NA	NA	$58,987	$136,123	$136,123
1200	NA	NA	$70,784	$163,347	$163,347
1600	NA	NA	$94,378	$217,796	$217,796
1800	NA	NA	$106,176	$245,021	$245,021
2000	NA	NA	$117,973	$272,246	$272,246
2500	NA	NA	$147,466	$340,307	$340,307
3000	NA	NA	$176,960	$408,368	$408,368
4000	NA	NA	$235,946	$544,492	$544,492

Analog Meter Rate

Proposed Update to Base Rate for Analog Meter-Residential (Rate 121)

			Now	***New***	**Labor**	**Equipment**
Analog Meter-Residential						
Base Rate			**$30.00**	*$63.50*	$30.29	$12.83
Plus	Usage					
	1-800	kWh	**$0.08946**	*$0.08946*		
	801-2000	kWh	**$0.10222**	*$0.10222*		
	2000+	kWh	**$0.11485**	*$0.11485*		

*Labor $90.86 + Equipment $38.50 = $129.36/3 customers average per hour = $43.12 actual cost to send a lineman out to physically get a reading

The Existing $20.00 Residential Base Rate includes the cost of a radio read currently. With the introduction of AMI we will no longer have to drive around for reads so we will be physically required to make a special trip out to get these readings. We will also have to manually enter those reads each month. Those meters are also not a common meter, or one that we stock, so there's a cost involved with ordering additional specialized meters. We would like to recoup at least the cost required to collect that reading. **$20 Residential Base Rate + $43.12 actual cost for physical read = $63.12**

Exhibit "A" Amendments

			Rate Effective 9/1/24 (July-Aug usage)	[redacted]	Current Rates as of 4/1/23	Analog Base Rate Increase
Residential						
Base Charge (Rate 101, 107)			$ 20.00		20	20
Plus	Usage		$ -		0	
	1-800	KWh	$ 0.08946		0.089463	0.089463
	801-2000	KWh	$ 0.10222		0.102223	0.102223
	2000+	KWh	$ 0.11485		0.114851	0.114851
			$ -		0	
ANALOG METER-Residential			$ -		0	
Base Charge (Rate 121)			$ 63.50		30	63.5
Plus	Usage		$ -		0	
	1-800	KWh	$ 0.08946		0.089463	0.089463
	801-2000	KWh	$ 0.10222		0.102223	0.102223
	2000+	KWh	$ 0.11485		0.114851	0.114851
			$ -		0	
Electric-Agricultural 1P			$ -		0	
Base Charge - Single Phase (Rate 108)			$ 18.00		18	18
Plus	All KWh		$ 0.09380		0.093797	0.093797
			$ -		0	
			$ -		0	
Electric-Agricultural 3P			$ -		0	
Base Charge - Three Phase (Rate 111)	All KWh		$ 24.50		24.5	24.5
Plus			$ 0.10761		0.107613	0.107613
			$ -		0	
Small Commercial 1P			$ -		0	
Base Charge - Single Phase (Rate 105)			$ 19.00		19	19
Plus	Usage		$ -		0	
	1-800	KWh	$ 0.10302		0.103015	0.103015
	801+	KWh	$ 0.10880		0.108801	0.108801
Plus	Demand Charge over 50KWh		$ 8.50		8.5	8.5
			$ -		0	
Small Commercial 3P			$ -		0	
Base Charge - Three Phase (Rate 106, 112, 113)			$ 24.50		24.5	24.5
Plus	Usage		$ -		0	
	1-800	KWh	$ 0.10302		0.103015	0.103015
	801+	KWh	$ 0.10880		0.108801	0.108801
Plus	Demand Charge over 50KWh		$ 8.50		8.5	8.5
			$ -		0	
Alternative Large Commercial Rate - Interruptible 3P			$ -		0	
Base Charge - Three Phase (Rate 110)			$ 320.00		320	320
Plus	Usage		$ -		0	
	All KWh		$ 0.06658		0.066583	0.066583
	Demand Charge		$ 4.55		4.55	4.55
			$ -		0	
Large Commercial 3P			$ -		0	
Base Charge - Three Phase (Rate 104)			$ 320.00		320	320
Plus	Usage		$ -		0	
	All KWh		$ 0.06658		0.066583	0.066583
Plus	Demand Charge		$ 9.10		9.1	9.1
			$ -		0	
Old Commercial Rate			$ -		0	
Base Charge (Rate 199)			$ 18.50		18.5	18.5
Plus	Usage		$ -		0	
	1-800	KWh	$ 0.09209		0.092092	0.092092
	801-1500	KWh	$ 0.10525		0.105248	0.105248
	1501-26500	KWh	$ 0.10170		0.101695	0.101695
	26501+	KWh	$ 0.09183		0.091828	0.091828
Plus	Demand Charge over 50KWh		$ 7.60		7.6	7.6
			$ -		0	
CITY-1P			$ -		0	

Base Charge - Single Phase (Rate 102)			$	18.00	[redacted]	18	18
Plus	Usage		$	-	[redacted]	0	
	1-800	KWh	$	0.10064	[redacted]	0.100639	0.100639
	801+	KWh	$	0.11051	[redacted]	0.110506	0.110506
			$	-	[redacted]	0	
CITY-3P			$	-	[redacted]	0	
Base Charge - Three Phase (Rate 103)			$	24.50	[redacted]	24.5	24.5
Plus	Usage		$	-	[redacted]	0	
	1-800	KWh	$	0.10064	[redacted]	0.100639	0.100639
	801+	KWh	$	0.11051	[redacted]	0.110506	0.110506
			$	-	[redacted]	0	
Electric Production-Solar refund (Rate 177)	All		$	(0.04)	[redacted]	-0.04	-0.04
			$	-	[redacted]	0	
OLD Residential Solar			$	-	[redacted]	0	
Base Charge (Rate 115)			$	20.00	[redacted]	20	20
Plus	Usage		$	-	[redacted]	0	
	1-800	KWh	$	0.08946	[redacted]	0.089463	0.089463
	801-2000	KWh	$	0.10222	[redacted]	0.102223	0.102223
	2000+	KWh	$	0.11485	[redacted]	0.114851	0.114851
			$	-	[redacted]	0	
1P System Solar			$	-	[redacted]	0	
Base Charge (Rate 116)			$	30.00	[redacted]	30	30
Plus	Usage		$	-	[redacted]	0	
	1-800	KWh	$	0.08946	[redacted]	0.089463	0.089463
	801-2000	KWh	$	0.10222	[redacted]	0.102223	0.102223
	2000+	KWh	$	0.11485	[redacted]	0.114851	0.114851
			$	-	[redacted]	0	
3P Basic System Solar			$	-	[redacted]	0	
Base Charge - Three Phase (Rate 118)			$	90.00	[redacted]	90	90
Plus	Usage		$	-	[redacted]	0	
	1-800	KWh	$	0.10302	[redacted]	0.103015	0.103015
	801+	KWh	$	0.10880	[redacted]	0.108801	0.108801
	Demand Charge over 50KWh		$	8.50	[redacted]	8.5	8.5
			$	-	[redacted]	0	
PACIFICORP POWER (OLD UP&L/ROCKY MTN PWR) (Rate 109)					[redacted]		
This is a contracted rate and not subject to rate changes passed by resolution	All	KWh	$	0.19487	[redacted]	0.19487	0.19487

Resolution No. 2025-xx

A RESOLUTION OF THE CITY COUNCIL OF HURRICANE, UTAH, ESTABLISHING A NEW POWER RATE SCHEDULE FOR HURRICANE CITY POWER

WHEREAS the Hurricane City Council is authorized by Section 10-3-717 of the Utah Code and Section 1-5-6(G)(1) of the Hurricane City Code to establish fees for municipal services; and

WHEREAS Hurricane City Code sections 8-1-4 & 8-4-4 authorize the City Council to set by resolution fees, rates, deposit requirements, and charges associated with municipal power and water services; and

WHEREAS Hurricane City has reevaluated the fiscal effects of the rate previously established for residential analog meters and determined that the base rate needed to be increased; and

WHEREAS the City Council desires to ensure power rates are revenue neutral, and the Power Board has recommended an increase in the base rate for residential analog meters to accomplish revenue neutrality; and

WHEREAS the Hurricane City Council finds that these clarifications and amendments are necessary and desirable for the preservation and protection of the health, safety, and welfare of the residents of Hurricane,

BE IT HEREBY RESOLVED by the Hurricane City Council that the base rate charged to Hurricane City Power residential analog meter customers shall increase to a standard $63.50/month. This updated base charges for all Hurricane City Power service areas are set forth in Exhibit “A” attached hereto. The updated rates and charges set forth in this Resolution shall be effective for electricity usage occurring in August 2025, which will be billed in September 2025.

PASSED AND APPROVED this 7th day of August 2025.

____

Nanette Billings, Mayor

Attest:

____

Cindy Beteag, Hurricane City Recorder

The foregoing Resolution was presented at a regular meeting of the Hurricane City Council held at the Hurricane City Office Building on the 7th day of August 2025. Whereupon a motion to adopt and approve said Resolution was made by ___________________________ and seconded by ____________________________. A roll call vote was then taken with the following results:

	Yea	Nay	Abstain	Absent
David Hirschi	___	___	___	___
Kevin Thomas	___	___	___	___
Clark Fawcett	___	___	___	___
Drew Ellerman	___	___	___	___
Joseph Prete	___	___	___	___

____
Cindy Beteag, Recorder

Exhibit "A"

			Rate Effective 9/1/24 (July-Aug usage)
Residential			
Base Charge (Rate 101, 107)			$ 20.00
Plus	Usage		$ -
	1-800	KWh	$ 0.08946
	801-2000	KWh	$ 0.10222
	2000+	KWh	$ 0.11485
			$ -
ANALOG METER-Residential			$ -
Base Charge (Rate 121)			$ 63.50
Plus	Usage		$ -
	1-800	KWh	$ 0.08946
	801-2000	KWh	$ 0.10222
	2000+	KWh	$ 0.11485
			$ -
Electric-Agricultural 1P			$ -
Base Charge - Single Phase (Rate 108)			$ 18.00
Plus	All KWh		$ 0.09380
			$ -
			$ -
Electric-Agricultural 3P			$ -
Base Charge - Three Phase (Rate 111)	All KWh		$ 24.50
Plus			$ 0.10761
			$ -
Small Commercial 1P			$ -
Base Charge - Single Phase (Rate 105)			$ 19.00
Plus	Usage		$ -
	1-800	KWh	$ 0.10302
	801+	KWh	$ 0.10880
Plus	Demand Charge over 50KWh		$ 8.50
			$ -
Small Commercial 3P			$ -
Base Charge - Three Phase (Rate 106, 112, 113)			$ 24.50
Plus	Usage		$ -
	1-800	KWh	$ 0.10302
	801+	KWh	$ 0.10880
Plus	Demand Charge over 50KWh		$ 8.50
			$ -
Alternative Large Commercial Rate - Interruptible 3P			$ -
Base Charge - Three Phase (Rate 110)			$ 320.00
Plus	Usage		$ -
	All KWh		$ 0.06658
	Demand Charge		$ 4.55
			$ -
Large Commercial 3P			$ -
Base Charge - Three Phase (Rate 104)			$ 320.00
Plus	Usage		$ -
	All KWh		$ 0.06658
Plus	Demand Charge		$ 9.10
			$ -
Old Commercial Rate			$ -
Base Charge (Rate 199)			$ 18.50
Plus	Usage		$ -

	1-800	KWh	$	0.09209
	801-1500	KWh	$	0.10525
	1501-26500	KWh	$	0.10170
	26501+	KWh	$	0.09183
Plus	Demand Charge over 50KWh		$	7.60
			$	-
CITY-1P			$	-
Base Charge - Single Phase (Rate 102)			$	18.00
Plus	Usage		$	-
	1-800	KWh	$	0.10064
	801+	KWh	$	0.11051
			$	-
CITY-3P			$	-
Base Charge - Three Phase (Rate 103)			$	24.50
Plus	Usage		$	-
	1-800	KWh	$	0.10064
	801+	KWh	$	0.11051
			$	-
Electric Production-Solar refund (Rate 177)	All		$	(0.04)
			$	-
OLD Residential Solar			$	-
Base Charge (Rate 115)			$	20.00
Plus	Usage		$	-
	1-800	KWh	$	0.08946
	801-2000	KWh	$	0.10222
	2000+	KWh	$	0.11485
			$	-
1P System Solar			$	-
Base Charge (Rate 116)			$	30.00
Plus	Usage		$	-
	1-800	KWh	$	0.08946
	801-2000	KWh	$	0.10222
	2000+	KWh	$	0.11485
			$	-
3P Basic System Solar			$	-
Base Charge - Three Phase (Rate 118)			$	90.00
Plus	Usage		$	-
	1-800	KWh	$	0.10302
	801+	KWh	$	0.10880
	Demand Charge over 50KWh		$	8.50
			$	-
PACIFICORP POWER (OLD UP&L/ROCKY MTN PWR) (Rate 109)				
This is a contracted rate and not subject to rate changes passed by resolution	All	KWh	$	0.19487

UAMPS UPDATES


ENERGY MANAGEMENT
• Load & Resource Forecasting
• Energy Operations Center
• Power Supply Portfolio
• Real-Time Power Exchange
• Fuel Acquisition
GENERATION & INFRASTRUCTURE
• Generation Development & Operations
• Network Transmission
• DOE Resilience Grants
COMMUNICATION & COLLABORATION
• Quarterly Newsletter "Plugged in with UAMPS"
• Annual Conferences & Workshops
• Annual Awards
• Information Sharing Platform
Net Metering, Wildfire Mitigation, Large Loads
UAMPS SERVICES
Delivering low-cost, reliable power to member communities
MEMBER & COMMUNITY SUPPORT
• Smart Energy Efficiency Program
• REC Management
• Real-Time Metering
• Scholarships & Education
• OSHA Training
FINANCIAL & REGULATORY
• Federal & State Advocacy
• Financing Services
• Member Internal Generation Support
• Financial Assessment Reports
• Annual Budget to Actual Reports

UAMPS Services
July 2025

Utah Associated Municipal Power Systems (UAMPS) provides low-cost, reliable power and strategic energy services to its members through innovative projects and economies of scale. A high-level overview of the energy services is listed below.

Load and Resource Forecasts: UAMPS conducts long-term power supply studies and develops load and resource forecasts through its **Integrated Resource Plan** and **Annual Resource Procurement Plan** to ensure it has ample power supply to meet the growing load needs of its member communities. UAMPS also develops annual load and resource forecasts for each member.

Power Supply: UAMPS adheres to its **Energy Risk Management Policy** to manage a diverse power supply portfolio, which includes a combination of UAMPS-owned generation projects, member-owned internal generation, long-term power purchase agreements, and short-, long- and spot-market purchases. Leveraging its strategic location near the California market, UAMPS actively participates in wholesale market transactions to reduce members' wholesale power costs.

Generation Development: UAMPS investigates the feasibility of new generation projects through its **Resource Project,** using two methods: self-build projects and third-party power purchase agreements. Each generation feasibility study includes a holistic assessment of the project's costs for all stages of development including construction, operations, and decommissioning. Upon completion of the investigation, viable projects move to either a **Standalone Project** (for the self-build option governed by take-or-pay power sales contracts) or into the **Firm Power Supply Project** (for third-party power purchase agreements).

Generation Operations: UAMPS operates, maintains and dispatches approximately 200 megawatts (MW) of owned generation. This fleet includes the **Nebo Project**, a 140 MW combined-cycle natural gas unit; the **Veyo Project**, a 7.8 MW waste heat energy recovery facility; and the **Horse Butte Wind Project**, a 57.6 MW wind farm. UAMPS prioritizes cost-effective operations and continually evaluates opportunities to optimize fuel acquisition, reduce emissions, enhance maintenance improvements, and improve economic dispatch to achieve the highest efficiencies for its generation projects. To meet growing member needs and ensure long-term reliability, UAMPS is expanding its generation portfolio with two major projects currently in development: the 184 MW **Millard County Project**, featuring a fleet of reciprocating internal combustion engines; and the 388 MW **Power County Project,** a frame-style combined-cycle generation plant.

Energy Operations Center: UAMPS operates its energy operation center around the clock —365 days a year —to provide load management, generation operation, renewable integration, transmission availability, and real-time operations including short-term power supply acquisition. Through its **Pool Project**, the energy operations center continuously matches members' load and resource needs on an hourly basis through the pooling of resources and economically dispatches power at the lowest available cost. UAMPS' online power exchange provides members with real-time meter and operation information, enhancing transparency and informed decision-making.

Fuel Acquisition: UAMPS purchases and schedules natural gas and transportation for its own generation facilities and for member-owned internal generation through its **Natural Gas Project**, which provides economies of scale and ensures reliable fuel access.

Transmission: UAMPS facilitates transmission service for its members within the PACE balancing area through its Transmission Service and Operating Agreement (TSOA) with PacifiCorp. The TSOA provides members with delivery flexibility over the PacifiCorp network at a wholesale rate. UAMPS also files transmission services requests on behalf of members for distribution system interconnections and actively monitors NERC and FERC proceedings to safeguard UAMPS' rights as a transmission-dependent, load-serving entity.

Real-time Metering: UAMPS owns, installs, and tests meters at its owned generation projects, members delivery points and member-owned internal generation projects to provide accurate, real-time data to support operational reliability and informed energy management.

Financing Services: UAMPS finances capital projects through tax-exempt bonds, grant funding, and partnerships with private entities. Its financial services also include prepay electricity and gas transactions, which help reduce the overall cost of energy for its members.

Legislative and Regulatory Oversight: UAMPS actively monitors state and federal legislative and regulatory developments that affect energy policy and public power. UAMPS uses this insight to advocate on behalf of its members and ensure their voices are represented in key policy discussions.

FACT Sheet

WESTERN AREA POWER ADMINISTRATION

Proposed spectrum auction impacts national power grid

System relies on dedicated frequencies for communications

WAPA delivers wholesale electricity to more than 680 customers – powering rural communities across the West and Great Plains. Not only do our customers depend on cost-based hydropower, but they rely on WAPA to maintain a stable and secure energy grid.

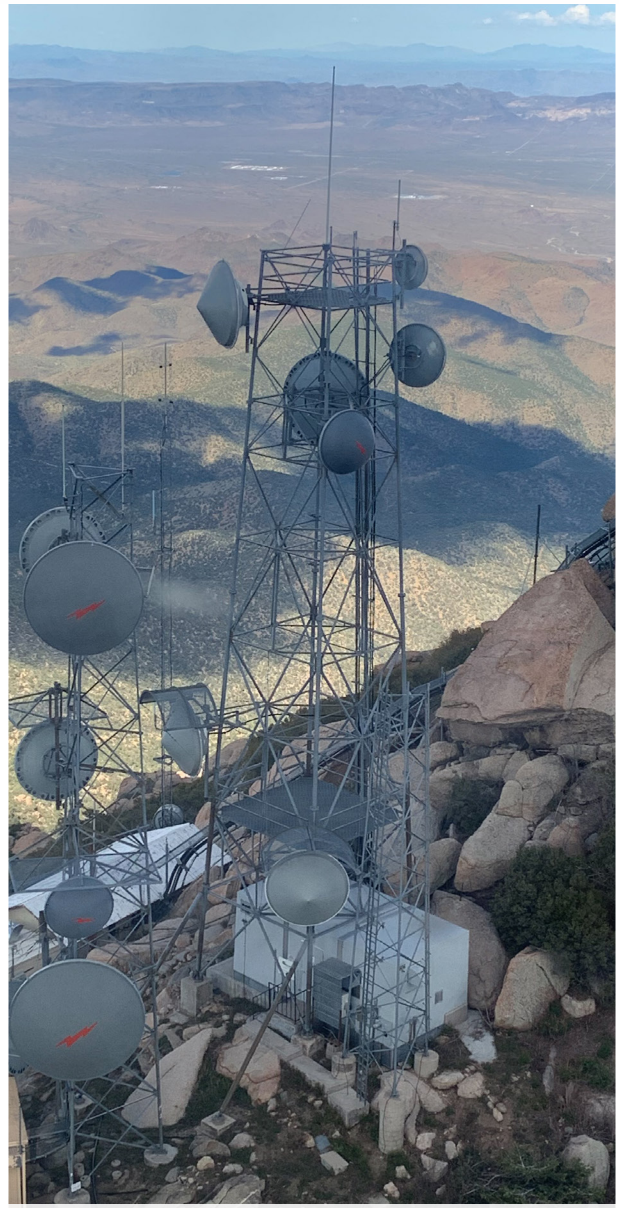
As one of the nation's largest transmission providers, WAPA also delivers hydropower to 35 federal facilities, including more than 25 military installations and research institutions.

However, a provision in the budget bill currently before Congress could significantly impact the ability of WAPA and its sister Power Marketing Administrations (PMAs) – Bonneville Power Administration, Southeastern Power Administration and Southwestern Power Administration – to meet the needs of customers.

Running the power grid is like flying a plane: Operators need constant communication to make sure everything is safe, reliable and working together. WAPA uses microwave radio systems to control substations and transmission lines remotely, monitor and respond to outages and problems, and keep the power system safe for our line crews and the public.

WAPA currently operates its microwave radio systems in the seven and eight gigahertz (GHz) ranges. Historically, this spectrum has been limited to use by the PMAs, their federal hydropower generating partners, the U.S. military and other federal agencies exclusively. It's like a quiet, reliable road we've used for decades.

The legislation proposes auctioning off 600 megahertz (MHz) of spectrum to private companies for things like cellular and other services. This has the potential to significantly impact the tried-and-true systems PMAs and federal hydropower agencies, including the Bureau of Reclamation and Army Corps of Engineers, use to control major portions of the electric grid.



WAPA's transmission system operations depend on microwave radio installations like this communications site near Kingman, Arizona.

WAPA file photo

Potential solutions present technical and cost challenges

If the PMAs are required to change the power grid's command-and-control communications systems, this would mean moving to a more crowded "road" or building a new one. Establishing new communications systems such as fiber optics or higher frequency systems could cost $10-15 billion and require 20 to 25 years to implement.

- Federal power providers could install fiber optic cable instead of using radio, but that would be extremely expensive and take years or decades to complete. It involves securing permits and land rights, and some areas we serve are so remote or rugged, it might not even be possible.
- Higher frequencies like 15 GHz or 23 GHz don't travel as far and are easily impacted by weather and other atmospheric conditions. They're simply not viable.
- If other entities squeeze or "co-locate" into our current spectrum, it could cause signal interference, increase risk and limit our ability to adapt as power needs grow. Testing how other systems would operate or interfere with ours would take time and resources we don't currently have.
- Because available spectrum is finite, losing portions of our frequency band to commercial entities is irreversible.

Note that if the PMAs retain their current radio spectrum but the generating agencies do not, federal power system reliability and safety would be compromised. We must be treated as a system, or the consequences will cascade.

National economic growth depends on grid expansion

Data centers, artificial intelligence and further electrification will require a bigger, better power grid. But imposing burdensome costs for new communications systems could stifle economic growth and impact grid reliability. Even if the spectrum auction proceeds cover the cost of building new infrastructure, the cost to operate and maintain it will fall on customers already facing economic pressure.

If this proposal succeeds, WAPA and its customers could face major impacts including:

HIGHER RATES

Federal law requires WAPA to recover its costs from customers through rates. Building and maintaining new systems will result in higher rates for customers and consumers.

SLOWER GRID EXPANSION

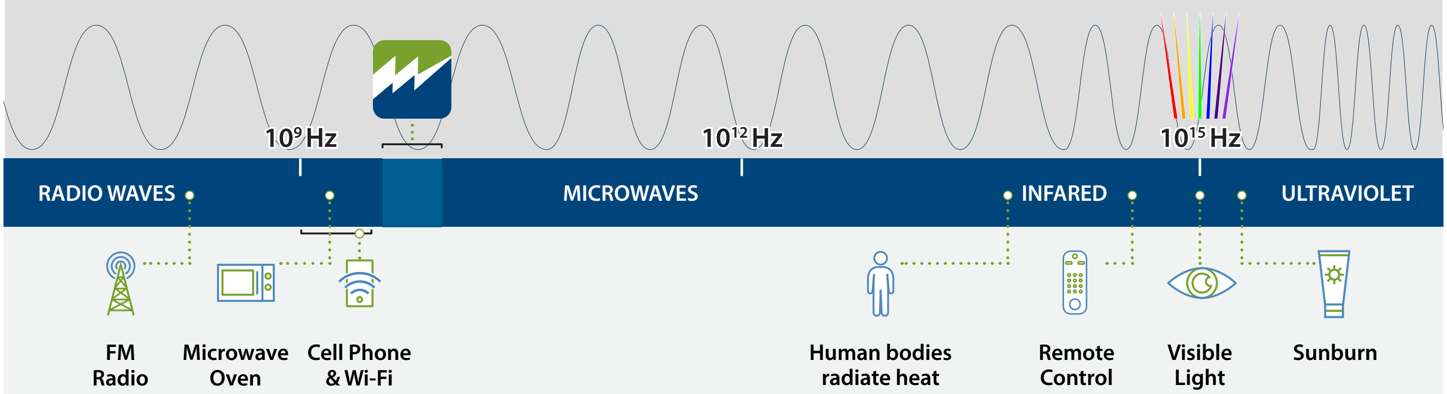
As demand for electricity grows for data centers and other new industries, grid expansion may be hindered without adequate spectrum.

LOWER RELIABILITY

New systems could be more vulnerable to weather and other technical problems.

Reliable grid operations require constant communication. This proposal could undermine grid reliability and America's ability to meet future energy demands. Without fully funded alternatives, relocation could jeopardize grid and rate stability and undermine national priorities like AI, economic competitiveness and energy security.

FEDERAL HYDROPOWER AND THE ELECTROMAGNETIC SPECTRUM



Delivery of federal hydropower depends on communications systems that operate in the seven and eight GHz range.

Energy Efficiency Rebates: UAMPS supports conservation efforts through its **Smart Energy Program**, which provides energy efficiency incentives to members' utility customers. Under this program, UAMPS processes and issues rebate checks to customers, who invest in qualifying energy-efficient products and technologies, contributing to reductions in overall energy consumption and cost.

Renewable Energy Credit Management: UAMPS manages Renewable Energy Credits (RECs) generated from its owned renewable energy projects and solar power purchase agreements through the Western Renewable Energy Generation Information System. To help offset wholesale power costs, UAMPS sells all or a portion of its RECs depending on the current needs of the members.

Scholarship Programs: UAMPS awards scholarships to high school seniors to further their education in renewable energy or related fields, which fosters a pipeline of skilled professionals who are well-prepared to contribute to the industry's growth and sustainability for years to come.

Education Services: UAMPS hosts an annual conference and toolkit workshop for member governing boards to educate them about new products, strengthen relationships, and foster collaboration among utilities facing similar challenges in the electric energy industry. These events empower members with the insights and tools they need to make informed decisions, improve operations, and stay ahead in a rapidly evolving industry.

Awards Program: UAMPS presents annual awards to recognize exceptional member-led projects and individuals who demonstrate leadership, innovation, and service in their communities. These honors celebrate the meaningful contributions of members in advancing public power and strengthening the communities they serve.

Information Sharing Platforms: UAMPS facilitates information sharing among members about lessons learned on a variety of areas including 5G, net metering, wildfire mitigation, and large loads. UAMPS provides real-time text notifications to keep members informed of operational changes to generation projects, transmission restrictions, and PacifiCorp wildfire alerts.

Member Services Program: UAMPS' **Member Services Project** delivers services that enhance operational efficiency and reduce costs for its members through economies of scale.

- **Shared Equipment**: UAMPS facilitates joint ownership of specialized testing equipment such as pole test set(s), a power factor test set, a battery test set, and a borescope test set, allowing members to access tools without bearing the full cost individually.

- **Subscriptions and Dues**: UAMPS pays annual subscriptions and dues on behalf of members for American Public Power Association, eReliability Tracker, Intermountain Power Superintendent Association, and Energy Trader.
- **Mobile Generator:** UAMPS owns a 1.8 MW generator that members may utilize during a power outage or system emergency.
- **Safety Training:** UAMPS offers online safety training programs that allow member utility staff to complete high-quality courses at their own pace and convenience.
- **Member Internal Generation:** UAMPS provides financial services for its members developing their own internal generation projects.
- **Grant Assistance:** UAMPS assists members in applying for Department of Energy grants, including preparing the grant and overseeing ongoing grant reporting obligations.
- **Advanced Metering Infrastructure:** UAMPS offers financing options for its members to purchase and install advanced metering infrastructure, which allows members to provide improved data and customer service to their electric customers.

Other Services: UAMPS provides a variety of value-added services—beyond its core offerings—to keep members informed, financially sound, and aligned with industry standards.

- **Quarterly Newsletters "Plugged in with UAMPS"**: UAMPS publishes a quarterly newsletter featuring information and updates on organizational activities, member highlights, and developments across the electric industry.
- **Financial Assessment Reports:** UAMPS conducts individualized financial assessments for its members that evaluate the fiscal health of their electric departments using the same key financial metrics employed by credit rating agencies when assessing UAMPS projects.
- **Annual Budget to Actual Reports:** UAMPS provides members with an annual analysis comparing UAMPS' fiscal annual budget compared to its actual costs, offering transparency and accountability in financial performance.