SRP Price Process Comments Week ending February 22, 2025

SRP Public Price Process Comments from: 2/16/2025

Name: Wes Hevener

Record Number: a6d828d0

Delivery Method: Digital Submission

Comment:

As a member of Boilermakers Local 627 I have seen how the investment of SRP to support coal communities has helped the whole economy of these towns. St. John's Is a great example! I support the rate increase because the return on investment to the forgotten towns around Arizona that are built and survive because of the power plants and the economic impact they provide. SRP is a great partner for well paying jobs to areas that lack large industry job opportunities. In an area that has some of the highest temperatures of the Southwest we need a power provider that has our needs in the forefront of their vision and expansion for the future needs of their customers.

SRP Public Price Process Comments from: 2/17/2025

Name: Elizabeth M McNamara

Record Number: 7d30c016

Delivery Method: Digital Submission

Comment:

I'm extremely concerned about the change in hours for the TOU plans. The idea of these plans is to avoid using appliances (i.e ac) during the leak hours. My current TOU plan is 3-6pm. As I'm at work I'm able to super cool my house in the late morning & early afternoon so the AC can be off during these peak hours. This would be much more challenging with the new plans. Peak pricing will now be until 9 or 10pm. I would basically have to run my AC all day to avoid using it during this time. I would be going to bed when the house is at its hottest. It's doesn't seem like a very consumer friendly change & could be downright dangerous given the high heat we've experienced in the last couple of years. I hope this change is not permitted

---

Name: Joy Seitz

Record Number: MI7076907

Delivery Method: Email to Corporate Secretary

Attachments: please accept into the files.pdf

To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7076907

Comment:

https://www.yourvalley.net/stories/how-srps-new-solar-rate-proposal-could-crush-solar-in-arizona,564158

Joy E. Seitz

CEO

American Solar & Roofing

Name: Gregory Mishaga

Record Number: MI7077342

Delivery Method: Email to Corporate Secretary

Attachments: Give solar customers a fair deal!_Mishaga.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7077342*

Comment:

Give solar customers a fair deal!

Dear Corporate Secretary,

Arizona is a solar leader but SRP's rates and policies do not currently reflect that. I am writing as a concerned Arizonan to urge SRP to reconsider its pricing and ensure that customers are rewarded for investing in clean and efficient technologies like solar power.

Arizonans deserve energy choice and the opportunity to invest in local, resilient energy sources. SRP's proposal to increase the monthly fixed charge not only discourages customers from investing in clean energy projects, it also hits low-income households the hardest. Ultimately, high fixed fees discourage efforts to conserve electricity, putting more strain on Arizona's energy system.

Arizona is a leading producer in solar energy. I strongly urge you to ensure that SRP's pricing plans are fair to customers who have chosen to invest in solar.

Thank you for your consideration,

Sincerely,

Rev. Gregory Mishaga

Name: Joy Seitz

Record Number: MI7078425

Delivery Method: Email to Corporate Secretary

Attachments: Article.pdf

To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7078425

Comment:

From: Joy Seitz
Sent: Monday, February 17, 2025 11:06 AM
To: David Rousseau
Cc: Jim M Pratt ; Michael J O'Connor ; SRP Corporate Secretary
Subject: Article

David –

Good morning and happy President's Day. I share this article as one more opportunity to keep talking. As President of the SRP board, I am asking you to implore Jim Pratt to meet with me and find a solution that will support the continuation of solar deployment. For years, I have asked Mr. Pratt to meet with me and discuss the utilities issues, to find ways solar and storage can help. For years, he has pushed me off. I do not understand why. I can text the CEO and/or the COO of APS anytime and they will take my call to discuss how we can work together, even if the answer isn't exactly what I hope for.

https://www.yourvalley.net/stories/how-srps-new-solar-rate-proposal-could-crush-solar-in-arizona,564158

I have sent this article to the Corporate Secretary; I have added legal and the corporate secretary for any other housekeeping items.

Thank you for taking this request seriously.

Joy E. Seitz

CEO

American Solar & Roofing

Name: Joy Seitz

Record Number: MI7079514

Delivery Method: Email to Corporate Secretary

Attachments: Article & Amendment Language.pdf; Amendment 1_final.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7079514*

Comment:

From: Joy Seitz
Sent: Monday, February 17, 2025 11:13 AM
To: Christopher J Dobson
Cc: Michael J O'Connor; SRP Corporate Secretary
Subject: Article & Amendment Language

Mr. Dobson –

Good morning and happy President's Day. I share this article and amendment language because you were unfortunately absent from the meeting, I gave public testimony and I know there is a lot of data coming out of this process. As Vice President of the SRP board, I am asking you to implore Jim Pratt to meet with me and find a solution that will support the continuation of solar deployment. For years, I have asked Mr. Pratt to meet with me and discuss the utilities issues, to find ways solar and storage can help. For years, he has pushed me off. I do not understand why. I can text the CEO and/or the COO of APS anytime and they will take my call to discuss how we can work together, even if the answer isn't exactly what I hope for.

If he is unwilling to find a solution that works, I ask that you be willing to support this amendment when it is discussed at the board meeting.

https://www.yourvalley.net/stories/how-srps-new-solar-rate-proposal-could-crush-solar-in-arizona,564158

I have sent this article and the amendment to the Corporate Secretary; I have added legal and the corporate secretary for any other housekeeping items.

Thank you for taking this request seriously. I am available anytime t take your call and answer any questions.

Joy E. Seitz

CEO

American Solar & Roofing

**See attached letter dated Feb. 10th

February 10, 2025

Salt River Project Board of Directors
c/o Corporate Secretary
1500 N. Mill Ave.
Tempe, AZ 85288

RE: Act Now to Protect Rooftop Solar and Its Customers

Dear Salt River Project Board of Directors,

Founded in 2001, American Solar & Roofing is Arizona's original solar installation company and a SRP Preferred Solar Installer. The "solar rates" proposed by Management (E-16 and E-28) necessitate battery integration for customer adoption to occur. While AS&R strongly advocates for the deployment of utility-scale energy storage as a critical component of a resilient, sustainable energy grid, we do not recommend, nor do we sell, residential batteries.

SRP must not turn its back on its solar customers while industry makes a more reliable battery solution. **We urge the SRP Board of Directors to motion for and adopt the following amendment language at the next board meeting:**

1. **Preserve the E-14 rate structure for solar-only customers (with or without EVs). Cap participation of 5,000 customers per year.**

2. **Adopt Management's recommendation for calculating the Export Rate.**

3. **Align the E-14 basic service charge with other rate structures.**

Below are several key reasons why we do not support residential battery adoption currently:

- Between 70-90% of residential battery systems contain cells manufactured in China. With the new administration proposing additional tariffs on Chinese products, the cost of cells will rise, making the adoption of residential batteries less economically viable.

[redacted]

- Installing a functional residential battery system is complicated. Whether they exist in a Virtual Power Plant (VPP) network or are stand-alone, battery systems require competent management and technical support.
- Solar installers throughout the nation are experiencing high failure rates with reputable battery solutions. This places the installation company at financial and legal risk.
- Some battery solutions are on back order for up to six months, making deployment unpredictable.
- At least one study from Australia shows that capacity degradation occurs quickly when batteries are cycled often. This degradation impacts the financial viability of the system. Ratepayers being encouraged to adopt Management's proposed "solar" rate will begin to experience financial losses within a few years of cycling their battery.
- Safety.

Since SRP proposed the E-32 rate back in 2014, AS&R has been dedicated to finding a reliable and safe battery solution for our customers. Our customers ask for a solution regularly. SRP's grid reliability does not necessitate the adoption of batteries for self-consumption and SRP's E-14 rate is "equitable" for a solar-only homeowner and SRP.

Sincerely,

Joy E. Seitz

Joy E. Seitz
CEO
[redacted]

Name: Norm Sendler

Record Number: MI7080383

Delivery Method: Email to Corporate Secretary

Attachments: New Mexico Land Issues.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7080383*

Comment:

From: Norm UP
Sent: Monday, February 17, 2025 3:02 PM
To: Norm UP ; SRP Corporate Secretary
Subject: New Mexico Land Issues

Happy Monday and (belated) Valentine's Day; hope you had a nice weekend.

I know that SRP pricing meetings are coming to a close and the normal portal will not permit the characters used in a web link.

So, once again, might I ask for your assistance and pass this along to the Board Members?

https://estancia.news/attention-doge-department-of-energy-charging-ahead-with-land-grab-in-new-mexico-and-colorado-for-green-energy-and-is-in-desperate-need-of-cancellation/

Thank you again and have a wonderful day,

Norm Sendler

SRP Public Price Process Comments from: 2/18/2025

Name: Maureen Rojas

Record Number: 189ed554

Delivery Method: Digital Submission

Comment:

The proposed rate increase is especially burdensome on lower income customers, who are struggling to afford basic housing expenses. This includes many of my neighbors. I am especially troubled by the even higher rate increase for residential solar customers. This is highly unfair to those who have invested in clean, renewable energy, and discourages others who may be considering it. SRP's continued disincentives for adopting residential solar fly in the face of reason and science. Sunshine is the most abundant and clean resource we have in Arizona, yet more than half of power generation comes from fossil fuels with no meaningful movement away from the number one cause behind our extreme heat, much less toward clean renewable energy. SRP does a lot of other good work in support of the environment, but in the area where you can make the biggest difference, your lack of responsible action on behalf of the people you serve is simply shameful.

Name: Blake Sacha

Record Number: 8a176fac

Delivery Method: Digital Submission

Comment:

Why are residential solar customers being charged more with this increase? The explanation does not provide any justification for charging solar customers more than the additional amount already paid. Existing solar customers don't cost any more than non-solar customers.

Name: Laura Hudson

Record Number: 1196149e

Delivery Method: Digital Submission

Comment:

The proposed rate increase is too high and particularly unfair to solar customers.

Name: SHERI DON

Record Number: ab6c436a

Delivery Method: Digital Submission

Comment:

Every time we turn around we're getting hit with rate hikes. In just the few short weeks of this year, I have had increases in property tax, HOA, car and house insurance. I keep my house colder than I'd like in the winter and hotter in the summer to keep my bill down. In a state that has about 350 days of sunshine why are we still so reliant on fossil fuels? It's bad enough that gasoline prices in Arizona are about $.20 higher than the national average, but to keep relying on fossil fuels for energy seems archaic.

Name: Joy Carter

Record Number: 6a3fea44

Delivery Method: Digital Submission

Comment:

The increased pricing for SRP electricity plans will put increased financial hardship on families already struggling with increases in prices for basic needs such as food and housing. With record-breaking heat and consecutive days over 110 degrees each summer, this increase could result in people living in unsafe conditions due to the heat and lack of ability to pay high summer electric bills. SRP could look into using more sustainable ways of generating power to reduce the reliance on fossil fuels and save costs instead of passing on increases to customers who are already struggling financially. Thank you for your time and consideration.

Name: Gregg R. Hooker

Record Number: MI7084646

Delivery Method: Mailed to SRP

Attachments: PriceProcessComment_20250218_Hooker.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7084646*

Comment:

2/1/2025

Dear SRP Board Members,

As a long time, SRP customer and recent solar energy system owner, I am deeply concerned about the proposed changes to SRP's rate plan. These changes will negatively impact my
household and others who have invested in clean energy solutions. I have recently invested in a new solar system to help offset some of my household electric costs which I need because I have recently retired.

Specifically:

• Time-of-Use Hours Shift: Reducing the value of energy produced during daylight hours unfairly penalizes solar customers.

• Unfair Grandfathering Policies: Offering only four years of protection for newer solar customers, compared to 20 years for older customers, is inequitable.

• Inconvenient Appliance Use Hours: Shifting time-of-use schedules forces families to use appliances during inconvenient late-night hours.

• Higher Demand Charges: Increased charges erode the financial benefits of my solar system, discouraging clean energy adoption.

These changes contradict SRP's commitment to sustainability and fairness. I urge you to reconsider these proposals and work toward solutions that support solar customers and encourage renewable energy investment.

Thank you for your attention. I look forward to hearing SRP's plans to protect the interests of its customers and the environment.

PS: President Trump will be making big ENERGY CHANGES in 2025 that will help significantly drive down the cost of energy which will help offset operating costs for SRP. This will lower the cost of producing energy at SRP and these savings should be able to reduce the need for the currently proposed changes.

Sincerely,
Mr. Gregg R. Hooker

Name: Karen E. Hooker

Record Number: MI7085945

Delivery Method: Mailed to SRP

Attachments: PriceProcessComment_20250218_KHooker.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7085945*

Comment:

2/1/2025

Dear SRP Board Members,

I am writing as a proud SRP customer and advocate for solar energy. My family made the decision to invest in solar power because it benefits our community, the environment, and our
finances. However, I am disheartened by SRP's proposed rate changes, which threaten all three.

Reducing the value of daytime solar production undermines the effectiveness of solar systems, discouraging clean energy investments that benefit all SRP customers. Additionally, penalizing newer solar customers with limited grandfathering protections feels deeply unfair.

These changes do not align with SRP' s stated commitment to sustainability. I believe we must prioritize solutions that support solar adoption, protect the environment, and maintain fairness for all customers.

Please reconsider these changes and stand with customers like me who are working toward a cleaner, more sustainable future.

PS: President Trump will be making big ENERGY CHANGES in 2025 that will help significantly drive down the cost of energy which will help offset operating costs for SRP. This will lower the cost of producing energy at SRP and these savings should be able to reduce the need for the currently proposed changes.

Sincerely,

Karen E. Hooker

Name: Mary Ann Gorombei

Record Number: MI7088300

Delivery Method: Mailed to SRP

Attachments: PriceProcessComment_20250218_Gorombei.pdf

To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7088300

Comment:

2-9-25

To whom it may concern:

Price increases:

You always send out notices of how we are doing - well you should be on a budget yourself as a company an cut back waste.

Quite increasingly your rates and our bill would not be so high.

And about plans you should have loyalty plans because we real do not have competition for prices.

And how about seniors - other companies have deals for seniors not just low income but all seniors.

And about solar to much money as the supply is the sun and the sun does not charge you but you do a good job of charging customers one way or another.

So lets think about budget and seniors in our pricing plans as it should be.

Thank you for your time if you read this and I hope it give you something to think about in your pricing.

Thank you

Mary Ann Gorombei

P.S. Not every one has competitors!

Also for what you charge us all customers should get free home assessment!

Name: David A SKINNER

Record Number: 53d0ea90

Delivery Method: Digital Submission

Comment:

You say the data centers won't increase residential customers yet rates keep going up via the rubber-stamp council. Give us something to make us believe you!

Name: David Bender

Record Number: f0173bd8

Delivery Method: Digital Submission

Comment:

This Fifth Set of questions continues numbering from prior sets. 25. Reference your response to prior request #20, which states that you applied “an estimate of the FY26 24 7 carbon-free energy value to SRP” from “SRP's market traders” to segregate an energy-related and demand-related amounts. Please identify the “FY26 24 7 carbon-free energy value to SRP” from “SRP's market traders” that was applied. Please provide the prices separated by the shortest time period for which such prices are available (such as hourly or sub-hourly prices if available).

Name: Pauline Smith

Record Number: 696cc302

Delivery Method: Digital Submission

Comment:

No one likes rate increases but the proposed higher rate increase for solar household is concerning. We need to continue to explore and encourage more sustainable means to supply energy and less energy source from fossil fuel. Your proposed rate increases does not promote sustainable energy generation. Please promote and encourage solar use to produce household energy needs.

SRP Public Price Process Comments from: 2/19/2025

Name: Robert Humphrey

Record Number: 377ea1e8

Delivery Method: Digital Submission

Comment:

This reduction in kWh credits to solar electric system owners is ridiculous. Talk about a bait and switch strategy. We spent our money on solar electric systems and helped the grid. Now a complete loss of benefit for helping out at peak demand times. If this gets approved, the Commission is just a rubber stamp for SRP.

Name: Mark F Miller

Record Number: 8e9ad8e5

Delivery Method: Digital Submission

Comment:

Is the customer generated price plan going away?

Name: Helga Canfield

Record Number: MI7094136

Delivery Method: Email to Corporte Secretary

Attachments: Solar must stay_Canfield.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7094136*

Comment:

From: Helga Canfield
Sent: Tuesday, February 18, 2025 6:12 PM
To: SRP Corporate Secretary
Subject: Solar must stay

It is my understanding that SRP will finalize its rate case next week.

As we all know, the emergence of data centers in the Valley, the continued electrification of homes and the rise in EV adoption will all spur a huge increase in demand. Not even to mention all the air pollution caused by an ever increasing population. As such, distributed generation through solar should be an important part of the mix.

The new rate proposal will decimate the solar effort in the state of Arizona once again. I sincerely hope SRP will reconsider the current rate proposal and not set the state back again.

Best regards,

Helga Canfield

RSM - Southwest

Qcells

Name: April Ayers

Record Number: MI7095718

Delivery Method: Email to Corporte Secretary

Attachments: Solar Customer Rate Increase_April.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7095718*

Comment:

From: April Ayers
Sent: Tuesday, February 18, 2025 8:51 PM
To: SRP Corporate Secretary
Subject: Solar Customer Rate Increase

I'm writing this in response to a news story I just viewed re: a possible rate increase for SRP customers. This story mentioned that solar customers would receive a higher increase than standard SRP customers.

I am requesting an explanation as to how it places more demand on the grid or the system to deliver electricity to my house (solar) than to my next door neighbor (non solar)?

We actually alleviate demand OFF the grid. You buy our electrical power surplus at a lower rate than what you sell it for. Solar customers help the extreme demand on our grid in multiple ways yet you want to punish us? You will penalize my household instead of my neighbor who does nothing to improve your situation or our planet?

Please respond in a timely fashion as I will be contacting the Utility Commission and will be attending the meeting with the Public Board of Directors meeting on the 27th. I can work with Az Family since they aired the story to be sure they are present as well. They will assist with publicizing this issue until we reach a resolution.

Thank you in advance for your time. I look forward to speaking with you.

April Ayers

Name: Rob Ayers

Record Number: MI7096712

Delivery Method: Email to Corporte Secretary

Attachments: Residential rate increase_Ayers.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7096712*

Comment:

From**:** Rob Ayers
Sent: Tuesday, February 18, 2025 8:59 PM
To: SRP Corporate Secretary
Subject: Residential rate increase

I saw on the news this evening, that a price increase is coming. That's normal. I don't like it, but I get it. Your Board of Directors probably need new cars or something.

The news story said the rate hike will be disproportionate between solar and non-solar customers, with the higher increase going to the solar customers. The same news story cites that the reason for the hike is that higher demand taxes the grid more heavily. It seems that the non-solar customers would exacerbate this increased load while the solar customers help to alleviate the demand. I think your rationale is, for lack of a better vocabulary, ass-backwards.

Name: JoAnna Mendoza

Record Number: MI7097311

Delivery Method: Email to Corporte Secretary

Attachments: Submission of Public Comments for SRP Special Board of Directors Meeting – February 27, 2025_Mendoza.pdf; SRP Comments VetsFwd_Mendoza.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7097311*

Comment:

From: JoAnna Mendoza
Sent: Tuesday, February 18, 2025 10:13 PM
To: SRP Corporate Secretary
Subject: Submission of Public Comments for SRP Special Board of Directors Meeting – February 27, 2025

To Whom It May Concern;

I hope this email finds you well. I am submitting public comments on behalf of **VetsForward**, an organization committed to ensuring that the voices of veterans and military families are heard in critical policy decisions. Please ensure that the attached comments are included in the **public record** and submitted for consideration at the **SRP Special Board of Directors Meeting on February 27, 2025, at 9:30 AM.** If there are any additional steps I need to take to ensure these comments are properly recorded and reviewed by the Board, please let me know.

Thank you for your time and assistance. I appreciate your help in making sure our concerns are heard.

Best regards,

JoAnna Mendoza

See attached letter

February 18, 2025

Re: **Public Comment on SRP's 2025 Pricing Proposal**

Dear Members of the SRP Board of Directors,

VetsForward, a veteran-led advocacy group. Many of our members rely on affordable and stable energy prices, and we are deeply concerned that SRP's proposed rate increases and pricing changes will disproportionately harm veterans, military families, and working-class Arizonans.

Key Concerns:

- **Unnecessary Rate Hikes:** The proposed 3.4% increase for residential customers and 5.5% hike for solar users will disproportionately impact veterans, military families, and working-class Arizonans. SRP should focus on energy efficiency investments to lower long-term costs.
- **Limited Pricing Options:** Forcing all customers into just four pricing plans by 2030—with peak-hour rates from 5-10 p.m.—will raise costs when families need power most. Veterans, seniors, and workers can't easily shift their usage.
- **Hidden Fees:** Increasing fixed service charges to $30-$40 per month unfairly shifts costs to customers, reducing their ability to control energy bills. SRP should focus on efficiency programs, not flat-rate hikes.
- **Attacking Solar & Energy Independence:** A 5.5% solar rate increase discourages clean energy adoption, despite its role in energy security and cost savings. SRP should support, not penalize, renewables.
- **Misplaced Spending Priorities:** SRP spent $1.5 billion on fossil fuels—the real driver of these rate hikes. Instead, it should invest in renewables, battery storage, and energy efficiency to reduce long-term costs.

On behalf of VetsForward and the veterans and military families we advocate for, I urge the Board to reject these rate increases and pricing plan changes in favor of policies that ensure affordable, sustainable, and energy-independent solutions for all Arizonans.

Sincerely,

JoAnna Mendoza
Executive Director, VetsForward
[redacted]

Name: JO LYNN GROENING

Record Number: cdeb896d

Delivery Method: Digital Submission

Comment:

Prices under President Trump are going to begin decreasing and we would appreciate not having a raise until the following year when things have settled down. Thank you.

Name: Autumn Johnson

Record Number: MI7099613

Delivery Method: Email to Corporte Secretary

Attachments: AriSEIA Final SRP Recs 2.19.2025.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7099613*

Comment:

From: Autumn Johnson
Sent: Wednesday, February 19, 2025 1:00 PM
To: John M Felty
Subject: AriSEIA Pricing Proceeding Recommendations

John,

Please distribute our attached comments to the board members in advance of the 2/27 meeting. Thank you.

Autumn T. Johnson

CEO **|** Tierra Strategy

See attached letter

[redacted]

February 19, 2025

Salt River Project
1500 N. Mill Avenue
Tempe, AZ 85288

RE: 2025 Pricing Proceeding Recommendations

Mr. President, Board Members, and Staff,

The Arizona Solar Energy Industries Association (AriSEIA) is the solar, storage, and electrification trade association for the State of Arizona. We advocate for pro renewables policies at every level of government. AriSEIA does not speak for or represent a single company. We represent nearly 100 companies in the State and we advocate for policies that we think are beneficial for the industry and the grid and best serve the public interest to the greatest extent possible.

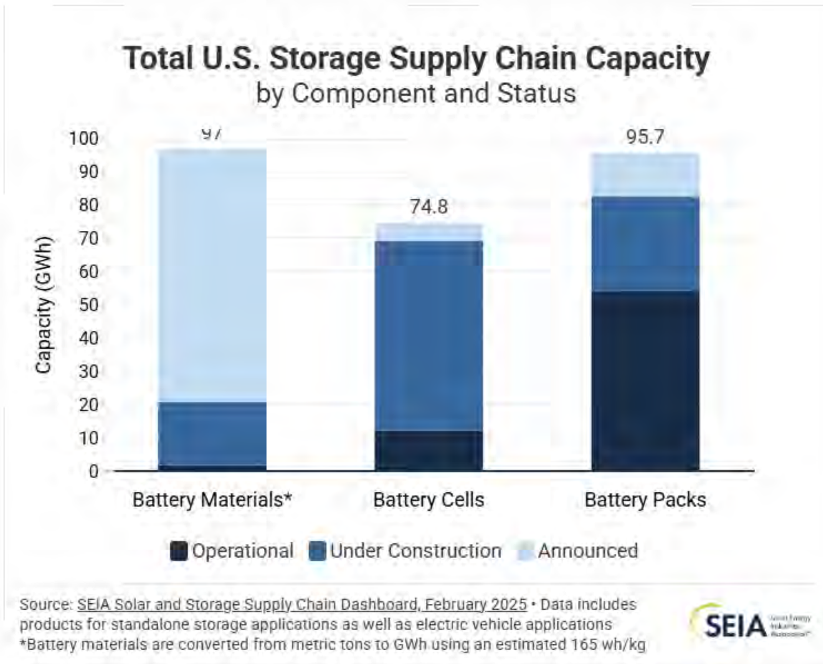
As such, we agree with most of the proposals made by the other organizations, namely Southwest Energy Efficiency Project (SWEEP), Vote Solar, Wildfire, Arizona PIRG, Western Resource Advocates, and Sierra Club on February 6th. We also support many of the points made by Mr. Neil. We agree with an evidenced based approach to policy and ratemaking. We do not support or endorse comments or proposals that impede the clean energy transition, either by individual commenters or individual companies. Batteries are an essential and integral component to increased renewables on the grid, both at the distributed and utility scale levels. Misinformation about the safety or efficacy of batteries is unhelpful and shortsighted and we encourage the board and management to disregard such comments and proposals.

Correcting Battery Misinformation

While China is currently the world's leading manufacturer of battery cells, a diversified supply chain outside of China is rapidly developing, including manufacturing here in the U.S. The risk of China-only sourcing diminishes by the day.

Residential batteries do not fail at high rates; they work well when properly installed. Very few residential batteries fail. Like any other mechanical or chemical device, batteries degrade over time. The manufacturer maps, specifies, discloses, and guarantees this degradation. After 10 years, typical home batteries are guaranteed to still produce 70% (on average) of their original rated capacity. Capable installers consider this degradation when modeling system performance and expected savings and discuss these factors with their clients. Every home is different, uses different amounts of energy, and has different load profiles from other houses. Ethical, competent solar installers study the complexities of home batteries and design the best system for the home, the homeowner's usage, and savings goals. Batteries are often used to achieve these goals, and when designed and installed correctly, they will provide many years of reliable operation and savings.

There are very few fire risks associated with modern batteries. Manufacturers have incorporated numerous safety features designed to ensure safety, and data shows very few issues. Additionally, the best practice in Arizona is to install the battery inside of a home, in a garage or utility room, and not outdoors. Home batteries are widely available and can be ordered, delivered, and installed today. Out of half a dozen popular battery manufacturers, only one is experiencing supply issues.



<u>Virtual Power Plants</u>
Distributed batteries allow individual ratepayers to reduce their electric bills and increase their resiliency in the event of a power outage, while also benefiting the utility and other ratepayers, by providing valuable capacity when the grid needs it most. Valuing that capacity sends a price signal to a ratepayer who has used their own capital to install a battery to provide the stored energy to the grid, instead of their own home, when there is strain on the grid. This is a supply virtual power plant (VPP). SRP can call an event on a hot August afternoon and thousands of homeowners can respond by allowing SRP to use their batteries, instead of them using the stored power themselves.

According to the U.S. Department of Energy, there is currently 30-60 GW of VPP capacity on the grid today, but that amount needs to triple by 2030.[1] Arizona Public Service (APS) is in the process of adopting a VPP modeled off of AriSEIA's proposal, which is derived from a very successful VPP program called ConnectedSolutions. Our proposal is a pay for performance only model that allows the utility to call up to 60 events in the summer season for up to three hours. A third party aggregator operates the program just like a smart thermostat program. Participants can lock in their rate for five years. **While we understand that actual adoption of a VPP program within this pricing proceeding may not be possible, we recommend the Board direct management to engage with AriSEIA to develop a program to bring to the board for consideration by the end of the year.**

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[1] U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants, Sept. 2023, *available here* https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.

<u>Time of Use</u>
64% of SRP's customers are not on a time of use rate and 95% of SRP's customers can opt out of a time of use rate. Only 5% of SRP's customers are solar customers and, yet, they are the only customers required to be on a time of use rate. All customers should have the same rate plan options and all customers should be defaulted onto a time of use rate. Contrary to the comments of the board consultant, no one has argued for 100% participation on the time of use rates, but it should be the majority of customers and customers should have to opt out, rather than opt in. No current time of use customers should be defaulted to non-time of use rates in 2029. They should instead be defaulted to E-28. The differential between the on peak and off peak rates should be roughly 3:1 and that differential should be between on and off peak, not on and super off peak. The on peak time of use window should be three hours to maximize participation.

We recommend that E-16 and E-28 have the same on peak period. To alleviate management's concern about the shifting on peak window and the need to cover more than just 3 hours, we recommend customers have the option of one of two staggard on peak windows. **We recommend a 4-7pm on peak option *and* a 6-9pm on peak option.** This alleviates strain on the grid, allows families to select which plan works best for their schedule, and does not penalize solar owners.

We also recommend that the super off peak window be 10-3pm in the winter. This aligns with both the costs experienced by SRP and with what other utilities, such as APS, are currently offering. This will reduce customer confusion, creates an evidence and cost based program, and does not unnecessarily penalize solar customers.

Needed change to TOU periods

From	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
To	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM	12:00 AM
Total	H03	H04	H05	H06	H07	H08	H09	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
January	1.87	1.84	1.87	1.94	2.20	2.56	2.18	1.56	1.22	1.07	0.97	0.87	0.86	0.99	1.59	2.32	2.55	2.50	2.42	2.33	2.20	2.02
February	1.47	1.45	1.45	1.52	1.72	2.01	1.62	0.93	0.62	0.50	0.42	0.37	0.36	0.44	0.74	1.51	1.99	2.12	1.98	1.90	1.82	1.66
March	1.03	1.02	1.05	1.18	1.46	1.41	0.79	0.32	0.12	0.05	0.00	(0.02)	(0.02)	0.03	0.20	0.79	1.43	1.66	1.55	1.43	1.29	1.17
April	0.99	0.99	1.04	1.19	1.36	0.89	0.29	0.07	(0.03)	(0.05)	(0.07)	(0.07)	(0.05)	0.00	0.14	0.59	1.34	1.72	1.61	1.41	1.23	1.13
May	1.15	1.14	1.21	1.35	1.30	0.57	0.15	0.02	(0.02)	(0.04)	(0.04)	(0.01)	0.03	0.13	0.28	0.71	1.54	2.24	2.19	1.82	1.49	1.35
June	1.32	1.30	1.33	1.46	1.34	0.77	0.57	0.52	0.53	0.58	0.66	0.73	0.88	1.19	1.49	2.52	2.40	2.82	2.47	2.08	1.63	1.50
July	1.75	1.72	1.74	1.81	1.97	1.55	1.39	1.38	1.42	1.53	1.69	1.97	2.43	7.00	14.38	23.63	48.05	58.56	15.86	4.96	3.12	2.61
August	1.89	1.85	1.87	1.98	2.22	1.80	1.52	1.46	1.49	1.59	1.76	2.44	2.48	4.34	6.34	10.43	19.44	17.45	4.98	3.26	2.59	2.34
September	1.47	1.44	1.45	1.56	1.67	1.44	1.05	0.95	0.95	1.02	1.12	1.27	1.46	2.42	3.19	3.43	5.47	4.18	2.88	2.13	1.86	1.70
October	1.10	1.09	1.12	1.23	1.44	1.33	0.88	0.65	0.58	0.57	0.59	0.63	0.72	0.84	1.13	1.70	2.06	1.76	1.57	1.51	1.32	1.22
November	1.30	1.28	1.29	1.36	1.54	1.66	1.27	0.81	0.65	0.61	0.60	0.61	0.64	0.80	1.31	1.82	2.01	1.80	1.73	1.68	1.61	1.44
December	1.80	1.77	1.77	1.81	1.97	2.37	2.05	1.66	1.44	1.34	1.27	1.24	1.26	1.37	1.80	2.25	2.42	2.35	2.28	2.24	2.17	1.99
Summer	1.26	1.25	1.28	1.40	1.44	1.03	0.66	0.53	0.51	0.54	0.58	0.65	0.77	1.15	1.52	2.09	2.87	2.75	2.28	1.88	1.57	1.44
Peak	1.82	1.79	1.81	1.90	2.09	1.68	1.45	1.42	1.46	1.56	1.72	2.21	2.46	5.67	10.36	17.03	33.75	38.00	10.42	4.11	2.85	2.47
Winter	1.41	1.39	1.41	1.50	1.71	1.82	1.37	0.89	0.67	0.59	0.53	0.50	0.51	0.61	0.96	1.55	1.96	2.02	1.93	1.83	1.72	1.57
Annual	1.43	1.41	1.43	1.53	1.68	1.53	1.15	0.86	0.75	0.73	0.75	0.84	0.92	1.63	2.72	4.31	7.56	8.26	3.46	2.23	1.86	1.68

<u>Fixed Fees</u>

AriSEIA agrees with the other organizations that made comments on February 6th. Fixed fees should be as low as possible, as volumetric charges better align price signals with behaviors that improve efficiency. However, to the extent SRP has fixed fees, there should be parity between solar and non-solar residential customers. Solar customers should not be singled out for punitive and discriminatory fees.

<u>Export Rate</u>

SRP's export rate is significantly below the other large utilities in Arizona. The valuation of the avoided cost is not correct. That methodology has not been highly scrutinized by the Arizona Corporation Commission or stakeholders because the Resource Comparison Proxy (RCP) framework has not yet rendered it necessary; however, SRP's proposed export rate methodology in this case is inadequate. AriSEIA met with SRP extensively about our concerns with the value of solar study in 2024. The current cost allocation study does not correctly assign value to capacity costs and avoided transmission and distribution costs. **We recommend that SRP adopt an export rate closer to that of Tucson Electric Power (TEP) to be evaluated on an annual basis and locked in for existing customers for a period of ten years, not one year.** Even though SRP is three times larger than TEP, their current number of solar customers are comparable. Therefore, TEP is a reasonable starting place for an export rate that is fair to solar customers, but is closer to the current SRP proposal.

Additionally**, any customers on a net metered rate should be allowed to stay on that rate until 2034** and not be inadvertently bumped in 2029, as is currently proposed.

Current SRP Solar Policies Compared

Utility	# of Customers	# of Solar Customers	Export Rate	Duration
APS	~1.4 million	~185,000	$.06857	10 years
TEP	~400,000	~53,000	$.0570	10 years
SRP (proposed)	~1.2 million	~56,000	$.0345	1 year

If SRP provided more than two months to process this pricing proceeding, AriSEIA could provide a more detailed analysis and recommendation as to solar rate design. Organizations need time to hire an expert, have the expert review the workpapers, run their own analyses, and make a detailed recommendation. Therefore, we recommend the board set a vote on this pricing proceeding this summer, since the rate will not take effect until November of 2025, so that the best possible recommendations can be brought forward.

Commercial Rates

SRP seems to want to move to more plans with a storage component, but not in a way that will increase the adoption of storage. We recommend SRP adopt a pilot storage rate similar to the E-32L SP rate that APS adopted in 2024. APS developed that tariff in 2023 as a result of the prior rate case in a stakeholder process with AriSEIA. A copy of that tariff is included as Attachment A.

Recommendations

As such, AriSEIA recommends the Board offer amendments that accomplish the following:

1. Move the final vote on the pricing proposal until summer of 2025, with new rates to still take effect in November of 2025;
2. Open all four proposed rate plans to solar and non-solar customers;
3. Default all new customers to E-28 with an opportunity to opt out;
4. Have the super off peak time be 10-3pm in winter, instead of 8-3pm year round;
5. Have the same on peak time of 4-7pm or 6-9pm on both E-28 and E-16 with the ability of the customer to choose which of those periods works better for their family;
6. Move the export rate closer to that of TEP with a 10 year lock in, evaluated annually by SRP;
7. Adopt a pilot commercial storage rate similar to APS' E-32L SP;
8. Grandfather all net metered customers on their current rate until 2034, if so desired by the customers; and
9. Management should be directed to work with AriSEIA via a stakeholder process to develop a VPP program to be presented to the board by the end of the year.

Respectfully,

Autumn T Johnson

/s/ Autumn T. Johnson
Executive Director
AriSEIA
[redacted]

ATTACHMENT A

AVAILABILITY

This rate schedule is for a pilot rate available only to non-residential Customers that meet all of the following criteria:

a. Have average summer monthly peak site loads of 401 kW and greater.
b. Do not qualify for Rate Schedules E-34 or E-35.
c. Are not taking service under rate rider AG-X or through Direct Access.
d. Operate a chemical, mechanical, or thermal energy storage system located on their premises.

This rate schedule will be capped at a peak demand total of 35,000 kW of installed systems and active interconnection applications, on a first-come first-served basis. This rate is subject to the availability of required metering equipment, including bidirectional production meters for solar systems and bidirectional meters for the battery installation for the evaluation of effectiveness of the pilot program, and completion of necessary enhancements to the Company's billing system.

DESCRIPTION

This rate has three parts: (1) a basic service charge; (2) a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month; and (3) an energy charge for the energy (kWh) used during the month. The demand and energy charges vary by season (i.e., summer or winter) and time of day (i.e., On-Peak and Off-Peak).

If a Customer no longer meets the requirements of this rate schedule, the Company will place that Customer on the applicable Time-of-Use Rate Schedule (E-32 TOU XS, E-32 TOU S, E-32 TOU M, E-32 TOU L) based on the Customer's average summer monthly maximum demand, as determined by the Company each year.

A customer's monthly peak site load is the average kW supplied during the 15 minute period of maximum use during on-peak hours for each respective billing period.

TIME PERIOD

Summer Hours

On-Peak hours:	4:00 pm – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Winter Hours

On-Peak hours:	4:00 pm – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Summer season:	Bill cycles months May through October
Winter season:	Bill cycles months November through April

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	$ 3.307	per day
For service through Instrument-Rated Meters	$ 4.238	per day
For service at Primary Voltage	$ 7.410	per day
For service at Transmission Voltage	$ 41.918	per day

Demand Charges (only one set applies)				
		Summer	Winter	
Secondary	On-Peak kW	$ 6.994	$ 5.455	per kW
	Off-Peak kW	$ 2.634	$ 1.885	per kW
Primary	On-Peak kW	$ 6.696	$ 5.448	per kW
	Off-Peak kW	$ 2.513	$ 1.868	per kW
Transmission	On-Peak kW	$ 5.399	$ 4.885	per kW
	Off-Peak kW	$ 1.707	$ 1.413	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$ 0.21763	$ 0.08455	per kWh
Off-Peak	$ 0.07889	$ 0.04959	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$ 2.597	per day
Meter Reading	$ 0.010	per day
Billing	$ 0.032	per day
Metering* (only one applies)		
Self-Contained Meters	$ 0.668	per day
Instrument-Rated Meters	$ 1.599	per day
Primary	$ 4.771	per day
Transmission	$ 39.279	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

		Summer	Winter	
Transmission On-Peak		$ 2.870	$ 2.870	per kW
Generation On-Peak		$ 1.462	$ 1.462	per kW
Generation Off-Peak		$ 0.934	$ 0.934	per kW
Delivery - Secondary	On-Peak kW	$ 2.662	$ 1.123	per kW
	Off-Peak kW	$ 1.700	$ 0.951	per kW
Delivery -Primary	On-Peak kW	$ 2.364	$ 1.116	per kW
	Off-Peak kW	$ 1.579	$ 0.934	per kW
Delivery - Transmission	On-Peak kW	$ 1.067	$ 0.553	per kW
	Off-Peak kW	$ 0.773	$ 0.479	per kW

Energy Charge Components

System Benefits Charge:	$ 0.00361	per kWh
Delivery Charge	$ 0.00000	per kWh

	Summer	Winter	
Generation On-Peak	$ 0.21402	$ 0.08094	per kWh
Generation Off-Peak	$ 0.07528	$ 0.04598	per kWh

For billing demand purposes:
The On-Peak kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during On-Peak hours for each respective billing period, as determined from readings of the Company's meters or in accordance with the Company's Service Schedule 8.

2. The minimum kW specified in the agreement for service or individual contract.

3. 300 kW.

Off-peak kW will be based on the average kW supplied during the 15-minute period of maximum use during Off-Peak hours of the billing period, as determined as recorded by the Company's meters or in accordance with the Company's Service Schedule 8.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

Summer Billing Season: May through October billing cycles
Winter Billing Season: November through April billing cycles

Seasonal billing charges will be applied to a Customer's bills by monthly bill cycle.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.

2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.

4. The Demand Side Management Adjustment Charge, Adjustment Schedule DSMAC-1.

5. The Tax Expense Adjustor Mechanism charge, Adjustment Schedule TEAM.

6. The Court Resolution Surcharge, Adjustment Schedule CRS-1.

7. The System Reliability Benefit Adjustment Mechanism charge, Adjustment Schedule SRB-1

8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, and generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56 R	Partial Requirements – Renewable
GPS-1, GPS-2, GPS-3	Green Power

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements, the Customer will pay the cost to install and remove the Company's equipment.

5. If the load does not meet the power factor requirements, the Customer must resolve the issue with the Company. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These Service Schedules provide details about how the Company serves Customers.

2. Electric service provided will be single-phase, 60 Hertz at the Company's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

3. Electric service is supplied at a single point of delivery and measured through a single meter.

4. At the Company's option, a Customer will be required to sign the Company's standard agreement for service. If additional construction is required to serve the Customer, the contract period will be five years. If no additional distribution construction is required to serve the Customer, the contract period will be two years. At the end of a two-year service agreement, the Customer may request to modify the minimum kW in the standard agreement for service to reflect the Customer's actual usage during those two years.

Name: Patrick Woolsey

Record Number: MI7101865

Delivery Method: Email to Corporte Secretary

Attachments: Sierra Club Comments re SRP Pricing Proceeding 2.19.2025.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7101865*

Comment:

From: Patrick Woolsey
Sent: Wednesday, February 19, 2025 3:51 PM
To: John M Felty; SRP Corporate Secretary
Cc: Sandy Bahr
Subject: Sierra Club's Comments Re: SRP Pricing Proceeding

Hi John,

Attached are Sierra Club's comments regarding the SRP pricing proceeding. Please distribute these comments to the SRP Board members in advance of the Board's February 27 meeting.

Please confirm receipt of the attached letter.

Thank you,

Patrick

Patrick Woolsey
Staff Attorney
Sierra Club Environmental Law Program

See attached Letter

February 19, 2025

District Board of Directors
John Felty
Corporate Secretary
Salt River Project Agricultural Improvement and Power District
1500 N. Mill Ave.
Tempe, Arizona 85288
CorporateSecretary@srpnet.com

Re: Sierra Club's Comments on Salt River Project's 2025 Pricing Proposal

Sierra Club offers the following comments regarding Salt River Project Agricultural Improvement and Power District's ("SRP") 2025 pricing proposal. Unfortunately, the pricing proposal put forward by SRP management suffers from serious flaws. SRP's proposed 3.4% rate increase for residential customers and associated changes to the pricing structure will place a significant burden on SRP customers. These changes would disproportionately harm low-income customers, as well as customers who have rooftop solar on their homes. Moreover, SRP's price increase is being driven by excessive, imprudent spending on high-cost fossil fueled-generation, despite the availability of cheaper, cleaner alternative energy sources. Since 2018, over 80% of SRP's capital spending has been on coal and gas, totaling over $1.5 billion, while less than 20% of SRP's capital spending has been on renewable energy.

Sierra Club urges the Board not to approve the pricing proposal in its current form. While Sierra Club recognizes the need to invest in new generation and the challenge of controlling costs, we urge SRP to adopt a more balanced approach that minimizes the financial impacts to customers while prioritizing development of affordable clean energy solutions that will reduce costs for ratepayers instead of costly fossil fuels. In particular, we recommend that the Board:

- Delay the final Board vote on the pricing proposal until summer 2025 and allow additional opportunities for public comment and stakeholder input;
- Open all four proposed rate plans to solar and non-solar customers alike;
- Maintain the current monthly service charge rather than increasing it in the tiers proposed;
- Reduce the rate increase for residential solar ratepayers to be consistent with increases for other residential customers, recognizing the benefits that rooftop solar customers provide to the grid;
- Commit to reduce spending on uneconomic coal-fired and gas-fired power plants and invest in cheaper alternatives in order to minimize future rate increases for customers;

- Conduct a study by 2026 evaluating the economics of retiring Coronado Generating Station in 2030 instead of 2032, and identifying an economic retirement date for Springerville Unit 4; and
- Commit to make additional investments in clean energy and just transition funding in communities impacted by upcoming coal-fired power plant retirements.

Sierra Club agrees with most of the proposals put forward by the Arizona Solar Energy Industries Association (AriSEIA), Southwest Energy Efficiency Project (SWEEP), Vote Solar, Wildfire, Arizona PIRG, and Western Resource Advocates in their presentations to the Board on February 6, 2025. Sierra Club also supports the recommendations proposed by those stakeholder organizations in their written comments. We urge the Board to implement those suggestions, in addition to the recommendations offered in the following comments.

I. Background

Sierra Club has long participated in public processes related to SRP's pricing and resource planning. Sierra Club provided comments in SRP's last pricing proceeding in 2019. Sierra Club also engaged extensively in SRP's Integrated System Plan ("ISP") process in 2022-2023. Sierra Club retained an expert, Strategen Consulting, to evaluate SRP's ISP to prepare an alternative resource plan in 2022.[1] Strategen used Encompass capacity expansion modeling to evaluate SRP's modeling of resource portfolios and to identify the least-cost resources that meet SRP's projected load.[2] Strategen's analysis found that SRP's planned expansion of new gas-fired generation, including the Coolidge Expansion Project, was not part of a least-cost portfolio.[3] Strategen found that SRP could save hundreds of millions by retiring SRP's remaining coal-fired generating units and replacing them with clean energy resources.[4] Strategen recommended that SRP avoid investments in new gas generation, move up the retirement date of SRP's coal-fired Coronado Generating Station, and increase investment in renewable energy and demand-side resources.[5]

II. SRP's Pricing Proposal Imposes Greater Costs on Residential Customers.

SRP is proposing an overall net price increase of 2.4%, effective in November 2025.[6] However, the impact on residential customers would be larger: The average residential customer would see a 3.4% net price increase, and the average residential solar customer would see a 5.5% net price increase.[7] Thousands of residential solar customers currently on the E-13 pricing plan

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[1] Strategen Consulting, Alternative Resource Plan for Salt River Project Integrated System Plan (Oct. 2022), attached as Exhibit B hereto.
[2] *Id*., Exhibit B at 2.
[3] *Id*.
[4] *Id*.
[5] *See id*. at 3.
[6] Proposed Adjustments to SRP's Standard Electric Price Plans, 29, 31 (Dec. 2, 2024) (hereinafter "Proposal").
[7] Proposal at 31; Modifications to Proposal at 4 (Dec. 30, 2024).

would see bill increases of 6% or higher.[8] There would be a 4% base revenue increase, partially offset by a 1.6% decrease in the Fuel and Purchased Power Adjustment Mechanism ("FPPAM").[9] SRP's proposal is based on a Fiscal Year 2026 Test Year (May 1, 2025, to April 30, 2026).[10]

SRP states that the price increases are driven by capital spending on generation and other infrastructure as well as increases in operations and maintenance expenses.[11] However, SRP is not fully transparent about the drivers of the increase. In fact, a major driver of this price increase is SRP's excessive spending on new and expanded fossil-fueled generation, as discussed in Section III below.

SRP proposes that ten residential and solar residential price plan options be frozen to new participation and eliminated by 2029. SRP proposes that all residential and solar customers will have only four price plans by 2030: the E-23 Basic Price Plan, E-24 Pre-Pay (M-Power), E-16 Manage Demand and Save, and the E-28 Conserve and Save plans.

SRP also proposes a tiered fixed Monthly Service Charge ("MSC") structure based on the size of a customer's home, with a $20 fixed MSC for single units in multi-family housing, a $30 MSC for typical single-family homes, and a $40 MSC for large single-family homes. Higher fixed customer charges (like the MSC) mean lower usage-based or volumetric charges, reducing the incentive and ability for customers to save money by using less energy. The significant overall increase in the monthly service charge tiers imposes a significant financial burden on residential customers. Instead of penalizing residential customers by raising fixed charges, SRP should incentivize energy efficiency programs or demand-side management to help residential customers reduce energy consumption and keep their household energy bills manageable.

SRP's proposed rate increases will harm many customers. SRP's proposed 3.4% rate increase disproportionately harms low-income families, people on fixed incomes, and people struggling with rising living costs who already spend a high percentage of their income on energy bills. Many Arizonans are already struggling to cope with increases in energy costs and may have to choose between paying higher electric bills and paying for other basic needs.

III. SRP's Imprudent Spending on Fossil Fuels Is Driving Higher Costs for Customers.

Since SRP's last pricing proceeding, the vast majority of SRP's capital spending has been on fossil fuels. SRP states that it spent $1.9 billion in capital expenditures on generating resources over a 6-year period from May 2018 through April 2024.[12] **Of that $1.9 billion total, SRP states that it spent 71% or $1.35 billion on gas-fired generation and 12% or $227**

[8] Proposal at 51, Figure 9; Modifications to Proposal at 10.
[9] Proposal at 2, 29.
[10] Proposal at 20.
[11] Proposal at 20.
[12] SRP Management Response to Sierra Club Information Request 3, attached as Exhibit A hereto; SRP Proposal at 13.

million on coal-fired generation.[13] **In other words, 83% of SRP's capital spending on generation over that 6-year period—a total of roughly $1.58 billion—was spent on fossil fuels**.

SRP's $1.35 billion in capital expenditures on gas included spending on development of the twelve-turbine, 575-megawatt ("MW") Coolidge Expansion Project, as well as construction of two new 49.5 MW gas-fired generating turbines at Desert Basin Generating Station, two new 49.5 MW gas turbines at Agua Fria Generating Station, and two new 49.5 MW gas turbines at Copper Crossing Energy Center.[14] This brings SRP's new gas generating capacity additions at these four sites to approximately 872 MW.

SRP's $227 million in capital spending on coal included $78 million on a project to "split" Selective Catalytic Reduction ("SCR") pollution controls at Coronado Generating Station to serve Unit 1 as well as Unit 2, in order to prolong the operating life of this costly, aging coal plant until 2032, rather than retiring one of those units earlier as originally planned.[15] SRP confirms that the cost of the "split" SCR project will be passed on to customers via this proceeding as a depreciation expense.[16] But as noted above, a 2022 study by Strategen Consulting found that SRP could have saved money for ratepayers by retiring Coronado earlier, avoiding the need for the "split" SCR project.[17]

As SRP's remaining coal plants continue to age, operation and maintenance expenses and sustaining capital expenses at those plants will continue to increase. SRP could very likely save customers money by moving up the retirement dates of its remaining coal-fired generating units and replacing them with lower-cost resources. For example, Arizona Public Service Company found in its 2023 Integrated Resource Plan ("IRP") that the Company could save tens of millions by retiring Four Corners Power Plant in 2028, 2029, or 2030, instead of the reference case of 2031 retirement, with the largest savings ($139 million) from 2028 retirement.[18] While SRP owns a smaller share of Four Corners than APS, SRP should evaluate whether it could also save money for customers by exiting Four Corners early. SRP should similarly evaluate whether it can reduce costs for customers by moving up the retirement date for both Coronado units.

SRP's gas plants are driving increased operations and maintenance expenses. Overall, SRP states that its annual generation maintenance expenses will increase by roughly $30 million from Fiscal Year 2020 through the Fiscal Year 2026 test year.[19] Nearly half of this increase is

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[13] Exhibit A, SRP Management Response to Sierra Club Information Request 3(a),(b).
[14] Proposal at 13, 15.
[15] *See* Proposal at 13, 19.
[16] Exhibit A, SRP Management Response to Sierra Club Information Request 5(a),(b).
[17] Exhibit B at 3, 8, 12.
[18] Arizona Public Service Company, 2023 Integrated Resource Plan, 75 (Nov. 1, 2023), *available at* https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&sc_lang=en&hash=DF34B49033ED43FF0217FC2F93A0BBE6.
[19] Proposal at 22.

driven by a major overhaul at the gas-fired Mesquite Generating Station planned for Fiscal Year 2026.[20]

SRP's coal and gas-fired units are costly. An appendix to SRP's proposal quantifies spending and revenue requirements at SRP's coal-fired and gas-fired power plants, including capital spending, operations & maintenance, fuel costs, etc.[21] In Fiscal Year 2024, SRP states that it had a $430 million net cost of plant at Springerville Generating Station, a $221 million net plant at Coronado, $55 million at Four Corners, $278 million at Coolidge, and $184 million at Desert Basin.[22] Total annual cost in Fiscal Year 2024 was $269 million at Coronado, $194 million at Springerville, $66 million at Four Corners, $140 million at Desert Basin, and $74 million at Coolidge.[23]

SRP's spending on coal and gas is imprudent and has resulted in unnecessary costs to customers. Available alternatives such as solar, wind, and energy efficiency are significantly cheaper than coal or gas generation. Solar and wind power are among the lowest-cost generating resources available in Arizona today, and clean energy projects provide the greatest value over the lifetime of the resource.[24] Solar and wind resources have lower operating costs than conventional generation, and zero fuel costs, avoiding fuel price volatility.[25] Development of clean energy resources ultimately results in lower-cost electricity generation, resulting in lower utility bills for consumers.[26] Moreover, energy efficiency is the cheapest, most competitive energy resource option available, often costing three or four times less than other options.[27] It is much less expensive to reduce power consumption via increased efficiency than it is to spend money building new generating resources to provide an equivalent amount of power.

Despite directing 83% of its capital spending—over $1.5 billion—to costly fossil-fueled generation over the last six years, SRP refuses to clearly acknowledge that its spending on goal and gas is a major driver of the proposed rate increase. In response to a discovery request, SRP attempts to argue that *none* of the proposed rate increase can be attributed to its spending on coal-fired and gas-fired generation, based on SRP's claim that alternatives would have been more expensive.[28] On the contrary, Strategen Consulting's analysis in SRP's 2022-2023 ISP found that SRP's expansion of new gas-fired generation was not part of a least-cost portfolio,

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[20] Proposal at 22.
[21] *See* Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices at 31-32, Table 3.
[22] *Id.*
[23] *Id.*
[24] *See, e.g,* Direct Testimony of Theodore Geisler at 20-21, Docket No. E-01345A-22-0144 [Arizona Public Service Company Rate Case] (Ariz. Corp. Comm'n Oct. 28, 2022), *available at* https://edocket.azcc.gov/search/document-search/item-detail/304050.
[25] *Id.* at 20.
[26] *Id.* at 21.
[27] *See, e.g.,* Tucson Elec. Power Co., 2017 Integrated Resource Plan at 93 (Chart 20: 2017 Levelized Cost of All Resources), (Apr. 3, 2017), *available at* https://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource-FINAL-Low-Resolution.pdf.
[28] SRP Management Response to Sierra Club Information Request 8.

and that SRP could save hundreds of millions by retiring its remaining coal-fired plants and replacing them with clean energy resources.[29]

In addition to imposing unnecessary costs on customers, SRP's fossil fuel spending spree is also exacerbating the climate crisis and hurting public health. SRP's dirty coal-fired and gas-fired power plants are major sources of greenhouse gas emissions that cause climate change, and also emit other air pollutants that are harmful to human health. For example, air pollution from the Coolidge Expansion Project alone will cause increases in respiratory illnesses, heart attacks, and mortality rates that are projected to increase total healthcare costs for Arizona residents by millions of dollars per year and by hundreds of millions over the project's operating life. Air pollution from the Coolidge project will worsen already-poor air quality in Pinal County and have a disproportionate harmful impact on a community that is predominantly people of color.

Going forward, SRP must closely scrutinize its capital expenditures and operations and maintenance spending on uneconomic coal-fired and gas-fired power plants in order to minimize future rate increases for customers. SRP must rigorously evaluate potential cost savings for customers that can be achieved by reducing spending on fossil fuel resources and accelerating investment in affordable clean alternatives including solar, wind, battery storage, energy efficiency, and demand-side management. SRP should commit to conduct a study within one year of the final Board vote in this proceeding (i.e. in 2026) evaluating the economics of retiring and replacing Coronado Generating Station in 2030 instead of 2032, and identifying an economic retirement date for Springerville Unit 4. Given the significant lead time needed to plan for coal unit retirements and to develop replacement resources, SRP must not wait until its next ISP in 2028 to conduct this analysis. SRP must plan for coal retirements now.

IV. SRP's Pricing Proceeding Does Not Allow for Adequate Stakeholder Review

SRP's pricing proceeding has followed a rushed, arbitrary process that has made it difficult for the public to participate and severely limited stakeholder engagement. SRP publicly issued its pricing proposal on December 2, 2024. Together, the proposal and its supporting studies total hundreds of pages and include highly technical information that requires expertise to fully evaluate.

SRP required interested stakeholders wishing to present to the Board to provide copies of their presentations to SRP by February 3, 2025, only two months later. This did not allow sufficient time for interested stakeholders to retain expert witnesses to review SRP's proposal. Because SRP's compressed timeline precluded hiring the expert witnesses necessary for full participation, stakeholders seeking to understand and analyze SRP's proposal and to provide recommendations are at a disadvantage. Limiting stakeholder participation in this way undermines transparency and accountability, allowing SRP to operate without full scrutiny.

SRP also impeded public participation via a slow and limited discovery process which prevented stakeholders from receiving information in time to incorporate it in their analyses. SRP routinely took three or more weeks to respond to information requests from stakeholders. For example, Sierra Club sent an information request to SRP on January 13, 2025, but did not

[29] Exhibit B at 2.

receive a response until February 4, more than three weeks later, and *after* the deadline to provide copies of stakeholder presentations to SRP. Other stakeholders did not receive responses to their requests for a month or more, a major obstacle given the short duration of the proceeding. SRP also arbitrarily limited stakeholder interviews to a single day, and allowed each stakeholder only one hour to question company representatives.

SRP is seeking to have the Board approve the proposal on February 27, 2025, less than three months after the price increase was first proposed. There is absolutely no need for SRP to conduct its pricing proceeding on such an abbreviated timeline. By contrast, rate cases for Arizona Public Service, Tucson Electric Power, and other regulated utilities routinely take six to eight months or more, allowing far more opportunities for stakeholder review, discovery, questioning of company representatives, and public participation, including several evening public comment sessions. SRP's abbreviated process prevents the public from meaningfully reviewing the pricing proposal or its impacts. In light of these failings, SRP should delay voting on the proposed price increase until summer 2025. This would allow additional time for public participation and more meaningful stakeholder engagement.

V. Conclusion

For the foregoing reasons, Sierra Club urges the Board not to approve the pricing increase as currently proposed. SRP should adopt a more balanced approach that minimizes the financial impacts on customers while prioritizing development of affordable clean energy solutions instead of costly fossil fuels. It should also adopt a process that accommodates greater public engagement and input. We recommend that the Board:

- Delay the final Board vote on the pricing proposal until summer 2025 and allow additional opportunities for public comment and stakeholder input;
- Open all four proposed rate plans to solar and non-solar customers alike;
- Maintain the current monthly service charge rather than increasing it in the tiers proposed;
- Reduce the rate increase for residential solar ratepayers to be consistent with rate increases for other residential customer classes, recognizing the benefits that rooftop solar customers provide to the grid;
- Commit to reduce spending on uneconomic coal-fired and gas-fired power plants and invest in cheaper alternatives in order to minimize future rate increases for customers;
- Conduct a study by 2026 evaluating the economics of retiring Coronado Generating Station in 2030 instead of 2032, and identifying an economic retirement date for Springerville Unit 4; and
- Commit to make additional investments in clean energy and just transition funding in communities impacted by upcoming coal-fired power plant retirements.

As noted above, Sierra Club also supports the recommendations proposed by AriSEIA, SWEEP, Vote Solar, Wildfire, Arizona PIRG, and Western Resource Advocates in their presentations to the Board and in their written comments. We urge the Board to implement those suggestions, in addition to Sierra Club's recommendations in these comments.

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Respectfully submitted this 19th day of February, 2025.

__*/s/ Sandy Bahr*_____________
Sandy Bahr
Director
Sierra Club Grand Canyon Chapter
sandy.bahr@sierraclub.org

Exhibits:

Exhibit A: SRP Management Response to Sierra Club First Set of Information Requests, Feb. 4, 2025

Exhibit B: Strategen Consulting, Alternative Resource Plan for Salt River Project Integrated System Plan, Oct. 2022

EXHIBIT A

SRP Management Response to
Sierra Club's First Request for Information Regarding
SRP's Proposed Changes to its Electric Rate Schedules

1. Please provide copies of SRP's responses to all written information requests received from other stakeholder organizations or law firms, including AriSEIA, Vote Solar, SWEEP, Earthjustice, Tierra Strategies, and Rose Law Group, related to SRP's pricing proceeding. Please provide these responses on an ongoing basis as they become available.

   SRP Response:

   All responses from SRP management are posted at Pricing process documents and materials | SRP. If any response references a separate data file or attachment, those materials are available for inspection at SRP's main administrative offices. To receive a copy of a particular record, please submit a specific written request.

2. Please provide copies of the transcript and video recording of the stakeholder interviews of SRP management and consultants conducted on January 16, 2025 as soon as that transcript and recording become available.

   SRP Response:

   For the interviews on January 16, 2025, if the transcript is not posted on SRP's website, SRP management will provide a copy. The interviews were not video recorded.

3. Please refer to the Proposed Adjustments to SRP's Standard Electric Price Plans ("Proposal"), page 13. Here, SRP states that it made approximately $2 billion in capital investments in generation resources from May 2019 through April 2024.

   a. What percentage of that $2 billion total was invested in gas-fired generating resources during that 5-year period?

   b. What is the total amount (in dollars) of SRP's capital investment in gas-fired generating resources from May 2019 through April 2024?

   c. What percentage of that $2 billion total was invested in coal-fired generating resources during that 5-year period?

   d. What is the total amount (in dollars) of SRP's capital investment in coal-fired generating resources from May 2019 through April 2024?

   SRP Response:

In reference to page 13, the approximately $2 billion in capital investments in generation resources is also inclusive of capital spent between May 2018 through April 2019. When excluding that year to focus on capital spent from May 2019 through April 2024, $1,470 million was spent on generation resources. Throughout the Proposed Adjustments to SRP's Standard Electric Plans, all other references to the May 2019 through April 2024 timeframe have the associated dollars referenced.

For the purposes of breaking out into percentages and total amounts, $1,908M was spent in total on generating resources from May 2018 through April 2024.

a. Approximately 71% was invested in gas-fired generating resources
b. Approximately $1,348M was invested in gas-fired generating resources.
c. Approximately 12% was invested in coal-fired generating resources.
d. Approximately $227M was invested in coal-fired generating resources.

When removing the May 2018 through April 2019 capital, $1,470M was spent in total on generating resources from May 2019 through April 2024. We see a similar percentage allocation to gas-fired and coal-fired generation in this timeframe.

a. Approximately 67% was invested in gas-fired generating resources
b. Approximately $984M was invested in gas-fired generating resources.
c. Approximately 14% was invested in coal-fired generating resources.
d. Approximately $201M was invested in coal-fired generating resources.

4. Please refer to the Proposal, page 18. Here, discussing generation maintenance and improvements, SRP states that from May 2019 to April 2024, SRP spent approximately $660 million on power plant betterments, driven largely by work at Palo Verde Generating Station (approximately $181 million) and Gila River Generating Station (approximately $125 million).
    a. Please describe the $125 million in spending at Gila River Generating Station during that period.
    b. Of the $660 million spent on power plant betterments from May 2019 through April 2024, how much of that total was spent on gas-fired generating resources?
    c. Of the $660 million spent on power plant betterments from May 2019 through April 2024, how much of that total was spent on coal-fired generating resources?

SRP Response:

The $660M spent on power plant betterments is a subset of the $2B spent on generation resources from page 13 and is representative of capital spent between May 2019 through April 2024.

a. The $125 million in spending at Gila River Generating Station was associated with Gila River Block 1, Block, 4, common equipment, and switchyard refurbishment and reliability projects between May 2019 and April 2024. Approximately 82% of this total allocation was associated with combustion turbine overhauls at Block 1 (FY21) and Block 4 (FY24), a new generator step-up transformer (GSU), GSU repairs, and Block 4 full generator rewind in FY20, significant water and chemistry system updates, controls improvements, and fogger enhancements for FY21-FY23, Block 1 cooling tower rebuild, Block 4 steam turbine repairs, turbine controls replacements, environmental catalysts, station transformers, and a new well in FY24. The remaining 18% was allocated to smaller projects, each under $2M in magnitude.

b. Approximately 55%, or $363M, of the $660M spent on power plant betterments was spent on gas-fired generating resources.

c. Approximately 18%, or $119M, of the $660M spent on power plant betterments was spent on coal-fired generating resources.

5. Please refer to the Proposal, page 19. Here, SRP states that the project to "split" the selective catalytic reduction (SCR) system to accommodate both Coronado Generating Station units will cost approximately $78 million and is expected to be in service by February 2025.

    a. Is SRP seeking to recover that $78 million cost from customers via this pricing proceeding, in whole or in part?

    b. If so, how much of that $78 million cost is SRP seeking to recover from customers via this proceeding?

SRP Response:

a. Yes, the cost of the selective catalytic reduction (SCR) system is included in this proceeding.

b. The $78 million flows through to the Cost Allocation Study through annual depreciation expense. The $78 million will be depreciated on a straight-line basis through the accounting life of 12/31/2028.

6. Please refer to the Proposal, page 19. SRP states that the Coronado "split" SCR project and its operational strategy for Coronado "will reliably and economically meet customer load growth while allowing SRP to meet its 2035 Sustainability Goals to reduce CO2 emissions" and that "[t]his approach will result in less CO2 emissions than if CGS Unit 1 were retired in 2025, while maintaining critical capacity to serve SRP customer needs during the highest demand seasons."

    a. Has SRP performed any analysis demonstrating that the Coronado split SCR upgrade will provide reliable and economic supply for customer load growth? If so, please provide that analysis.

    b. Did SRP perform any analysis of alternatives to the Coronado split SCR project, including analysis of other resources that could replace Coronado and their CO2 emissions relative to Coronado emissions? If so, please provide that analysis.

SRP Response:

In 2019, SRP identified and compared several alternatives for meeting the U.S. Environmental Protection Agency's (EPA's) Regional Haze Rule requirements and source-specific, better-than Best Available Retrofit Technology (BART) determination for Coronado Generating Station (CGS). The results of the comparison are summarized in the attached SRP Board presentations.

As described in the December 2019 presentation, SRP considered three options for complying with EPA's CGS BART determination: 1) install Selective Catalytic Reduction (SCR) on Unit 1 by 2025 by procuring all new components; 2) retire and replace Unit 1 by 2025; and 3) install SCR on Unit 1 by splitting the existing SCR installed on Unit 2, so that each unit would have SCR upon completion of the project.

As part of Option #3, SRP also proposed voluntarily to operate the CGS units at reduced output beginning in 2026 and to cease coal generation by end of 2032. This operating approach was designed to reduce CO_2 emissions from Option #3 to a level comparable to retiring coal operations at Unit 1 by 2025 (Option #2). To implement this operating approach, SRP agreed to a CO_2 emissions cap from both CGS units, as described in the January 2020 SRP Board presentation.

Option #3 was selected based on several considerations:

- The split SCR will comply with EPA's BART emission limits for CGS at similar or lower costs and CO_2 emission levels than the other alternatives considered.
- At the time of this assessment, SRP's peak demand was projected to grow at three times the national average. The split SCR option preserved the generation capacity provided by the CGS units to meet this unprecedented demand growth.
- At the time of this assessment, alternatives such as energy storage technologies were advancing, but were not yet proven to be capable of reliably meeting SRP's projected demand. The split SCR option provided additional time for SRP to gain more operating experience with battery storage technology, which may ultimately help to reduce the amount of new gas generation that will be needed.
- The commitment to retire both units by 2032 allows additional time for CGS employees and the surrounding communities to plan for closure compared to Option #2.

Construction of the split SCR was completed in late 2024 and SRP will begin operations in 2025 in accordance with CGS BART operating strategy.

7. Please refer to the Proposal, page 22. Here, SRP states that its annual generation maintenance expenses have increased nearly $30 million since Fiscal Year 2020 Test Year through Fiscal Year 2026 Test Year, which SRP states is primarily attributable to increases for maintenance at Palo Verde Generating Station and a "major overhaul" at Mesquite Generating Station.

    a. Please describe the "major overhaul at Mesquite Generating Station planned for Fiscal Year 2026."

    b. From Fiscal Year 2020 Test Year through Fiscal Year 2026 Test Year, has there been an increase in generation maintenance expenses at coal-fired power plants wholly or partly owned by SRP? If so, what is the dollar amount of SRP's share of those generation maintenance expenses?

    c. During that period, has there been an increase in generation maintenance expenses at SRP's gas-fired power plants besides Mesquite Generating Station? If so, what is the dollar amount of that increase?

d. Please provide SRP's annual generation maintenance expenses in Fiscal Year 2020 Test Year and in Fiscal Year 2026 Test Year at (i) its coal-fired generating facilities and (ii) its gas-fired generating facilities.

SRP Response:

a. The Scope of Mesquite major overhaul: This major overhaul involves work on SRP's block 1 combined cycle unit. The work involves a hot gas path inspection and replacement/repair of key components, a steam unit inspection and replacement/repair of key components, replacement of both gas turbine rotors, cooling tower repairs, various valve, pump and motor repairs along with steam piping inspection and repairs.

b. There has not been an increase in generation maintenance expenses at coal-fired power plants from Fiscal Year 2020 Test Year through Fiscal Year 2026 Test Year.

c. There has been a $12 million increase in generation maintenance expenses at all other gas-fired power plants besides Mesquite Generating Station from Fiscal Year 2020 Test Year through Fiscal Year 2026 Test Year.

d. (i) The annual generation maintenance expenses at coal-fired generating facilities was $65 million in Fiscal Year 2020 Test Year and $56 million in Fiscal Year 2026 Test Year. (ii) The annual generation maintenance expenses at gas-fired generating facilities was $66 million in Fiscal Year 2020 Test Year and $92 million in Fiscal Year 2026 Test Year.

8. Please refer to the Proposal, page 31, Table 1.
    a. Of the targeted annual 3.4% revenue adjustment for residential customers, (i) what percentage of that increase is attributable to SRP's spending on coal-fired generating resources, and (ii) what percentage of that increase is attributable to SRP's spending on gas-fired generating resources?
    b. Of the targeted annual 5.9% revenue adjustment for residential customers, (i) what percentage of that increase is attributable to SRP's spending on coal-fired generating resources, and (ii) what percentage of that increase is attributable to SRP's spending on gas-fired generating resources?
    c. Of the targeted annual 2.4% revenue adjustment for all customer classes, (i) what percentage of that increase is attributable to SRP's spending on coal-fired generating resources, and (ii) what percentage of that increase is attributable to SRP's spending on gas-fired generating resources?

SRP Response:

This specific analysis is not typically performed by SRP, making it challenging to provide a precise quantitative answer due to the fungible nature of expenses and pricing. However, it is important to note that SRP's prices are generally lower because of the continued use of coal-fired and gas-fired resources, compared to a scenario where these resources were retired early or not utilized.

For instance, as highlighted on page 163 of the Integrated System Plan, “the addition of 2,000 MW of firm natural gas in the Balanced System Plan allows the average system cost to be considerably lower than the No New Fossil and Minimum Coal strategic approaches.”

Lower natural gas prices contributed towards the FPPAM price decrease included in Management’s Proposal.

When comparing the average $/kWh price under the current proposal and that from the last Pricing Process (in 2019), and calculating the average $/kWh price attributable to coal and natural gas depreciation, O&M, and in-lieu taxes, the amount has declined for both coal and natural gas.

For these reasons, it is correct to say that none of the price increases for residential, residential solar, or all customer classes are attributable to SRP’s spending on coal or natural gas.

9. Please refer to the Proposal, page 15. SRP states that for the Copper Crossing project and Coolidge Expansion Project, it is using a new vendor to achieve savings relative to quotes from previous vendors. Why wasn’t the lowest-cost vendor used for the Desert Basin and Agua Fria expansion projects?

   SRP Response:

   The LM6000 work at Desert Basin and Agua Fria was performed 2 years prior to the work at Copper Crossing. At that time, the low cost vendor was relatively unknown and had very little experience in building LM6000 units. In addition, the timeline for building the Desert Basin and Agua Fria units was very tight and didn’t allow sufficient time to explore the new vendor option given their significant lack of experience. Over the course of the next couple of years, the new vendor completed multiple units and SRP had sufficient time to complete a thorough evaluation of the vendor so that when the Copper Crossing and Coolidge Expansion evaluations were performed, SRP had strong confidence that the new vendor could complete the projects and result in significant cost savings.

10. Please refer to the document titled “Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices,” pages 31-32, Table 3. The portions of Table 3 on these pages provide revenue requirement data for Fiscal Year 2024 for SRP’s coal and gas-fired resources.
    a. Please provide equivalent data for Fiscal Years 2022 and 2023 for Coronado, Four Corners, Springerville, Craig and Hayden.
    b. Please provide equivalent data for Fiscal Years 2022 and 2023 for Agua Fria, Desert Basin, Gila, Kyrene, Mesquite, Santan, and Coolidge.

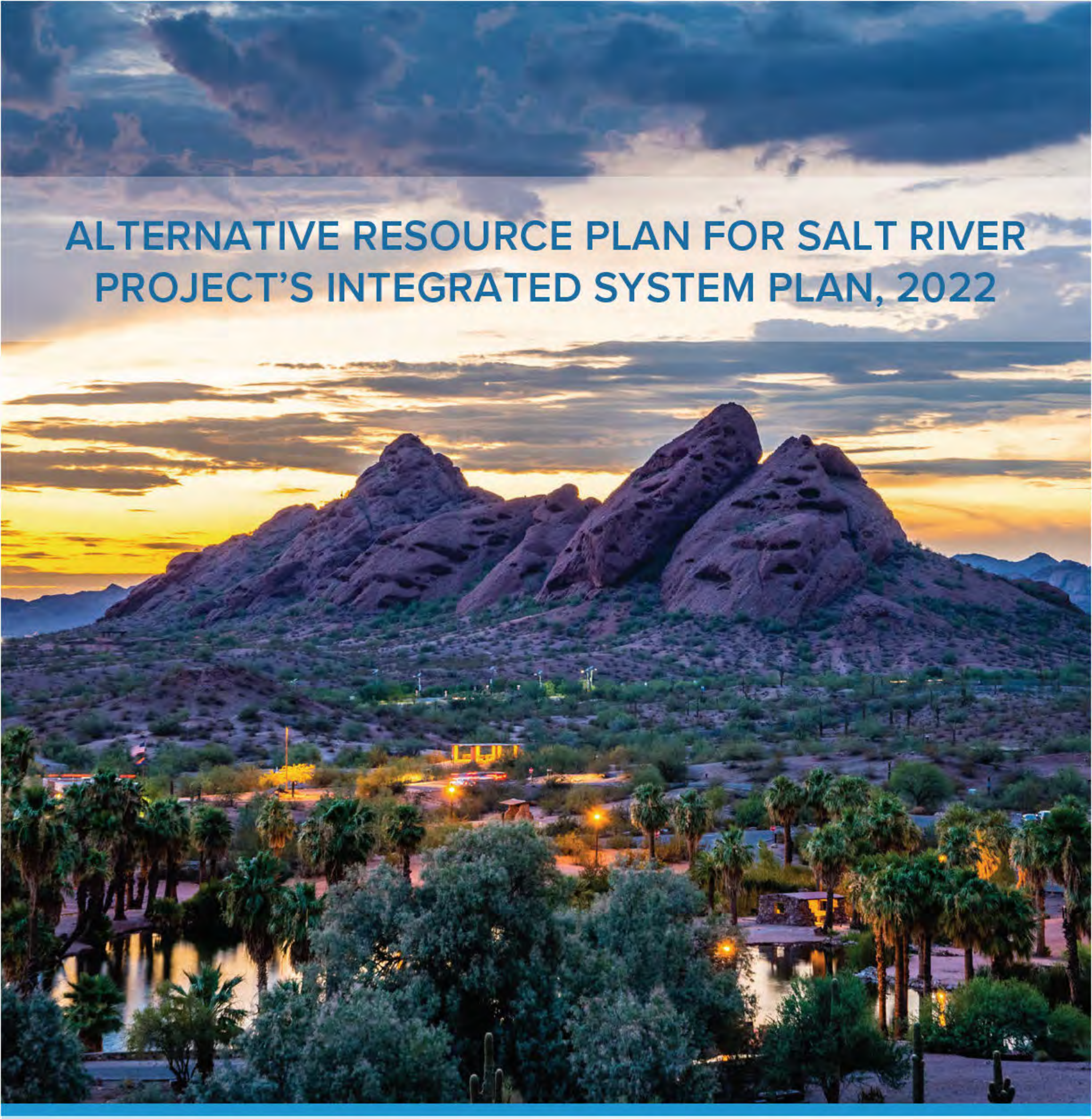
    SRP Response:

    Fiscal Years 2022 and 2023 data were not used in or pertinent to the recently published Derivation of Proposed Changes to SRP’s Transmission and Ancillary Services Prices. Because data from those years was not used, Total Annual Cost by Generating Station was not calculated for those years.

In addition, no ancillary study was performed to determine percentage allocation factors - and therefore revenue requirements - for those years. The last update to the Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices was in 2019 and is attached for reference. Table 3 can be found on pages 28-30.

EXHIBIT B

ALTERNATIVE RESOURCE PLAN FOR SALT RIVER PROJECT'S INTEGRATED SYSTEM PLAN, 2022



STRATEGEN

PREPARED FOR SIERRA CLUB
SEPTEMBER, 2022

YOUR PARTNER IN THE ENERGY TRANSITION

Alternative Resource Plan for Salt River Project's Integrated System Plan, 2022

Prepared by Strategen Consulting

This report is provided by Strategen Consulting on behalf of Sierra Club.

Strategen is a professional services company that specializes in power sector modeling and utility regulatory analysis. The firm has extensive experience working with global Fortune 500 corporations, utilities, governments, project developers, non-governmental organizations, and associations seeking to evaluate next generation grid and clean energy technologies.[1]

[1] For more information visit www.www.strategen.com

1. Executive Summary

Salt River Project ("SRP") has long been reliant on fossil fuels to generate electricity and is continuing to pursue new natural gas generation. Most recently, SRP proposed the Coolidge Expansion Project, which would include installation of 16 new gas turbines, a project with a budget of nearly $1 billion. The Coolidge Expansion Project would result in significant -- and avoidable -- costs and risks for customers, while also imposing a disproportional environmental burden on the Randolph community.

Despite the Arizona Corporation Commission's ("ACC") vote rejecting the Certificate of Environmental Compatibility for the Coolidge Expansion Project, SRP is still exploring options to move forward with the project or install at least some of these gas turbines at other sites, citing a near-term energy and capacity need. However, it is not clear that SRP has considered the full range of alternatives. The timing of this Integrated System Plan ("ISP") provides a unique opportunity for SRP to reconsider its commitment to new gas resources while transitioning away from coal resources in accordance with its 2035 Sustainability Goals. With the recent passage of the federal Inflation Reduction Act, new tax credit provisions are available that can help the utility meet its near-term energy and capacity needs with resources that are both clean and affordable. By seizing this opportunity, SRP can accelerate its transition from coal, avoid investing in new natural gas generation, and build a clean energy portfolio that will save its customers money and reduce emissions for decades to come.

For this report, Strategen used the EnCompass modeling platform in capacity expansion mode to identify the least cost of resources that meet SRP's projected load. The performance, cost, and emissions of the portfolios were then assessed through an hourly production cost simulation.

We find that:

- The Coolidge Expansion Project is not part of a least cost portfolio. Even prior to considering the Inflation Reduction Act ("IRA") tax credits, the Coolidge gas expansion was not selected as part of the optimal portfolio selected by the EnCompass model. After including tax credit extensions enabled by the IRA, the least cost portfolio for SRP includes no new gas generating capacity.

- Retiring and replacing SRP's coal units with clean energy resources could save SRP customers $390 million (net present value, 2023-2035) and 45 million tons of cumulative CO_2 emissions in the same period even prior to the extension of tax credits under the IRA. Re-optimizing the Clean Replacement Portfolio to find the optimal timing of retirements given the new federal support for clean energy results in a significantly accelerated transition and saves an additional $740 million while reducing CO_2 emissions by a total of 59 million tons.

- A more ambitious target that reduces CO_2 by 85% (from 2005 levels) by 2035 is feasible and can generate additional emission savings. The "Lower Carbon Scenario" portfolio results in cost savings of $110 million and 49 million tons of CO_2 over the study period. Re-optimizing the portfolio to include the extended tax credits, the portfolio saves $590 million and 63 million tons of CO_2. This clean energy portfolio further protects customers from fossil fuel price spikes like those experienced in early 2022 by reducing reliance on gas generation from existing units as well.

Based on this analysis, our recommendations are that SRP:

- Avoid or cease expenditures on gas units.
- Move up dates for retirement of or exit from coal-fired generating facilities:
    - Exit Four Corners Units 4&5 by 2025.
    - Retire Coronado Units by the end of 2025, avoiding the need to build the infrastructure to share the selective catalytic reduction equipment between the two units and freeing up transmission for wind resources.
- Continue investing in and supporting demand side resources.
- Set meaningful carbon reduction targets.
- Explore all options and incentives available through the Inflation Reduction Act.

2. Background

Salt River Project is Arizona's second-largest electric utility. SRP has long been reliant on fossil fuels to generate electricity and is continuing to pursue new fossil fuel generation. Most recently, the Company proposed the Coolidge Expansion Project, which includes installation of 16 new gas turbines, a project of 820 MW with a budget of nearly $1 billion resulting in significant – and potentially avoidable -- costs and risks for customers. SRP claims that the proposed Coolidge Expansion Project is needed to meet the significant near-term increase in energy demand in the service territory. However, this report shows that this demand can be more economically met by carbon free resources. The Coolidge Expansion Project's proposed location is near the community of Randolph, a historic Black community south of Coolidge, which has raised concerns over environmental justice.

While the Arizona Corporation Commission ("ACC") does not regulate SRP's rates, the Coolidge Expansion Project was required to obtain a Certificate of Environmental Compatibility ("CEC") from the Commission for the siting of the project. In April 2022, the ACC voted to deny the CEC for the Coolidge Expansion, finding that the project would have significant adverse environmental impacts on the already-burdened Randolph community and that SRP had not adequately evaluated alternatives to the project. The Commission reaffirmed that decision in June 2022.[2] SRP has filed a lawsuit to overturn the Commission's rejection of the Coolidge Expansion Project and is also proposing the installation of gas turbines at other sites, including at the site of SRP's Copper Crossing solar facility.

SRP is currently transitioning from Integrated Resource Planning to Integrated System Planning. The ISP process is intended to be a more comprehensive systemwide plan. The process began in November 2021, and in April 2022 SRP concluded its meetings with stakeholders to develop a study plan and began the modeling phase of the ISP process. This process is ongoing through November 2022. SRP plans on releasing the completed ISP report in April 2023. According to SRP, the key goal of transitioning to an ISP process is to support SRP's decarbonization goals. SRP currently has set a goal of reducing its emissions rate from 1,576 lbs. of CO_2 per MWh in 2005 to 550 lbs. in 2035, or about 65%.[3]

Given SRP's imminent energy needs, this ISP will guide significant resource investment decisions, the impacts of which will be experienced by customers in the next decades. If SRP continues to pursue new gas generation, customers will be left exposed to significant risks for decades, paying for higher cost, polluting electricity generation. Considering the provisions of the Inflation Reduction Act ("IRA"), and the recent significant increase in natural gas prices, it is increasingly sensible for SRP to create a path to reliable, clean, and affordable energy, while also being considerate of environmental justice concerns and providing a just and equitable transition for coal communities. The portfolios presented here demonstrate that all those goals can be met, while also protecting consumers from price volatility and risks of stranded assets. This report outlines a path for SRP to reduce both costs, greenhouse gas emissions, and local air pollution for customers.

The timing of this ISP presents SRP a unique opportunity to reconsider its new gas proposal, examine the current costs of its coal fleet, and assess the current market opportunities for cost effective, clean options, especially in light of the IRA. The IRA not only provides significant cost reductions for new renewable generation and energy storage assets in the form of extended tax credits, but also increases those credits if those carbon free resources replace retired coal units. Thus, IRA provisions further increase the cost differential between clean portfolios and the portfolio SRP seems to be considering.

SRP projects that it will meet 70% of its 2022 load with fossil fuel resources, including coal, gas, and oil. SRP has announced a plan to start to decommission certain coal-fired plants. The plan includes Hayden in 2027, Craig Unit 1 in 2025 and Unit 2 in 2028, Four Corners in 2031, and Coronado no later than 2032. Recently,

[2] Arizona regulators again reject SRP's proposed 820-MW gas plant expansion, Utility Dive, published 05/17/2022, updated 06/07/2022.

[3] https://www.srpnet.com/grid-water-management/sustainability-environment/sustainability-overview

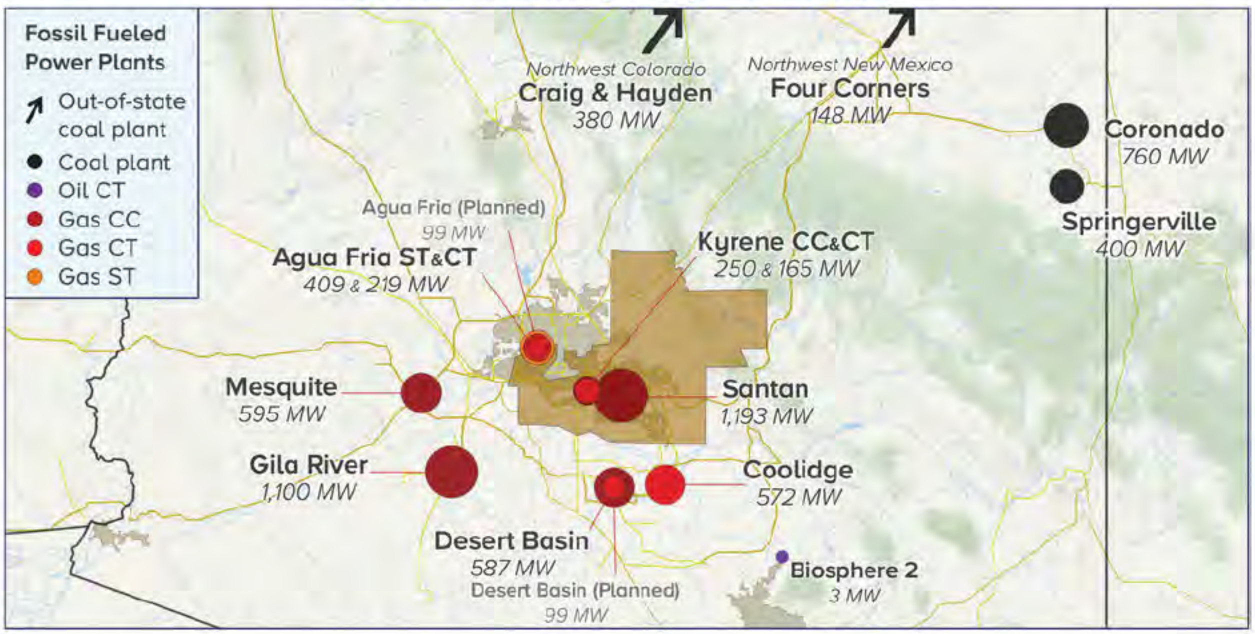
SRP indicated its intention to exit coal by May 2034.[4] Keeping the coal units in the system results in fuel, fixed and variable operations and maintenance costs, and also requires incremental capital expenses.

Multiple stakeholders, including Sierra Club, have pointed out that SRP's existing sustainability goals, including its carbon reduction target, are not ambitious enough, and have called for SRP to pursue an accelerated transition to clean energy resources.

To investigate this possibility, Strategen conducted a comprehensive analysis of SRP's resource portfolio and operations, which are detailed in this report. Strategen's analysis included a "baseline" scenario as well as two "clean replacement" portfolios. Under the baseline scenario, SRP's coal units retire according to the schedule outlined above. The clean replacement portfolios allow for the earlier retirement with a latest retirement date of 12/31/2029.

This report summarizes Strategen's findings and includes discussions around coal retirement decisions, gas plant expansions, and investment in renewable energy and storage technologies. The appendix details the methodology, inputs, and assumptions used in this analysis.

Figure 1. Fossil fueled power plants serving SRP



[4] SRP Integrated System Plan Study Plan Appendix – Assumptions Used in Scenarios, Sensitivities and Strategic Approaches, August 2022

3. Modeled Scenarios

Strategen conducted an analysis to evaluate different resource portfolios for SRP that minimize costs, maintain reliability, and further SRP's clean energy goals. This portfolio evaluation included SRP's existing power plants along with potential new resource investment options such as solar and storage.

Inputs and assumptions for the analysis were compiled from publicly available data on SRP's website, data from the S&P Market Intelligence Platform, and Strategen's expertise.[5]

Strategen considered three key scenarios to evaluate SRP's resource portfolio options:

1. **Baseline**: The Baseline scenario is not an exact replication of SRP's resource portfolio, as the ISP was not filed at the time this study was conducted. This portfolio serves as an approximation of the resource portfolio SRP will release once the IRP is complete and is meant to capture basic elements of SRP's baseline resource portfolio. It assumes that currently planned coal retirements will proceed as planned and the Coolidge Expansion Project or equivalent capacity will be built in 2025. Although the gas turbines might not be installed at the Coolidge Station, there is indication that SRP will install some of these turbines at other existing sites. The portfolio assumes least cost replacement and is aligned with the utility's "Current Trends" scenario: energy efficiency ("EE") reaches 3,800 GWh by 2035, Demand Response ("DR") goes up to 300 MW by 2035, and distributed solar levels reach 1,300 MW by 2035. No carbon constraint is explicitly modeled, but the portfolio readily achieves the 550 lbs/MWh target included in SRP's 2035 Sustainability Goals.

2. **Clean Replacement with Distributed Generation**: The Clean Replacement with distributed generation ("DG") scenario serves as the base case of a clean portfolio. Under the Clean Replacement with DG scenario, the coal fleet is retired by 2030. The Craig and Hayden units retire on the announced dates, while Four Corners, Coronado, and Springerville are allowed to retire economically, with a latest retirement date of Dec 31st, 2029. This scenario also assumes that the Coolidge Expansion Project or other new gas units will not be built. Planned gas unit upgrades are included in the scenario. EE and DR follow SRP's high EE and DR sensitivities, reaching 4,500 GWh and 400 MW by 2035, respectively. Distributed solar follows SRP's "Strong Climate Policy" assumption and reaches 2,300 MW by 2035. No carbon constraint is explicitly modeled, but the portfolio readily achieves the 550 lbs/MWh target included in SRP's 2035 Sustainability Goals.

3. **Lower Carbon with Distributed Generation**: The Lower Carbon with distributed generation scenario ramps up clean energy resources more significantly than the other scenarios. This scenario, like the Clean Replacement with DG scenario, retires the coal fleet by 2030, assumes the Coolidge Expansion Project is not built, and does not include any new gas. Energy Efficiency includes additional savings going up to 5,100 GWh by 2035 (reflecting approximately twice the incremental savings of SRP's high EE sensitivity). A carbon constraint is implemented limiting emissions to 85% of 2005 levels by 2035.

   A summary of the key inputs for each scenario is provided in the following table.

[5] In 2021 and 2022, Sierra Club made requests to SRP to provide detailed data and information on SRP's existing resource portfolio and other key planning assumptions used by the utility. One purpose of these requests was to ensure the accuracy of inputs used in this analysis. Since SRP did not provide much of this data to Sierra Club, Strategen relied on public data sources for its analysis.

Table 1. Summary of scenario assumptions

	Baseline / BAU	Clean Replacement	Lower Carbon
Fossil Resources	- Announced coal unit retirements[6] - Coolidge expansion (or equivalent) built	- Economic coal replacement by 2030 - Coolidge expansion not included	- Economic coal replacement by 2030 - Coolidge expansion not included
Replacement Resources	- 2022 ISP constraints	- Least cost clean replacement - No new gas allowed[7]	- Least cost clean replacement - No new gas allowed
Energy Efficiency & Demand Response	- Base EE (current trends)	- High EE sensitivity	- 2x High EE sensitivity
Distributed Solar	- Base DS (current trends)	- High distributed solar	- High distributed solar
Carbon Constraint	- None	- None	- 85% mass reduction by 2035 in capacity expansion model

Furthermore, while this analysis was under way, the Inflation Reduction Act was passed and signed into law on August 16, 2022. The IRA will have a significant impact on renewable resource deployment, further reducing the costs of renewable energy generation and making the transition to a cleaner portfolio an increasingly "no regrets" course of action for utilities.

To ensure the important effects of the IRA are included, Strategen re-optimized the Clean Replacement with DG, and the Lower Carbon with DG portfolios including the tax credit extensions of the Inflation Reduction Act. Strategen's understanding is that SRP as of the date that this report is written does not plan to include the extended credits in their 2021 ISP modeling. Consequently, the Baseline Portfolio was not re-optimized in order to better mimic SRP's own planning assumptions.

3.1 Findings

We find that:

- The Coolidge Expansion Project is not part of a least cost portfolio. Even prior to considering the Inflation Reduction Act tax credits, the Coolidge gas expansion was not selected as part of the optimal portfolio selected by the EnCompass model. After including tax credit extensions enabled by the IRA, the least cost portfolio for SRP includes no new gas generating capacity.

- The clean replacement of SRP's coal units could save SRP customers $390 million (net present value, 2023-2035) and 45 million tons of cumulative CO_2 emissions in the same period even prior to the extension of tax credits under the IRA. Re-optimizing the Clean Replacement Portfolio to find the optimal timing of retirements given the new federal support for clean energy results in a significantly accelerated transition and saves an additional $740 million while reducing CO_2 emissions by a total of 59 million tons.

[6] Currently planned coal retirements include Craig Unit 1 in 2025, Craig Unit 2 in 2028, Hayden 2 by 2027, Four Corners 4 & 5 by 2031, Coronado 1 & 2 by 2032.

[7] Approved natural gas upgrades are included in the model.

- A lower carbon emissions target that reduces CO_2 by 85% (from 2005 levels) by 2035 is feasible and can generate additional savings. The Lower Carbon portfolio results in cost savings of $110 million and 49 million tons of CO_2 over the study period. Re-optimizing the portfolio to include the extended tax credits, the portfolio saves $590 million and 63 million tons of CO_2. This clean energy portfolio further protects customers from fossil fuel price spikes like those experienced in early 2022 by reducing reliance on gas generation from existing units as well.

3.2 Detailed Results

3.2.1 Generation Portfolio

In the Clean Replacement Portfolio, allowing for SRP's coal units to retire economically in the initial runs results in the retirement of the Four Corners units in the end of 2024 (as early as allowed in the model). When including the extended tax credits, retirement of the entire coal fleet becomes economic in earlier years, as renewable generation and energy storage are more economic than the continued operation of the coal units. Coronado retires by the end of 2026 avoiding the additional cost of splitting the existing selective catalytic reduction equipment between the units and freeing up transmission for wind resources (that receive the production credit, with the bonus of the energy community siting). Springerville Unit 4 also retires early and is replaced by solar plus storage resources.

In the Lower Carbon Portfolio, in which we have assumed a more ambitious carbon reduction limit than SRP's 2035 sustainability goals, the emissions limit becomes binding at the end of the period despite the retirement of all the coal units and drives higher investment in wind resources which displace generation from existing combined cycle units.

Figure 2. Nameplate capacity for modeled portfolios in years 2022, 2029, 2035

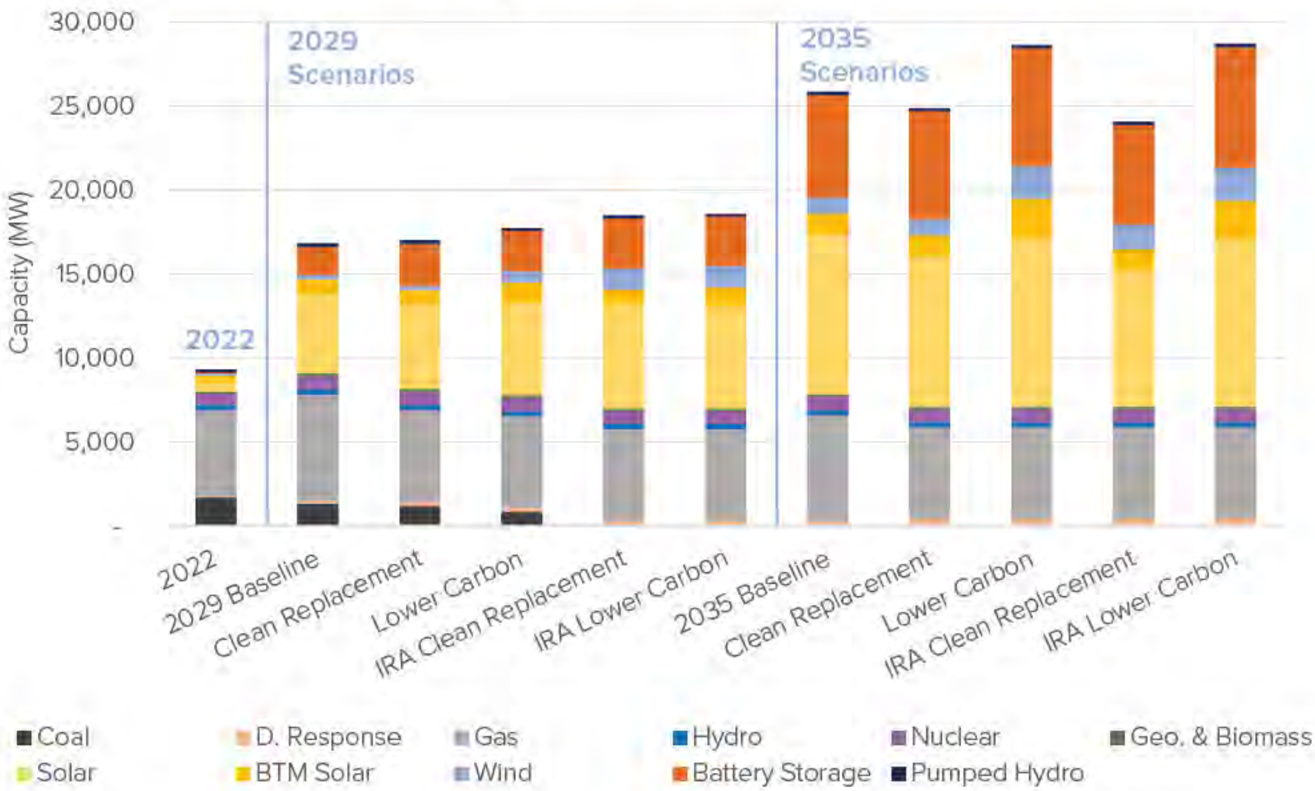
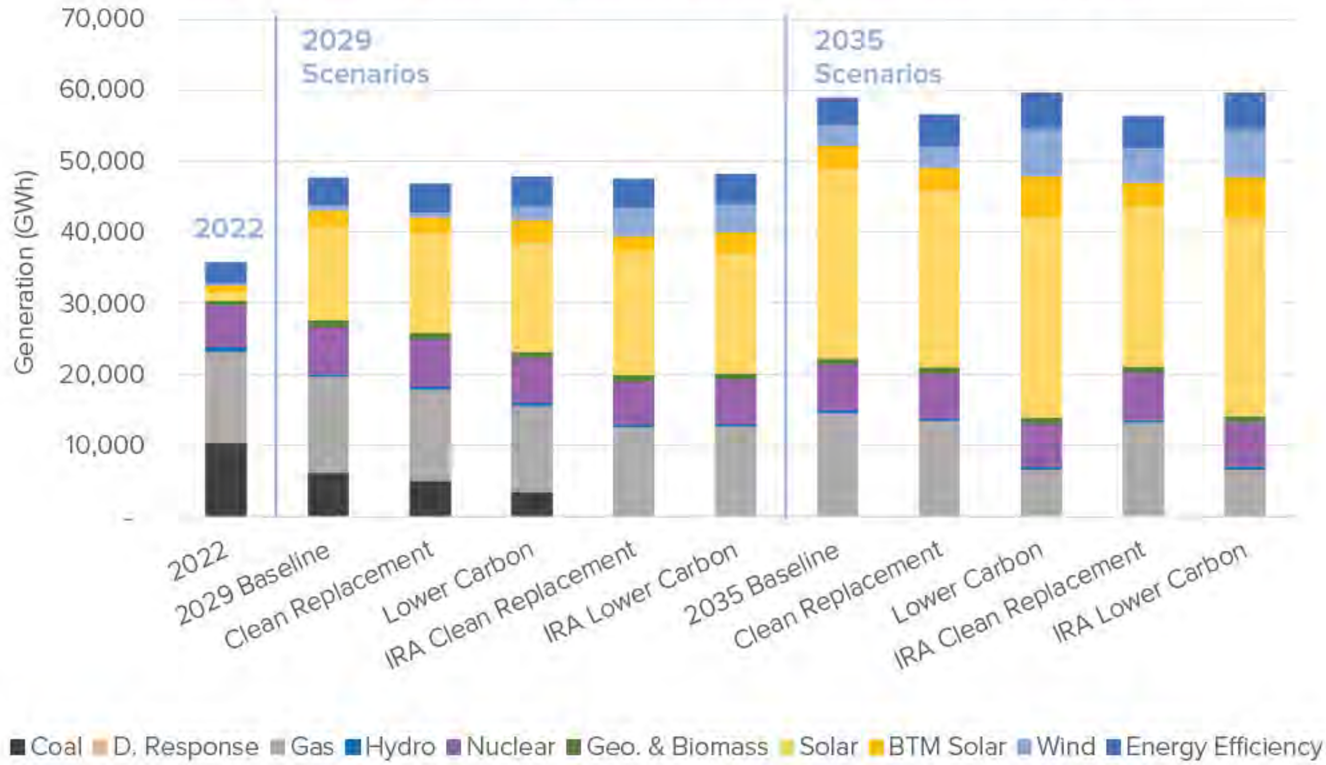


Figure 3. Annual generation for modeled portfolios in years 2022, 2029, 2035



3.2.2 Revenue Requirement

The model found the least cost portfolio for each scenario modeled and calculated the net present value of the revenue requirement ("NPVRR") for the period 2023-2035. The table below shows the cost differential of the different portfolios.

Table 2: Revenue requirement of modeled portfolios (2023-2035)

NPVRR[8] (Delta from Baseline In $Billion)		
	Initial Runs	IRA runs
Baseline	13.35	12.65[9]
Clean Replacement	12.96	11.91
Lower Carbon	13.24	12.07

The revenue requirement for the Baseline scenario is $390 million more than the Clean Replacement portfolio and $110 million more than the Lower Carbon portfolio, indicating that SRP's plan to add new gas resources in the near term and keep operating its coal units results in significantly higher costs for its customers.

[8] Note that the revenue requirement totals displayed represent the going-forward generation capital and operating costs only and exclude certain items such as depreciation on existing plants, distribution costs, etc., that are not expected to vary across between scenarios. As such, these absolute values are not comparable to revenue requirement values used in the SRP ISP.

[9] SRP indicated that their ISP modeling will be based on existing credits. Consequently, the Baseline was not re-optimized based on the IRA credits, but simply re-priced.

The Lower Carbon scenario requires additional emissions reductions from SRP's existing gas fleet in order to meet the 85% reduction target and consequently results in slightly elevated costs compared to the Clean Replacement portfolio. However, its NPVRR remains significantly lower than the cost of the Baseline portfolio.

When the assumptions are adjusted to reflect the IRA, the potential savings achieved by the clean energy portfolios are even further increased, relative to the baseline. Strategen estimates that the clean energy portfolios (inclusive of the IRA credits) will achieve savings of $590-$740 million when compared to the baseline portfolio (also inclusive of the IRA credits).

In conducting this comparative analysis, the Baseline portfolio was repriced to include the IRA tax credits, ensuring an "apples to apples" comparison. However, the underlying baseline resource portfolio was not re-optimized. This repricing resulted in a $700 million reduction in the baseline portfolio (with IRA), relative to the initial baseline portfolio (without IRA). The $590-$740 million in savings estimated for the clean energy portfolios are in addition to this initial $700 million reduction.

Sensitivity Analyses

An additional sensitivity run that did not include the incremental distributed solar was conducted and indicated that the Clean Replacement portfolio remains a more economic option than the Baseline. The inclusion of distributed solar displaces some of the utility scale solar but it results in significant NPVRR reduction, showing that rate design incentivizing distributed generation can reduce the NPVRR while also alleviating transmission constraints.

At the timing of this analysis, SRP had not announced a preferred portfolio. However, the baseline captures some core elements of what we expect the utility's proposed portfolio to be. However, since resource planning economics have dramatically shifted with the Inflation Reduction Act, we conducted one additional run that simulates an "alternative baseline" portfolio that includes no investment in new gas (neither the Coolidge Expansion Project, nor other new gas). It is Strategen's understanding that absent the Coolidge expansion, SRP presently intends to install several gas turbines at other existing sites that in total will achieve a similar capacity expansion.[10] This "alternative baseline" portfolio captures a scenario in which that the utility does not invest in any new gas. The NPVRR of the alternative baseline is close to the main Baseline Portfolio presented: specifically, the alternative baseline results in NPVRR that is approximately $30 million higher in cost than the one that includes the Coolidge expansion or equivalent gas capacity without including the IRA tax credits and $163 million lower in cost when including the IRA tax credits. This indicates that the Coolidge Expansion Project is not part of a least cost portfolio. Furthermore, this sensitivity analysis further confirms Strategen's overall findings. That is, significant savings are achieved from the clean energy portfolios. Those savings are a result of minimizing investment in new gas, but even in the case that SRP's preferred portfolio were to include no new gas resources, additional savings could be achieved by transitioning away from coal resources and investing in demand side resources.

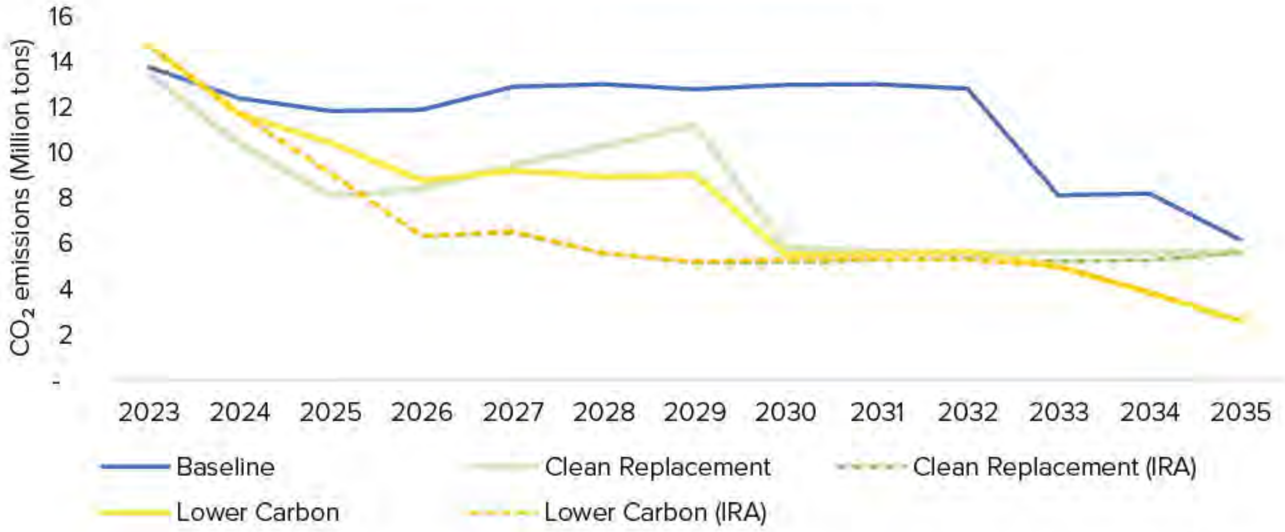
3.2.3 CO_2 Emissions Trajectory

The model also calculated the annual emissions from the operations of the portfolios, which are depicted in the graph below. Installing solar plus storage resources in early years for all the clean portfolios results in significant emissions savings compared to the baseline case. Additional emissions savings are achieved in 2030 for the clean energy portfolios when the Coronado and Springerville units retire.

When federal support from the IRA is included in the optimization of the portfolio, the coal units retire as early as allowed, resulting in significantly lower cumulative emissions over the study period.

[10] On 09/12/2022, the SRP Board of Directors voted to approve the first phase of a multi-phase continued development project at SRP's Copper Crossing facility to create the "Copper Crossing Energy and Research Center" which will include the installation of two natural gas turbines (out of the 16 of the Coolidge Expansion Project). SRP Board Approves Continued Resource Development at Copper Crossing, 09/12/2022

Figure 4: CO_2 emissions trajectory



Measuring emissions reduction at a single point in time, as usually done with emission reduction targets, is not informative enough. For example, focusing on 2035 the emissions of the Baseline portfolio are very close to the ones reported for the Clean Replacement portfolio. Despite the two portfolios having similar emissions levels in 2035, their cumulative emissions are very different. The two portfolios look similar in **2034**. However, the impact of keeping SRP's Springerville, Four Corners, and Coronado units online until then cannot be ignored.

With respect to emission reduction targets, it is important to note that a rate emissions reduction target for a utility with a high growing load like SRP is less meaningful that the same reduction in mass emissions.[11] The rate target does not necessarily reduce the tons of CO_2 emitted as generation keeps growing. In the case of SRP, the 2035 sustainability goal is achieved just based on its projected load growth and announced coal retirements.

A more ambitious mass emissions reduction target as the one included in the Lower Carbon case eliminates new fossil fuel generation as a viable resource option, results in the retirement of coal units, but also further reduces the generation of existing gas units. To achieve the additional emissions reduction, the model selects wind to diversify the portfolio and reduce the generation of existing combined cycle units in the later years of the study.

Table 3: Cumulative CO_2 emissions (2023-2035)

(Delta from Baseline In million tons)		
	Initial Runs	IRA runs
Baseline	-	-
Clean Replacement	(45)	(59)
Lower Carbon	(49)	(63)

[11] One of the primary reasons for pursuing the carbon reduction policy is to mitigate catastrophic climate change. However, the climate impacts of carbon emissions are the result of cumulative emissions, not annual emissions or an emissions rate. Thus, even if the baseline portfolio ultimately reaches annual emissions similar to the clean replacement portfolio, the overall trajectory of these reductions is what matters from a climate perspective. A faster pace of reduction such as the Clean Replacement or Lower Carbon portfolios will lead to fewer cumulative emissions, and thus have a more beneficial impact.

4. Recommendations

SRP currently has a unique opportunity to set the right path for its transition to a cleaner generation fleet. The utility faces a significant near-term energy and capacity need, and the IRA provides the tools and credits to help meet that need with a clean, lower-cost portfolio. SRP's resource planning decisions should account for costs, emissions, fuel price volatility and policy risks associated with new fossil fuel generation, as well as the impacts on local communities. Building a clean portfolio, similar to the ones presented in this analysis, is not only a no-regrets course of action, but the least-cost and least-risk option.

This analysis yields several key recommendations:

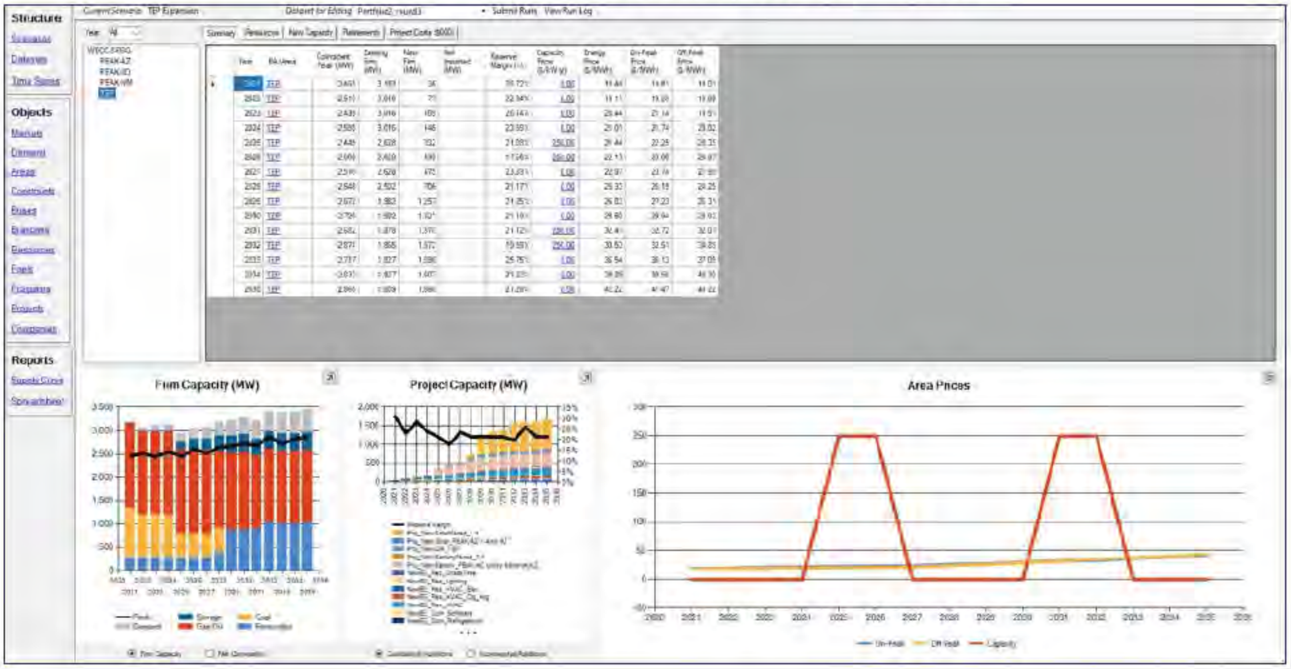
- **Avoid expenditures on gas units**. SRP should avoid or cease expenditures on gas generation, including the proposed Coolidge Expansion Project as well as the installation of gas turbines at other existing sites. Especially now, with the IRA provisions in place, new gas generation not only poses significant risks, but is no longer part of a least cost portfolio.
- **Retire uneconomic coal units as soon as possible while ensuring a just and equitable transition plan**. Strategen's initial modeling indicated that retiring coal units before 2030 can result in significant emission savings without raising costs for SRP customers. The IRA not only supports this finding, but dramatically accelerates the optimal timeline by providing bonus credits to eligible resources that are sited in communities where a coal plant retired. Strategen's capacity expansion modeling indicated that earlier retirement dates of 2025, and 2026 for the Four Corners, Springerville, and Coronado units are optimal. The model did not allow the earlier retirement of coal units with an announced retirement date before 2030 (Craig and Hayden). Strategen recognizes the need for careful planning prior to a unit retirement especially as the local community might be affected. Respecting the need for just transition planning, we recommend that SRP explores the retirement of its entire coal fleet prior to 2030 and as soon as possible.
- **Continue investing in and supporting demand side resources**. SRP should adopt more ambitious energy efficiency targets and programs, and incorporate these targets into the resource planning process. SRP can also offer flexible demand response programs for large customers and expand residential DR program offerings. SRP can further explore rate options that will incentivize distributed generation, especially as federal support will significantly reduce costs through extended credits.
- **Set *meaningful* carbon reduction targets.** SRP's current 2035 sustainability goals do not appear to drive any incremental emissions reductions and are readily achieved via SRP's previously announced coal retirements. Setting a more ambitious mass-based target could be helpful in focusing the utility's resource planning efforts towards both cleaner and cheaper portfolios.
- **Explore all options and incentives available through the Inflation Reduction Act**. SRP should explore available IRA provisions, including solar, storage, wind, and other clean electricity tax credits, transmission planning provisions, demand side resource incentives (tax credits and rebates for EE and distributed generation), credits for interconnection of smaller projects, as well as many other provisions that can support SRP in pursuing a cleaner, cheaper portfolio for its customers. It is important that SRP considers the impact of the IRA in this ISP cycle and does not lock itself and its customers into a sub-optimal portfolio.

5. Appendix

5.1 Methodology

In conducting this analysis, Strategen used the EnCompass power planning software tool, developed by Anchor Power Solutions. EnCompass is commercially available and can be configured either as a capacity expansion model or a production cost model.

Figure 5: Snapshot of the EnCompass user interface



A capacity expansion model finds the least cost resource portfolio that meets the projected electricity demand over a period of several years. A production cost model finds the least cost dispatch of a given or pre-determined system of generators. Capacity expansion models have been traditionally used to provide investment guidance, while production cost models have been employed to provide answers to short-term operational questions or to perform comparisons of pre-selected or pre-determined portfolios. A capacity expansion model selects the resources that can serve the forecasted load over a period of several years at minimum cost. It is, therefore, suitable for developing utility resource plans and assessing the costs and benefits of longer looking utility regulatory policies.

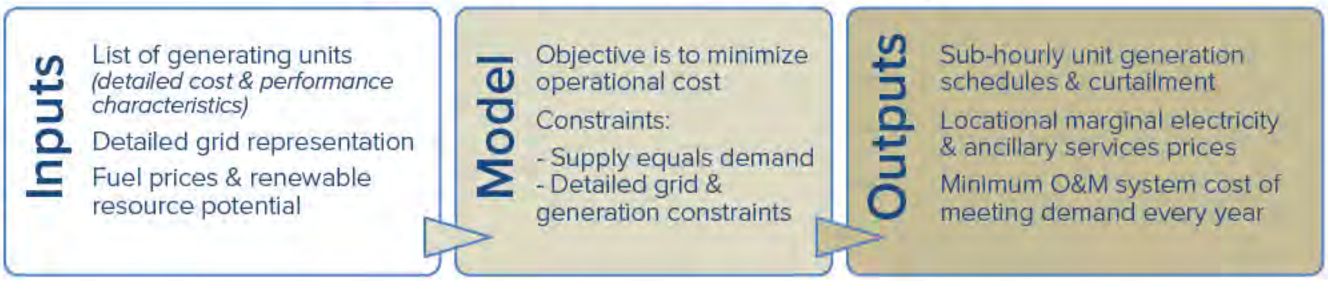
Accordingly, for this study, EnCompass was run as a capacity expansion model with a planning horizon of 2035. In this mode, the model determines not only the most economical way to utilize existing resources, but also which technologies should be added in the future, and which existing resources should be retired, while meeting the forecasted load and any policy goals outlined in each simulation.

The figure below shows the inputs and outputs of a capacity expansion model.

Figure 6: Capacity expansion model: inputs & outputs

After selecting the resources that comprise the least cost portfolio under a set of assumptions, the operations, costs, and emissions of the portfolio were modeled through a detailed hourly production cost simulation.

Figure 7: Production cost model: inputs & outputs



The model simulates the SRP balancing area; import/export capability to the Palo Verde hub as a representation of the utilities' interconnection to other utilities in the state and the broader region and includes out of state wind resources for selection.

5.2 Inputs & Assumptions

The analysis uses public data from diverse sources including goals and resources from SRP's Integrated System Planning process, cost values from the National Renewable Energy Laboratory (NREL), operational data from the Energy Information Administration (EIA) and the S&P Market Intelligence Platform, and emissions records from the Environmental Protection Agency (EPA), as well as adjustments based on recent policy developments, and the Strategen team's expert judgement.

5.2.1 Load Forecast

Forecasting load is a foundational component of a resource plan, fundamental to analyzing the number, timing, and type of resources a utility need. The forecast is long-term in nature, with more emphasis placed on the near-term, as the near-term outlook guides short-term decision-making in a utility's three-to-five year "Action Plan" window, while the long-term forecast is important to develop a long-term strategy, directional resource targets, and assess policy impacts.

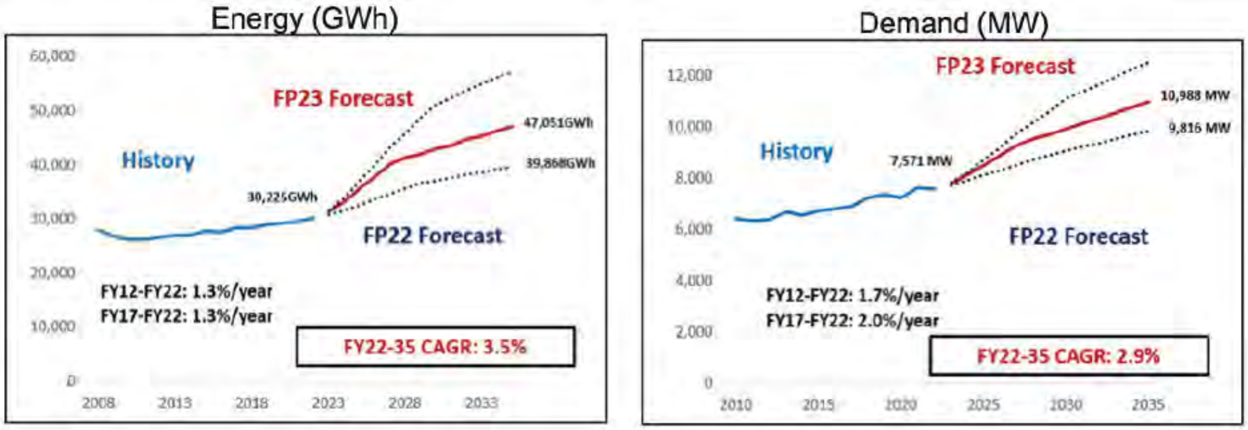
The present analysis projects energy needs up to 2035 based on SRP's forecasted annual energy consumption and system peak.[12] The hourly profile is derived from SRP's historical load from 2021, as reported by EIA,[13] Specifically, SRP's forecast assumed an average 3.5% annual growth rate of energy and a 2.9% annual growth rate of peak demand. SRP's forecast is assumed to include the effects of energy

[12] Itron the forecast, published in SRP's Power Committee meeting of April 21, 2022

[13] EIA's Hourly Electric Grid Monitor. Using data collected in form EIA-930, the agency collects data about the high-voltage bulk electric power grid from each balancing authority in the 48 lower states.

efficiency and distributed generation as those included in the utility's "Current Trends" portfolio. SRP's load forecast was then adjusted to reflect higher energy savings from Energy Efficiency in the Lower Carbon Scenario portfolio.

Figure 8. SRP's load forecast, Itron review



5.2.2 Planning Reserve Margin and Market Reliance

All modeled portfolios assume 525 MW of market availability and a 16% planning reserve margin. This is based on the utility's base assumption in the "Current Trends" scenario.

5.2.3 Capacity Value of Intermittent Resources

The capacity contribution of generation resources was based on E3's "Resource Adequacy in the Southwest" study published in February 2022.

5.2.4 Demand Side Resources

Future EE, DR, and distributed solar levels were included in the model based on SRP's projections. The graphs below summarize the forecasts showing how each of those are included in the SRP developed scenarios and the scenarios examined in this report:

Figure 9. SRP's demand response projections

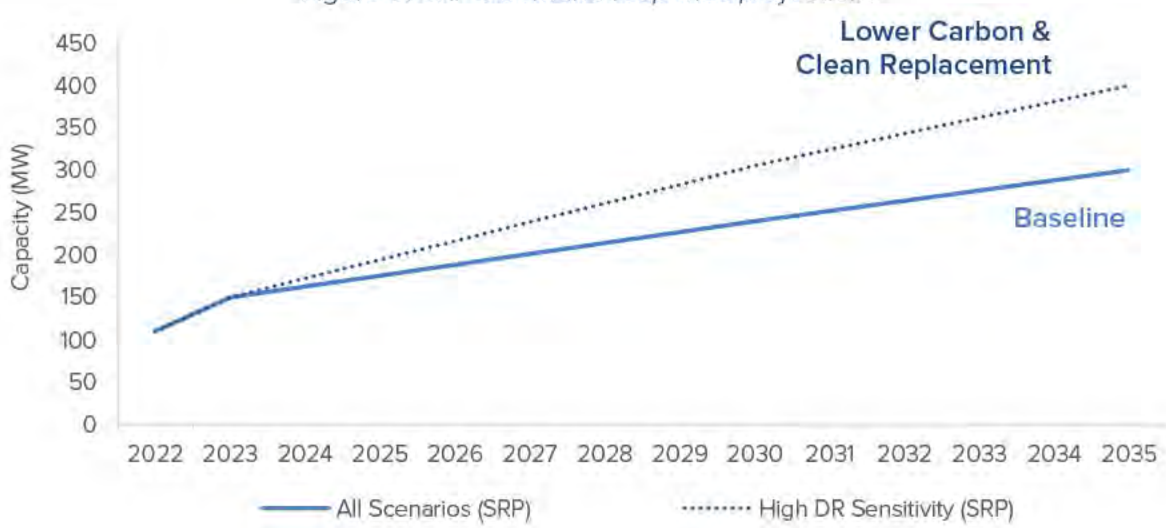
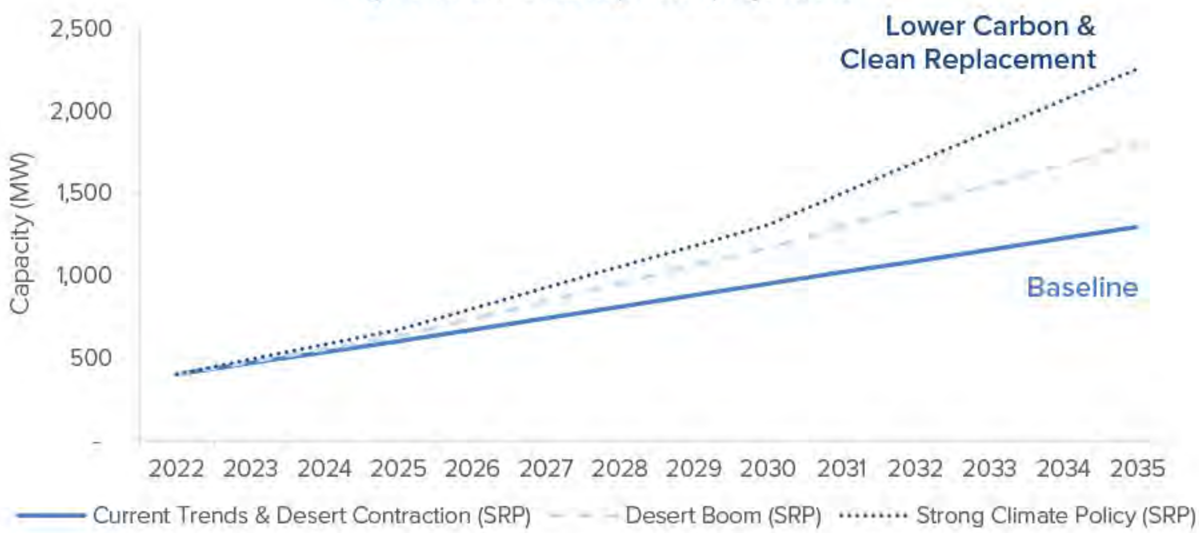


Figure 10. SRP's energy efficiency projections

Figure 11. SRP's rooftop solar projections



The incremental EE cost has been estimated based on estimates provided in a recent study performed by Lawrence Berkeley National Laboratory, extrapolated to the relevant time periods.[14] Distributed solar costs were not included in the revenue requirement estimates.

5.2.5 Supply Side Resources

SRP's supply resources include generators of a variety of technologies, both owned and contracted by the utility. Strategen complied data on these resources and the ones SRP has committed to acquire in the near term.

[14] Based on LBL's "The Future of U.S. Electricity Efficiency Programs Funded by Utility Customers" study which presents costs by state for EE in 2020, 2025, and 2030. The analysis uses the "High EE" scenario for costs.

5.2.6 Existing Resources

Natural Gas Generation

Generating Station	Fuel	Capacity
Agua Fria	Natural gas	626 MW
Coolidge	Natural gas	575 MW
Gila River	Natural gas	1,100 MW
Desert Basin	Natural gas and steam	577 MW
Kyrene	Natural gas and oil	521 MW
Mesquite	Natural gas	625 MW
Santan	Natural gas	1,193 MW

The model also includes planned gas upgrades in the Agua Fria and Desert Basin Stations.
Operational and cost characteristics of the gas resources including heat rates, forced outage rates, emission rates, and variable operations and maintenance costs are based on data from the S&P market intelligence platform or information about generic units of the same technology. No gas unit was allowed to retire economically for the study period.

Coal Resources

Operational and characteristics of the coal resources including heat rates, forced outage rates, emission rates, fixed and variable operations and maintenance costs are based on data from the S&P market intelligence platform or information about generic units of the same technology. Incremental capital expenses were calculated based on Energy Information Administration's (EIA) "Generating Unit Annual Capital and Life Extension Costs Analysis".

For Coronado, an additional cost of $50 million was modeled at the beginning of 2026 that would allow Unit 2 to share the existing selective catalytic reduction equipment with Unit 1 (CGS Split SCR project).
In the Clean Replacement and Lower Carbon Portfolios the Coronado, Four Corners, and Springerville units were allowed to retire economically.

Salt River Power resources were assumed to operate at capacity factors similar to those of 2018, while Colorado river resources were reduced to half of that starting in 2025. The model results indicate hydro generation of approximately 0.7 TWh for 2022, which is consistent with SRP's projections for the year.[15]

Table 4: SRP's coal units

	Nameplate Capacity SRP share (MW)	Announced Retirement Date	Earliest Retirement Date Modeled	Seasonal Operations
Coronado Unit 1	382	12/31/2023	1/1/2026	Yes
Coronado Unit 2	380	12/31/2032	1/1/2026	Yes
Craig Unit 1	124	12/31/2025	-	
Craig Unit 2	124	12/31/2028	-	
Four Corners Unit 4	74	12/31/2031	1/1/2025	Yes
Four Corners Unit 5	74	12/31/2031	1/1/2025	
Hayden Unit 2	131	12/31/2027	-	
Springerville Unit 4	400		1/1/2025	Yes

[15] SRP website, Today's energy mix (2022)

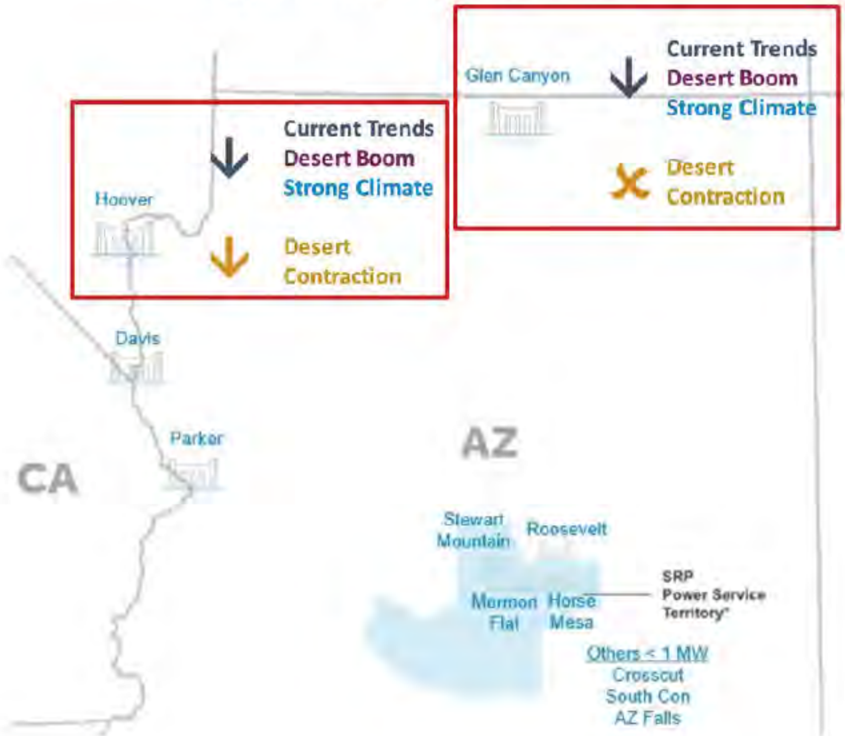
Nuclear Resources

SRP receives 689 MW from the Palo Verde Generating Station (17.49% share). SRP will acquire 104MW of Unit 1 on 1/1/2023 and 10MW on 1/1/2024 from Public Service Company of New Mexico. In one of the

Hydro Resources

SRP receives energy from several hydro resources, depicted below:

Figure 12. SRP's hydro resources[16]



Solar and Storage Resources

SRP owns or has contracts for wind, solar, and energy storage assets. Information around the utility's existing assets and power purchase agreements were compiled from SRP's website and are summarized below. All existing and planned additions were included in the model.

Table 5: SRP's solar and energy storage resources

Project	Nameplate Capacity	Commercial Operation Date
Copper Crossing Solar Ranch, Florence	20 megawatts (MW)	2011
Queen Creek Solar, Queen Creek	19 MW	2012
Sandstone Solar Facility, Florence	45 MW	2015
Kayenta 1, Navajo Nation	27 MW	2017
Pinal Central Energy Center, Casa Grande	20 MW + 10 MW 4-hour battery	2018
Dorman Energy Center, Chandler	10 MW, 4-hour battery	2019

[16] SRP's Integrated System Plan Technical Working Sessions:
Advisory Modeling Subgroup Meeting 2: Inputs for the ISP Study Plan

Project	Nameplate Capacity	Commercial Operation Date
Kayenta 2, Navajo Nation	28 MW	2019
Saint Solar	100 MW + 100 MW, 4-hour battery (in 2025)	2020
East Line Solar	200 MW	2020
Bolster Battery	25 MW, 4-hour battery	2021
Central Line Solar	100 MW	3/18/2022
West Line Solar	100 MW	10/31/2022
Sonoran Solar + Battery	260 MW Solar + 260 MW, 4-hour battery	By 2025
Storey Solar + Battery	88 MW Solar + 88 MW, 3-hour battery	By 2025
Saint Battery	100 MW, 4-hour battery	By 2025
Valley Farms Solar	200 MW	By 2025
Randolph Solar	200 MW	By 2025
Co Bar Solar	400 MW	By 2025

Wind Resources

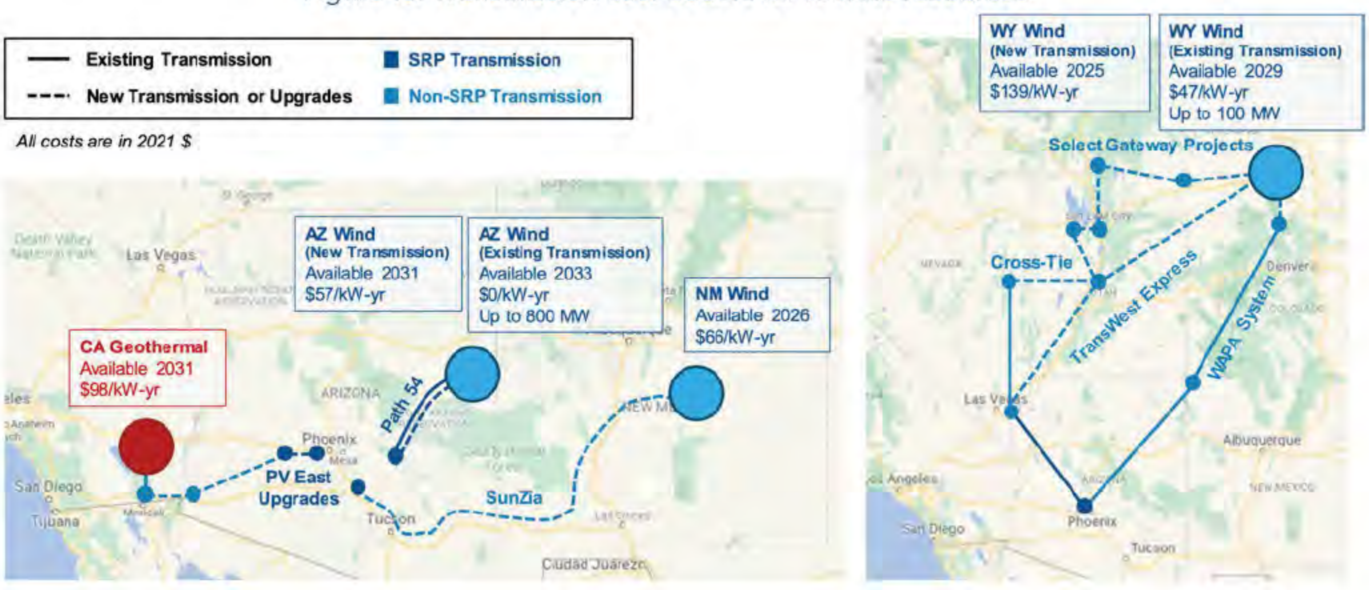
SRP has an agreement to purchase electricity from the Dry Lake Wind Power Project, located near Heber, Arizona (127 MW).

5.2.7 New Resources

Resource Options

The model was allowed to select combustion turbines, solar, wind, and energy storage assets. The initial modeling of the clean portfolios allowed no combustion turbines, while no such restriction was necessary in the IRA scenarios. A hybrid configuration of solar plus storage (50% of solar, 4hrs) was also included. Storage options included 4hour batteries for the duration of the study, and 8hour batteries post 2030. Wind resources included options from Arizona, New Mexico, and Wyoming and included transmission costs per SRP's assumptions:

Figure 13. Transmission cost adders for remote resources[17]



[17] SRP's Integrated System Plan Technical Working Sessions:
Advisory Modeling Subgroup Meeting 3: Inputs for the ISP Study Plan – Part 2

Wind from Arizona using existing transmission was made available in the model upon retirement of the Coronado units. In addition to the AZ wind utilizing existing transmission, the model was limited to select up to 1,000 MW of additional wind for the study period.

Resource Costs

The capital costs, fixed costs and variable operating costs of all resources were based on the 2022 National Renewable Energy Laboratory's Annual Technology Baseline (NREL ATB). Wind and solar costs, as well as gas turbine costs were based on the moderate cost projection, while energy storage costs were based on the advanced cost projection.

5.2.8 Commodity Prices

Gas prices were based on the EIA Annual Energy Outlook ("AEO") 2022 for delivered energy prices in the Mountain region (reference case). Monthly variation of gas prices was included in the forecast based on Strategen's expertise.

Coal prices were based on EIA's historical coal price database for Arizona units (ranging from $1.9/MMBtu for the Craig units to $3.1/MMBtu for the Four Corner units in 2021). Coal prices are assumed to escalate at the inflation rate.

5.2.9 Federal Tax Credits

Initial portfolios included investment tax credits ("ITC") for solar and solar plus storage assuming that though "commence-construction" or "safe-harboring" provisions by 2023, solar ITC projects can secure the 26% and 22% credits in 2022 through 2025. Post 2025, the modeled ITC dropped to 10%. No Production Tax Credit ("PTC") for wind resources was modeled.

For the IRA portfolios, extended ITC and PTC provisions are modeled. The ITC and PTC provisions in the model assume both the base credits and the adders for projects that meet labor requirements, resulting in ITC of 30%. The credits are assumed to phase down after 2033.[18] Solar plus storage projects that replace coal generation (whether planned or endogenously retired in the model) receive an additional 10% ITC based on the "energy community" siting provision. When Coronado retires, 800 MW of AZ wind with no additional transmission charge are eligible for the PTC with the bonus for siting in "energy community". The additional available bonus for meeting domestic content minimums was not included.

[18] Inflation Reduction Act: Solar Energy and Energy Storage Provisions Summary, Solar Energy Industries Association

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Name: Allison George

Record Number: MI7102861

Delivery Method: Email to Corporte Secretary

Attachments: Second Pricing Proposal Comment Letter FINAL with Attachments.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7102861*

Comment:

From: Allison George
Sent: Wednesday, February 19, 2025 4:12 PM
To: SRP Corporate Secretary
Cc: Emily Doerfler; Gwen Farnsworth
Subject: WRA's Second Set of Comments on 2025 Pricing Proposal

Dear Mr. Felty,

Western Resource Advocates submits the attached comments to the SRP Board as part of the 2025 Pricing Process. We ask that these comments be provided to the Board as part of the mailed packet in advance of the final Pricing Process Meeting on February 27th. Please let me know if you have any questions or concerns.

Thank you for your assistance,

Allison George

See attachments

February 19, 2025

Salt River Project
1500 N. Mill Avenue
Tempe, AZ 85288

Dear SRP Board of Directors:

I. Introduction

On December 2nd, 2024, Salt River Project ("SRP") Management ("Management") announced that it would be opening a Public Pricing Process that seeks a number of adjustments to its existing Price Plan Portfolio.[1] Concurrent with that announcement, SRP provided public documents describing Management's pricing proposals in the "Proposed Adjustments to SRP's Standing Electric Price Plans Effective with the November 2025 Billing Cycle,"[2] ("Proposed Adjustments") and supporting documentation. To that end, the SRP Board ("Board") scheduled Special Board Meetings about the Public Pricing Process on January 31st, February 6th, February 11th, and February 27th.[3] Western Resource Advocates ("WRA") has taken an active role in SRP's Public Pricing Process and has provided initial written comments[4] to the Board and also presented at the February 6th Special Board Meeting.[5]

In addition to these comments, WRA submitted public written comments to SRP on January 23rd, 2025, which was provided to the Board in the January 31st Board Meeting Packet. In WRA's January 23rd written comments, WRA recommended that: **1)** EZ-3 customers should be moved into the E-28 plan instead of the E-23 plan; **2)** the price differentiation between on-peak and off-peak rates

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[1] Schuricht, *SRP Initiates Pricing Process that Seeks Price Increase and New Price Plan Options*, SRP (Dec. 2, 2024), https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/2024%20Price%20Process%20Opens%20News%20Release%20FINAL.pdf.
[2] *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle,* https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/Proposed%20Adjustments%20to%20SRP's%20Standard%20Price%20Plans%20Effective%20with%20the%20November%202025%20Billing%20Cycle_Web.pdf.
[3] *Learn about the public pricing process*, https://www.srpnet.com/price-plans/electric-pricing-public-process/learn-about-the-public-pricing-process?utm_campaign=1742205&utm_medium=vm&utm_source=multi&utm_id=2454858749.
[4] *SRP Price Process Comments Week ending January 25, 2025* at 509, https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/Q&A/20250125_PriceProcess_Weekly_Comments.pdf.
[5] *Id*. at 34.

ARIZONA 340 E. Palm Lane, Suite A140 Phoenix, AZ 85004
COLORADO – *Boulder* 2260 Baseline Road, Suite 200 Boulder, CO 80302
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NEW MEXICO 141 E. Palace Ave, Suite 220 Santa Fe, NM 87501
UTAH 307 West 200 South, Suite 2000 Salt Lake City, UT 84101

should be increased for the E-28 plan; **3)** SRP develop managed charging programs for electric vehicles ("EVs") in the future; **4)** the Board should add Sustainability as a pricing principle for future pricing processes; **5)** the Board require Management to provide greater detail about SRP's new Energy Attribute Rider; **6)** the Board reject the proposed Carbon Reduction Rider; and **7)** the Board advise Management to explore and propose alternative cost allocation methods in its next Public Pricing Process to address the risks of transferring the costs of Data Center Growth to Residential Customers.

WRA provides these comments to supplement its previous recommendations with further detail and to address some concerns expressed by Management over the course of the Public Pricing Process. More specifically, WRA will **1)** discuss the importance of customer education for the rollout of TOU ("Time of Use") price plans and address some of the concerns Management and its Consultants have about the recommendation to transition EZ-3 customers to the E-28 plan; **2)** provide greater detail about the development of managed charging programs; and **3)** discuss how stakeholder engagement can be improved for the next Public Pricing Process.

II. The Importance of TOU Customer Education

Management is proposing to sunset SRP's existing TOU plans, including the EZ-3 plan, and proposes transitioning any customers still on those plans to alternative plans before 2029.[6] Management's proposal would shift any customers remaining on the EZ-3 plan at the sunset date onto the new E-23 tariff, which is a non-TOU plan. Considering the benefits of keeping TOU customers on TOU plans, WRA recommended that SRP transition EZ-3 plan customers to the E-28 plan (not the E-23 plan) in its comments to the Board in January,[7] and then again during its presentation to the Board on February 6th.[8] Since making those recommendations, there has been some discourse amongst Management and its Consultants about WRA's recommendations and TOU plans in general. WRA wants to address some of that discourse here.

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[6] *Proposed Adjustments To SRP's Standard Electric Price Plans Effective With The November 2025 Billing Cycle* at 47, https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/Proposed%20Adjustments%20to%20SRP%27s%20Standard%20Price%20Plans%20Effective%20with%20the%20November%202025%20Billing%20Cycle_Web%20%281%29.pdf.
[7] *SRP Price Process Comments Week ending January 25, 2025* at 509.
[8] *SRP Board Meeting February 6, 2025 – Organizational and SRP Management Materials* at 34, https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/20250206_DB_packet_Pricing.pdf.

A. Concerns from SRP Management and Christensen Associates

Management and its Consultant, Christensen Associates, made several comments about the recommendations from stakeholder groups and TOU plans during both the February 6th and February 11th Special Board Meetings. WRA will address each of these concerns in light of its specific recommendations to transition EZ-3 customers to the E-28 plan and increase the price differential between on-peak and off-peak hours for the E-28 plan.

1. Mandatory TOU Plans

In his comments during the February 11th Special Board Meeting, Mr. Chapman from Christensen Associates took issue with the recommendation by some stakeholders to make TOU plans "mandatory."[9] A mandatory TOU plan is a standard tariff that customers are required to be placed in automatically with no alternative option. This is not what WRA is recommending. To clarify, WRA's recommendation is to transition customers already on TOU plans to the new and complementary E-28 TOU plan once their existing plan sunsets. Customers who have already opted into a TOU plan would then remain on a TOU plan, rather than be forced to exit a TOU plan and have to opt-in again. Any customer who is currently on the sunsetting EZ-3 plan would be able to select an alternative plan, either before being transitioned to E-28 at the sunset date or by opting out of the E-28 plan.

2. Choice and TOU Plan Price Differentials

Mr. Chapman from Christensen Associates also took issue with the suggestion from stakeholders, including WRA, that the price differential between on-peak and off-peak hours should be increased.[10] Mr. Chapman heavily implied that certain price differentials between on-peak and off-peak periods made TOU plans punitive and took away customer choice.[11] The idea that TOU plans take away customer choice is simply inaccurate. In fact, TOU plans actually increase customer choice.[12] TOU plans give customers greater flexibility than traditional plans and allow customers to take control of their energy use, and in extension, their energy bill.[13] In addition to the potential to manage bills by

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[9] *February 11th SRP Public Pricing Process Board Meeting Recording* at 1:40:00, https://app.frame.io/presentations/cf03367f-8381-4bf7-9bbe-47e5922e5230.
[10] *Id*.
[11] *Id*. at 1:45:50.
[12] Questline, *Utilities tackling time-of-use enrollment with new tactics*, UTILITY DRIVE (Oct. 2, 2023), https://www.utilitydive.com/spons/utilities-tackling-time-of-use-enrollment-with-new-tactics/694800/.
[13] *Id*.

reducing energy use—a prospect difficult to achieve with record breaking heat here in Arizona—TOU plans allow customers to lower their energy bills by changing *when* they use that energy.[14] While increasing the price differential between on-peak and off-peak periods does provide stronger inducement to customers to change behaviors, this does not negate the flexibility and control that TOU plans in general provide.

Additionally, Mr. Chapman made a few comments that seemed to contradict his assessment that SRP should not increase its price differential above its current ratio. First, Mr. Chapman stated that according to price response analyses, unless there was a price differential of 3:1, price response in residential customers was undetectable.[15] In other words, utilities could not detect noticeable customer behavior change unless there was a price ratio of 3:1 between on-peak and off-peak periods. Second, Mr. Chapman stated that over forty years of statistics showed that a price differential of 3:1 was a good idea.[16] While Mr. Chapman's statement that TOU ratios are often 2:1 in the wholesale energy market may be true,[17] it is unclear how norms in a market that residential customers rarely if ever participate in should override over 40 years of statistics and evidence that show a 3:1 price ratio is favorable. WRA's recommendation to increase the price differential for on-peak and off-peak periods for the E-28 plan does not make the E-28 plan punitive and is supported by evidence.

3. Customer Education and the Transition to a New TOU Plan

In a presentation on February 6th, Management stated that it was "open to moving [EZ-3 customers] to E-28 if desired by the Board."[18] However, Management also mentioned some concerns around transitioning customers who currently have on-peak periods of 3-6 PM and 4-7 PM to an on-peak period of 6-9 PM.[19] Management also mentioned that it preferred that customers choose a new price plan themselves, a preference that WRA also shares. These are reasonable concerns; however, both concerns can be addressed through SRP's education of TOU customers about the sunsetting of their current plans and the possible transition to a new TOU plan with new on-peak and off-peak periods. WRA will discuss this topic further in the section below.

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[14] *Id*.
[15] *February 11th SRP Public Pricing Process Board Meeting Recording* at 1:42:10, https://app.frame.io/presentations/cf03367f-8381-4bf7-9bbe-47e5922e5230.
[16] *Id*. at 1:42:30.
[17] *Id*. at 1:42:35.
[18] *SRP Board Meeting February 6, 2025 – Organizational and SRP Management Materials* at 153.
[19] *Id*.

B. TOU Plans and Customer Education

Educating all SRP customers is essential for successful TOU enrollment, as most customers are used to traditional flat rate plans.[20] It is also important for SRP to educate customers on sunsetting TOU plans for the successful roll out of the E-28 plan and the E-16 plan, as those plans have different on-peak and off-peak periods than SRP's existing TOU plans. A 2022 report found that only 28% of utility customers are even aware that they can choose between different electric rate plans, but once those customers were made aware of that possibility, 70% said they would be interested in signing up for an alternative plan.[21] Outreach around TOU rollouts should go beyond generic content, should occur at every stage of a customer's rate transition journey, and should even extend into after a customer enrolls in a TOU Plan.[22] Ongoing, evolving, and proactive engagement can inspire confidence in customers transitioning to a new rate and can establish trust.[23]

SRP has already proposed a plan and schedule to educate customers prior to sunsetting its existing tariffs.[24] The education rollout begins when the new price plans go into effect on November 1, 2025, and extends to two months past the sunsetting date of the existing plans.[25] If implemented in a proactive, individualized, and consistent manner, SRP's communications regarding the transition to new plans would increase customer education and would result in fewer customers who have to be transitioned to a new plan by default. SRP should aim to increase enrollment in TOU plans, or at the very least maintain its existing TOU customer base.

In its engagement with regular and TOU customers, SRP can help to ensure better quality of customer education and therefore better engagement with its customers by following five best practices: **1)** creating a holistic view of customers; **2)** building customer trust; **3)** providing a consistent experience; **4)** continually engaging customers; and **5)** creating a process to assess customer trends and impacts.[26]

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[20] Questline, *Utilities tackling time-of-use enrollment with new tactics*, UTILITY DRIVE (Oct. 2, 2023), https://www.utilitydive.com/spons/utilities-tackling-time-of-use-enrollment-with-new-tactics/694800/.
[21] *Id*.
[22] Lopez, *How Utilities Can Solve 'Time of Use' Rate Rollout Puzzle in Just Three Steps*, POWER MAGAZINE (Oct. 22, 2022), https://www.powermag.com/how-utilities-can-solve-time-of-use-rate-rollout-puzzle-in-just-three-steps/.
[23] *Id*.
[24] *SRP Board Meeting February 6, 2025 – Organizational and SRP Management Materials* at 152.
[25] *Id*.
[26] *Five Best Practices for a Successful TOU Customer Roll-Out*, UPLIGHT 7 (2019), https://uplight.com/wp-content/uploads/2019/10/U_eBook_TOU_Rate-1.pdf.

The first thing SRP needs to do is create a holistic view of its customers. SRP can do this by personalizing its communications and by integrating a 360-degree view of its customers to provide insights and guidance.[27] SRP should personalize its messages to proactively target important sub-groups of its customer base, such as those who own EVs, seniors, and low-income families, to ensure that knowledge reaches the largest group of people possible. [28] SRP should use historical data and new information collected to personalize the frequency and content of ongoing communications with its customers.[29]

SRP needs to build customer trust in every step of its customer education plan during the sunsetting of existing TOU plans and the implementation of new TOU plans. SRP can do this through messages that highlight the opportunity for TOU customers to take control of their energy usage and energy bills by shifting their load.[30] SRP should clearly communicate how it plans to roll out its new TOU rates, how that will impact each of its customers, and how the customer can benefit from that transition.[31] SRP should continue this messaging to newly enrolled customers to educate them on an ongoing basis.

The successful implementation of a TOU rollout requires consistent messaging and synchronization for every customer interaction, whether this interaction is initiated by SRP or by the customer.[32] This means consistent messaging provided by customer service representatives, digital communications, customer portals, SRP's website, and through direct mail from SRP.[33]

SRP should aim to become a trusted "energy advisor" by continuing its communications to its customers about how to optimize the benefits of their new plan even after they have enrolled in a TOU plan.[34] Continuing education past the enrollment date can improve customer satisfaction with TOU plans, minimize customer turnover, and reduce peak energy use, the ultimate goal of TOU enrollment.[35] SRP can minimize customer dissatisfaction by proactively engaging with customers that will likely have high energy bills, by providing customers with advice on how to shift their energy load,

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[27] *Id*. at 7.
[28] *Id*.
[29] *Id*.
[30] *Id*. at 8.
[31] *Id*.
[32] *Id*. at 10.
[33] *Id*. at 10-12.
[34] *Id*. at 13.
[35] *Id*.

and by providing additional information on available rebates or programs.[36] SRP can also improve satisfaction by continually gathering information as customers engage with SRP through all of its channels. This can help SRP to make better recommendations in the future for customers of specific groups.[37] Additionally, SRP can provide information on its website to help customers generally understand the benefits of TOU rates, how they can respond to the peak and super-off-peak price signals, and which types of homes or appliances fit best for customers interested in managing their energy under a TOU rate.

Finally, SRP should also utilize customer usage analytics and data to gauge the success of its rollout programs so that the process can be improved on an ongoing basis.[38] Utilizing this data quickly and effectively, on top of introducing complementary programs like the installation of smart thermostats and appliance incentives, can help SRP develop knowledge on what is most effective in its customer outreach and can help improve communications that are not having the desired impact. Utilizing these best practices, SRP can best maintain and improve customer satisfaction and energy impacts on its system when transitioning customers to different TOU plans.

C. TOU Plans and Pricing Calculators

Another path that SRP could consider in educating its customers on TOU plans is the implementation of a pricing calculator that customers could use to see potential bill impacts of changing their plans. However, SRP should be extremely cautious in how it develops and implements a pricing calculator to avoid logistical and legal issues[39] that may arise, or simply to avoid providing customers with unrealistic expectations about their future bills given the likely limitations of an online calculator. If SRP were to implement a pricing calculator, it should go beyond allowing customers to compare estimated bills under different rate plans based on historical energy use by also providing modifiers to simulate savings that customers can achieve by taking simple and appropriate load shifting actions.[40] These actions can include installing a smart thermostat and/or deferring energy use

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[36] *Id*.
[37] *Id*.
[38] *Id*. at 14.
[39] Newland, *APS to pay overcharged customers $24 million*, KYMA (Feb. 21, 2021), https://kyma.com/news/top-stories/2021/02/23/aps-to-pay-overcharged-customers-24-million/, (showing that APS was required to pay 24 million dollars to about 225,000 customers after an investigation found that an online calculation tool utility customers used to choose their cheapest plan was giving erroneous recommendations.).
[40] Lopez, *How Utilities Can Solve 'Time of Use' Rate Rollout Puzzle in Just Three Steps*, POWER MAGAZINE (Oct. 22, 2022), https://www.powermag.com/how-utilities-can-solve-time-of-use-rate-rollout-puzzle-in-just-three-steps/.

to off-peak periods. Without these modifiers, a pricing calculator can actually steer customers *away* from TOU plans if these customers have not already shifted their energy use from peak pricing periods. Excluding energy shifting modifiers in such a calculator may show higher bills with TOU—an often incorrect result for those who can shift their energy use away from on-peak periods.

A pricing calculator is not the only option that SRP could use to assist customers in picking a pricing plan. SRP could also create an advisory tool on its website developed as an interactive online form by which a customer selects certain appliances, home characteristics, and activities or preferences to identify one or more recommended tariffs best matched for their home, goals and lifestyle. This approach would be different from an estimated bill calculator as the "output" is a recommended rate plan, rather than an estimated bill that may be inaccurate.

D. WRA's Recommendations

WRA recommends that the Board follow the advice of multiple stakeholder groups, including WRA, and transition EZ-3 customers who are on the plan when it sunsets to the E-28 plan instead of the E-23 plan, as well as increase the price differential between on-peak and off-peak hours for its E-28 price plan to better induce customer behavior change while maintaining flexibility and choice.

A Board member wishing to adopt WRA's recommendation could do so through a motion ***to require that Management transition SRP customers still on the EZ-3 plans when those plans sunset to the E-28 Price Plan*** and could additionally ***require that Management develop a comprehensive TOU outreach plan to be presented to the Board at a future Board meeting***. If SRP plans to develop a pricing calculator, a Board member could avoid directing customers away from TOU Plans by making a motion ***to direct Management to include in its pricing calculator tool modifiers to simulate savings that customers can achieve by taking simple and appropriate load shifting actions.***

III. Managed Charging Programs

WRA's January 23rd written comments recommended that SRP investigate and develop an active managed charging program.[41] These comments provide supplemental information expanding upon that recommendation. An active managed EV charging program should be designed to maximize the environmental and ratepayer benefits from shifting EV load into lowest cost and lowest emissions

[41] *SRP Price Process Comments Week ending January 25, 2025* at 509.

hours. While the structure of the new proposed E-28 plan creates an incentive to shift towards daytime charging, many customers will only be able to charge in the evenings when they are not at work. For those customers who are only able to charge in the evening, active managed charging programs will ensure that charging is done at a time when emissions and costs to the grid are lowest.

A. What Is Managed Charging and Why Is It Important?

Managed charging is a proactive approach to EV charging that shifts when and how an EV charges to better utilize the grid, while also ensuring a customer's EV is fully charged in the timeframe they require.[42] Residential Level 2 chargers allow EV charging at home to be inherently flexible, as EVs are parked for many hours at home but only need a few hours of charging to reach driver's necessary state of charge. Managed charging seeks to utilize this inherent flexibility by focusing charging to achieve system benefits such as avoiding system peak, reducing renewable curtailment, minimizing local distribution constraints, etc.[43]

Managed charging programs can take many forms but are broadly categorized as "active managed charging" or "passive managed charging."[44] Active managed charging implies direct utility control of a customer's EV charging, where a utility communicates a signal to a plugged-in EV through a networked charger or through the vehicle's on-board telematics, allowing real-time or near real-time responsiveness to grid conditions.[45] Active managed charging has the greatest long-term potential to utilize EV charging flexibility to benefit the grid,[46] although these programs are more complex and utilities are just beginning to deploy them at scale.

Passive managed charging provides a price signal to a customer which incentivizes them to charge at a certain time but relies on individual customers to adjust charging to those periods. The most common form of passive managed charging programs are time-differentiated rates,[47] like SRP's E-28 rate. These passive managed charging programs are very important for near- and mid-term

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[42] Myers, *A Comprehensive Guide to Electric Vehicle Managed Charging,* Smart Electric Power Alliance 5 (May 2019), https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/.
[43] *Id*. at 8.
[44] *Id*. at 11.
[45] *Id.*
[46] Hale et. al., *Electric Vehicle Managed Charging: Forward-Looking Estimates of Bulk Power System Value*, National Renewable Energy Laboratory 14 (Sept. 2022), https://www.nrel.gov/docs/fy22osti/83404.pdf.
[47] Dougherty & Fitzgerald, *EV Managed Charging Incentives and Utility Program Design*, Smart Electric Power Alliance (Dec. 2, 2021), https://sepapower.org/knowledge/ev-managed-charging-incentives-and-utility-program-design/.

charging management, as they are simpler to implement, yet they lack the dynamic flexibility of active managed charging.

Taking the next step to implement managed charging is critically important to further enhance emission reductions from EVs and optimize the use of the utility's grid. Passive managed charging programs like SRP's proposed E-28 plan represent an important first step of managed charging, but active managed charging represents the greatest opportunity for effectively shifting EV charging load. WRA recommends that SRP begin investigating an active managed charging program and that they look to peer utilities that are in various phases of pilot development or full rollout of active managed charging programs.

B. How Does an Active Managed Charging Program Work?

An active managed charging program uses signals from an electric utility and the technology inherent in EVs and Residential Level 2 chargers to seamlessly coordinate when EVs charge.[48] For example, an electric utility may use day-ahead electricity forecasts conveyed into an algorithm which then takes in personal driver information to determine the best time to charge. Drivers input what level they want their vehicle charged to and what time they need it at that level. When the vehicle is plugged in the evening, the algorithm then considers variables such as how long a charging window is available and how much electricity is needed to get a customer to a full charge in order to determine which hours during the available window will be selected. The algorithm will select the most ideal hours for the electric grid that are available while still ensuring the vehicle gets a full charge by when the driver needs the vehicle. The algorithm can also balance when other EVs in the program are charging to avoid adverse grid impacts if managed EVs all charge at the same time. The "optimal hours" depend on how the program is structured and the targeted grid impacts. Depending on what goals the utility is trying to achieve, the program might focus charging during hours when renewable curtailment is likely, when system costs are lowest, or when emissions intensity is lowest.[49] Often these factors overlap. The program is usually set up by the electric utility but is often developed and implemented by specialist companies like WeaveGrid, FlexCharging, or Virtual Peaker who have active

[48] *What is EV Managed Charging*, WeaveGrid (May 8, 2024), https://www.weavegrid.com/news/what-is-ev-managed-charging.
[49] Blair & Fitzgerald, *The State of Managed Charging in 2024*, SMART ELECTRIC POWER ALLIANCE 27 (Sept. 2024), https://sepapower.org/resource/state-of-managed-charging-in-2024/.

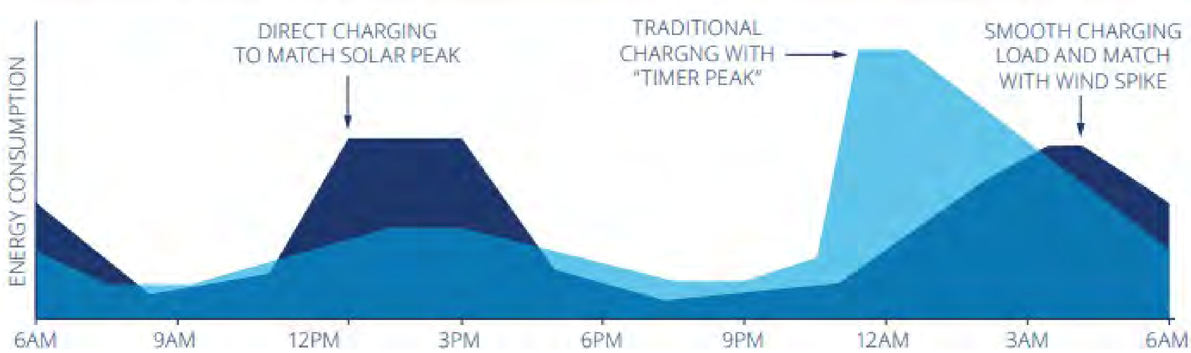
managed charging platforms which allow utilities to optimize EV charging for grid conditions and enrolled customers charging preferences.

C. When Is the Best Time to Charge?

The benefit of active managed charging programs over TOU plans is that they can better account for the day-to-day variability of grid conditions. While TOU plans can target hours that are "on average" the best for the grid, dynamic managed charging programs can respond to real world conditions on a day-to-day and even hourly basis.[50] This allows EVs to charge when grid conditions are optimal based on up-to-date real-world data, which makes EVs into grid assets benefiting all ratepayers. Active managed charging programs also help to avoid "timer peaks" or sudden upticks of electricity consumption on the grid that can occur with passive managed charging under TOU plans if too many EVs begin charging exactly when the off-peak period begins.[51] The concern about avoiding timer peak for EV charging under TOU plans is not significant at the moment, but it will become more significant as EV adoption continues to grow.

The figure below[52] provides an illustrative example of how a dynamic managed charging program can align with theoretical peaks on the grid, as compared to EV charging solely responding to the start of an off-peak period. It also demonstrates the concept of a timer peak, which can be avoided with managed charging to achieve a more "smooth charging load."

FIGURE 1: OPPORTUNITIES FOR EV MANAGED CHARGING TO MEET GRID NEEDS (ILLUSTRATIVE)



[50] *Id*.
[51] *Id*. at 8.
[52] Myers, *A Comprehensive Guide to Electric Vehicle Managed Charging*, SMART ELECTRIC POWER ALLIANCE 15 (May 2019), https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/.

D. Who Else in the Electric Utility Space is Developing and Implementing These Programs?

Many electric utilities are in various stages of developing and deploying pilot active managed charging programs, but a growing number are also deploying full-scale uncapped programs which are worth examining. The Smart Electric Power Alliance paper "State of Managed Charging in 2024", included as Attachment A, is a useful resource for exploring the status of more developed managed charging programs. Below is a list of some of the top utility charging programs in the country, including links to learn more:

- **Xcel Energy, Colorado—Charging Perks**[53]
- **Baltimore Gas and Electric, Maryland—BGE Smart Charge Management**[54]
- **Pacific Gas and Electric, California—EV Charge Manager**[55]
- **Eversource, Connecticut—Electric Vehicle Charging Program**[56]
- **DTE, Michigan—Smart Charge**[57]
- **Dominion, Virginia—Electric Vehicle Telematics Program**[58]

Western Resource Advocates has been involved with the Xcel Energy Colorado Charging Perks program since its conception in 2019 and has participated as a stakeholder as the utility continues to iterate on this program through regulatory proceedings throughout its lifespan.

An even longer list of electric utilities are still developing active managed charging programs or have yet to fully roll out recently launched initiatives. This includes Tucson Electric Power, which was approved to develop an active managed charging program in December 2022 and has been developing

[53] *Charging Perks*, XCEL ENERGY, https://ev.xcelenergy.com/charging-perks.
[54] Blair & Fitzgerald*, The State of Managed Charging in 2024*, SMART ELECTRIC POWER ALLIANCE 42-44 (Sept. 2024), https://sepapower.org/wp-content/uploads/2024/08/SEPA-State-of-Managed-Charging-2024-Report_print.pdf.
[55] *EV Charge Manager*, PG&E, https://www.pge.com/en/clean-energy/electric-vehicles/ev-charge-manager-program.html#:~:text=EV%20Charge%20Manager%20is%20a,and%20simplify%20their%20charging%20experience.
[56] Blair & Fitzgerald*, The State of Managed Charging in 2024*, SMART ELECTRIC POWER ALLIANCE 40-41 (Sept. 2024), https://sepapower.org/wp-content/uploads/2024/08/SEPA-State-of-Managed-Charging-2024-Report_print.pdf.
[57] *DTE Smart Charge*, DTE, https://www.dteenergy.com/content/dam/dteenergy/deg/website/residential/Service-Request/pev/plug-in-electric-vehicles-pev/SmartChargeBrochure.pdf.
[58] *Dominion Energy and WeaveGrid Launch New Rewards Program for Virginia EV Drivers*, (June 26, 2024), https://www.weavegrid.com/news/dominion-energy-and-weavegrid-launch-new-rewards-program-for-virginia-ev-drivers.

that program with Bidgely, a smart EV charging provider. The program is slated to launch "early in Q2 of 2025" and stands to be the first operational active managed charging program in Arizona.

E. WRA's Recommendation

WRA Recommends that SRP begin investigating an active managed charging program, and that they look to peer utilities that are in various phases of pilot development or full rollout of active managed charging programs.

A Board member wishing to adopt WRA's recommendation could do so through a motion ***to direct Management to begin exploring the development of an active managed charging program***. Such a motion could direct Management to start a working group comprised of stakeholders or go a step further and direct Management to develop a pilot program within a set period of time.

IV. Stakeholder Engagement During the Public Pricing Process

WRA and other stakeholders and Board members have expressed concern that the Public Pricing Process is too expedited to allow for meaningful stakeholder engagement and Board review of options and alternatives to the Proposed Adjustments. A.R.S § 48-2334 defines the procedure that SRP must follow in the process of changing its electric rates. The statute gives SRP a great deal of discretion in this process and directs the Board to "establish and enforce rules and regulations to carry out the purposes of this section." SRP did so, and those rules and regulations are located in section 2.2 of SRP Rules and Regulations.[59] Section 2.2 lays out a number of procedures in which stakeholders can be involved but, notably, requires that a Public Pricing Process occur in the short time period of 60 days.[60] The regulations also allow the Board to change the rules and regulations at any time.[61]

First, WRA wants to recognize the care that the Board and Management have taken in including stakeholder groups in its Public Pricing Process. The statute which governs SRP's change in electric rates does not technically require that stakeholders be involved in this process and certainly does not require that stakeholder groups are allowed to present to the Board. Nonetheless, SRP has provided these opportunities. However, as is almost always the case, the stakeholder process for SRP's Public Pricing Process can be improved to the betterment of ratepayers and SRP itself. It is clear from

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[59] *SRP Rules and Regulations* at 10, https://www.srpnet.com/assets/srpnet/pdf/about/rulesandregs.pdf.
[60] *Id.* at 12.
[61] *Id.* at 10.

its actions that both the Board and Management have recognized the benefit of the stakeholder process. Consequently, WRA recommends that the Board consider revising its stakeholder process for its next Public Pricing Process to improve upon the established process.

A. The Importance of Stakeholder Engagement

During the Public Pricing Process, the Board acts as a regulator would in determining whether Management's Proposed Adjustments properly balance the needs of the utility with the needs of ratepayers. As shifts in consumer expectations, policy, and technology continue to dynamically change the electric industry, the stakes for regulators and utilities continue to increase.[62] The issues underlying regulatory decisions are also becoming increasingly more complex, with outcomes of these decisions having significant financial consequences for ratepayers and market participants.[63] Given this landscape, regulatory bodies can receive a number of benefits by establishing a well-designed and inclusive stakeholder engagement process.

A recent report by ICF provides an overview of the benefits of informed and engaged stakeholder participation in a regulated utility process. The adoption of a collaborative and inclusive stakeholder process can provide a number of benefits to SRP, ratepayers and stakeholders. First, establishing a well-designed stakeholder process can foster a constructive working relationship between stakeholders and SRP and can build a level of trust essential to work through complex energy challenges.[64] Second, a well-designed stakeholder process can reveal common ground between different interests and improve the efficiency of regulatory processes.[65] This in turn can increase the likelihood of producing creative solutions to challenges and optimal outcomes for a variety of different interests.[66] Finally, all parties involved in a collaborative stakeholder process can benefit through better information sharing, decreased risk (both financial and otherwise), and smarter solutions.[67]

For regulators, a well-designed stakeholder process can result in better flows of actionable information on which to base decisions and a narrowing of issues where those decisions are needed.[68]

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[62] Martini et. al., *The Rising Value of Stakeholder Engagement in Today's High-Stakes Power Landscape*, ICF 1 (2016), https://www.icf.com/-/media/files/icf/white-paper/2016/energy-regulation-stakeholder-engagement.pdf?rev=1a8ab2d82ccc435d9f04bfcb25c49cd4.
[63] *Id*.
[64] *Id*. at 2.
[65] *Id*.
[66] *Id*.
[67] *Id*.
[68] *Id*. at 3.

Including stakeholder input in decision-making results in greater buy-in from the various interests and parties involved.[69] In this time of transformation in the electric industry, stakeholder engagement creates a sense of shared risk and collective action for unforeseen and uncertain circumstances and results.[70]

For utilities, a well-designed stakeholder process can be an opportunity to enhance relationships with stakeholders and create an environment of predictability, stability and transparency.[71] This, in turn, can decrease business risk and contribute to beneficial financial assessments.[72] Engagement with stakeholders can also illuminate for utilities previously unforeseen risks and consequences for its proposals.

Stakeholders in a well-designed stakeholder process are provided with the opportunity to further educate utilities and regulators about their needs and the needs of groups that they represent.[73] Engagement also allows stakeholders to learn about current utility practices and future plans, which can lead to more effective and informed participation in the regulatory process.[74]

With these benefits in mind, it is clear that establishing a well-designed stakeholder process should be a priority for any regulatory body. However, not all stakeholder processes are created equal, and in order for a stakeholder process to be beneficial it needs to include certain characteristics.

B. How SRP's Public Pricing Process Can Be Improved

SRP's current stakeholder engagement for its Public Pricing Process currently occurs over the course of only 60 days and includes several opportunities for participation including: **1)** Management interviews; **2)** the submission of comments to the Board; and **3)** a 15-minute presentation to the Board. There are currently several barriers in SRP's Public Pricing Process that lessen the quality of stakeholder engagement and therefore lessen the value of stakeholder participation for the Board. Many of the limitations of SRP's current stakeholder process stem from the short period of time in which stakeholders (and the Board) have to analyze, gather additional information, coordinate with Management, engage in the various opportunities to participate, and provide meaningful feedback and

[69] *Id*.
[70] *Id*.
[71] *Id*.
[72] *Id*.
[73] *Id*.
[74] *Id*.

recommendations. Other limitations stem from lack of clarity and uncertainty about stakeholder specific deadlines and a lack of sufficient information essential to meaningful participation.

Luckily, as the Board is able to change the rules and regulations concerning the Public Pricing Process "at any time,"[75] these limitations can be addressed in a straightforward manner with few procedural barriers. Improving the rules and process can begin with stakeholders, Management, and the Board engaging in a meaningful conversation on how the process can be improved for SRP's next Public Pricing Process. To inform such improvements, WRA recommends that Management and the Board use the Decision-Making Framework provided by the National Association of Regulatory Utility Commissioners ("NARUC"). While the Board is not a utility regulatory commission, it plays much of the same role during a Public Pricing Process. WRA has provided NARUC's Decision-Making Framework as Attachment B to these comments and will add some key take-aways here as well. SRP already applies in its Public Pricing Process many of the practices recommended in the NARUC's Decision-Making Framework, but notably fails to incorporate some key components of an effective process.

1. The Stakeholder Engagement Framework

NARUC advises regulators to look at six aspects of stakeholder engagement to improve stakeholder processes.[76] While there is no specific engagement approach that regulators must follow,[77] utilizing the Decision-Making Framework provided by NARUC in the changing regulatory landscape can actualize benefits of stakeholder engagement, including decreased risk.

i. Timeline

Perhaps the most critical way that SRP can improve its stakeholder process is to reconsider the extremely short 60-day timeframe that currently places so many limitations on meaningful stakeholder participation and Board evaluation and action during the Public Pricing Process. Appropriate timelines that allow for flexibility and adaptability are important for both stakeholders and regulators.[78] In a review of current practices across the country, NARUC found that many stakeholder processes were divided into phases with milestones being reached throughout the process.[79] Applied to the SRP Public

[75] *SRP Rules and Regulations* at 10, https://www.srpnet.com/assets/srpnet/pdf/about/rulesandregs.pdf.
[76] McAdams, *Public Utility Commission Stakeholder Engagement: A Decision-Making Framework*, NARUC (Jan. 2021), https://pubs.naruc.org/pub/7A519871-155D-0A36-3117-96A8D0ECB5DA.
[77] *Id*. at 16.
[78] *Id*. at 30.
[79] *Id*.

Pricing Process, WRA recommends that SRP create three separate phases for the pricing process: the first to allow time for stakeholders and Board members to study the material provided by Management, the second to allow stakeholders to submit data requests and interview Management on the recommended changes, and the third to allow for stakeholders to finalize their recommendations and present those recommendations to the Board.

For this current Public Pricing Process, all three of these phases are occurring at the same time, leaving little opportunity for meaningful interaction and little time for stakeholders to develop robustly informed and well-designed recommendations. For example, WRA received its first response to its data requests a day before it was to present to the Board and several days after it was required to finalize that presentation and send it to the SRP Corporate Secretary. This short time frame is not only a burden on stakeholders but also on Management and the Board, while likely limiting the input and alternative ideas from stakeholders that the Board and Management can consider. With a 60-day process, Management has little time to gather information, reply to data requests, and respond to stakeholder and Board questions and concerns. Board members are also disadvantaged as they, like stakeholders, must study the materials provided by Management and come to their own conclusions as to the adequacy of the Proposed Adjustments in only 60 days.

The 60-day time frame of the Public Pricing Process as currently required in SRP's Rules and Regulations is a severe impediment to all involved in the process and should be extended to fairly reflect the complexity and technical nature of changing electric rates.

ii. Engagement Approach

The stakeholder engagement approach that regulators use can foster inclusiveness for a diverse set of stakeholders who represent various constituencies that will be affected by regulatory decisions.[80] Early and consistent engagement is particularly helpful for highly technical topics.[81] Regulators should be proactively engaging stakeholders early and often during the stakeholder process and should ensure that trust and respect grows by clearly communicating ground rules.[82] Currently, SRP communicates many ground rules such as important deadlines on a "need to know" basis, with the result that stakeholders must actively and individually request information on input opportunities and

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[80] *Id*. at 22.
[81] *Id*. at 23.
[82] *Id*. at 5.

deadlines. This causes confusion and uncertainty for those groups wanting to engage in the Public Pricing Process.

iii. Meeting Format

The meeting format in a Public Pricing Process can create an inclusive and open stakeholder process that helps to ensure accessible participation.[83] Meetings should be announced well in advance, should be located at a neutral location, and should utilize technology to maximize participation.[84] It is also helpful to have both virtual and in-person meetings, to distribute meeting materials in advance, and to maintain and share meeting minutes.[85] To foster a diverse set of stakeholders, regulators should consider accessibility by offering language services (which SRP currently already offers) and hosting meetings outside of traditional 9 to 5 business hours. Regulators can improve inclusivity of meetings by relying on more than listservs to share when meetings will be held and by working through trusted community groups to reach diverse groups of constituents.[86]

iv. Engagement Outcomes and Follow-up

The time immediately following a stakeholder engagement process provides regulators with a unique opportunity to follow-up with stakeholders and gather feedback on the process itself as well as its outcome. Benefiting from the freshly opened channels of communication, SRP could use the period after the conclusion of the Public Pricing Process to receive feedback on how it could design an improved and more effective stakeholder process that the Board would later amend, approve and possibly adopt in its Rules and Regulations.

C. WRA's Recommendation

WRA Recommends that the Board utilize the period after the conclusion of the Public Pricing Process to create a working group to develop a more inclusive and effective stakeholder process for future electric rate changes, which the Board would then review, possibly amend, and then adopt.

[83] *Id*. at 28.
[84] *Id*.
[85] *Id*.
[86] DeRivi, *Community Decisions: How Public Power Meaningfully Engages Local Stakeholders*, AMERICAN PUBLIC POWER ASSOCIATION (Nov. 30, 2021), https://www.publicpower.org/periodical/article/community-decisions-how-public-power-meaningfully-engages-local-stakeholders; McAdams, *Public Utility Commission Stakeholder Engagement: A Decision-Making Framework*, NARUC 5 (Jan. 2021), https://pubs.naruc.org/pub/7A519871-155D-0A36-3117-96A8D0ECB5DA.

A Board member wishing to adopt WRA's recommendation could do so through a motion ***to direct Management to create a working group with an inclusive set of stakeholders with the purpose of designing a more effective stakeholder engagement process for the next Public Pricing Process***. A Board member could specify the frequency for that group to meet, a timeframe to present a proposal to the Board, and specific directives or guidelines defining what the Board would like to see in that proposal.

V. Conclusion

In conclusion, WRA respectfully requests that Board members adopt the following recommendations:

1. **WRA recommends that rather than moving EZ-3 customers into the E-23 plan, these EZ-3 customers should be moved into the E-28 plan, which is also a TOU plan.**

2. **WRA recommends that Management increase the price differentiation between on-peak and off-peak rates, which could better help incentivize optimal behaviors for those who do not have the option to charge their EV during the day.**

3. **WRA recommends that SRP develop managed charging programs in the future which can dynamically adjust EV charging in response to actual grid conditions.**

4. **WRA recommends that SRP build upon the existing Pricing Principles in place by adding Sustainability to guide future pricing processes.**

5. **WRA recommends that the Board require Management to provide greater detail about how the new and expanded Energy Attribute Rider will be administered to customers.**

6. **WRA respectfully requests that the Board avoid the risk of using customers funds dedicated to decarbonizing programs that will fail to impact SRP's emissions in a meaningful way by rejecting the proposed Carbon Reduction Rider.**

7. **WRA recommends that the Board advise Management to explore and propose alternative cost allocation methods in its next Public Pricing Process to address the risks of transferring the costs of Data Center Growth to Residential Customers.**

8. **WRA recommends that the Board utilize the period after the Public Pricing Process has concluded to create a working group to develop a more inclusive and effective stakeholder process for future electric rate changes which the Board would then review, possibly amend, and adopt in its Rules and Regulations.**

***We appreciate the opportunity to provide these comments*.**

[redacted]

Attachment A

Smart Electric Power Alliance

A Comprehensive Guide to Electric Vehicle Managed Charging

MAY 2019

A COMPREHENSIVE GUIDE TO ELECTRIC VEHICLE MANAGED CHARGING

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SEPA does not claim that this report is entirely complete and may be unintentionally missing projects, vendors, or other information. SEPA advises readers to perform necessary due diligence before making decisions using this content. Please contact SEPA at research@sepapower.org to provide additional information.

ABOUT SEPA

The Smart Electric Power Alliance (SEPA) is an educational nonprofit working to facilitate the electric power industry's smart transition to a clean and modern energy future through education, research, standards and collaboration. SEPA offers a range of research initiatives and resources, as well as conferences, educational events, advisory services, and professional networking opportunities. To learn more and discover our pathways, visit www.sepapower.org.

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Glossary[1]

Aggregator: An aggregator is a third party intermediary linking electric vehicles to grid operators. Increasingly, aggregators are stepping into a role of facilitating interconnections to entities that provide electricity service. Broadly, aggregators serve two roles: downstream, they expand the size of charging networks that electric vehicle (EV) customers can access seamlessly, facilitating back-office transactions and billing across networks; upstream, they aggregate a number of EVs and Charging Station Operators (CSO) to provide useful grid services to Distribution Network Operators (DNO) and Transmission System Operators (TSO).

Charging station: The physical site where the Electric Vehicle Supply Equipment (EVSE) (also known as the charger) or inductive charging equipment is located. A charging station typically includes parking, one or more chargers, and any necessary "make-ready equipment" (i.e., conduit, wiring to the electrical panel, etc.) to connect the chargers to the electricity grid, and can include ancillary equipment such as a payment kiosk, battery storage, or onsite generation.

Charger: A layperson's term for on-board or off-board device that interconnects the EV battery with the electricity grid and manages the flow of electrons to recharge the battery. Also known as Electric Vehicle Supply Equipment (EVSE).

Electric Vehicle Supply Equipment (EVSE): The equipment that interconnects the AC electricity grid at a site to the EV. It can be level 1, level 2, or Direct Current Fast Chargers (DCFC) charging. Also known as a charger.

Interoperability: The ability of devices, systems, or software provided by one vendor or service provider to exchange and make use of information, including payment information, between devices, systems, or software provided by a different vendor or service provider.

Managed charging (V1G, controlled charging, intelligent charging, adaptive charging, or smart charging): Central or customer control of EV charging to provide vehicle grid integration (VGI) offerings, including wholesale market services. Includes ramping up and ramping down of charging for individual EVs or multiple EVs whether the control is done at the EVSE, the EV, the EV management system, the parking lot EV energy management system or the building management system, or elsewhere.

Network Service Provider (NSP): The NSP provides services related to chargers, such as data communications, billing, maintenance, reservations, and other non-grid information. The NSP sends the grid commands or messages to the EV or EVSE (e.g., rates information or grid information based on energy, capacity or ancillary services markets; this is sometimes called an electricity grid network services provider). The NSP may send non-grid commands (e.g., reservations, billing, maintenance checks). The NSP may receive data or grid commands from other entities, as well as send data back to other entities.

Networked EVSE: These devices are connected to the Internet via a cable or wireless technology and can communicate with the computer system that manages a charging network or other software systems, such as a utility demand response management system (DRMS) or system that provides charging data to EV drivers on smartphones. This connection to a network allows EVSE owners or site hosts to manage who can access EVSE and how much it costs drivers to charge.

Non-networked EVSE: These devices are not connected to the internet and provide basic charging functionality without remote communications capabilities. For example, most Level 1 EVSE are designed to simply charge a vehicle; they are not networked and do not have additional software features that track energy use, process payment for a charging session, or determine which drivers are authorized to use the EVSE. Secondary systems that provide these features can be installed to supplement non-networked EVSE.

Open Standards: Generally denotes a data format, communications protocol, payment protocol, or other technical interface developed in an open and transparent process by a non-profit party that allows any entity to contribute to its development and can be used royalty-free.

Platform: The base hardware and software upon which software applications run.

1 Source: Adapted from the California Public Utilities Commission (CPUC) Vehicle Grid Integration Communications Protocol Working Group Glossary of Terms (http://www.cpuc.ca.gov/vgi/), 2017. Disclaimer: These definitions are "working definitions" and are not meant to be formal or conclusive, but rather help clarify the concept addressed. Many of these definitions were edited; refer back to the original document for the official working group version of the definition.

Proprietary Protocol: A protocol that is owned and used by a single organization or individual company.

Protocol: Set of rules and requirements that specify the business process and data interactions between communicating entities, devices, or systems. Most protocols are voluntary in the sense that they are offered for adoption by people or industry without being mandated in law. Some protocols become mandatory when they are adopted by regulators as legal requirements. A standard method of exchanging data that is used between two communicating layers.

Standard: An agreed upon method or approach of implementing a technology that is developed in an open and transparent process by a neutral, non-profit party. Standards can apply to many types of equipment (e.g., charging connectors, charging equipment, batteries, communications, signage), data formats, communications protocols, technical or business processes (e.g., measurement, charging access), cybersecurity requirements, and so on. Most standards are voluntary in the sense that they are offered for adoption by people or industry without being mandated in law. Some standards become mandatory when they are adopted by regulators as legal requirements.

Standardization: Process where a standard achieves a dominant position in the market due to public acceptance, market forces, or a regulatory mandate.

Telematics: In the context of EV charging, including managed charging, telematics refers to the communication of data between a data center (or "cloud") and an EV, including sending control commands and retrieving charging session data.

Use Case: Defines a problem or need that can be resolved with one or more solutions (technical and/or non-technical) and describes the solutions. The use case is a characterization of a list of actions or event steps, typically defining the interactions, describing the value provided and identifying the cost.

Vehicle Grid Integration (VGI): VGI includes any action taken via a grid-connected electric vehicle and / or electric vehicle supply equipment, whether directly through resource dispatching or indirectly through rate design, to alter the time, magnitude, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle charging and provides value to the customer and the grid. Examples of such actions include, but are not limited to, reducing charging expenses, increasing electric grid asset utilization, avoiding distribution or transmission infrastructure upgrades, integrating renewable energy, offering resiliency and backup power, and offering reliability and wholesale energy services. VGI spans a wide range of use-cases, actors, assets, and technologies. The consensus in industry is that VGI includes both V1G (managed charging) and V2G (vehicle to grid) solutions. (Source: SEPA)

Vehicle to Grid (V2G): V2G assumes a bidirectional energy transfer capability and not just a discharging of the battery. Energy from the EV battery is converted to an AC current which flows from the EV back to the electricity grid or to a facility circuit which is connected to the electricity grid, even if there is no net export of power from the facility. Other applications include Vehicle to Home (V2H), Vehicle to Building (V2B), or Vehicle to Load (V2L).

Foreword

Since SEPA's first report on managed charging, *Utilities & Electric Vehicles: The Case for Managed Charging*, was published two years ago, much has changed in the industry.[2] Not only have the capabilities of the technology become more widely acknowledged, but vendors and solution sets have become increasingly sophisticated. Today, many stakeholders, including electric utilities, regulatory commissions, consumer advocates, environmental organizations, and others strongly contend that an electric vehicle future must include some form of managed charging in order to reap the maximum benefits for consumers, the grid, and society as a whole.

Despite the symphony of support, there is still much that needs to be done to make this vision a reality. In order to fully leverage the benefits of the technologies, all chargers must be capable of accommodating managed charging. The good news is that the total percentage of vendors with managed charging-capable equipment has increased to 63% from 33% in 2017. Further, the number of Network Service Providers that provide managed charging platforms has increased more than three-fold since 2017.

However, some of these chargers and platforms are not currently programmed to speak an open "language." Although there is broad industry consensus on the potential of managed charging in the U.S., stakeholders have not converged around a common managed charging open protocol or set of protocols that could help reduce costs, avoid stranded assets, and streamline the implementation of aggregation programs. Further, the industry must continue to develop ways to send communication signals to the devices and vehicles that are *inexpensive*, *reliable*, and *customer-friendly*.

In other countries, such as the United Kingdom (UK), the EV community has coalesced around the need for managed charging to reduce distribution infrastructure upgrade costs. The UK has mandated that all future EV charging equipment must be managed charging-capable, though work continues on defining what this means. The nation has also invested millions of dollars in demonstration projects to test the capabilities of managed charging and understand consumer behavior.[3]

Without swift action to resolve the outstanding business, policy, and technological barriers for managed charging, we may look back in a decade and wonder what went wrong. Just as we now have a million distributed residential solar systems without advanced inverters due to the long lag time in the development of standards, we could see millions of EVs on the road without any kind of managed charging functionality. This could lead to grid constraints and increased transmission and distribution peaks that prompt the construction of more peaker plants, unplanned grid upgrades, and other costly solutions. To accelerate adoption, managed charging solutions must be easy to implement, low risk, and net-positive to the parties involved, including the customer, the utility, and the auto manufacturers.

In 2019, SEPA will be working closely with our members and industry partners to identify solutions to these challenges and make managed charging a reality. We hope to work with you in the coming year. If you would like to be involved, please contact SEPA at research@sepapower.org.

Sincerely,

Erika H. Myers
Principal, Transportation Electrification
Smart Electric Power Alliance

2 Managed charging is also known as V1G, intelligent charging, adaptive charging, or smart charging.

3 See SEPAPower blogs at: https://sepapower.org/knowledge/why-the-uk-is-beating-the-us-on-transportation-electrification-part-1-customers-first/ and https://sepapower.org/knowledge/why-the-uk-is-beating-the-us-on-transportation-electrification-part-2-utility-innovation/

I. Executive Summary

With estimates of more than 20 million electric vehicles (EVs) expected on the road in the U.S. by 2030, EVs represent the most significant new electric load since the rise of air conditioning in the 1950s. In an era of flat and declining electric usage, this is welcome news to electric utilities.

But unlike the 1950s, when the cost of new generation was falling, the electric grid was a simpler construct, and environmental concerns from carbon emissions were negligible, today's utility response to a dynamic new load is far more nuanced than a matter of matching supply to demand. EVs are considered one of the customer-driven and owned distributed energy resources (DERs) that are changing the nature of the utility business. While EVs are welcome as a new and perhaps historically significant end-use of electricity, they also present the potential for disruption.

California is the nation's largest early market for EVs. It is also the nation's largest market for solar power and as a result is the home of the "duck curve", the load shape that skews grid demand to an abrupt early evening peak after the sun sets. If customers in California plug in their EVs just as that peak is spiking, the demand will likely intensify the negative impacts on the grid. It is an example of the unwelcome side effects that can impact utilities everywhere as the EV market grows.

One plausible antidote is the managed charging of EVs. It is in many ways a technology, customer, and business model challenge, which is the core focus of this report. But it is also a challenge and an opportunity for electric utilities to take a leadership position. Utilities can lead the development of innovative approaches that effectively integrates EVs into the grid, help further accelerate their adoption, and help to advance a 21st century clean, smart, and affordable energy system. This must be done in concert with the expectations and acceptance of regulators, automotive companies, EV charging infrastructure manufacturers, information and communication technology providers—and of course, of utility customers.

THE VALUE OF MANAGED CHARGING

Managed charging can—and many would suggest, must—become a key part of a demand response portfolio. If the timing and intensity of charging vehicles can be effectively managed, the result will be a suite of benefits that touch every part of the electricity marketplace. EV owners will see savings ranging from lower cost of electricity to payments for the supply of ancillary services to the grid. Wholesale markets and transmission and distribution grid operators will have another tool to meet demand and improve efficiency. A significant amount of off-peak capacity will absorb excess renewable energy production, thereby reducing overall emissions. A more efficient and cost-effective energy system will bring monetary benefits to all utility customers.

OVERCOMING BARRIERS TO MANAGED CHARGING

There is a long list of reasons why the smart management of EV charging makes sense. But turning the concepts of managed charging into mainstream practice depends upon advances on several fronts, such as developing an understanding of the value and market mechanisms, technology, standards and protocols, and established use cases. As with other elements of demand response and grid modernization, making improvements in network communication and equipment interoperability is key to the success of managed charging.

Some managed charging is currently, and will continue to be, achieved through a passive approach, generally relying upon customer behavior as a means of changing charging patterns. Customer behavior is generally influenced by time-of-use rates or other incentives for the vehicle owner to use an on-board vehicle computer or electric vehicle supply equipment (EVSE) timer to set charging at times that align with utility grid management goals. In active managed charging, the utility (or a market aggregator working with charging networks) can determine and/or control charging time, scale, and location in order to achieve a variety of outcomes, such as managing peaks, absorbing excess renewable generation or supplying some ancillary services to a structured market.

Active managed charging in particular relies upon a reliable two-way flow of information through a variety of communications technologies (such as Wi-Fi, cellular and telematics) from the vehicle and EVSE to the utility or aggregator. While there are protocols for the transport of the information, as well as protocols for the messaging (the instructions for the required actions), there are no industry-wide standards for the entire "ecosystem" of information exchange and communication, which is an obstacle the industry is currently working to solve. For managed charging to work at scale, different devices, whether in the vehicle or within the charging infrastructure, must be able to communicate freely, without disruption from closed or proprietary protocols. In addition, to achieve widespread adoption and align with consumer preferences, managed charging programs will need to understand and support various consumer preferences for specific charging solutions while providing utilities an efficient means of interacting with a variety of devices and associated networks.

An essential part of current managed charging pilot projects involves testing network communication interfaces to ensure that the information is delivered across a range of devices and expected results are achieved.

In general, the broad deployment of managed charging will depend upon establishing the reliability of hardware, software and communication systems, finding ways to generate benefits and lower costs, and delivering results that yield a sufficient economic return on the investment.

THE ROLE FOR UTILITIES IN ADVANCING GRID-FRIENDLY EV ADOPTION

Electric utilities have a significant role to play in improving the integration of EVs with the grid. First, utilities are supporting EV charging infrastructure deployment through direct procurement, providing rebates or other incentives to encourage customer and third-party investments, and by requiring open protocols as a component of a utility-managed program. Second, utilities are contributing to the development of the standards for managed charging equipment, and they are supporting the evolution of software and other methods used to modulate charging rates or shift charging events in order to provide grid services.

With a growing charging load that can be flexible and intelligent, EVs are part of the larger discussion around the evolution of the grid and the future of the electric utility industry. Most industry analysts treat EVs as a way to increase load in an era of flat or declining electricity sales. However, managed EV charging can also be a useful means to better align and balance a power supply that is increasingly diverse, decentralized, renewable and intermittent with flexible demand. By integrating more renewables and avoiding dispatch of peaker plants, managed charging can reduce emissions in the transportation and utility sectors and improve grid economics.

SEPA's *A Comprehensive Guide to Electric Vehicle Managed Charging* has six sections to help readers understand what managed charging is and how it could be beneficial, provides an overview of the current managed charging industry, outlines what utilities want from managed charging programs, defines how managed charging communication pathways can relay signals, and defines the current managed charging vendor landscape.

II. Introduction

Electric vehicles (EVs) are quickly becoming one of the largest flexible loads on the grid in certain parts of the United States. Depending on vehicle type (including plug-in hybrid electric and battery electric vehicles) a single EV represents from 1.4 kW to 20 kW of instantaneous load[4], or 500 to 4,350 kWh/year of energy consumption (as shown in Table 1). This is reminiscent of the grid consequences of the proliferation of air conditioning systems decades ago. As of January 2019, over 1.13 million EVs had been sold in the United States[5] consuming an estimated 4.4 terawatt-hours (TWh) per year.[6]

4 Using Level 1 to Level 2 charging stations; DCFC load would be higher.

5 Electric Drive Transportation Association, April 2019, https://electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952

6 Assumes 3,858 kWh per EV per year based on data from the U.S. Department of Energy Alternative Fuels Data Center. Assumes all vehicles sold since 2010 are still operating in the U.S.

TABLE 1: ANNUAL EV CONSUMPTION BY VEHICLE TYPE			
VEHICLE TYPE*	**ASSUMED % ALL-ELECTRIC MILES****	**AVERAGE ANNUAL CONSUMPTION (KWH)**	**MAXIMUM POWER DRAW WHEN CHARGING VIA LEVEL 2 EVSE (KW)*****
PHEV10	10 - 15%	500	3.3 - 3.6
PHEV20	33%	1,400	3 - 3.3
PHEV40	75%	3,500	3.3 - 6.6
BEV100	100%	3,500	3.3 - 10
BEV300	100%	4,350	10 - 20

Sources: ICF, The EV Project, Ford Motor Company, Smart Electric Power Alliance, 2017

* PHEV = plug-in hybrid electric vehicle, BEV = battery electric vehicle; e.g., a PHEV10 has a battery capacity for approximately 10 all-electric miles

** It is assumed that all vehicle types would be driven 12,000-13,000 miles annually, except a BEV100 at 10,000 miles due to the range restrictions of the battery

*** Level 2 EVSE = electric vehicle supply equipment that operates using a 240-volt outlet

Continued EV deployment is expected as battery prices decline and EV manufacturers offer new models at progressively lower price premiums over conventional vehicles. Navigant forecasts that EVs in the U.S. will reach over 20 million in 2030 with an energy consumption of 93 TWh.[7] According to models by the National Renewable Energy Laboratory (NREL), electrified transportation may result in between 58 to 336 TWh of electricity consumption annually by 2030 depending on the speed and type of vehicle deployment.[8] This represents the equivalent average annual energy consumption of 5.6 million to 32.3 million U.S. homes.[9]

In addition to growth in EV purchases, a rapid increase electric vehicle supply equipment (EVSE) deployment is also forecasted. Navigant estimates approximately 1.2 million charging ports installed through North America as of 2018, growing to over 12.6 million by 2027.[10] EEI and IEI estimate that 9.6 million EV charging ports will be required by 2030.[11] The amount of incremental grid capital investment to support a significant number of EVs varies by region and the degree of charge management deployed.[12]

Utilities can take advantage of early opportunities to improve EV integration. First, utilities can participate directly in the process of EV charging infrastructure deployment through direct procurement or by providing rebates and requiring open managed charging standards as a component of the program. Second, utilities can contribute to the development of the standards for managed charging equipment and support the evolution of software and other methods to modulate charging rates or shift charging events in order to provide grid services.

This report covers managed charging in six sections (outlined in Table 2). Readers can leverage additional information found in the appendices for more detail about existing managed charging projects and vendors. Updated spreadsheets are available through SEPA's website for download.

7 Navigant forecast provided in April 2019 to SEPA staff. See also: EEI/IEI, November 2018, *EV Sales Forecast and the Charging Infrastructure Required through 2030*.

8 National Renewable Energy Laboratory, 2018, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, https://www.nrel.gov/docs/fy18osti/71500.pdf.

9 Based on 2017 U.S. Energy Information Administration data that residential U.S. electricity consumers used an average of 10,400 kWh per year. See https://www.eia.gov/tools/faqs/faq.php?id=97&t=3.

10 Navigant, 2Q 2018, *EV Charging Equipment Market Overview*, Table 4.7.

11 EEI/IEI, November 2018, *EV Sales Forecast and the Charging Infrastructure Required through 2030*.

12 D. Tuttle et al, 2018, *The Conversation*, "Switching to EVs could save the US billions, but timing is everything," https://theconversation.com/switching-to-electric-vehicles-could-save-the-us-billions-but-timing-is-everything-106227.

TABLE 2: REPORT ROADMAP	
Introduction	Defines managed charging, the factors that would allow a utility to scale up a managed charging program, and the value of managed charging. Also includes information on the future of vehicle-to-grid and customer concerns related to managed charging, including range anxiety.
The Managed Charging Landscape	Defines the benefits and opportunities for managed charging and provides the results of SEPA's 2019 Utility Demand Response survey about utility interest and plans for managed charging. Provides information on the market opportunity for managed charging with a focus on the capability set and managed charging acquisitions and investments to date. Includes a proposed Vehicle Grid Integration (VGI) Valuation Framework by Pacific Gas & Electric. Showcases three utility managed charging case studies.
Managed Charging Communication Pathways	Defines Transport Layer Protocols (Network Communication Interface) and Messaging Protocols (Application Protocols), including existing managed charging open protocols and vehicle telematics. Includes other managed charging strategies, including front-of-the-meter, behind-the-meter, and behavioral techniques.
Managed Charging Technology and Vendors	Highlights currently available managed charging vendors, including Network Solution Providers (NSPs), EV charging equipment manufacturers, and automotive manufacturers. Includes information highlighting the Open Vehicle Grid Integration Platform (OVGIP).
Conclusion	Further defines the role of the utility in managed charging and recommends next steps for utilities to advance managed charging objectives. Discusses a new initiative to support interoperability conformance testing for grid devices, including EVSE.
Appendices	Includes a comprehensive list of utility-run managed charging programs, a list of Network Service Providers with managed charging-capabilities, and a list of EV charging equipment manufacturers with managed charging-capabilities.

Source: Smart Electric Power Alliance, 2019.

DEFINITION OF MANAGED CHARGING

Since SEPA's first managed charging report was published in April 2017, thinking around managed charging has evolved. If the ultimate goal is to influence charging behavior, then managed charging could take one of two forms: passive or active as differentiated in Table 3. They both qualify as forms of vehicle grid integration (VGI).

Passive managed charging (also known as behavioral load control) relies on customer behavior to affect charging patterns. For example, EV time-of-use rates provide predetermined price signals to customers to influence when they choose to charge their vehicles.[13] Another example could involve notifying users and requesting a certain behavior without an incentive.

Active managed charging (also known as direct load control) relies on communication (i.e., "dispatch") signals originating from a utility or aggregator to be sent to a vehicle or charger to control charging in a predetermined

TABLE 3: EXAMPLES OF ACTIVE AND PASSIVE MANAGED CHARGING

PASSIVE	ACTIVE
EV time-varying rates, including time-of-use rates and hourly dynamic rates	Direct load control via the charging device
Communication to customer to voluntarily reduce charging load (e.g., behavioral demand response event)	Direct load control via automaker telematics
Incentive programs rewarding off-peak charging	Direct load control via a smart circuit breaker or panel

Source: Smart Electric Power Alliance, 2019.

13 We do not cover passive managed charging at length in this report, but plan to have content in future reports, such as the winter 2019 SEPA report titled, *The Efficacy of Electric Vehicle Time-Varying Rates*.

specific way. The communications signals used in managed charging can adjust the time and/or rate of charge (both load curtailment and load increase), relative to a baseline. In this way, active managed charging is form of demand response. Further, these controls can be leveraged by utilities, load balancing authorities via aggregators, or other third-parties to provide grid services, such as capacity, emergency load reduction, regulation, or to absorb excess generation from renewable energy resources, like solar and wind.[14] This report also documents other opportunities to manage load that are not directly linked to the vehicle telematics or charging device.

It is important to note that different EV charging levels offer different potential for managed charging, with different trade-offs. Charging via Level 1 (L1) or Level 2 (L2) provide more time for managed charging events due to their longer durations and flexibility for deferring customer charge. Alternatively, the high power demand of Direct Current Fast Charging (DCFC) may be attractive for managing from a capacity perspective, though possibly less useful, depending on EV driver needs and priorities (i.e., a driver typically uses a fast charger to "refuel" more quickly).

THE FUTURE OF VEHICLE-TO-GRID (V2G)

Managed charging (V1G) has many of the same capabilities as vehicle-to-grid (V2G), with the exception of enabling the vehicle to supply electricity to the grid when plugged in, tapping available battery capacity.

There are several demonstration projects around the country, but the technology is in its earliest commercialization phases. While V2G technology will continue to develop, it will require additional elements for widespread adoption, such as approval or consent of vehicle manufacturers so as to not invalidate warranties and usage guidelines[15], additional hardware expenses for AC/DC[16] conversion and control, and interconnection permits and engineering or technical requirements of local grid operators and utilities.[17]

V1G can lay the groundwork necessary through the development of the controls and infrastructure that could facilitate a V2G future and therefore is worth investing in. V2G is not discussed at length in this report.

OPPORTUNITIES TO SCALE MANAGED CHARGING

The scale of the managed charging opportunity is strongly affected by many of the same regional and state factors that have influenced the rate of EV deployment. These factors include, but are not limited to:

1. State incentives and policies, including rebates, tax credits, and access to high-occupancy vehicle lanes
2. Demographics of the service territory
3. State requirements for zero emission vehicles
4. Transportation fuel costs
5. Availability of EVSE or vehicles capable of managed charging
6. EV readiness planning by local jurisdictions
7. Regional vehicle preferences and EV model types offered in the area

In addition to the rate of EV deployment, managed charging opportunities will also be influenced at the broader market level by:

1. Technological maturity and data integration
2. Customer participation and responsiveness
3. Incentive design
4. Utility program design and business models
5. Changes to existing policies and regulations
6. Standards for charging technology
7. Established market rules

Despite the small size of today's EV market, some utilities are playing an influential role in shaping EV deployments and developing managed charging program design to appeal to customers. Through active participation in

14 ISO New England, June 2016, *ISO Markets and Grid-Scale Services*, Union of Concerned Scientists Smart Charging Workshop, https://www.dropbox.com/sh/zmkca2v9cdiu9os/AAA4YtWgmeu0dJPmz1xnPHCZa/ISO%20Markets%20and%20Grid-Scale%20Services?dl=0&preview=parent_ucs_final_updated.pdf

15 At the date of publication, only one known light-duty vehicle manufacturer (Nissan) provides a warranty for V2G activities due to concerns about battery life and safety. Honda has plans to include V2G capabilities (see https://efiling.energy.ca.gov/GetDocument.aspx?tn=226038&DocumentContentId=56744)

16 AC=alternating current, DC=direct current

17 Note: The Rule 21 Working Group 3 was preparing a recommendation on V2G interconnections (Issue 23) for the California Public Utilities Commission at the time of publication.

WHAT ABOUT RANGE ANXIETY AND OTHER CUSTOMER CONCERNS?

Managed charging may not work in every use case. Unlike other distributed energy resources (DERs), EVs are designed for transportation. Customers may have concerns about being able to make it to their final destination if their car does not have adequate vehicle charge—a concern that is described as range anxiety. Defining 1) various charging use cases, 2) the EV driver's ability to participate, and 3) the opportunity for participants to opt-out of or override a managed charging event are important program considerations.[19]

In addition to range anxiety, utilities will also need to garner customer buy-in on direct load control of their charger, understand and address consumer preferences for different charging solution features and interaction, and other factors that would impact customer willingness to enroll in a program.

Good implementations of managed charging will take into account customers' mobility preferences and could be differentiated along a continuum as shown in Table 4.

As demonstrated in this report, the EV industry should align to connect EVSE and EVs in an automated and customer-friendly fashion. Standards will enable automation and interoperability, and original equipment manufactured at scale will ensure cost effectiveness.

TABLE 4: MANAGED CHARGING CUSTOMER OPTIMIZATION PATHWAY

Basic	Customer manual opt-in or opt-out of a managed charging event
Good	Automate user preferences during managed charging program enrollment
Better	Use standards to ensure interoperability and automated inputs across location types (e.g., where there may be more local grid constraints) to improve customer experience
Superior	Leverage intelligence throughout the network to improve predictive capabilities and maximize load forecast estimates over time and location (i.e., to minimize charging disruptions except where most needed)

Source: California Energy Commission, 2019.[20]

infrastructure deployment, programs, incentives, and educational support, utilities can provide value to the grid within their service territories and help ensure that EVs become grid assets and not burdens.[18]

THE VALUE OF MANAGED CHARGING

Our knowledge of the value of managed charging is incomplete and largely dependent on specific use-cases in the near-term. For example, recent efforts have started quantifying the grid benefits of specific managed charging use cases in California, as discussed throughout the report through the California Public Utilities Commission VGI Working Group. However, for the time being, one can strongly argue from a broader EV context (not just from managed charging), that there is real societal value.

- According to a report by the Illinois Citizens Utility Board from 2019, optimizing charging patterns for in-state EVs can generate significant savings for utilities and customers. Shared savings could reach as much as $2.6 billion in Illinois by 2030 if regulations encouraging off-peak charging through charging optimization are implemented.[21]
- EVs represent significant economic opportunities. According to a five-state economic analysis report by MJ Bradley & Associates, EVs could lead to a cumulative

18 Examples of these activities are discussed in SEPA's 2018 report, *Utilities and Electric Vehicles: Evolving to Unlock Grid Value*.

19 Alternatively, customers may choose longer-range all-electric vehicles, plug-in hybrid electric vehicles which offer a conventional motor back-up, or recharging via a DCFC network.

20 Provided by California Energy Commission staff, March 2019.

21 Illinois Citizens Utility Board, March 2019, *Charging Ahead: Deriving Value from Electric Vehicles for all Electricity Customers*, https://www.citizensutilityboard.org/wp-content/uploads/2019/03/Charging-Ahead-Deriving-Value-from-Electric-Vehicles-for-All-Electricity-Customers-v6-031419.pdf.

net benefit of nearly $3,900 per person (or over $200 billion) derived from utility electric bill savings, direct savings for EV customers, and greenhouse gas emissions reductions benefits through 2050.[22]

- Gabel Associates prepared an economic-benefit analysis for EV programs in New Jersey, New York, and Washington D.C. In one of those models, Gabel estimated about $2,000 per year in operational savings for individual EV drivers in New Jersey.[23]
- According to analysis by Siemens, the direct financial savings to non-EV driving ratepayers amounts to an estimated $3,071 per EV over a 10-year period.[24] This is the amount of additional revenue associated with transmission and distribution rates paid by EV owners to charge their vehicles, increasing kWh throughput via the grid.

Where managed charging becomes challenging is defining the appropriate amount of incremental investment to enable the technology. Active managed charging programs rely on two-way communication to the EVSE and/or EV in order to measure energy usage and/or send signals to modulate the level of charging. This requires technology on-board the EVSE and/or EV to provide such features and a reliable communication signal to transmit the information. These features can be incorporated in what is commonly referred to as "networked" or "smart" EVSE.

Networked EVSE typically costs more than non-networked EVSE due to the enhanced features, on-board metering, and communication capabilities. However, managed charging-capable equipment can ensure that EVSE will be able to provide valuable charging data and the ability to manage load, even if not implemented in the first year. In the long-term, utilities, automakers, and Network Service Providers should work together to improve the capabilities and reduce the associated costs of implementing managed charging programs as discussed in subsequent sections.

III. The Managed Charging Landscape

In order to better understand the opportunity for managed charging, it is important to assess the current market landscape. In this section, we include an overview of the benefits of managed charging. Next, we provide survey results from our 2019 Utility Demand Response Survey to understand the utility interest in managed charging and how it will be leveraged in their respective service territories. This section also includes a discussion of the market opportunity with forecasts by noted analysts and a review of investments and acquisitions in the managed charging industry. Finally, three utility case studies are featured.

BENEFITS AND OPPORTUNITIES FOR MANAGED CHARGING

Managed charging can provide:

- Energy supply cost reductions by making greater use of lower-cost resources and limiting the highest cost energy,
- Transmission and distribution grid services, including: congestion and stress relief, capacity upgrade deferral, and resiliency,
- System (wholesale market) services, including capacity and ancillary services (i.e., frequency regulation, spinning, and non-spinning reserves),
- Emissions reduction benefits by aligning charging with surplus renewable generation or reduced curtailment,
- Economic returns to EV owners through access to dynamic, off-peak rates and potential payments for the supply of both ancillary services as well as energy from connected vehicles with available battery capacity, and
- Economic benefits to all utility customers through the grid efficiencies captured by managed charging.

Similar to battery energy storage, it may be possible to "stack up" several of the applications highlighted above in

22 MJ Bradley & Associates, 2017, *Electric Vehicle Cost-Benefit Analyses, Results of Plug-in Electric Vehicle Modeling in Five Northeast & Mid-Atlantic States*, https://mjbradley.com/sites/default/files/NE_PEV_5_State_Summary_14mar17.pdf. Based on a projected 2050 population in these states of 52.3 million people, up from 48.8 million today. Included: Connecticut, Maryland, Massachusetts, New York, and Pennsylvania.

23 Data provided by Gabel Associates, 2018.

24 *British Columbia Utilities Commission Inquiry into the Regulation of Electric Vehicle Charging Service*, Project No. 1598941-Phase 2, evidence presented by Siemens, January 28, 2019. Note: The analysis assumed most of the charging would be off peak and, therefore, would not require grid upgrades—the direct result of smart and managed charging as discussed in this report.

order to maximize the benefits of managed charging, as explained in the Multi Use Application initiatives under the California Public Utilities Commission.[25]

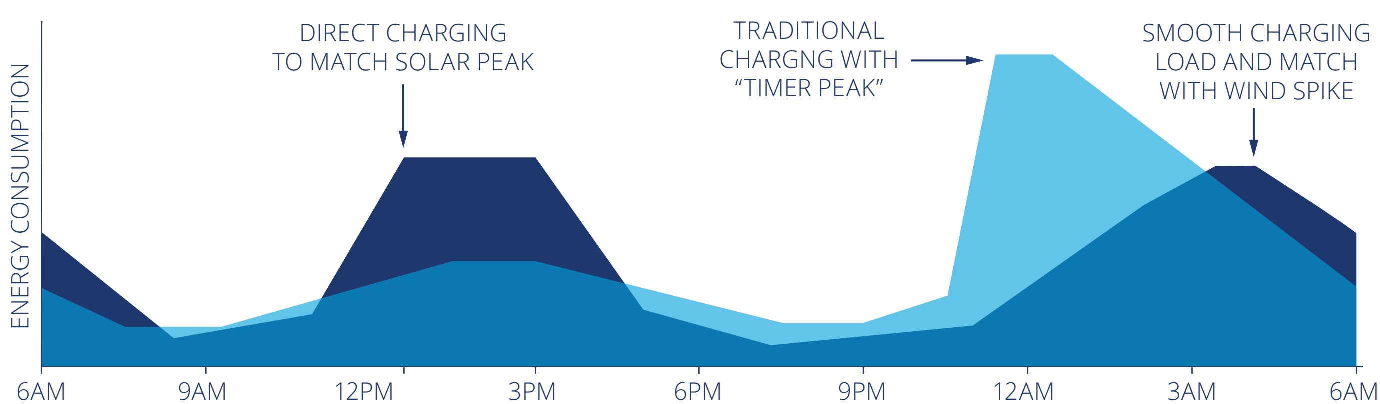
Many utilities have turned first to instituting EV specific time-of-use (TOU) rates to influence drivers to shift their EV loads to off-peak times of day. This approach allows customers to reduce their energy bill and encourages EV charging when it is least-disruptive to the grid, such as night-time hours. Some utilities may also further refine these time-of-use rate schedules to reflect local conditions. For example, Hawaii Electric Company, has a super off-peak time-of-day rate to absorb excess solar rooftop generation.[26] PG&E also recently proposed a TOU rate with a super-off-peak during the middle of the day, specifically for EV charging in the commercial sector.[27]

Though TOU rates for EVs can be helpful, the static nature of a rate schedule can also introduce new challenges. For example, San Diego Gas & Electric's (SDG&E) lowest-priced super off-peak EV rate begins at midnight.[28] Some concerns have been raised about the potential for households to program their EVs to begin charging exactly at midnight. If most or all of these chargers start at the same time, the result could be a steep ramp rate and a new load spike (also known as a timer peak) at the local distribution level.[29] Ideally, this concern would be allayed by staggering charging times using an intelligent assessment of charge status, incorporating customers' desired "charge by" times, the charge rate, and other factors, thus distributing the charging across a wider time window.

Auto manufacturers, such as Chevrolet and Ford, offer a special delayed charging mode that can be used to mitigate timer peak. The driver programs the desired departure time through controls in the car, and the vehicle calculates when charging should begin in order to be fully charged by that departure time. This particular program randomizes the start of charging, so the charging loads could be distributed as desired. Similarly, Network Service Providers, such as Greenlots, ChargePoint, EV Connect, and eMotorWerks, offer intelligent algorithms that can be scheduled through the EVSE. While these options are helpful, the benefits may be variable as they generally require action on the part of the customer.[30]

As shown in Figure 1, managed charging has the potential to absorb excess renewable capacity, such as PV production during peak solar hours and wind power

FIGURE 1: OPPORTUNITIES FOR EV MANAGED CHARGING TO MEET GRID NEEDS (ILLUSTRATIVE)



Source: BMW of North America, 2016 with edits by Smart Electric Power Alliance, 2017

Note: The light blue area illustrates the impacts of a hypothetical TOU residential charging rate with the lowest rate period beginning at 11 pm. The dark blue area shows how managed charging could distribute charging loads with peaks in renewable energy generation.

25 California Public Utilities Commission, 2018, *Proposed Decision on Rulemaking 15-03-011*, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K478/204478235.pdf

26 See: Hawaiian Electric Company, https://www.hawaiianelectric.com/products-and-services/save-energy-and-money/time-of-use-program (accessed April 2019).

27 UtilityDive, "PG&E, SCE, SDG&E pursue subscriptions, time-of-use rates to drive more California EVs," https://www.utilitydive.com/news/pge-sce-sdge-pursue-subscriptions-time-of-use-rates-to-drive-more-cali/545907/.

28 See: SDG&E, https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans (accessed April 2019).

29 Interview with SDG&E staff in March 2019. Note: The time peak issue has not yet been a major issue for SDG&E.

30 Note: Some vendors support opt-out (rather than opt-in) control, where customer preferences are collected upfront during the time of enrollment ensuring the battery is charged when needed.

spikes during off-peak hours. At the same time, managed charging can smooth unintended TOU timer peaks.

Avoiding grid upgrades is potentially an even more significant value for utilities. Even during the early days of EV deployment, researchers with The EV Project identified the "clustering" trend, in which multiple EVs connected to a single distribution transformer caused strain on the equipment.[31] In some areas, this impact is even more pronounced today, leading to a risk of triggering costly upgrades to distribution equipment. More EV owners are installing L2 chargers at home that have demands of 7.2 kW and higher. Seeking to mitigate these costs, a Sacramento Municipal Utility District (SMUD) report found that managed charging reduced almost all of the cost impacts of higher residential charging levels, even at loads up to 19.2kW, potentially saving significant dollars in transformer upgrades.[32] The impact to transformers is expected to be highly dependent on the distribution design, capacity, age, other customer loads, and the degree of clustering and overlap of EV charging.

UTILITY INTEREST IN MANAGED CHARGING

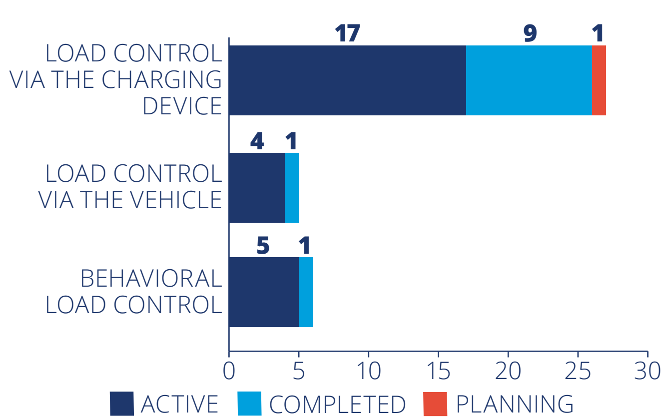
Given this projected growth in EVs and charging infrastructure, it is not surprising that utilities are evaluating managed charging. In fact, 38 utility-run managed charging pilot and demonstration projects were identified at the date of publication (see Appendix A). Of these projects, the majority (26) were actively available to customers, while one-third were implemented as pilot or demonstration projects that are now complete and in various stages of evaluation or review.

The projects were segmented between load control via the charging device, load control via the vehicle, and behavioral load control as shown in Figure 2. The most popular type of managed charging project at the date of publication is load control via the charging device, representing 71% of the total projects. This trend appears likely to continue as a higher percentage of surveyed utilities are interested in load control via the charging device (as shown in Figure 3).

Load control via automaker telematics is in the earlier stages of implementation and has very few completed projects—the majority of those identified are active. Behavioral load control largely included projects that used the on-board diagnostic port (OBD-II) to research customer vehicle behavior and provide incentives to customers to charge during off-peak hours.

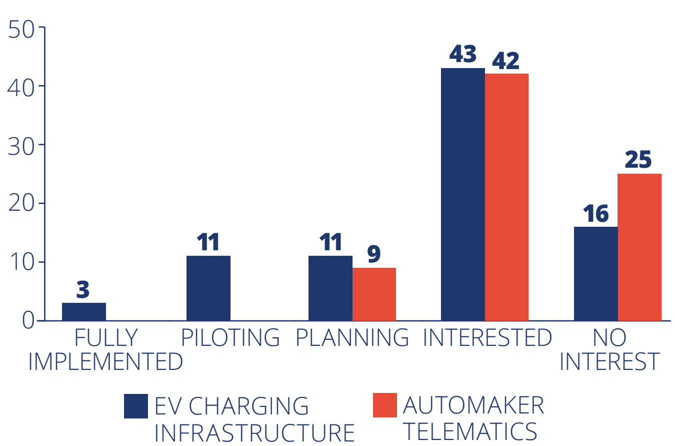
To gain additional clarity about utility-run managed charging programs, SEPA administered a Utility Demand Response Survey between January and April 2019. Of 84 respondents, 53% were interested in EV managed charging

FIGURE 2: UTILITY-RUN MANAGED CHARGING PROJECTS BY TYPE AND STAGE, UNITED STATES, 2012-2019



Source: Smart Electric Power Alliance, 2019. See Appendix A for details. N=38

FIGURE 3: UTILITY INTEREST IN MANAGED CHARGING PROGRAMS BY TECHNOLOGY TYPE



Source: Smart Electric Power Alliance, 2019. N=84

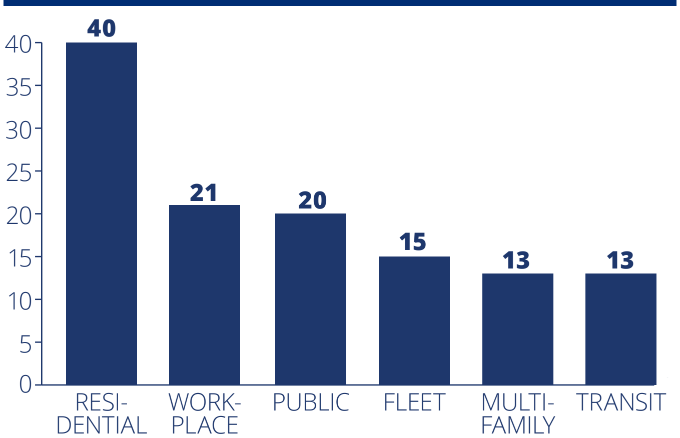
31 The EV Project, 2013, *What Clustering Effects have been seen by The EV Project?*, https://avt.inl.gov/sites/default/files/pdf/EVProj/126876-663065.clustering.pdf.

32 SEPA, April 2017, *Utilities and Electric Vehicles: The Case for Managed Charging* and SEPA, Black & Veatch, and the Sacramento Municipal Utility District, May 2017, *Beyond the Meter: Planning the Distributed Energy Future, Volume II: A Case Study of Integrated DER Planning by Sacramento Municipal Utility District*.

demand response programs and only 26% expressed no interest (aggregated results from managed charging via charging infrastructure and automaker telematics).[33] The survey revealed more utility interest in direct load control via the charging infrastructure than through automaker telematics (see Figure 3).

Of those that had interest or a project in place,[34] utility respondents were asked what application types the utility had targeted, or were targeting, for a managed charging program (see Figure 4). The leading applications were for residential (33%), followed by workplace charging (17%) and public (16%).

FIGURE 4: APPLICATION TYPES TARGETED FOR A MANAGED CHARGING PROGRAM



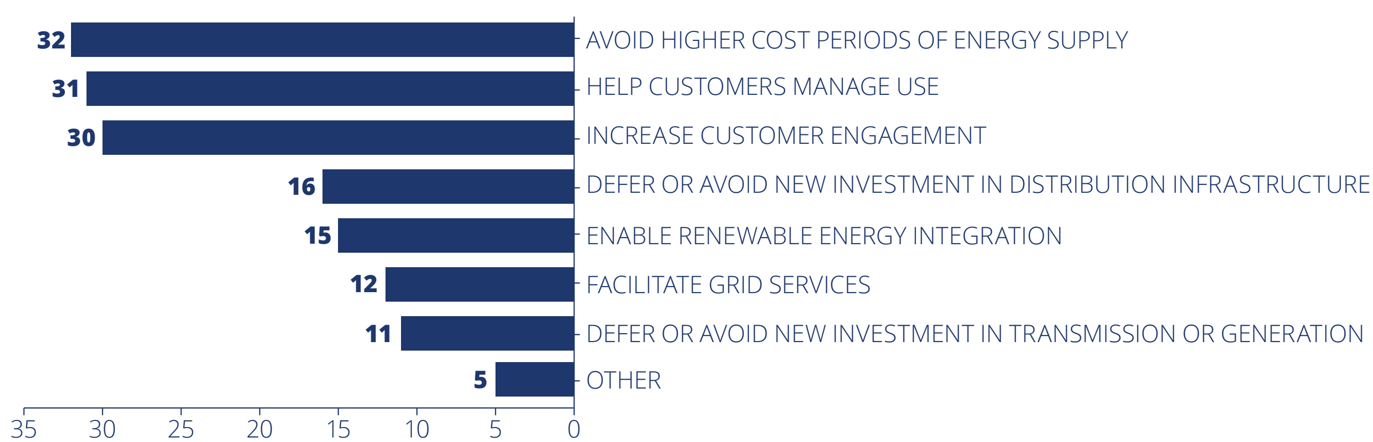
Source: Smart Electric Power Alliance, 2019. N=49.
Note: Utilities selected all that applied.

Utilities were also asked how they were using, or planned to use, managed charging as shown in Figure 5. The most common planned use was to avoid higher cost periods of energy (22%), followed by helping their customers manage their energy use (21%) and increasing customer engagement (20%). These options do not represent an "either-or" choice if managed charging is to be a feasible and successful program. Managing charging to avoid high cost time periods should be done in ways that maximize customer savings and ease of use, and minimize customer disruption.

When asked about the barriers to implementing a managed charging program, these same utilities consistently identified two major constraints: uncertainty around the availability of EVs to manage (23%) and the uncertainty around customer participation in the programs (21%) as shown in Figure 6. Other high ranking concerns were related to the cost-benefit uncertainty (16%) and limited information about how to design a managed charging program (15%). The "other" responses suggested concerns about how to prioritize managed charging relative to other demand side management programs or that there wasn't a need for additional demand response resources. Several utilities also mentioned there were very few EVs in their service territory, so it was not a priority.

When asked what three industry activities would most significantly help their utility implement a managed charging program, the most popular was the development of a managed charging program design guide (19%) as shown in Figure 7. (Note: SEPA's Electric Vehicle

FIGURE 5: HOW UTILITIES ARE USING OR PLANNING TO USE MANAGED CHARGING

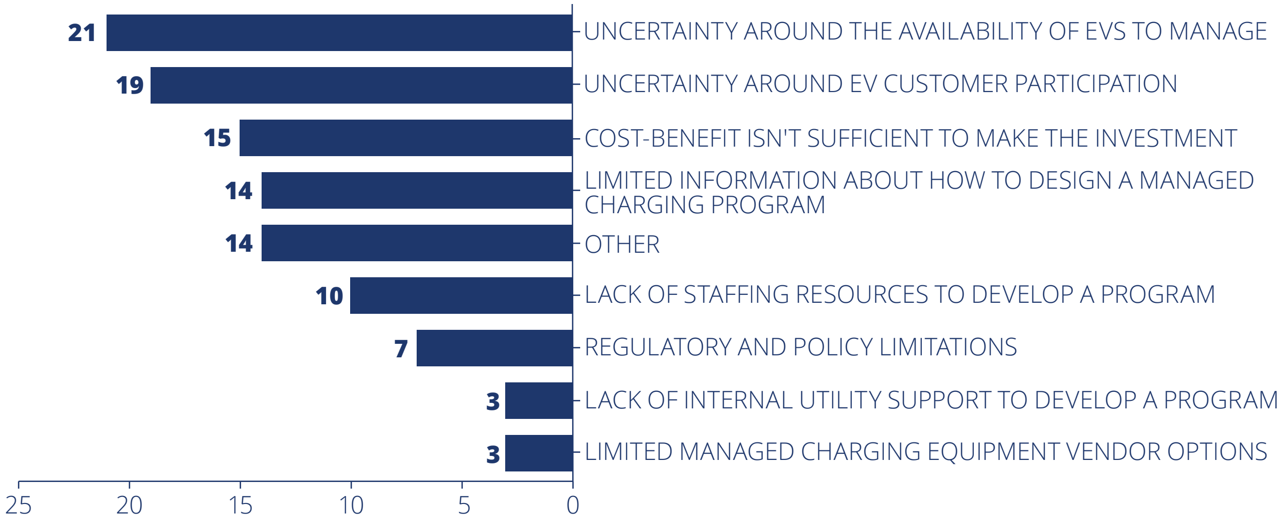


Source: Smart Electric Power Alliance, 2019. N=48. Note: Utilities selected all that applied.

33 Specifically for managed charging via EV charging infrastructure, only 19% expressed no interest (down from 20% in 2018)

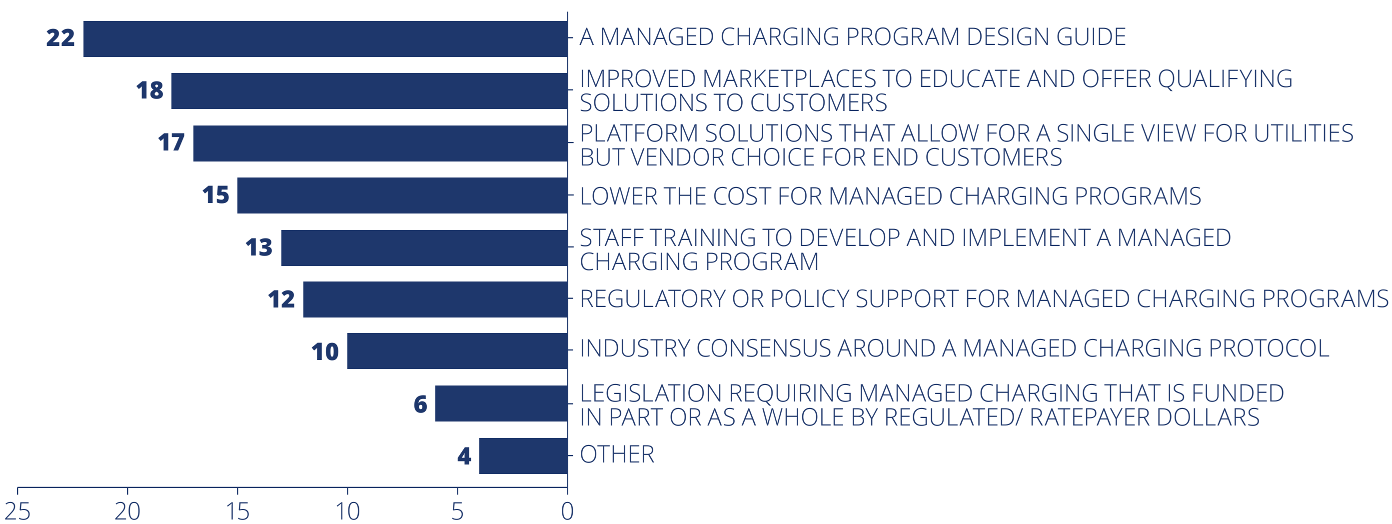
34 Note: Includes those that had implemented, piloted, planned or were interested in a managed charging program.

FIGURE 6: BARRIERS TO IMPLEMENTING A MANAGED CHARGING PROGRAM



Source: Smart Electric Power Alliance, 2019. N=45. Note: Utilities selected all that applied.

FIGURE 7: INDUSTRY ACTIVITIES THAT WOULD HELP UTILITIES IMPLEMENT A MANAGED CHARGING PROGRAM



Source: Smart Electric Power Alliance, 2019. N=49. Note: Utilities selected top three options.

Working Group is currently developing a managed charging program design guide.) Other popular options were improved marketplaces to educate about or offer qualifying equipment (16%) and platform solutions that allowed for a single utility view but vendor options (15%). Among the "other" responses, utilities were looking for more information on customer load profiles and benefits that would be specific to their systems. They also would like to see a greater selection of lower-cost EVs. Another utility was seeking an integration platform that would enable a direct signal from the utility distribution energy resource management system (DERMS).

Finally, when asked for an estimate of the average cost per vehicle per year to make a managed charging program viable in their service territory, the vast majority of utility respondents didn't answer the question. Of those that did answer, the most common estimates were in the range of less than $100 to $300 per vehicle per year.[35]

35 Note: N=15. Choices were: Less than $100, $101-$200, $201-$300, $301-$400, $401-$500, $500 or more, I don't know, not applicable, or other.

The survey reveals a high level of interest in managed charging, prioritizing managed charging as a way to better serve EV customers, as opposed to addressing a utility issue, such as managing demand. There is still a great deal of uncertainty about the availability of the EV load for managed charging and the degree of customer participation. More than anything else, utilities express a need for help in designing and developing managed charging programs in order to move forward.

THE MARKET OPPORTUNITY FOR MANAGED CHARGING

As indicated above, the economic viability and potential of managed charging programs depends heavily on the actual value of the grid services that EVs can provide, similar to many other DER technology discussions today. Some progress has been achieved to try to quantify the benefits of managed charging in states like California. However, the full range of benefits, as well as the costs, remain uncertain. Overall, the value of managed charging, including that of TOU rates, will remain unclear until 1) the wide range of use cases are properly articulated, 2) their benefits and costs are methodically estimated and compared, and 3) deployment is ramped up to verify net benefits in real life. With well-established economic signals in active markets, value determination will become more transparent.

This section discusses the grid services opportunities for managed charging, including a proposed valuation framework by Pacific Gas and Electric (PG&E). The section also includes the forecasted value of the EV grid services market and major investments in managed charging Network Service Providers to date.

GROWING CAPABILITIES AND GRID SERVICES

Managed charging technical capability sets were defined at length by the California Public Utility Commission's (CPUC) VGI working group. These include a wide range of functional requirements such as compliance with California's Rule 21[36], implementation of certain rate structures, load control, monitoring, and restart capabilities. Mirroring the wide range of necessary technical capabilities is the wide range of managed charging use cases. The same CPUC VGI Working Group attempted to document a comprehensive list of use cases for managed charging, with several proposals from expert stakeholders. However, no industry consensus was reached on the best framework or methodology to do so at the date of publication, though progress continues.[37]

PG&E proposed a VGI valuation framework that captures where many of these value streams are likely to be derived based upon the defined use cases relative to seven different elements as discussed in the sidebar.

A NEW VALUATION FRAMEWORK FOR VEHICLE GRID INTEGRATION

As conversations in California evolved around the role of EVs as a grid resource and their fit within the larger DER ecosystem, the need to frame and make sense of the broad VGI space became readily apparent. The complexity and variety of VGI use cases has, quite often, resulted in industry stakeholders talking past each other rather than to each other. This was largely due to individual points of view and a limited focus on a subset of applications, technologies, or business models. Developing an inclusive, methodical, and robust VGI framework has emerged as a priority, in order to accurately describe, evaluate, and enable the wide array of VGI use cases.

Building on the progress achieved during the California Public Utilities Commission VGI Working Group in 2017, PG&E has taken the initiative to develop a VGI framework that can help steer these conversations forward. As shown in Figure 8, PG&E's VGI Valuation Framework identifies seven key dimensions along which VGI use cases can be designed, and their value subsequently quantified. While this framework may still evolve as the industry progresses, it can help different stakeholders communicate about VGI.

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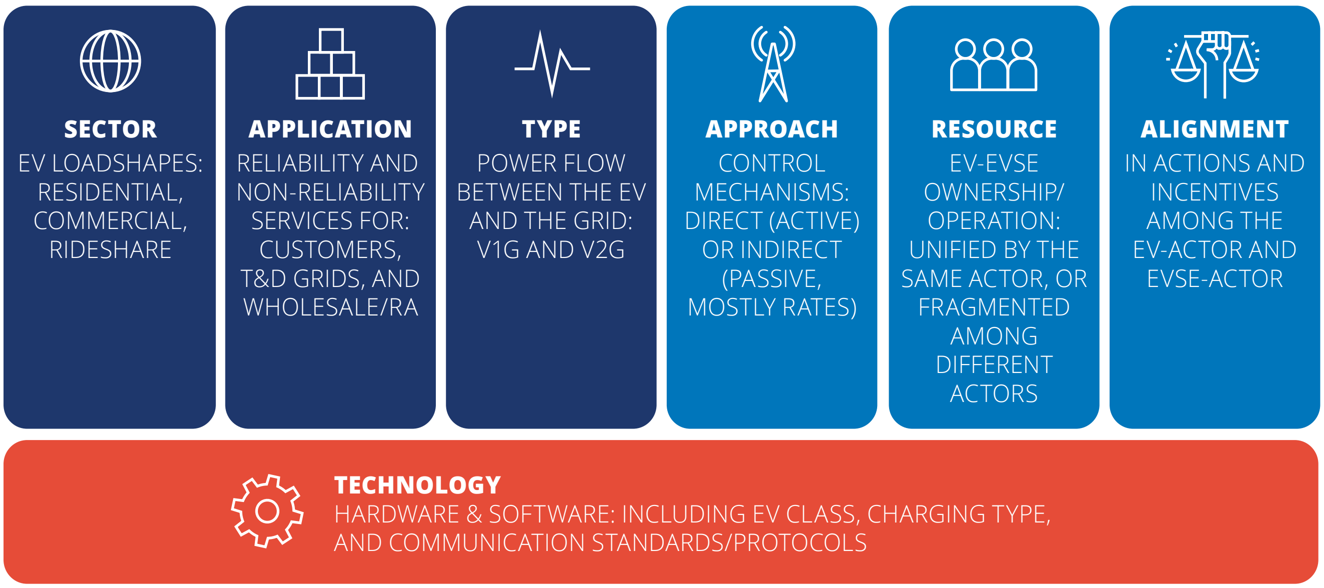
36 Rule 21 specifically excludes vehicle charging unless it is V2G because it only pertains to distributed generators interconnected with utility distribution systems (e.g., PV inverters). IEEE 2030.5 is identified as a default protocol for smart inverter controls, but the inverter is on the vehicle (as the onboard charging device), not the EVSE. Rule 21 inverter signaling do not require a solution that communicates with the car directly. For example, communications are permitted to a DER aggregator, or facility energy management system (EMS), or an individual DER itself. Those aggregator<>DER and EMS<>DER controls may be protocols other than IEEE 2030.5.

37 Vehicle-Grid Integration Communication Protocol Working Group—Use Case Sub-Working Group Report, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454524 (accessed April 2019).

A NEW VALUATION FRAMEWORK FOR VEHICLE GRID INTEGRATION, CONTINUED

FIGURE 8: VGI VALUATION FRAMEWORK



For further information on PG&E's VGI efforts, contact Karim Farhat (karim.farhat@pge.com)

The **seven key dimensions** include:

1. **Sector:** It is important to define the sector where the vehicle is used and charged, because that most often determines the corresponding EV load shape and therefore the opportunity to manage charging. Broadly speaking, the three main sectors with unique load shapes are residential (e.g., single-family or multi-unit dwellings), commercial (e.g., workplace, fleet, or public) and rideshare (e.g., transportation network companies like Uber or Lyft). A residential light-duty vehicle charging profile looks very different from that of a commercial-fleet medium- or heavy-duty vehicle. While rideshare EV drivers will likely leverage both residential and commercial charging, their needs are unique enough to carve out their distinct sector. Different load profiles result in different load management actions and yield different VGI values, depending on the needs.

2. **Application:** Refers to the service(s) the EV is used to fulfill. PG&E breaks down applications into reliability and non-reliability services, which are further characterized at the customer-level (e.g., customer bill reduction), transmission and distribution grid level (e.g., capacity investment deferral), and the broader wholesale market level (e.g., ancillary services, capacity, renewable integration, etc.). An EV may fulfill, and therefore may get compensated for, one or more of these services. The prospect of "stacking" these services, and their values, is important and relevant not only to VGI, but also to other DERs such as battery energy storage.

3. **Type:** This defines the power flow between the EV and the grid. A unidirectional flow (V1G) results in charging modulation (increase or decrease load) only, whereas a bi-directional flow (V2G) also allows discharging the EV back to the facility or back to the grid. These different types result in different performance and use of the EV battery, and therefore result in different values.

PG&E's framework treats Sector, Application, and Type as "value creation" dimensions, since they determine how VGI value (both benefits and costs) is created and where it comes from. Value along these dimensions is additive: residential charging can be added to commercial charging, wholesale ancillary services can be added to capacity services, and managed charging can be added to managed discharging, resulting in additional benefits and/or costs from VGI.

4. **Approach:** As discussed in the definitions, managed charging can be defined as both active (e.g., demand response programs) and passive (e.g., TOU rates). The

A NEW VALUATION FRAMEWORK FOR VEHICLE GRID INTEGRATION, CONTINUED

control mechanisms by which managed charging is enabled have different associated costs and benefits. For example, demand response events may result in limited load shifting during specific time periods on specific dates, whereas TOU rates may result in consistent load shifting on a daily basis throughout the year. Demand response participation may result in incremental benefits per event while necessitating additional investment in technological upgrades. On the other hand, TOU rates may result in bill savings over time while imposing administrative costs to setup and run the program.

5. **Resource:** Defines whether the EVSE-EV actors are unified (e.g., a fleet operator that owns and/or control the operation of both the vehicle and the charging device) or fragmented (e.g., a workplace site host that owns and/or control the charging device but doesn't control how EV-driving staff use the asset). When EVSE-EV actors are unified, it is easier to fulfil the VGI application and capture its value. When EVSE-EV actors are fragmented, further effort may be needed to ensure their alignment, which is the focus of the last VGI dimension.
6. **Alignment:** Alignment and Resource are tightly linked. When the EVSE and EV actors are unified, they are aligned by default. In the case that the EVSE and EV actors are fragmented, they may be either aligned or misaligned. Among other factors, incentive design is an important consideration to achieve alignment and guarantee the delivery of the VGI service. Misalignment makes it harder for managed charging/discharging to fulfill its purpose and therefore may erode the value of VGI.

PG&E's framework treats Approach, Resource, and Alignment as "value enablement" dimensions, since they determine how VGI value (both benefits and costs) can be unlocked and effectively captured. Value-enablement dimensions complement value-creation dimensions to accurately characterize benefits and costs. For example, no matter how significant the potential net benefits may be from managing the load of EV fleets for distribution grid capacity deferral, that value may never been realized in real life if the Approach is sub-optimal, the Resource is fragmented, and/or Alignment is not established. Effectively, the value-enablement dimensions help inform the design of successful business models for the VGI use cases, and they help identify any policy or market inefficiencies that need to be resolved for that purpose.

7. **Technology:** Includes the hardware and software to bring about the necessary capabilities to fulfill a VGI offering. Technology solution sets are diverse and span across the other six VGI dimensions. Examples of technology considerations could include the type of EV (e.g., light-duty vehicle versus heavy-duty vehicle, or plug-in hybrid vehicle versus battery electric vehicle; a battery electric vehicle typically has a larger battery capacity than a plug-in hybrid electric and therefore more opportunity for load shifting), the charging device type (e.g., a networked L2 charger may be more expensive but allow higher charge/discharge rate than a networked L1 charger), and the corresponding communications protocols to pass information and commands between the vehicle and ultimately the grid.

PG&E sees the VGI landscape as a decision tree that keeps branching out, with each branch ultimately characterizing a unique use case. A VGI use case is defined by choosing a Sector, an Application, and a Type, then selecting a direct or indirect Approach, a unified or fragmented Resource, and the corresponding state of Alignment.

Ultimately, this framework yields a long list of possible VGI use cases—potentially hundreds. A few examples include:

- A residential (Sector) EV load decrease (Type) in the afternoon to avoid peak pricing and minimize monthly energy bill (Application) by setting charging device timer based on TOU rate schedule (Approach), where both the charging device and EV are owned by the meter customer (Resource and Alignment).
- A workplace (Sector) EV load increase (Type) to soak up excess renewable energy during the day (Application) via demand response (Approach), where the EVSE and EV are operated by different actors (Resource and Alignment).

While all use cases may be worthy of consideration, some will likely be more valuable and/or market-ready than others.

PG&E does not see technology as the main area of concern in the bigger picture. Where it sees the greatest challenge—and opportunity—is gathering and integrating the necessary information and data to quantify the benefits and costs of the use cases and designing successful programs for the most promising. While some industry stakeholders can—and reasonably

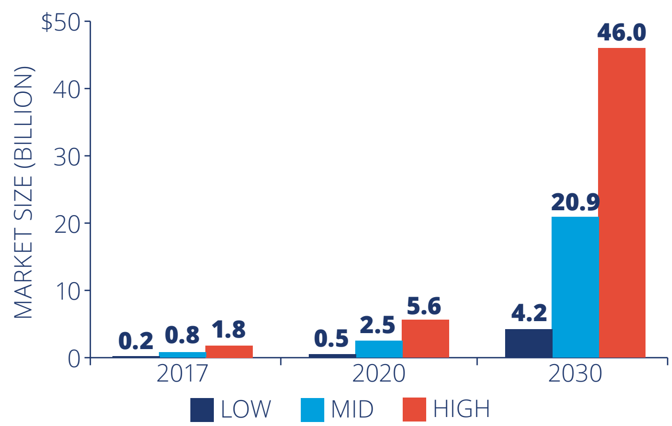
A NEW VALUATION FRAMEWORK FOR VEHICLE GRID INTEGRATION, CONTINUED

do—focus their business offerings on a limited set of VGI use cases, the utility needs to be able to assess, compare, and plan across the full range of feasible use cases since they all eventually impact the grid.

Overall, the VGI Valuation Framework PG&E developed achieves three objectives: (1) defining a comprehensive list of VGI use cases, (2) quantifying their value, and (3) aligning VGI policy and regulations with those impacting the broader transportation electrification goal and other DERs. Simply put, the framework serves as an accounting mechanism that charters a clear path for VGI valuation.

According to Wood Mackenzie Power and Renewables, the size of the grid services market for electric vehicles is growing. Wood Mackenzie defines grid services to be the total market potential of smart charging (V1G), vehicle-to-grid (V2G) and other services EVs can provide to the electricity grid.[38] This does not include any retail cost mitigation value streams such as program reimbursements for V1G or V2G program participation or lowered demand or TOU charges. It would include potential value generated through peak load reduction, ancillary services, and capacity. Between low-, medium-, and high-case scenarios, by 2030 the value of EV grid services in North America could be between $4.2 billion and $46 billion.[39] Wood Mackenzie Power & Renewables expects the actual value for grid services from EVs to be most in-line with the low-case as shown in Figure 9. In comparison, the Navigant Research base-case forecasts up to $48 million for the EV grid services market in North America by 2026.[40]

FIGURE 9: NORTH AMERICAN EV GRID SERVICES MARKET, 2017-2030



Source: Wood Mackenzie Power and Renewables, 2018.

MANAGED CHARGING INVESTMENTS AND ACQUISITIONS

In the past two years, we have seen a large number of major domestic and international investments and acquisitions in EV network service providers and EVSE manufacturers—particularly those with managed charging capabilities. While half of the investments in Table 5 were undisclosed, at least $680 million was identified.

38 Information provided by Wood Mackenzie, March 2019.

39 Wood Mackenzie, December 2018, *Vehicles and the grid edge: The market for EV grid services.* https://www.woodmac.com/our-expertise/focus/Power--Renewables/vehicles-grid-edge/?utm_source=pardot&utm_medium=email&utm_campaign=wmpr_evgriddec2018. Note: Each scenario uses a static view of the $/EV grid services value irrespective of EV, battery or DER market saturation. This analysis was an extrapolation, based on assumptions of value on a per car basis for these services. This analysis was not a based on power modeling and does not factor in crowding out, EV participation rates, or bidding behavior.

40 Information provided by John Gartner, Principal, Navigant Research, January 2019.

TABLE 5: NETWORKED ELECTRIC VEHICLE CHARGING COMPANY ACQUISITIONS AND INVESTMENTS, NORTH AMERICA, 2018-2019			
NETWORK SERVICE PROVIDER/ EVSE MANUFACTURER	**ACQUIRED BY/ INVESTMENT BY**	**AMOUNT**	**ADDITIONAL INFORMATION**
Aerovironment's Efficient Energy Solutions (EES)	Webasto Group (acquisition)	$35M	Webasto is a German-based automotive industry supplier. The EES business includes EV charging devices and test systems, unmanned aircraft, and tactical missile systems
ChargePoint	AEP, Daimler Trucks & Buses, Chevron, etc. (investment round)	$240M (2018)	Global EV charging network with over 62,000 networked ports. Total investment to date: $530M w/ previous funding from Daimler, Constellation, BMW, Chevron, etc.
eMotorWerks	Enel (acquisition)	$400M	U.S. based manufacturer of popular residential L2 chargers; see examples of projects in Appendix A
EVBox	Engie (acquisition)	Undisclosed	The residential L2 charger, Elvi, will be integrated into Engie's on-demand building and energy platform, known as Serviz. It has deployed 50,000 charging stations to date, including in the U.S.
FleetCarma	Geotab (acquisition)	Undisclosed	Geotab is a leader in IoT and connected transportation, specializing in vehicle telematics
Freewire Technologies	BP (investment)	$5M	Manufacturers the Mobi, a mobile charging station
Greenlots	Shell (acquisition) and Energy Impact Partners (investment)	Undisclosed	Shell also invested in the Ionity network in Europe with over 30,000 stations
Nuvve Corporation	EDF (investment)	Undisclosed	Series A financing to advance commercialization of the NUVVEgives Grid Integrated Vehicle platform

Source: Smart Electric Power Alliance, 2019. Compiled from various online resources.

UTILITY CASE STUDIES

Utilities have hosted some of the most innovative field tests of managed charging technologies to date and have experimented with many different vendors and technology types with varying degrees of success. Many of these projects emerged from policy and regulatory initiatives or the availability of research funding. Three examples of utility managed charging projects are highlighted in this section to showcase the diversity of possible approaches through the vehicle, the charging equipment, or some other intermediary, such as through the vehicle's On-Board Diagnostic Port (OBD-II).

In all instances, customer adoption and buy-in was paramount to the success of each project. Customer incentives for each were structured differently either through the use of a free charging device, rebate, or monthly incentive payment. In all instances, customers had the ability to opt-out of a managed charging event, which helped with enrollment and retention.

AVISTA MANAGED CHARGING PILOT PROJECT DEMONSTRATES CUSTOMER BUY-IN, BUT ALSO HIGHLIGHTS GROWING PAINS[41]

When Avista Corporation, with service territories in Washington, Idaho, and Oregon, developed its EV plans, it identified managed charging as an opportunity to address customer charging needs and retain utility value from those assets.

41 Source: Phone call with Rendall Farley and Mike Vervair, January 2019 and Docket No. UE-160082 – *Avista Utilities Semi-Annual Report on Electric Vehicle Supply Equipment Pilot Program*, November 1, 2018.

Avista designed the pilot to own, maintain, and install EVSE on a residential or commercial customer premise and rate-base the assets. To participate in the project, customers allowed Avista to collect charging data and run demand response (DR) events. Customers had the option to be notified about upcoming DR events the day before and to opt-out of an event. In order to have a diverse sample, Avista recruited individuals with a variety of driving patterns (e.g., commuters vs. non-commuters) and vehicle types (e.g., long and short-range BEVs, PHEVs).

One of the goals of the project was to determine how to deploy managed charging without upsetting customers. While the final report for the project won't be issued until fall 2019, based on early findings Avista successfully shifted EV charging load to off-peak hours without customer disruption.

According to Mike Vervair, EV engineer with Avista, "We were able to curtail load up to 75% and had no complaints from customers. As long as the vehicle is fully charged when they need it, customers don't care when the load is being shifted. We saw about a 10% opt-out rate overall for the program for residential sessions."[42]

Despite the success with customers, Avista ran into a number of program challenges, particularly with residential locations that were networked via the customer's on-site Wi-Fi connection. Some of the hardware and software used for the program were not entirely reliable. For example, they found issues with how much information the devices were able to store internally before transmitting data out via the Wi-Fi connection. The devices had a tendency to "glitch out" causing between a 30-45% offline rate for the units during the course of the program. Some devices had more chronic issues than others, but on average 55% of the residential systems were dependably online. The commercial units were far more reliable because they were connected via cellular on a more robust network.

Avista plans to continue making improvements and expanding its DR experiments for several years, and is exploring other communications methods—potentially through its future AMI network—as cellular isn't feasible due to current costs. As stated in the company's May 2019 EVSE report, "Although DR progress has been delayed due to a combination of technical problems related to connectivity, EVSE hardware and firmware, and network controls, overall improvements and initial results indicate that DR learning objectives will be met as the number of participants increase, and additional control group experimentation and data accumulate over time."[43]

Rendall Farley, program manager with Avista, said, "It is clear that the costs outweigh the grid benefits of a managed charging program at this time. However, at what EV penetration and with improved technology and costs will it make financial sense? Each utility needs to look at this in order to be good grid stewards. If utilities don't manage these charging loads intelligently, it will cost more for everyone in the long-term." Farley also stated that

TABLE 6: APPLICATION OF THE VGI VALUATION FRAMEWORK IN THE PG&E EV SMART CHARGING PILOT

	SECTOR	APPLICATION	TYPE	APPROACH	RESOURCE	ALIGNMENT	TECHNOLOGY
Phase 1							
Use-case 1	Residential	Wholesale, Capacity	V1G	Direct	Unified	Aligned	LDV, L2, Telematics
Use-case 2	Residential	Wholesale, Energy	V1G	Direct	Unified	Aligned	LDV, L2, Telematics
Phase 2							
Use-case 3	Residential	Wholesale, Overgeneration	V1G	Direct	Unified	Aligned	LDV, L1 & L2, Telematics
Use-case 4	Workplace	Wholesale, Overgeneration	V1G	Direct	Fragmented	Not aligned	LDV, L1 & L2, Telematics

Source: PG&E, 2019.

42 Note: It was not an option for commercial customers.

43 Avista Utilities, May 1, 2019, *Semi-Annual Report on EVSE Pilot Program RE: Docket No. UE-160082*, Washington Utilities & Transportation Commission.

"electric transportation is about serving customers and it is important for utilities to go about doing this in a way that maximizes benefits for customers, whether they are driving electric or not. Economically managing loads to go off-peak will be one of those challenges."

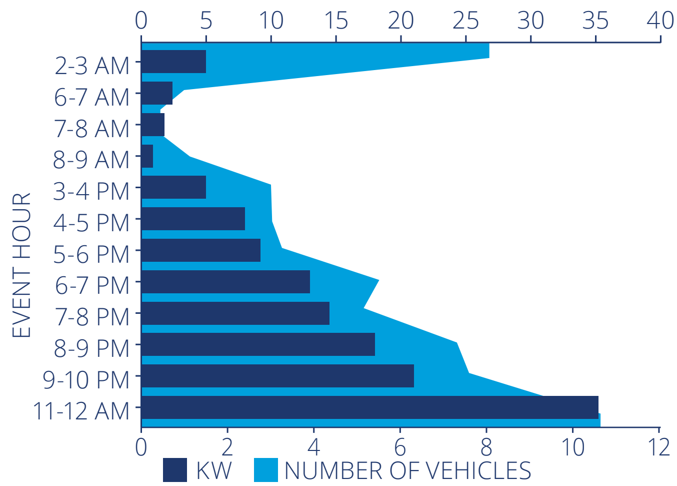
PG&E'S ELECTRIC VEHICLE SMART CHARGING PILOT

As part of a PG&E Demand Response Pilot and a California Energy Commission Electric Program Investment Charge (EPIC) grant, PG&E and BMW partnered to "demonstrate the technical feasibility and grid value of managed charging of electric vehicles, as a flexible and controllable grid resource."[44] The pilot spanned four VGI use-cases over its two phases, as illustrated in Table 6.

In the first phase of the pilot, partners focused on demand response and load curtailment.[45] BMW enrolled 96 Model i3 drivers and utilized proprietary aggregation software to delay charging via cellular (GSM-based) telematics. While the program was designed to minimize customer mobility interruptions, it also provided customers with an opt-out feature. To minimize disruptions, BMW used second-life stationary batteries (100 kW/225 kWh) to fill any load gaps for the required 100 kW of DR capacity. The drivers were provided with a L2 charging station at their homes and directed to charge primarily at home during the pilot.

During the 18-month trial, the i3s were called upon 209 times.[46] Events were tested in both Day Ahead (24 hour advance notification) and Real Time (4 minute advance notification) scenarios. BMW met the performance requirements for 90% of those events, with an average contribution of 20% from the vehicles and 80% from the 2nd life battery system.[47] While opt-out rates were very low, the greater challenge was the lack of availability of vehicles during DR events. This lack of availability may require the utility to deploy more sophisticated over-booking algorithms to meet its commitments. About 60% of the vehicles were enrolled in PG&E's TOU rate that incentivizes charging after 11pm, which limited the total number of vehicles available to participate during typical events as shown in Figure 10.[48]

FIGURE 10: AVERAGE KW CONTRIBUTION AND VEHICLE PARTICIPATION PER EVENT HOUR



Source: PG&E and BMW, 2017.[48]

Building on the successful partnership between the utility and the auto manufacturer in the first phase, the pilot continued for a second phase.[50] It expanded to over 350 participating vehicles and focused on the customer experience by giving users more managed charging information to make smart choices. The pilot ultimately made an even stronger case for using EVs to optimize for load conditions, including when energy was the cheapest or cleanest. For example, during a weeklong test around Earth Day in 2017, participants received more than 57% of their energy from renewable sources.[51] PG&E provided BMW with data on the status of renewable energy generation as well as excess supply on the system, and BMW optimized the EV charging by sending push notifications to participating drivers.[52] The pilot will continue into 2019 and final results will be published later in the year.

Because the vehicles are controlled using on-board vehicle telematics, a vehicle can participate regardless of where it is currently charging. The challenge will be to estimate how much value there is to the utility with this kind of program so that it can ultimately become economically attractive or self-sustaining without subsidies.

44 Pacific Gas & Electric, 2017, *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, pg. 6, https://efiling.energy.ca.gov/GetDocument.aspx?tn=221489.
45 This was funded under PG&E's 2018 Demand Response Pilot program.
46 *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, pg. 23.
47 *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, pg. 23.
48 *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, pg. 26.
49 *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, pg. 17.
50 Note: Phase 2 was funded by the California Energy Commission EPIC grant.
51 GreenTech Media, August 2018, "BMW's Plan to Optimize EV Charging with Renewables on the Grid," https://www.greentechmedia.com/articles/read/bmw-optimizing-ev-charging-renewable-energy#gs.S=Y9Qkc.
52 Provided by PG&E, March 2019.

PG&E expects to see more than 1.5 million EVs in its service territory by 2030.[53] Based on the results of the Phase 1 study, the potential load drop (based on the number of participants, participation rate, and the average of 4.4 kW per vehicle) of a single event in 2030 could be as much as 77.6 MW—enough to power 58,000 homes in California.[54]

CONSOLIDATED EDISON'S SMARTCHARGE NEW YORK

Consolidated Edison (ConEdison) partnered with FleetCarma and ChargePoint to design a program called SmartCharge New York to incentivize drivers to charge their vehicles at off peak times and study customer response to non-tariff rebates.[55] The program was active at the date of publication and open to all EV owners and fleet operators residing in the Metropolitan New York City (NYC) area and NYC commuters in New Jersey and Connecticut.[56]

Participants can receive a FleetCarma C2 connected device that plugs into the vehicle's Onboard Diagnostic Port (OBD-II), which then collects the customers charging data and makes it available to ConEdison and the customer via an online portal. Participants can also compare and contrast their data with other EV drivers nearby—a gamification

REGULATORY OPPORTUNITIES FOR MANAGED CHARGING CAPABILITIES

As utility EV infrastructure filings are submitted to commissions across the country, stakeholders and commissioners are examining opportunities to future-proof infrastructure and enable future functionality, which include managed charging. For example:

- In 2018, the Public Utilities Commission of Ohio approved a $10 million EV charger rebate program over the next four years to support the installation of 300 L2 and 75 DCFCs in American Electric Power's (AEP) Ohio service area.[57] All of the charging stations installed as part of this program will have managed charging capabilities and will be used for data gathering. Each year, AEP will share collected data with signatory parties to improve current and future programs.
- In 2018, the Utilities Commission of Pennsylvania approved a $1.3 million EV charger rebate program to support the installation of public L2 chargers in Duquesne Light Company's service area.[58] Similar to the AEP Ohio program, all of the charging stations installed as part of this program will have managed charging capabilities and will be used for data gathering.
- PG&E's EV Charge Network program offers EV charging station incentives for workplaces and multi-unit dwellings. PG&E will fund, own, and maintain equipment from the transformer to the parking space and the program participant can either own the charging station or have PG&E own it.[59] In order to be eligible, PG&E requires participants choose from a list of approved vendors selling managed charging-capable equipment.[60]

According to recommendations produced by California's Vehicle Grid Integration (VGI) Working Group, at a minimum, any equipment funded by the ratepayers should be managed charging-capable to be in the best interest of the consumers.[61]

53 Provided by PG&E, March 2019.

54 *BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot*, pg. 39. Note: Based on a total projected enrollment of 250,200 EVs by 2030, with 7% (or 17,514 EVs) participating in an event. SEPA believes the 7% participation rate used to calculate this forecast may be an error as 8% is noted in PG&E report.

55 Lisa Cohn, September 2018, "EV Programs Roll Forward with Efforts to Support the Grid," Microgrid Knowledge, https://microgridknowledge.com/ev-programs-us/.

56 Kyle Campbell, April 2018, "Con-Ed Offers Electric Car Perks to Drivers, Landlords," Real Estate Weekly, https://rew-online.com/program-pays-off-electric-car-owners-landlords/.

57 CleanTechnica, April 2018, "$10 Million EV Charging Infrastructure Plan Approved by Ohio PUC," https://cleantechnica.com/2018/04/28/10-million-ev-charging-infrastructure-plan-approved-by-ohio-puc/.

58 Pennsylvania Public Utilities Commission, March 2019, "PUC Approves Duquesne Light Filing for Third-Party Electric Vehicle Charging Stations; Ongoing Statewide Effort to Remove Uncertainty & Potential Barriers," http://www.puc.state.pa.us/about_puc/press_releases.aspx?ShowPR=4173.

59 See: PG&E ownership specifically for disadvantaged communities or multifamily locations: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/about-the-program.page (accessed April 2019).

60 See: Approved EV Charge Network Vendors, https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/approved-program-vendors.page (accessed April 2019).

61 VGI Communication Protocol Working Group, *Energy Division Staff Report*, October 2018.

strategy to increase user rates and improve the customer experience.

Customers earn rebates by joining, keeping the device plugged into the car, and referring other individuals.[62] The program also has a behavioral element, offering $20 per month to drivers who avoid charging their EV's from 2 pm to 6 pm on weekdays from June through September. Drivers can save $0.10/kWh by charging EVs between midnight and 8 am all year round.

Fleet operators can also participate in the program by granting ConEdison access to their fleet charging. In the case of the N.Y. Department of Citywide Administrative Services (DCAS), this was enabled through the ChargePoint Network. By request of the fleet EV charging station owner, ChargePoint is able to provide ConEdison interval level charging data for each fleet vehicle and charging station associated with the fleet. DCAS expects to earn up to $150,000 per year for charging its EVs overnight by participating in the program. The city will then reinvest the money earned from the program into buying additional EVs and chargers.[63]

The SmartCharge New York program not only helps New York meet its carbon emissions goals, but also complements EVolve NY, a $250 million EV infrastructure expansion program. In addition to state funding, EVolve NY seeks to create partnerships between the state government and the private sector through 2025 to accelerate the adoption of EVs throughout New York State.[64] ConEdison recently proposed to expand the SmartCharge New York program from light-duty to medium- and heavy-duty EVs, which was still under consideration by the NY Public Service Commission at the date of publication.[65]

IV. Managed Charging Communication Pathways

Network communication and equipment interoperability are a challenging barrier for managed charging, not unlike other grid modernization technologies, such as advanced metering infrastructure (AMI) and smart thermostats. The difficulty arises in finding a cost-effective way to send communication signals. Beyond just getting the standards right, the key to the broad deployment of managed charging is that it must be *inexpensive*, *reliable*, and *customer-friendly*.

Figure 12 illustrates the links in the chain of communication between the utility and the vehicle. Communications to EVs and EVSE from a utility consist of a combination of messaging (or application) protocols (e.g., OpenADR 2.0/OCPP) and transport layer protocols (also known as network communication interfaces) (e.g., Wi-Fi, cellular, and AMI). Though intertwined, the protocols for messaging and transport are distinct. The messaging protocol contains the instructions—e.g., wait to charge until after midnight—but is agnostic as to how the message is actually transported between the actors. The transport layer ensures a message gets from point A to point B but does not provide instructions as to specific behaviors of the receiving devices.

An example of how transport layer protocols and messaging protocols route communications from the utility or aggregator to the vehicle can be found in Figure 11. In this scenario the transport layer is illustrating two scenarios, one using cellular for the home and the other using broadband for a workplace program. The scenario also illustrates how multiple messaging protocols may be layered between the EV, the EVSE, and the aggregator, which can be leveraged for different purposes. This diagram succinctly demonstrates how complex the managed charging ecosystem can be. There are currently no industry-wide standards for the entire "ecosystem" of information exchange and communication, which is an obstacle the industry is currently working to solve.

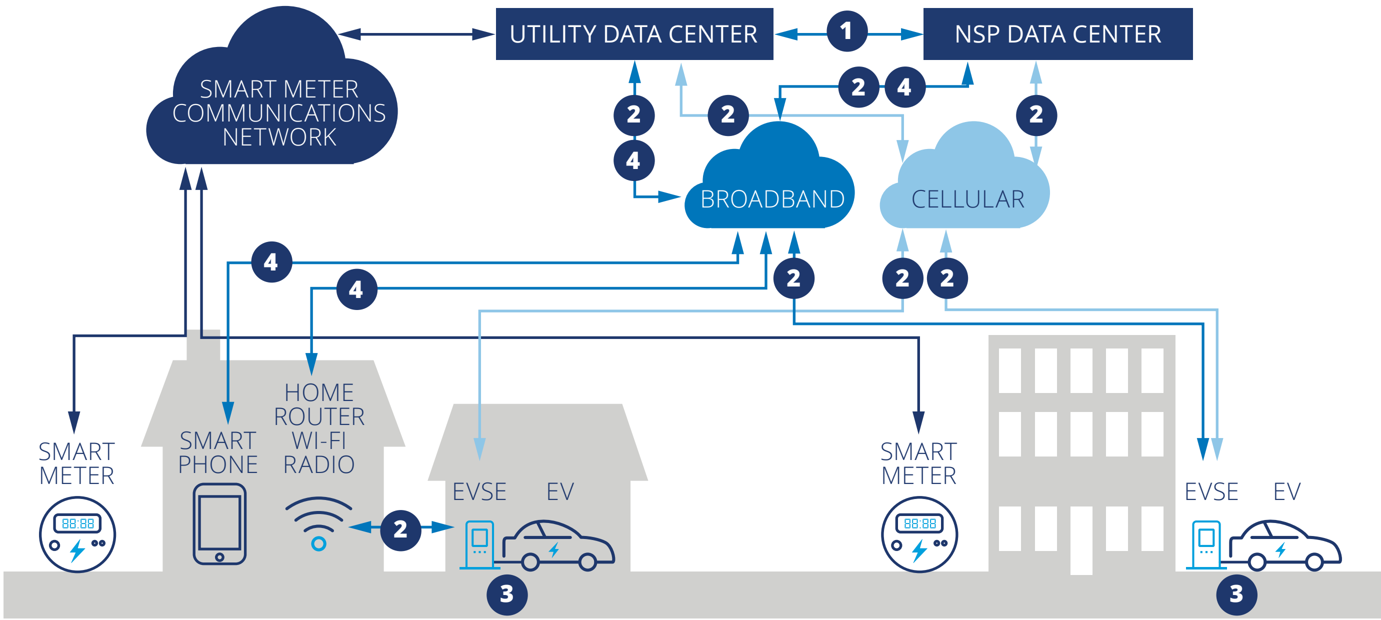
62 Tom Moloughney, July 2017, "SmartCharge New York: Get Paid To Charge Your EV." Inside EVs, https://insideevs.com/smartcharge-new-york-get-paid-to-charge-your-ev/.

63 Jillian Jorgensen, February 2019, "Con Edison Reward Program Allows NYC to Boost Its Electric Vehicle Fleet" — NY Daily News, https://www.nydailynews.com/new-york/edison-program-nyc-boost-electric-vehicle-fleet-article-1.3635739.

64 James B. Rhodes, September 2018, "Con Edison SmartCharge Program Expanded to Encourage Use of Electric Cars — Groundwork Laid to Increase Electric Vehicles in Con Edison's Service Territory," NY Public Service Commission.

65 Rhodes, Sayre, Burman, and Alesi. *Order Expanding Electric Vehicle Charging Program Eligibility*. 2018. State Of New York Public Service Commission, New York, Albany.

FIGURE 11: USE OF OPEN PROTOCOLS IN MANAGED EV CHARGING



Source: Siemens, EV Technical Workshop, NY Public Service Commission, July 2018.

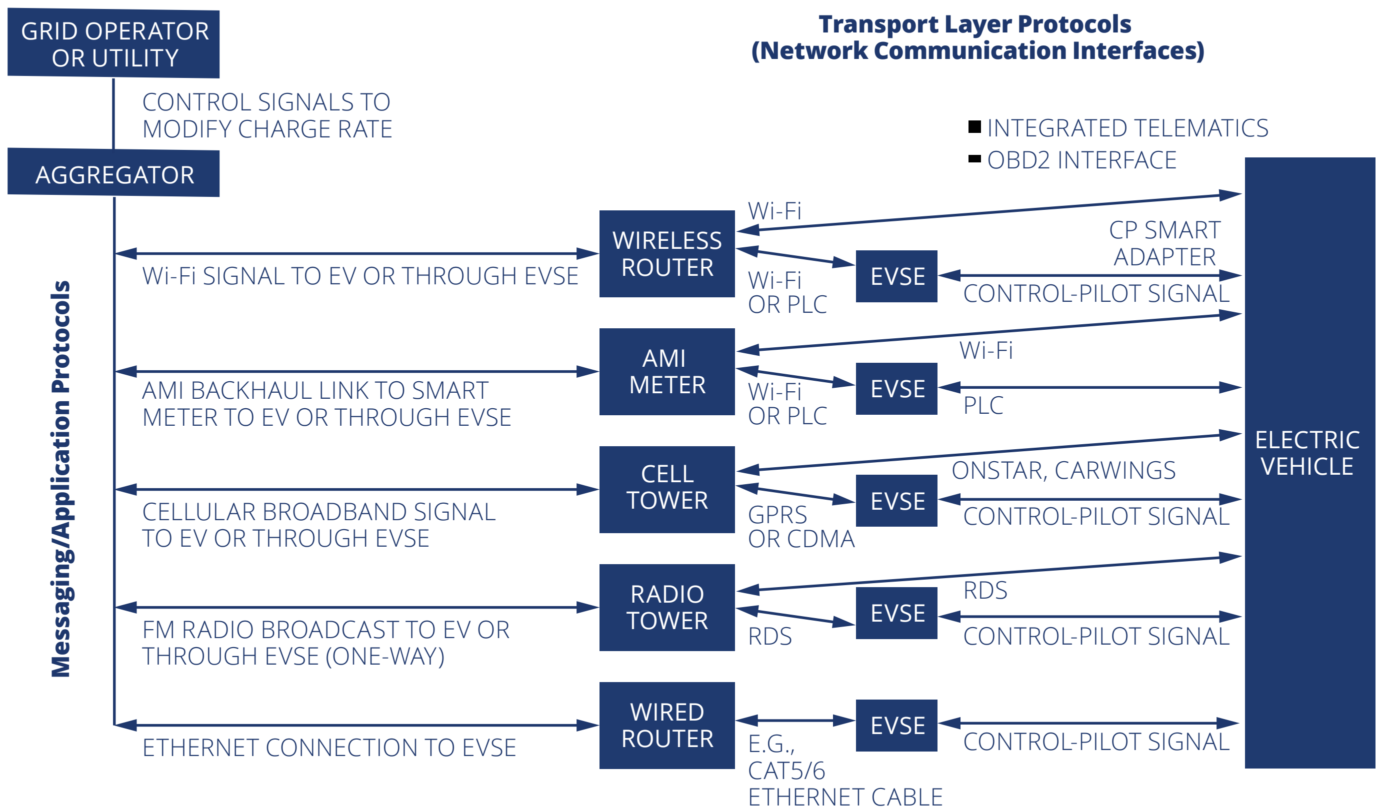
TRANSPORT LAYER PROTOCOLS (NETWORK COMMUNICATION INTERFACE)

Figure 12 provides a graphical view of five transport layer options for sending signals to a vehicle. These options correspond to preferences implemented by various vehicle or charging equipment manufacturers and locations (e.g., workplace, residential, fleet). As a note, the term "aggregator" is used generically and can represent a Network Service Provider, utility, or other entity facilitating a managed charging program. To summarize, the options are:[66]

1. Aggregator to home communications can be done by piggybacking on a residential broadband internet and Wi-Fi or Power Line Carrier (Zigbee or HomePlug Green PHY) connection in a similar fashion to many smart thermostats. Charging can be managed through a Wi-Fi connected EVSE that is able to decrease or increase charging via the Control Pilot (CP) signal, through a direct Wi-Fi connected vehicle, or with a Wi-Fi connected OBD-II module.
2. Aggregator to home communications can be done using a utility AMI backhaul link to a smart meter. The meter then forwards the messages either through a Wi-Fi, HomePlug Green PHY or ZigBee wireless link or Power Line Carrier (PLC) to communicate to the EVSE or the vehicle.
3. Aggregator communications to the home EVSE or to the vehicle can be done via a cellular signal such as the Global System for Mobile communications (GSM). In this case, the data travels through general packet radio service (GPRS) or through code division multiple access (CDMA) low bandwidth wireless connections. Cellular data transmission speed requirements can also vary based on the needs of the EVSE or vehicle (e.g., 2G, 3G, 4G, LTE). Cellular signals can be directed to the vehicle through onboard integrated communications such as OnStar or CarWings.
4. Aggregator communications to the EVSE or vehicle can be done by embedding digital command information in an FM radio broadcast using a communication protocol standard, known as a radio data system (RDS).

66 Dr. David Tuttle, 2016, *PEV-Grid Interactions Communications Types & Costs*, University of Texas at Austin, Union of Concerned Scientists Smart Charging Workshop, https://www.dropbox.com/sh/zmkca2v9cdiu9os/AADy4CkK7fxIUYMIW05kTQZya/Technical%20Aspects?dl=0&preview=Tuttle+-+UT+-+Communication+Options.pdf.

FIGURE 12: MANAGED CHARGING NETWORK COMMUNICATION INTERFACE OPTIONS



Source: Dr. David P. Tuttle, 2019[67] with edits by Smart Electric Power Alliance, 2019

5. Aggregator communications to the EVSE can be done via a home's broadband connection, through its wired router, and then over its Local Area Network (LAN) connection to the EVSE. Typically this would be deployed as an EVSE connected to the home's wired router via a standard CAT5 or CAT6 Ethernet cable.

POWER LINE COMMUNICATION (PLC) INTERFACES

While there are many network communication interface options to choose from, some utilities have chosen Zigbee and HomePlug to send demand response signals to behind the meter networked devices. While there are other PLC-based interfaces, we identified a total of eight charging equipment manufacturers and one Network Service Provider that use Zigbee and Green PHY.

Zigbee

Zigbee Smart Energy is a standard that enables interoperable devices (also known as Internet of Things—or IoT) to be monitored, controlled, informed, and automated to deliver and use energy. Utilities use Zigbee via smart meters and a home area network (HAN) to connect devices to the internet and/or mesh networks. Zigbee-enabled devices can provide demand response and load control by scheduling events, building in support for customer override of those events, targeting specific groups of devices (such as EVSE), building in duty cycling, and randomizing start and end times of a charging event (e.g., to avoid demand spikes).[68]

HomePlug Green PHY

Also known as the IEEE 1901 standard, HomePlug Green PHY was developed in part by utility industry members interested in using powerline networking to communicate

67 Dr. David Tuttle, 2016, *PEV-Grid Interactions Communications Types & Costs*, University of Texas at Austin, Union of Concerned Scientists Smart Charging Workshop, https://www.dropbox.com/sh/zmkca2v9cdiu9os/AADy4CkK7fxIUYMIW05kTQZya/Technical%20Aspects?dl=0&preview=Tuttle+-+UT+-+Communication+Options.pdf.

68 See: Zigbee Alliance, Smart Energy, https://www.zigbee.org/zigbee-for-developers/smart-energy/ (accessed April 2019).

with behind-the-meter devices. The goal of the standard was intended to reduce costs, reduce power consumption, and increase range of the communication interface.[69] A number of auto manufacturers committed to incorporating Green PHY into their vehicles back in 2011 (details of automaker plans are included in Table 12). Charging equipment manufacturers (e.g., FLO Home X5) and Network Service Providers (e.g., Greenlots) use the network communication interface. Green PHY is also embedded in other home devices beyond charging stations and EVs, including smart appliances and programmable thermostats.

WIRELESS INTERFACES

Wi-Fi

Nearly ubiquitous in the residential use case, Wi-Fi is commonly used by consumers for wide range of connected devices including smart speakers, smart thermostats, home security, and EV charging. Many EVSE and EV network solution providers provide models that allow consumers to connect their home charging station via Wi-Fi and then enable a range of features through their mobile application on their smartphone. Through the mobile app, EV drivers can track usage, schedule charging, set reminders, select TOU rates, sync their devices to their smart home, and even request to join utility managed charging programs. Wi-Fi is found in many residences, doesn't incur any incremental costs for communications, and can be incorporated as a universal solution regardless of existing utility advanced metering deployments and associated communication technologies, like Zigbee. However, as noted in the Avista case study, there may be issues with reliability/signal strength.

Cellular

In the commercial sector, networked charging stations typically use cellular communications to connect charging stations to the EV network cloud services. Hardwired connections, such as Ethernet, are possible but typically avoided due to the inherent security risks of connecting an outside system to existing building internet systems. Cellular solutions allow for secure, encrypted, stand-alone communications and the cost to enable and transmit data has experienced drastic reductions in the past few years. The cost of the actual communication pathway is often simply bundled as part of a network service or software-as-a-service fee in which the station operator also gains access to data, reporting, access controls, driver pricing and transaction capabilities, load management and much more. The data and load control capabilities enabled by such network services can also be leveraged by utilities regardless of who owns the stations.

PLC VS. WI-FI: LESSONS FROM GREEN MOUNTAIN POWER

Green Mountain Power's eCharger program, which provides free L2 networked charging stations to new residential EV customers, enrolled 300 customers as of February 2019. The program includes two brands of chargers: ChargePoint Home and FLO Home X5. In addition to performing demand response functions, the project was also designed to compare two types of communication interfaces:

- The ChargePoint systems communicate via a Wi-Fi signal to the customer's router and requires the customer to enter their Wi-Fi password during the initial set-up.
- The FLO systems use Power Line Communication (PLC) via HomePlug Green PHY and communicate directly with the router, going around the customer password configuration process and eliminating any issues in the future if a customer changes the password or gets a new router.

Despite the benefits of HomePlug, according to a SEPA interview with Craig Ferreira with Green Mountain Power, they have not "seen any issues so far with the password configuration process with the [Wi-Fi enabled] ChargePoint systems and the process is generally straightforward enough for customers."

Green Mountain Power is also using L2 data from the on-board metrology in the charging stations for billing functions. According to Ferreira, "ChargePoint performed a brief study to test the internal accuracy of this method and showed an extremely low variance." The low variance points to an opportunity to use data from the charging stations for billing purposes.

69 See: HomePlug, GreenPHY, http://www.homeplug.org/tech-resources/green-phy-iot/ (accessed February 2019).

MESSAGING PROTOCOLS (APPLICATION PROTOCOLS)

Most of the managed charging debate today is related to which messaging protocols to use in charging equipment. Many industry stakeholders are advocating for open, non-proprietary communications messaging protocols to reduce the cost of managed charging implementation and prevent future stranded assets.[70]

In late 2017, after significant discussion, messaging protocols recommendations were developed by a subcommittee of the California Vehicle Grid Integration Working Group as shown in Table 7. Not all communication protocols are, or can be, applicable across the full chain of assets needed for managed charging. For example, ISO/IEC 15118 is only applicable between the EV and the EVSE, whereas OpenADR 2.0 is applicable between the aggregator (referred to as the Power Flow Entity (PFE) in the CPUC VGI Working Group) and the EVSE. These protocols may need to be paired in order to achieve the desired outcome.

In its final report, the California Public Utilities Commission (CPUC) stated that "based on stakeholder feedback and guidance, [CPUC] staff have determined it is not advisable to require the investor-owned utilities to only use a single protocol, or specific combination of protocols, for their infrastructure investments at this time. However, [CPUC staff] does provide certain hardware performance recommendations intended to enable the market to trial and potentially converge on a protocol in the future."[71] The group provided some elaborate discussion on two standards in particular, ISO/IEC 15118 and IEEE 2030.5 (SEP 2.0). More detail about these and other relevant standards are included in Table 8.

TABLE 7: RECOMMENDED PROTOCOLS TO ENABLE VEHICLE GRID INTEGRATION

DOMAIN OF COMMUNICATION	RECOMMENDED PROTOCOLS CURRENTLY AVAILABLE
PFE to EVSE	One or a combination of the following: 1. OpenADR 2.0b 2. IEEE 2030.5 3. OCPP 1.6 4. IEC 63110
EVSE to EV	One or a combination of the following: 1. ISO/IEC 15118 v1 2. IEEE 2030.5
Vehicle OEM to EV	Telematics (using proprietary protocols or IEEE 2030.5)

Source: California Vehicle Grid Integration Communications Protocols Working Group, 2017, with edits by SEPA.[72]

ELECTRIFY AMERICA'S COMMITMENT TO MANAGED CHARGING STANDARDS

Electrify America is investing $2 billion over the next ten years in EV infrastructure across the country. According to Electrify America's Cycle II Plan released in February 2019, the company supports open protocols, including OCPP, "that allow more standardized communication between different chargers and networks. Electrify America will work to maintain OCPP 1.6+ compliance and other measures to help maximize interoperability."[73] The plan also notes that, "Electrify America's public stations will be equipped with back end systems that can use Open Charge Point Interface (OCPI) 2.1 to communicate with other networks and Open InterCharge Protocol (OICP) to be able to connect to roaming platforms, when a business agreement is secured, in a manner that does not require use of any particular firm's intellectual property."[74]

70 Note: We do not cover proprietary or API-based messaging protocols in detail in this report, though we do note when they are used in the vendor tables later in the report.

71 VGI Communication Protocol Working Group, Energy Division Staff Report, October 2018.

72 VGI Communications Protocols Working Group, December 15, 2017 Draft Recommendations, http://www.cpuc.ca.gov/vgi/ (final document was not available).

73 Electrify America, February 2019, *National ZEV Investment Plan: Cycle 2: Public Version*, https://www.electrifyamerica.com/news-updates.

74 Ibid.

TABLE 8: ECOSYSTEM OF MANAGED CHARGING STANDARDS	
STANDARD	**DESCRIPTION**
OPEN PROTOCOLS VIA CHARGING DEVICE AND/OR VEHICLE	
OSCP 1.0, OCPP 1.5, OCPP 1.6, OCPP 2.0	The Open Charge Point Protocol (OCPP) and the Open Smart Charging Protocol (OSCP) were developed by the members of the Open Charge Alliance and are an open protocol for communications between charging points and the EV charging network administrator. These protocols provide charging station owners the option of changing EV charging network administrators without stranding equipment assets. The OSCP acts between the charging station and the energy management system, can provide 24-hour prediction for local available capacity, and fits charging profiles to grid capacity. OCPP 1.6 includes smart charging support for load balancing. The most recent version, OCPP 2.0, includes support for ISO/IEC 15118 (among other things).[75] Although not yet formalized as a standard and managed by a recognized standards defining organization (SDO), there is significant adoption of the OCPP protocol and efforts are underway to develop it into a full standard within the IEC.
OpenADR 2.0	The Open Automated Demand Response (OpenADR 2.0b is the most updated version) standard is currently managed by the OpenADR Alliance, and provides an open and standardized way for Virtual Top Nodes (e.g., electricity providers and system operators) to communicate with various Virtual End Nodes (e.g., aggregators, EV charging network operators, etc.) using a common language over any existing IP-based communications network. Originally developed as a peak load management tool, it has since expanded to include other DERs. Messaging protocols such as OpenADR can also be used in combination with other protocols, such as those used to communicate between a charging station and a network operator (e.g., OCPP[76], IEEE 2030.5, etc.).
ISO/IEC 15118	ISO/IEC 15118 (also referred to as "OpenV2G"), enables the managed charging functionality in an EV, such as optimized load management.[77] More specifically, it specifies the communication between the EV and the EVSE and supports the EV authentication and authorization (also known as "Plug & Charge"), and metering and pricing messages.[78] Version 2 is currently under review with the final version anticipated by mid-2020 that will include V2G.
IEEE 2030.5/ SEP2.0	IEEE 2030.5 (formerly Smart Energy Profile 2.0 or SEP2.0), is an application layer protocol that defines messages between any client/server.[79] Pricing, demand response, and energy use are among the types of information that can be exchanged using the protocol and can integrate a wide variety of DER devices, including EVs and EVSE.[80]
IEC 63110	IEC 63110 is an international standard defining a protocol for the management of electric vehicle charging and discharging infrastructures. It is part of an IEC group of standards for electric road vehicles and electric industrial trucks, and is assigned to the Joint Working Group 11 of the IEC Technical Committee 69. At the date of publication it was still under development.[81]

75 See: Open Charge Alliance, https://www.openchargealliance.org/ (accessed April 2019).

76 OpenADR, 2016, Using OpenADR with OCPP: Combining these two open protocols can turn electric vehicles from threats to the electricity grid into demand-response assets, https://openadr.memberclicks.net/assets/using%20openadr%20with%20ocpp.pdf

77 See: Open V2G Project, http://openv2g.sourceforge.net or ISO, https://www.iso.org/standard/55365.html (accessed April 2019).

78 See: CPUC Vehicle Grid Integration Communications Protocol Working Group VGI Glossary of Terms, http://www.cpuc.ca.gov/vgi/.

79 See: CPUC Vehicle Grid Integration Communications Protocol Working Group VGI Glossary of Terms, http://www.cpuc.ca.gov/vgi/.

80 See: IEEE Smart Grid Resource Center, http://resourcecenter.smartgrid.ieee.org/sg/product/education/SGWEB0043 (accessed April 2019).

81 Wikipedia, IEC 63110, https://en.wikipedia.org/wiki/IEC_63110.

TABLE 8: ECOSYSTEM OF MANAGED CHARGING STANDARDS, CONTINUED	
STANDARD	**DESCRIPTION**
IEEE P2690	This standard defines communications between EV charging stations and a device, network, and services management system. "It defines patterns, messages and parameters for monitoring and controlling such functions as user/vehicle authentication and authorization; charging session state; energy and service pricing, delivery and metering; managed and "smart" charging; EVSE device health; system fault detection and diagnosis; environmental sensing (vehicle proximity, position, presence); user-oriented communication; and support for other "e-mobility" and value added services."[82] At the date of publication this standard was still under development
TELEMATICS	
Telematics	Vehicles can also be managed via a direct telematics link. Most vehicles sold today are considered "connected" vehicles and have built-in capabilities, such as GPS location software, which can be managed according to the local grid circuit. Many EVs also have the ability to program a charging window, allowing the vehicle driver to align charging with TOU or other EV rates. A more sophisticated way to leverage these vehicles would be for the utility or aggregator to send price, emissions, or grid stress signals directly to the vehicle to capture optimal value.
Open Vehicle-Grid Integration Platform	The Electric Power Research Institute (EPRI) is coordinating work on an Open Vehicle-Grid Integration Platform (OVGIP)[83]—a software application that connects EVSE and EVs to various nodes to allow utilities to more proactively manage charging activity that could help with a variety of grid services. Simply put, OVGIP enables streamlined integration of various EVs and EVSEs—regardless of types, specs, or manufacturer—as an energy resource capable of offering grid services. In this approach, the utility communicates with the OEM's data center via the OVGIP, which then uses the vehicle telematics to control charging in the vehicle. This approach allows the use of on-vehicle communications technologies (i.e., IEEE 2030.5, ISO/IEC 15118, and telematics) with utility standard interface protocols (i.e., OpenADR 2.0b, IEEE 2030.5) and EV charging station application program interfaces (i.e., ISO/IEC 15118, OCPP, and industry applied standard and proprietary APIs) through a common platform. This is discussed in more detail in the Automobile Original Equipment Manufacturer section of the report.

Source: Smart Electric Power Alliance, 2019

OTHER MANAGED CHARGING TECHNOLOGIES AND SOLUTIONS

Often the conversation around managed charging focuses around coordination directly with the EV charging station and the vehicle as the default grid resource, but there are a number of alternatives springing up in the industry marketplace. While they are not covered extensively as part of this report, we did want to highlight these emerging opportunities, re-emphasizing the breadth of use-cases and solutions associated with managed charging. These options could include in front-of-the meter solutions, behind-the-meter solutions, and behavioral solutions as shown in Table 9.

82 IEEE, P2690 - *Standard for Charging Network Management Protocol for Electric Vehicle Charging Systems*, https://standards.ieee.org/project/2690.html.

83 EPRI, *Open Vehicle-Grid Integration Platform: General Overview*, July 2016, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008705.

TABLE 9: OTHER MANAGED CHARGING TECHNOLOGIES AND SOLUTIONS	
FRONT-OF-THE-METER SOLUTIONS	
Distributed Energy Resource Management System (DERMS)	According to a 2019 SEPA report, "A DERMS is a hardware and software platform to monitor and control DERs in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system."[84] As it specifically relates to EV charging, DERMs can 1) aggregate integration with multiple EV charging network operators, 2) manage charging levels by coordinating EV charging settings through algorithms in conjunction with the utility's distribution management system (DMS) requirements, 3) provide operating information to the DMS, and 4) forecast EV charging load (among other things). A DERMS platform could allow the utility to access a large number of EV charging network operators while maintaining a single interface for all associated charging data and load control functionality. Further, since the DERMS platform would be aggregating multiple DERs, it could more nimbly coordinate electricity production (e.g., distributed solar) and consumption (e.g., EV charging load) among the aggregated technologies at a more granular level.
BEHIND-THE-METER SOLUTIONS	
On-Board Diagnostic Interface (OBD-II)	Devices plugged into an OBD-II port provide a post-production retrofit option to communicate with a vehicle and provide telematics information (e.g., vehicle battery state of charge, charging profiles) and relay charging signal commands (e.g., delay a charging event) via a third-party not associated with the automaker. An example of this technology was provided in the ConEdison case study.
Adaptive Load Management	Customers can manage the load of on-site charging to minimize their power bill or to limit interconnection upgrades. PowerFlex Systems, for example, has one such technology that "coordinates EV charging, building loads, solar generation, and battery storage which maximizes electrical infrastructure and minimizes peak demand charge."[85] By proactively accounting for the needs of all drivers—for example, in a workplace or multi-unit dwelling location—the system can figure out which drivers need what amount of charge and by when, and then distribute available energy based on that need.
Smart Circuit Breakers and Smart Panels	Another opportunity to manage EV charging could take place at the circuit breaker or the panel itself. At least two circuit breaker manufacturers, Eaton and ABB, have designed smart circuit breakers that could manage charging devices that are wired to those specific circuit breakers. Eaton's circuit breaker offers the user revenue-grade branch circuit metering, communications capabilities and remote access. Utilities can remotely cycle major loads like air conditioning to help offset peak usage energy demands. The circuit breaker's user interface would become a real-time dashboard allowing both the utilities and customer to better understand when and how they use electricity. In the future, the breaker could simplify charging and metering of EVs. Koben Systems has developed a smart panel, known as GENIUS, which is an alternative to standard breaker panels for residential, retail, and commercial applications. The panel provides additional intelligent monitoring and control of circuit activity, including real-time energy usage data and automation capabilities that could reduce EV charging costs.[86]

84 SEPA, February 2019, *DERMS Requirements*, https://sepapower.org/resource/distributed-energy-resource-management-system-derms-requirements/

85 PowerFlex Systems, 2017, *Introduction to Adaptive Load Balancing*, http://www.electricleague.net/uploads/resource-101.pdf.

86 ChargedEV, January/February 2019, "Koben System's Smart Breaker Panel and Battery Pack help to enable large infrastructure installations." Also, interview with Koben Systems CEO, Vic Burconak, February 2019.

TABLE 9: OTHER MANAGED CHARGING TECHNOLOGIES AND SOLUTIONS, CONTINUED	
BEHAVIORAL SOLUTIONS	
Behavioral Load Control	While much of this report focuses on direct load control options, much could be done through behavioral techniques. For example, sending email or text alerts to turn off charging during a peak event could reduce load impacts with nominal investment. Companies such as Bidgely have designed strategies to send targeted information to EV drivers, who are identified through load disaggregation at the meter that allows them to micro-target these customers with special rebates, offers, or enrollment in other demand response programs. Bidgely can also compare the charging habit efficiency of a driver with others in the same neighborhood and provide gamification opportunities to influence behavior through a system of “badges” or non-financial rewards.
EV-specific Time-Varying Rates	One form of behavior load control is through price signals. For example, EV drivers could manually select charging times that correspond to the cheapest hours of the day or automate charging times during optimal cost windows. For example, SDG&E offers this service through the Power Your Drive program and has a phone app that provides customers with day-ahead, hourly price varying rate for each publicly-accessible or workplace charging stations within the network.
Load Management via Distributed Ledgers	Some companies, such as ChargingLedger, have created distributed ledgers, in this case a blockchain-based solution, for energy companies to handle financial transactions, including the award of incentives. The idea is to shift charging load directly through the ChargingLedger software and then award incentives through a blockchain transaction or the user’s billing method. The blockchain also allows users to define their own preferences, including charging override for demand response events and optimization of self-supply vs. utility-supply power.

Source: Smart Electric Power Alliance, 2019.

NEED FOR HARMONIZATION OF MANAGED CHARGING TECHNOLOGIES

The diversity of standards and associated applications illustrates the need for industry groups to coalesce around a common subset of options that simplify procurement, implementation, and testing. The harmonization process requires the development of a common set of requirements that document key points of interoperability and associated interfaces, creating flexibility by enabling interchangeability between different standards with overlapping functionality and mitigating the risk of interoperability failures.

There is ongoing work at SEPA to develop Interoperability Profiles to address this need. Interoperability profiles are being developed to capture common standards-based requirements agreed upon by a user community, testing authorities, and standards bodies. Interoperability Profiles would not replace or be considered as standards, but would instead serve to clarify common baseline requirements as determined by the industry. An Interoperability Profile based on EV managed charging would define physical performance specifications, communication protocols, and information models needed to for the likely application environment. This profile would enable a simpler procurement process backed by well-defined conformance testing giving all stakeholders greater confidence in asset functionality.

V. Managed Charging Technology and Vendors

Since *Utilities & Electric Vehicles: The Case for Managed Charging* was published in 2017 there has been significant growth in the total number of utility-run managed charging pilots (see Appendix A for details) and the amount of managed charging-capable hardware and software.

The following sections provide more detail about the growth of the industry and the convergence around certain managed charging standards and protocols by Network Service Providers, EVSE manufacturers, and automotive manufacturers.

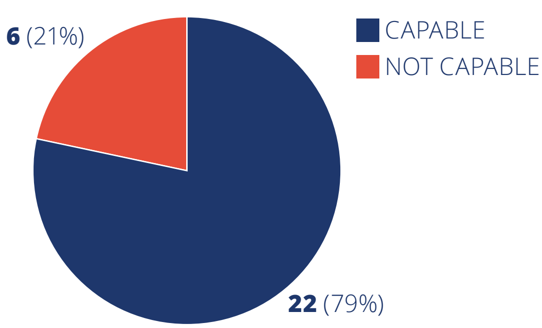
NETWORK SERVICE PROVIDERS

Network Service Providers (NSPs) are the cloud based technology platforms (i.e., the software) that provide the interface between charging stations, their operators, and the EV drivers.

For the EV driver, NSPs provide mobile applications that provide drivers a map of existing nearby charging stations, various information about those stations (e.g., price to use, current status, pictures, directions, user feedback, etc.), and a method to initiate and pay fees to use the station.

For station operators, the NSP provides web-based portals that allow station owners the ability to access and analyze charging data, set access controls and driver pricing, conduct load management, and other features to optimize utilization of the station. Typically, these platforms have the ability to provide charging data and load control capabilities to utilities as well—with the consent of the station owner—allowing utilities access to more chargers regardless of who owns or operates the stations.

FIGURE 13: PERCENTAGE OF NETWORK SERVICE PROVIDERS WITH MANAGED CHARGING CAPABILITIES, U.S., 2019



Source: Smart Electric Power Alliance, 2019.

Given the existence of multiple NSPs in the market today, utilities can be challenged in interfacing with the various networks. Various solutions exist to help facilitate this challenge in the form of application programming interfaces (APIs) and Distributed Energy Resource Management Systems (DERMS). APIs and open standards, such as OpenADR, allow utilities to integrate these networks into their IT systems automatic and standardized calls to NSPs to obtain EV charging data and/or conduct load management events. Associated charging data can be brought back into internal utility servers for further analysis, and dashboards can be created to provide a unified view for the utility. Alternatively, utilities are also evaluating tools, such as DERMS, to provide a unified portfolio that incorporates a variety of distributed energy resource assets, such a solar, energy storage, smart thermostats, and more.

While some NSPs support an open protocol, such as OpenADR, from cloud to cloud, some may use a proprietary protocol between the cloud and the EVSE, creating vendor lock-in, which prevents the utility from changing NSPs (i.e., no other provider can communicate with the EVSE that use the proprietary protocol) and being unable to add EVSE from different vendors over time. Utilities should consider this issue when making decisions to acquire, or provide funding for, both EVSE and NSPs. Open standards and protocols solve the complexity associated with managing charging activity across different EVSE manufacturers, station types (e.g., L2 and DCFC), vehicle makes and models, utility service territories, and utility energy management systems.

Since 2017, the number of NSPs in the U.S. with managed charging capabilities increased from 7 to 22[87]—more than a three-fold increase—in the span of two years. This

87 Note: Vendors were compiled by SEPA using resources including but not limited to https://www.goelectricdrive.org/, CISION (https://www.prnewswire.com/news-releases/electric-vehicle-supply-equipment-evse-market-report-2018-2028---visiongain-report-683333781.html), Wood Mackenzie, Navigant, and other online sources.

represents a sign of market growth. As shown in Figure 13, nearly 80% of the total identified NSPs have managed charging capabilities with the vast majority of those NSPs using open standards and protocols as shown in Table 10.

There also appears to be some alignment around messaging protocols—primarily OCPP (including OSCP) representing at least 63% of the total platforms. At least 50% of those NSPs also use OpenADR. ISO/IEC 15118 is also gaining traction and is found in at least 45% of the NSPs.[88] It is important to note that this is not an apples to apples comparison as many of these protocols may be layered together in an EV to EVSE to aggregator to utility ecosystem. A list of known NSPs with managed charging capabilities is available in Appendix B.

TABLE 10: NUMBER OF MANAGED CHARGING-CAPABLE NETWORK SERVICE PROVIDERS BY MESSAGING PROTOCOL TYPE, U.S., 2019

OSCP/ OCPP	OPENADR 2.0	ISO/IEC 15118	API	IEEE 2030.5
14	11	10	6	2

Source: Smart Electric Power Alliance, 2019. Note: Many Network Service Providers use more than one messaging protocol.

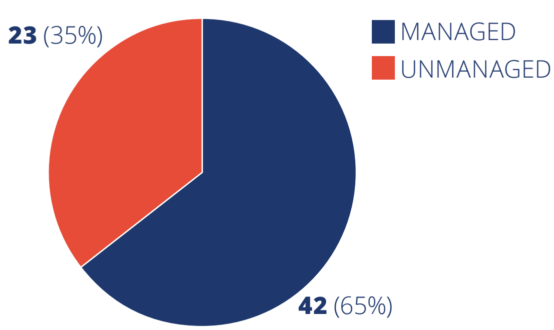
ELECTRIC VEHICLE SUPPLY EQUIPMENT MANUFACTURERS

EVSE manufacturers have been active over the last two years as they work to enhance their product offerings (i.e., the hardware). As shown in Figure 14, of the 65 identified EVSE manufacturers with products available in the U.S.,[89] 42 have at least one managed charging-capable product—a little under two-thirds (65%) of the total. This is up from one-third of the manufacturers just two years ago and shows a positive sign of progress. Also, the majority of those manufacturers are using open standards and protocols as shown in Table 11.

Of the managed charging-capable EVSE identified in the survey (a total of 99),[90] the majority were L2 chargers (63%), followed by DCFC for light-duty vehicles (24%). A much smaller percentage was available for L1 and DCFCs for medium- and heavy-duty applications (primarily for bus charging) as shown in Figure 15.

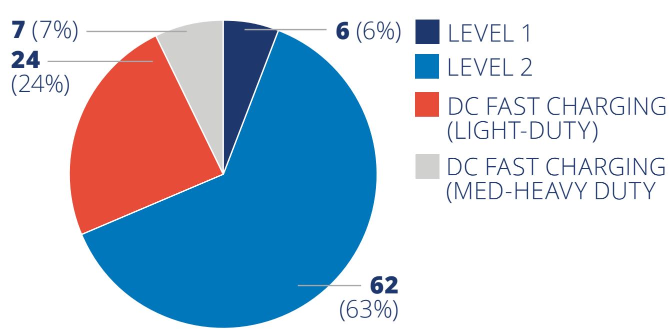
In the first version of the report, there was little uniformity among manufacturers for messaging protocols, representing an interoperability challenge to utilities. The industry appears to be coalescing around OCPP (including OSCP) with at least 66% (29) of managed charging-capable EVSE manufacturers integrating it. Of those 29 vendors, 8 paired the equipment with OpenADR 2.0 as well. The second most common standard is ISO/IEC 15118 reflecting

FIGURE 14: PERCENTAGE OF EVSE MANUFACTURERS WITH MANAGED CHARGING CAPABILITIES, U.S., 2019



Source: Smart Electric Power Alliance, 2019.

FIGURE 15: NUMBER OF MANAGED CHARGING-CAPABLE EVSE BY LEVEL, U.S., 2019



Source: Smart Electric Power Alliance, 2019. Note: Some manufacturers offer multiple configurations of chargers in a series type. Only one base configuration in a series was included in the tally.

88 Note: At the time of publication, SEPA was unable to identify the messaging protocols of certain vendors.

89 Note: Vendors were compiled by SEPA using resources including but not limited to https://www.goelectricdrive.org/, CISION (https://www.prnewswire.com/news-releases/electric-vehicle-supply-equipment-evse-market-report-2018-2028---visiongain-report-683333781.html), Wood Mackenzie, Navigant, and other online sources.

90 Note: Some manufacturers offer multiple configurations of chargers in a series type. Only one base configuration was included in the tally.

a similar trend with the NSPs. Again, as noted earlier, this is not an apples to apples comparison as many of these protocols may be layered together in an EV to EVSE to aggregator to utility ecosystem. A list of known managed charging-capable EVSE manufacturers and equipment at the time of publication can be found in Appendix C.

TABLE 11: NUMBER OF MANAGED CHARGING-CAPABLE EVSE MANUFACTURERS BY MESSAGING PROTOCOL TYPE, 2019

OSCP/ OCPP	OPENADR	ISO/IEC 15118	IEEE 2030.5	API	PROPRIETARY
29	8	8	4	2	7

Source: Smart Electric Power Alliance, 2019. Note: Many EVSE include more than one messaging protocol.

AUTOMOTIVE ORIGINAL EQUIPMENT MANUFACTURERS (OEMs)

OEMs are also entering the managed charging space primarily through existing vehicle telematics, such as GM's OnStar, and in partnership with utilities, such as BMW's i ChargeForward program with PG&E (referenced in an earlier case study). Other OEMs have also integrated open standards and protocols into their vehicle platforms, such as IEEE 2030.5 and ISO/IEC 15118. Table 12 includes a list of automakers short- to medium-term planning targets.

There are a number of other demonstration projects that have shown how a utility can send charging signals to a vehicle as provided in Appendix A. For example, PG&E partnered with American Honda Motor Company and IBM in 2012 to test the ability to delay or adjust vehicle charging based on grid conditions (particularly peak hours) and the vehicle's state of charge.[91] The demonstration project showcased how individualized charging plans

TABLE 12: PROTOCOLS INCLUDED IN AUTOMAKERS' 10-YEAR TIME HORIZON, 2017

AUTOMAKER	AC CONDUCTIVE	DC CONDUCTIVE	WIRELESS INDUCTIVE
BMW	ISO 15118 (HomePlug Green PHY)	ISO 15118 (HomePlug Green PHY)	ISO 15118
Fiat Chrysler	IEEE 2030.5	ISO 15118 (HomePlug Green PHY)	WiFi, ISO 15118 v2
Ford	Telematics & ISO 15118 (future)	ISO 15118 (HomePlug Green PHY)	ISO 15118 v2
GM	No High Level Communication	DIN Spec, no timeframe for ISO/IEC	WiFi and Telematics
Honda	TBD High Level Communication, Vehicle to Grid	DIN Spec / ISO 15118, Vehicle to Grid	Premium product
Lucid	ISO 15118 (HomePlug Green PHY)	ISO 15118 (HomePlug Green PHY)	
Mercedes Benz	ISO 15118 (HomePlug Green PHY)	ISO 15118 (HomePlug Green PHY)	J2954 / ISO 15118
Nissan	Telematics	CHAdeMO	In development
Porsce/Audi/ Volkswagen	ISO 15118 (HomePlug Green PHY)	ISO 15118 (HomePlug Green PHY)	ISO 15118 (In development—2018)

Source: Vehicle-Grid Integration Communications Protocol Working Group, Final Staff Report, 2017.[92]

91 IBM, 2012, "IBM, Honda, and PG&E Enable Smarter Charging for Electric Vehicles," http://www-03.ibm.com/press/us/en/pressrelease/37398.wss.

92 VGI Communication Protocol Working Group, Energy Division Staff Report, October 2018. "[The table] reflects product plans presented by industry stakeholders during their participation in the working group as of 2017. These business plans represent are reflective of or may change due to market factors including the costs of alternatives, consumer demand, and functionality."

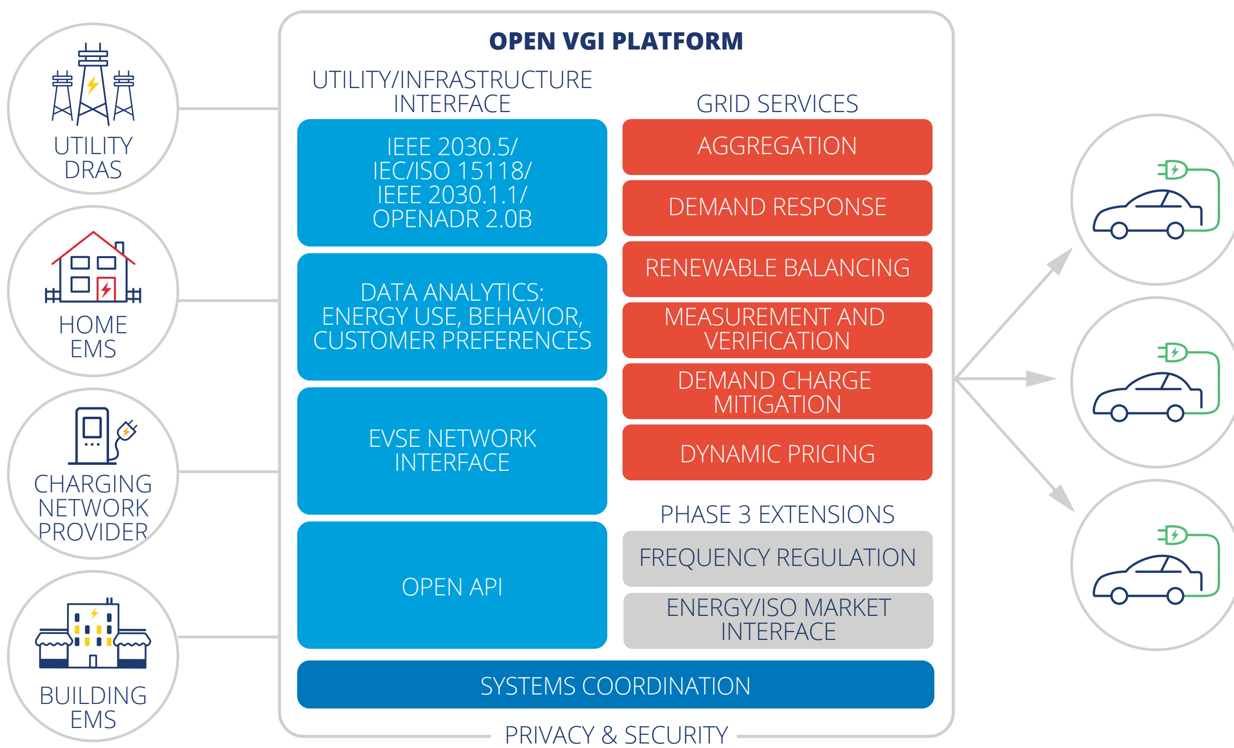
could be developed for Honda's Fit EVs using IBM's cloud based software platform via the vehicle on-board telematics system.

A potential challenge with OEM-provided integrated telematics-based managed charging is cost to the utility or EV owner of the monthly subscription charges paid to the vehicle OEM. If the costs to support the monthly communications or telematics link are too high, the utility business case can be more difficult to justify.

OPEN VEHICLE-GRID INTEGRATION PLATFORM (OVGIP)

The Electric Power Research Institute (EPRI) is coordinating work on an Open Vehicle-Grid Integration Platform (OVGIP)[93]—a software application that connects EVSE and EVs to various nodes to allow utilities to more proactively manage charging activity that could help with a variety of grid services as shown in Figure 16 below. In this approach, the utility communicates with the OEM's data center via the OVGIP, which then uses the vehicle telematics to control charging in the vehicle. This approach allows the use of existing on-vehicle communications protocols (i.e., IEEE 2030.5, ISO/IEC 15118, and telematics) with utility standard interface protocols (i.e., OpenADR 2.0b, IEEE 2030.5) and EV charging device application program interfaces (i.e., ISO/IEC 15118, OCPP, and industry applied standard and proprietary APIs) through a common platform. These will ultimately allow utilities to provide: "time-of-use (TOU) pricing, peak load reduction, demand charge mitigation, load balancing for intermittent solar/wind generation, Real Time Pricing (RTP), aggregated Demand Response (DR), and scheduling dispatch for ancillary services,"[94] to EVSE or EVs across manufacturers. Utilities are currently testing the capabilities of OVGIP, including DTE Energy, referenced in Appendix A.

FIGURE 16: OPEN VEHICLE-GRID INTEGRATION PLATFORM SCOPE



Source: Electric Power Research Institute, 2016

93 EPRI, *Open Vehicle-Grid Integration Platform: General Overview*, July 2016, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008705

94 Ibid.

VI. Conclusion

As more EVs hit the road in the coming years, widespread grid and business impacts will affect multiple levels of utility operations, from planning to operations and from transmission to distribution. Utilities are uniquely positioned to take proactive steps now before EV adoption rates accelerate, laying the groundwork to develop plans and programs to optimize policies, regulations, and open standards and protocols for the future so that EVs can be valuable grid assets.

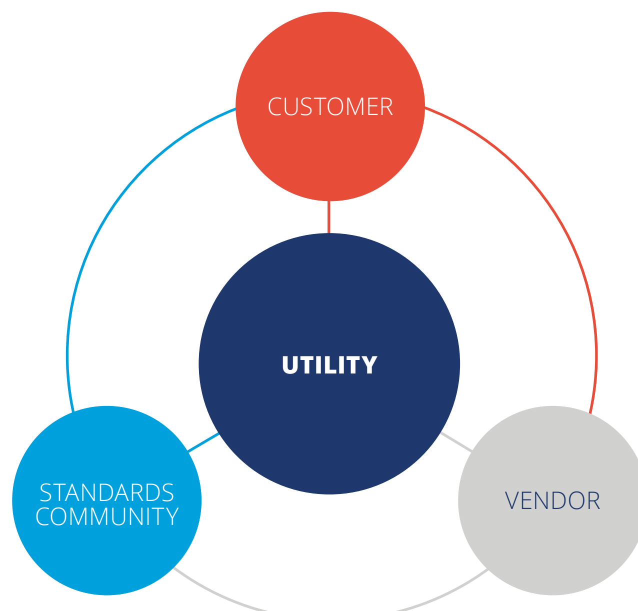
THE ROLE OF THE UTILITY

Many EVSE and automotive OEMs have already begun to integrate managed charging capabilities into their products to better meet the needs of third-parties, including utilities, for control and management of vehicle charging events. Open communications protocols, cost-effectiveness, reliability, and customer satisfaction are key variables of managed charging success. Utilities have an important role in the outcome of these variables by:

- providing thought leadership on managed charging use-cases, including needs, applications, proper valuation, testing, and validation
- influencing advantageous charging habits through managed charging program design options, both active and passive
- participating in the managed charging communication standards development process
- collaborating with industry to adopt standards and best practices
- engaging vendors to share utility needs and learnings from other comparable DER efforts
- providing a test bed or pilot effort for new solutions
- developing solutions to integrate EV charging into demand response systems
- providing EV education and awareness to their consumers
- continuing to evolve rate structures matched with active load management strategies to incentivize charging during grid friendly periods, including periods of high or excess renewable generation
- encouraging greater deployment of managed charging-capable infrastructure among customers

The nature of managed charging allows utilities to more proactively engage their customers, the vendors, and the standards community to derive grid benefits that help society at large, and move towards a smarter, nimbler grid of the future. As shown in Figure 17 below, utilities can play a central role in steering a path that will balance the needs and expectations of customers, communicate customer and grid requirements to vendors, and relay the most cost-effective and efficient strategies for open messaging protocols to the standards community.

FIGURE 17: UTILITY ROLE IN MANAGED CHARGING



Source: Smart Electric Power Alliance, 2019

NEXT STEPS FOR UTILITIES:

- Quantify the value (both benefits and costs) of managed charging to enhance the business case and provide greater visibility of the need in certain regions.
- Define the business model for managed charging—including the costs and payback for both the utility and the EV driver—and establish industry standards to reduce costs, barriers, and complexity.
- Work with the EV industry to develop industry-wide standards for the entire "ecosystem" of information exchange and communication.
- Understand what types of incentives and management strategies will shift load effectively, while maintaining a satisfactory user experience for drivers.
- Identify least-cost and reliable communication solutions.
- Develop a managed charging program that offers consumers maximum flexibility—including opt-out and override capabilities and financial benefits, to increase customer participation.
- Gain visibility into where EV resources are located on the distribution system, and define the cost-benefit of avoided distribution upgrades, which can vary significantly from one circuit to the next.
- Proactively engage customers and provide information on managed charging-capable charging EVSE and NSPs.
- Understand how utility-run managed charging fits into, and can leverage, the broader networked charging industry.

FUTURE EFFORTS FROM SEPA'S TESTING AND CERTIFICATION WORKING GROUP

DEVELOPING EV EQUIPMENT INTEROPERABILITY PROFILES BACKED BY CONFORMANCE TESTING

New devices must be able to integrate with the current grid - correctly the first time - to avoid risks in safety and reliability, prevent costly field repairs, and contribute to resilience. To address this challenge, the Testing and Certification Working Group (TCWG) at SEPA, in conjunction with the National Institute of Standards and Technology (NIST) and other stakeholders, has launched an initiative to support interoperability conformance testing for grid devices, including EVSE. This effort includes the development of:

1. **Interoperability Profiles** to document the requirements and boundaries for applications or use cases (such as functionality, performance and operational limits, communication requirements, relevant standards, etc). The TCWG is examining EVSE as a potential candidate as well as other critical components as determined by the electric sector and is seeking input and collaborations to develop Interoperability Profiles for EVSE.
2. **Open-source requirements for testing** based on the Interoperability Profiles to stimulate consistent testing standards among third-party testing organizations.
3. **Model Procurement Language** that will enable buyers and developers to incorporate consistent interoperability requirements as part of the part of the product development and procurement process.

Industry feedback is critical to the success of all three efforts. To learn more about these activities or to participate, contact research@sepapower.org.

Appendix A: Utility-Run Managed Charging Programs by Program Type, 2012-2019

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019

UTILITY NAME, STATE	PROGRAM NAME	PROJECT PARTNERS	PROJECT STAGE*	SHORT DESCRIPTION
PROGRAM TYPE: DIRECT LOAD CONTROL VIA CHARGER				
American Electric Power (AEP), Ohio	AEP Ohio EV Charging Incentive Program		Active	In April 2018, the Public Utilities Commission of Ohio approved a $10 million rebate program to support the installation of 375 charging stations in AEP Ohio service territory. The incentive program allows commercial site hosts to select pre-approved hardware and networks that are managed-charging capable. Rebates are available to government and non-government owned properties, workplace charging, multi-housing unit buildings and low-income neighborhoods. Rebates apply toward the chargers and make-ready infrastructure, with amounts varying based on the types of station, the type of owner, and the public's ability to access the station.
American Electric Power (AEP), Kyte Works	Kyte Works EV Home Charging Program	eMotorWerks and Kyte Works LLC	Active	Kyte Works LLC, a subsidiary of AEP, for a monthly fee of $39.99 offers the equipment and installation of an eMotorWerks JuiceBox Pro 40 L2 EVSE. Participants can choose to enroll in one of two programs, 1) "Third Shift Pricing" which will shift charging to 8pm-6am on weekdays in return for a $5 monthly credit with up to 5 "opt-out" events each month or 2) "Rush Hour Rates" which will automatically reduce the rate of charge between 4pm-7pm on weekdays in exchange for a $3 monthly credit with the option to "opt-out" up to 2 times each month. AEP will also alert customers to high-load events and in exchange for turning off the charger will provide $5 per event.
Avista Utilities, Oregon/ Washington	EVSE Pilot Program	Multiple vendors	Active	Avista designed the pilot to own, maintain, and install EVSE on a residential or commercial customer premises and rate-based those assets. To participate in the project, the customers allowed Avista to collect charging data and perform demand response (DR) experiments. The customers had the option to be notified about upcoming DR events the day before and to opt-out of that event. The project was able to curtail load up to 75% with about a 10% opt-out rate overall for the program for residential sessions.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED				
UTILITY NAME, STATE	**PROGRAM NAME**	**PROJECT PARTNERS**	**PROJECT STAGE***	**SHORT DESCRIPTION**
Baltimore Gas & Electric (BGE)			Planning	BGE will provide customers with rebates for managed charging-capable chargers. Along with the program, BGE will develop an EV TOU rate for residential rebate customers, enabled by using load data from the smart chargers rather than a separate EV-only meter. BGE will provide performance updates of the program.
Green Mountain Power (GMP), Vermont	eCharger	ChargePoint, FLO	Active	GMP provides a free at-home Level 2 charger to new EV customers. These chargers collectively represent one of the largest residential managed charging programs in the country with 300 customers enrolled in the program as of February 2019.
Hawaiian Electric Company (HECO), Hawaii	Electrification of Transportation: Strategic Roadmap		Active	HECO's strategic roadmap for EVs, includes much work focused on "smart" or managed charging, including for workplace, multi-unit dwellings, and electric buses. Specifically related to e-buses, they plan to offer a bus battery service agreement to partially offset the cost premium over diesel buses. The program will include a pilot demand response program, and explorer V2G, as well as second-life battery use for stationary storage.
Los Angeles Department of Water and Power (LADWP), California	Charge Up L.A.!	Multiple vendors	Active	The program offers up to $5,000 for commercial chargers with an extra $750 for each additional port for workplace, multi-unit dwelling, and parking lots. As a condition of the rebate program, receipts must agree to participate in LADWP's DR program for the life of the installation. Further, LADWP can disconnect the load from the EV charger for the duration of the event without notice.
Marin Clean Energy (MCE), California	Smart EV Charging Pilot	eMotorWerks	Completed	Via a public-private partnership pilot, MCE and eMotorWerks provided a $150 discount on new smart-grid enabled EV charging stations. Customers with existing EVSE were eligible for a free adapter that would upgrade their EVSE to be controlled via a smartphone app.
Marin Clean Energy (MCE), California	MCE Workplace and Multifamily Property Charging Station Program	Pacific Gas & Electric and multiple vendors	Active	The rebate program provides rebates from $1,610-$2,500 per port for the hardware and installation costs for workplaces and multifamily properties (including market rate and low income) within MCE's service area. Rebates are only eligible for MCE approved EVSE vendors which include networked and managed-charging capable equipment. Further, MCE provides 50% or 100% renewable energy for the charging infrastructure.
Massachusetts Municipal Wholesale Electric Company	Scheduled Charging Program	Multiple utilities, including Sterling Municipal Light Department (Sterling), ChargePoint	Active	This program provides customers with a $300 rebate for a ChargePoint L2 charger. As part of the rebate, customers are automatically enrolled in scheduled charging program that aligns with the utility's (e.g., Sterling) TOU rate. It also requires the customer to enroll in an emergency scheduling program to reduce energy consumption during peak hours.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED				
UTILITY NAME, STATE	**PROGRAM NAME**	**PROJECT PARTNERS**	**PROJECT STAGE***	**SHORT DESCRIPTION**
Maui Electric Company, Hawaii	OATI Electric Vehicle DR Aggregation	Open Access Technology International, Inc. (OATI)	Completed	OATI enrolled 40 customers who own Nissan Leafs in a pilot program to provide grid services through OATI's Level 2 chargers. This program involved installing devices to allow communication with customer devices and to collect data on their usage. Maui Electric used a PJM performance scoring methodology to evaluate the pilot and it rated highly. Participants were satisfied overall with the project, but customers' vehicles were only available to respond less than half the time.
Maui Electric Company, Hawaii	JUMPSmartMaui	Nissan, Hitachi, EPRI, Hawaiian Electric Company	Completed	While this project included V2G objectives, much of the project included R&D related directly to managed charging. Phase I of JUMPSmart Maui demonstrated that the fundamental goals of managed charging can be achieved, though more work is needed. For example, despite shifting charging to off-peak, it still didn't match high wind production in the middle of the night and it was difficult to recruit participants. In Phase II of JUMPSmart Maui, several key priorities, including aligning charging with renewable energy generation and coordinating EVs with other DERs to create virtual power plants, were accomplished.
National Grid, Massachusetts	EV Market Development Program	Multiple vendors	Active	National Grid is preparing for future integration of EVs into its electric distribution system by implementing a research plan "that will use detailed utilization and transaction data from participating charging site hosts to evaluate the electric system impacts of charging stations." These charging stations—approximately 700 Level 2 and 80 DCFC stations—are being installed through National Grid's Electric Vehicle Market Development Program that funds the installation of the electrical infrastructure to the station stub and rebates toward the stations ("make ready"). The research plan will consider potential demand response approaches that "could be conducted via charging stations or via direct communication to vehicles, and will evaluate other technology integration approaches for high-capacity Direct Current Fast Charging stations," according to the application.
New York Power Authority (NYPA), New York	Charge New York Initiative	EV Connect	Completed	EV Connect provided 100 EV charging stations in 37 locations for NYPA that will use EV Connect's open charging network and provide NYPA and its customers with real-time charge station monitoring, electricity usage, payment processing, reporting, and demand response capabilities.
New York Power Authority (NYPA), New York	Charging Program		Active	This $40 million initiative will install 200 DCFC stations by the end of 2019 across the state at key interstate corridors and urban hubs, including New York City airports, and developing EV-friendly model communities where utilities manage EV charging infrastructure. The initiative is part of a larger $250 million proposed investment.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED

UTILITY NAME, STATE	PROGRAM NAME	PROJECT PARTNERS	PROJECT STAGE*	SHORT DESCRIPTION
Pacific Gas & Electric (PG&E), California	EV Charge Network-Load Management Plan		Active	PG&E is in the process of implementing a three-year $130 million program to install 7,500 Level 2 electric vehicle (EV) chargers at multi-unit dwelling and workplaces. The chargers will be installed throughout PG&E's service territory between 2018 and 2020. EV Charge Network program participants who choose to implement their own pricing (Custom Pricing), such as free charging or a flat fee, must participate in the EV Charge Network Load Management Plan. The Load Management Plan utilizes a PG&E Demand Response (DR) pilot program, and as a part of this program participants will be asked to shift the amount of EV charging at their site on certain occasions (called "events") to support the grid.
Pacific Gas & Electric (PG&E), California	Electric School Bus Renewables Integration		Active	The $2.2 million project will explore opportunities for managed charging in the medium and heavy-duty vehicle sectors, specifically focused on school buses, by testing the value of incentives provided to school bus fleet operators in exchange for shifting the time of vehicle charging. It will test managed charging strategies with a goal to minimize costs and emissions by optimizing charging for both local and grid-side renewable generation. The project will produce data on duty cycles, charging needs, electric school bus procurement, ownership and maintenance, and best practices for charge management and facility-wide local renewables integration for EV charging.
Pacific Power, Oregon	Electric Vehicle Charging Station Grant Program		Active	As part of the funding criteria for this infrastructure grant program, Pacific Power provides additional scoring points if the project can be integrated into a future DR and VGI networked program.
Pepco Holdings Inc. (Pepco), Maryland	Demand Management Pilot Program for Plug-In Vehicle Charging	EPRI, Itron, ClipperCreek	Completed	Pepco's pilot program reduced chargers from a Level 2 to a Level 1 rate of charge for an hour during a DR event and provided opt-out capabilities for customers. When assessing the economics of the pilot, Pepco found that the ongoing costs of the communications link were too expensive. Identifying a cheaper solution would increase the viability of future projects.
Platte River Power Authority, Colorado	Smart Electric Vehicle Charging Study	eMotorWerks	Active	EV drivers in Northern Colorado can receive a $200 instant rebate on a JuiceBox smart charging station (250 target) that is managed-charging capable. Customers can program the charger for time-of-day rates and will be enrolled in a demand response program.
Portland General Electric (PGE), Oregon	Employee Research Pilot		Completed	20 employees in the pilot were using a DR-enabled home charger to evaluate feasibility, customer experience, and potential curtailment opportunities. Enrollment launched in January 2016 and data collection will go through 2019.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED

UTILITY NAME, STATE	PROGRAM NAME	PROJECT PARTNERS	PROJECT STAGE*	SHORT DESCRIPTION
Portland General Electric (PGE), Oregon	PGE Workplace Smart Charging Pilot		Active	As of 2017, PGE installed 69 workplace charging spots among 18 locations and 20 chargers are DR-enabled.
San Diego Gas & Electric (SDG&E), California	Power Your Drive	ChargePoint, Greenlots, and Siemens	Active	As part of a large demonstration project, Power Your Drive will install over 3,000 charging stations at multi-unit dwellings and workplace locations. SDG&E operates and maintains chargers that are managed charging capable. Participants pay a one-time participation fee and SDG&E covers the cost of planning, permitting, and installation.
Sonoma Clean Power, California	Drive EV + Grid Savvy	eMotorWerks	Active	In exchange for a $5 monthly bill credit, choice of three subsidized EVSE, and an EVSE activation rebate, customers are enrolled in Sonoma's "GridSavvy" demand response (DR) program. The JuiceNet-enabled EVSE can be scheduled to charge during off-peak TOU hours as well as participate in DR events. The customer always has the ability to override DR events via the JuiceNet app and dashboard.
Southern California Edison (SCE), California	Charge Ready Pilot Program	EV Connect	Completed	As part of the Charge Ready pilot program, EV Connect and site host partners deployed nearly 400 networked stations in MUDs, workplace, and public locations. One goal of the pilot was to demonstrate DR capabilities by reducing the rate of charge by 50%. This was successfully demonstrated using two methods: 1) stations with throttling capabilities were reduced to half charging rates and 2) stations without adjustable charging speeds used a duty-cycling technique, which stopped charging in 15 minute increments for half of the locations' chargers.
Southern California Edison (SCE), California	Charge Ready Program	Multiple vendors	Active	As part of the full-scale program, SCE provides L1 and L2 charging equipment from approved vendors that can provide DR services for workplace, fleet, multi-unit dwellings, and destination centers (e.g., hotels, sports venues). The program covers all electric infrastructure costs and a rebate to offset some or all of the equipment and installation. To participate in the program, customers must agree to participate in DR events.
Tennessee Valley Authority (TVA), Tennessee	Medium Duty PEV and Charging Infrastructure	EPRI, US Department of Energy	Completed	TVA purchased light- and medium-duty equipment for its own fleet and then used managed-charging capable equipment.
Xcel Energy, Colorado	Electric Vehicle Charging Station Pilot		Completed	In exchange for a credit, customers participated in this 2014 EV charging pilot that allowed Xcel Energy to interrupt their vehicle charging for a limited number of hours throughout the year.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED				
UTILITY NAME, STATE	**PROGRAM NAME**	**PROJECT PARTNERS**	**PROJECT STAGE***	**SHORT DESCRIPTION**
Xcel Energy, Minnesota	EV Service Pilot	ChargePoint, eMotorWerks	Active	Xcel Minnesota's managed charging pilot project is available for 100 residential customers. Xcel provides turn-key EVSE, installation, and operation and maintenance for a single monthly fee, paying for the charger up front or monthly. Load monitoring and data management are included in the service package and participants are automatically enrolled in the EV electric pricing plan, which uses the charger for billing purposes. Customers can choose between an eMotorWerks JuiceBox Pro 40 or a ChargePoint Home Level 2 residential charger and data is collected through the customer's Wi-Fi.
DIRECT LOAD CONTROL VIA AUTOMAKER TELEMATICS				
Consumers Energy, Michigan	Consumers Energy Smart Charging Program	General Motors	Active	As part of this program, Consumers Energy and General Motors will test new technology to delay charging to start until overnight hours.
DTE Energy, Michigan	OVGIP PEV DR Pilot	EPRI	Active	DTE Energy will be working with automakers to test the capabilities of EPRI's OVGIP program with their DR and DSM programs. Including potential energy reduction (kW); Testing results from different time of events (11 am—3 pm event, and 3 pm -7 pm events); PEV user behavior in response to different incentives; Override (Opt in / Opt out) approach by PEV user; and Deliverability of event (ensure communication signals functioned properly) The pilot program started in 2018, and is expected to extend through June 2021. The target of PEV users enrolled in the program is capped at 1,000 participants. Based on the verified benefits (i.e., peak load reduction), the Company will evaluate if an expansion to a fully developed program with significantly more customer engagement makes sense from a DR perspective.
Pacific Gas & Electric (PG&E), California*	Cloud-based PEV Communication Pilot	Honda, IBM	Completed	Between 2012 and 2013 this pilot project experimented with "cloud-to-cloud" interaction between a utility and an aggregator for managed charging.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED

UTILITY NAME, STATE	PROGRAM NAME	PROJECT PARTNERS	PROJECT STAGE*	SHORT DESCRIPTION
Pacific Gas & Electric (PG&E), California	BMW i ChargeForward	BMW	Active	In the first phase of the pilot, partners focused on three goals: (1) test aggregation via an automaker coordinating grid-services; (2) test technical feasibility and performance of EV charging curtailment plus second-life EV batteries for grid services; (3) test customer willingness to participate in EV load management. BMW enrolled 96 i3 drivers and utilized proprietary aggregation software to delay charging via cellular (GSM-based) telematics. While the program was designed to minimize customer mobility interruptions, it also provided customers with an opt-out feature. Results from the first phase showed that the vehicle pool contributed 20% of the target kW reduction on average. Also, more than 90% of surveyed participants were satisfied and indicated that they were likely to recommend the program to friends and family. In the second phase, the program pilot expanded participating vehicles to more than 350 and focused on the customer experience. The pilot aimed to test EV charging optimization, based on: (1) maximizing renewable energy intake while managing customer bill; (2) accounting for both residential and away-from-home charging; (3) Offering load-curtailment and load- increase grid services. The pilot will continue into through 2019 and final results will be published later in 2019.
Southern California Edison (SCE), California	Honda SmartCharge™	Honda, eMotorWerks	Active	Honda Fit owners in SCE service territory are eligible for bonus' for participating in DR events coordinated through eMotorWerks' JuiceNet software platform and relayed via Honda's onboard vehicle telematics. eMotorWerks coordinates the DR events based on CAISO signals. The HondaLink EV App considers real-time electricity grid conditions to reduce costs to the customer, while also considering the customers charging preferences.
BEHAVIORAL LOAD CONTROL				
Austin Energy, Texas	EV360 Time-of-Use Rate Pilot Program	Austin Energy's GreenChoice Program	Active	EV360 is a fixed, time-of-use rate that includes unlimited charging at any public Plug-In Everywhere™ station and unlimited off-peak charging at home for $30 a month. Off-peak hours are from 7:00 pm - 2:00 pm on weekdays, and anytime on weekends. Eligible residential customers install a separate residential meter circuit attached to an L2 charger.
Consolidated Edison (ConEdison), New York	SmartCharge New York	FleetCarma, ChargePoint	Active	Using gamification, this program incentives customers to reduce charging during on-peak periods of time. Customers are financially rewarded—up to $500 a year—for participating in the program.

*Project stages = proposed, planning, active, completed

TABLE 13. UTILITY-RUN MANAGED CHARGING PROGRAMS BY PROGRAM TYPE, 2012-2019, CONTINUED				
UTILITY NAME, STATE	**PROGRAM NAME**	**PROJECT PARTNERS**	**PROJECT STAGE***	**SHORT DESCRIPTION**
Duke Energy Florida, Florida	Park & Plug Program	NovaCHARGE	Active	Duke Energy Florida will own and operate 530 EV charging stations at site host locations within their service territory between 2019 and 2022. In addition to collecting vehicle charging data, hosts must also allow Duke to conduct demand response events for the purpose of understanding and evaluating charging stations as a DR resource. The equipment will be aggregated through the NovaCHARGE network.
Nashville Electric Service and Middle Tennessee Electric Membership Cooperative, Tennessee	SmartCharge Nashville	FleetCarma	Active	Using gamification, this program will eventually reward customers for participating in DR events, but is currently being used to identify load profiles on their system.
San Diego Gas & Electric (SDG&E), California	Power Your Drive	ChargePoint, Siemens, Greenlots	Active	San Diego Gas & Electric's day-ahead, price-varying EV rate reflects circuit and system conditions and the changing price of energy throughout the day. Through a user-friendly phone app, EV drivers can save money by setting vehicle charging times to low-priced hours of the day.
Southern California Edison (SCE), California	Demand Response Workplace Charging Pilot	Greenlots	Completed	Southern California Edison used a workplace charging pilot—leveraging afternoon peaks and load reduction strategies—to learn more about driver behavior and responsiveness to pricing signals. The program included a high price option allowing users to have no charging disruption; a medium price allowing for peak demand curtailment from a faster Level 2 to a slower Level 1 charging rate; and a low price allowing drivers to be entirely curtailed during a demand event. One of the findings of the study was that drivers need maximum optionality, meaning if they need to charge at certain times, they want the ability to opt out.

*Project stages = proposed, planning, active, completed

Source: Smart Electric Power Alliance, 2019.
Please note: This list may not include all utility-run managed charging programs.

Appendix B: Network Service Providers with Managed Charging-Capabilities

This appendix contains a list of known Network Service Providers available in the U.S. with managed charging-capabilities identified at the date of publication. A more complete and updated list is available in spreadsheet format on the SEPA website. The table includes the application/messaging protocols and network communication interfaces used by each of the platforms.

TABLE 14. NETWORK SERVICE PROVIDERS WITH MANAGED CHARGING-CAPABILITIES

VGI PLATFORM PROVIDER NAME	PLATFORM(S) (DEVICES)	APPLICATION/ MESSAGING PROTOCOLS	NETWORK COMMUNICATION INTERFACES
Amply Power	Amply Power platform	OCPP 1.5, 1.6, and 2.0, ISO/IEC 15118, OpenADR 2.0b, other API-based systems	Cellular, Wi-Fi, Ethernet
ChargePoint	ChargePoint Network	OCPP v1.6 + extensions, ChargePoint Web Services APIs OpenADR 2.0b, ISO/IEC 15118 (DC)	Wi-Fi (residential), GSM, CDMA Cellular (commercial)
Connectivity Solutions Plus	INSYS Powerline GP	ISO/IEC 15118	Ethernet
Driivz	Driivz platform	OCPP 1.5, 1.6 and 2.0 and ISO/IEC 15118	Not available
Electrify America	EV Connect, Greenlots, SemaConnect, Signet, ABB	OCPP, ISO/IEC 15118	Wi-Fi
eMotorWerks	JuiceNet platform (JuicePlug EVSE adapter)	OCPP, OpenADR, other API-based systems	Wi-Fi, Ethernet, Cellular
EnergyHub	Mercury DERMS (EVSE and OEM partners)	OpenADR 2.0, IEEE 2030.5, other API-based systems	Wi-Fi, Ethernet, Cellular
EV Connect	EV Cloud platform (EVSE partners include Efacec, GE, and OpConnect)	OCPP, OpenADR 2.0, OCPI, other API-based systems	Wi-Fi, Ethernet, Cellular GSM (GPRS and CDMA)
evGateway (Tellus Power)	Vendor Agnostic	OCPP, OpenADR 2.0	LAN: 2.4GHz., Wi-Fi modem card (802.11 b/g/n) WAN: 3G GSM, 3G CDMA

TABLE 14. NETWORK SERVICE PROVIDERS WITH MANAGED CHARGING-CAPABILITIES, CONTINUED			
VGI PLATFORM PROVIDER NAME	**PLATFORM(S) (DEVICES)**	**APPLICATION/ MESSAGING PROTOCOLS**	**NETWORK COMMUNICATION INTERFACES**
FleetCarma	SmartCharge Rewards Platform, (OBD-II C2 device) and SmartCharge Manager (multi-device)	OCPP, OpenADR, Proprietary	C2 device - cellular OEM API - cellular EVSE- Wi-Fi, PLC, and Ethernet
Greenlots (Shell New Energies)	SKY Smart Charging platform	OCPP, OpenADR 2.0b, ISO/IEC 15118, OCPI	Wi-Fi, Ethernet, Cellular
Hubject	Charge eRoaming Platform; Hubject Plug&Charge: Ecosystem; PKI; Certificate Management	OICP; ISO/IEC 15118	Not available
IoTecha	IoTecha's Intelligent Power Platform (I2P2)	ISO/IEC 15118	Not available
Kitu Systems	Kitu Convoy Electric Vehicle Service Platform (EVSP)	OCPP 1.6, SEP 2.0 (IEEE 2030.5-2018), OpenADR 2.0 VEN	Cellular (3G), Wi-Fi, Ethernet
Koben Systems Inc. (KSI)	myEVroute network	OCPP	Not available
Liberty Plugins	HYDRA-R Multi-Charger Control System	OpenADR 2.0	Cellular, Ethernet
Mobility House	TMH Charging and Energy Management (CEM)	OCPP 1.6/ 2.0, ISO/IEC 15118	Multiple
PowerFlex	PowerFlex Adaptive Load Management Platform	Not available	ZigBee or Wi-Fi
Saascharge	EV Charging Platform	OCPP, OCPI	Wi-Fi, Ethernet, Cellular
Schneider Electric	EVlink™	Not available	Not available
Siemens	Siemens eCar Operation Center (OC)	OpenADR 2.0B, OCPP 1.6, ISO/IEC 15118, OICP, OCPI (in progress), API web services for integration with billing, DR, and other utility systems	Wi-Fi, Cellular, Ethernet, Modbus
Virtual Peaker	Not available	API	Wi-Fi
ZEF Energy	ZEF Smart Charging Network	Not available	Not available

Source: Smart Electric Power Alliance, 2019. Please note: This list may not include all available vendors.

Appendix C: EV Supply Equipment Manufacturers with Managed Charging-Capabilities

This appendix includes a list of known managed charging-capable equipment that is sold in the U.S. The table also includes identified application/messaging protocols and the corresponding network communication interfaces (also known as the transport layer protocols). Please note that a complete and updated list of equipment is also available through SEPA's website.

TABLE 15. EV SUPPLY EQUIPMENT MANUFACTURERS WITH MANAGED CHARGING-CAPABILITIES

EV SUPPLY MANUFACTURER NAME	CHARGER NAME(S) (LEVEL AND TYPE)	PROPRIETARY/ EXTERNAL PLATFORM(S)	APPLICATION/ MESSAGING PROTOCOLS	NETWORK COMMUNICATION INTERFACES
ABB	Terra DCFC chargers (50-350kW) eBus, Depot and Fleet chargers (50-450kW)	ABB Ability Connected Services; EV Connect	OCPP and OCPP enabled protocols; OpenADR via OCPP; D/R API, Custom APIs, ISO/IEC 15118	Cellular (GSM), Ethernet
ABL	eMC2, eMC3 (Level 2)	Not available	OCPP 1.6	GSM
AddEnergie Technologies	SmartTWO (Level 2) SmartDC Fast Charger (SAE and CHAdeMO Combo)	Cloud-based control system	Not available	Wi-Fi (IEEE 802.15.4), Cellular (3G), ZigBee
Advanced Charging Technologies	Level 2 Commercial, DC Fast Charger (SAE Combo and CHAdeMO)	Not available	SEP 1.x, SEP 2.0	Ethernet, Wi-Fi (IEEE 802.11 b/g/n, ICPT IP/ Internet, Cellular GSM (GPRS), ZigBee
Alfen	EVE S-line, EVE Pro-line (Single and Double), Twin	Alfen Smart Charging Network	OCPP 1.6	Ethernet, GPRS
Andromeda Power, LLC	ORCA Mobile and Air DC Fast Charger (CHAdeMO and SAE Combo) ORCA Zen and Strada Level 2 (SAE)	ORCA InCISIVE Power Cloud platform	OpenADR 2.0b, OCPP 1.6, Open Smart Charging Protocol (OSCP)	Wi-Fi (IEEE 802.11g), Cellular (3G/4G), Ethernet
Blink (Car Charging Group)	Level 2 and DCFC (CHAdeMO and SAE Combo	Blink Network	Not available	Wi-Fi (IEEE 802.11g). Cellular and LAN/ Ethernet
Bosch	Power Max 2 Level 2 and Power DC Plus (SAE Combo)	Not available	OCPP 1.5	Wi-Fi (IEEE 802.11 b/g/n)

TABLE 15. EV SUPPLY EQUIPMENT MANUFACTURERS WITH MANAGED CHARGING-CAPABILITIES, CONTINUED				
EV SUPPLY MANUFACTURER NAME	**CHARGER NAME(S) (LEVEL AND TYPE)**	**PROPRIETARY/ EXTERNAL PLATFORM(S)**	**APPLICATION/ MESSAGING PROTOCOLS**	**NETWORK COMMUNICATION INTERFACES**
BTCPower	Level 2 Residential and Commercial EV Charging Station DC Fast Charger (CHAdeMO and SAE combo)	BTCP Network, EVConnect, EVGateway, EVgo, Greenlots, innogy	OCPP 1.5/1.6, OpenADR 2.0b, SEP1.x, SEP2.0, ISO 15118	Ethernet, Cellular (4G), Wi-Fi (2.4 GHz, 802.11 b/g/n), Zigbee
ChargePoint	CT4000 Commercial (includes CT4011, CT4021, CT4023, CT4025, CT4027, CT4011, CT4013), ChargePoint Express 250 and Express Plus (DC), CPF25 ChargePoint Home	ChargePoint Network	OCPP v1.6 + extensions, ChargePoint Web Services APIs, OpenADR 2.0b, ISO/ IEC 15118 (DC)	Wi-Fi (residential), GSM, CDMA Cellular (commercial)
Circontrol	WallBox Smart Series (Level 2)	Not available	OCPP 1.5 and 1.6J	3G/ GPRS / GSM
ClipperCreek	CS-100 (Level 2) (SAE) HCS-40; ACS-15, ACS-20	External (e.g., JuiceNet by eMotorWerks, ZEF Energy, Liberty PlugIns HYDRA-R platform) COSMOS interface for HCS-Series	Not available	Wi-Fi, Ethernet, Cellular
Delta Electronics, Inc	EV AC Charger series (Level 2) (SAE)	Numerous	Not available	Ethernet, Wi-Fi (optional), Cellular GSM/GPRS (3G) (optional)
Ebee Technologies	Chargespot Berlin Level 2 22kW	Grid Chargespot	ISO/IEC 15118, OCPP 1.5 / 1.6 (with binary option, roaming capable)	2G (GSM, GPRS, EDGE), 3G (UMTS) & 4G (LTE)
Efacec	HV Range (HV 160/175/350 UL), QC45 UL, QC20 UL (SAE Combo and CHAdeMO)	Any network	OCPP 1.5 or proprietary	Wireless 3G (GSM or CDMA), LAN, Wi-Fi
eMotorWerks	JuiceBox Pro (Level 2) 32(C), 40(C), 75(C)	JuiceNet by eMotorWerks	OCPP, OpenADR, other API-based systems	Wi-Fi, Ethernet, Cellular
EV Box	Type 1 (SAE J1772) or Type 2 (EN/IEC 62196-2) plug 1; EVB-BSHW-25FtS; EVB-BSHP; EVB-BSHP-25FtsD	EV Connect; Greenlots	OCPP 1.5 S, 1.6 S, 1.6 J	Wi-Fi 2.4/5 GHz (IEEE 802.11 a/b/g, IEEE 802.11 d/e/i/h) / Bluetooth 4.0

TABLE 15. EV SUPPLY EQUIPMENT MANUFACTURERS WITH MANAGED CHARGING-CAPABILITIES, CONTINUED				
EV SUPPLY MANUFACTURER NAME	**CHARGER NAME(S) (LEVEL AND TYPE)**	**PROPRIETARY/ EXTERNAL PLATFORM(S)**	**APPLICATION/ MESSAGING PROTOCOLS**	**NETWORK COMMUNICATION INTERFACES**
EVoCHARGE	30A EVoReel Level 2 (SAE); EVO72-310-001A; EVO30-110-001A; EVO-410-002A; EVO30-610-001A; EVO30-610-002A	Optional RFID Access Control with Network Capability	OCPP 1.5, 1.6	Cellular, Ethernet, GPRS
EVSE LLC (Control Module Ind.)	ChargeWorks 3703 (Level 1 and Level 2); 3703; 3704-002 REV G	External (e.g., Greenlots SKY Smart Charging platform)	OCPP	Ethernet, Cellular, radio, Wi-Fi
FLO	FLO Home X5 Level 2, SmartTWO-BSR L2 Charger	Global Management Services	Not available	PLC (HomePlug Green PHY and Zigbee), Cellular (3G)
Freewire Technologies	Mobi L2 and DC Boost Chargers	AMP platform	OCPP, OpenADR, ISO/ IEC 15118	Cellular (4G) and Wi-Fi
IES	KeyWatt 22-24kW wallbox single/multi standard Level 2 and DC fast (CCS Combo & CHAdeMO); KeyWatt eBus 50kW depot charger (also 2 stations can be combined into a 100kW unit) (CCS Combo 2 Protocol)	Not available	OCPP 1.6, ISO/IEC 15118	Ethernet, Cellular (3G)
Ingeteam	INGEREV CITY and GARAGE products	INGEREV Web Manager	OCPP	Ethernet, GPRS/ 3G
Itron and ClipperCreek	Smart Charging Station	OpenWay network	Proprietary	Wi-Fi, RF Mesh, Cellular, ZigBee
Juice Bar LLC	Energy Bar DC Fast Chargers (CHAdeMO and CCS combo; single CCS output) and Mini Bar (Level 1&2)	External (Greenlots)	OCPP 1.6	Ethernet, Cellular (3G), LAN
KebaAG	KeContact P30 x-series (Level 2 and DC Fast Charging)	Not available	OCPP 1.5 and 2.0	Ethernet, WLAN, Cellular (GSM), USB, Nodbus TCP, UDP
Leviton	Evr-Green 4000 (Level 2 Commercial) (SAE)	External (e.g., ChargePoint platform or Liberty PlugIns HYDRA-R platform)	Not available	Wi-Fi (IEEE 802.11 a/b/g/n), Cellular (GSM (3G) and CDMA (3G))

TABLE 15. EV SUPPLY EQUIPMENT MANUFACTURERS WITH MANAGED CHARGING-CAPABILITIES, CONTINUED				
EV SUPPLY MANUFACTURER NAME	**CHARGER NAME(S) (LEVEL AND TYPE)**	**PROPRIETARY/ EXTERNAL PLATFORM(S)**	**APPLICATION/ MESSAGING PROTOCOLS**	**NETWORK COMMUNICATION INTERFACES**
LIVA	Level 2 charger	IoT.ON™ Cloud Services	ISO/IEC 15118 OCPP 1.6	2.4GHz Wi-Fi (802.11 b/g/n), Bluetooth, Ethernet, Cellular
MOEV, Inc.	Smart EV Charger (Level 1 and 2)	Cloud-based control center	Not available	Ethernet, Wi-Fi, Cellular (3G), ZigBee
Nuuve	Nuvve Powerport	Nuvve GIVVes™	Not available	2.4 GHz Wi-Fi, 3G/LTE, 4G/60Hz, Ethernet RJ 45
OATI	EVolution L2 and Express DC fast charging (CHAdeMO and SAE Combo)	OATI Private Cloud	OCPP 1.5 and 1.6	Cellular (4G), Ethernet
Oxygen Initiative & innogy SE	Oxygen eStation and eBox (Level 2)	Oxygen eOperate	ISO/IEC 15118	Cellular (3G)
Proterra	60kW, 125kW, and 500kW depot chargers	Not available	OCPP 1.6	Not available
Schneider Electric	EVlink Smart Wallbox (EVBI)	EVlink Energy Management	OCPP 1.5	Ethernet
SemaConnect	ChargePro (Level 2 Commercial and Residential)	SemaConnect Network platform	Proprietary	Cellular (CDMA and GSM/GPRS)
SETEC Power Co.	10kW portable, 20 kW wall-mount, and 30-100kW	Not available	OCPP 1.5	PLC
Siemens	VersiCharge SG 1 (Level 2) Rave High Powered DCFC Overhead Bus Charging Systems	Siemens Network connections to reporting and control backend, Integration with OCPP 1.6 compliant platforms through direct connection	OpenADR 2.0b, OCPP 1.6, Proprietary Siemens	Wi-Fi (IEEE 802.11 b/g/n), PLC, Cellular (4G), Modbus TCP/IP, Ethernet
Signet Systems, Inc	SAE J1772/ IEC 62196-2 and CHAdeMO	Electrify America (Cycle 2)	OCPP 1.6 JSON	CDMA, TCP/ IP, Cellular, Ethernet
Smartenit	SmartElek L1/L2, Model 4500	Smartenit Cloud Services and DRMS Multi-speak	Custom API or Zigbee/ Multi-speak standard	Flexnet, Wi-Fi, Cellular (3G), Zigbee

TABLE 15. EV SUPPLY EQUIPMENT MANUFACTURERS WITH MANAGED CHARGING-CAPABILITIES, CONTINUED				
EV SUPPLY MANUFACTURER NAME	**CHARGER NAME(S) (LEVEL AND TYPE)**	**PROPRIETARY/ EXTERNAL PLATFORM(S)**	**APPLICATION/ MESSAGING PROTOCOLS**	**NETWORK COMMUNICATION INTERFACES**
Tellus Power	Tellus Power Package Level 2 and Level 1; UP160J-CMP-COM; UP160J-CMP; UP160J-WMP-COM; UP160J-WMP; UP160J-PMP; UP80J-CMP-COM; UP80J-CMP; UP80J-WMP-COM; UP80J-PMP-COM; UP80J-PMP	evGateway (Proprietary platform)	OpenADR 2.0, OCPP 1.5	LAN, Wi-Fi (IEEE 802.11 b/g/n), Cellular (2G and CDMA)
Tritium PTY LTD	Veefil UT, WP, 5022kW (DC Fast Charger (CHAdeMO and CCS SAE Combo)	EV Connect	OCPP 1.5 and 1.6J	Cellular (3G), Ethernet
Webasto (formerly Aerovironment)	EVSE-RS 32A, TurboDX 16A and 32A, 15' and 25' cables	Network Platforms—Webasto, JuiceNet by eMotorWerks, EV Connect, and other External Partners	SEP 2.0, OCPP 1.6J and 2.0	Wi-Fi, Cellular

Source: Smart Electric Power Alliance, 2019. Please note: This list may not include all available vendors.

Attachment A

Smart Electric
Power Alliance

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Attachment B

NARUC
National Association of Regulatory Utility Commissioners

Public Utility Commission Stakeholder Engagement: A Decision-Making Framework

Jasmine McAdams

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Disclaimers

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Contents

I. Executive Summary

Public utility commissions (PUCs) across the country are facing the challenges of an evolving regulatory landscape as consumer needs, new technologies, and policy goals increasingly lead to changes in traditional utility and regulatory practices. Emerging stakeholder engagement processes are a key tool for informed decision-making in this landscape and can help achieve win-win outcomes in the public interest. To ensure that stakeholder engagement processes deliver on these benefits, PUCs will want to evaluate an array of options for how to proceed at key points. This stakeholder engagement framework offers commissions a road map to evaluate these decision points by providing key questions to consider, emerging best practices, and related resources informed by other commissions' experiences. The framework is organized into six decision categories: scope, facilitation approach, engagement approach, meeting format, timeline, and engagement outcomes and follow-up actions. Each category is defined in *Figure 1*. *Table 1* consolidates the emerging best practices and key questions to consider for each decision category as discussed in the framework.

Figure 1. Decision-making Framework Category Definitions

A. Scope:
Delineates the extent, or the bounds, of the stakeholder engagement approach. In this framework, the scope is discussed as a function of the focus, purpose, internal capacity, and initiating factor for the stakeholder process

B. Facilitation Approach:
Refers to who is leading the facilitation and the role of the facilitator throughout the stakeholder process

C. Engagement Approach:
Methods used to engage stakeholders. The engagement approach is discussed through outreach and recruitment, communication of scope, stakeholder education and issue framing, and consensus building

D. Meeting Format:
Considerations for the structure and accessibility of the stakeholder engagement process

E. Timeline:
Schedule and phases of the stakeholder engagement process

F. Engagement Outcomes and Follow-Up:
Interim and final outputs of the stakeholder engagement process and relevant activities that continue or commence after the process is formally complete

Table 1. Emerging Best Practices and Key Questions for Commissions

A. Scope

Emerging Best Practices

- Clearly define the scope of the proceeding early in the process.
- Communicate the purpose and goals to stakeholders early in the process.
- Assess commission capacity and identify where capacity may be limited. Consider the possibility of needing to invest in increased staffing and/or additional resources to accommodate needs.

Key Questions for Commissions

- What is the purpose of the process?
- Who is determining the focus of the process?
- Has the focus been explicitly defined prior to beginning stakeholder engagement? Or, will the stakeholder engagement process help define the focus?
- How does this process meet the commission's need in a way that could not be met in a litigated proceeding?
- Are there priority issues that must be addressed?
- How and when will the scope of the process be communicated to stakeholders?
- What is the capacity of the commission's staff, and what resources are available? Is there a need for additional resources?

B. Facilitation Approach

Emerging Best Practices

- Commissions select a neutral facilitator who is familiar with the regulatory process. Facilitators can be prequalified, and RFPs issued on a case-by-case basis to facilitators with demonstrated requisite expertise.
- Commissions prioritize receiving actionable input from stakeholders to make a decision and clearly communicate this priority to the facilitator.
- Some facilitators may not be aware of the historical relationships between stakeholders; in these instances, commission staff will need to bring the facilitator up to speed to understand how stakeholder relationships may have an impact on the current process.
- The role of the facilitator is clearly defined.
- Frequent communication between the facilitator and the commission can ensure alignment with commission objectives and allow the commission to adjust or incorporate process developments into its plans.
- Facilitators establish clear boundaries, goals, and ground rules with participants.

Key Questions for Commissions

- How will the facilitator address concerns of bias?
- What is the intended role of the facilitator?
- How much technical knowledge should the facilitator have for their role in this process?
- Does the facilitator need to be aware of any historical relationships between stakeholders?
- Does the facilitator have experience building consensus or productive collaboration among diverse stakeholders?

Table 1 continued

C. Engagement Approach

Emerging Best Practices

- Engage stakeholders early and often throughout the process.
- If relevant to the proceeding, recruit stakeholders through a well-publicized process.
- Ensure trust and respect are built through clean communications and development of ground rules to support meaningful engagement.
- To accommodate stakeholders with a wide range of background knowledge, include tools for stakeholder education early in the process to establish general knowledge.
- For consensus-building activities, maintain detailed meeting minutes.
- Reach consensus in small increments throughout the process, rather than on all matters at the end.
- Facilitate informal discussions to negotiate or mediate outside of the larger group.

Key Questions for Commissions

- Is broad participation important to this proceeding?
- Which mediums are available for reaching potential stakeholders?
- Should stakeholders have a level of background knowledge prior to participating? If so, what is this level, and how will this be evaluated?
- What approach should be used to educate stakeholders?

D. Meeting Format

Emerging Best Practices

- Consider a multitier organizational approach for engagement.
- Evaluate barriers to access that potential stakeholders may face and outline steps for eliminating or reducing these barriers to participation.
- Set limits to the number of participants per meeting.
- Offer virtual options to enable increased participation.
- Consider meeting times outside of traditional business hours.
- Distribute meeting materials in advance.
- Take meeting minutes and distribute notes after meeting, with extra attention paid to any matters that reached consensus so that stakeholders can review the outcome.
- Consider the role of commissioners and commission staff in meetings.

Key Questions for Commissions

- What venues of participation are most appropriate for this type of engagement?
- What steps are being taken to ensure that the process is accessible to all potential participants?
- How many stakeholders is the commission anticipating will be involved in the process?
- What is the maximum number of participants that can participate in any meeting? Does this number change for in-person versus virtual meetings?
- Are there any logistical constraints limiting the size of stakeholder groups/meetings?
- What overall organization structure should be employed? Should the process consist of an advisory board?
- Are stakeholders expected to come to consensus? If so, what steps will be taken if consensus is not able to be reached?
- Is virtual participation an option? What platforms are available?
- What online platforms are available for sharing meeting documents?
- Will commissioners or staff participate in meetings? If so, how?

Table 1 continued

E. Timeline

Emerging Best Practices

- When final product due dates have been decided, consider setting the timeline by working backward from these dates.
- Design timelines to accommodate flexibility.
- Clearly communicate the timeline to stakeholders early in the engagement process. Include who will be engaged at each step, relevant outputs, and milestones.

Key Questions for Commissioners

- Can the process be divided into phases? If so, how?
- What are the interim milestones that indicate the process can move toward the next phase?
- When are the due dates of final products?
- What resources are needed at each step?
- Which stakeholders will be involved at each step?
- Which staff members or facilitators will be involved at each step?
- What are the relevant activities for each step?

F. Engagement Outcomes and Follow-Up Actions

Emerging Best Practices

- Set clean intentions for how stakeholder will contribute and give input to the development of interim and final process products.
- During the planning process, consider and set resources aside to continue follow-up discussions and activities.
- Solicit input from stakeholders on the engagement process and use feedback to incorporate and demonstrate process improvements.

Key Questions for Commissions

- How and to what extent will stakeholder inputs be incorporated into process products?
- What opportunities are there to follow up on proceeding outputs? Does the commission have resources ready to utilize if the opportunity arises?
- What type of feedback from stakeholders could help to improve future processes?
- Given the structure of the process, can feedback be gathered at regular intervals?

II. Introduction

Public utility commissions (PUCs) across the country are faced with making decisions that are increasingly complex, broad in impact, and intersectional across an array of issues. These factors are driven by evolving consumer needs, emerging technologies, and new policy goals that are redefining utility regulation in the public interest beyond just the objectives of ensuring affordable, safe, and reliable services to consumers. These evolving elements are expanding these objectives to now include additional needs and expectations such as environmental performance, expanded consumer choice, resilience, and equity (Cross-Call et al. 2018; Billimoria, Shipley, and Guccione 2019). These considerations are growing increasingly present in regulatory decision-making with regards to dynamic issues such as:

- **Energy infrastructure modernization**, including the proliferation of distributed energy resources (DERs; NARUC 2016),[1] electric vehicle (EV) infrastructure ownership and siting, and smart grid technologies and connected devices;
- **Electricity system transition**, including distribution system planning, performance-based ratemaking, advanced rate design, and hosting capacity analysis;
- **Energy system resilience**, including critical infrastructure policy, cybersecurity, grid resilience, and development of microgrids;
- **Energy policy goals**, including greenhouse gas emissions reduction targets, renewable portfolio standards, and zero emission vehicle standards; and
- **Intersection of utility regulation with other economic sectors**, including the transportation and manufacturing sectors. This is particularly relevant to the challenges and opportunities of transportation and building electrification.

Decisions relevant to these topic areas, which are often interrelated, have highlighted the benefits of transitioning from traditional to emerging regulatory processes that enable increased and improved stakeholder engagement (Cross-Call, Goldenberg, and Wang 2019). In this context, a stakeholder is defined as an individual, group, or organization that can affect or be affected by PUC decision-making. Examples of stakeholders can include, but are not limited to: utilities, consumer advocates, large customers, small businesses, municipalities, environmental organizations, DER solution providers, project developers, environmental justice advocates, and others.

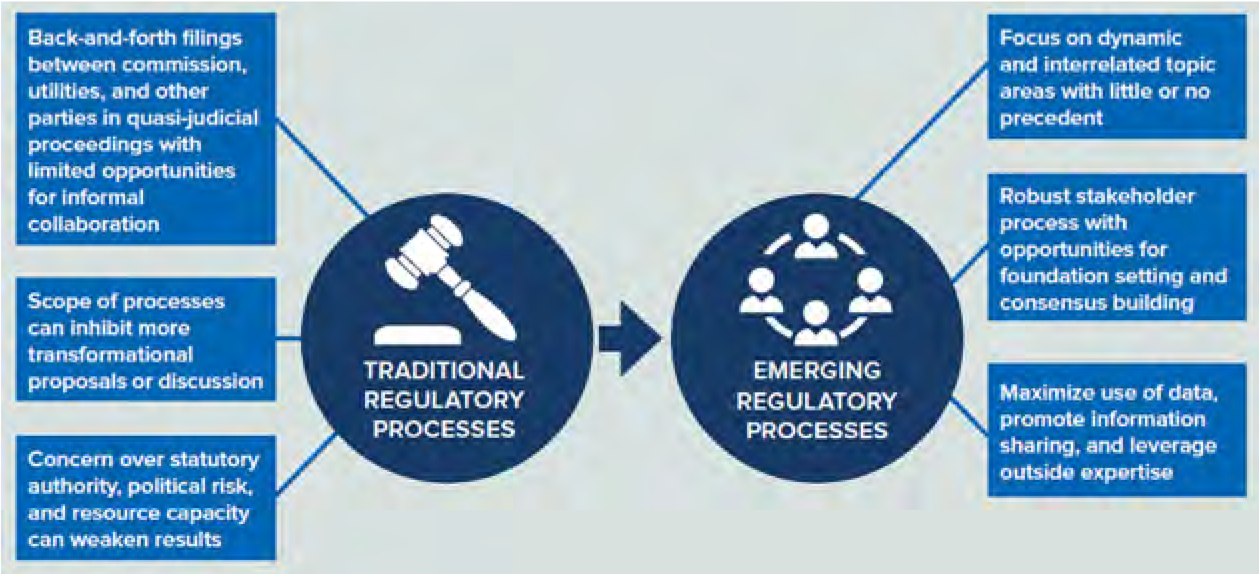
Figure 2, replicating key portions of Cross-Call, Goldenberg, and Wang's (2019) Process for Purpose diagram, illustrates some of the key differences in scope and stakeholder involvement between traditional and emerging regulatory processes.

These emerging stakeholder engagement processes are instrumental in helping meet the needs of this changing regulatory landscape, and have been undertaken in more than a dozen states. When the stakeholder engagement process is well-designed, the benefits are actualized as "better information, decreased risk, and smarter solutions" (De Martini et al. 2016, 2) for all parties. In addition, robust stakeholder engagement processes inform regulatory rulemakings with more complete and up-to-date considerations of stakeholder concerns and challenges. De Martini et al. (2016, 2–3) further elaborate on the advantages of this approach as it:

1 A DER is an energy resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), EVs, microgrids, and energy efficiency (EE).

- Provides inclusive and accessible environments for discussion,
- Builds stakeholder support throughout the regulatory process,
- Improves the quality and efficiency of regulatory proceedings,
- Encourages constructive working groups,
- Identifies common ground and areas of disagreement proactively, and
- Increases support for prudent capital investments through mutual education.

Figure 2. Characteristics of Traditional And Emerging Regulatory Processes
(Cross-Call, Goldenberg, and Wang 2019)



Commissions partaking in these nontraditional approaches, however, often face challenges that can influence the extent and impact of the engagement. These challenges include:

- **Legal barriers:** formal processes may have legal requirements for intervention that can be used by regulators or other parties to include or exclude participants.
- **Capacity limitations:** time and resources of commissioners, commission staff, and stakeholders can limit the participation and engagement capacity for each party.
- **Fair and objective decision-making:** commissions are tasked with maintaining fair and effective processes that allow them to appropriately integrate stakeholder input into decision-making.
- **Timely proceedings:** proceedings must be conducted in a way that aligns with statutory deadlines and concurrent activities.
- **Stakeholder knowledge:** limited background knowledge can potentially limit the ability for stakeholders to participate in a meaningful way (Bishop and Bird 2019, 21).

This stakeholder engagement decision-making framework was developed to respond to the growing need for more expansive stakeholder engagement processes among state utility commissions. The framework draws from various commission experiences in stakeholder processes and serves as a resource to support commissions as they plan and design these processes.

III. Methodology

National Association of Regulatory Utility Commissioners (NARUC) gathered experiences and lessons learned from members to inform the development of this decision-making framework. NARUC staff hosted three peer sharing calls (NARUC 2019a, 2019b, 2019c) with PUC staff from across the country and conducted five one-on-one interviews with commissioners/PUC staff, in addition to completing a literature review. Ultimately, NARUC gathered feedback from PUCs regarding 11 recent utility commission processes (see *Table 2*) to identify key questions and emerging best practices. (See also *Table 3* for details about each initiative.)

Table 2. Examined Proceedings

State Commission	Initiative Title	Initiative Type/ Relevant Issue	Related Dockets
Arkansas Public Service Commission	Three dockets related to DERs	DERs	16-028-U
District of Columbia Public Service Commission	Modernizing the Energy Delivery System for Increased Sustainability (MEDSIS)	Grid modernization	Formal Case No. 1130
Maryland Public Service Commission	Transforming Maryland's Electric Grid (PC44)	Distribution system planning	PC44
Michigan Public Service Commission	MI Power Grid	Grid modernization	U-20645 U-20757
Minnesota Public Utilities Commission	Grid Modernization Distribution System Planning Investigation	Distribution system planning	15-556
Public Utilities Commission of Nevada	Investigation and Rulemaking to implement Senate Bill 146	Utility distributed resources planning	17-08022
Public Utility Commission of Ohio	PowerForward Initiative	Grid modernization	18-1595-EL-GRD 18-1596-EL-GRD 18-1597-EL-GRD
Oregon Public Utility Commission	Senate Bill 978 Stakeholder Process	Grid modernization	—
Puerto Rico Energy Bureau	Distribution Resource Planning	Distribution system planning	—
Rhode Island Public Utilities Commission	Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System	Benefit-cost framework	4600
Washington Utilities and Transportation Commission	Statewide Advisory Group	EE	UE-171087

IV. Summary of Commission Experiences

Table 3 shows a high-level summary of 11 commission experiences with focused stakeholder engagement processes, collected from peer sharing calls, and one-on-one interviews. Commissioners and staff provided both factual feedback and lessons learned. Lessons learned are indicated with an "LL" in the table. These experiences informed NARUC's development of the decision-making framework.

Table 3. Summary of Commission Experiences

State and Related Process	Scope	Facilitation Approach	Engagement Approach	Meeting Format	Timeline	Engagement Outcomes and Follow-Up Actions
Arkansas Public Service Commission Dockets related to DERs	• Dockets related to DERs	• Third-party facilitation • LL: Staff recommend clearly defining the role of facilitator vs. staff	• The facilitator reached out to new stakeholders • Facilitator attempted to build shared knowledge • LL: As the facilitator may not be aware of historical relationships between stakeholders, staff may need to brief facilitators	• Monthly meetings via webinar and quarterly meetings in-person		
District of Columbia Public Service Commission (DCPSC) MEDSIS	• Addressed grid modernization, gaps in regulation, how to spend $25 million in funding on pilot programs from Exelon-Pepco merger • The output of Phase I was a staff report • Part of Phase II of the MEDSIS initiative aimed to address questions raised in the Phase I staff report	• Third-party facilitation • Prioritized facilitator experience, independence, regulatory knowledge, staff capacity, transparency, and ability to host in-person meetings	• Shared meetings via social media and professional networks • Spent the first month on stakeholder education; brought in experts and commission staff to address knowledge gaps • LL: Useful feedback gathered from stakeholders by using strawman proposal to solicit input • LL: Was sometimes difficult for facilitator to go in direction of achieving consensus • Recommend prioritizing receiving actionable advice and communicating this priority to the facilitator	• Topical working groups were formed and met monthly • Provided several venues for participation (town halls and technical conferences) • Communication through an online portal	• 2015–2019 from the start of MEDSIS to final report • Open stakeholder meetings held August 2018–May 2019	• Facilitation consultant wrote a report summarizing stakeholder opinions; did not include recommendations • Stakeholder surveys conducted at end of process • Produced a staff report with recommendation for the DCPSC • The staff report identified several ongoing DCPSC processes where MEDSIS recommendations could be incorporated

Table 3 continued

State and Related Process	Scope	Facilitation Approach	Engagement Approach	Meeting Format	Timeline	Engagement Outcomes and Follow-Up Actions
Maryland Public Service Commission PC44	• Targeted review of electric distribution systems in Maryland with specific focus on topics of rate design, EVs, competitive markets and customer choice, interconnection process, energy storage, and distribution system planning	• Commission staff-led facilitation • Consultants hired to work as advisors and used sparingly (generally when staff capacity was limited) • Facilitators assigned homework to stakeholders to avoid tangents • Facilitators required clear direction and guidance from the commission • Facilitators aimed to be accommodating, respectful, and neutral	• Consultant wrote a study on a topic to educate stakeholders • Facilitators had discussions with stakeholders outside the larger group to educate, negotiate, mediate, and inform subsequent conversations	• Six topical working groups created that were led by commission staff	• 2016–present	• Staff provided summaries and options to the commission (but did not make recommendations or find consensus)
Michigan Public Service Commission (MPSC) MI Power Grid	• A customer-focused, multi-year stakeholder initiative was established by the governor in cooperation with the MPSC to maximize benefits of transition to clean energy resources • LL: Bandwidth issues arose if staff weren't focusing on facilitation full-time	• Commission staff-led facilitation • Conversations were focused on evolving utility business model, which could lead to bias concerns with a utility- or advocate-led approach	• Reached out directly to stakeholders who expressed interest in the topics in the past and solicited assistance from national experts • Focus on diversity and equity to make process as accessible as possible • Initial session used to provide background and educate stakeholders	• Working groups (14–15 total) met monthly on independent timelines • Phase 2 initiated new working groups • Each working group had its own website and listserv for information sharing • Remote options available (before COVID-19 restrictions)	• 2019–present • First categorized relevant issues, talked to commissioners and determined staff availability, then identified stakeholders and the timeline • The timeline was optimized relative to due date for deliverable • LL: Important to be flexible and adaptable with planning	• Staff report due one year and final report due two years from start • Staff reports to summarize issues raised, provide status updates on work being done, and offer recommendations to the commission • Stakeholders able to comment on staff reports before sending to commissioners

Table 3 continued

State and Related Process	Scope	Facilitation Approach	Engagement Approach	Meeting Format	Timeline	Engagement Outcomes and Follow-Up Actions
Minnesota Public Utilities Commission Grid Modern-ization and Distribution System Planning	• Minnesota PUC initiated an inquiry into electric utility grid modernization with a focus on distribution system planning	• Commission-led facilitation with external support • Commissioners led public workshops, and staff led public comment periods for transparent input limited by ex parte rules • Facilitation type varies depending on the stage in the process. Work began more informally, but became increasingly formal to ensure the record enabled deci-sions to be made	• At onset, new (nontradition-al) stakeholders were sought out to share perspectives • Used an open, inclusive approach to workshops and participants • Verbal, written, and in-per-son outreach were used to gather stakeholder input during the early stages; toward more formal portion of the process (record-based decisions), formal methods were used. • LL: It was important to define scope and hold early workshops—utilities and other stakeholders had time to understand what was coming and make preparations • LL: It was critical for the commission to prioritize flexibility and a collaborative approach, and communicate that to stakeholders to keep engagement	• Workshops held every 6–8 weeks at the onset • Planning meeting format for staff-led updates to PUC (and public) • Commission meeting (deci-sional meetings) to articulate formal decisions	• Stakeholder workshops in 2015–2016, staff report in 2016 • 2017 stakeholder written solicitation of comments • 2018 straw proposals and transition to formal proceeding using vetted straw pro-posals • LL: It was import-ant to set a clear timeline so com-mission staff could anticipate areas of disagreement and prepare for diffi-cult discussions	• Report on options the PUC could use to advance grid modernization • After receiving comments on the report, the PUC drafted a scope for distributed system planning requirements and solicited stakeholder feedback • Using feedback, staff created straw proposals to be used as the basis for the standard commission proceeding

Table 3 continued

State and Related Process	Scope	Facilitation Approach	Engagement Approach	Meeting Format	Timeline	Engagement Outcomes and Follow-Up Actions
Public Utilities Commission of Nevada (PUCN) Investigation and Rulemaking to Implement Senate Bill 146	• Legislation required utilities to submit distribution resource plans to the commission; a utility asked the PUCN if it could accept stakeholder input	• Utility-led • Some meetings were led by expert stakeholders • LL: PUCN staff somewhat concerned with perceptions of utility bias but ultimately pleased with utility leadership	• The utility was open to input from a wide range of stakeholders • Consensus draft formed and parties filed their own comments regarding areas where consensus was not reached • Bias avoided by having all voices added to record	• Meetings via conference calls and webinars because of broad geographic spread of participants • Meetings twice per month • Information circulated at least a week in advance of meetings • Periodic updates provided to PUCN	• 2017–2018 • PUCN considered the draft regulation immediately following the process	• Final document was a draft regulation submitted to the PUCN
Public Utilities Commission of Ohio (PUCO) PowerForward Initiative	• PowerForward viewed as an educational process for commission and staff	• Mostly commission-led • Commission sought a facilitator with deep technical knowledge • A consultant was hired to facilitate two follow-up work groups, but initial panels were facilitated by PUCO chairman	• Utilities, the governor's office, and the legislature all provided suggestions for which stakeholders to include • Reached out to new stakeholders directly, sent general solicitation for participants (listserv and webpage), asked experts if there were any voices missing, published meeting notices in local newspapers and social media • PUCO traveled around the state to visit utilities and organizations to facilitate panels • Used funnel approach to educate: breadth to depth approach	• All presentations were webcast and held in-person • Meeting materials posted on the PUCO website • Work groups worked with consultants for one year to propose specific suggestions for how the PUCO should move forward	• 2017–2019 • Occurred in three phases • LL: Each phase improved on the previous; it was useful to have gaps between phases	• Commissioners wrote a final road map document that was a culmination of all the discussion and called for the formation of work groups • The road map was successful at educating staff and the commission. It was a useful baseline for stakeholders, and the stakeholders continue to reference the road map

Table 3 continued

State and Related Process	Scope	Facilitation Approach	Engagement Approach	Meeting Format	Timeline	Engagement Outcomes and Follow-Up Actions
Oregon Public Utility Commission Senate Bill 978 Stake-holder Process	• Commission wanted a process that was broad and inclusive because questions posed by Senate Bill 978 were broad • Engaged stake-holders to identify priority items • Bandwidth was available at the leadership level but not always at the staff level • Time and resource commitment from the PUC was essential to under-stand how the PUC should act	• Third-party facilitation • Two consultants were hired for the process: one served as a facili-tator and the other as a technical advisor • Third-party facilitation allowed PUC staff to partici-pate and weigh-in	• PUC staff conducted one-on-one interviews with stakeholders to understand what they wanted to get out of the process and how they wanted to engage • Meetings were open to the public and took place in two cities • White papers were devel-oped by the technical consultant and provided to stakeholders to fill knowl-edge gaps	• Stakeholders selected sub-groups of their interest and each subgroup created a 2-page consensus document	• 2018 • The timeline was set by legislation • Each month/meet-ing had its own interim milestone	• Final output was a legislative report with recommendations for legislative action. It was not a consensus document, but offered a chance for formal stakeholder comments • Identified an unofficial strategic plan for PUC focus • Momentum from the process can be used to start making changes
Puerto Rico Energy Bureau (PREB) Distribution Resource Planning	• Public feedback needed before initiating multiyear distribution plan-ning process • Ground rules of respect were reiterated at the beginning of every meeting	• Third-party facilitation • Each work group had a facilitator that communicated scope of the work group	• Invited organizations that had previously appeared in PREB proceedings • Published notices in news-papers about workshop • Compared with past PREB processes, workshops were well attended • The first workshop estab-lished general knowledge • Work groups put out a report by consensus • PREB was present during workshops as observers	• Participants were divided into 3 work groups—each aimed to provide PREB with recommen-dations on data and hosting capacity, resilien-cy, and planning • Microsoft Teams app used during workshops • Short and virtual meetings to get wider participation	• Monthly topical work groups held from 2019 to 2020 • Work groups met monthly	• Worked with U.S. Department of Energy to issue a white paper with recommendations that PREB will consider when developing regulation on distribution system planning

Table 3 continued

State and Related Process	Scope	Facilitation Approach	Engagement Approach	Meeting Format	Timeline	Engagement Outcomes and Follow-Up Actions
Rhode Island Public Utilities Commission Investigation into Changing Electric Distribution System and the Modernization of Rates	• Goal of the process was to populate a cost-benefit framework • Ground rules were set • Staff capacity was limited	• Third party–led facilitation • Consultants led the process, and staff participated at the stakeholder level • Facilitators provided some education throughout meetings	• Stakeholders petitioned to be a part of the process, which provided an overview of the subject matter • Informal conversations/ breakout groups when issues arose	• In-person meetings in the PUC hearing room	• Nine working group meetings between May 2016 and March 2017 • Stakeholder report accepted by PUC in May 2017	• Final output was a stakeholder report (non- consensus), which influenced a staff recommendation document that was adopted, in part, by the PUC • The process led to a consumer advocate-led initiative • LL: No Phase 2 on how to use the guidance document yet; would be helpful if stakeholders and utilities referenced; adding that Phase 2 for the new performance-based regulation process
Washington Utilities and Transportation Commission (UTC) Statewide Advisory Group	• UTC ordered commission staff and regulated utilities to form a joint advisory group to resolve issues with EE in the state's biennial conservation process	• Utility-led facilitation • Utility bias was a concern, leading to less consensus on questions of utility incentives	The joint advisory group was composed of members of each utility's existing advisory groups	• Met in-person and via webinar • One utility volunteered to host	• Seven meetings from 2018 to 2019	• Recommendations/ agreement coming out of the advisory group were proposed to the UTC on the topic at hand (but lack of consensus hurt process)

V. Stakeholder Engagement Decision-Making Framework

There is no single approach that PUCs should follow for undertaking a stakeholder engagement process. Rather, the success of the process is reliant on a design that is tailored to the unique ambitions and considerations of each state (Billimoria, Shipley, and Guccione 2019). More than a dozen states have used some type of robust stakeholder engagement process in recent years to inform their decision-making. With these experiences as reference, this paper presents a decision-making framework to guide PUCs in developing a process that accommodates their needs. It:

- Identifies factors that influence the selection of a stakeholder engagement approach,
- Provides emerging best practices for PUCs to consider,
- Offers key questions that influence the stakeholder engagement design process, and
- Points PUCs to additional relevant resources.

The stakeholder engagement decision-making framework offers commissions a road map of key questions they will answer in determining whether, and how, to implement dedicated stakeholder engagement processes as a way to inform their decision-making. The framework synthesizes the experiences of 11 commissions as they have undertaken stakeholder engagement efforts and provides a synopsis of emerging best practices and questions to consider at each of the key decision points.

This framework is not intended to serve as a step-by-step planning document or a prescriptive set of recommendations, but is designed to offer options for composing an effective stakeholder engagement planning process by presenting insights for each decision category. Categories discussed include the scope, facilitation approach, engagement approach, meeting format, timeline, and engagement outcomes and follow-up actions (see *Figure 3*). The categories are defined as follows:

- **Scope:** delineating the extent, or the bounds, of the stakeholder engagement approach. In this framework, the scope is discussed as a function of the focus, purpose, internal capacity, and initiating factor for the stakeholder process.
- **Facilitation Approach:** refers to who is leading the facilitation and the role of the facilitator throughout the stakeholder process.
- **Engagement Approach:** the methods used to engage stakeholders. The engagement approach is discussed through outreach and recruitment, communication of scope, stakeholder education and issue framing, and consensus building.
- **Meeting Format:** considerations for the structure and accessibility of the stakeholder engagement process.
- **Timeline:** the schedule of the stakeholder engagement process.
- **Engagement Outcomes and Follow-up:** the interim and final outputs of the stakeholder engagement process and relevant activities that continue or commence after the process is formally complete.

Figure 3. Stakeholder Engagement Decision-Making Framework Categories

A. Scope

Scoping allows commissions to clearly identify the focus, purpose, and initiator of a stakeholder engagement process, as well as assess the internal capacity to execute the approach. Scoping provides context for setting clear objectives and process parameters, which De Martini et al. (2016) identifies as one of the "must-do" factors that determines the effectiveness of stakeholder processes. This step includes establishing clear policy and business objectives, and defining the purpose and desired outcomes. Furthermore, the process of establishing the scope should result in a common understanding of what the process is and is not intended to achieve (De Martini et al. 2016).

Focus

Defining the focus sets the tone and structure for the entire stakeholder engagement process. It can lead to important subsequent decisions, such as helping to determine appropriate work groups, identifying when expert staff/ consultants might need to be engaged, or establishing the timeline. In general, the focus can be broad or narrow to address specific topic areas for further investigation.

Oregon's Senate Bill 978 stakeholder engagement process is an example of a process with a broader scope, as the law directed the Oregon PUC to "establish a public process for the purpose of investigating how developing industry trends, technologies, and policy drivers in the electricity

Related Resource

Renovate Solution Set

This solution set offers ready-to-implement approaches for regulators to consider when addressing challenges related to people and knowledge, managing risk and uncertainty, managing increased rate of chance, and complexity of objectives.

Smart Electric Power Alliance. 2020.
Renovate Solution Set
https://sepapower.org/resource/renovate-solution-set/

sector might impact the existing regulatory system and incentives currently employed by the commission" (Senate Bill 978). Within this broad scope, four major themes emerged from stakeholder discussions (Oregon Public Utility Commission 2018):

- Societal interests in climate change, social equity, and participation,
- Rapid change in capabilities and costs of new technology,
- Balancing individual choices and collective system goals, and
- Competition and market development.

Alternatively, in a process with a limited focus, the topic(s) of investigation may be predetermined by the legislature, commission, or stakeholders. The Washington Utilities and Transportation Commission (UTC) established the focus for its Statewide Advisory Group proceeding in a January 2018 order (Docket No. UE-171087, Order 01 2018). The UTC required that three electric utilities form a joint advisory group with all stakeholders to engage in discussion about whether Northwest Energy Efficiency Alliance (NEEA) savings should be included in conservation target calculations. The order specified that the discussions address:

- Whether to include the various subsets of NEEA savings,
- Whether the Energy Independence Act requires that NEEA savings be included in target calculations,
- Consistency with target setting requirements for consumer-owned utilities, and
- The degree of control the utilities have over NEEA's execution of its programs.

Purpose
In addition to focus, the purpose of the engagement process can take different forms. Generally, the purpose of a proceeding is investigatory or decisional in intent, or may evolve from an investigatory to a decisional process:

- An investigatory process is one that explores system needs or reform options, and can lead to outputs such as summaries of stakeholder concerns or recommendations for legislation or rulemaking. Ohio's PowerForward Initiative was an example of this type of approach.
- Decisional processes use outputs from the investigation phase to design rules or programs (Cross-Call et al. 2019). Nevada's investigation and rulemaking to implement Senate Bill 146 process offers an example of this type of approach.

Whether a process is investigatory or decisional will have a significant influence on how a commission will proceed with designing the timeline, facilitation approach, engagement approach, meeting format, engagement outcomes, and follow-up actions.

Internal Capacity
Evaluating the appropriate approach for stakeholder engagement also requires considerations of internal capacity. Commission feedback indicated that availability of staff, hosting options, data, and funding were all factors that influenced the stakeholder engagement approach. During the process design phase, commissions should take inventory of available resources and needs.

One area where capacity issues come to the forefront most obviously is around facilitation (see next section). Whether a commission chooses to have commission staff lead stakeholder facilitation, partner with an external third party, or encourage a utility to conduct an engagement process is driven by a combination of factors, most fundamentally around capacity.

Initiator of the Stakeholder Engagement Process
Additional characteristics that define the scope depend on the initiating actor behind the process. Processes can be initiated by the commission, through legislative or executive action, by stakeholders, or by utilities

(Cross-Call et al. 2019, 15–19). *Table 4* summarizes considerations relevant to the initiating approach that Cross-Call et al. (2019) discuss in Process for Purpose.

Table 4. Considerations for Approach Based on the Initiator of the Engagement Process

Initiator of the Process	Considerations for Approach
Commission-initiated process	• Regulators' decision to initiate process depends on the commission's interest in reform, statutory authority, and perceived political feasibility • Other influencing factors include: ◦ Grid needs and market forces ◦ Utility motivation ◦ Stakeholder support ◦ Commission resources and capacity ◦ Commission staff engagement
Legislative- or governor-initiated process	• Can provide legal justification or momentum for stakeholder engagement proceedings • The level of direction provided by policy makers varies
Stakeholder-initiated process	• Can help conduct initial analysis of system and regulatory needs and educate stakeholders, improve collaboration, and demonstrate support for reform • Can build an informal record of evidence to demonstrate need for reform • Useful when resources are limited • Discussions may eventually reside with a regulatory or other authorized agency to make actual policy changes • Risk of being viewed as skewed toward specific interest groups • May lead to utility resistance
Utility-initiated process	• May seed suspicion among participants of utility bias • May need to be housed in PUC dockets, where clear and comprehensive records can be developed

Emerging Best Practices

- Clearly define the scope of the proceeding early in the process.
- Communicate the purpose and goals to stakeholders early in the process.
- Assess commission capacity and identify where capacity may be limited.
    - Consider the possibility of needing to invest in increased staffing and/or additional resources to accommodate needs.

Key Questions for Commissions on Establishing the Scope

- What is the purpose of the process?
- Who is determining the focus of the process?
- Has the focus been explicitly defined prior to beginning stakeholder engagement? Or, will the stakeholder engagement process help define the focus?
- How does this process meet the commission's need in a way that could not be met in a litigated proceeding?

- Are there priority issues that must be addressed?
- How and when will the scope of the process be communicated to stakeholders?
- What is the capacity of the commission's staff, and what resources are available? Is there a need for additional resources?

B. Facilitation Approach

The facilitator plays a key role in the stakeholder engagement process by guiding and encouraging discussion, educating stakeholders or commission staff, and/or helping bring a group to consensus. A successful stakeholder engagement process thus relies on a skillful facilitator, but is also contingent on the facilitation approach.

This section of the framework explores three common facilitation approaches that have been employed by commissions: commission-led, utility-led, and third party–led. In a commission-led approach, commission staff often serve as facilitators. A utility-led approach relies on staff from the utility to convene and lead the facilitation. Last, in a third party–led approach, the commission will select a neutral organization to facilitate engagement. Feedback from commission experiences are summarized in *Table 5* with advantages and challenges associated with each approach.

Table 5. Commissioner Views on Advantages and Challenges Associated with Three Facilitation Approaches

Facilitation Approach	Advantages	Challenges	Examples
Commission-Led	• Ability to utilize staff with relevant expertise • Well-suited when utility or third-party facilitator may engender perceptions of bias	• Potential perceptions of staff bias • Limits staff capacity	• Ohio PowerForward • Michigan MI Power Grid • Maryland PC44 • Minnesota distribution system planning
Utility-Led	• Relieves staff when capacity is limited • Well-suited to handle complex topics	• Potential perceptions of utility bias, which may impede the ability to reach consensus	• Nevada Senate Bill 146 Investigation • Washington Statewide Advisory Group
Third Party–Led	• Relieves staff when capacity is limited • Allows for more meaningful participation from the commission • Contributes to transparency of the process • Limits perceptions of bias and increases transparency	• Facilitator may not have technical or historical background • Additional costs associated with hiring a third-party facilitator	• Arkansas DER dockets • District of Columbia MEDSIS • Puerto Rico Distribution Resource Plans • Oregon Senate Bill 978 • Rhode Island distribution system planning

Regardless of the facilitation approach, commissions should prioritize selecting a facilitator who is neutral and familiar with regulatory processes. In addition, the role of the facilitator should be well defined to build trust among participants (Cross-Call et al. 2019) and lead to a more transparent process.

Commissioners and staff interviewed for this publication shared that facilitator responsibilities often include the following:

- Outlining the scope of the proceeding,
- Establishing and enforcing ground rules,
- Deciding and communicating objectives for each meeting,
- Designing meeting agendas,
- Educating stakeholders on relevant issues,
- Communicating updates to commission staff,
- Leading, mediating, and negotiating group discussions,
- Providing direction and guidance on deliverables,
- Assigning homework to participants,
- Distributing meeting minutes and summaries,
- Providing draft summaries of opinions to stakeholders, and
- Inviting input and summarizing responses.

Emerging Best Practices

- Commissions select a neutral facilitator who is familiar with the regulatory process. Facilitators can be prequalified, and RFPs issued on a case-by-case basis to facilitators with demonstrated requisite expertise.
- Commissions prioritize receiving actionable input from stakeholders to make a decision and clearly communicate this priority to the facilitator.
- Some facilitators may not be aware of the historical relationships between stakeholders; in these instances, commission staff will need to bring the facilitator up to speed to understand how stakeholder relationships may have an impact on the current process.
- The role of the facilitator is clearly defined.
- Frequent communication between the facilitator and the commission can ensure alignment with commission objectives and allow the commission to adjust or incorporate process developments into its plans.
- Facilitators establish clear boundaries, goals, and ground rules with participants.

Key Questions for Commissions on Selecting a Facilitator

- How will the facilitator address concerns of bias?
- What is the intended role of the facilitator?
- How much technical knowledge should the facilitator have for their role in this process?
- Does the facilitator need to be aware of any historical relationships between stakeholders?
- Does the facilitator have experience building consensus or productive collaboration among diverse stakeholders?

C. Engagement Approach

Key aspects of the engagement approach include: outreach and recruitment, communicating scope, stakeholder education and issue framing, and consensus building.

Stakeholder Identification and Outreach

An inclusive approach assembles diverse stakeholders who are representative of the constituencies affected by commission decision-making, and is fundamental to a robust stakeholder engagement process (De Martini et al. 2016). This method has been underscored through innovative planning efforts such as the Task Force on Comprehensive Electricity Planning, led by NARUC and the National Association of State Energy Officials (NASEO; NARUC and NASEO 2020).[2] As task force members developed a vision for better aligned planning processes, they invited stakeholders and experts from across the electricity system to offer input about gaps and opportunities for improvement to electricity system planning. Invited stakeholders included those typically engaged in integrated resource planning or distribution planning processes and also those with a stake in the outcome who are not traditional participants. A sampling of the represented stakeholder categories included:

- Demand-side management or demand response providers and aggregators,
- DER developers, technology providers, and advocates,
- Electric utilities,
- Energy efficiency program administrators, providers, and implementers,
- Environmental groups,
- Large energy consumers,
- Low income and consumer advocates,
- Renewable energy developers,
- Regional transmission organizations and independent system operators,
- State environmental and state air regulators,
- State legislators, and
- Transportation electrification organizations and advocates (NARUC and NASEO 2020).

A relevant and diverse constituency of stakeholders can be identified by developing a stakeholder map. This method, described by the Energy Transitions Initiative: Islands Playbook (2015), helps to visualize stakeholders based on their impact on and interest in the outcome under consideration. The stakeholder map can also organize stakeholders based on the type of engagement required, such as to:

- Consult: regularly and actively seek support for and feedback on how best to achieve upcoming goals.
- Coordinate: establish an ongoing relationship regarding all aspects of the transition, ranging from day-to-day operations to timing significant milestones.
- Inform: keep the stakeholder apprised of developments and progress.
- Involve: invite the stakeholder to participate in certain activities, such as meetings or outreach that touch on the stakeholder's interest in the outcome.

Figure 4 provides an example stakeholder mapping matrix, which can be adapted by commissions seeking to use this approach.

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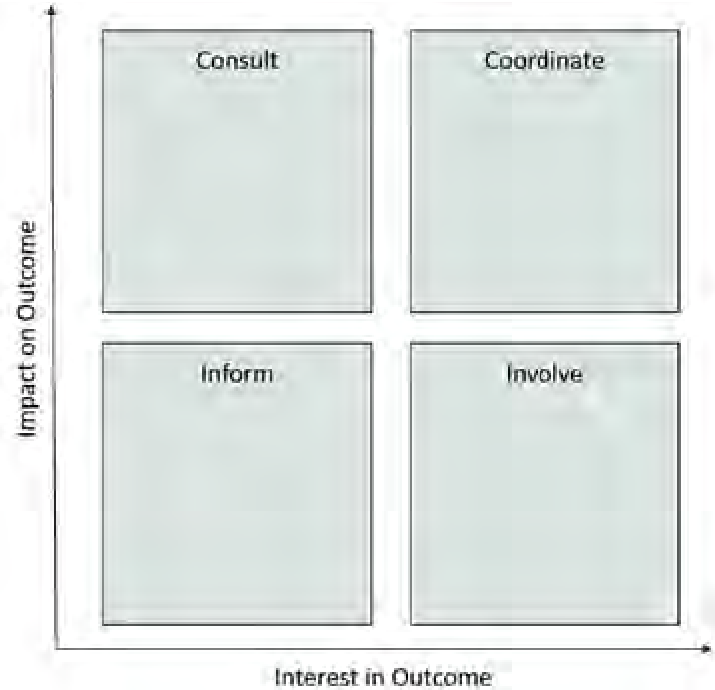
2 NARUC and NASEO, in partnership with the U.S. Department of Energy, launched the Task Force on Comprehensive Electricity Planning in 2018. This two-year initiative provided a forum for the development of state-led pathways toward planning for a more resilient, efficient, and affordable grid.

Figure 4. Example Stakeholder Mapping Matrix

adapted from Energy Transitions Initiative (2015)



Stakeholder outreach is another key component to organizing and inclusive approach. This view is shared among many of the commissions interviewed, who employed different methods to recruit and engage a wide range of stakeholders. Commissions utilized social media, newspapers, listservs, webpages, and professional networks for outreach.

- During Ohio's PowerForward initiative, the Public Utility Commission of Ohio (PUCO) worked with outside experts and states to determine if any stakeholders were missing. PUCO also discussed early stakeholder engagement efforts prior to the start of the PowerForward initiative. PUCO reached out directly to key stakeholders; staff visited their offices or held meetings to build relationships.
- Other stakeholder proceedings, such as the Washington Statewide Advisory Group, did not necessitate extensive public outreach, but utilized existing stakeholder structures.

Early and consistent engagement is also helpful for engaging stakeholders. This is particularly advantageous when the topic is highly technical, such as with Hosting Capacity Analysis (HCA; Stanfield and Safdi 2017).[3] Regarding HCA development and implementation processes in California, Minnesota, and New York, Stanfield and Safdi (2017, 25) note:

Related Resource

SB512 Research Project Report

California Senate Bill 512 directed the California PUC to study outreach efforts undertaken by other state and federal utility regulatory bodies and make recommendations to the commission to promote effective outreach.

California Public Utilities Commission News and Outreach Office. 2018. SB512 Research Project Report https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/About_Us/Organization/Divisions/News_and_Outreach_Office/SB%20512%20Research%20Project%20Report.pdf

3 "Hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades. HCA evaluates a variety of circuit operational criteria—typically thermal, power quality/voltage, protection, and safety/reliability—under the presence of a given level of DER penetration and identifies the limiting factor or factors for DER interconnections.

If regulators permit utilities to commit to a specific HCA method in advance, stakeholders engaged later may raise issues and insights, which show that method not best suited to the state's needs, leading to wasted time and expense. To avoid this pitfall, stakeholders should be engaged in the process of setting and refining the uses cases and goals for HCA and involved in every step of the HCA development and implementation process thereafter, including in selecting and refining the HCA method used, in evaluating results and in updating it as lessons are learned and methodologies improved.

Communicating Scope

Multiple commissions discussed the importance of clearly defining the scope of their proceedings, and several highlighted the importance of plainly communicating this scope to stakeholders to set expectations early and maintain focus throughout the process. After determining the focus and purpose of a stakeholder engagement process, commissions will utilize different strategies for communicating the scope of the proceedings to stakeholders.

- The Rhode Island Docket 4600 proceeding required interested stakeholders to complete a petition for participation. The petition included an overview of the subject matter, ground rules, and required potential participants to explain their stake in the process.
- For the MEDSIS proceeding, the District of Columbia Public Service Commission (DCPSC) developed charters for each work group, outlining the purpose and scope, as well as composition, term and schedule, responsibilities and duties, key questions to address, desired outcomes, and deliverables (DCPSC n.d.).
- During the Oregon Senate Bill 978 process, PUC staff developed a work calendar, which mapped how each workshop fit into the larger process. The work calendar also indicated when stakeholders might expect subgroup work and would be asked to provide written comments (Billimoria et al. 2019, 18).

When communicating scope to participants, the commission also has an opportunity to communicate ground rules, which can establish a foundation of trust and respect among participants. Ground rules and expectations for participation allow the stakeholder engagement process to level the playing field and foster open dialogue (De Martini et al. 2016). Ground rules are helpful, and may be considered necessary, even in smaller group settings (SEPA 2017).

Related Resource

Just Energy Policies and Practices Action Toolkit—Module 3: Engaging Your Utility Companies and Regulators

A guidance document for stakeholders to learn about how public utilities and PUCs operate and how they can engage.

Franklin, M., K. Taylor, L. Steichen, S. Saseedhar, and E. Kennedy. 2017. Module 3: Engaging Your Utility Companies and Regulators. Just Energy Policies and Practices Action Toolkit. NAACP Environmental and Climate Justice Program. https://naacp.org/wp-content/uploads/2014/03/Just-Energy-Policies-and-Practices-ACTION-Toolkit_NAACP.pdf

Basics of Traditional Utility Regulation and Oregon Context

A stakeholder briefing paper developed for the OR Senate Bill 978 process

Shipley, J. 2018. Basics of Traditional Utility Regulation and Oregon Context. The Regulatory Assistance Project http://esf-oregon.org/lib/exe/fetch.php?media=pdf:puc:oregon_978_framingpaper_rap_feb_16.pdf

A Citizen's Guide to the Public Utility Commission

A brief guide for stakeholders outlining basics of the Vermont PUC and how stakeholders can participate in proceedings

Vermont Public Utility Commission. 2019. A Citizen's Guide to the Public Utility Commission: Public Participation in PUC Proceedings https://puc.vermont.gov/sites/psbnew/files/doc_library/Citizens-Guide-2019.pdf

Stakeholder Education and Issue Framing

One of the challenges with assembling diverse stakeholders is addressing knowledge gaps with regards to both technical expertise and the situational context for decision-making. Establishing a baseline level of expertise before diving into the issues of the proceeding is particularly important for more technical proceedings, and establishing this baseline can help bolster collaboration and cultivate useful ideas (Billimoria et al. 2019). Stakeholder education can also encourage participation by representatives of residential consumers or help solicit comments from the general public.

Issue framing educates stakeholders on the larger decision-making context by providing a broader regulatory and/or policy background. Issue framing is also useful to help clarify the relevant jurisdictional issues for consideration. Often, the facilitator is responsible for leveling the playing field by providing background information to address technical gaps and frame issues, and can employ a range of different tools to do so. See *Table 6* for examples of tools used in proceedings to educate stakeholders:

Table 6. Tools for Stakeholder Education and Issue Framing

Tools for Stakeholder Education	Examples
Briefings and white papers	The Oregon Senate Bill 978 stakeholder process offered discussion and briefing papers developed by staff or outside experts to build a common understanding and frame issues (e.g., Basics of Traditional Utility Regulation and Oregon Context, and Trends in Technology and Policy with Implications for Utility Regulation; Billimoria et al. 2019, 22–23).
Petition for participation	The Rhode Island Docket 4600 proceeding required all interested stakeholders to complete a petition to participate. The petition provided an overview of the subject matter.
Presentations	During processes such as PowerForward, MEDSIS, and MI Power Grid, presentations in early meetings or work groups were used to establish general knowledge. During the PowerForward process, a funnel approach was used—providing a breadth of information at the beginning, then moving to specifics in subsequent meetings.
Engaging experts	During processes such as MEDSIS and MI Power Grid, outside and staff experts were engaged to address knowledge gaps.

Consensus Building

Commissions should ensure that stakeholders have full opportunity to actively voice their perspectives and concerns, particularly where it may be necessary to build consensus during the engagement process.

Facilitators often distributed minutes following meetings. In some instances, any matters that reached consensus were recorded in detail within the meeting minutes so stakeholders could review and understand what they agreed to. Facilitators may have more success reaching consensus with their group in small increments throughout the process, rather than on all matters at the end. This approach helps maintain consensus and avoid misunderstanding.

- One commission reported that such a misunderstanding occurred when a verbal agreement was made earlier in the process, but later fell apart when stakeholders recalled the earlier discussion in contradictory ways.

Even where consensus may not be reached, stakeholders should have a platform to communicate divergent views (Stanfield and Safdi 2017).

Related Resources

Collaborative Approaches to Environmental Decision-Making

A case studies–based guide for state agencies employing collaborative approaches to environmental decision-making.

Cohen, S. 2013. Collaborative Approaches to Environmental Decision-Making. MIT-Harvard Public Disputes Program. https://www.cbi.org/assets/files/NE%20Agency%20Guide%20to%20SE_FINAL.pdf

Alternative Dispute Resolutions at PUCs

A paper illustrating examples of alternative dispute resolution practices used at PUCs across the country.

Peskoe, A. 2017. Alternative Dispute Resolution at Public Utility Commissions. Harvard Environmental Policy Initiative. http://eelp.law.harvard.edu/wp-content/uploads/Alternative-Dispute-Resolution-at-PUCs-Harvard-Environmental-Policy-Initiative.pdf

Stakeholder Engagement through EE Collaboratives

Many PUCs across the country have used EE collaboratives as a way to solicit stakeholder input on EE programs. These collaboratives provide a flexible forum for stakeholder input outside of litigated proceedings, and are a valuable method for assembling diverse voices, particularly the voices of nontraditional utility stakeholders. State and Local Energy Efficiency Action Network. 2015. Energy Efficiency Collaboratives. Michael Li and Joe Bryson.

https://www7.eere.energy.gov/seeaction/system/files/documents/EECollaboratives-0925final.pdf

- Working group facilitators during the Maryland PC44 proceeding, for example, met with stakeholders outside of the larger group to negotiate or mediate subsequent conversations.

Emerging Best Practices

- Engage stakeholders early and often throughout the process.
- If relevant to the proceeding, recruit stakeholders through a well-publicized process.
- Ensure trust and respect are built through clear communications and development of ground rules to support meaningful engagement.
- To accommodate stakeholders with a wide range of background knowledge, establish general knowledge using tools for stakeholder education early in the process.
- For consensus-building activities, maintain detailed meeting minutes.
- Reach consensus in small increments throughout the process, rather than on all matters at the end.
- Facilitate informal discussions to negotiate or mediate outside of the larger group.

Key Questions for Commissions on Identifying and Educating Stakeholders

- Is broad participation important to this proceeding?
- Which mediums are available for reaching potential stakeholders?
- Should stakeholders have a level of background knowledge prior to participating? If so, what is this level, and how will this be evaluated?
- What approach should be used to educate stakeholders?

D. Meeting Format

Stakeholder engagement will ultimately occur at various times and places. The venue(s) and level of inclusivity and accessibility are important decisions to consider.

Venues for Participation

Commissions can consider various venues for engagement and participation. Among the proceedings examined for this publication, commissions engaged stakeholders through town hall meetings, technical conferences, advisory groups, working groups, workshops, conference calls, and webinars. The Spectrum of Processes for Collaboration and Consensus-Building in Public Decisions (Orenstein, Moore, and Sherry 2008; *Figure 5*) presents a useful guide for commissions to consider when deciding which venues may be most appropriate given the scope of the process.

Figure 5. Spectrum of Processes for Collaboration and Consensus-Building in Public Decisions[4]

(Orenstein et al. 2008)

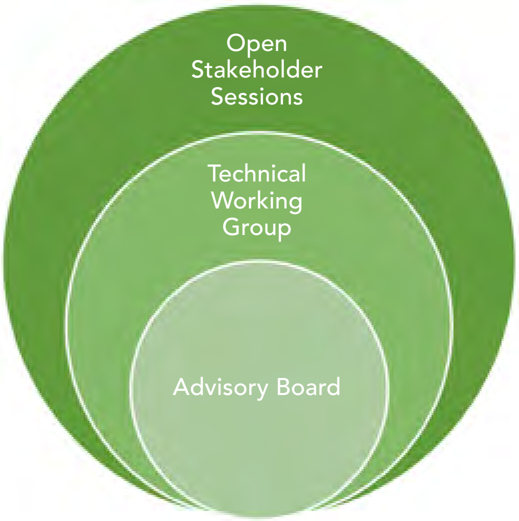
	Explore/Inform	Consult	Advise	Decide	Implement
Outcomes[5]	• Improved understanding of issues, process, etc. • Lists of concerns • Information needs identified • Explore differing perspectives • Build relationships	• Comments on draft policies • Suggestions for approaches • Priority concerns/issues • Discussion of options • Call for action	• Consensus or majority recommendations, on options, proposals or actions, often directed to public entities	• Consensus-based agreements among agencies and constituent groups on policies, lawsuits or rules	• Multi-party agreements to implement collaborative action and strategic plans
Sample Processes	• Focus Groups • Conferences • Open houses • Dialogues • Roundtable Discussions • Forums • Summits	• Public meetings • Workshops • Charettes • Town Hall Meetings (w & w/o deliberative polls) • Community Visioning • Scoping meetings • Public Hearings • Dialogues	• Advisory Committees • Task Forces • Citizen Advisory Boards • Work Groups • Policy Dialogues • Visioning Processes	• Regulatory Negotiation • Negotiated settlement of lawsuits, permits, cleanup plans, etc. • Consensus meetings • Mediated negotiations	• Collaborative Planning processes • Partnerships for Action • Strategic Planning Committees • Implementation Committees
Use When	• Early in projects when issues are under development • When broad public education and support are needed • When stakeholders see need to connect, but are wary	• Want to test proposals and solicit public and stakeholder ideas • Want to explore possibility of joint action before committing to it	• Want to develop agreement among various constituencies on recommendations, e.g. to public officials	• Want certainty of implementation for a specific public decision • Conditions are there for successful negotiation	• Want to develop meaningful on-going partnership to solve a problem of mutual concern • To implement joint strategic action
Conditions for Success	• Participants will attend	• There are questions or proposals for comment • Affected groups and/or the public are willing to participate	• Can represent broad spectrum of affected groups • Players agree to devote time	• Can represent all affected interests and potential "blockers" • All agree upfront to implement results, incl. "sponsor" • Time, information, incentives and resources are available for negotiation	• Participants agree to support the goal for the effort • Participants agree to invest time and resources • Conditions exist for successful negotiations

Part of achieving an effective organizational structure is maintaining a manageable group size while simultaneously including a wide range of stakeholders. De Martini et al. (2016) recommends keeping group size to 20 or fewer, as effective decision-making has been shown to diminish with groups sized up to this critical threshold. To accommodate a wider range of people while maintaining a small group size, they suggest commissions use a multitier approach (*Figure 6*), as was used in the New York Reforming the Energy Vision (REV) and California More than Smart proceedings.

4 Developed by Suzanne Orenstein, Lucy Moore, and Susan Sherry, members of the Ad Hoc Working Group on the Future of Collaboration and Consensus on Public Issues, in consideration of and inspiration from the spectra developed by International Association for Public Involvement. http://www.iap2.org/associations/4748/files/IAP2%20Spectrum_vertical.pdf) and the National Coalition for Dialogue and Deliberation. http://www.thataway.org/exchange/files/docs/ddStreams1-08.pdf

5 While all types of processes have intrinsic value on their own, those on the right side of the spectrum tend to include early phases akin to those on the left side and those on the left side often support participants in moving to next steps akin to those on the right side.

Figure 6. Example Structure of a Multitier Organization Approach to Engagement
adapted from De Martini et al. (2016)



Within the multitier approach, an advisory board can provide guidance on the objectives, scope, schedule, and deliverables. The advisory board should also be representative of the participants. Working groups can serve as the forum for addressing more technical issues and consist of subject matter experts. De Martini et al. suggests working groups be compromised of no more than approximately 20 people. However, working group participation can be expanded by including more stakeholders virtually. Outside of working groups and advisory boards, a larger group of stakeholders can get involved through open stakeholder sessions. (De Martini et al. 2016).

Related Resources

Best Practices for Virtual Engagement
A guidance document offering considerations and techniques for effective virtual public engagement.

Local Government Commission. 2020. Best Practices for Virtual Engagement. https://www.lgc.org/wordpress/wp-content/uploads/2020/05/LGC_Virtual-Engagement-Guide_5-2020.pdf

Increasing Access to Public Meetings and Events
A tip sheet with guidelines for increasing access to public meetings and events.

Institute for Local Government. Increasing Access to Public Meetings and Events for People with Disabilities. https://www.ca-ilg.org/sites/main/files/file-attachments/inreasing_access_to_public_meetings_and_events.pdf

Virtual Meeting Experiences—An Exchange
Insights from a peer exchange facilitated by NARUC's Center for Partnerships and Innovation on commission virtual meeting experiences.

NARUC. 2020. Virtual Meeting Experiences—An Exchange. https://pubs.naruc.org/pub/72D219DD-155D-0A36-317C-03B95EF37742

Accessibility

An open and inclusive stakeholder process ensures that participation is accessible. Measures for accessibility include announcing meetings well in advance, holding meetings in a neutral location, hosting in-person and virtual meetings, utilizing technology to maximize meaningful participation, and maintaining meeting minutes (Stanfield and Safdi 2017). Additional considerations for accessibility include providing language services, hosting meetings outside the hours of 9 a.m. to 5 p.m., and making accommodations to people with disabilities. Ways that commissions can increase accessibility for people with disabilities include (Institute for Local Government n.d.):

- Making accommodation/accessibility statements on meeting announcements,
- Ensuring meeting space is fully accessible,
- Being aware of food sensitivities, if food is served,
- Offering meeting material in alternative formats, such as raised print, large print, Braille, or audio file,
- Ensuring sound equipment is clear,
- Designating and enforcing regularly scheduled break times, and
- Providing virtual options for participation.

Of the 11 stakeholder engagement proceedings reviewed for this publication, meetings were generally held in-person, but some proceedings also provided virtual options for participation to engage a broader audience. Websites and listservs were used for distributing meeting materials such as ground rules, agendas, meeting minutes, and other background documents. Furthermore, because of the COVID-19 pandemic, most commissions have had experience facilitating virtual convenings, including stakeholder processes. Insights and best practices from a few states were gathered during a peer exchange hosted by NARUC in May 2020. A summary of these experiences, additional questions, and relevant resources can be found in the Virtual Meeting Experiences—An Exchange document. These experiences can provide further guidance for commissions seeking to utilize virtual methods of stakeholder engagement even after the pandemic.

Emerging Best Practices

- Consider a multitier organizational approach for engagement.
- Evaluate barriers to access that potential stakeholders may face and outline steps for eliminating or reducing these barriers to participation.
- Set limits to the number of participants per meeting.
- Offer virtual options to enable increased participation.
- Consider meeting times outside of traditional business hours.
- Distribute meeting materials in advance.
- Take meeting minutes and distribute notes after meetings, with extra attention paid to any matters that reached consensus so that stakeholders can review the outcome(s).
- Consider the role of commissioners and commission staff in meetings.

Key Questions for Commissions on Meeting Venues, Platforms, and Accessibility

- What venues of participation are most appropriate for this type of engagement?
- What steps are being taken to ensure that the process is accessible to all potential participants?
- How many stakeholders is the commission anticipating will be involved in the process?
- What is the maximum number of participants that can participate in any meeting? Does this number change for in-person versus virtual meetings?
- Are there any logistical constraints limiting the size of stakeholder groups/meetings?
- What overall organizational structure should be employed? Should the process consist of an advisory board?
- Are stakeholders expected to come to consensus? If so, what steps will be taken if consensus is not able to be reached?
- Is virtual participation an option? What platforms are available?
- What online platforms are available for sharing meeting documents?
- Will commissioners or staff participate in meetings? If so, how?

E. Timeline

Feedback from commissions revealed the importance of setting timelines to anticipate times when disagreements might arise and prepare for difficult discussions during the stakeholder engagement process.

In many instances, the stakeholder engagement process timeline was divided into phases with interim milestones throughout the process. Several interviewees also noted the benefit of intentionally designing timelines to allow for flexibility and adaptability. The Rocky Mountain Institute also recommends using a multistage process, which allows for valuable discussion and iteration (Cross-Call et al. 2019).

- The phases in Ohio's PowerForward initiative, for example, were separated by a few months to accommodate any changes or allow for more information gathering.
- One commission noted that their approach involved defining the scope and participation prior to defining the timeline, and that the timeline was set by working backward from final product due dates.
- Stakeholders who participated in the Oregon Senate Bill 978 process discussed the need to ensure the timeline was clear to participants, including the number of meetings and length of time to completion (S.B. 978, Appendix A).

The timeline is important both for commissions and stakeholders. *Figure 7* provides a sample time-base outline of key types of information to determine and communicate, which can be adapted to commission needs and help describe the process to the public.

Figure 7. Sample Timeline with Key Details

Emerging Best Practices

- When final product due dates have been decided, consider setting the timeline by working backward from these dates.
- Design timelines to accommodate the need for flexibility.
- Clearly communicate the timeline to stakeholders early in the engagement process. Include who will be engaged at each step, relevant outputs, and milestones.

Key Questions for Commissions on Determining a Process Timeline

- Can the process be divided into phases? If so, how?
- What are the interim milestones that indicate the process can move toward the next phase?
- When are the due dates of final products?
- What resources are needed at each step?
- Which stakeholders will be involved at each step?
- Which staff members or facilitators will be involved at each step?
- What are the relevant activities for each step?

F. Engagement Outcomes and Follow-Up

Commissions have leveraged stakeholder engagement processes to develop a range of interim and final outputs that could feed into broader regulatory processes. Among interviewees, there was a mix of both consensus and nonconsensus documents; in some circumstances, stakeholders were provided with the opportunity to comment on documents before the final product was sent to the commission. These products have included:

- Reports with recommendations for the commission or legislature,
- Draft regulations,
- Road maps,
- Summaries of issues and opinions, and
- Stakeholder submitted proposals.

The period immediately following a stakeholder engagement process offers a unique opportunity for commissions to follow up on the outputs from the engagement process. The decision-making momentum and newly opened channels of communication can allow for the collaborative efforts to continue (Cohen 2013).

- For the PowerForward Initiative, PUCO conducted follow-up work groups facilitated by a third party, which was intended for stakeholders to propose how the commission could move forward.
- Consideration of next steps arose as a challenge for proceedings associated with the Oregon Senate Bill 978 stakeholder process. Challenges included figuring out how to evolve recommendations into specific and clear steps while considering resource constraints, and how to translate priorities into concrete action. The process also led to recommendations to the legislature that were not ultimately incorporated by the legislature.

In addition to engaging in continued collaboration, follow-up activities can also involve seeking feedback from participants after the engagement process. At the conclusion of MEDSIS, the DCPSC released a stakeholder survey, which provided the commission insight into how well the process worked for stakeholders. Alternatively, commissions can gather feedback from participants at regular intervals during the process to make necessary corrections mid-stream (Cohen 2013).

Emerging Best Practices

- Set clear intentions for how stakeholders will contribute and give input to the development of interim and final process products.
- During the planning process, consider and set resources aside to continue follow-up discussions and activities.
- Solicit input from stakeholders on the engagement process and use feedback to incorporate and demonstrate process improvements.

Key Questions for Commissions on Outputs and Next Steps

- How and to what extent will stakeholder inputs be incorporated into process products?
- What opportunities are there to follow up on proceeding outputs? Does the commission have resources ready to utilize if the opportunity arises?
- What type of feedback from stakeholders could help to improve future processes?
- Given the structure of the process, can feedback be gathered at regular intervals?

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Name: Elizabeth

Record Number: ab219a21

Delivery Method: Digital Submission

Comment:

Please don't increase the monthly rates. Half of Az residents can't afford that.

Name: Tatyana Johnson

Record Number: MI7100456

Delivery Method: Other

Attachments: PriceProcessSignatures_Rousseau_Received.pdf; PriceProcessSignatures_Dobson_Received.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7100456*

Comment:

Hand-Delivered Letters dated 2/19/2025 addressed to President Rousseau and Vice President Dobson from Tatyana Johnson representing **Mi Familia en Accion** with attached petition including 200 signatures.

<u>Petition Language</u>

SRP: NO RATE INCREASES!!

As customers of SRP, we, the undersigned, say NO to rate increases! Under the new SRP rate proposal, all customers would pay more for electricity. Residential customers would pay 3.4% more per year on their electricity bills, while residential solar customers would face a higher average increase of 5.5%. With inflation and the high cost of housing, too many families, students and workers in the Phoenix metro area are already struggling. Arizona residents deserve affordable energy rates - these changes will only drive up our bills and make it harder to make ends meet. SRP, listen to your customers - now is NOT the time to raise our rates!

See letter attachments

February 19, 2024

Dear President David Rousseau,

Re: Comments in response to 2025 Pricing Process

We, along with the enclosed 200 SRP customers, are writing to express our opposition to SRP's proposed rate increase and associated changes to the pricing structure. While we recognize the importance of infrastructure investments and the challenges of balancing costs, we encourage SRP to adopt a more balanced approach that minimizes customer financial impacts while advancing long-term sustainability.

As an organization that works with the Latino community throughout metro Phoenix, we are expressing our concerns about the undue harm these rate increases will have on community members within your service areas. Many Latino and working-class families already pay a higher percentage of their income on utility bills. Families are struggling to make ends meet, especially with the current cost of living. A higher electric bill would mean less money for rent, food and healthcare– things one cannot live without.

We respectfully urge SRP to explore alternatives that address these concerns, ensuring affordability, equity, and a commitment to cleaner energy solutions that benefit all stakeholders.

Thank you for your time and consideration.

Sincerely,
Tatyana Johnson

Organizer

Mi Familia en Acción

PHOENIX, AZ
TATYANA JOHNSON
CIVIC ENGAGEMENT ORGANIZER
[redacted]
mifamiliaenaccion.org | mifamiliavota.org
Mi Familia en Acción | @mfenaccion
@mifamiliavota

MI FAMILIA EN ACCIÓN

February 19, 2024

Dear Vice President Christopher Dobson,

Re: Comments in response to 2025 Pricing Process

We, along with the enclosed 200 SRP customers, are writing to express our opposition to SRP's proposed rate increase and associated changes to the pricing structure. While we recognize the importance of infrastructure investments and the challenges of balancing costs, we encourage SRP to adopt a more balanced approach that minimizes customer financial impacts while advancing long-term sustainability.

As an organization that works with the Latino community throughout metro Phoenix, we are expressing our concerns about the undue harm these rate increases will have on community members within your service areas. Many Latino and working-class families already pay a higher percentage of their income on utility bills. Families are struggling to make ends meet, especially with the current cost of living. A higher electric bill would mean less money for rent, food and healthcare– things one cannot live without.

We respectfully urge SRP to explore alternatives that address these concerns, ensuring affordability, equity, and a commitment to cleaner energy solutions that benefit all stakeholders.

Thank you for your time and consideration.

Sincerely,
Tatyana Johnson

Organizer

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MI FAMILIA EN ACCIÓN | MI FAMILIA VOTA

PHOENIX, AZ
TATYANA JOHNSON
CIVIC ENGAGEMENT ORGANIZER

[redacted]

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Mi Familia en Acción I @mfenaccion
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SRP: NO RATE INCREASES!!

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Genesis	Corral	85251	[redacted]	
Cody	Makil	85256		
Max	Dallyn	85013		
Abigail	Marquez	85012		
Jan Dwayne	Cacnio	45051		
Kimberlee	Christiansen	85008		
Mason	Kizih	85018		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Ava	Phillips	85288	[redacted]	
Eman	Massoud	85233		
Grace	Hadley	85201		
Cynthia	Gonzalez	85051		
Maribel	Cacho	85342		
Wendy	Benson	85027		
Jessica	Hunt	85013		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Alexis	Diaz	85202	[redacted]	[redacted]
Mabel	Sproule	85629	[redacted]	[redacted]
Gaytan	[illegible]	85035	[redacted]	[redacted]
Johann	Sproule	85629	[redacted]	[redacted]
Michelle	Stone	85017	[redacted]	[redacted]
Cynthia	McWhorter	85014	[redacted]	[redacted]
Jaqueline	Jimenez	85388	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Brionnin	Gross	85015	[redacted]	[redacted]
Lourdes	Roman	85355	[redacted]	[redacted]
Denise	Chavarria	85051	[redacted]	[redacted]
Andy	Peraza	85006	[redacted]	[redacted]
Jeanette	Aguilar	85019	[redacted]	[redacted]
Sofia	Silva	85008	[redacted]	[redacted]
Janette	Hernandez	85013	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Tatyana	Johnson	85014	[redacted]	
Greg	Olszta	85143		
Osvaldo	Alvarez	85033		
Jeremy	Garrett	85282		
Armonee	Jackson	85284		
Victoria	Stahl	85037		
John	Stahl	85037		

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NOMBRE DE PILA	APELLIDO	CÓDIGO POSTAL	TELÉFONO	CORREO ELECTRÓNICO*
Stephanie	Vargas	85353	[redacted]	[redacted]
Marisa	Mata	85008	[redacted]	[redacted]
Leo	Araiza	85353	[redacted]	[redacted]
Derek	Duba	85003	[redacted]	[redacted]
Alex	Murillo	85021	[redacted]	[redacted]
Chris	Hill	85233	[redacted]	[redacted]

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NOMBRE DE PILA	APELLIDO	CÓDIGO POSTAL	TELÉFONO	CORREO ELECTRÓNICO*
Jennifer Might	6202 E Catalina Dr Scottsdale AZ	85251	[redacted]	[redacted]
Richard Gage	6202 E, CATALINA SCOTTSDAL	85251	[redacted]	[redacted]
Mary Jo Kelsey	6138 E. Avalon Dr Scottsdale, AZ	85251	[redacted]	[redacted]
Kristy Stanford	3285 E Ray Rd PH, AZ 85044		[redacted]	[redacted]
ROBERT HOWARD	515 N. CITRUS LANE GILBERT, AZ ~~85234~~	85234	[redacted]	[redacted]

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NOMBRE DE PILA	APELLIDO	CÓDIGO POSTAL	TELÉFONO	CORREO ELECTRÓNICO*
Elsa	Osorio	85301	[redacted]	
Fernando	Flores	85301		
Ana loaiza	Loaiza	853946		
Vanessa	Hernandez	85037		
Jose	Hernandez	85037		
Janete	Martinez	85014		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Tatyana	Johnson	85014	[redacted]	[redacted]
Jp	Smith	85383	[redacted]	[redacted]
Jack	Tuber	85381	[redacted]	[redacted]
Robert	Longoria Jr.	85205	[redacted]	[redacted]
Elizabeth	Hourican	85015	[redacted]	[redacted]
Victor	Jaime	85022	[redacted]	[redacted]
Saundra	Cole	85037	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Nicole	Morales	85043	[redacted]	[redacted]
Carl	Freeman	85710	[redacted]	[redacted]
Linda	Stenholm	85282	[redacted]	[redacted]
Elena	Morra	85338	[redacted]	[redacted]
Kathryn	Dorn	85284	[redacted]	[redacted]

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NOMBRE DE PILA	APELLIDO	CÓDIGO POSTAL	TELÉFONO	CORREO ELECTRÓNICO*
Nancy	Ramirez	85353	[redacted]	
Adamy	peña	85204		
Carmen	Duran	85017		
Gustavo	Felix	85035		
Martha	Angulano	85019		
Selina	Razoco	85019		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Sylvia	Adamec	85382	[redacted]	[redacted]
Jose	Dominguez	85303	[redacted]	[redacted]
Miguel	Vega	85037	[redacted]	[redacted]
Mariela	Cruz	85323	[redacted]	[redacted]
Andrea	Tinoco	85301	[redacted]	[redacted]
GuadalupeLopez	Lopez	85041	[redacted]	[redacted]
[illegible]	Bonilla	85008	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Michael	Stuart	85041	[redacted]	[redacted]
Cecilia	Acosta	85353	[redacted]	[redacted]
ROBERTO	PACHECO	85326	[redacted]	[redacted]
Luis	Gnuchola	85828	[redacted]	[redacted]
Victor	Encinas	85353	[redacted]	[redacted]
vivian	Lara	85326	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Felipe	Lotfsner	85323	[redacted]	
Melina	Nava	85353		
Heidi	Del Rio	85035		
Stephanie	Fernandez	85323		
Yanira	Herrera	85017		
Gonzalo	Baeza	85353		
Vanessa	Nieto	85353		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Jose	VArGAS G.	85305	[redacted]	[redacted]
Juana	Gonzalez	85305	[redacted]	[redacted]
Miguel	Ramirez	85392	[redacted]	[redacted]
patty	Ramirez	85392	[redacted]	[redacted]
ramon	ortiz	85353	[redacted]	[redacted]
Griselda	Rojas	85323	[redacted]	[redacted]
[illegible]	[illegible]	[illegible]		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Grace	Humphery	85251	[redacted]	
John	corral	85258		
Johnny	CORRAL	85250		
Veronica	corral	85257		
Margarita Cor	Corral	85250		
Sarah	Martin	85251		
Paige	Molina	85255		

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NOMBRE DE PILA	APELLIDO	CÓDIGO POSTAL	TELÉFONO	CORREO ELECTRÓNICO*
Sean ~~Ramirez~~	Ramirez	85251	[redacted]	[redacted]
Joe	Amadio	85258	[redacted]	[redacted]
Reba	Corral	85257	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Alex Bryant	Bryant	85251	[redacted]	[redacted]
Diana Corral	Corral	85250	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Catherine	Herman	85008	[redacted]	
Pat	Barrett	85209		
Edarra	Johnson	85308		
Vanessa	Cady	85201		
Araceli ~~Coronado~~	Coronado	85201		
Angela	Kelley	85015		
Jake	Stoner	85201		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Jessee	Stalcup	85268	[redacted]	[redacted]
Kent	Stalcup	85268	[redacted]	[redacted]
Truly	Klingler	85143	[redacted]	[redacted]
Justine	Dachel	85008	[redacted]	[redacted]
Ash	Luden	85008	[redacted]	[redacted]
Eunice	Balgara	85323	[redacted]	[redacted]
Fernanda	Frias	85305	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Bob	HEIDENREICH	85203	[redacted]	
Morgan	Kurtz	85012		
michael	Six	85201		
Philip	Minette	85306		
Shirley	Thomas	85224		
JAMES	moses	85205		
BRIAN	SATTERTHWAITE	85202		

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Matilda	Martinez	85256	[redacted]	[redacted]
Pam	Morrison Kellen	85041	[redacted]	[redacted]
Roland	Selaya	85282	[redacted]	[redacted]
Amanda	Lee	85225	[redacted]	[redacted]
Mia	De la Torre	85282	[redacted]	[redacted]
CHRISTY	HURST	85282	[redacted]	[redacted]
Doris	Hardwidge	85345	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Geraldine	Cornejo	85353	[redacted]	
Lola	Kim	85138		
PAUL	EDMEIER	85042		
Ignacia	Muniz	85016		
Rena	Aldrich	85018		
Jiana	Karim	85298		
DAVID	NANCE	85021		

MI FAMILIA EN ACCIÓN

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SRP: NO RATE INCREASES!!

As customers of SRP, we, the undersigned, say NO to rate increases! Under the new SRP rate proposal, all customers would pay more for electricity. Residential customers would pay **3.4% more per year** on their electricity bills, while residential solar customers would face a higher average **increase of 5.5%**. With inflation and the high cost of housing, too many families, students and workers in the Phoenix metro area are already struggling. Arizona residents deserve affordable energy rates — these changes will only drive up our bills and make it harder to make ends meet. **SRP, listen to your customers – now is NOT the time to raise our rates!**

FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
MARJORIE	Greenhut	85044	[redacted]	[redacted]
Derek	Carbajal	85208	[redacted]	[redacted]
Cynthia	Leach	85281	[redacted]	[redacted]
Sky	Hugo	85303	[redacted]	[redacted]
Michael	Glazier	85044	[redacted]	[redacted]
CHRISTINE	WILSON	85041	[redacted]	[redacted]
Marcella	Calzado	85044	[redacted]	[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Carey	Nolan	85281		[redacted]
Bunny	Marcinkute	85303		[redacted]
Tara	Simmons	85234		[redacted]
Michael	Browder	85012		[redacted]
Nathan	Landis	85251		[redacted]
William	Wilson	85741		[redacted]
Gregory ~~Luebkin~~	Luebkin	85302		[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Landon	Nef	85215	[redacted]	
Jaclyn	Brown	85202		
John Brown	Brown	85202		
Kimberlee	Carter	85302		
Deborah	Nagurski	85044		
Jesse	Verdugo	85202		
Renee	Porter	85202		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Isidro	Olivos	85326		
Kenedie	Reynolds	85020		
Bree	Nef	85215		[redacted]
Beth	Trachy	85003		[redacted]
Armand	Massimini	85032		[redacted]
Cindy	Gaspar-Rust	85213		[redacted]
Lisa	Roseburgh	85302		[redacted]

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Kevin	Wisema	85209	[redacted]	
Catherine	Bacon	85044		
Krystal	Gauvin	85044		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Rita	Shannon	85015	[redacted]	
Russell	Fedorka	85018		
Judith	Coburn	85205		
Megan	Rodman	85284		
Adrienne	O'Donnell	85225		
JULIE	GALLEGOS	85210		
LAURA	HEIDENREICH	85203		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Tyler	Velarde-Day	85257	[redacted]	[redacted]
Nicholas	Reiels	85016	[redacted]	[redacted]
Francisco	Figueroa	85283	[redacted]	[redacted]
Breanna	Cisneros	85392	[redacted]	[redacted]
Brittania	Figueroa	85283	[redacted]	[redacted]
Taylor ~~Ma~~	Clore	85201	[redacted]	[redacted]
Heidi	Estrada	85283	[redacted]	[redacted]

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SRP: ¡¡SIN AUMENTOS DE TARIFAS!

Como clientes de SRP, los abajo firmantes decimos ¡NO a los aumentos de tarifas! Según la nueva propuesta tarifaria de SRP, todos los clientes pagarían más por la electricidad. Los clientes residenciales pagarían **3,4% más al año** en sus facturas de electricidad, mientras que los clientes solares residenciales enfrentarían un promedio más alto **aumento del 5,5%**. Con la inflación y el alto costo de la vivienda, demasiadas familias, estudiantes y trabajadores en el área metropolitana de Phoenix ya están pasando apuros. Los residentes de Arizona merecen tarifas de energía asequibles; estos cambios solo aumentarán nuestras facturas y harán que sea más difícil llegar a fin de mes. **SRP, escucha a tus clientes – ¡Ahora NO es el momento de aumentar nuestras tarifas!**

NOMBRE DE PILA	APELLIDO	CÓDIGO POSTAL	TELÉFONO	CORREO ELECTRÓNICO*
Ellen ~~Dillon~~	Dillon	85042	[redacted]	
Michael	Beltran	85035		
Monica	Sandschafer	85041		
Nicholas	Wiesinger	85041		
Candi	Fleischman	85257		
Ellen	Smith	85234		

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FIRST NAME	LAST NAME	ZIP CODE	PHONE	EMAIL*
Christina	Felix	85257	[redacted]	
Jerod	Smith	85234		
Casey	Corbett	85251		
Angela	Sewell	85338		
Eliz	Beaty	85253		
Ruth	Allen	85282		
Rebeka	Magaña	85303		

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Name: Robert Rose

Record Number: MI7123511

Delivery Method: Mailed to SRP

Attachments: PriceProcessComment_20250224.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7123511*

Comment:

2/6/2025

Dear SRP Board Members,

I am writing as an SRP customer and advocate for solar energy and fairness. My family mode the decision to invest in solar power because it benefits our finances, community, the environment, and supports your decreased cost of production
and distribution. However, I am disheartened by current SRP's proposed rote changes, which threaten all four.

Reducing the value of daytime solar production undermines the effectiveness of solar systems. discouraging clean energy investments that benefit all SRP customers. Additionally, penalizing newer solar customers with limited grandfathering protections feels deeply unfair. These changes do not align with SRP's stated commitment to sustainability. I believe we must prioritize solutions that support solar adoption, protect the
environment. and maintain fairness for all customers and providers.

Please reconsider these changes and stand with customers and providers like me who ore working toward a cleaner, more sustainable future.

Sadly, this has to be addressed this way,

Rob Rose

Rob Rose

[redacted]

RECEIVED
FEB 19 2025
BY:

Salt River Project
Board of Directors
1500 N. Mill Ave.
Tempe, AZ 85288

2/6/2025

Dear SRP Board Members,

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Sadly, this has to be addressed this way,

Rob Rose

Rob Rose

[redacted]

PHOENIX AZ 852

10 FEB 2025 PM 8 L

PAB315

~~PAB [illegible]~~

Salt River Project
Board of Directors
1500 N. Mill Ave.
Tempe, AZ 85288
2/6/2025

85288-125200

SRP Public Price Process Comments from: 2/20/2025

Name: Earl Schneider

Record Number: 3bb06622

Delivery Method: Digital Submission

Comment:

Why do you charge us with solar more? We are producing power.back on the line , so it saves you more, why charge us more?

Name: Barbara Temples

Record Number: 00ed2446

Delivery Method: Digital Submission

Comment:

In glendale many are retired and on fixed income. With the change in administration there shouldnt be an increase. Dont appreciate a raise in prices again. If energy prices go down how come the customer should be charged more when the price goes down for the company. Should just leave the prices where they are at and if energy goes down then customer prices should go down as well instead of going up. Budget billing going up too much

---

Name: Matthew Camp

Record Number: 2f6b3610

Delivery Method: Digital Submission

Comment:

I am not very excited in the slightest that solar customers are taking the biggest hike in this change. I like my E-27 customer generation plan. Where my solar is purchased back at a 1:1 rate AS IT SHOULD BE. All of the future alternative price plans have a solar export rate LESS than the "super off peak" hours cost to the customer. This is very disappointing. What can be done to maintain this price plan?

Name: Joy Bliss

Record Number: MI7105183

Delivery Method: Email to Corporte Secretary

Attachments: Give solar customers a fair deal!_Bliss.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7105183*

Comment:

Give solar customers a fair deal!

Dear Corporate Secretary,

SRP's rates and policies do not currently reflect that Arizona is a solar leader. I write now to urge SRP to reconsider its pricing and ensure that customers are rewarded for investing in clean and efficient technologies like solar power.

We have solar collectors and battery backup on our home. SRP's proposal to increase the monthly fixed charge discourages us customers from investing in clean energy.

I urge you to ensure that SRP's pricing plans are fair to customers who have chosen to invest in solar.

Thank you for your consideration,

Joy V Bliss

Sincerely,

Dr. Joy Bliss

Name: Gay Dybwad

Record Number: MI7106636

Delivery Method: Email to Corporte Secretary

Attachments: Give solar customers a fair deal!_Dybwad.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7106636*

Comment:

Give solar customers a fair deal!

Dear Corporate Secretary,

Arizona is a solar leader but SRP's rates and policies do not currently reflect that. I am writing to urge SRP to reconsider its pricing and ensure that customers are rewarded for investing in clean and efficient technologies like solar power.

Arizonans deserve energy choice and the opportunity to invest in local, resilient energy sources. SRP's proposal to increase the monthly fixed charge not only discourages customers from investing in clean energy projects, it also hits low-income households the hardest. Ultimately, high fixed fees discourage efforts to conserve electricity, putting more strain on Arizona's energy system.

Arizona is a leading producer in solar energy. I urge you to ensure that SRP's pricing plans are fair to customers who have chosen to invest in solar.

Thank you for your consideration,

Sincerely,

Mr. Gay Dybwad

Name: Kate Bowman

Record Number: MI7109424

Delivery Method: Email to Corporte Secretary

Attachments: Vote Solar comments to SRP Board 2.19.2025.pdf; FW_ Vote Solar Comments to SRP Board of Directors_ Public Pricing Process.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7109424*

Comment:

From: Kate Bowman
Sent: Wednesday, February 19, 2025 4:45 PM
To: John M Felty; SRP Corporate Secretary
Cc: David Bender; Robert Rigonan
Subject: Vote Solar Comments to SRP Board of Directors: Public Pricing Process

Hello Mr. Felty,

Attached please find Vote Solar's comments for distribution to the SRP Board of Directors in advance of the February 27, 2025 Board meeting.

Best,

Kate Bowman

Vote Solar

See attached Letter

VOTE SOLAR

Salt River Project Board of Directors
1500 N. Mill Ave
Tempe, AZ 85288
Via electronic mail to: [redacted]

February 19, 2025

Re: 2024–25 SRP Public Pricing Process

Dear Directors,

Vote Solar submits these comments to the Board related to Management's proposed adjustments to rates. Vote Solar is an independent 501(c)(3) non-profit organization working to repower the U.S. with clean energy by making solar power more affordable and accessible through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants, in order to realize a 100% clean energy transition that puts the interests, health and well-being of people at its center. Vote Solar has over 90,000 members nationally, including over 5,600 in Arizona. Vote Solar's members include individual customers of SRP who own and plan to own distributed solar generating systems.

As Vote Solar presented during the February 6 Board meeting, Vote Solar sees several areas of alignment with Management's proposal as well as several necessary changes to the proposal. As to areas of alignment, Vote Solar agrees with the proposal to eliminate higher – and in Vote Solar's view, discriminatory – fixed monthly service charges imposed on solar customers compared to customers without solar. Vote Solar also agrees that price plans E-16 and E-28 should be open to all residential customers, whether they have solar or not. We agree that the costs for a second meter, which is required by SRP for solar customers but is not necessary for providing them service, should not be allocated to solar customers in the Cost Allocation Study (CAS). We agree that time of use rates should send price signals to conserve during high-cost periods and that credits for solar customer exports should reflect the full avoided cost value of the electricity.

Vote Solar asks the Board to make the following changes to Management's proposal, which are discussed more fully below:

- Do not increase the fixed monthly service charge above the current $20 for the typical residential customer (including solar and non-solar) and consider reducing it to a level no higher than basic customer costs of metering, billing, and service connection.
- Ensure that the price for exports from solar customers and qualifying facilities under the QF-24 tariff equals full avoided cost, including SRP's own generation costs and bilateral contracts whenever higher than the CAISO energy market price.

- Permit solar customers to take service under all price plans available to non-solar customers, including E-23 and EZ-3 (until the latter closes in 2029).
- Make several changes to remove anti-solar biases from the Cost Allocation Study ("CAS"). First, remove the asymmetrical treatment of customer exports in the CAS by ensuring that all cost allocations are allocated on net load (deliveries reduced by exports) just as revenue calculations are net of export credits. Second, remove the disproportionate allocation of customer service costs to solar customers. Third, when comparing level of cost recovery for the solar customer subclass, compare solar customers to otherwise similar non-solar customers, such as non-solar customers with similar kilowatt-hour consumption and load factors.
- Reduce the E-16 on-peak period to three hours and align it with the E-28 on-peak window.
- Delay implementation of new price plans until a bill comparison tool is available to customers.
- Initiate a stakeholder process to inform the development of a Virtual Power Plant program for customer-sited energy storage.

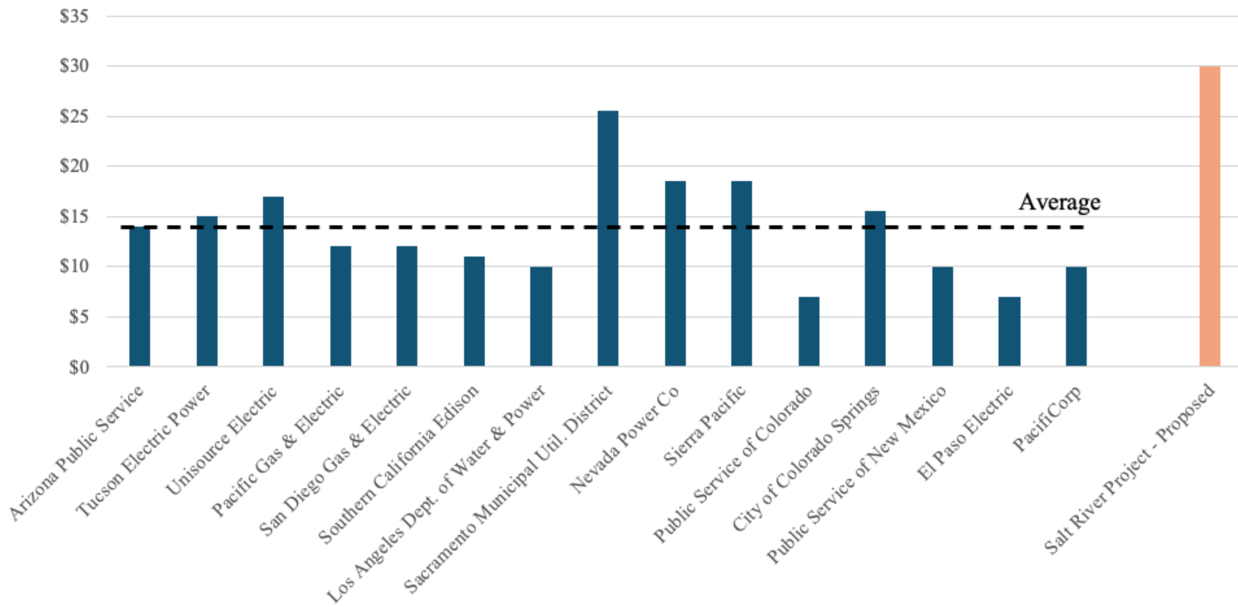
<u>Discussion</u>

1) Monthly Service Charge

Management proposes a tiered monthly service charge of $20 for multi-family homes, $30 for single-family homes, and $40 for large homes. A monthly service charge is also commonly known as a "fixed" charge because it is imposed on every customer, each month, regardless of how much electricity the customer consumes. Because the monthly service charge is fixed, it cannot be avoided or lowered by energy efficiency. A higher monthly service charge also raises utility costs for low-use customers, who are disproportionately low-income customers. Thus, fixed charges are overwhelmingly opposed by consumer advocates and regulatory commissioners.

The proposed $30 monthly service charge for a typical family is neither gradual nor proportionate. It reflects an increase of 50% from the current charge, and it far exceeds market norms. As illustrated in Figure 1, a survey of utilities in Arizona and neighboring states shows that the maximum monthly service charge for residential customers is $25, with an average of $14. SRP's proposed charge for single-family homes is more than double the average of other utilities – including the utilities that Management itself selected as relevant for comparing to SRP's rates.

Figure 1. Comparison of Utility Fixed Monthly Service Charge for a Typical Residential Customer.



The decision to collect a larger portion of revenue through a high fixed charge results in lower volumetric energy rates, weakening price incentives for energy conservation. A high fixed charge limits families' ability to reduce their monthly utility costs by conserving energy or investing in energy-saving technologies. Ultimately, this drives up costs for all customers because the utility must build new generation resources and infrastructure that could have been avoided or deferred by encouraging families to invest in energy efficiency and conservation instead. Of particular concern is the disproportionate impact on low-income households, who typically have lower energy usage and yet face higher energy burdens.

It has long been the practice of SRP, like most utilities, to utilize volumetric pricing to "incentivize reduced energy consumption" or "prudent energy consumption." Promoting conservation is a "feature of the [volumetric pricing] system rather than a bug."[1] Commissions around the country have repeatedly rejected high fixed charges because doing so undermines "customer inclination to save energy" and negatively impacts "lower-income and fixed-income customers."[2] Many utilities limit costs collected through fixed charges to the "basic customer costs" that vary with the number of customers on the system (including metering, billing, and service connection) in order to promote conservation and efficiency.[3]

[1] *In re Westar Energy, Inc*., 460 P.3d 821, 822–23 (Kan. 2020)
[2] Kansas Corporation Commission, Docket No. 08-GIMX-441-GIV Final Order ¶¶ 67, 76
[3] See e.g., *In re DTE Elec. Co.*, No. U-20162, 2019 WL 2028379, at *83 (May 2, 2019) ("monthly customer charge for residential and commercial secondary customers should only recoup those costs directly linked to the customer's mere existence (i.e., costs to connect the customer to the system)"); *In re Pac. Gas and Elec. Co.*, No. 16-06-013, Decision D.17-09-035 at 2, 33 (Cal.P.U.C. Sept. 28, 2017) (fixed charge should be limited to costs for account set-

The experience in Kansas is especially relevant here. In 2020, the Kansas Supreme Court reversed and remanded a commission-approved rate design specific to solar customers.[4] On remand, the utility proposed a grid access charge and, in the alternative, a $35 per month minimum bill for all residential customers.[5] A minimum bill is a fixed charge that only applies to customers if their bill is less than the minimum bill amount. A minimum bill is more favorable than a fixed charge because it preserves the incentive for moderate- or high-usage customers to conserve energy, but effectively operates like a fixed charge for low-use customers whose energy consumption would produce a bill lower than the minimum bill. Recognizing the impact that such rates have on low-income customers, the Kansas utility proposed to exempt low-income customers from the minimum bill.[6] Even so, the commission rejected a $35 minimum bill as "overly regressive" by "disproportionately hurt[ing] low-income customers" and because it "sends undesirable price signals" discouraging conservation.[7]

While the proposed $30/month fixed charge is too high, Management's proposal does have one positive feature: it eliminates the disparate treatment of solar customers by imposing the same monthly fixed charges for all residential customers regardless of whether they have solar. Equal treatment of customers with and without solar is required by law and appropriate. However, a $30 fixed charge is too high for all residential customers. Therefore, we strongly recommend that SRP follows the path of other commissions and limits the monthly service charge for all customers (solar and non-solar) to the existing $20 for a typical single-family home. While still higher than most other utilities in the region, it is closer and better aligns with SRP's sustainability goals while maintaining operational sustainability.

2) Definition of On-Peak

Vote Solar supports Management's efforts to develop time-of-use rates that send price signals encouraging customers to limit their electricity consumption during times when utility costs are highest. If customers respond to the price signal, it produces a win-win: bills are reduced for customers who shift usage to lower-cost hours and SRP's costs are reduced. However, for price signals to work, they must be actionable. Research demonstrates that shorter on-peak windows are more effective at driving energy savings because customers find them to be more manageable and actionable. The five hour on-peak window for price plan E-16 is too long

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up, metering services, billing and payment, all meter capital costs, and minimum observed costs for service drop and final line transformer); *In re Union Elec. Co.,* 320 P.U.R.4th 330 (Apr. 29, 2015) (limiting fixed charge to basic customer costs because "customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy").

[4] Westar, supra.

[5] *In re Westar Energy*, Docket No. 18-WSEE-328-RTS, Order ¶ 19 (Feb. 25, 2021).

[6] Id. para. 53.

[7] Id. para. 54-55, 59.

for many customers to manage around and will not be effective at driving energy conservation. For maximum impact and consistency, the Board should reduce the E-16 on-peak period to three hours and align it with the E-28 on-peak window. This streamlined approach would not only enhance customer participation, but also deliver more substantial energy and cost savings.

3) Price Plan Suite

Management proposes consolidating SRP's current ten residential price plans (including four solar-specific plans) into four options: E-16, E-23, E-24, and E-28. Two of these plans are new, and E-23 is a continuation of the current two-part flat rate with some adjustments. Under Management's proposal, non-solar customers would have access to any of those plans. Non-legacy solar customers would be limited to E-16 or E-28, while legacy solar customers could access E-23 (the Basic Price Plan). Existing price plans would be frozen to new customers (including customers switching between plans) and sunset by November 2029, when customers remaining on a frozen price plan would be moved to one of the four remaining plans.

We have two concerns with this transition plan. First, only solar customers will be required to take service on a TOU price plan. We support encouraging all residential customers to take service on a TOU price plan. However, if SRP elects to allow some residential customers to take service on a flat two-part rate (E-23), it must permit solar customers to do so as well. Disparate treatment of solar and non-solar customers is unlawfully discriminatory. Second, Management proposes moving solar customers on price plans E-15 and E-27 to price plan E-16. While we recognize Management's intent to move customers onto a price plan that is structured similarly to their old plan, this would eliminate net metering of exported energy and instead provide an export credit of 3.4 cents per kilowatt-hour. (The 3.4 cents is based on a purported "avoided cost" of energy. We disagree with the determination of this avoided cost value, which is addressed separately below). The dramatic reduction in bill savings from net metering to an avoided cost based export credit will surprise many customers. We expect that over time many customers may elect to install battery storage to manage the reduced value of exported electricity. To avoid surprises, the Board should provide a gradual step-down from the net metering credit to the final avoided cost based export rate. To ensure that customers make the decision to transition to a price plan that is in their best interest and install energy storage where appropriate, we encourage SRP to offer a bill comparison tool that helps customers understand which of the new price plans will result in their lowest costs and how battery storage would affect their bills. To the extent a bill comparison tool is not available when the new rates are in effect, the Board should start the gradual step down in export credits only after the tool is available to customers.

4) Cost Allocation

The current Cost Allocation Study (CAS) methodology significantly undervalues the contributions of distributed solar customers, creating an artificially inflated revenue deficiency for solar price plans. While Management's proposal will make most price plans available to solar and non-solar customers alike by using a common revenue requirement, rather than imposing different rates on solar and non-solar customers based on the CAS, we do not want to leave the incorrectly stated under-collection of costs from solar customers unaddressed. Management's calculation of solar customer cost recovery suffers several methodological problems that bias the analysis against solar customers.

A primary concern is that the CAS treats solar customer exports inconsistently. The primary purpose of the CAS is to allocate shared system costs to each customer class, calculate the revenue produced by each customer class, and compare the costs and revenues to ensure that each customer class is contributing to pay for shared system costs in an equitable manner. The CAS accounts for the cost of the export credit provided to solar customers as a reduction in revenues. That is, each kilowatt-hour a solar customer exports is reflected in the analysis as a revenue reduction based on the export credits to solar customers for the electricity they supply to SRP. However, not all cost allocations are reduced by exported electricity. While most categories of costs are allocated to customers with solar based on their net load (which equals deliveries minus exports), certain cost categories are allocated on delivered load. As a matter of simple math, the choice to allow exported electricity to fully reduce revenues but only partially reduce cost allocations produces an apparent revenue deficiency as a direct result of a policy choice alone. Additionally, the CAS allocates a disproportionate amount of customer service costs to solar customers. The customer service cost category includes services that all customers use and benefit from, such as the customer support call center, the blue stake program, and community events. Without a demonstration of specific additional customer service costs from solar customers, these costs should be smoothed across all customers.

A corrected analysis demonstrates that when customer service costs are smoothed and generation and ancillary services are allocated based on net load, the apparent revenue deficiency from solar customers is reduced to -3.4% on average, and solar price plan E-14 results in a positive return equal to the average residential return.

Another concern is Management's decision to compare the percentage of cost recovery from the solar customers – a subclass historically disfavored by Management – to the large and heterogenous residential class as a whole. Doing so incorrectly implies that any difference between the two categories is due to customers having solar, rather than other attributes. It also incorrectly implies – by omission – that no other sub-group within the broad residential class produces similar or lower cost recovery than solar customers.

To the extent that solar customers under-collect their cost of service compared to the large residential class as a whole, it is because they are low use customers. The nature of volumetric rates is that all customers who use less electricity contribute less towards certain short-term-fixed costs of service compared to customers who use more energy.[8] From the limited perspective of a single test year, all low-usage customers will under-collect their costs by more than the class average. Solar customers have lower consumption, on average, than the larger residential and non-solar subgroup on average. But many non-solar residential customers have lower than average usage and also produce lower cost recovery than the residential class average. If Management had compared solar customers to non-solar customers with similar billing determinants (such as kilowatt-hour usage and load factor), solar customers would not under-collect their cost relative to comparable customers without solar.

Management did not produce load data for individual customers in response to our request, therefore were not able to produce a comparison between solar customers and other low-usage customers without solar. However, information about customer load factors provided by SRP during the last pricing proceeding and an analysis completed by Vote Solar using APS customer data as part of their recent rate case shows that the average solar customer has a lower load factor (meaning they use less electricity relative to their peak usage) than the average residential customer. It also shows that, given the relatively small number of solar customers in SRP territory – less than 5% – there are many more residential customers without solar with a load factor below that of the average solar customer than there are total solar customers. A comparison of solar customers to non-solar customers with similar kilowatt-hour billing determinants would show that (1) solar customers collect more of their costs than non-solar customers with similar consumption and (2) the number of non-solar customers who under collect their costs by a greater degree than solar customers exceeds the total number of solar customers.

Finally, we agree with the decision to allocate the cost of generation meters across all customers. SRP requires customers with solar to install generation meters, but these meters are not required for solar installations to function safely and provide no value to the solar customer. Generation meters are used for system-wide purposes and so we agree with Management's decision to smooth the cost of generation meters across all customers.

In the future, we recommend that SRP conduct a CAS that includes residential customers with solar as part of the residential class. Should Management wish to evaluate the contribution to revenue of sub-groups on a more granular basis, we recommend defining sub-groups based on

[8]While this is true in the short run, it is not true in the mid- to long-run. Low-use customers put downward pressure on rates because they contribute less to the need for new energy resources and infrastructure.

common features such as electricity usage or load factor, rather than singling out customer sub-groups based on a specific technology or behavior.

5) Solar Export Rate

The proposed solar export rate is based on a 3-year average of prices from the CAISO External Load Aggregation Point (ELAP). We do not agree that CAISO market prices are a reasonable proxy for the avoided cost value of exported solar energy.

Exports from solar energy displace marginal energy, which is to say the next most expensive kilowatt-hour that SRP would have paid for were it not for solar exports. Exports from solar customers may allow a utility to avoid more expensive market purchases, but may also allow a utility to reduce output from a more expensive generation resource or purchases from bilateral contracts

Vote Solar requested marginal cost data from Management, including contracts and pricing for individual resources. However, Management asserted confidentiality and refused to produce the responsive information. The data that were provided were not sufficient or granular enough to specifically determine whether SRP's marginal costs exceed the CAISO ELAP price. But, based on the information provided, it appears that the marginal cost of SRP's own resources exceed the market value of energy as determined by CAISO ELAP prices. For example, the cost to ratepayers of generation from the Four Corners coal plant during FY2026 is $78.07/MWh and the cost of fuel, alone, for Four Corners is $43.52/MWh. Excluding peaking gas plants that operate infrequently, the cost to ratepayers of SRP's other generating resources ranges from $33.83 (Palo Verde) to $76.30 (Coronado) per MWh, and the fuel costs alone range from $6.65 (Palo Verde) to $34.81 (Coronado) per MWh. Additionally, as noted below, cost data provided by Management pursuant to 18 C.F.R. 292.302(b)(3) range from $0.006 to $0.102/kWh for planned resource additions. The marginal cost of energy under both sets of costs appears to exceed the CAISO market price. Therefore, it does not appear that the CAISO price reflects SRP's actual marginal costs.[9]

6) Customer Certainty

We agree with the principles SRP Management espouses in the price proposal, in particular the commitment to gradualism and smoothing the impact of cost movements on customers. To further this goal, we recommend SRP allow new customers who install solar to lock-in the export rate value applicable when they interconnect their system for at least 10 years.

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[9] The pricing from bilateral contracts must also be included in calculating SRP's marginal costs. The pricing from power purchase contracts was not made available to us in this pricing process.

SRP proposes that the solar export rate, which is currently a fixed value, be updated on an annual basis. A rate that updates annually presents serious challenges for customers who are trying to estimate the long-term financial impacts of installing solar and evaluate whether an investment in solar panels makes sense for their family. Many states – including other utilities in Arizona – allow customers to lock-in the export rate current at the time of their installation for a period of 10 to 20 years. This puts distributed solar generation on more comparable footing with utilities and other power providers, who commonly recover the upfront cost of generation assets over long time periods or through a long-term Power Purchase Agreement.

7) Energy Storage

As customer adoption of distributed storage has grown, an increasing number of utilities have developed "Virtual Power Plant" programs to encourage customers to dispatch their batteries to provide power to the grid during high-cost hours. While higher volumetric pricing during on-peak periods sends customers with batteries a price signal to dispatch to meet the customer's own needs during times when the electricity and grid services from their batteries are most valuable, Virtual Power Plant programs go one step further by allowing the utility to dispatch customer batteries to meet grid needs.

Other utilities have demonstrated successful pre-payment and pay-for-performance battery storage programs that provide customers with an incentive based on the amount of capacity they provide to the grid during utility-defined events. SRP's neighbor, APS, recently proposed a battery storage program at the directive of the Arizona Corporation Commission, which currently awaits ACC approval.[10] Incentive payments for storage services provided by customers' behind the meter storage are equal to or less than the cost a utility would have otherwise incurred to obtain capacity, reducing costs for all customers.

The trends impacting the cost of power and the shift towards evening on-peak hours create a strong case for developing a performance-based incentive for battery storage dispatch. We recommend that SRP initiate a stakeholder process to inform the development of a Virtual Power Plant program for customer-sited energy storage.

8) Qualifying Facilities

Concurrent with the pricing process, management is also proposing to establish a "Standard Rate Plan for Qualifying Facilities under 18 C.F.R. 292.304(c)"—which it identifies

[10] See ACC Docket No. E-01345A-22-0144, APS Application for Approval of New Bring-Your-Own-Device Battery Plan of Administration, August 30 2024. *Available at: https://docket.images.azcc.gov/E000037788.pdf?i=1736896107068.*

as "QF-24."[11] This plan would be available to Qualifying Facilities (QFs) of 100 kW or less, including to customers with on-site solar generation instead of optional service under other price plans.[12] The price for electricity sold to SRP pursuant to the proposed QF-24 would be based on "the locational marginal price specified for the CAISO-administered Western Energy Imbalance Market Load Aggregation Point for SRP ("ELAP")."[13] While the Qualifying Facility can also earn a theoretical capacity value for electricity provided to SRP "during periods when SRP has identified a capacity need," Management's proposal asserts that the current value for capacity is "$0" because "SRP has no capacity need for the next two years."[14]

PURPA requires SRP to buy all power provided to it from QFs at a rate that does "[n]ot discriminate against" the QF.[15] This requirement prohibits the utility from favoring its own generation over QFs by paying the QF less than the utility charges customers for its own generation. FERC rules currently provide "a rebuttable presumption that a state regulatory authority… may use a Locational Marginal Price as a rate" for energy.[16] But that is only a presumption. FERC rejected an across-the-board *per se* use of LMPs as the value of QF energy because it "recognize[d] that an LMP selected by a state to set a purchasing utility's avoided energy cost component might not always reflect a purchasing utility's actual avoided energy costs."[17] Recognizing that utilities often incur supply costs that exceed the short-run market value of their generation in FERC-regulated markets, FERC only allowed rebuttable use of LMPs on the premise that state commissions would deny rate-regulated utilities recovery of costs greater than the LMP.[18] Or, put another way, if a utility "buys or builds a power plant or enters a contract with any power supplier for purposes of serving utility customers, it must demonstrate that the cost of the resource's energy and capacity are justified relative to" the same price and cost projections used to set QF rates.[19]

The record provided by Management is incomplete and unclear about whether the CAISO ELAP reflects SRP's actual marginal cost of production from generating assets it owns and controls. Additionally, the CAISO ELAP value for energy and "$0" value for capacity does not reflect the costs of SRP's recent and planned capacity and energy resource additions.

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[11] Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle (Amended and Restated) at 40 (Dec. 30, 2024).
[12] Id.
[13] Proposed QF-24 at 2 (Jan. 29, 2025).
[14] Id.
[15] 18 C.F.R. § 292.304(a)(1)(ii).
[16] Id. § 292.304(b)(6).
[17] Order 872 P 152, 85 Fed. Reg. 54,638,54,659 (September 2, 2020).
[18] Order 872 P 122, 85 Fed. Reg. at 54,656; Order 872-A n.212, 85 Fed. Reg. 86,673.
[19] *In re NorthWestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1, Qualifying Facility Power Purchase*, Final Order ¶ 114, Docket No. D216.5.39, 2017 WL 3169003 (Mont.Pub.Serv.Comm'n, July 21, 2017).

Vote Solar attempted to obtain the information necessary to determine whether SRP incurs variable costs for its own generation, or generation it obtains through bilateral contracts, that exceed the CAISO ELAP value. Vote Solar asked Management to provide SRP's hourly system lambda for the last three years. That calculation—if done correctly—should provide the marginal cost of energy, including whether production or acquisition costs exceed the CAISO ELAP value. However, Management responded that it "has determined that the requested data is confidential under Section 30-805(B) of the Arizona Revised Statutes."[20] Additionally, Vote Solar asked Management whether "SRP has ever dispatched generation, or received energy pursuant to a bilateral agreement, at a cost to SRP that exceeds the simultaneous CAISO… ELAP price for that energy." However, Management refused to answer, stating that the information "is beyond this scope of the price process and the QF-24 Standard Rate" and that "certain of the information responsive to this request is confidential" but that it would "provide record(s) of bilateral purchases and the corresponding hourly EIM ELAP price from April 1, 2020, to present within 30 days."[21] Vote Solar has not yet received the bilateral contract information.

Additionally, Management provided two sets of incomplete data that appear to confirm that SRP's marginal costs exceed the CAISO ELAP prices. First, as described above, SRP's own generating resources cost ratepayers–in revenue requirement divided by production–between $33.83 and $78.07/MWh. Fuel cost is only one component of marginal dispatch costs for energy, and the fuel cost alone for several generating plants appears to exceed the CAISO market price.

Second, Management provided the following data, illustrated in Figures 2 and 3, reflecting planned capacity additions, purchases, and retirements purportedly kept pursuant to 18 C.F.R. 292.302(b).

Figure 2. SRP Avoided Cost Tables 18 C.F.R. 292.302(b)

18 CFR 292.302(b)(2)																
		Additions								Retirements						
Fiscal Year	Calendar Year	Solar & Storage	Standalone Storage	Nat. Gas	Wind	Solar	Nuclear	Biomass	Pumped Storage	Nat. Gas	Coal	Wind	Geothermal	Nuclear	Biomass	Solar
FY25	2024	300	340	395	161	200	40	-	-	-	-	-	-	-	-	-
FY26	2025	-	-		-	-	-	-	-	-	-	-	-	-	-	-
FY27	2026	200	250	288	-	55	-	-	-	-	(124)	-	-	-	-	(200)
FY28	2027	-	-	287	-	400	-	-	-	-	-	-	-	-	-	-
FY29	2028	480	400	-	-	394	-	-	-	-	(131)	-	-	-	-	-
FY30	2029	-	-	-	-	-	-	-	-	-	(119)	-	-	(40)	-	-
FY31	2030	-	-	-	-	-	-	-	-	-	-	(63)	-	-	-	-
FY32	2031	-	-	-	-	-	-	-	-	-	(150)	(64)	-	-	-	-
FY33	2032	-	-	-	-	-	-	-	-	(975)	(382)	-	-	-	-	-
FY34	2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(19)
FY35	2034	-	-	-	-	-	-	-	-	-	-	-	(25)	-	(14)	
FY36	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[20] Response to Public Comment #MI6924594.
[21] Response to Earth Justice [sic] Fourth Request for Information # 23.

Figure 3. SRP Avoided Cost Tables 18 C.F.R. 292.302(b)(3).

18 CFR 292.302(b)(3)			
Fiscal Year	Resource Additions	$/KW-M	Cents/KWh
FY25	Project 1	NA	2.8
FY25	Project 2	$15.13	0.6
FY25	Project 3	NA	4.1
FY25	Project 4	$11.92	0.6
FY25	Project 5	$16.77	2.8
FY25	Project 6	NA	10.2
FY25	Project 7	$13.30	8
FY25	Project 8	$12.87	0.6
FY27	Project 9	$12.75	2.6
FY27	Project 10	NA	3.3
FY27	Project 11	$8.68	9.3
FY27	Project 12		4.6
FY27	Project 13	$12.15	4.6
FY28	Project 14	$15.72	0.7
FY28	Project 15	NA	3.3
FY29	Project 16	$14.40	4.7
FY29	Project 17	$11.91	2.9

The costs in Figures 2 and 3 also appear to confirm that the cost to SRP of new generation resources acquired in calendar year 2024, and additional resources SRP intends to acquire in calendar years 2026, 2027, and 2028, will have costs greater than the values reflected in QF-24. Specifically, the projected energy costs of a number of the projects to be added within fiscal year 2025 (Figure 3: Projects 3, 6, 7) as well as projects planned in later years (Figure 3: Projects 11, 12, 13, and 16) appear to have energy costs greater than the CAISO ELAP value for energy.

As to capacity, the fact that there are forecasted capacity additions in each of calendar years 2026, 2027, and 2028 conflicts with Management's claim that the QF-24 capacity value "is currently calculated at zero, because at this time SRP does not have a capacity need."[22]

The Board must ensure that the rate for Qualifying Facilities is equal to the full avoided cost, which must be no lower than any self-generation or bilateral contract costs. Based on the information available, it appears that the CAISO ELAP and "$0" capacity value proposed in the QF-24 plan are below full avoided costs.

[22] SRP Response to Earth Justice [sic] Request for Information # 24.

Recommendations

As described above, Vote Solar requests that the Board to make the following changes to Management's proposals:

- Do not increase the monthly service (fixed) charges above the current $20 for residential customers (including solar and non-solar) and consider reducing them to a level no higher than basic customer costs of metering, billing, and service connection.
- Ensure that the price for exports from solar customers and qualifying facilities under the QF-24 tariff are at full avoided cost, including SRP's own generation costs and bilateral contracts whenever higher than the CAISO energy market price.
- Permit solar customers to take service under all price plans available to non-solar customers, including E-23 and EZ-3 (until the latter closes in 2029).
- To remove anti-solar biases, make several changes to the CAS, including:
    - Remove the asymmetrical treatment of customer exports in the CAS by ensuring that all cost allocations are reduced by exports (allocated on net load) just as revenue calculations are net of all export credits;
    - Remove the disproportionate allocation of customer service costs to solar customers; and
    - When comparing solar customers' level of cost recovery, compare solar customers to otherwise similar non-solar customers, such as non-solar customers with similar kilowatt hour consumption and load factors.
- Reduce the E-16 on-peak period to three hours and align it with the E-28 on-peak window.
- Delay implementation of new price plans until a bill comparison tool is available to customers.
- Initiate a stakeholder process to inform the development of a Virtual Power Plant program for customer-sited energy storage.

Sincerely,

Kate Bowman

Kate Bowman
Regulatory Director, Interior West
Vote Solar
[redacted]

Name: William Adamson

Record Number: MI7110499

Delivery Method: Mailed to SRP

Attachments: PriceProcessComment_20250220_Adamson.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7110499*

Comment:

Dear SRP Board Members,

My name is William Adamson, and I am a proud SRP customer who invested in solar energy to reduce my family's energy costs and contribute to a cleaner future. Unfortunately, the proposed rate changes threaten the value of my investment and the progress we've made toward sustainable energy in Arizona.

The shift in time-of-use hours diminishes the value of solar energy during the day, when my system is most productive. Limiting grandfathering protections for newer customers feels
especially unfair, penalizing those of Li"> who recently chose to go solar.

These changes discourage clean energy adoption and harm families who have worked hard to make environmentally responsible choices. I hope SRP will reconsider these proposals and protect customers like me who have invested in a better future for our community.

Sincerely,

William Adamson

Name: Jay and Colrena Johnson

Record Number: MI7111313

Delivery Method: Mailed to SRP

Attachments: PriceProcessComment_20250220_Johnson.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7111313*

Comment:

January 29,2025

Salt River Project
1500 N. Mill Ave.
Tempe, AZ 85288-1252

Dear SRP Board Members,

As an SRP customer and solar energy system owner, I am deeply concerned about the proposed changes to SRP's rate plan. These changes will negatively impact my household and others who have invested in clean energy solutions.

Specifically:

• Time-of-Use Hours Shift: Reducing the value of energy produced during daylight hours unfairly penalizes solar customers.

• Unfair Grandfathering Policies: Offering only four years of protection for newer solar customers, compared to 20 years for older customers, is inequitable.

• Inconvenient Appliance Use Hours: Shifting time-of-use schedules forces families to use appliances during inconvenient late-night hours.

• Higher Demand Charges: Increased charges erode the financial benefits of my solar system, discouraging clean energy adoption.

These changes contradict SRP's commitment to sustainability and fairness. I urge you to reconsider these proposals and work toward solutions that support solar customers and encourage renewable energy investment.

Thank you for your attention. I look forward to hearing SRP's plans to protect the interests of its customers and the environment.

Sincerely,

SRP Public Price Process Comments from: 2/21/2025

Name: David Bender

Record Number: MI7112575

Delivery Method: Other

Attachments: Action needed, please upload new comment_bender.pdf

**To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7112575*

Comment:

A response request for additional information on EJ04, from 2/5/2025.

Response #23 . SRP will provide record(s) of bilateral purchases and the corresponding hourly EIM ELAP price from April 1, 2020, to present within 30 days.

Name: Peyton S Hare

Record Number: cc5539a7

Delivery Method: Digital Submission

Comment:

Apt-1096

Name: William Souders

Record Number: ff8604ad

Delivery Method: Digital Submission

Comment:

In 15 years since 2010, why hasn't SRP built enough plants to keep residential customers from paying for peak hour energy rates? Why aren't you working for residential rate payers? Is reducing the cost of electricity one of your goals? Why not? Has SRP reduced gifts to charities and schools since 2010? By what percentage have SRP salaries increased since 2010?

Name: Jane Breakiron

Record Number: 269b4f99

Delivery Method: Digital Submission

Comment:

Is the cost increase going to fund the green new deal polices? From what I have heard that these policies are unreliable and will increase our electric bills significantly. I am most concerned about black outs in the summer which can lead to heat related deaths. This happened to one of my family members when their AC didn't work.

Name: Amanda

Record Number: 86ca338a

Delivery Method: Digital Submission

Comment:

In reading the proposal I didn't see a why. I'm already struggling to pay with Gilbert's increased water and trash doubling over the last year with more to come and now this increase! Groceries, gas, utilities, I've never seen such high prices. At 61 years old, my wages aren't increasing and retirement is a fantasy now. Please don't raise our rates.

Name: Dave Vernon

Record Number: MI7122856

Delivery Method: Email to Corporte Secretary

Attachments: SRP Solar Rate Proposal Critique.pdf

To receive a copy of Attachments please contact the Corporate Secretary's Office and Reference Record #MI7122856

Comment:

SRP Proposes to Largest Rate Increases on Solar Customers
SRP's new proposed rate plans for their customers are advertised as a 2.5% increase for ratepayers. However, there is one subsection of SRP customers that would be hit with an
increase of well over the 2.5% that SRP claims customers' bills will increase by – customers who choose to produce a portion of their own energy with solar.

SRP's new rate proposal seeks to increase the cost of energy for times of the day when solar energy is not being produced by homeowners. They justify this price increase by reducing the cost of electricity between 8 AM – 3PM, when solar energy is abundant, and homeowners with solar rely less (or not at all) on grid power. SRP's offer of cheaper power to solar customers during the 8 AM – 3 PM window is purposeful; they know that solar customers won't use grid power during those hours. However, SRP is providing that cheap power between 8 AM – 3 PM in exchange for something – the solar customer has to pay much higher prices for energy for all other hours of the day. This means that solar customers will receive little-to-no benefit from the cost reduction between 8AM – 3PM, and yet they'll get hit with a massive price increase for the hours of the day that solar isn't producing.

The proposal SRP is making would allow them to put current and future solar customers onto the E-28 standard time-of-use with super off-peak energy between 8AM – 3PM, or the E-16 time-of-use demand rate plan.

For solar customers on the current time-of-use rate plan (E-13), non-solar production hours have energy costs ranging from 9.28 cents per kWh off-peak to 26.10 cents per kWh on-peak, not including taxes. On the new time-of-use rate plan SRP is proposing for solar customers, the kWh costs during non-solar production hours ranges from 12.82 cents per kWh off-peak to 40.26 cents per kWh on-peak, not including taxes. For solar customers, this means they'll see a price increase of 38% at the low end for off-peak and

54% at the high end for on-peak energy.

For solar customers currently on the time-of-use demand rate plan (E-27), the cost increases SRP is proposing are just as bad, if not worse. Again, I'm going to look at cost increases as they relate to grid-supplied energy during non-solar production hours because solar customers are unlikely to pull any meaningful amount of grid power during the day when solar energy is abundant. The current E-27 demand rate plan provides a tiered demand cost, so that customers who use the least amount of power during peak hours are rewarded, and customers that use a lot more power are penalized with higher per-kW demand charges. SRP is proposing to eliminate tiered demand rate plans for solar customers, so that everybody gets hit with the same per-kW demand cost regardless of how good they are at reducing demand for SRP's power. This makes little sense to me, since SRP's supposed goal has been that they want to encourage customers to reduce their own demand for power during peak hours, thus reducing strain on grid resources, and reducing SRP's costs to generate and distribute power during those high-use hours.

A customer who currently uses 3 kW – 6 kW peak power on the E-27 pays $214 to $592 before taxes for their annual demand costs. On the proposed E-16, those customers will pay $377 to $754 for the same peak demand throughout the year. This is a price increase of 76% for customers that work to keep their demand lower at 3 kW, and an increase of 27% for customers that have a higher peak demand of 6 kW monthly. What's really aggravating, is thatcustomers would use an average of 14 kW peak demand monthly pay 13.4% less than they would on the current E-27, and customers that would use 20 kW peak demand monthly pay 26.8% less than they would on the current E-27. So, effectively, SRP is punishing those that work the hardest to keep their peak power demands the lowest, while rewarding those that do nothing to reduce strain on grid resources. They're taking away the carrot for folks that actually want to save money in favor of a bigger stick. Those that do nothing to reduce their peak demand, on the other hand, would get a bigger carrot and a smaller stick.

On the same E-27 that many solar customers currently use, SRP also provides kWh prices ranging from 5.64 cents off-peak to 7.98 cents on-peak. But the E-16 (which they propose to put all solar demand rate customers on), will increase the cheapest off-peak kWh to 9.94 cents per kWh, and the most expensive on-peak kWh to 16.54 cents per kWh. This is a kWh rate hike of 76.24% for the cheapest off-peak energy and a rate hike of 107.27% for the most expensive on-peak energy. On top of that, they are currently offering solar customers on the E-27 demandrate a 1:1 credit for any excess solar kWh that the customer provides to the grid, but SRP's proposing to do away with that 1:1 ratio and drop the credit to 3.45 cents for each solar kWh that a customer supplies to the grid. This is at best a 1:3 ratio and at worst a 1:4.7 credit, where a customer who supplies a kWh of solar to SRP only receives a fraction of 1 kWh of credit.

SRP is proposing to offer a variety of residential rate plans to their customers. However, they proposed that solar customers should only be able to choose from the E-16 or E-28. Ratepayers with or without solar should be able to choose from all the residential rate plans that SRP is offering. This would allow individual solar customers to have the same right as non-solar customers; namely, to choose a rate plan that helps them save the most money on their electricity bills. I don't believe that any of SRP's customers should be systematically blocked
from rate plans that would benefit their families. Blocking them from choosing the same rate plans that everybody else has access to only serves to place a higher financial burden on solar customers, while allowing everybody else to have cheaper rates for SRP-supplied power. In summary, I hope SRP will reconsider their proposal in order to give solar customers more freedom to determine the future of their financial situation as it relates to electricity cost. I hope that SRP will listen closely to solar industry advocacy groups that are working with them to remedy some of the problems outlined above.

SRP Proposes to Largest Rate Increases on Solar Customers

SRP's new proposed rate plans for their customers are advertised as a 2.5% increase for ratepayers. However, there is one subsection of SRP customers that would be hit with an increase of well over the 2.5% that SRP claims customers' bills will increase by – customers who choose to produce a portion of their own energy with solar.

SRP's new rate proposal seeks to increase the cost of energy for times of the day when solar energy is not being produced by homeowners. They justify this price increase by reducing the cost of electricity between 8 AM – 3PM, when solar energy is abundant, and homeowners with solar rely less (or not at all) on grid power. SRP's offer of cheaper power to solar customers during the 8 AM – 3 PM window is purposeful; they know that solar customers won't use grid power during those hours. However, SRP is providing that cheap power between 8 AM – 3 PM in exchange for something – the solar customer has to pay *much higher prices for energy for all other hours of the day.* This means that solar customers will receive little-to-no benefit from the cost reduction between 8AM – 3PM, and yet they'll get hit with a massive price increase for the hours of the day that solar isn't producing.

The proposal SRP is making would allow them to put current and future solar customers onto the E-28 standard time-of-use with super off-peak energy between 8AM – 3PM, or the E-16 time-of-use demand rate plan.

For solar customers on the current time-of-use rate plan (E-13), non-solar production hours have energy costs ranging from 9.28 cents per kWh off-peak to 26.10 cents per kWh on-peak, not including taxes. On the new time-of-use rate plan SRP is proposing for solar customers, the kWh costs during non-solar production hours ranges from 12.82 cents per kWh off-peak to 40.26 cents per kWh on-peak, not including taxes. For solar customers, this means they'll see a price increase of 38% at the low end for off-peak and 54% at the high end for on-peak energy.

For solar customers currently on the time-of-use demand rate plan (E-27), the cost increases SRP is proposing are just as bad, if not worse. Again, I'm going to look at cost increases as they relate to grid-supplied energy during non-solar production hours because solar customers are unlikely to pull any meaningful amount of grid power during the day when solar energy is abundant. The current E-27 demand rate plan provides a tiered demand cost, so that customers who use the least amount of power during peak hours are rewarded, and customers that use a lot more power are penalized with higher per-kW demand charges. SRP is proposing to eliminate tiered demand rate plans for solar customers, so that everybody gets hit with the same per-kW demand cost regardless of how good they are at reducing demand for SRP's power. This makes little sense to me, since SRP's supposed goal has been that they want to encourage customers to reduce their own demand for power during peak hours, thus reducing strain on grid resources, and reducing SRP's costs to generate and distribute power during those high-use hours.

A customer who currently uses 3 kW – 6 kW peak power on the E-27 pays $214 to $592 before taxes for their annual demand costs. On the proposed E-16, those customers will pay $377 to $754 for the same peak demand throughout the year. This is a price increase of 76% for customers that work to keep their demand lower at 3 kW, and an increase of 27% for customers that have a higher peak demand of 6 kW monthly. What's really aggravating, is that customers would use an average of 14 kW peak demand monthly pay 13.4% less than they would on the current E-27, and customers that would use 20 kW peak demand monthly pay 26.8% less than they would on the current E-27. So, effectively, SRP is punishing those that work the hardest to keep their peak power demands the lowest, while rewarding those that do nothing to reduce strain on grid resources. They're taking away the carrot for folks that actually want to save money in favor of a bigger stick. Those that do nothing to reduce their peak demand, on the other hand, would get a bigger carrot and a smaller stick.

On the same E-27 that many solar customers currently use, SRP also provides kWh prices ranging from 5.64 cents off-peak to 7.98 cents on-peak. But the E-16 (which they propose to put all solar demand rate customers on), will increase the cheapest off-peak kWh to 9.94 cents per kWh, and the most expensive on-peak kWh to 16.54 cents per kWh. This is a kWh rate hike of 76.24% for the cheapest off-peak energy and a rate hike of 107.27% for the most expensive on-peak energy. On top of that, they are currently offering solar customers on the E-27 demand rate a 1:1 credit for any excess solar kWh that the customer provides to the grid, but SRP's proposing to do away with that 1:1 ratio and drop the credit to 3.45 cents for each solar kWh that a customer supplies to the grid. This is at best a 1:3 ratio and at worst a 1:4.7 credit, where a customer who supplies a kWh of solar to SRP only receives a fraction of 1 kWh of credit.

SRP is proposing to offer a variety of residential rate plans to their customers. However, they proposed that solar customers should only be able to choose from the E-16 or E-28. Ratepayers with or without solar should be able to choose from *all* the residential rate plans that SRP is offering. This would allow individual solar customers to have the same right as non-solar customers; namely, to choose a rate plan that helps them save the most money on their electricity bills. I don't believe that any of SRP's customers should be systematically blocked from rate plans that would benefit their families. Blocking them from choosing the same rate plans that everybody else has access to only serves to place a higher financial burden on solar customers, while allowing everybody else to have cheaper rates for SRP-supplied power. In summary, I hope SRP will reconsider their proposal in order to give solar customers more freedom to determine the future of their financial situation as it relates to electricity cost. I hope that SRP will listen closely to solar industry advocacy groups that are working with them to remedy some of the problems outlined above.

SRP Public Price Process Comments from: 2/22/2025

Name: carol

Record Number: be0871cf

Delivery Method: Digital Submission

Comment:

CUSTOMER SERVICE IS ALWAYS POLITE.... THANK YOU. I OBJECT TO THE INCREASE, ANY INCREASE. MILLIONS OF PEOPLE PAYING FOR ELECTRIC AND IT'S ONLY GETTING WORSE WITH THE HEAT INCREASING. YOU ARE MAKING LOADS OF MONEY. AND WHAT'S THIS $25 SERVICE CHARGE THAT APS DOESN'T CHARGE. SO THAT'S MORE EXTRA MONEY SQUEEZED FROM YOUR HARD WORKING CUSTOMERS. WHEN I WORKED FOR THE UTILITY DEPARTMENT AT THE CITY OF MESA, WE ALWAYS GOT A GOOD PAY INCREASE JUST AFTER THEY RAISED THE UTILITY RATES. I ACTUALLY FELT SORRY FOR UNFORTUNATE. IT'S ALL A SCAM.,..
