Louisa Eberle - AZ Bar No. 035973
Patrick Woolsey (*Admitted Pro Hac Vice*)
Nihal Shrinath (*Admitted Pro Hac Vice*)
Sierra Club Environmental Law Program
2101 Webster Street, Ste 1300
Oakland, CA 94612
(415) 977-5757
louisa.eberle@sierraclub.org
patrick.woolsey@sierraclub.org
nihal.shrinath@sierraclub.org
Attorneys for Sierra Club

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>

JIM O'CONNOR - Chairman
LEA MARQUEZ PETERSON
ANNA TOVAR
KEVIN THOMPSON
NICK MYERS

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01345A-22-0144 **SIERRA CLUB'S NOTICE OF FILING OF DIRECT TESTIMONY OF DEVI GLICK**

Pursuant to the Rules of Practice and Procedure of the Arizona Corporation Commission ("Commission") and the Administrative Law Judge's May 10, 2023 procedural order in this matter, Sierra Club hereby provides notice of its filing of the attached Direct Testimony of Devi Glick in Docket No. E-01345A-22-0144. Ms. Glick's testimony contains information designated by Arizona Public Service Company ("APS") as confidential and highly confidential information, which is redacted in the attached public version of the testimony. Confidential and highly confidential versions of Ms. Glick's testimony have been provided to the Administrative Law Judge and to APS. APS has indicated that it will post the confidential and highly confidential versions of Ms. Glick's testimony to APS's Extranet web platform. Via that online platform, the confidential version of Ms. Glick's testimony will be available to parties that have signed the protective agreement in this matter and Exhibit A to that agreement, and the highly confidential version of Ms. Glick's testimony will be available to parties that have signed Exhibit B of the protective agreement. Public discovery responses in spreadsheet form have also been provided via a Google Drive link.

RESPECTFULLY SUBMITTED this 5th day of June, 2023.

/s/ Patrick Woolsey

Louisa Eberle - AZ Bar No. 035973
Patrick Woolsey (*Admitted Pro Hac Vice*)
Nihal Shrinath (*Admitted Pro Hac Vice*)
Sierra Club Environmental Law Program
2101 Webster Street, Ste 1300
Oakland, CA 94612
(415) 977-5757
louisa.eberle@sierraclub.org
patrick.woolsey@sierraclub.org
nihal.shrinath@sierraclub.org
Attorneys for Sierra Club

ORIGINAL of the foregoing e-Filed
with Docket Control via ACC Portal
this 5th day of June, 2023.

COPIES of the foregoing emailed this
5th day of June, 2023 to:

Vicki M. Baldwin
Richard J. Angell
PARSONS BEHLE & LATIMER
201 South Main Street, Suite 1800
Salt Lake City, UT 8411 l
Attorneys for Walmart Inc.
vbaldwind@parsonsbehle.com
rangell@parsonsbehle.com
Consented to Service by Email

Gary Hays
LAW OFFICES OF GARY D. HAYS, P.C.
2198 E. Camelback Rd., Ste. 230
Phoenix, AZ 85016
Ghays@lawgdh.com
Consented to Service by Email

Gregory Adams
RICHARDSON ADAMS, PLLC
515 N. 27th St.
Boise, ID 83702
Attorney for Calpine Energy Solutions, LLC
greg@richardsonadams.com
Consented to Service by Email

Amy Mignella
HOPI TRIBE
P.O. Box 123
Kyktsmovi, AZ 86039
Attorney for Hopi Tribe
flomayesva@hopi.nsn.us
amignella@hopi.nsn.us
Consented to Service by Email

Patrick J. Black
Lauren A. Ferrigni
FENNEMORE
2394 E. Camelback Road, Suite 600
Phoenix, AZ 85016
Attorneys for Freeport Minerals Corporation
PBlack@fennemorelaw.com
LFerrigni@fennemorelaw.com
khiggins@energystrat.com
Consented to Service by Email

Ayensa I Millan
CIMA LAW GROUP, PC
350 E. Virginia Ave., Ste. 100
Phoenix, AZ 85004
Attorney for AARP
ayensa@cimalawgroup.com
Consented to Service by Email

Kristin Nelson
1926 E. Janice Way
Phoenix, AZ 85022
KristinNelson@HSmove.com
Consented to Service by Email

John B. Coffman
JOHN B. COFFMAN LLC
871 Tuxedo Blvd.
St. Louis, MO 63119
Attorney for AARP
john@johncoffman.net
Consented to Service by Email

Melissa M. Krueger
Theresa Dwyer
Jeffrey S. Allmon
PINNACLE WEST CAPITAL CORPORATION
400 North Street, MS 8695
Phoenix, AZ 85004
Attorneys for Arizona Public Service Company
Melissa.Krueger@pinnaclewest.com
Theresa.Dwyer@pinnaclewest.com
Jeffrey.Allmon@pinnaclewest.com
Rodney.Ross@aps.com
Ratecase@aps.com
Consented to Service by Email

Daniel W. Pozefsky, Chief Counsel
RESIDENTIAL UTILITY CONSUMER OFFICE
1110 West Washington, Suite 220
Phoenix, AZ 85007
dpozefsky@azruco.gov
procedural@azruco.gov
jimccarty@azruco.gov
czwick@azruco.gov
rdelafuente@azruco.gov
Consented to Service by Email

Tim Hogan
Chanele N. Reyes
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
352 E. Camelback Road, Suite 200
Phoenix, AZ 85012
Attorneys for Arizona School Board Association; Arizona Association of School Business Officials; Arizona School Administrators; and Vote Solar
thogan@aclpi.org
chanele@aclpi.org
czwick@wildfireaz.org
Consented to Service by Email

Kurt J. Boehm
Jody Kyler Cohn
BOEHM, KURTZ & LOWRY
36 E. Seventh Street, Suite 1510
Cincinnati, OH 45202
Attorneys for The Kroger Co.
kboehm@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
Consented to Service by Email

Holly L. Buchanan, MAJ, USAF
Marcus Duffy, Capt, USAF
Thomas A. Jernigan
AF/JAOE-ULFSC
139 Barnes Dr., Suite 1
Tyndall Air Force Base, FL 32403
and
Karen S. White
AFIMSC/JAQ
139 Barnes Dr.
Tyndall Air Force Base, FL 32403
Attorneys for the Federal Executive Agencies
holly.buchanan.1@us.af.mil
marcus.duffy.3@us.af.mil
thomas.jernigan.3@us.af.mil
ebony.payton.ctr@us.af.mil
rafael.franjul@us.af.mil
ulfsc.tyndall@us.af.mil
karen.white.13@us.af.mil
Consented to Service by Email

Michael W. Patten
SNELL & WILMER
One East Washington Street, Suite 2700
Phoenix, AZ 85004
Attorney for Tucson Electric Power Company
mpatten@swlaw.com
bcarroll@tep.com
Consented to Service by Email

Laura K. Granier
Amber Rudnick
HOLLAND & HART, LLP
5441 Kietzke Lane, Second Floor
Reno, NV 89511
and
Cory Talbot
HOLLAND & HART, LLP
222 South Main Street, Ste. 2200
Salt Lake City, UT 84101
Attorneys for Brookfield Renewables Trading and Marketing LP
LKGranier@hollandhart.com
CATalbot@hollandhart.com
Steve.Greenleaf@brookfieldrenewable.com
ALRudnick@hollandhart.com
EKNannini@hollandhart.com
ALSanchez@hollandhart.com
Consented to Service by Email

John William Moore, Jr.
LAW OFFICE OF JOHN W. MOORE
5110 North 40th Street, Suite 210
Phoenix, AZ 85018
Attorney for the Kroger Co.
john@johnmoorelawaz.com
Consented to Service by Email

Nicholas J. Enoch
LUBIN & ENOCH, P.C.
349 N. Fourth Ave.
Phoenix, AZ 85003
Attorney for Locals 387, 640, and 769 of the International Brotherhood of Electrical Workers, AFL-CIO
nick@lubinandenoch.com
morgan@lubinandenoch.com
clara@lubinandenoch.com
Consented to Service by Email

Court Rich
ROSE LAW GROUP
7144 E. Stetson Dr., Suite 300
Scottsdale, AZ 85251
Attorneys for Arizona Solar Energy Industries Association and Solar Energy Industries Association
crich@roselawgroup.com
hslaughter@roselawgroup.com
Consented to Service by Email

Todd F. Kimbrough
BALCH & BINGHAM, LLP
919 Congress Ave., Suite 840
Austin, TX 78701
Attorneys for the Navajo Nation
tkimbrough@balch.com
aquinn@nndoj.org
ckimble@balch.com
Consented to Service by Email

Nathan Schott
GUST ROSENFELD, P.L.C.
125 E. Elm Ave.
Flagstaff, AZ 86001
Attorney for Joseph City Unified School District
nschott@gustlaw.com
Consented to Service by Email

Robin Mitchell, Director
Legal Division
UTILITIES DIVISION
1200 West Washington Street
Phoenix, AZ 85007
LegalDiv@azcc.gov
Utildivservicebyemail@azcc.gov
Consented to Service by Email

Greg Patterson
MUNGER CHADWICK & DENKER
1049 E. Sandpiper
Tempe, AZ 85283
Attorney for Arizona Competitive Power Alliance
Gpatterson3@cox.net
Consented to Service by Email

Matthew J. Ochs
HOLLAND & HART LLP
555 Seventeenth Street, Suite 3200
Denver, CO 80202
Attorneys for Arizona Large Customer Group
mjochs@hollandhart.com
mbking@hollandhart.com
tnelson@hollandhart.com
acbriggerman@hollandhart.com
awjensen@hollandhart.com
kdspriggs@hollandhart.com
aclee@hollandhart.com
Consented to Service by Email

Timothy M. Hogan (004567)
Chanele N. Reyes (034898)
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
352 E. Camelback Rd. Suite 200
Phoenix, Arizona 85012
Attorneys for Citizen Groups, Southwest Energy Efficiency Project, Vote Solar, Wildfire, and Western Resource Advocates
thogan@aclpi.org
chanele@aclpi.org
Consented to Service by Email

Jason Mullis
WOOD SMITH HENNING BERMAN, LLP
2525 E. Camelback Rd., Ste. 450
Phoenix, AZ 85016
Attorney for Calpine Energy Solutions, LLC
jmullis@wshblaw.com
Consented to Service by Email

Autumn T. Johnson (035811)
ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION AND SOLAR ENERGY INDUSTRIES ASSOCIATION
7144 E. Stetson Dr., Suite 300
Scottsdale, Arizona 85251
Pro Hac Vice
Attorney for AriSEIA and SEIA
autumn@ariseia.org
Consented to Service by Email

By: *<u>/s/ Maddie Lipscomb</u>*

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	))))))))))	**DOCKET NO. E-01345A-22-0144**

PUBLIC VERSION

Direct Testimony of

Devi Glick

On Behalf of

Sierra Club

June 5, 2023

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DG-23: TEP Response to Staff Data Request 5.04(a), Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Dec. 1, 2022)

DG-24: Excerpt of Direct Testimony of Devi Glick, Case No. 19-00170-UT (N.M. Pub. Reg. Comm'n. Nov. 22, 2019)

DG-25: U.S. Environmental Protection Agency, Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule

DG-26: Excerpt of Ryan Hledik et al., The National Potential for Load Flexibility: Value and Market Potential through 2030 (2019)

DG-27: APS, Comments in Response to Questions from Commissioner Sandra Kennedy, Docket No. E-01345A-21-0087 (Ariz. Corp. Comm'n Mar. 18, 2022)

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 10 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Attachment DG-1.

Q **On whose behalf are you testifying in this case?**

A I am testifying on behalf of Sierra Club.

Q **Have you testified previously before the Arizona Corporation Commission ("Commission" or "ACC")?**

A Yes. I submitted direct and surrebuttal testimony in Tucson Electric Power Company's ("TEP") 2022 rate case (Docket No. E-1933A-22-0107), and reply testimony in TEP's 2019 rate case (Docket No. E-01933A-19-0028). I also participated on behalf of Sierra Club in Arizona Public Service Company's ("APS" or "the Company") and TEP's respective 2020 Integrated Resource Planning ("IRP") processes. I am participating again in both TEP's and APS's 2023 IRP processes on behalf of Sierra Club.

Q What is the purpose of your testimony in this proceeding?

A In this proceeding I evaluate the Company's continued investments in, and operations of, its coal and gas plants.

First, I evaluate the economic performance of APS's coal-fired units at the Four Corners Generating Station ("Four Corners") and the Cholla Power Plant ("Cholla"). I evaluate the plants' likely economic performance going forward. I review the sufficiency of the Company's analysis to justify continued operations of Four Corners through 2031, and I evaluate in detail the Company's post-test-year plant ("PTYP") spending at Four Corners to comply with the U.S. Environmental Protection Agency's ("EPA") updated Effluent Limitation Guidelines ("ELG"). I also review the Company's current plan to shut down Cholla by 2025.

Second, I review the Company's recent investments in chiller systems at the gas-fired Redhawk Power Plant ("Redhawk") and Sundance Power Station ("Sundance") to increase the summer output of those gas plants.

Third, I review the Company's load forecast and the measures it is taking to manage peak load and secure new resources moving forward. I evaluate the Company's current demand-side management efforts in the context of its continued investments in fossil fuel resources.

Finally, I discuss how a flexible and proactive resource procurement model is better suited for the current energy transition than a just-in-time resource planning approach focused around firm capacity needs.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I describe the Four Corners and Cholla coal plants and the Sundance and Redhawk gas plants, and I discuss APS's requested test-year spending and PTYP spending at each plant. I also summarize the Company's load forecast, near-term energy and capacity needs, and recent and planned procurement efforts.

In Section 4, I analyze the economic performance of the Four Corners and Cholla power plants. I review the most recent analysis the Company completed to justify retirement of Cholla in 2025, investment at Four Corner to comply with EPA's updated ELG regulations, continued operation of Four Corners, and inclusion of the associated operations and maintenance ("O&M") and sustaining capital costs in test-year spending. I also review the analysis performed by APS to justify installing chillers at the Redhawk and Sundance gas plants to increase the units' summer output in place of investment in clean energy alternatives. I discuss major changes that have occurred since APS completed its most recent economic analysis, and I outline avoided costs associated with the retirement of the Company's coal plants and their replacement with alternatives.

In Section 5, I assess APS's current resource procurement efforts and its peak-management and firm capacity needs. I explain the need for APS to be more proactive in procuring replacement resources to accelerate its transition to clean energy, rather than focusing on procuring resources when it identifies a firm capacity need.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of APS's witnesses. I also rely on public information from other ACC proceedings and other publicly available documents.

2. <u>FINDINGS AND RECOMMENDATIONS</u>

Q Please summarize your findings.

A My primary findings are:

1. The cost to operate and maintain Four Corners substantially exceeds the cost of alternatives, including clean energy resources. APS has not economically justified its ongoing O&M and capital spending at the Four Corners coal plant, which the Company is asking to include in test-year spending in this rate case.
2. The analysis that APS used to support the ongoing operations of and spending at Four Corners is nearly two-and-a-half years old, relies on outdated assumptions that pre-date the federal Inflation Reduction Act ("IRA") and current market conditions, and substantially understates the risk associated with continued reliance on its coal plants.
3. APS can avoid substantial unnecessary capital expenditures and O&M costs at Four Corners by retiring Four Corners earlier than the Company's currently planned retirement date of 2031.
4. APS has not justified $36.7 million in post-test-year spending at the Four Corners Power Plant to make plant modifications necessary to comply with EPA's updated ELG requirements. Ratepayers would be better off if APS had planned to retire the plant by 2028, mitigating required ELG upgrades.
5. With falling gas prices, APS's decision not to pursue seasonal operations at Four Corners is not justified. APS can avoid unnecessary excess near-term variable

costs at Four Corners by switching to seasonal operations in Fall 2023 as originally planned.

6. APS's decision to retire the Cholla Power Plant in 2025 is justified. The cost to operate and maintain Cholla substantially exceeds the cost of alternatives. Retirement of Cholla in 2025 and replacement with alternatives lowers costs and risks for ratepayers. It also avoids the need to pay for costly environmental upgrades, and other ongoing O&M and capital costs that would have been necessary to keep the plant online longer.

7. APS decision to spend $105.1 million on chiller projects at the Redhawk and Sundance gas plants to increase peak output at both plants locks ratepayers into risky and volatile gas capacity for decades to come.

8. APS has not taken sufficient action to implement and invest in demand-side management programs, technologies, and resources on its system.

9. APS's current resource planning approach of waiting until it has a capacity need to procure new resources is not well matched with the resources needed for a clean energy transition.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should disallow all test-year O&M and capital spending at Four Corners on the basis that the plant has incurred costs above market prices in recent years, the plant is uneconomic relative to alternatives, and in both this docket and the prior 2020 IRP docket, APS has failed to conduct an adequate analysis to evaluate the cost of early retirement and replacement with alternatives.

2. APS should minimize capital and unnecessary O&M investments in Four Corners going forward and retire the plant as soon as it can procure replacement resources.

3. The Commission should disallow the $36.7 million in PTYP ELG project spending at Four Corners on the basis that this spending was at least partially avoidable if APS retired the plant by 2028 rather than upgrading its coal-ash wastewater system to allow three extra years of operation.

4. APS should switch Four Corners to seasonal operations starting in Fall 2023.
5. APS should retire Cholla in 2025 as planned.
6. APS should minimize future investment to expand its gas capacity, both through resources it owns and through power purchase tolling agreements, and focus instead on diversifying its fleet. This will protect ratepayers from expensive and volatile natural gas prices.
7. APS should continue to look for ways to manage peak load, including load from new data centers, by using demand management and energy efficiency measures.
8. The Commission should require APS to move away from a planning model that procures resources only in response to firm capacity needs and instead require that APS transition to a rolling model that brings on new clean energy resources that can lower energy costs as they become available. This will facilitate a clean energy transition and protect ratepayers from volatile fuel and market prices, project delays, and legacy unit breakdowns.

3. SUMMARY OF APS RATE CASE APPLICATION

Q Please provide an overview of APS's coal-fired power plants.

A APS has two coal-fired power plants: Four Corners Generating Station and Cholla Power Plant.

Four Corners is a two-unit (Units 4 and 5) coal-fired power station located near Farmington, New Mexico. Units 4 and 5 are each 770 megawatts ("MW") and went into service in 1969 and 1970 respectively.[1] The plant is operated by APS and co-owned by TEP, Salt River Project Agricultural Improvement and Power

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[1] U.S. Energy Information Administration Form 860, 2021, *available at* https://www.eia.gov/electricity/data/eia860/ [hereinafter "U.S. EIA Form 860"]; APS Response to Staff Data Request ("Staff DR") 1.2, Attachment Staff 1.2_APS22RC02270_APS Owned Plants. All public discovery responses referenced in this testimony are compiled and available within Attachment DG-2 ["Attach. DG-2"].

District (“SRP”), and Public Service Company of New Mexico (“PNM”). APS owns 70 percent of Units 4 and 5.

Cholla is a two-unit (Units 1 and 3) coal-fired power station located near Joseph City, Arizona. Unit 1 is 116 MW and went into service in 1962. Unit 3 is 271 MW and went into service in 1980.[2] Units 1 and 3 of the plant are wholly owned and operated by APS.

Q What is APS requesting in this docket related to the Cholla and Four Corners coal plants?

A APS is requesting two things relating to its coal plants in this docket: (1) PTYP spending for the ELG project at Four Corners, and (2) approval to include in rates its costs to operate and maintain Cholla Units 1 and 3 through 2025 and Four Corners Units 4 and 5 through 2031. This includes capital expenditures (“capex”) and O&M costs incurred during the test year ending June 30, 2022.

Q What test-year and PTYP costs for the Four Corners and Cholla coal plants is APS requesting to include in rates?

A As shown in Table 1 below, APS is requesting to place approximately $37 million in capital expenditures[3] into its rate base, and over $140 million in O&M costs into rates.[4] These costs were incurred at Cholla Units 1 and 3 and at Four Corners Units 4 and 5 during the test year ending June 30, 2022. APS is also requesting

[2] Attach. DG-2, APS Response to Staff DR 1.2, Attachment Staff 1.2_APS22RC02270_APS Owned Plants.

[3] Attach. DG-2, APS Response to Sierra Club Data Request (“SC DR”) 2.1.

[4] Attach. DG-2, APS Response to SC DR 1.3.

approval for $36.7 million in PTYP spending for modifications required to comply with EPA's updated ELG guidelines, specifically to convert Four Corners' existing wastewater systems to a closed-loop configuration system.[5] The system is expected to be in service before June 30 of this year (2023).[6]

Table 1. Test-year sustaining capital expenditures and operations & maintenance costs and PTYP spending

Plant	Sustaining capital expenditures ($Millions)	Operations & maintenance costs ($Millions)	PTYP Spending ($Million)
Cholla	$7.9	$41.7	-
Four Corners	$29.2	$98.9	$36.7
Total	**$37.1**	**$140.6**	**$36.7**

Source: Attach. DG-2, APS Response to SC DR 1.3; Attach. DG-2, APS Response to SC DR 2.1.

Q What is the undepreciated balance at each plant?

A The net plant balances for Cholla Units 1 and 3 and APS's share of Four Corners Units 4 and 5 were $207.1 million and $1.15 billion respectively as of June 30, 2022.[7]

Q Has APS committed to a retirement date for each coal plant?

A Yes. As shown in Table 2 below, APS plans to retire all coal by 2031. Specifically, it plans to retire Cholla Units 1 and 3 by 2025 to avoid the costly compliance upgrades required for the plant to stay online beyond 2025. The 2025

[5] Direct Testimony of Jacob Tetlow at 24:9-13 [hereinafter "Tetlow Direct"].

[6] Tetlow Direct, Attachment JT-05DR.

[7] Attach. DG-2, APS Response to SC DR 1.3.

retirement date was based on a compromise proposal, offered by APS and approved by EPA, for meeting required environmental and emission standards at Cholla. That compromise was approved by the Commission in a 2017 Settlement Agreement.[8]

APS plans to retire Four Corners Units 4 and 5 at the end of July 2031 when the plant's current coal supply contract ends.[9] Four Corners' depreciation date is set for 2038, as set forth in the Company's most recent Commission-authorized depreciation study. APS is not requesting to change the depreciation date in this docket.[10]

Table 2. Retirement and seasonal operations dates for APS coal plants

Plant	Year Online	Planned Retirement Year
Cholla Unit 1	1962	2025
Cholla Unit 3	1980	2025
Four Corners Unit 4	1969	2031
Four Corners Unit 5	1970	2031

Source: Direct Testimony of Justin Joiner at 11 [hereinafter "Joiner Direct"]; Tetlow Direct at 28; U.S. EIA Form 860.

Q Is APS requesting any other test-year or PTYP spending on major plant upgrades in this docket?

A Yes. APS is requesting $105.1 million in PTYP spending to install chiller projects at the Redhawk and Sundance gas plants. Both plants were built in 2002.

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8 FERC Form 1, included as Schedule E-9, at 46.

9 Tetlow Direct at 28:7-8; Direct Testimony of Elizabeth Blankenship at 29:9-11, 36:24-26 [hereinafter "Blankenship Direct"].

10 Blankenship Direct at 24:1-5.

Redhawk is a 940 MW two-unit combined-cycle gas plant. Sundance is a 420 MW, 10-unit gas plant with 10 combustion turbines. The chillers are intended to improve plant performance at high temperatures by pre-cooling air during off-peak times. This will allow for increased peak output during the hottest months.[11]

Q Does APS have any near-term resource needs?

A Yes, APS has updated its near-term load growth forecast through 2026. The Company now projects 1,400 MW in load growth through 2026, which is 300 MW more than projected in its 2020 IRP.[12] This increase is due mainly to anticipated growth in large technology and manufacturing load in the region.

With the retirement of Cholla in 2025, the expiration of several power purchase agreements ("PPA") that provide 700 MW of capacity around the same time, and the Company's projected increase in load, APS anticipates it will need around 2,300 MW of new on-peak capacity by 2026.[13]

Q Has APS acquired any new resources or signed any new PPA or tolling agreements over the past five years?

A Yes. APS signed a number of tolling agreements, PPAs, and engineering procurement and construction ("EPC") deals[14] over the past five years for solar

[11] Tetlow Direct at 14:4-7, 24:2-5.

[12] Attach. DG-5, Arizona Public Service Company, 2020 Integrated Resource Plan at 387, Docket No. E-00000V-19-0034 (Ariz. Corp. Comm'n June 26, 2020) [hereinafter "Attach. DG-5, APS 2020 IRP"].

[13] Direct Testimony of Theodore N. Geisler at 19:17-18, 28:1-3.

[14] EPC contracts are for the construction of resources that APS will own and operate.

photovoltaics ("PV"), wind, battery storage, and paired solar and storage projects. These deals, and the associated procurement efforts that solicited them, are summarized in Highly Confidential Attachment 7.

[redacted]

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[15] APS Response to Initial Request 1.63, Attachment Initial 1.63_APS22RC02103_South Point w Amendments_HIGHLY CONF, Attachment Initial 1.63_APS22RC01935_Griffith Energy_HIGHLY CONF, Attachment Initial 1.63_APS22RC01818_Arlington Valley LLC_HIGHLY CONF; APS Response to Sierra Club Request 1.21, Attachment SC 1.21_APS22RC03196_Arlington Valley PPA Ext_HIGHLY CONF. All highly confidential discovery responses referenced in this testimony are compiled and available within Attachment DG-4 ["Attach. DG-4"].

[16] Attach. DG-4, APS Response to Staff DR 1.16, Attachment APS Response to Staff Request 1.16, Staff 1.16_ExcelAPS22RC03035_2020 ASRFP Final Selection_HIGHLY CONF; Attach. DG-12, APS Presentation from APS RPAC Meeting at 8, 16 (April 21, 2023) [hereinafter "Attach. DG-12, APS RPAC Meeting Presentation (April 21, 2023)"].

[17] Attach. DG-4, APS Response to Initial Request 1.63, Attachment Initial 1.63_APS22RC00754_SRP Eastern Area PPA 2020_HIGHLY CONF, Attachment Initial 1.63_APS22RC01936_SRP Eastern Area PPA 2022_HIGHLY CONF, Attachment Initial 1.63_APS22RC02182_Harquahala Tolling 2021_HIGHLY CONF, Attachment Initial 1.63_APS22RC02033_Harquahala Tolling 2022_HIGHLY CONF; Attach. DG-4, APS Response to Sierra Club Request 1.21, Attachment SC 1.21_APS22RC03204_Powerex WSPP Schedule C FA_HIGHLY CONF, Attachment SC 1.21_APS22RC03205_Rainbow WSPP Sch B_HIGHLY CONF, Attachment SC 1.21_APS22RC03206_Vitol WSPP Firm 1_HIGHLY CONF, Attachment SC 1.21_APS22RC03207_Vitol WSPP Firm 2_HIGHLY CONF; Attach. DG-4, APS Response to Staff Request 1.3, Attachment Staff 1.3_APS22RC02735_Powerex 2021_HIGHLY CONF, Attachment Staff 1.3_APS22RC02736_Powerex 2022_HIGHLY CONF, Attachment Staff 1.3_APS22RC02737_REMC_HIGHLY CONF, Attachment Staff 1.3_APS22RC02734_Calpine Energy Service_HIGHLY CONF.

[redacted]

Q Summarize APS's procurement efforts over the past five years.

A In 2019 APS issued the 2019 Wind Request for Proposals ("RFP").[18] This resulted in the [redacted]

In 2020, APS issued an All Source RFP for 300–400 MW of renewables with in-service dates of 2023 or 2024, and 200–300 MW of capacity resources, also with in-service dates of 2023 or 2024.[21] Through this RFP, APS signed contracts for the following:[22]

- [redacted])

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[18] *APS to Request Proposals for New Solar and Wind Resources*, Bloomberg (July 29, 2019), *available at* https://www.bloomberg.com/press-releases/2019-07-29/aps-to-request-proposals-for-new-solar-and-wind-resources.

[19] Attach. DG-4, APS Response to Initial Request 1.63, Initial 1.63_APS22RC01903_Aragonne_Restated PPA_HIGHLY CONF at 9, 24.

[20] Attach. DG-4, APS Response to SC DR 1.21, Attachment SC 1.21_APS22RC03189_AES Energy Storage Tolling Westwing_HIGHLY CONF, Attachment SC 1.21_APS22RC03190_El Sol Energy Storage TA_HIGHLY CONF.

[21] Attach. DG-2, APS Response to Staff DR 1.16, Attachment Staff 1.16_APS22RC02878_All Source RFP Dec 11 2020 at 5.

[22] Attach. DG-4, APS Response to Staff DR 1.16, Attachment Staff 1.16_ExcelAPS22RC03035_2020 ASRFP Final Selection_HIGHLY CONF.

[redacted]

In December 2020, several months after the original 2020 RFP was issued, APS issued an addendum requesting EPC bids to build a 100–150 MW solar PV project to be installed at the Redhawk generating station, with an in-service date of Q4 2022 or Q1 2023.[23] [redacted].[24]

In May 2022, APS issued a 2022 All Source RFP for 1,000–1,500 MW of new resources, including 600–800 MW of additional renewables with an in-service date of 2025 or 2026. APS is currently in negotiations with bidders for more megawatts of capacity than it originally sought and announced that it expects to bring online 2,264 MW of new resources by 2025, 1,056 MW of which will be renewables.[25] The projects APS is bringing online include the following:

- Chevelon Butte wind (216 MW in phase two)[26]
- [redacted]

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[23] Attach. DG-2, APS Response to Staff DR 1.16, Attachment Staff 1.16_APS22RC02899_2020 RFP Addendum at 4.

[24] Attach. DG-4, APS Response to Staff DR 1.16, Staff 1.16_ExcelAPS22RC03071_2020 ASRFP Addendum Final Selection_HIGHLY CONF.

[25] Attach. DG-2, APS Response to Staff DR 1.16, Attachment Staff 1.16_APS22RC03036_2022 All Source RFP; Attach DG-12, APS RPAC Meeting Presentation at 16 (Apr. 21, 2023).

[26] AES, *Chevelon Butte Wind Farm*, *available at* https://www.aes.com/chevelon-butte (last visited May 31, 2023).

[redacted]

APS also plans to extend two summer tolling PPAs with natural gas plants.[28]

APS is planning to issue yet another all-source RFP in Summer 2023 focused on resources that will come online in 2027 and 2028. As part of this RFP, APS is seeking 150–400 MW of energy storage for the Agave site, 168 MW solar and 168 MW battery storage for the Ironwood site, up to 250 MW of renewable generation to be sited on Navajo Nation land, up to 115 MW of new generation to be located at the existing Cholla site, and 400 MW of new incremental gas generation at its existing gas plants.[29]

These new resources, in combination with the firm capacity tolling agreements discussed above, should meet and exceed APS's projected 2,300 MW increase in peak capacity need by 2026.

Q What are APS 's carbon dioxide ("CO_2") reduction and renewable energy goals?

A APS has a goal to provide 100 percent clean, carbon-free electricity to customers by 2050. The Company has an interim 2030 goal to achieve a resource mix that is 65 percent clean energy, with 45 percent of its generation portfolio coming from

[27] Attach. DG-4, APS Response to SC DR 1.21, Attachment SC 1.21_APS22RC03212_Serrano Solar+Storage_HIGHLY CONF, Attachment SC 1.21_APS22RC03195_Sun Streams 4 _HIGHLY CONF.

[28] Attach. DG-2, APS Response to Staff DR 1-16, Attachment Staff 1.16_APS22RC03036_2022 All Source RFP at 21-22; Attach. DG-12, APS RPAC Meeting Presentation at 8, 16 (Apr. 21, 2023).

[29] Attach. DG-12, APS RPAC Meeting Presentation at 18 (Apr. 21, 2023); Attach. DG-13, APS Presentation from APS RPAC Meeting at 12 (May 17, 2023).

renewables. The Company plans to end coal generation by 2031.[30] To achieve this goal, APS must reduce its reliance on fossil fuels, retire its coal plants, and build out substantial new renewable energy and battery storage capacity.

[30] Direct Testimony of Andrew Cooper at 14:11-13 [hereinafter "Cooper Direct"]; APS, *APS Clean Energy Commitment*, *available at* https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Energy-Resources/CleanEnergyCommittment.ashx?la=en&hash=EC0606653A170A6A83A716703CD62B44/ (last visited May 31, 2023).

4. <u>The economic and operational performance of APS's aging fossil resources are declining, reliance on those resources is becoming increasingly risky, and APS has provided no current analysis to justify much of its test-year and PTYP spending.</u>

i. <u>My analysis indicates that Cholla should retire in 2025 as planned, and Four Corners should retire earlier than 2031.</u>

Q What are the utilization levels of Cholla and Four Corners in recent years?

A APS's utilization of Cholla Units 1 and 3 and Four Corners Units 4 and 5 has been relatively high over the past few years. As shown in Table 3 below, between 2018 and 2022, APS operated Four Corners at a relatively high capacity factor of between 47 percent and 76 percent.[31] APS operated Cholla at between 29 percent and 69 percent capacity factors over the same time period. At both plants, utilization was at its highest level in 2022 due to the short-term impacts of the war in Ukraine and accompanying gas price and market price spikes. These spikes have already subsided, with gas prices dropping substantially in 2023 and projected to fall to back to pre-pandemic levels in the near future, as I will discuss later.

[31] U.S. Energy Information Administration Form 923, 2019-2022 (2022 only through September), *available at* https://www.eia.gov/electricity/data/eia923/ [hereinafter "U.S. EIA Form 923"].

Table 3. Historical capacity factors 2018–2022

	2018	2019	2020	2021	2022
Cholla Unit 1	47%	29%	38%	67%	66%
Cholla Unit 3	52%	42%	45%	52%	69%
Four Corners Unit 4	47%	71%	60%	51%	76%
Four Corners Unit 5	64%	59%	53%	65%	76%

Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx.

Q How reliable have Cholla Units 1 and 3 and Four Corners Units 4 and 5 been in recent years?

A APS's coal fleet has had reliability challenges in recent years. As shown in Table 4 and Table 5 below, each of APS's coal units had a high forced outage rate during at least one of the last five years. In particular, Four Corners Units 4 and 5 had high forced outage rates in every year between 2018 and 2022, with equivalent forced outage rates ranging from 9.5–28.2 percent.[32] Cholla performed better overall, but still had a forced outage rate of nearly 15 percent at Unit 3 in 2021.

The outage rates at Four Corners between 2018 and 2022, and at Cholla Unit 3 in 2021, are higher than the national average reported by the North American Electric Reliability Corporation ("NERC"), which was around 7.25 percent across all grid resources for the five years between 2017 and 2021.[33] According to the NERC study, outage rates at coal units averaged around 10 percent nationally,

[32] The equivalent forced outage rate measures the percentage of time that a unit was unavailable during only the hours that it was expected to be available. This means it excludes hours when the unit was planned to be offline.

[33] North American Electric Reliability Corporation, 2020 State of Reliability (July 2020), *available at* https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

which was worse than during the prior five-year study period, and part of a pattern of worsening fleet performance.[34] These high outage rates are concerning because, as discussed later in this section and in Section 5, gas and market prices are currently high, meaning the short-term replacement resources that APS has to rely on in the event of outages are very expensive for APS ratepayers.

Table 4. Equivalent availability factors

Unit	2018	2019	2020	2021	2022
Cholla Unit 1	90.35	70.58	89.71	88.69	77.10
Cholla Unit 3	92.24	89.29	92.46	68.45	79.73
Four Corners Unit 4	51.55	83.06	67.50	57.25	82.66
Four Corners Unit 5	71.90	70.54	60.29	74.84	83.72

Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx.

Notes: The equivalent availability factor measures the percentage of time that a unit was available during all the hours in that period. This includes hours in which the unit was planned to be unavailable.

Table 5. Equivalent forced outage rate for APS's coal units 2019–2021

Unit	2018	2019	2020	2021	2022
Cholla Unit 1	2.95	3.22	3.95	3.10	4.39
Cholla Unit 3	2.33	7.40	1.38	14.76	3.32
Four Corners Unit 4	25.48	9.52	24.17	15.79	7.95
Four Corners Unit 5	28.20	21.29	14.30	20.82	10.19

Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx.

Q How much have outages at APS's coal plants cost ratepayers?

A APS incurred [redacted] in costs at Cholla to purchase replacement energy and capacity when the plant experienced unplanned outages between January 2021

[34] *Id.*

and February 2023 (the most recent month for which APS provided data).[35] At Four Corners, one of the units was in forced outage every day in January 2023, resulting in [redacted] in replacement power costs for that month alone.[36] These are costs that APS seeks to pass on to ratepayers.

Q Describe Four Corners' recent financial performance.

A As shown in Table 6 below, Four Corners Units 4 and 5 have consistently been costly to operate. Recent spikes in energy prices have temporarily made Four Corners appear valuable relative to high-priced market energy or high-priced natural gas. While gas prices are not expected to remain high, the costs to operate and maintain aging legacy fossil units such as Four Corners are expected to remain high, and are likely to increase as the plants continue to age and as more environmental regulations are implemented.

[35] APS Response to Staff DR 1.138, Attachment Staff 1.138_ExcelAPS22RC03245_Replacement Power Costs_CONF. All confidential discovery responses referenced in this testimony are compiled and available within Attachment DG-3 ["Attach. DG-3"].

[36] *Id.*

Table 6. Costs of Four Corners 2018–2022

($2022 Million)	**2018**	**2019**	**2020**	**2021**	**2022**
Fuel costs	$176.2	$195.5	$156.2	$213.5	$252.2
Variable O&M costs	$44.28	$30.35	$26.08	$25.65	$31.28
Estimated total variable cost	**$220.5**	**$225.8**	**$182.3**	**$239.1**	**$283.5**
Total O&M costs	$56.4	$52.7	$66.6	$60.9	$45.9
Sustaining (non-environmental) capital expenditures	$55.6	$43.3	$68.2	$57.7	$18.4
Environmental capital expenditures	$60.8	$18.3	$25.5	$21.7	$27.8
Total Cost	**$393.3**	**$340.1**	**$342.5**	**$379.5**	**$375.7**
Total Generation (GWh)	4,700	5,536	4,819	4,951	6,464
Total Cost ($/MWh)	$84/ MWh	$61/ MWh	$71/ MWh	$77/ MWh	$58/ MWh

Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.

Q Describe Cholla's recent financial performance.

A Because Cholla is scheduled to retire in 2025, APS has ramped down investments in the plant in recent years. As shown in Table 7 below, even with reduced investments, the plant has remained expensive to operate. If APS were to reverse course on retirement, it would have to make a substantial investment in the plant to catch up on the routine maintenance it has avoided with the early retirement plan. To postpone the plant's retirement, APS would also have to invest a substantial amount of money in environmental compliance costs, which were the driving factor in APS's decision to retire the plant. Some of these costs would have been incurred during the test year and the PTYP period.

Table 7: Costs of Cholla 2018–2022

($2022 Million)	**2018**	**2019**	**2020**	**2021**	**2022**
Fuel costs	$58.20	$43.72	$42.28	$51.89	$94.94
Variable O&M costs	$6.37	$3.78	$4.18	$8.84	$8.71
Estimated total variable cost	**$64.57**	**$47.50**	**$46.45**	**$60.74**	**$103.72**
Total O&M costs	$24.78	$29.60	$27.49	$34.73	$30.27
Sustaining (non-environmental) capital expenditures	$0.41	$10.59	$2.16	$4.20	$5.52
Environmental capital expenditures	$0.53	$0.67	$5.34	$6.12	$5.93
Total Cost	**$90.29**	**$88.36**	**$81.43**	**$105.78**	**$145.44**
Total Generation (GWh)	1,699	1,298	1,476	1,926	2,317
Total Cost ($/MWh)	$53/ MWh	$68/ MWh	$55/ MWh	$55/ MWh	$63/ MWh

Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.

Q Explain the methodology you used to evaluate the historical performance of APS's coal units.

A I relied on APS data provided in discovery. Specifically, APS provided historical fuel costs in dollars per metric million Btu, which I converted to annual fuel costs using the Company's unit-level generation and heat rate data for each year.[37] APS provided fixed O&M costs in dollars per MW, and variable O&M costs in dollars per megawatt hour ("MWh"), which I converted to annual costs by combining with unit-level capacity and generation respectively.[38] APS also provided plant-level annual capital expenditures (broken out by environmental and non-

[37] Attach. DG-2, APS Response to SC DR 1.15, Attachment SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.

[38] *Id.*

environmental spending).[39] To calculate estimated total variable cost, I summed fuel costs and variable O&M costs. To calculate total plant cost, I summed all fuel costs, fixed and variable O&M, sustaining capital expenditures, and environmental capital expenditures. I then divided total costs by annual generation to get total costs on a per-MWh basis.[40]

Q Describe the projected financial performance of APS's coal plants over the next 10 years.

A As part of its 2020 IRP, APS calculated the forward-going levelized cost of energy ("LCOE") for each of its resources, as shown in Table 8 below. The Company calculated an LCOE of $89.2/MWh for Four Corners and $120.8/MWh for Cholla. These costs are inclusive of all fuel, O&M, and capital costs (environmental and otherwise) required to operate and maintain the plants. But the LCOE for Four Corners does not include the estimated [redacted] total in shortfall costs that APS projects it will have to pay the Navajo Mine to meet APS's minimum contract requirements between 2020 and when the Four Corners plant retires in 2031.[41]

The cost for Cholla does not include the cost to comply with the environmental regulations that would have been necessary to keep the plant online beyond 2025 but is avoidable with the early retirement. The LCOE for Cholla is also slightly skewed by the reduction in output planned in advance of the plant's retirement in 2025.

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[39] *Id.*

[40] *Id.*

[41] Attach. DG-3, APS Response to SC DR 6.6, Attachment SC 6.6_ExcelAPS22RC03420_FC_Coal_Shortfall 2020 IRP_CONF.

Table 8. LCOE of APS's coal plants 2020–2030

Resource	LCOE ($/MWh)
Four Corners	$89.2
Cholla	$120.8

Source: Attach. DG-2, APS Response to SC 1.10, Attach. SC 1.10_ExcelAPS22RC03200_Bridge_Base_EXISTING BUSBARS.

Q Do you believe APS's calculated LCOE reflects the current forward-going costs to operate Cholla?

A No. As I mentioned above, APS would have to catch up on all the routine maintenance it has been foregoing at the Cholla plant because of the plant's planned retirement in 2025, which was mandated under a 2017 settlement agreement. If Cholla were not closing in 2025, APS would also have to install a selective catalytic reduction ("SCR") pollution control system at the plant, which APS was able to avoid because of its commitment to shut down Cholla by 2025.[42] I estimated that the cost of that upgrade would be around $180 million in capital expenditures, and around $1.4 million in annual incremental O&M costs.[43]

Q Do you believe APS's calculated LCOE reflects the current forward-going costs to operate Four Corners?

A No. APS's LCOE calculations for Four Corners were developed for APS's 2020 IRP, before the Company made its costly investments in the ELG project at Four Corners. They were also developed before APS amended its fuel contract and operational agreements to allow it to switch Four Corners to seasonal operations

[42] Attach. DG-5, APS 2020 IRP at 195.

[43] U.S. Environmental Protection Agency, *Retrofit Cost Analyzer* (updated Apr. 19, 2023), *available at* https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

based on current market conditions.[44] The LCOE also does not include shortfall costs associated with APS's coal contract. I expect that if APS utilized current and complete cost data on Four Corners, it would find that each unit is even more expensive to operate than APS projected in its 2020 IRP.

The cost of APS's post-test-year ELG investments at Four Corners was $36.7 million.[45] APS did not include any costs associated with the ELG project in its 2020 IRP, stating that the "Company had not committed to completing those projects at the time of the IRP filing."[46] Therefore, the LCOEs for the Four Corners units understate the forward-looking costs to operate the plant.

Second, I am concerned that the data APS provided to Sierra Club in discovery does not reflect a switch to seasonal operations at Four Corners. Figure 1 below shows the Company's projected generation data for both Four Corners and Cholla.[47] Specifically, this figure shows that APS expects Four Corners to continue to operate with approximately the same annual output over the next decade as it has historically. But the Four Corners plant currently operates year-round, and therefore is unlikely to generate the same quantity of energy if it switches to seasonal operations. With a lower quantity of generation, the LCOE or cost per MWh will increase because APS's fixed costs will not change – they will just be spread over fewer MWh. But because the variable cost to operate the plant is high, APS ratepayers will likely still benefit from reduced operations at the plant.

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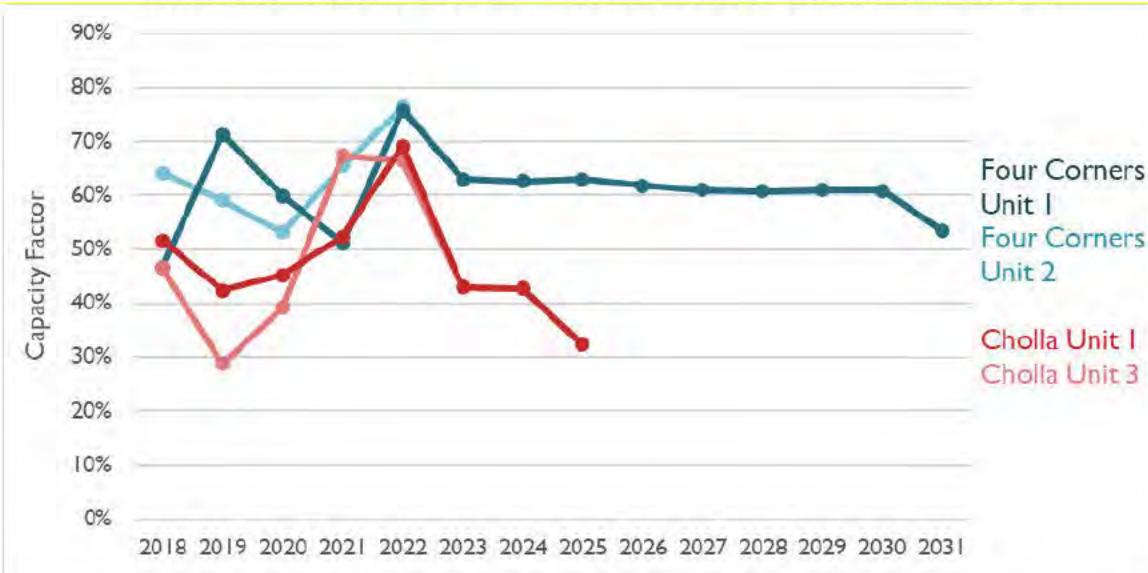
[44] Attach. DG-2, APS Response to Staff DR 1.14(a-b).

[45] Tetlow Direct at 24:9-13.

[46] Attach. DG-2, APS Response to SC DR 6.2.

[47] Attach. DG-2, APS Response to SC DR 1.15, Attachment SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx.

Figure 1. APS recent historical and projected capacity factors for coal-fired units



Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx; Attach. DG-2, APS Response to SC DR 1.10, Attach. SC 1.10_ExcelAPS22RC03200_Bridge_Base_EXISTING BUSBARS.

Even though APS has indicated that it no longer plans to switch the Four Corners plant to seasonal operations for the fall of 2023, the Company *does* plan to reevaluate this decision for future years.[48]

Third, the LCOE for Four Corners does not include the shortfall costs that APS has to pay its coal supplier when it utilizes less coal than contracted.[49] Because APS is locked into a minimum quantity of coal each year, it should be modeling its minimum fuel cost as a fixed cost.

[48] Attach. DG-2, APS Response to Staff DR 1.14(a-b); Attach. DG-2, APS Response to SC DR 1.13, Attachment SC 1.13_APS22RC03068_Letter to Owners re Seasonal Ops.

[49] Attach. DG-2, APS Response to SC DR 6.6.

Q Why is it concerning that APS provided operational projections that do not match its stated operational plans for Four Corners?

A APS's operational projections for Four Corners are concerning for three reasons. First, while APS may have updated its operation agreements, it has not provided updated resource planning analysis that shows the impact of seasonal operations. Second, a switch to seasonal operations impacts not just output but also O&M costs, capital investments, and replacement resource decisions. This switch should directly lead to lower fuel and variable costs and should also impact planning around long-term spending on O&M and sustaining capital expenditures. It is unclear if or how APS considered this.

Finally, lower generation levels at each unit also mean that there are fewer MWh to recover the units' fixed costs. APS should be carefully tracking and evaluating all spending and taking all measures possible to minimize unnecessary spending at Four Corners. Instead, the Company is continuing to make large investments in the plant, including the PTPY ELG project the Company is asking to recover in this docket. If APS had committed to retire Four Corners by 2028, it would have been held to less stringent discharge standards, and therefore would likely have incurred lower ELG compliance costs.[50] APS did not consider the option of early retirement in 2028 to reduce avoid the ELG upgrade because it claimed it could not procurement replacement capacity in the required timeframe.[51]

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[50] *See* 40 C.F.R. Part 423.

[51] Attach. DG-2, APS Response to SC DR 5.4.

Q **How does the cost to operate APS's existing coal plants compare with the cost of alternative resources?**

A At an estimated \$89 to \$120 per MWh, the costs to operate APS's existing coal plants are very high relative to the cost of alternatives as shown in Highly Confidential Attachment 8 and Highly Confidential Attachment 9. Solar PV is currently being built in the region for \$15–\$30 per MWh. APS modeled new wind at [redacted] in its 2020 IRP[52] [redacted].[53] Paired solar PV plus battery storage projects are being built in the region for between \$24.50 and \$30 per MWh for the solar PV component and between \$5.36 and \$10.99 per kW-month for the battery storage. APS is building standalone battery storage projects for [redacted], as shown in Highly Confidential Attachment 10.

Q **How do these costs compare to the costs for alternatives that APS modeled during its 2020 IRP?**

A APS provided only capital costs for new resources in its discovery responses to Sierra Club, so I calculated levelized costs based on the capital cost and operational cost assumptions that APS provided. Table 9 shows LCOE assumptions for new solar and wind resources based on the APS 2020 IRP.

[52] Attach. DG-5, APS 2020 IRP at 287.

[53] Attach. DG-4, APS Response to Initial Request 1.63, Attachment Initial 1.63_APS22RC01903_Aragonne_Restated PPA_HIGHLY CONF at A1-A2.

Table 9. APS 2020 IRP new renewable cost assumptions

Resource	LCOE ($/MWh) $2022
Solar PV	$32.71
Wind	$29.72

Source: Attach. DG-5, APS 2020 IRP.

Q How do these new resource cost assumptions compare to recent cost projections from APS as well as other industry projections?

A Since APS's 2020 IRP, there have been several developments that have impacted clean energy resource costs. Supply chain constraints have increased capital costs. In a recent presentation given to APS's Resource Planning Advisory Council ("RPAC"), APS presented new renewable resource capital costs that were substantially higher than those in its 2020 IRP. APS indicated that single-axis utility solar capital costs were approximately $1,650 per kW, up from $1,160/kW in 2020, and wind was approximately $1,670 per kW, up from $1,343 per kW in 2020 (all values given in real 2022 dollars).[54] Other industry projections have also increased over the past year. The most recent subsidized and unsubsidized renewable cost estimates from Lazard[55] and the National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB") [56] are shown in Table 10. However, as discussed further in Section 4.iii below, the passage of the IRA in August 2022 extended and expanded the Production Tax Credit ("PTC")

[54] Attach. DG-12, APS Presentation from APS RPAC Meeting at 26, 28 (Apr. 21, 2023).

[55] Lazard's Levelized Cost of Energy + (April 2023), *available at* https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/.

[56] NREL, *2022 ATB data, available at* https://atb.nrel.gov/electricity/2022/index (last visited May 31, 2023).

and the Investment Tax Credit ("ITC") for clean energy resources through at least 2032, driving down subsidized costs.[57]

The IRA tax credits include adders based on whether the resource is located in an energy community, whether the resource is produced domestically, and whether wage and apprenticeship requirements are satisfied.[58] Differing tax credit adder eligibilities between projects, as well as geographic and temporal variation in supply chain constraints will likely lead to a range of LCOEs for future projects, which is reflected in the wide range of Lazard's 2023 cost estimates. NREL's ATB was last published in in July 2022, so it does not incorporate the IRA. However, the 2022 ATB does incorporate the tax credits that were available at the time, including a 26 percent ITC for solar PV and a $10.54 PTC for wind. Arizona has especially strong solar potential, and so I would expect the LCOEs of solar PV projects in APS's service territory to fall on the lower end of Lazard's estimate range.

Table 10. Recent renewable LCOE estimates ($2022 /MWh)

Resource	APS 2023 IRP		Lazard 2023		ATB 2022 (pre-IRA)
	unsubsidized	subsidized	unsubsidized	subsidized	*
Solar PV	$44	$28	$24–96	$0–77	$25–27
Wind	$35	$20	$24–75	$0–66	$25–40

Note: 26% ITC for solar PV, $10.54 PTC for wind.

Source: Attach. DG-12, APS RPAC Meeting Presentation (Apr. 21, 2023); Attach. DG-5, APS 2020 IRP; Attach. DG-14, Lazard's LCOE+ (April 2023); NREL's 2022 ATB data.

[57] *See* Inflation Reduction Act of 2022, Pub. L. No. 117-169, §§ 13101, 13102, 13701, 13702, 136 Stat. 1818, codified at 26 U.S.C. §§ 45, 45Y, 48, 48E.

[58] *See* 26 U.S.C. § 45(b)(11)(B); U.S. EPA, *Summary of Inflation Reduction Act provisions related to renewable energy* (May 2023), available at https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy#:~:text=Through%20at%20least%202025%2C%20the,projects%20over%201%20MW%20AC.

Q Explain the methodology you used to calculate these LCOEs.

A To calculate the LCOEs for the solar PV and wind resources modeled in APS's 2020 IRP, I used APS's assumptions from its 2020 IRP. I used the capacity, capacity factor, capital expenditure, fixed O&M, variable O&M, and book life from the 2020 IRP[59] for each resource to create projected cost and generation streams extending over the book life for each resource. I then used the Company's weighted average cost of capital ("WACC") of 7.17 percent[60] to calculate the net present value of the costs and the net present value of the energy generated by each resource. Finally, I divided the net present value of the cost by the net present value of the energy to calculate the LCOE for each resource.

For the 2023 APS IRP LCOEs, I used the same assumptions for the capacity, capacity factor, O&M, and book life as for the 2020 LCOEs, but I updated the capital expenditures to reflect the updated capital costs presented at a recent APS RPAC meeting on April 21, 2023.[61] For the unsubsidized values, I performed the same calculation described above for the 2020 IRP calculations. For the subsidized LCOE estimate, I estimated the annual PTC payment that each resource would receive for 10 years from the operational start date, using the capacity and capacity factor assumptions. I used $26 per MWh for the PTC value, which assumes wage and apprenticeship requirements are satisfied, but does not include any additional adders. I then subtracted the PTC payments from the projected cost streams and calculated the present value of the net costs, minus the tax credits, again using the Company's WACC of 7.17 percent. I finally divided

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[59] Attach. DG-5, APS 2020 IRP at 375.

[60] APS Application at 5.

[61] Attach. DG-12, APS RPAC Meeting Presentation at 26, 28 (Apr. 21, 2023).

the present value of the net costs by the present value of the energy to find the subsidized LCOE.

I performed similar calculations assuming each resource opted for the ITC, and found the LCOEs were higher than the PTC option. I have presented the results obtained under the PTC regime in Table 10, since it is the more cost-effective tax credit option given APS's cost assumptions.

Q Do the costs shown in Highly Confidential Attachments 8 and 9 reflect the near-term impact of inflation and supply chain challenges?

A Yes. The prices for the Buena Vista, Carne, Atrisco, and San Juan solar plus storage projects all reflect recent PPA amendments that the developers requested. These amendments increase the project cost to account for supply chain challenges and inflation (and in some cases also extend the online date).

Q How does the cost of a clean energy portfolio compare to the cost of continuing to rely on APS's aging coal resources?

A The *Arizona Coal Plant Valuation Study* (Attachment DG-15) conducted by Strategen Consulting on behalf of Sierra Club in September 2019 found substantial cost savings from replacing Four Corners with alternative portfolios of resources consisting of solar PV plus storage, market energy, and wind.[62]

In the time since this study was published there have been changes in the market that will, on net, substantially improve the economics of clean energy resources. Most notably, the IRA passed by Congress in August 2022 extends tax credits for

[62] Attach. DG-15, Strategen Consulting, *Arizona Coal Plant Valuation Study* at 13-14, 32 (Sept. 16, 2019).

solar PV and wind and adds critical new tax credits for battery storage. I discuss the IRA in more detail below.

Q Can clean energy portfolios paired with market energy provide the same or a better level of reliability as APS currently gets from its fossil fuel power plants?

A Yes, if deployed correctly, clean energy resources (including renewables, battery storage, demand-side management programs, and transmission build-out) paired with market energy, can provide the same if not better reliability than APS's fossil fuel power plants, at a lower cost. APS's coal-fired plants have all faced reliability challenges in recent years, as shown by the forced outage rates discussed above. Additionally, as outlined in detail below, APS's coal plants and other coal plants in the region have faced challenges procuring the full contracted amount of coal. If a plant does not have a firm and certain fuel supply, then it cannot be relied on to provide its full firm capacity and should be de-rated.

With renewables, on the other hand, there are zero fuel requirements and therefore no possibility that a fuel supply constraint will disrupt firm capacity. The output of solar PV also aligns well with APS's peak summer demand needs, and wind output generally increases during the later afternoon and early evening, when APS's net peak loads increase at and around sunset. Moreover, with transmission reform underway across the United States, it may soon become easier and less costly for APS or other regional entities to build out the transmission network needed for APS to access high quality wind.[63] While it is true that APS will also

[63] For example, the SunZia transmission line from New Mexico to Arizona recently received key approvals. *See* Press Release, U.S. Dept. of the Interior, Biden-Harris Administration Advances

need firm capacity, battery storage can provide and already is providing firm capacity and many of the grid services currently provided by APS's fossil resources. I am not suggesting that APS retire Four Corners Units 4 and 5 immediately and replace those units with energy market purchases or energy efficiency measures. But, if implemented correctly, and based on adequate reliability assessments, APS can replace the Four Corners capacity with a combination of resources with equal or possibly better reliability performance, likely by the end of 2028.

Q What costs would APS avoid by accelerating the retirement of its coal plants?

A APS would avoid substantial sustaining capex, environmental capex, and O&M costs with early retirement of its coal plants. As shown in Table 11 below, APS projected that its future capital expenditures at the Four Corners and Cholla plants will be much lower than its spending was historically. The lower Cholla capital spending is reasonable, given Cholla's imminent 2025 retirement. But I am concerned that APS may be under-projecting the likely forward-going cost to maintain Four Corners. APS's historical spending at Four Corners is much higher than industry averages, as measured by Sargent & Lundy. This indicates that the plant has been relatively expensive to maintain relative to other coal plants, which are already expensive to maintain compared to alternative resources. Yet APS' forward-going cost projections for Four Corners are lower than industry averages. This leads me to conclude that APS's projected capex spending at Four Corners is unrealistic.

SunZia Southwest Transmission Project (May 18, 2023), *available at* https://www.doi.gov/pressreleases/biden-harris-administration-advances-sunzia-southwest-transmission-project.

Table 11. Projected and historical sustaining capex for APS's coal plants

	Capex ($2022 $/kW-year)		
	Sargent & Lundy sustaining capex estimates	APS historical sustaining capex spending	APS projected sustaining capex spending
Four Corners Unit 4	$34.41	$50.15	$25.41
Four Corners Unit 5	$34.41	$50.15	$25.41
Cholla Unit 1	$35.89	$20.54	$11.86
Cholla Unit 3	$34.41	$37.07	$14.96

Source: Attach. DG-2, APS Response to SC DR 1.15, Attach. SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics; Attach. DG-2, APS Response to SC DR 1.10, Attach. SC 1.10_ExcelAPS22RC03200_Bridge_Base_EXISTING BUSBARS; U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (Dec. 2019), available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

Table 12 below shows APS's projected O&M spending at its coal plants. These projections are relatively in line with historical O&M spending at Four Corners, but substantially higher than historical spending at Cholla. The Company's historical and projected O&M spending at Four Corners and Cholla are also much higher than industry averages. It is unclear why APS's costs to operate and maintain the plants are so much higher than the costs incurred by other utilities.

Table 12. Projected and historical O&M costs for APS coal plants

	Operations & Maintenance (O&M) ($2022 $/kW-year)		
	Sargent & Lundy O&M estimates	APS historical O&M spending	APS projected O&M spending
Four Corners Unit 4	$51.03	$89.51	$101.39
Four Corners Unit 5	$51.03	$91.92	$101.39
Cholla Unit 1	$51.03	$95.29	$144.54
Cholla Unit 3	$51.03	$93.90	$144.54

Source: See Table 11.

Q Based on the above, what do you conclude about APS's plan to retire Cholla in 2025?

A Retirement of Cholla in 2025 as planned is the least-cost option for APS ratepayers. Continuing to operate the plant beyond 2025 would require sizable capital investments that would lock ratepayers into a risky and high-cost legacy fossil unit. The Company would not only incur certain capital and O&M costs; it would also subject its ratepayers to additional risks from increased regulation and market uncertainty, discussed below.

Q Based on the above, what do you conclude about APS's plan to operate Four Corners through 2031?

A Continued operation of Four Corners through 2031 is not the most economic option and is not in the best interest of ratepayers. As I discuss in the next section, if APS updated its modeling, the results would likely show that Four Corners is no longer economic to operate. Instead, the Company utilizes its prior modeling exercises—which assume the plant is locked into continued operations through

2031, due to the coal contract. APS has not evaluated Four Corners retirement before 2031.[64]

ii. <u>APS's decision to invest $105.1 million in chiller upgrades at Sundance and Redhawk further locks APS ratepayers into expensive and risky gas resources.</u>

Q How were the Sundance and Redhawk gas plants projected to perform before the chiller upgrades?

A As shown in Confidential Table 13 below, APS calculated the LCOEs for the Sundance and Redhawk gas plants in its 2020 IRP. These LCOEs do not include the $105.1 million capital cost for the chillers[65] or the incremental O&M costs of $300,000 per year per unit (i.e., $600,000 per year total) that APS estimated would be required to maintain the plants.[66]

[64] Attach. DG-5, APS 2020 IRP at 133, 136.

[65] Attach. DG-2, APS Response to SC DR 6.1.

[66] Attach. DG-2, APS Response to SC DR 4.6(b).

Confidential Table 13. LCOE of the Sundance and Redhawk plants

Resource	2020 IRP LCOE 2020–2030 ($/MWh)	Updated LCOE with chiller cost 2023–2033 ($/MWh)
Redhawk	[redacted]	[redacted]
Sundance	[redacted]	[redacted]

Note: The 2022/2023 LCOE appears to be based on an entirely new analysis with a new set of assumptions. This updated analysis does not simply reflect the 2020 IRP analysis with the added chiller project costs.
Source: Attach. DG-2, APS Response to SC DR 1.10, SC 1.10_ExcelAPS22RC03201_Bridge_Base_EXISTING BUSBARS; Attach. DG-3, APS Response to SC DR 6.1, Attach. SC 6.1_ExcelAPS22RC03428_2022 Q3 Redhawk & Sundance Busbar LCOE_CONF.

The LCOE for the Sundance gas plant is exceptionally high at [redacted] because it is a peaking resource whose fixed costs are spread over a small amount of energy production. As shown in Confidential Figure 2, APS projects that the Sundance CT will operate at around a 1 percent capacity factor going forward. The Redhawk gas plant is a combined-cycle energy resource and is expected to have a higher capacity factor going forward (also shown in Confidential Figure 2 below). Before the chiller project was installed, APS projected an LCOE of [redacted].

Confidential Figure 2. Gas plant capacity factors (2020–2035)

[redacted]

Source: Attach. DG-2, APS Response to SC DR 1.10, SC 1.10_ExcelAPS22RC03201_Bridge_Base_EXISTING BUSBARS; Attach. DG-3, APS Response to SC DR 6.1, Attach. SC 6.1_ExcelAPS22RC03428_2022 Q3 Redhawk & Sundance Busbar LCOE_CONF.

Q How are the Redhawk and Sundance plants projected to perform with the chiller projects installed?

A In APS's updated analysis, which includes the cost of the chillers along with updated capacity factors, APS finds that the projected LCOEs for both gas plants are substantially higher than it calculated for the 2020 IRP. Because the fundamental purpose of the Sundance plant is to provide capacity, the exact LCOE value of [redacted] is less meaningful than the fact that its cost went up so dramatically between the 2020 and 2022 analysis. APS still projects that Sundance will operate at around a 1 percent capacity factor. For Redhawk, APS's projected LCOE [redacted]. APS projects Redhawk's capacity factor will average around 60 percent between now and 2035.

Q What was the timeline of APS's decision to install chillers at Sundance and Redhawk?

A [redacted]

Q How much do the chiller projects cost?

A APS is requesting $105.1 million in the PTYP for the chiller upgrades: $55.8 million for the Redhawk combined cycle plant and the remaining 49.4 million for the Sundance combustion turbines.[70] This is [redacted] the Company's original cost estimate for the project of [redacted].[71]

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[67] Attach. DG-3, APS Response to Staff DR 3.30, Attachment Staff 3.30_APS22RC03224_Sundance and Redhawk Capacity Improvement Evaluation Sep 21_CONF at 1.

[68] *Id.* at 4.

[69] *Id.*

[70] Tetlow Direct, Attachment JT-05DR.

[71] Attach. DG-3, APS Response to Staff DR 3.30, Attachment Staff 3.30_APS22RC03224_Sundance and Redhawk Capacity Improvement Evaluation Sep 21_CONF at 4.

Q What analysis did APS conduct to justify the chiller upgrades at the Sundance and Redhawk plants?

A APS conducted an avoided cost analysis using the Aurora software to determine whether to upgrade the Sundance and Redhawk plants and install the chiller projects. Specifically, APS says that it compared the energy and capacity values provided by the chiller projects to the cost of the least-cost incremental resource on APS's system.[72] APS calculated the avoided energy cost by evaluating the production cost differences of relying on the upgraded Redhawk and Sundance plants for more generation, and other units in its fleet for less generation. To calculate the avoided capacity cost, APS compared the cost of the upgrades to that of "a comparison resource which would need to be procured to maintain reliability should these upgrades not be pursued)."[73] APS found a total net benefit of [redacted] (net present value) over the time period 2023–2041.[74]

Q Do you have any concerns with this analysis?

A As discussed above, APS's original cost estimate for the chiller projects was nearly half what APS is now asking to recover. That means that APS's original conclusion from October 2021 that the upgrades were competitive with other sources of capacity[75] was based on an assumption that the project was substantially cheaper than it turned out to be. When the Company conducted its

[72] Attach. DG-2, APS Response to SC DR 1.27(a-n).

[73] Attach. DG-2, APS Response to SC DR 4.7(e).

[74] Attach. DG-3, APS Response to SC DR 1.27, Attachment SC 1.27_ExcelAPS22RC03197_All Unit Chillers Total Value_CONF.

[75] Attach. DG-3, APS Response to Staff DR 3.30, Attachment Staff 3.30_APS22RC03224_Sundance and Redhawk Capacity Improvement Evaluation Sep 21_CONF at 3.

full analysis in May of 2022, its cost estimates were closer to the final cost, but still around $14 million less than APS is now asking to recover from ratepayers.

Q Do you have any other concerns with APS's decision to install the chillers at the gas plants?

A Yes. I have several more general concerns: (1) APS should have more proactively and robustly evaluated renewables alternatives to the chiller projects; (2) APS already has a substantial quantity of gas capacity that it owns or contracts for, therefore continued investment in gas does not diversify its fleet; (3) natural gas prices are inherently volatile, and therefore gas plants are risky as long-term resource options; and (4) APS does not have a firm gas contract in place to serve the additional gas capacity added with the chillers at the Redhawk and Sundance gas plants.

First, APS should have evaluated clean energy alternatives, including demand-side management, solar PV, wind, and standalone and paired battery storage. Based on the renewable projects APS and other regional utilities have recently brought online (as shown in Highly Confidential Attachments 8, 9, and 10), and the projects it has contracted to bring online in the near future (as shown in Highly Confidential Attachment 7), APS has low-cost renewable and battery storage resources available to it that the Company should have considered in place of investing over $100 million in its existing gas plants.

Second, APS owns over 3,500 MW of gas generation, which represents over half of the Company's total resource capacity.[76] APS also has [redacted] of gas

[76] APS Response to Staff Request 1.2, Attachment Staff 1.2_APS22RC02270_APS Owned Plants.

capacity contracted through power purchased tolling agreements and has plans to extend most, if not all, of these agreements.[77] The tolling agreements and owned capacity total more than [redacted] of gas resources serving APS ratepayers. This is [redacted] of the 9,385 MW of capacity APS projects it will need to meet its peak demand plus reserve margin for the summer of 2023.[78] Adding more gas capacity to APS's system in the form of chiller upgrades does not diversify the Company's fleet, but rather further concentrates its reliance on gas resources and places ratepayers more at risk from fuel price volatility.

Third, fuel price volatility from gas is a major concern. APS has seen a large increase in the price of gas from the San Juan Basin in recent years. The San Juan Basin supplies around 80 percent of the Company's gas. The price went up from $2/MMBtu in 2019 to $3.75/MMBtu in 2021 and was expected to increase to $5.93/MMBtu in 2022 (an increase of 196 percent increase from 2019 levels) before leveling out.[79]

This increase was due in large part to the global conflict in Ukraine, which increased the price of natural gas and created general instability around supply availability and long-term prices. This has made it much more expensive and riskier to operate natural gas plants and has driven up market prices. Although market prices have leveled back out, natural gas prices are volatile; and therefore

[77] Attach. DG-4, APS Response to Initial Request 1.63, Attachment Initial 1.63_APS22RC02103_South Point w Amendments_HIGHLY CONF, Attachment Initial 1.63_APS22RC01935_Griffith Energy_HIGHLY CONF, Attachment Initial 1.63_APS22RC01818_Arlington Valley LLC_HIGHLY CONF; Attach. DG-4, APS Response to Sierra Club Request 1.21, Attachment SC 1.21_APS22RC03196_Arlington Valley PPA Ext_HIGHLY CONF.

[78] Attach. DG-12, APS RPAC Meeting Presentation at 7 (Apr. 21, 2023).

[79] Joiner Direct at 26.

reliance on gas resources over the long term inherently introduces risk to the system that APS will seek to pass on to its ratepayers.

Finally, APS indicated that while the Redhawk and Sundance gas plants are currently served by a firm gas contract, it does not plan to expand its firm gas contracts as a result of the chiller projects.[80] This is concerning because a gas plant can only truly provide firm capacity if it has a firm supply of fuel. If APS is increasing the capacity of the two plants by a combined 140 MW but does not have additional firm fuel to supply that 140 MW, it may end up not being able to utilize each plant at its full capacity at times of highest demand.

iii. APS has provided no current analysis to justify the $36.7 million in PTYP spending on ELG upgrades as well as the ongoing capex and test-year spending at Four Corners.

Q What analysis has APS conducted to justify the ELG investments at the Four Corners plant?

A Unlike the chiller projects at Sundance and Redhawk, APS did not perform any analysis to support its decision to move forward with ELG upgrades at Four Corners[81] or to evaluate whether continued investment in, and operation of, Four Corners is in the best interest of ratepayers. Instead, APS evaluated options to comply with EPA's ELG requirements while pre-supposing continued operation of the Four Corners plant through 2031.

[80] Attach. DG-2, APS Response to SC DR 6.4.

[81] Attach. DG-2, APS Response to SC DR 4.5(b).

This is concerning because it means APS is asking ratepayers to pay the costs required to keep the Four Corners plant online, regardless of the cost of alternatives. APS has already made substantial capital investments in the plant for environmental compliance in recent years. From 2018 through 2022, APS spent $154 million on mandatory environmental upgrades at Four Corners.[82] In 2018, APS determined that several of its coal combustion residual disposal units required corrective actions and would need to be replaced by 2019 under current regulations.[83] Prior to that, under EPA's Regional Haze Rule, APS was required to make upgrades and restorations to its Flue Gas Desulfurization systems and to install SCR technology at Four Corners by 2018. The SCR installation also required a Dry Sorbent Injection system to remove sulfuric acid mist created in the SCR.[84] All these projects were costly and added to the undepreciated plant balance.

The Company's most recent projections show that the Four Corners ELG project cost is expected to be substantially higher than originally planned. As of March 2023, APS estimates the ELG project will cost [redacted] of which APS is responsible for. That is a significant increase from an authorized budget of [redacted],[85] [redacted] of which APS was responsible for. APS's share of the original authorized budget is close to the $36.7 million that APS is seeking to recover in the PTYP here.[86]

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[82] Attach. DG-2, APS Response to SC DR 1.15, Attachment SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx.

[83] Attach. DG-5, APS 2020 IRP at 197.

[84] *Id.* at 196.

[85] Attach. DG-3, APS Response to Staff DR 3.26, Attachment Staff 3.26_APS22RC03221_CBI Reauthorization_R2_March 2023_CONF at 5.

[86] Tetlow Direct at 24.

Q What analysis has APS conducted to demonstrate the reasonableness of continuing to operate Four Corners relative to alternatives?

A I am not aware of APS having conducted *any* recent analysis on the reasonableness of continuing to operate Four Corners through 2031 relative to alternatives. APS's most recent analysis on Four Corners was conducted as part of its prior IRP process in 2020 and is outdated. In all its 2020 IRP modeling, APS assumed a Four Corners retirement date in 2031 and did not evaluate other possible retirement dates.[87]

Despite substantial feedback from stakeholders, APS resisted modeling an earlier Four Corners retirement during the 2020 IRP process, pointing to the long-term coal supply contract for the Four Corners plant. *APS should be evaluating whether it is lower cost, even with the locked-in fuel costs under the contract, to retire the plant early and replace it with alternatives*.

APS has begun its next IRP process, during which the Company indicated it will consider retirement dates of 2027, 2028, 2029, 2030, and 2031 for Four Corners.[88] But in the meantime, APS is requesting to place the costs associated with maintaining Four Corners into rates and rate base without providing any contemporaneous evidence that doing so is in the best interest of ratepayers. Meanwhile, APS's own analysis shows that the plant is projected to be very expensive to operate and maintain going forward.[89] My analysis, based on the Company's own data, shows that earlier retirement of Four Corners—and thus avoidance of these maintenance and sustaining capital costs—is in the best

[87] Attach. DG-5, APS 2020 IRP at 133, 136.

[88] Attach. DG-16, Excerpt of APS 2023 IRP Stakeholder Meeting at 35 (Apr. 7, 2023).

[89] Attach. DG-2, APS Response to SC DR 1-10, Attachment SC 1.10_ExcelAPS22RC03201_Bridge_Base_EXISTING BUSBARS.

interest of APS ratepayers. This leads me to conclude that continued operation of and spending on Four Corners without robust updated analysis is imprudent.

Q How did APS determine the proposed retirement dates for Four Corners?

A The 2031 retirement date for Four Corners was set by APS to align with the expiration of its coal contract in 2031. I am not aware of APS conducting any analysis, either as part of its 2020 IRP or any time subsequently,[90] on whether it was cheaper to retire Four Corners earlier than 2031, pay off the coal supply contract, and build or procure alternative resource options. APS is required to purchase a minimum quantity of fuel each year under the Four Corners coal contract; this is coal that it must pay for regardless of whether it is economic to operate the plant or not.

As mentioned above, the Company has indicated that it plans to test earlier retirement dates for Four Corners as part of the current 2023 IRP process.[91]

Q Have any of the Four Corner's co-owners evaluated the economics of retiring Four Corners?

A Yes, in its 2020 IRP analysis, TEP found that retiring the Company's share of Four Corners once the coal contract expires in 2031 and replacing it with less costly wind and solar would produce cost savings for customers while reducing emissions, thereby mitigating the risk of additional carbon control or carbon-

[90] Attach. DG-2, APS Response to Staff DR 1.14(c).

[91] Attach. DG-16, Excerpt of APS 2023 IRP Stakeholder Meeting at 35, 38 (Apr. 7, 2023).

related costs and supporting progress towards TEP's carbon reduction goals.[92] TEP conducted very limited modeling to evaluate whether an even earlier retirement of Four Corners would produce additional savings. This modeling was limited partly because of TEP's minority ownership of Four Corners, which gives TEP somewhat limited control over plant management decisions.[93]

Notably, TEP stated that its decision to accelerate the retirement dates for the coal-fired Springerville Generating Station was influenced by TEP's "determination that coal is no longer the lowest-cost year-round energy supply resource."[94]

Q Has APS conducted any analysis to evaluate whether it is in ratepayers' best interest to switch Four Corners to seasonal operations?

A APS conducted limited analysis to justify the Company's decision to switch to and from seasonal operations at Four Corners.[95] As discussed above, APS decided in June 2021 to assess the feasibility of conducting seasonal operations at Four Corners.[96] After making the decision to move forward with seasonal operations beginning in Fall 2023, APS then reversed course in July 2022, sending a letter to

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[92] Attach. DG_17, Excerpt of Direct Testimony of Susan Gray at 9:24-10:8, Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n June 17, 2022) [hereinafter "Attach. DG-17, TEP 2022 Gray Direct"].

[93] See Attach DG-18, Direct Testimony of Devi Glick at 25-27, 38, Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Jan. 11, 2023) [hereinafter "Attach. DG-18, TEP 2022 Rate Case Glick Direct"].

[94] Attach DG-17, TEP 2022 Gray Direct at 10:20-25.

[95] Attach. DG-4, APS Response to SC DR 2.3, Attachment SC 2.3_ExcelAPS22RC03239_Summary Update_230322_HIGHLY CONF; Attach. DG-4, APS Response to Staff DR 1.14, Attachment Staff 1.14_APS22RC02419_2023 Seasonal Operations Assessment_HIGHLY CONF (1).

[96] Joiner Direct at 27:10-13.

the Four Corners co-owners informing them of this reversal. APS cited higher prices and volatility in the gas market as reasons for this decision.[97]

While it is reasonable for APS to respond to market conditions in making decisions about seasonal operations, APS reversed course so far in advance of Fall 2023 that its justification for postponing seasonal operations has since eroded considerably. As noted in the letter, APS is only required to provide seven days' notice for a change in operations. Had APS waited until Summer 2023 to make the decision on whether to still pursue seasonal operations in Fall 2023, it could have accounted for the fact that market conditions have already changed substantially from July 2022. Specifically, gas prices have fallen significantly and are expected to return to the levels projected before the war in Ukraine (as shown in Figure 3 below). APS's own analysis stated that when gas prices return to around [redacted] the Company should review its decision to cancel seasonal operations at Four Corners.[98] Henry Hub gas prices have been below $3/MMBtu since February of this year.[99]

Looking forward, current (2023) forecasts from leading industry sources are projecting even lower gas prices than previously projected. The U.S. Energy Information Administration's ("EIA") March 2023 Annual Energy Outlook included an updated gas price forecast, which projects slightly higher gas prices in the immediate near term (as markets recover from the 2022 price spikes) and then a settling in gas prices below what the EIA had projected in its 2022 forecast.

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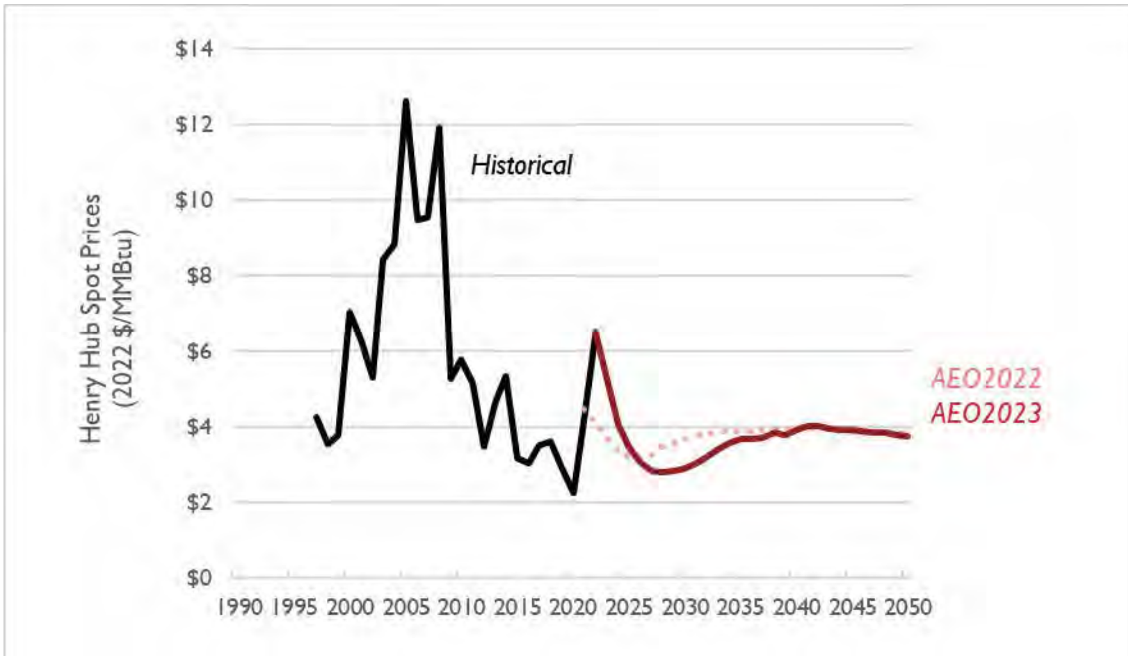
[97] Attach. DG-2, APS Response to SC DR 1.13, Attachment SC 1.13_APS22RC03068_Letter to Owners re Seasonal Ops.

[98] APS Response to Staff DR, Attachment Staff 1.14_APS22RC02419_2023 Seasonal Operations Assessment_HIGHLY CONF (1).

[99] U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price (updated June 1, 2023), *available at* https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

With this return to lower gas and market prices, a switch to seasonal operations is once again prudent and reasonable.

Figure 3. U.S. Energy Information Administration gas price forecasts



Source: U.S. Energy Information Administration, Annual Energy Outlook 2023, available at https://www.eia.gov/outlooks/aeo/.

Q Do you have any other concerns with APS's reliance on its 2020 IRP analysis?

A Yes, in addition to the concerns I outlined above, there have been substantial changes in the market since APS published its 2020 IRP. These changes make APS' 2020 IRP analysis essentially obsolete and the Company's continued reliance on that analysis to justify ongoing operation of its coal plants even more concerning. While it is normal for there to be some level of market and regulatory shift in the time between publication of successive resource plans, the level and scope of changes seen recently and many of the drivers (including a global pandemic, geopolitical conflict, and major domestic legislative efforts) are unprecedented. Specifically, these drivers include:

1. Congress's passage of the Inflation Reduction Act,
2. High inflation and supply-chain challenges,
3. High and volatile natural gas prices,
4. High and volatile Palo Verde hub market prices,
5. Coal supply availability challenges and high price risks,
6. Water supply availability risks, and
7. Future environmental regulatory risks.

I will explain each of these factors in detail below.

Q What tax credits were available for clean energy resources when APS conducted its IRP modeling in 2020?

A When APS conducted its 2020 IRP modeling, solar PV projects could access the ITC, but this was set to be phased out by 2024. Wind projects could access the PTC through the end of 2021. Solar PV could not access the PTC and battery storage was not eligible for the ITC. The PTC was not available for projects beginning construction after December 31, 2021.

Q How did APS account for the impacts of the IRA in its rate case application?

A APS witness Andrew Cooper acknowledged that the IRA represents a substantial federal investment in clean energy which reduces the cost of investments in clean energy resources.[100] Witness Elizabeth Blankenship indicated that APS included in its PTYP pro forma an offset for ITCs related to energy storage investments for which APS is seeking recovery.[101] For its PTYP solar investments, APS indicated it intends to claim the PTC, and include those credits as part of the expanded Renewable Energy Adjustment Charge.[102]

Q How does the IRA change the tax credits available to APS for clean energy resources?

A The IRA provides additional tax credits for solar PV and wind, as well as new tax credits for battery storage that were not available before.[103] The IRA benefits wind by extending the existing ITC and PTC tax credits. But it is even more impactful and transformative for solar PV, which now qualifies for both the ITC and PTC, and for battery storage, which is now eligible for the ITC. Table 14 shows how the ITC and PTC values have increased for projects placed into service in the next few years.

[100] Cooper Direct at 18.

[101] Blankenship Direct at 20:13-16.

[102] *Id*. at 20:16-21

[103] 26 U.S.C. §§ 45, 45Y, 48, 48E.

Table 14. Clean energy tax credits before and after the IRA

	Tax credit type	Quantity	Eligible resource types	Tax credit level for projects that began construction in:			
				2021	**2022**	**2023**	**2024**
Pre-IRA	**PTC**	2.5 cents/kWh, adjusted for inflation	Wind	60%	0%	0%	0%
	ITC	Percent of total investment	Wind	26%	26%	22%	10%
			Solar	26%	26%	22%	10%
Post-IRA	**PTC**	2.5 cents/kWh, adjusted for inflation	Solar, Wind, Storage		100%	100%	100%
	ITC	Percent of total investment	Solar, Wind, Storage		30%†	30%	30%

Note: The 30% tax credit level assumes that prevailing wage and apprenticeship requirements are met. Sources: Attach DG-19, Congressional Research Service, The Energy Credit or Energy Investment Tax Credit (2021), available at https://crsreports.congress.gov/product/pdf/IF/IF10479; Attach DG-20, Congressional Research Service, Energy Tax Provisions: Overview and Budgetary Cost (2021), available at https://crsreports.congress.gov/product/pdf/R/R46865; 26 U.S.C. §§ 45, 48.

Beyond what is depicted in Table 14, the IRA added new ITC and PTC tiers that entitle any solar, wind, or battery storage projects to an additional 10 percent tax credit adder if they meet domestic content criteria and an additional 10 percent adder if they are located in an energy community. Any census tract where a coal mine or coal-fired power plant has closed since 2009 is defined as an energy community (as well as the census tracts directly adjacent).[104] Additionally, brownfield sites and areas where fossil fuels have (1) accounted for at least 0.17 percent of direct employment or (2) 25 percent of local tax revenues and where the unemployment rate is above the national average for the previous year qualify

[104] 26 U.S.C. § 45(b)(11)(B).

as energy communities.[105] The maximum ITC and PTC credits available across a broad swath of the country are thus 50 percent, notably larger than when APS developed its 2020 IRP.[106]

Q Explain how inflation and supply chain challenges have impacted APS's resource planning efforts.

A Inflation and supply chain challenges originally stemming from the COVID-19 pandemic, compounded by uncertainty from the U.S. Department of Commerce anti-dumping investigation pertaining to solar cells and modules,[107] have persisted and have driven up the cost of both new conventional and renewable resources in the near term. This has led to project delays and a general level of uncertainty in whether projects will be able to come online at the scheduled date. But critically, many of these forces impact not just new resource costs but also the cost to operate and maintain existing fossil-fueled generating facilities. The costs of labor and parts to maintain existing generating facilities have gone up, and even the availability of parts to repair existing resources has become constrained in some cases (as discussed below in Section 5). This means that APS needs to continue to

[105] *Id*.

[106] Attach. DG-21, Tony Lenoir, *Mapping Communities Eligible for Additional Information Reduction Act Incentives* at 2, S&P Global Market Intelligence (Oct. 11, 2022) (identifying "more than 2,800 [ ] U.S. census tracts across 42 states[,]" including Arizona, eligible for the 10 percent adder).

[107] Throughout 2022, the Department of Commerce investigated a complaint that certain solar companies have been evading certain requirements placed on solar cells and modules produced in the People's Republic of China. *See* Press Release, Dept. of Com., Department of Commerce Issues Preliminary Determination of Circumvention Inquiries of Solar Cell and Modules Produced in China (Dec. 27, 2022), *available at* https://www.commerce.gov/news/press-releases/2022/12/department-commerce-issues-preliminary-determination-circumvention. Uncertainty surrounding the outcome of this investigation has placed additional pressure on solar cell and module availability in the United States.

regularly issue RFPs and adopt a more proactive and flexible approach to resource planning that brings new clean energy resources online in a rolling process. This approach will leave a buffer if there is a project delay and provide a back-up if an existing resource fails and needs replacement.

Q Explain the changes in natural gas prices and volatility in recent years.

A As discussed above in Section 4ii, APS saw a large increase in the price of gas from the San Juan Basin in the past few years.[108] This was driven by the global conflict in Ukraine, which created general instability around gas supply availability and long-term prices. Although market prices have leveled back out in 2023, gas prices remain inherently volatile and susceptible to global forces. Therefore, reliance on gas resources inherently introduces risk to the system.

Q Explain the change in Palo Verde market power prices and volatility in recent years.

A Average around-the-clock wholesale power prices at Palo Verde have also increased. Specifically, on-peak power prices increased from an annual average of $35.26 per MWh in 2019 to $58.25 per MWh in the test year. That is an increase of around 57 percent. APS expected prices to go up further in 2023 to $100.56 per MWh.[109] Market prices in the West have increased dramatically, due in part to the California Independent System Operator's ("CAISO") institution of new market rules, but also due to high natural gas prices and general supply constraints. This means that if APS experiences an unplanned outage, or otherwise must rely on the market for energy, its ratepayers will likely have to pay very high costs. This does

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[108] Joiner Direct at 26.

[109] *Id.* at 28.

not mean APS cannot rely on the market, but rather that as market prices become higher and more volatile, APS should take steps to minimize the need for unplanned reliance on the market.

Q Explain the risk of coal supply availability that APS faces at its coal plants.

A The risk of coal supply availability stems from challenges facing coal suppliers themselves and from the railroads that transport the coal. Even though Four Corners is served by a long-term coal supply agreement with the Navajo Transitional Energy Company ("NTEC"), a mine-to-mouth supplier, and therefore has relative price stability and limited transportation needs, it is not immune to all risks and challenges associated with its coal supply. Moreover, Cholla is not served by a long-term mine-to-mouth supplier and could face the coal supply challenges outlined below should it stay online beyond 2025.

Individual coal mines are facing challenges delivering the required quantities of coal. At San Juan Generating Station, for example, the coal supplier was unable to supply the required quantity of coal due to mine conditions and issued a force majeure. APS's neighboring utility TEP and the other plant co-owners had to de-rate their ownership shares at San Juan to ensure the coal supply would last until the plant retired in June 2022.[110] The mines serving both Cholla and Four Corners could face similar production challenges based on mine conditions.

Many coal plants in the region have retired or are planning to retire, including the Navajo Generating Station in Arizona that shut down in 2019, the San Juan Generating Station in New Mexico that shut down in 2022, and the Cholla Power

[110] Attach. DG-22, TEP Response to Staff Data Request 5.11, Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Nov. 23, 2022). The last unit was eventually shut down in September of 2022.

Plant that is scheduled to be retired in 2025. These closures are driving down the coal demand in the region.

Coal transportation companies have also caused reliability challenges by failing to deliver contracted quantities of coal. The Burlington Northern Santa Fe Railroad ("BNSF") informed TEP in the spring of 2022 that it would not be able to meet its 2022 delivery obligations for Springerville Generating Station due to "lack of workforce availability." TEP's coal and lime inventories at the plant dropped to the lowest level seen in the plant's life.[111] To accommodate this coal supply shortage, TEP had to de-rate the plant for months. Although Four Corners is unlikely to be impacted by this, because the Four Corners plant and Navajo Mine are co-located, Cholla could face transportation-related coal supply challenges in its remaining years online.

Q Does APS face any risks of high fuel costs at Four Corners?

A While APS is relatively more insulated from coal price volatility with its long-term coal supply contract at Four Corners, there are disadvantages to being locked into a long-term coal contract. First, APS has had to pay its coal supplier, the Navajo Transitional Energy Company, liquidated damages for shortfalls in coal deliveries because the plant is not using as much coal as contracted. In 2021, APS paid NTEC [redacted] for coal delivery shortfalls between 2020–2021.[112] Similarly, for Cholla, APS paid [redacted]

[111] Attach. DG-23, TEP Response to Staff Data Request 5.04(a), Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Dec. 1, 2022).

[112] Attach. DG-4, APS Response to Staff DR 1.8, Highly Confidential Attachment Staff 1.8_APS22RC02412_Four Corners LD Coal_HIGHLY CONF.

[redacted].[113] Those liquidated damages are costs APS has incurred and will seek to pass on to ratepayers, while receiving no value in return. However, APS paid these costs because it was likely more expensive to operate the plants than it was to pay the shortfall costs. As discussed above, APS anticipates paying [redacted] in shortfall costs going forward.[114]

Second, as APS is seeing now, signing long-term coal contracts makes it harder to retire a plant even when it is uneconomic. This means that APS has locked its ratepayers into high-cost energy that could be obtained at lower cost from alternative resources.

Third, even though APS has entered into a long-term contract with NTEC, as we have seen with PPA contracts in the region (and around the country), the contract is only as good as its terms. APS relies entirely on NTEC to obtain coal for Four Corners. If NTEC can no longer provide coal at the price agreed upon and requests to renegotiate the price with APS, APS has no option except to comply. It has no other way to power Four Corners and will not be able to bring replacement resources online in a short timeframe, and thus will be at the mercy of the mine.

[113] Attach. DG-4, APS Response to Staff DR 1.8, Highly Confidential Attachment Staff 1.8_ExcelAPS22RC02411_Cholla_Liquidated_Damages_HIGHLY CONF.

[114] Attach. DG-3, APS Response to SC DR 6.6, Attachment SC 6.6_ExcelAPS22RC03420_FC_Coal_Shortfall 2020 IRP_CONF.

Q Explain the risks of water scarcity and availability and how that will impact APS's operation of its coal plants.

A Water scarcity in the West has driven up the cost and risk to operate steam-fired power plants that rely on water for cooling. APS itself has at least partially acknowledged this risk in its 2020 IRP.[115]

APS anticipates using between 15,000–18,000 acre feet of water per year at Four Corners and believes it will have enough water under its permit for the foreseeable future.[116] But given the increasing level of water scarcity in the West, APS needs to do more to analyze and mitigate this risk. Four Corners relies on surface water from the San Juan River. The river has faced water shortages before, including during a drought in 2000 when a shortage sharing agreement was subsequently executed between the Bureau of Reclamation and the parties utilizing the water.[117] The much-anticipated update of the Colorado River Compact as soon as this year is expected to include reductions in water allocations for Western states including New Mexico. As part of the Colorado River basin, the San Juan River will be impacted and water supply will be further restricted.

The risks posed by a water shortage are not just theoretical: Xcel Energy ("Xcel") recently announced that it was moving up the retirement of the coal-fired Tolk Generating Station from 2032 to 2028 because it could no longer economically secure sufficient water to operate the plant through its planned retirement date in

[115] Attach. DG-5, APS 2020 IRP at 29–33.

[116] Attach. DG-2, APS Response to SC DR 5.7.

[117] Attach. DG-5, APS 2020 IRP at 29–33.

2032.[118] This was after Xcel proposed in its prior rate case to move Tolk's retirement date up from 2042 to 2032 and switch the unit to seasonal operation. This move was also driven by projected water shortages, specifically Xcel's projection that it would run out of water in the mid-2020s if it continued to operate year-round. I served as an expert witness in that case and cautioned that Xcel was ignoring the risks clearly outlined in its groundwater reports and data.[119] Specifically, Xcel ignored the risks that it would have trouble meeting its groundwater demands, especially peak demands in the summer, and that depletion rates for the aquifer Xcel relies on were likely underestimated based on uncertainty about groundwater pumping rates from area irrigators who also relied on the aquifer.[120] Xcel ignored these cautions and now has a shorter window to plan for replacement resources.

Q Explain the risk posed by future environmental regulations and potential carbon pricing.

A There are a variety of environmental rules and regulations that Congress and regulators are considering, all of which would increase the cost to operate some or all fossil fuel power plants, especially coal-fired power plants. These include, for instance, the EPA's review of recently submitted state implementation plans under the Clean Air Act to implement Round II of the Regional Haze Rule, EPA's

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[118] Ethan Howland, *Xcel to retire Texas coal-fired power plant early, speeding up companywide exit from coal in 2030*, Utility Dive (Nov. 1, 2022), *available at* https://www.utilitydive.com/news/xcel-retire-texas-coal-fired-power-plant-tolk/635437/.

[119] Attach. DG-24, Excerpt of Direct Testimony of Devi Glick at 44-46, Docket No. 19-00170-UT (N.M. Pub. Reg. Comm'n Nov. 22, 2019) .

[120] *Id*.

proposed decision for the reconsideration of the national ambient air quality standards for particulate matter ("PM") issued on January 6, 2023,[121] and EPA's proposed rule strengthening emissions limits for mercury and other toxic pollutants from coal plants (expected to go into effect in 2024).[122] Additionally, on May 11, 2023, the EPA announced a proposed rule to limit greenhouse gas emissions from new and existing power plants. Specifically, the rule limits emissions from current coal units set to retire by 2032 at their current emissions rates and does not allow an increase in emissions. For units retiring beyond 2032, the rule imposes capacity factor limits (20 percent for units retiring by 2035), co-firing on natural gas requirements (40 percent starting in 2030 for units retiring by 2040), and carbon sequestration and storage requirements (90 percent CO_2 capture starting in 2030 for units operating beyond 2040).[123]

Each of these rules has the potential to require significant pollution reductions at coal plants, which the plant operators could meet either through installation of expensive pollution control technologies or closure of the plant. While there may be uncertainty around exactly which rules and policies will be implemented, what form the final rules will take, and when the rules will be finalized, the direction of impact from increased environmental regulations is clear: coal plants will become more highly regulated and therefore more costly and riskier to operate.

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[121] Reconsideration of the National Ambient Air Quality Standards for Particular Matter, 40 C.F.R. Parts 50, 53, 58.

[122] AP, *The EPA proposes tighter limits on toxic emissions from coal-fired power plants*, National Public Radio (Apr. 5, 2023), *available at* https://www.npr.org/2023/04/05/1168216664/epa-mercury-emissions-coal-power-plants.

[123] Attach. DG-25, U.S. Environmental Protection Agency, *Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule* (last visited June 1, 2023).

Q What takeaways do you have about Four Corners after reviewing APS's application and analysis?

A I find it is in the best interest of ratepayers for APS to evaluate a pre-2031 retirement date for Four Corners and retire the plant as soon as it can secure replacement resources. I also find that Four Corners should be switched back to seasonal operations in Fall 2023 as originally planned. In the meantime, APS should limit future spending at the plant. Four Corners has been costly to operate, it has a high forced outage rate, and it is likely to only become more costly and unreliable in the future.

5. APS SHOULD WORK TO PROCURE MORE CLEAN ENERGY RESOURCES ON A ROLLING BASIS TO MEET FIRM CAPACITY NEEDS, MANAGE PEAK, AND REDUCE CUSTOMER COSTS AND RISKS.

i. Current resource procurement efforts

Q Provide an overview of APS's recent procurement efforts.

A As discussed in Section 3 above, APS issued an all-source RFP in 2020 and another one in 2022. APS also plans to issue another RFP this year, once it finishes reviewing the bids from the 2022 RFP. Following the 2020 RFP (and the addendum), APS signed [redacted]

[redacted] For the 2022 RFP, APS has announced it is negotiating with bidders for 2,264 MW of new resources by 2025, of which 1,056 MW will be renewables.[125] APS also has a number of tolling agreements for firm summer capacity in place (discussed in detail below in Section 5iii), and the Company plans to extend two summer tolling PPAs with natural gas plants.[126]

Q What types of resources are other regional entities developing to meet their projected future needs?

A Arizona Southwest Public Power Agency ("SPPA") recently entered into a joint venture with BrightNight to have 300 MW of solar energy capacity and 600 MWh of battery energy storage delivered. SPPA expects the project will meet around a third of its peak capacity needs and roughly 20 percent of its energy needs. The power will come from the Box Canyon solar project in Pinal County and is expected to be operational in 2025.[127] SPPA selected this project after issuing an RFP for up to 200 MW of gas-fired generation and 100 MW of solar PV. SPPA

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[124] Attach. DG-4, APS Response to Staff DR 1.16, Attachment Staff 1.16_ExcelAPS22RC03035_2020 ASRFP Final Selection_HIGHLY CONF; Attach. DG-4, Staff 1.16_ExcelAPS22RC03071_2020 ASRFP Addendum Final Selection_HIGHLY CONF.

[125] Attach. DG-12, APS RPAC Meeting Presentation at 16 (Apr. 21, 2023).

[126] *Id.*

[127] Ryan Kennedy, *BrightNight to meet one third of Arizona utility's peak demand with solar and storage project*, PV Magazine (July 19. 2022), *available at* https://pv-magazine-usa.com/2022/07/19/brightnight-to-meet-one-third-of-arizona-utilitys-peak-demand-with-solar-and-storage-project/.

chose the solar plus storage project instead of a gas project because the scope of technology surpassed its requirements as outlined in its RFP.[128]

In New Mexico, El Paso Electric ("EPE") is currently building or seeking approval for 390 MW of solar PV and 115 MW of battery storage across three different projects. Specifically, EPE is building a 120 MW solar PV and 50 MW storage project at Buena Vista, and a 140 MW solar PV project at Hecate. EPE is also requesting approval to build a 130 MW solar PV and 65 MW battery storage project at Carne.

TEP has brought online 465 MW of new renewables and 60 MWh of battery storage since the Company's last rate case in 2020. This includes the 250 MW Oso Grande Wind project which came online in December 2020. TEP also issued an all-source RFP in April 2022 for 250 MW of renewables and energy efficiency resources. The RFP also seeks 300 MW of a firm capacity resource that can be called on at any time, including 4-hour energy storage and demand response.[129]

ii. ***APS needs supply- and demand-side resources to help manage peak demand.***

Q Why does APS need more peak management resources?

A As discussed above, APS projects 1,400 MW of load, which is 300 MW more than it projected in its 2020 IRP. This projected increase is mainly due to

[128] Andy Colthorpe, *Arizona utility groups sign PPA for 300 MW/600 MWh solar-plus-storage power plant*, *Energy Storage News* (July 20, 2022), *available at* https://www.energy-storage.news/arizona-utility-groups-sign-ppa-for-300mw-600mwh-solar-plus-storage-power-plant/.

[129] Attach DG-18, TEP 2022 Rate Case Glick Direct at 9:2-11.

anticipated growth in large technology (data centers) and manufacturing load in the region.

With the retirement of Cholla in 2025 (which currently provides 387 MW), the expiration of several PPAs that provide 700 MW of capacity around the same time, and its projected increase in load, APS anticipates it will need around 2,300 MW of on-peak capacity by 2026.[130] Further out, with Four Corners planned for retirement in 2031, and with additional retirements of aging fossil fueled resources needed to achieve APR's carbon-reduction goals, APS will have substantial additional resource needs.

In addition to building out renewable and battery storage resources, APS can sustainably manage peak demand by investing in demand-side resources that flatten demand and reduce the differences between off-peak and on-peak hours. Emerging technologies such as heat-pump water heaters, electric vehicles, and local batteries enable large and small customers to reduce consumption during peak hours or even supply energy to the grid. Rooftop solar and microgrids provide local resilience and can also level out demand, if paired with load-shifting technologies. Intelligently designed rates can maximize demand-side resources by incentivizing energy use in the middle of the day, when emissions and energy demand are lowest, while also discouraging energy use during peak evening hours. Large industrial customers can be compensated by demand response programs for reducing consumptions during extreme peak hours, reducing reliance on dirty and expensive gas peaker plants.

[130] Joiner Direct at 11.

Q What efforts has APS taken to meet increasing demand and manage peak load?

A APS states it has been working to increase demand response capacity since 2016, noting an increase of 250 percent in reported demand-side management program peak capacity between 2016 and 2022.[131] APS has undertaken a range of efforts to manage peak load, including time-varying rates and customer programs focused on energy efficiency, load shifting, demand response, and energy storage.[132]

Q How have APS load-management programs been performing?

A For program year 2022, APS states its demand-side management ("DSM") portfolio delivered more than 323 MW of peak demand reduction in 2022, including 176 MW of dispatchable demand response capacity.[133] This 323 MW of peak demand reduction represents 4.3 percent of APS's peak demand of 7,587 MW from the summer of 2022.[134]

However, APS has consistently underspent its planned budgets for several demand response initiatives, shown in Table 15 below. This indicates that APS could have recruited more customers to participate in these programs to achieve greater demand savings. While the effects of the COVID pandemic likely had an impact on participation rates, APS also underspent program budgets in years prior to 2020.

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[131] Attach. DG-2, APS Response to SWEEP Request ("SWEEP DR") 2.4.

[132] Attach. DG-2, APS Response to SC DR 1.19.

[133] *Id*.

[134] Attach. DG-12, APS RPAC Meeting Presentation at 7 (Apr. 21, 2023).

Table 15. APS demand response program spending and savings

Year	Peak Solutions C&I Demand Response Program		DRESLM / Rewards Program		Managed EV Charging Pilot		Residential Battery Storage Pilot		Energy Savings Days - Behavior Conservation DR	
	% of Budget	% of MW Goal	% of Budget	% of MW Goal	% of Budget	% of MW Goal	% of Budget	% of MW Goal	% of Budget	% of MW Goal
2018	86%	100%	46%	45%	N/A	N/A	N/A	N/A	N/A	N/A
2019	85%	205%	71%	100%	0%	N/A	N/A	N/A	N/A	N/A
2020	85%	166%	87%	64%	0%	N/A	N/A	N/A	N/A	N/A
2021	28%	37%	76%	52%	27%	N/A	168%	0%	N/A	N/A
2022	36%	90%	47%	57%	37%	38%	65%	33%	100%	62%

Source: Attach. DG-2, APS Response to SWEEP DR 2.3, Attach. SWEEP 2.3_ExcelAPS22RC03333_Historical Demand Response Program Spend.

It is clear there is more APS can achieve through its existing demand response programs. A recent report from the Brattle Group estimates that, on average, 20 percent of system peak load could be controlled by demand response by 2030.[135] APS is performing well below this potential. For example, in recent comments to the Commission, APS indicated it had 141 MW of controllable capacity through its Cool Rewards residential smart thermostat demand response program and 28 MW in its Peak Solutions commercial program. This represented only 2 percent of the Company's 2021 summer peak.[136]

[135] Attach. DG-26, Excerpt of Ryan Hledik et al., *The National Potential for Load Flexibility: Value and Market Potential Through 2030* at 18, The Brattle Group (June 1, 2019).

[136] Attach. DG-27, Arizona Public Service Company, Comments in Response to Questions from Commissioner Sandra Kennedy at 1-2, Docket No. E-01345A-21-0087 (Ariz. Corp. Comm'n Mar. 18 2022).

Q How do the Company's peak demand savings compare to other utilities in the region?

A The American Council for an Energy-Efficient Economy ("ACEEE") publishes a Utility Scorecard that analyses utility performance related to end-use energy efficiency programs. The most recent 2020 Utility Scorecard examines 52 of the largest electric utilities by retail sales.[137] This scorecard is a valuable resource to benchmark how APS's energy efficiency programs are performing compared to other utilities in the region and to the top-performing utilities in the country. In the 2020 Utility Scorecard, APS ranked poorly in terms of energy efficiency savings, peak savings, and program spending compared to the top-performing utilities and to those in the southwest region.

Table 16 below shows how APS compares to other utilities in the region in terms of achieved MWh savings as a percentage of total retail sales. This metric is a common benchmark for comparing energy efficiency programs across utilities. The top-performing utilities in the country achieve energy savings between 2 to 3 percent of total retail sales each year.[138] As this table shows, APS is well below 2 percent and has room for improvement when compared to other utilities in its region. It is also worth noting ACEEE found the average savings across the utilities in the study to be 1.03 percent of sales, indicating that APS is also below average for this metric.[139]

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[137] Grace Relf et al., *The 2020 Utility Energy Efficiency Scorecard,* American Council for an Energy-Efficient Economy (Feb. 20, 2020), *available at* https://www.aceee.org/research-report/u2004 [hereinafter "ACEEE 2020 Utility Scorecard".

[138] *Id.* at 26.

[139] *Id*.

Table 16. Energy efficiency savings as a percentage of retail sales

Utility	State	Net incremental savings (MWh)	Savings as percent of sales
SCE	CA	1,415,400	1.55%
Xcel	CO	453,854	1.45%
PacifiCorp	UT	230,839	0.87%
APS	**AZ**	**212,752**	**0.71%**
AEP Texas Central	TX	53,294	0.19%
Oncor Electric Delivery	TX	182,620	0.13%

Source: ACEEE 2020 Utility Scorecard.

The ACEEE Utility Scorecard also examines the peak demand reductions that result from energy efficiency measures that are coincident with system peak. These are passive peak demand savings that will continue to occur over the life of the installed energy efficiency measures. As shown in Table 17 below, APS is achieving more peak demand savings from its energy efficiency measures than some utilities in its region, yet is below Southern California Edison ("SCE") and Public Service Company of Colorado ("Xcel Colorado"). APS is also well below the top-performing utilities in the country, with San Diego Gas & Electric in California achieving 2.99 percent and National Grid and Eversource in Massachusetts achieving 2.39 percent and 2.19 percent, respectively.[140]

[140] *Id*. at 30-31.

Table 17. Peak demand savings as a percent of total peak demand

Utility	State	Peak MW	Peak savings as a percent of total peak demand
SCE	CA	301	1.22%
Xcel	CO	75	1.06%
APS	**AZ**	**68**	**0.88%**
PacifiCorp	UT	47	0.41%
AEP Texas Central	TX	17	0.41%
Oncor Electric Delivery	TX	59	0.24%

Source: ACEEE 2020 Utility Scorecard.

A final metric that is helpful when comparing across energy efficiency programs is total spending as a percentage of total revenues. As shown in Table 18, APS is spending well below the other utilities in the region.[141]

Table 18. Energy efficiency spending as a percentage of total revenues

Utility	State	Total spend	Spending as a percent of total revenues
Xcel	CO	$79.5M	2.90%
PacifiCorp	UT	$42.0M	2.12%
SCE	CA	$197.4M	1.67%
AEP Texas Central	TX	$12.9M	1.30%
Oncor Electric Delivery	TX	$38.5M	1.09%
APS	**AZ**	**$28.2M**	**0.81%**

Source ACEEE 2020 Utility Scorecard.

Q What additional efforts could APS be taking to manage peak load?

A There are several ways APS can increase its efforts to manage peak load. First, as indicated above, APS should look to increasing customer enrollment and capacity targets within its existing demand response programs and increase its focus on

[141] *Id*. at 28-29.

energy efficiency measures that create savings coincident with system peak demand.

Second APS should implement additional programs that target reductions in peak demand. Examples include dispatchable residential and small commercial central air conditioner load control programs, as well as irrigation load management and interruptible or curtailment programs.

Lastly, APS should develop a demand-side management program that specifically targets the sectors contributing to load growth, including large technology facilities like data centers. For example, ConEdison in New York developed a suite of energy conservation measures related to data center equipment. This includes measures such as uninterruptable power supplies ("UPS"), UPS rectifiers, computer room air handlers, in/row/in-rack cooling equipment, electronically commutative plug fans, and server virtualization.[142] Similarly, CenterPoint Energy also has a Data Center Energy Efficiency Program ("DCEEP"). This program offers no-cost assistance to encourage data center energy efficiency improvement and financial incentives based on verified peak demand reduction and annual energy savings.[143] Lastly, Pacific Gas and Electric (PGE) in California provides resources on its website specific to energy efficiency

[142] ConEdison, C&I 2021 Energy Efficiency Program Guidelines, *available at* https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/commercial-and-industrial-program/data-center-equipment.pdf (last visited May 22, 2023).

[143] CenterPoint Energy, *Data Center Energy Efficiency Program*, *available at*https://www.centerpointenergy.com/en-us/SaveEnergyandMoney/Pages/Data-Center-Energy-Efficiency-Program.aspx?sa=ho&au=bus (last visited June 1, 2023).

resources for high-tech companies.[144] This webpage includes available rebates and an energy efficiency best practice guide for data centers.[145] Creating programs and engagement materials that directly target this customer segment will help to target energy conservation and load management where it is needed the most.

Q Has the Company indicated any plans to expand its current load management program?

A APS states it is currently working to update demand response plans and indicates it is conducting an energy efficiency and demand response potential study to inform the 2023 IRP.[146] However, it is unclear to what extent APS will expand energy efficiency and demand response programs. While in recent years, APS has increased its planned peak MW savings from energy efficiency and demand response programs, its 2023 DSM Implementation Plan shows a decrease in peak demand savings compared to prior years. Specifically, residential and commercial coincident demand (MW) savings are 4 percent lower and 5 percent lower, respectively.[147] In addition, the 2023 DSM Plan shows a 17 percent decrease in planned coincident demand savings (MW) from demand response and demand-

[144] PGE, *Energy-efficiency solutions for high-tech companies*, *available at* https://www.pge.com/en_US/small-medium-business/save-energy-and-money/rebates-and-incentives/industry-rebates/hightech.page (last visited June 1, 2023).

[145] PGE, *Data Center Best Practices Guide: Energy Efficiency Solutions for High-Performance Data Centers*, *Available at* http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/incentivesbyindustry/DataCenters_BestPractices.pdf (last visited June 1, 2023).

[146] Attach. DG-2, APS Response to SWEEP DR 2.4.

[147] Attach. DG-28, APS 2023 Demand Side Management Implementation Plan at 24 (Table 4), (Nov. 30, 2022); Attach. DG-29, APS 2022 Demand Side Management Implementation Plan at 25 (Table 4), (Dec. 17, 2021).

side management initiatives. At a time when APS is projecting increased demand, this is not the direction planned savings should be headed.

Q Are APS's coal plants good peak-management resources?

A No. Coal plants are large and relatively inflexible generation resources. They are costly and time-intensive to ramp up and down or to turn on and off. Because of these characteristics, coal plants are generally bad at responding quickly to price signals or changes in load or generation levels on the grid throughout the day. Putting aside their environmental impacts, coal plants may have been adequate baseload resources for the grid of the past, when they operated all the time. However, coal plants are poor choices to support the present grid, which has an increasing penetration of renewables and requires flexible, responsive resources such as battery energy storage.

iii. APS should shift its resource procurement efforts to focus on procuring clean energy on a rolling basis rather than just in response to capacity needs.

Q What are APS's current and projected capacity and energy needs?

A APS projects it will need a total of 9,385 MW of capacity to meet its peak demand and reserve margin for the summer of 2023.[148] Beyond this year, APS projects substantial near-term load growth from data centers and large manufacturing facilities. APS stated at a stakeholder meeting in the spring of 2023 that it has received so many indications of interest from companies looking to site large industrial or data center facilities in the region that it is no longer able

[148] Attach. DG-12, APS RPAC Meeting Presentation at 7 (Apr. 21, 2023).

to guarantee it can provide electricity service to all, should they all try to site facilities in APS's service territory.

Over the next 15 years, APS projects peak demand will grow on average 2.4 percent per year. This is up from a projected 2 percent per year in its 2020 IRP.[149] In 2035, APS's projected peak demand is 1,100 MW higher than it was in its 2020 IRP.

APS also plans to retire all its coal-fired generation by 2031. To serve the Company's projected demand and replace the retired coal capacity, APS will need to add a substantial quantity of new resources over the next decade.

Q What type of replacement resources should APS be considering?

A APS should be evaluating portfolios of resources that include solar PV, onshore wind, battery storage, demand-side management, transmission build-out, and market purchases.

As discussed above, with the recent passage of the IRA, tax credits available for renewables and battery storage are stabilizing prices in the near term and are expected to drive down prices in the near future. Arizona has excellent potential for solar PV, which now qualifies for the PTC and ITC. Battery storage, which in the past did not qualify for a tax credit, now qualifies for the ITC. The preference to delay deployment while technology costs fall should be less of an issue now, with the ITC offsetting a substantial portion of the project cost.

[149] Attach. DG-16, Excerpt of APS 2023 IRP Stakeholder Meeting at 29 (Apr. 7, 2023).

Additionally, the IRA will provide funding for transmission projects.[150] APS could use this funding to address load pockets and to access high quality wind resources from out of state, as well as to modernize and expand its transmission network to better integrate renewables.

Q How should APS be thinking about resource procurement?

A Currently, APS procures new resources when it identifies a capacity need during its IRP process. While utilizing existing resources is not inherently wrong, this model tends to favor the status quo. It keeps existing resources online and keeps the costs to operate and maintain these resources in rate-base, even if there are lower-cost feasible options. This model tends to understate the risk and cost of continuing to rely on existing resources, overstate the cost and risk of alternatives, and delay progress and action until something breaks or becomes so costly that it is impossible to ignore. Under this model, excess costs incurred when a plant breaks down or fuel prices spike are explained away as an anomaly, and something the utility never could have predicted.

But market and gas price spikes are becoming more frequent, and plant outages become more likely and frequent as a plant ages. The costs and risks associated with these factors can be mitigated with a rolling resource procurement model. For many of the reasons discussed in the section above, procuring new resources on a continuous basis can be lower cost and lower risk than relying on existing resources. Doing so also introduces flexibility into the resource planning process.

[150] Attach DG-30, Congressional Research Service, *Electricity Transmission Provisions in the Inflation Reduction Act of 2022* (updated August 23, 2022).

Q Won't a rolling procurement model just lead to over-procurement of capacity and produce an overbuilt system that is more costly for APS ratepayers?

A No, not necessarily. My recommendation is not that APS should dramatically overbuild, procuring thousands of megawatts more generation than it needs. But if an existing resource is facing forces that, while uncertain, are all likely to lead to higher costs and higher risks, and new low-cost clean energy resources are available but require lead time to come online, there is little downside to planning proactively.

Right now, APS is relying on its costly and sometimes unreliable fossil resources that break down, are facing coal supply challenges, and require expensive replacement energy purchases (as discussed above). The Company is also relying on expensive firm energy and capacity contracts as summarized in Highly Confidential Attachment 11 below. For example, for the summer of 2021 and 2022, APS relied on firm energy and capacity contracts with capacity prices as high as [redacted] respectively.[151] For the summer of 2023, APS has signed another firm energy and capacity agreement with a capacity payment of [redacted][152] This is more than the cost of new entry ("CONE") in several of the organized markets, which represents the current annualized capital cost of constructing a new power plant (based on the

[151] Attach. DG-4, APS Response to Initial Data Request 1.63, Attachment Initial 1.63_APS22RC02182_Harquahala Tolling 2021_HIGHLY CONF at 3, Attachment Initial 1.63_APS22RC02033_Harquahala Tolling 2022_HIGHLY CONF at 3.

[152] Attach. DG-4, APS Response to Initial Data Request 1.63, Attachment Staff 1.3_APS22RC02734_Calpine Energy Service_HIGHLY CONF.

cost of an advanced combustion turbine).[153] This means that APS could build replacement resources for less than the cost per MW that it is currently paying for capacity in its short-term firm contracts. APS could also build new clean energy resources, specifically solar PV and storage combined, for less than it is paying for short-term firm energy and capacity (see Highly Confidential Attachments 8, 9, and 10).

With renewables, battery storage, and demand-side management, the costs of early deployment are minimal relative to the risks the resources help avoid and the value that they provide. Renewables, energy storage, and demand management require no fuel and have limited and known variable operating costs, meaning that they are insulated from the risk of fuel price and market price volatility that can impact fossil resources. For renewables and storage, the only real costs are the revenue requirement impacts of building a resource a year or two in advance of when it is "needed" and at a cost that might be lower in a year or two. For demand management, the costs are limited to program costs. In the time it takes to bring the new resources online, it is likely that conditions will change such that the new resources either will be needed by the utility, will outcompete existing resources, or at the very least, will be valuable to other regional entities that are not as proactive.

Q Doesn't this approach of procuring before the utility has a capacity need conflict with industry best practices for resource procurement?

A No. Rolling procurement represents a necessary evolution in the planning process as the penetration of renewables on the grid increases, fossil fuel prices become

[153] *MISO Cost of New Entry (CONE) Planning Year 2023/2024* at 4, MISO Resource Adequacy Subcommittee (Oct. 12, 2022), *available at* https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf.

more volatile, and project development is shifted from a few centralized utilities and a few centralized energy resources to many small parties and resources.

In fact, other utilities are starting to adopt this resource planning approach. For example, Ameren stated in a recent Certificate of Public Convenience and Necessity ("CCN") that "…a gradual, sustained transition to renewable energy is more cost effective and practical than waiting until there is an actual capacity need and ensures the Company can continue to deliver sufficient quantities of reliable, affordable energy to customers…"[154]

Q Why is this rolling procurement model better suited for the current clean energy transition?

A Transitioning to clean energy resources now rather than waiting until there is an immediate need provides more flexibility to retire aging units as needed and protects ratepayers from reliance on the market or volatile fossil resources, from coal supply disruptions, and from project delays or unit breakdowns.

The costs to maintain existing fossil resources are high, and units can break down unexpectedly. Unplanned outages can require utilities to purchase expensive replacement market power. Coal supplies can also be interrupted, as discussed above, causing plants to de-rate their capacity when their coal supplies were limited. When this happens, the full capacity of each resource is not available.

As another example, in Indiana, Center Point is facing unexpectedly high fuel and market energy and capacity costs because one of its coal plants, Culley Unit 3, broke down and the Company has no replacement resources available. The part

[154] Direct Testimony of Ajay K. Akora, Docket No. EA-2022-0245 at 7 (Mo. Pub. Util. Comm'n July 14, 2022), *available at* https://efis.psc.mo.gov/mpsc/DocketSheet.html.

Center Point required to repair Culley 3 is no longer made by General Electric, so Center Point had to purchase the part from a retired coal plant in Montana and transport it to Indiana. This process required Center Point to take Culley 3 offline for a year and to purchase high-cost power in the interim.[155]

Additionally, all projects, especially renewable projects, may be delayed by a year or two with supply chain challenges. I have seen this around the country. PNM, for example, delayed the retirement of San Juan Generating Station by a year because the renewables PNM needed to replace the unit were delayed. As discussed above, EPE announced that the commercial operation dates for the Buena Vista and Hecate solar projects were delayed by one and two years respectively based on supply chain challenges and the Department of Commerce solar tariff.

Additionally, some renewable projects may require transmission build-out or investment, which cannot happen overnight. But with transmission funding available through the IRA, and other transmission reforms underway around the country, the pace of transmission expansion should pick up. These reforms should remove barriers to transmission development and help socialize the costs across a larger group of ratepayers that will reap the benefits of those lines, rather than just requiring the next project that comes online to bear the full transmission cost.

Planning a project around a specific deadline in the current energy environment is a risky strategy. That does not mean that APS should not rely on renewables; rather, it means that shifting to a model where resources are deployed as they

[155] Brady Williams, *Broken coal plant leads CenterPoint Energy to petition for rate increase*, 14 News (Nov. 22, 2022), *available at* https://www.14news.com/2022/11/22/broken-coal-plant-leads-centerpoint-energy-petition-rate-increase/.

become available will make it more likely that resources will be online by the time APS needs them.

Q Does this conclude your testimony?

A Yes.

Attachment DG-1

Resume of Devi Glick

Devi Glick, Senior Principal

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

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Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

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Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

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Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

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Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Cost §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilties Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC’s Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power’s Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company’s application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated January 2023

Attachment DG-2

APS Public Responses to Discovery Requests

Public APS Responses to Data Requests:

1. APS Response to Staff Data Request ("Staff DR") 1.2, Attachment Staff 1.2_APS22RC02270_APS Owned Plants
2. APS Response to Sierra Club Data Request 2.1
3. APS Response to SC DR 1.3
4. APS Response to Staff DR 1.16, Attachment Staff 1.16_APS22RC02878_All Source RFP Dec 11 2020
5. APS Response to Staff DR 1.16, Attachment Staff 1.16_APS22RC02899_2020 RFP Addendum
6. APS Response to Staff DR 1.16, Attachment Staff 1.16_APS22RC03036_2022 All Source RFP
7. APS Response to SC DR 1.15, Attachment SC 1.15_ExcelAPS22RC03211_Coal Generating Unit Statistics.xlsx **(provided on APS Extranet Site)**
8. APS Response to SC 1.10, Attachment SC 1.10_ExcelAPS22RC03200_Bridge_Base_EXISTING BUSBARS **(provided on APS Extranet Site)**
9. APS Response to Staff DR 1.14
10. APS Response to SC DR 6.2
11. APS Response to SC DR 1.13, Attachment SC 1.13_APS22RC03068_Letter to Owners re Seasonal Ops
12. APS Response to SC DR 6.6
13. APS Response to SC DR 5.4
14. APS Response to SC DR 6.1
15. APS Response to SC DR 4.6(b)
16. APS Response to SC DR 1.10, SC 1.10_ExcelAPS22RC03201_Bridge_Base_EXISTING BUSBARS **(provided on APS Extranet Site)**
17. APS Response to SC DR 1.27
18. APS Response to SC DR 4.7
19. APS Response to SC DR 6.4
20. APS Response to SC DR 4.5
21. APS Response to SC DR 5.7
22. APS Response to SWEEP DR 2.4
23. APS Response to SC DR 1.19
24. APS Response to SWEEP DR 2.3, Attachment SWEEP 2.3_ExcelAPS22RC03333_Historical Demand Response Program Spend **(provided on APS Extranet Site)**

ARIZONA PUBLIC SERVICE COMPANY
APS-OWNED GENERATION IN OPERATION
JANUARY 2021 - JANUARY 2023

PLANT	IN SERVICE	TYPE OF UNIT OR CONTRACT	(APS SHARE) CAPACITY MW	FUEL TYPE	FUEL LOGISTICS
Palo Verde					
Unit 1	1986	Nuclear Steam	382	Uranium	Fuel cycle stages (uranium production, conversion, enrichment, and fabrication) are under contract with various suppliers.
Unit 2	1986	Nuclear Steam	382	Uranium	
Unit 3	1988	Nuclear Steam	382	Uranium	
Four Corners					Four Corners is a mine-mouth plant served from the nearby Navajo Mine under a whole-site supply agreement.
Unit 4	1969	Steam	485	Coal	
Unit 5	1970	Steam	485	Coal	
Cholla					The El Segundo Mine serves the plant under a whole-site supply agreement. Coal is transported to the plant by rail under a separate agreement.
Unit 1	1962	Steam	116	Coal	
Unit 3	1980	Steam	271	Coal	
West Phoenix					
CT 1	1972	CT	55	Gas	Natural gas is delivered directly to the plant under a long-term gas transportation agreement with Kinder Morgan-El Paso.
CT 2	1973	CT	55	Gas	
CC 1	1976	Combined Cycle	88	Gas	
CC 2	1976	Combined Cycle	88	Gas	
CC 3	1976	Combined Cycle	88	Gas	
CC 4	2001	Combined Cycle	117	Gas	
CC 5	2003	Combined Cycle	506	Gas	
Ocotillo					
Unit 1 CT	1972	CT	55	Gas	Natural gas is delivered directly to the plant under a long-term gas transportation agreement with Kinder Morgan-El Paso.
Unit 2 CT	1973	CT	55	Gas	
Unit 3 CT	2019	CT	102	Gas	
Unit 4 CT	2019	CT	102	Gas	
Unit 5 CT	2019	CT	102	Gas	
Unit 6 CT	2019	CT	102	Gas	
Unit 7 CT	2019	CT	102	Gas	
Redhawk					Natural gas is delivered directly to the plant under long-term gas transportation agreements with Transwestern and Kinder Morgan-El Paso.
CC 1	2002	Combined Cycle	544	Gas	
CC 2	2002	Combined Cycle	544	Gas	
Saguaro					Natural gas is delivered directly to the plant under a long-term gas transportation agreement with Kinder Morgan-El Paso. Oil is delivered to the plant as necessary by truck.
Unit 1 CT	1972	CT	55/54 *(N1)*	Gas/Oil	
Unit 2 CT	1973	CT	55/54 *(N1)*	Gas/Oil	
Unit 3 CT	2002	CT	79	Gas	
Sundance					
Unit 1 CT	2002	CT	42	Gas	Natural gas is delivered directly to the plant under long-term gas transportation agreements with Transwestern and Kinder Morgan-El Paso.
Unit 2 CT	2002	CT	42	Gas	
Unit 3 CT	2002	CT	42	Gas	
Unit 4 CT	2002	CT	42	Gas	
Unit 5 CT	2002	CT	42	Gas	
Unit 6 CT	2002	CT	42	Gas	
Unit 7 CT	2002	CT	42	Gas	
Unit 8 CT	2002	CT	42	Gas	
Unit 9 CT	2002	CT	42	Gas	
Unit 10 CT	2002	CT	42	Gas	

ARIZONA PUBLIC SERVICE COMPANY
APS-OWNED GENERATION IN OPERATION
JANUARY 2021 - JANUARY 2023

PLANT	IN SERVICE	TYPE OF UNIT OR CONTRACT	(APS SHARE) CAPACITY MW	FUEL TYPE	FUEL LOGISTICS
Douglas					Oil is delivered to the plant as necessary by
Unit 1 CT	1972	CT	16	Oil	truck.
Yucca *(N4)*					
Unit 1 CT	1971	CT	19/19 *(N1)*	Gas/Oil	Natural gas is delivered directly to Units 1-3
Unit 2 CT	1971	CT	19/19 *(N1)*	Gas/Oil	under a long-term gas transportation
Unit 3 CT	1973	CT	55/54 *(N1)*	Gas/Oil	agreement with Kinder Morgan-El Paso, and to
Unit 5 CT	2008	CT	48	Gas	Units 5-6 under an agreement with North Baja
Unit 6 CT	2008	CT	48	Gas	and Kinder Morgan-El Paso. Oil is delivered to
					the plant as necessary by truck.
Microgrids					
Data Center Recip Diesel Engines	2017	CT	11	Oil	Oil is delivered to the plants as necessary by
MCASY Recip Diesel Engines	2017	CT	22	Oil	truck.
Solar *(N2)*					
Cotton Center	2011	Solar PV	17.0	Solar	
Hyder 1	2011	Solar PV	16.0	Solar	
Paloma	2011	Solar PV	17.0	Solar	
Chino Valley	2012	Solar PV	19.0	Solar	
Hyder II	2012	Solar PV	14.0	Solar	
Foothills I/II	2012	Solar PV	35.0	Solar	
Gila Bend	2014	Solar PV	32.0	Solar	
Luke AFB	2015	Solar PV	10.0	Solar	
Desert Star	2015	Solar PV	10.0	Solar	
Red Rock	2016	Solar PV	40.0	Solar	

NOTES:
1) First number indicates net maximum capacity on natural gas; second number indicates net maximum capacity on residual oil.
2) MW values for solar generating units are shown as AC.
3) All Navajo units ceased operation in November 2019. Salt River Project was the owner-operator of the plant.
4) Yucca Unit 4 CT is owned by the Imperial Irrigation District and is operated by APS.

SIERRA CLUB SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
APRIL 6, 2023

SC 2.1: Please refer to APS response to Sierra Club Data Requests 1.3 and 1.5.

a. Provide the capital expenditure additions for that APS has included in the Company's Test Year spending as proposed in this case for each of its coal and gas plants.

Response: Additions for each coal and gas plant by account during the test year ended June 30, 2022, are as follows:

Cholla
311 Structures and Improvements $153,069
312 Boiler Plant Equipment $6,305,902
314 Turbogenerator Units $797,665
315 Accessory Electric Equipment $486,419
316 Misc. Power Plant Equipment $59,284
390 Structures and Improvements $17,276
394 Tools, Shop and Garage Equipment $35,913
Total $7,855,528

Four Corners
303 Misc. Intangible Plant $23,151
311 Structures and Improvements $15,646,321
312 Boiler Plant Equipment $6,603,333
314 Turbogenerator Units $495,517
315 Accessory Electric Equipment $4,465,407
316 Misc. Power Plant Equipment $1,035,641
353 Station Equipment $262,131
390 Structures and Improvements $138,569
392 Transportation Equipment $23,260
394 Tools, Shop and Garage Equipment $315,111
397 Communication Equipment $159,076
Total $29,167,517

Ocotillo
341 Structures and Improvements $8,789
342 Fuel Holders, Products, and Accessories $50,145
343 Prime Movers $84,320,060
344 Generators $703,101
345 Accessory Electric Equipment $289,535
346 Misc. Power Plant Equipment $1,120,083
353 Station Equipment $1,150
390 Structures and Improvements $339,588
391 Office Furniture and Equipment $497
394 Tools, Shop and Garage Equipment $276,083
397 Communication Equipment $160
Total $87,109,191

Response to SC 2.1 (cont.):

Redhawk
303 Misc. Intangible Plant $3,686
341 Structures and Improvements $6,853,167
342 Fuel Holders, Products, and Accessories $2,648,667
344 Generators $16,420,865
345 Accessory Electric Equipment $421,649
346 Misc. Power Plant Equipment $3,278,883
391 Office Furniture and Equipment $387,596
394 Tools, Shop and Garage Equipment $53,222
397 Communication Equipment $1,434
Total $30,069,169

Saguaro
341 Structures and Improvements $4,194,039
342 Fuel Holders, Products, and Accessories $40,123
344 Generators $4,298,079
345 Accessory Electric Equipment $89,084
346 Misc. Power Plant Equipment $375,425
Total $8,996,750

Sundance
341 Structures and Improvements $1,973,251
343 Prime Movers $209,504
344 Generators $975,991
345 Accessory Electric Equipment $3,046,046
346 Misc. Power Plant Equipment $6,039,424
391 Office Furniture and Equipment $1,638,857
394 Tools, Shop and Garage Equipment $140,427
Total $14,023,500

West Phoenix
341 Structures and Improvements $814,535
342 Fuel Holders, Products, and Accessories $2,606,234
343 Prime Movers $551,908
344 Generators $44,032,797
345 Accessory Electric Equipment $10,462,077
346 Misc. Power Plant Equipment $12,710,542
356 Overhead Conductors and Devices $4,731,073
390 Structures and Improvements $209,872
391 Office Furniture and Equipment $28,756
394 Tools, Shop and Garage Equipment $115,852
Total $76,263,646

Response to SC 2.1 (cont.)	**Yucca** 341 Structures and Improvements $439,823 343 Prime Movers $329,112 344 Generators $2,644 345 Accessory Electric Equipment $289,100 346 Misc. Power Plant Equipment $623,148 394 Tools, Shop and Garage Equipment $61,895 **Total $1,745,723**

SC 1.3: For each of the Company's coal-fired generating units, please identify the amount of money that APS has included in the Company's Test Year spending as proposed in this case, by the following types:

a. Capital expenditures
b. Fuel
c. Non-fuel Operations & Maintenance
d. Other

Response: The summary below reflects the total company amounts included in the adjusted Test Year by Plant and by type.

Four Corners

a. $1,153,444,736 – Net Book Value @ 6/30/2022
b. $219,055,696 – Fuel expense
c. $98,947,127 – Non-fuel O&M expense
d. $1,247,460 – Other Expense

Cholla

a. $207,077,830 – Net Book Value @ 6/30/2022
b. $66,252,807 – Fuel expense
c. $41,715,703 – Non-fuel O&M expense
d. $9,257 – Other Income

Witness: Elizabeth A. Blankenship

Arizona Public Service Company

2020 All Source Request for Proposals

December 11, 2020

Table of Contents

A. OVERVIEW

1. Introduction

Arizona Public Service Company ("APS") is a regulated public utility that generates, transmits and distributes electricity for sale in Arizona. APS is headquartered in Phoenix, Arizona. As Arizona's largest and longest-serving electric company, we generate safe, affordable and reliable electricity for more than 1.3 million commercial and residential customers in 11 of Arizona's 15 counties.

Through a comprehensive planning process, APS determines how to meet future customer needs for reliable and affordable electricity, while achieving regulatory targets and reducing environmental impacts during the planning period. APS has worked with our team of resource experts, energy planners, and cross-sector stakeholders to develop a strategic roadmap on our path to a 100% carbon-free generation mix by 2050. Our Integrated Resource Plan ("IRP"), which is filed with the Arizona Corporation Commission ("ACC"), initiates that process and provides both a near-term action plan and a longer term vision that show how we plan to meet our customer and resource needs for the next 15 years. The IRP provides the strategic direction for APS's acquisition of a clean, diversified, balanced resource portfolio that meets customer needs, maintains reliability, results in reasonable energy supply costs, and mitigates market risks. It includes an interim target of achieving a 65% clean energy mix by 2030. We're focused on integrating renewable resources, empowering customers with flexible energy options and incorporating advanced technology to produce clean and affordable energy—all while providing reliable service and remaining good stewards of Arizona's diverse environment.

This All Source Request for Proposals (this "RFP") solicits competitive proposals ("Proposals") for resources to meet the needs identified through the IRP process. Both supply-side and non-supply side resources are eligible to participate in this RFP, as more fully described below. APS's main goal is moving toward our Clean Energy Commitment. At the same time, we have a preference for resources that provide high levels of flexibility, respond to dynamic changes in system demand, integrate well with APS's current resource portfolio, and can be called upon at APS's discretion.

Persons or entities responding to this RFP are referred to herein individually as a "Respondent" or collectively as "Respondents." A Respondent may consist of one or more persons or entities.

2. Resource Need

APS's IRP indicates a need for both renewable energy resources and additional flexible summer capacity resources to meet reliability requirements. The identified resources support APS's commitment to clean energy and are necessary to maintain system reliability in an environment of continued customer growth and expiring wholesale contracts.

3. Product Requested

APS is requesting resources that will: 1) increase renewable energy as part of our energy mix; and 2) meet our summer peak needs plus reserve margins as required to maintain system reliability.

Renewable Resources - In this RFP, APS requests competitive Proposals for renewable energy resources totaling approximately 300-400 MW per year with in-service dates in either 2023 or 2024. Several variables may impact the specific type and timing of resource additions, such as higher production levels of renewables, contribution to peak, and costs associated with project timing. Projects may be phased in over multiple years beginning as early as December 1, 2022 through December 31, 2024. To further accommodate a phased-in approach and optimize customer value, APS will accept Proposals for projects that reach full completion and commercial operation as late as June 1, 2025, provided that construction on any such project must begin no later than 2024 *and* the project must be partially in service in 2024.

Capacity Resources - In this RFP, APS also requests competitive Proposals for capacity resources totaling approximately 200-300 MW per year, with in-service dates in either 2023 or 2024. Projects may be phased in over multiple years beginning as early as December 1, 2022 through December 31, 2024. To further accommodate a phased-in approach and optimize customer value, APS will accept proposals for projects that reach full completion and commercial operation as late as June 1, 2025, provided that construction on any such project must begin no later than 2024 *and* the project must be partially in service in 2024.

Proposals may be designed to meet either the renewable only or capacity only product request, or may be designed to meet both renewable and capacity resource requests within the same project. APS will consider the value for both the renewable energy component as well as the capacity value component for all Proposals.

APS expects that a resource that provides both summer capacity and energy will have significant economic value. Energy that is non-dispatchable by APS and is proposed as must-take energy will generally be viewed and evaluated less favorably. In addition, clean, flexible, dispatchable resources are increasingly important in helping APS to meet its clean energy goals and maintain system reliability and will be valued accordingly. APS needs flexible resources that are shapeable and responsive to changes in actual customer demand.

Finally, APS must maintain a reliable electric system, which includes having firm capacity plus reserves to meet customer demands and reliability needs during summer system peak load times. APS must be able to respond to changes in customer demands or supply needs in real-time, and APS seeks to develop a portfolio of resources that will enable it to do so. A heat map, which is attached as Appendix A, provides guidance about the relative value of capacity and energy to be provided by any proposed resource during specified hours of the year and should be considered by Respondents as they prepare their Proposals.

4. Interconnection

Any proposed facility must interconnect directly to the APS transmission system, or in the alternative, the Respondent must demonstrate that it has, or can secure, firm transmission for delivery from the facility to the APS transmission system for the entire proposed term of the relevant transaction. Respondents should be aware that connection to an APS substation may not guarantee connection to the APS transmission system as required. Any additional firm transmission service needed to connect a proposed facility to the APS transmission system is the responsibility of Respondent and should be accounted for in Respondent's Proposal.

Respondents are advised to review the most complete and up-to-date information regarding interconnection on APS's Open Access Transmission Tariff ("OATT"). http://www.oasis.oati.com/azps/index.html

a. Interconnection Applications and Studies. APS recognizes that the timeline for executing an interconnection agreement is a critical element in the development process. For purposes of this RFP, APS will not require any Respondent to enter the APS interconnection queue process unless and until its Proposal is selected for Short List evaluation, which APS expects to determine on or about April 2, 2021. Respondents should note that there are locations within the APS system for which there are more interconnection requests than at other locations, and the application processing time for those more active locations may be greater. Each proposed facility must be able to be constructed and interconnected to meet proposed capacity and energy deliveries by the in-service dates established in this RFP. The interconnection queue at each location is available to the respondents at the APS OASIS site referenced above. Nevertheless, each Respondent is responsible for performing its own diligence with respect to the interconnection process and making its own determination about when it should submit its application to the APS interconnection queue, and otherwise participate in the interconnection process, in order to meet the requirements of this RFP.

Nothing in this RFP document is intended to provide definitive guidance to any potential Respondent regarding the specifics of the interconnection process that may be applicable to Respondent's proposed facility.

b. Energy Delivery Costs. Pricing included in any Proposal must be based on delivery to the APS system. If the Respondent is proposing to interconnect directly to the APS system, all losses between the generating station and the point of demarcation for equipment ownership and transfer to APS (typically referred to as the Delivery Point in the relevant agreement with APS) is the Respondent's responsibility. If the Respondent is proposing to interconnect to another utility's system, all transmission wheeling costs to transmit project energy to the APS system on a firm basis are also the responsibility of the Respondent and must be included in the Proposal price.

c. Project Interconnection Costs. Each Respondent must include reasonable interconnection cost estimates as part of its submitted Proposal. Respondents may, in their discretion, utilize third party consultants to determine accurate interconnection estimates. A detailed description of such interconnection costs must accompany each Proposal and should include a breakdown of the significant equipment costs. For interconnection related questions or information, please contact:

APS Interconnections
e-mail: INTERDEV@apsc.com
URL: http://www.oatioasis.com/azps/index.html

5. Transmission and Distribution System

Respondents should review Appendix B to this RFP for product deliverability guidance. Appendix B was prepared by APS Resource Planning personnel and represents, as of the date of this RFP, an estimate of what the deliverability of energy to the APS Phoenix metro load pocket in the years 2023 and 2024. This indicative guidance is neither binding nor definitive and is subject to change.

In Appendix B, deliverability is described using three (3) ratings: limited, location dependent, and available. A limited deliverability rating indicates a route that is less likely to be available to support delivery to the Phoenix metro load pocket in 2023 and 2024; a location dependent deliverability rating indicates a route that is reasonably likely to support such delivery, but may be size dependent or require additional evaluation; and an available deliverability rating indicates a route that is likely to support such delivery. Any Proposal for a project that is positioned to use infrastructure with a limited or location dependent deliverability rating may be less competitive than a Proposal for a project that is positioned to use infrastructure with a high deliverability rating.

B. General Eligibility Minimum Requirements

In addition to satisfying the interconnection and deliverability requirements described in Sections A(4) and A(5) above, Proposals must meet the following minimum requirements. Proposals must also meet the additional technology-specific requirements set forth in Section C below. Proposals that do not satisfy all applicable requirements will be considered non-conforming and may not be evaluated by APS.

1. Timely Document Submittal

Each Respondent must complete and submit all required documents, together with the Proposal fee, each as specified in Sections E and F below and in PowerAdvocate, no later than the due dates detailed in the RFP Schedule found in Section E(4) below. (APS's use of the PowerAdvocate platform for purposes of this RFP is explained in Section E (2) below.)

2. Eligible Resources

APS will accept Proposals for the following technologies (either stand-alone or in combination, such as solar plus energy storage):

a. Supply Side:

1. Solar
2. Energy Storage
3. Wind
4. Biomass/Biogas
5. Geothermal
6. Landfill Gas
7. Reciprocating Units
8. Simple cycle combustion turbines
9. Combined cycle combustion turbines
10. Other*

b. Non-Supply Side:

1. Demand Response (both Commercial & Industrial and Residential)
2. Energy Efficiency

*Any Respondent that is considering submitting a Proposal for a technology or combination of technologies not listed above should request a discussion with APS via the PowerAdvocate platform in order to determine the eligibility of the potential Proposal.

NOTE: APS is not accepting Proposals for transactions that are not directly backed by a specific generating asset or utility system, such as call options or wholesale market products.

3. Transaction Structure

APS will evaluate Proposals that incorporate the following transaction structures:

a. Renewable energy power purchase agreement ("PPA")*

b. Renewable energy tolling PPA*

c. Renewable energy build transfer agreement

d. Energy storage tolling PPA*

e. Energy storage build transfer agreement

f. Load management agreement for demand response or energy efficiency programs

g. Thermal tolling PPA

*With respect to Proposals using a power purchase agreement or tolling agreement structure (other than for a thermal resource), APS requires that Proposals incorporate an option for APS to ultimately purchase the resource. APS will evaluate any proposed option, and prefers those that establish a fixed price at a fixed point in time (for example, a tolling agreement that has an option for APS to purchase the project from the Respondent after year 7 at a specified fixed price).

APS's pro forma agreement or term sheet for each type of transaction structure can be found in the "Download documents TAB" in PowerAdvocate and can be accessed by a Respondent once it executes a Confidentiality Agreement.

Respondents must submit a copy of the relevant pro forma agreement or term sheet, redlined to reflect Respondent's required modifications, if any. APS expects minimal, if any, redlines to the posted pro forma Agreements and/or Term Sheets. Proposals that contain significant substantive changes will be viewed less favorably by APS and may be eliminated from further consideration.

NOTE: If Respondent's Proposal represents a combination of technologies, it is incumbent upon the Respondent to review the form of agreement and/or term sheet applicable to <u>each</u> type of technology and include as part of its Proposal any applicable agreement and/or term sheet, together with any required modifications described above.

APS views cybersecurity provisions as critically important, yet often overlooked, provisions in its power purchase, tolling, and BOT agreements. To facilitate Respondents' understanding of APS's cybersecurity requirements and APS's assessment of each Respondent's cyber risk, APS has provided the Data Security and Privacy Addendum ("DSPA") and the Third Party Risk Review ("TPRR") spreadsheet, both of which are located on the "Download Documents" tab in PowerAdvocate. The DSPA will be part of any agreement executed in connection with this RFP and is representative of, but not the entirety of, APS's cybersecurity requirements. The TPRR spreadsheet must be completed by Respondents and is fundamental to APS's evaluation of Proposals as the basis to approve a Respondent for storing restricted and confidential APS data. Additionally, APS has provided a Cybersecurity Specifications Spreadsheet in PowerAdvocate that contains additional cybersecurity requirements applicable to battery energy resources.

Each Respondent proposing an EPC or a build transfer Proposal, must have a license to do business as a construction contractor in the State of Arizona. If Respondent does not have a license at the time of Proposal submittal, Respondent must describe, in Power Advocate, "Commercial Experience" Tab, how Respondent will obtain its license no later than the Final Selection date set forth in Section E(4) below.

4. Commercial Viability

In the case of a project yet to be constructed and developed, Respondent must demonstrate in its Proposal that it and/or its partner(s) have previously *developed* a project to the point of commercial operation and that the size of such previously developed project is at least ten percent (10%) of the size of the proposed project. In the case of existing projects, each Respondent must demonstrate in its Proposal that it and/or its partner(s) has previously *operated* a project utilizing the same technology being proposed, that the size of such previously operated project is at least fifty percent (50%) of the size of the proposed project, and that such project will have operated successfully for a minimum of one (1) year by the Proposal due date of February 5, 2021.

Any Respondent that requires a partner to satisfy the commercial viability requirement set forth in this <u>Section B(4)</u> must also demonstrate, to APS's satisfaction, that the partner relationship has been legally established, is legally enforceable, and supports the Proposal being submitted.

5. Technical Characteristics

a. Proposal Size:

1. Supply Side Proposal: Proposal must offer a minimum of 50MW per site. APS prefers to limit any individual project size to a maximum 400MW in order to safeguard system integrity and mitigate risk associated with a single point of failure. APS will, however, accept Proposals for supply side resources larger than 400MW *provided that* the interconnection configuration for the proposed resource limits any single point of failure to 400MW.
2. Non-Supply Side Proposal: Proposal must offer a minimum of 25MW and must aggregate APS customer load accordingly. The maximum total amount of non-supply side capacity that will be considered as part of this RFP is 100 MW per year.
3. Combined technologies Proposal: Both supply side and non-supply side Proposals may combine technologies, subject to the requirement that each combined technologies Proposal must offer either a minimum of 50MW per technology per site for supply side resources or 25MW in aggregate for non-supply side resources.

b. Capacity, Energy, and Ancillary Services: Each proposed project must provide all available capacity, energy, and ancillary services for use exclusively by APS. Ancillary services may include frequency response, spinning reserve, non-spinning reserve, reactive power control, fixed power factor, and automatic voltage regulation. Any Proposal for a generating or energy storage resource must include pricing for the proposed resource both with AND without any of the foregoing ancillary service capabilities that are included as part of the Proposal.

c. Operations: For supply side resources, the proposed project must be able to operate autonomously and also be controlled remotely with the APS Automatic Generation Controls ("AGC"), with interface through APS's Energy Management System ("EMS"). All supply side proposals must allow for and support that the associated capacity and energy sold to APS may be included by APS for use in the CAISO Energy Imbalance Market. Any Respondent that submits a Proposal for a non-supply side resource should consider whether such resource could be capable of AGC control by APS and potential use in the CAISO Energy Imbalance Market. Proposals that include such capability may be more favorably evaluated than those that do not.

6. Sites

APS will NOT consider any Proposal for a facility to be developed on an existing APS-owned site. Respondent must demonstrate site control that is effective at the time of RFP Proposal submission and continues through the term of the associated agreement with APS. Additionally, any Proposal for a resource to be developed wholly or partially on state-owned land must demonstrate that Respondent is scheduled for lease approval on the AZ State Land Board of Appeals Meeting Notice and Agenda on a date prior to the short list date of this RFP (April 2, 2021) in order to satisfy APS's site control requirement.

7. Development Security Costs

Pricing shall include all costs for development security. The development security must be in the form of a letter of credit or cash deposit and must be submitted to APS in accordance with the terms of any agreement resulting from this RFP. In the case of a letter of credit, it must be in the form and from an issuing bank acceptable to APS in its sole discretion. Development security will be calculated in accordance with Table 1 below. APS may take into account Respondent's credit rating, proposed construction costs, any existing transactions between Respondent and APS which could create additional credit exposure to APS, and APS's own credit analysis to determine any necessary adjustments to collateral for final contracting.

8. Post-Development Security Costs

Pricing shall include all costs for post-development security. The post-development security must be in the form of a letter of credit or cash deposit and must be submitted to APS on or before COD in accordance with the terms of any agreement resulting from this RFP. In the case of a letter of credit, it must be in the form and from an issuing bank acceptable to APS in its sole discretion. Post-development security will be calculated as described in Table 1 below. APS may take into account Respondent's credit rating and any existing transactions between Respondent and APS which could create additional credit exposure to APS, and APS's own credit analysis to determine any necessary adjustments to collateral for final contracting.

Table 1

Resource	Contract Structure	Contract Execution	Post COD
New Energy Storage	PPA	$70/kWh	$55/kWh
Existing Energy Storage	PPA	$55/kWh	$55/kWh
New Energy Storage	Build Transfer (APS Owned)	$70/kWh	$55/kWh held until warranty period expires
New Renewable or Thermal	PPA	$100/kW	$40/kW
Existing Renewable or Thermal	PPA	$40/kW	$40/kW
Renewable	Build Transfer (APS Owned)	$100/kW	$40/kW held until warranty period expires
Energy Efficiency (EE)	Load Mgmt. Agreement	$100/kW	$40/kW
Demand Response (DR)	Load Mgmt. Agreement	$100/kW	$40/kW

9. Proposal Pricing

The Proposal price for a PPA or tolling agreement shall be fixed for the duration of the proposed PPA or tolling agreement term and may include a fixed annual escalation rate. APS will not accept Proposals with escalation rates tied to any index.

10. Tax Credit Strategy

APS's evaluation of Proposals will take into consideration each Respondent's proposed project schedule and its ability to satisfy the investment tax credit ("ITC") and production tax credit ("PTC") commence construction guidance, pursuant to either the "physical work test" or the "five percent (5%) safe harbor," at the earliest realistic time to capture the maximum ITC/PTC.

If a Respondent believes that it can achieve an overall lower Proposal price by satisfying the ITC/PTC commence construction guidance in a later year (i.e., lower percentage credit), Respondent should describe its approach and detail the cost savings it expects to achieve that will compensate for the reduced ITC/PTC.

Each Respondent must provide a detailed description of its tax credit strategy, including the following information:

- Explanation of holistic strategy regarding ITC/PTC capture
- Identification of the critical path items for meeting its proposed ITC/PTC physical work/5% safe harbor deadline (must be supported by a proposed project schedule)
- If applicable, project cost comparison for achieving ITC/PTC physical work/5% safe harbor in the earliest year Respondent believes possible, versus the overall lower price by satisfying the ITC/PTC commence construction guidance in a later year

C. Technology-Specific Eligibility Requirements

Additional Minimum Requirements and APS Preferences for Proposals based on Technology

In addition to satisfying the minimum requirements described in Section B above, each Proposal must satisfy additional minimum requirements specific to the technology proposed therein in order to be considered a conforming bid.

What follows is a list of the additional minimum requirements for each technology type, as well as "APS Preferences" associated with each. Satisfaction of any of the APS Preferences is not required for a Proposal to be deemed conforming, but Proposals that contain more of the APS Preferences may be more competitive than those that contain fewer of the APS Preferences.

1. Energy Storage Technologies

Any energy storage Proposal must conform to the general eligibility minimum requirements set forth in Section B above and to the minimum requirements set forth in this Section C (1).

Minimum Requirements:

a. PPA or tolling agreement term: at least (5) years and not more than twenty (20) years.

b. Technology: Proposals include the following technologies:

    1. Battery energy storage system ("BESS")
    2. Flywheel
    3. Pumped storage hydropower
    4. Compressed air energy storage system ("CAES")
    5. Other energy storage technologies that meet the minimum requirements in this RFP.

c. Technical Characteristics:

    1. Any proposed facility must meet all BESS safety requirements specified in the APS form of tolling agreement or build own transfer agreement. Proposal pricing shall include all equipment and design necessary to satisfy all such safety requirements.
    2. Any proposed facility must be capable of operating to 0° F for cold climate and to 122° F in desert climate, at 100% of the proposed contract capacity discharging for a minimum of four (4) consecutive hours.
    3. Proposed projects must provide a full duty cycle (one full charge and discharge) utilizing the following three (3) approaches:

i. Duty Cycle 1: 285 Equivalent Cycles per Year, 45% Annual Average State of Charge

ii. Duty Cycle 2: 330 Equivalent Cycles per Year, 50% Annual Average State of Charge

iii. Duty Cycle 3: 405 Equivalent Cycles per Year, 55% Annual Average State of Charge

4. Any proposed facility must be capable of satisfying a monthly availability requirement (as that term is defined in the applicable agreement with APS) of at least 97% during the term of the Agreement.

APS Preferences:

APS prefers the following:

a. Tested technology: technology that has already undergone safety testing, safety evaluations, and safety designs as evidenced by test results and other supporting documentation included in the Proposal. Proposals that plan to undergo safety testing, safety evaluations, or safety designs for the proposed technology after contract execution will be viewed less favorably.

b. Duration: a facility able to deliver the full proposed contract capacity for a duration of longer than four (4) consecutive hours to meet peak needs as represented in the heat map (Appendix A).

c. Location: a facility located in APS's service territory and interconnected to APS's transmission or sub-transmission system (69kV or higher).

d. Charge/discharge: a facility that charges in a timeframe as close to matching the amount of time it takes to discharge and does not de-rate the power capacity of the facility as it reaches the high or low end of the state of charge.

2. Renewable Energy Technologies

Any renewable energy technology Proposal must conform to the general eligibility minimum requirements set forth in Section B and the minimum requirements set forth in this Section C.2.

Minimum Requirements:

a. Transaction Structure: A conforming Proposal must offer renewable energy pursuant to a renewable energy power purchase agreement, tolling agreement with a term of at least five (5) years and not more than twenty (20) years, or build own transfer agreement. The PPA or tolling agreement must give APS ownership of all environmental attributes, as that term will be defined therein.

b. Eligible Resources: Eligible renewable energy resources are those defined in A.A.C. R14-2-1802(B): "Eligible Renewable Energy Resources are applications of the following defined technologies that would otherwise be used to provide electricity to APS customers: Biogas Electricity Generator, Biomass Electricity Generator, Eligible Hydro Facilities, Fuel Cells that Use Only Renewable Fuels, Geothermal Generator, Hybrid Wind and Solar Electric Generator, Landfill Gas Generator, Solar Electricity Resources, Wind Generator."

c. Technical Characteristics:

1. Renewable energy projects must offer operational flexibility, which can be achieved through a tolling agreement structure or through a PPA that includes curtailment rights. Proposals should be clear about the operational flexibility being offered and how that flexibility can be maximized to achieve the greatest value for APS.

2. Any Proposal for a solar photovoltaic facility shall include three (3) hourly production profiles (i.e.,8760 profiles), which represent the hourly output of the project at the APS Delivery Point in Mountain Standard Time ("MST") generated using the P90, P75 and P50 US TMY3 ("Typical Meteorological Year") Solar Anywhere data sets. The Solar Anywhere data sets should be based on site specific 1km x 1km grids/tiles.

3. Any Proposal for a wind facility shall provide on-site wind data used in preparing 8760 production profiles as well as the method(s) for collecting on-site wind data in the "Wind Performance Characteristics" spreadsheet found in PowerAdvocate "Download Documents" tab

APS Preferences:

APS prefers the following:

a. Duration: a facility able to generate 100% of the proposed contract capacity for a minimum of four (4) consecutive hours when operated at 122°F for desert climate sites and down to 0°F for cold climate locations.

b. Peak energy production: a facility that maximizes the amount of energy production that it will generate and deliver during the months of June through September between the hours of 3:00pm and 9:00pm Arizona time as identified in the heat map attached as Appendix A.

c. Reactive power: a facility that can provide reactive capabilities in excess of the minimum Interconnection Requirements and can also provide reactive capabilities without the need to be producing real power (i.e., grid-sourced reactive power).

3. Energy Efficiency

Any Proposal for an energy efficiency or other non-supply side, non-dispatchable resource (referred to herein as "Energy Efficiency") must conform to the general eligibility minimum requirements set forth in Section B and the minimum requirements set forth in this Section C (3).

Respondents assume the risk and impact of any future APS rate design changes when submitting a Proposal for an Energy Efficiency resource. In addition, nothing in this RFP shall limit APS's ability to offer its own Energy Efficiency programs in the future, regardless of whether or not it enters into a load management agreement for an Energy Efficiency resource as a result of this RFP.

Minimum Requirements:

a. Transaction Structure: A conforming Proposal must offer an energy efficiency resource pursuant to a Load Management Agreement that satisfies the terms specified in the Term Sheet found on the RFx Tab in PowerAdvocate for a term of at least five (5) years but not more than ten (10) years. The agreement must permit APS to count any energy savings that results from the proposed resource toward any established ACC Energy Efficiency goal and/or any other future regulatory requirements.

b. Technical Characteristics:

   1. Any proposed resource must pass the Societal Cost Test ("SCT") as defined by the ACC Energy Efficiency Standards defined in Arizona Administrative Code R14-2-2401(36). As such, APS will screen all Energy Efficiency Proposals using the SCT as prescribed by the ACC. All Respondents must provide input assumptions and calculations to pass the Societal Cost Test.
   2. Any proposed resource must be APS-branded.
   3. Any proposed resource may only aggregate customers within the APS service territory.
   4. Any Proposal must include a proposed Measurement and Verification Plan ("M&V Plan") to verify actual MWh & MW savings delivered, including estimated costs for implementing the M&V Plan. Load reductions must be verifiable by APS by using then-available APS metering. Resources that are educational in nature only (i.e., do not include tangible energy efficiency products) and do not result in MWh and MW savings delivered are not eligible.
   5. Proposals are limited to no more than 100 MW per year.

APS Preferences:

APS prefers the following:

a. Cost effectiveness: a system that passes the Ratepayer Impact Measure ("RIM") test and otherwise demonstrates cost effectiveness through other tests such as the utility cost test and the participant test.

b. Operating parameters: a system that is capable of operating at 115° F and twenty percent (20%) humidity, at 100% displaced capacity for a minimum of four (4) consecutive hours.

c. Peak energy displacement: a system that displaces energy during the months of June through September and between the hours of 3:00pm and 9:00pm Arizona time.

4. Demand Response

Any Proposal for a demand response or other non-supply side, dispatchable resource (referred to herein as "Demand Response") must conform to the general eligibility minimum requirements set forth in Section B and the minimum requirements set forth in this Section C (4).

Respondents assume the risk and impact of any future APS rate design changes when submitting a proposal to APS. In addition, nothing in this RFP is intended to limit APS's ability to offer its own demand response programs of any type in the future, regardless of whether or not it enters into a demand response load management agreement as a result of this RFP.

Minimum Requirements:

a. Transaction Structure: A conforming Proposal must offer a demand response program pursuant to a load management agreement that satisfies the terms specified in the Term Sheet found on the "RFx Tab" in Power Advocate with a term of at least five (5) years but not more than ten (10) years. The agreement must permit APS to count any energy savings that results from the proposed program toward any ACC Energy Efficiency goal and/or any other future regulatory requirements.

b. Technical Characteristics:

1. Commencement of Delivery and Delivery Time Periods: Proposals must provide for commercial operation and delivery of capacity beginning on June 1, 2023. All Proposals must provide capacity during the months of June through September during each year of the term of the load management agreement (the "Control Season").

2. Resource Size: Proposals must offer a minimum of 25 MW and a maximum of 100 MW of capacity per year, aggregated from eligible APS C&I or residential customer load.

3. Number of Dispatches per Control Season: The resource must be dispatchable a minimum of eighteen (18) times during each Control Season, June through September, during any Program Availability Hour, 4:00PM to 9:00PM, Arizona Time.

4. Notification: The resource must respond with two (2) hours prior notice.
5. Duration: The resource must be capable of delivering guaranteed load reduction for five (5) consecutive hours.
6. Frequency: The resource must be capable of performing for a minimum of three (3) consecutive days.
7. Availability of Capacity: The resource must provide one hundred percent (100%) of the contracted load reduction on each Monday through Friday and eighty percent (80%) of the contracted load reduction on each Saturday, Sunday, July 4th and Labor Day during the Control Season.
8. Verification of Load Reduction: Load reductions must be verifiable by APS using APS-owned AMI metering.
9. Customer Base: The resource may only aggregate eligible customers within the APS service territory.
10. Branding: The resource must be APS-branded.

APS Preferences:

APS prefers the following:

a. Number of Dispatches: a resource capable of more than eighteen (18) dispatches per Control Season.
b. Notification: a resource that responds with one (1) hour prior notice. Respondents should explain (in the Executive Summary) if responding with one (1) hour prior notice will result in any cost increase to APS, as compared to a two (2)-hour prior notice requirement.
c. Event Duration: a resource that can reduce load for longer than five (5) hours.
d. Event Frequency: a resource that can reduce load if called upon by APS for five (5) consecutive days or more.
e. Availability of capacity resources: a resource that can provide one hundred percent (100%) of the DR Capacity during all seven (7) days of the week including July 4th and Labor Day, during the Control Season.
f. Term: a resource that can be contracted with APS for a shorter term rather than a longer term, in order to enable APS to be responsive to future load changes.

5. Thermal Generation

Any Proposal for a thermal generation resource must conform to the general eligibility minimum requirements set forth in Section B above and to the minimum requirements set forth in this Section C (5).

Minimum Requirements:

a. Transaction Structure: Proposed transaction must be in the form of a tolling power purchase agreement with a delivery term of at least three (3) years and not more than eight (8) years and a delivery period of May 1 through October 30. Proposals must also include Respondent's plan, if any, to reduce carbon emissions over the term of the proposed transaction, including through the use of clean hydrogen or by other means.

b. Technical Characteristics:

1. Proposed gas-fired generation resources must be able to connect to a viable interstate natural gas pipeline. APS will evaluate the proposed point of connection to see if there are any constraints specific to that location.
2. Proposed resource must have adequate water rights to support performance for the full contract capacity and for the proposed term of the tolling agreement.
3. Proposed resource shall be capable of operating at 100% contract capacity for a minimum of six (6) consecutive hours.
4. The Proposed resource must be fully dispatchable by APS using AGC.
5. To the extent that carbon allowances are allocated to the proposed resource or part thereof, those allowances must be provided to APS for the term of the associated tolling agreement at no additional charge and may be allocated by APS toward its requirements pursuant to any applicable regulatory requirements.
6. APS evaluates gas turbine performance on the following parameters:
    a) Assumed elevation of 1,000 ft.
    b) June-September temperatures at 105°F and Relative Humidity of 19%.
        i. Equivalent to 115°F and Relative Humidity of 9.5%.
        ii. Assumes inlet cooling.
    c) October, March-May temperature 73°F and Relative Humidity of 37%.
        i. Assumes inlet cooling.
    d) November-February temperature 41°F and Relative Humidity of 51%.
        i. Inlet Cooling is assumed off.

APS Preferences:

APS prefers the following:

a. Stable operation: a resource capable of stable operation at a minimum operating level of twenty five percent (25%) loading or lower without exceeding the legal limits for emissions (CO, CO2, NOx, SO2, VOC, PM10), whether pursuant to an applicable air permit or otherwise.

b. Starts: a resource capable of at least two (2) starts per day.

c. Ramp rate: a resource with a minimum ramp rate of ten percent (10%) per minute of summer capacity rating.

d. Operating parameters: a resource capable of full contract capacity at 118°F and Relative Humidity of 20%

e. Fuel supply: a transaction that allows APS the option to supply any fuel and related gas transportation for delivery to the lateral pipeline interconnection for the facility.

f. Gas pipeline: for a natural gas resource, connection to both the El Paso and Transwestern pipelines.

D. General Evaluation Process

1. Process Overview

APS will use both quantitative and qualitative criteria to evaluate Proposals. APS may eliminate any Proposal it deems insufficient at any point throughout the evaluation process. First, APS will determine if each Proposal satisfies the minimum requirements. If the proposal meets minimum requirements, the proposal will undergo a screening evaluation process described below. Only those Proposals that both satisfy the minimum requirements and perform well in the screening evaluation will be further evaluated through a portfolio evaluation.

The portfolio evaluation considers the fit of a Proposal relative to APS's existing resources, other Proposals, projected resource needs, and further qualitative evaluation. If at any time during the evaluation process APS determines that a Proposal does not meet its requirements, including timely submission of all documents and fees required pursuant to this RFP, or fails to remain competitive with other Proposals though screening, portfolio analysis, or qualitative analysis, such Proposal may no longer be considered, and APS will notify the Respondent accordingly during its notification process. Respondents are advised that price will be a major factor in APS's evaluation, but APS will also consider qualitative factors for highly ranked Proposals as described below.

2. Evaluation for Compliance with Minimum Requirements

a. Compliance with Minimum Requirements. Proposals will be reviewed for compliance with the general eligibility minimum requirements described in Section B and the applicable technology-specific minimum requirements described in Section C.

b. Failure of Proposal to Meet Minimum Requirements. APS may reject a Proposal if the Proposal fails to meet the minimum requirements, or otherwise contains incomplete or inaccurate responses, as determined by APS in its sole discretion. APS may, in its sole discretion, seek clarification or remedying of a Respondent's Proposal prior to making a final determination regarding acceptance or rejection of a Proposal.

3. Screening Evaluation

a. Screening of Proposals. APS will screen and rank Proposals by resource type and cost. Proposals with prices significantly higher than other Proposals with similar characteristics may be removed from further consideration in APS's discretion. The screening process consists of a quantitative analysis (such as levelized busbar costs) to identify superior or highly ranked Proposals for further analysis.

4. Short List Selection of Proposal(s)

At APS's sole discretion, Proposals that satisfy the screening evaluation described in Section D(3) above may be shortlisted for further detailed evaluation by APS, which will include both a portfolio analysis and a broad qualitative analysis. APS will notify shortlisted Respondents, if any, along with those Respondents whose Proposals have been eliminated from further consideration, in accordance with the RFP schedule set forth in Section E(5) below.

a. Portfolio Analysis. APS will utilize resource planning models and production cost modeling software to evaluate how well any shortlisted Proposal meets system reliability requirements while minimizing projected APS system costs. Resources will be evaluated within the APS portfolio based on present value revenue requirements ("PVRR") for the APS system.

APS will not disclose to Respondents the generation cost estimates used for Proposal evaluation, but will provide that information to the Independent Monitor referenced in Section E below. Further, APS's avoided capacity and energy values are proprietary data and will not be disclosed to Respondents.

b. Qualitative Analysis. The qualitative analysis is comprised of a holistic risk assessment considering numerous factors, including but not limited to technology, project viability, developer experience, safety record, safety features, quality assurance and quality control experience, credit risk, counterparty viability, supply chain risk, and contract risk related to the development of the proposed project. APS will also evaluate the Respondent's proposed modifications to the relevant pro forma agreement or term sheet. Those Proposals that contain fewer changes to the pro forma agreement or term sheet may be more competitive than those that contain more changes (either in number or scope).

5. Detailed Evaluation of Shortlisted Proposals and Final Selection of Proposal(s)

a. Meetings with Shortlisted Parties. APS may conduct meetings or phone calls with shortlisted Respondents to gain a greater understanding of each Proposal. APS may also require shortlisted Respondents to submit project and/or Respondent-specific pro forma financial statements by year for the applicable facility development and construction period, including income statements, balance sheets and statements of cash flows. APS may then re-evaluate each shortlisted Respondent's Proposal including any new information provided during or as a result of the shortlist meetings, in a manner similar to the evaluation process described in Sections D(3) and D(4) above.

b. Final Evaluation and Selection. Following the shortlist process described above, APS may make a final selection of one or more Proposals for negotiation of an agreement in a form substantially similar to that set forth in the relevant pro forma agreement (or based on the terms contained in the relevant term sheet). APS will notify shortlisted Respondents whose Proposals are eliminated from further consideration in accordance with the RFP schedule set forth in Section E (4) below. APS reserves the right, in its sole discretion, to not select any Proposals for negotiation of an agreement if warranted by its evaluation.

c. Right to Terminate Negotiations. If APS cannot reach an agreement with the final selected Respondent or Respondents, APS reserves the right to terminate negotiations with such Respondents and begin discussions with other Respondents, begin a new solicitation, and/or cancel this RFP.

d. Regulatory Approval. Any final agreement resulting from this RFP may be conditioned upon actions and/or approvals by regulatory authorities, satisfactory to APS in its sole discretion.

E. RFP Process and Schedule

1. Independent Monitor

An IM will be used in the RFP process to ensure that it is conducted in a fair and unbiased manner. The IM will have access to all documentation provided by the Respondents in response to this RFP and will produce a final report summarizing its observations for use by APS, which may include submission to the ACC in connection with APS's regulatory requirements. The IM is obligated to maintain the confidentiality of all information that it reviews.

2. RFP Website and PowerAdvocate

a. Registration. Respondents must register online using the webform provided at http://www.aps.com/rfp (the "RFP Website"). Registration will open on December 11, 2020. Registration enables each Respondent to access all RFP-related documents and to receive relevant messages and notices from APS through PowerAdvocate, a third-party web-based platform for hosting solicitations. PowerAdvocate is subject to a confidentiality agreement with APS that prohibits the disclosure of confidential information submitted via the platform to unauthorized third parties. APS encourages each Respondent to carefully review the PowerAdvocate Terms of Use before submitting a Proposal. The Terms of Use are located at: https://www.poweradvocate.com/web/terms-of-use.html.

b. Communications. All communications from Respondents to APS, including questions regarding this RFP, should be submitted in writing via the PowerAdvocate messaging system. Depending upon the nature and frequency of the questions APS receives, APS will choose to either respond to individual Respondents directly or post a response to the question in PowerAdvocate (without disclosing the Respondent's name).

c. APS Contact. The PowerAdvocate messaging tool is the sole medium of communication for this RFP and will be monitored and responded to by APS. Respondents that experience any difficulty should contact:

Arizona Public Service Company
Subject Line: 2020 ALL SOURCE RFP
Email: ResourceAcquisition@aps.com

3. Confidentiality Agreement

Each Respondent must sign the Confidentiality Agreement ("CA") that is available in PowerAdvocate and upload the signed copy via PowerAdvocate no later than January 8, 2021, as specified in the RFP schedule found in Section E (5). Upon receipt, APS will then execute and return a copy for the Respondent's records. APS encourages Respondents to refrain from making changes to the CA. Modified CAs should not be executed by Respondents without APS's agreement; rather, a Respondent should make requested modifications using PowerAdvocate and such requests may be reviewed and either approved or rejected by APS. APS does not guarantee that any requested changes will be made, nor does it guarantee its ability to review such requests, depending upon the nature and volume of requested changes.

Any Respondent that fails to upload in PowerAdvocate its clean, signed Confidentiality Agreement (i.e., with no changes, or with changes expressly agreed upon by APS) by 2:00 PM Arizona time on January 8, 2021, shall be eliminated from further participation in this RFP.

4. RFP Schedule

The following schedule applies to this RFP:

Activity	RFP Deadline Date
PowerAdvocate Registration Open	December 11, 2020
RFP issued	December 11, 2020
Confidentiality Agreement Submittal DUE	January 8, 2021
Respondent Proposal and RFP Proposal Fee DUE	February 19, 2021
Shortlisted Respondents notified	April 2, 2021
Final selections	April 30, 2021
Contract Executions	June 30 – August 31, 2021

F. Miscellaneous Proposal Submittal Information

1. Schedule

Proposals shall be submitted in strict accordance with the RFP schedule. APS will not grant any extensions to the RFP schedule and will not accept late Proposals. Any Proposal received after the scheduled date will be rejected and the Respondent will be notified accordingly.

2. Currency

All prices must be clearly stated in United States Dollars.

3. Reservation of Rights

APS reserves the right to accept or reject in its sole discretion any or all Proposals for any reason at any time after submittal. APS also reserves the right to select an offer that is not the lowest price, if APS determines that in its judgment the overall Proposal may result in the greatest value to APS's retail customers.

4. No Liability

Respondents that submit Proposals do so without legal recourse against APS or its officers, directors, employees, agents, contractors or the Independent Monitor based on APS's rejection of any Proposal or for failure to execute any agreement in connection with this RFP. Neither APS, nor any of its officers, directors, employees, agents, or contractors shall be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to APS's acts or omissions arising out of or in connection with this RFP.

5. Return of Documents

None of the materials received by APS from Respondents in response to this RFP will be returned. All Proposals and exhibits will become the property of APS, subject to the provisions of the confidentiality agreement described in <u>Section E (3)</u> above.

6. Proposal Fee; What Constitutes a Single Proposal with a Single Proposal Fee?

A non-refundable RFP submission fee (the "Proposal Fee") of ten thousand dollars ($10,000) must be submitted with each Proposal.

Respondents are entitled to submit one Proposal and two (2) alternative pricing variations using the same single Proposal Fee. The alternative pricing variations may include different terms for characteristics of the Proposal, in Respondent's discretion (e.g., a different capacity or energy charge, different variable O&M costs, a different price escalation schedule, a different number of starts for the proposed facility, etc.), provided that the following terms may NOT change and still qualify as an alternative pricing variation to a single Proposal:

a. Term of transaction
b. Technology
c. Site/Location of facility
d. Size/Capacity
e. In the case of non-supply side Proposals, proposed program shape

If any of the foregoing characteristics of Respondent's Proposal change, then the changes amount to a separate Proposal for which Respondent will be required to submit a separate Proposal Fee.

APS must receive the Proposal Fee by the response date shown in <u>Section E (4)</u> above and funds must be wired using the information below. Any costs or fees associated with wiring the funds shall be paid directly by the Respondent.

Company:	Arizona Public Service Company
Bank:	Wells Fargo
ABA/Routing No.:	121000248
Account No.:	XXXXXXX921
OBI Field:	114903; AR114903202; 2020 All Source RFP Bid Fee; Respondent's name

7. Terms, Conditions and Pricing

Respondent shall include in each Proposal all costs necessary to deliver capacity and energy to the APS system including, but not limited to, construction of the project, transmission (if necessary), development security, post-development security, and all costs related to interconnection. Respondent will be bound to honor all terms of its Proposal, including but not limited to its price, which shall remain binding through the final selection notification and subsequent contract negotiations, as well as ACC approval (if required).

8. PowerAdvocate

Respondents are required to use PowerAdvocate to enter or upload all requested information. Respondents are encouraged to submit their Proposals as early as possible in order to avoid filing delays due to heavy use of PowerAdvocate immediately prior to the Proposal submission deadline. In order for a Respondent's proposal to be considered conforming, the Respondent shall timely post to PowerAdvocate the following documents:

a. Completed Proposal, including a detailed Executive Summary of the Proposal. (A sample Executive Summary can be found in PowerAdvocate under the "Download Documents" tab)

b. Executed CA posted in PowerAdvocate no later than January 8, 2021 at 2:00 PM AZ time

c. A complete response to each question, and a legible copy of each document specified on the commercial, technical and pricing tabs of PowerAdvocate

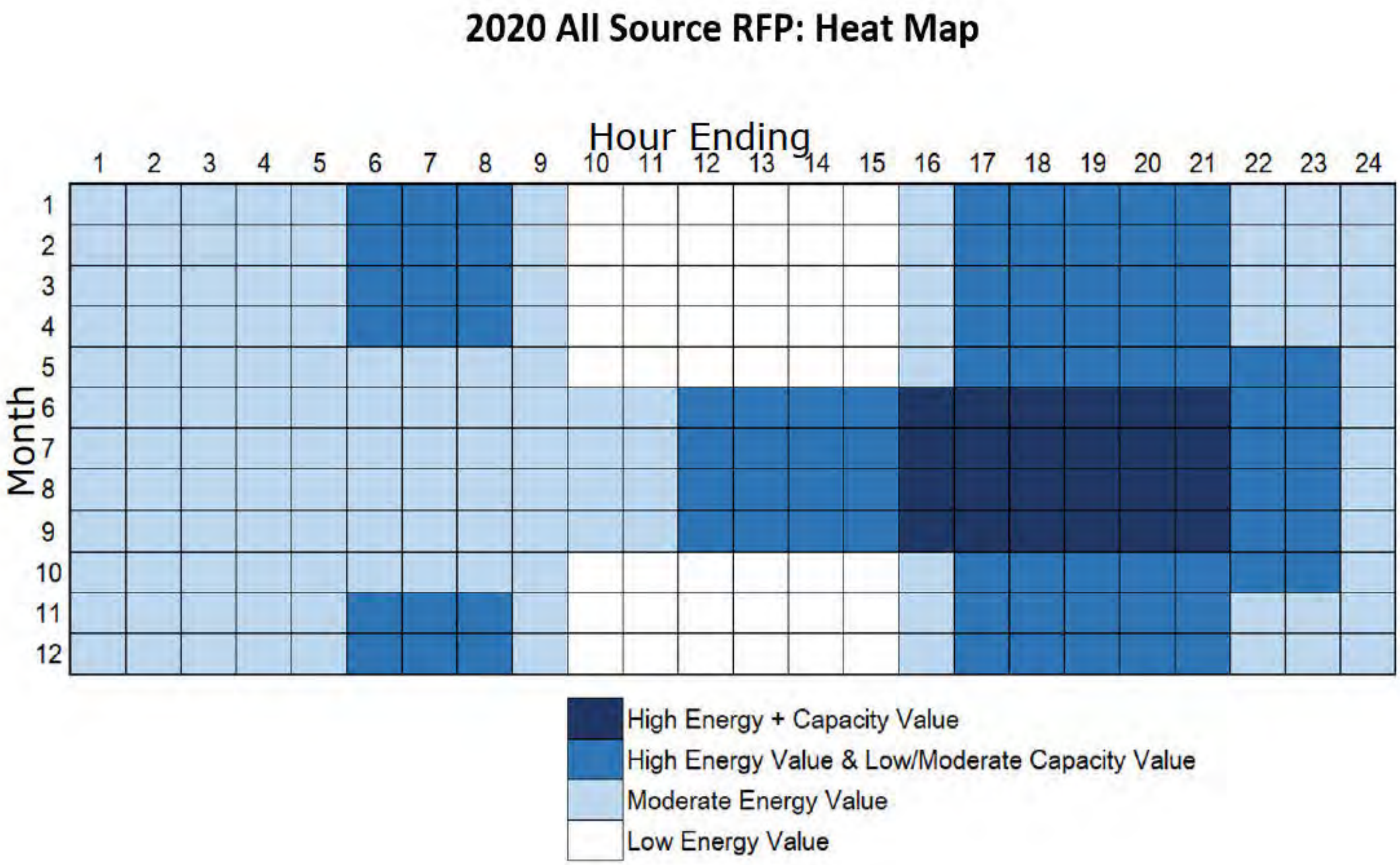
d. Executed certification page which demonstrates that the signatory has full authority to bind the Respondent to all of the terms and conditions contained in its Proposal. Respondents must use the certification page posted by APS on PowerAdvocate.

e. Project schedule shown in weeks, based on an assumed date for contract execution (which shall be stated in the schedule)

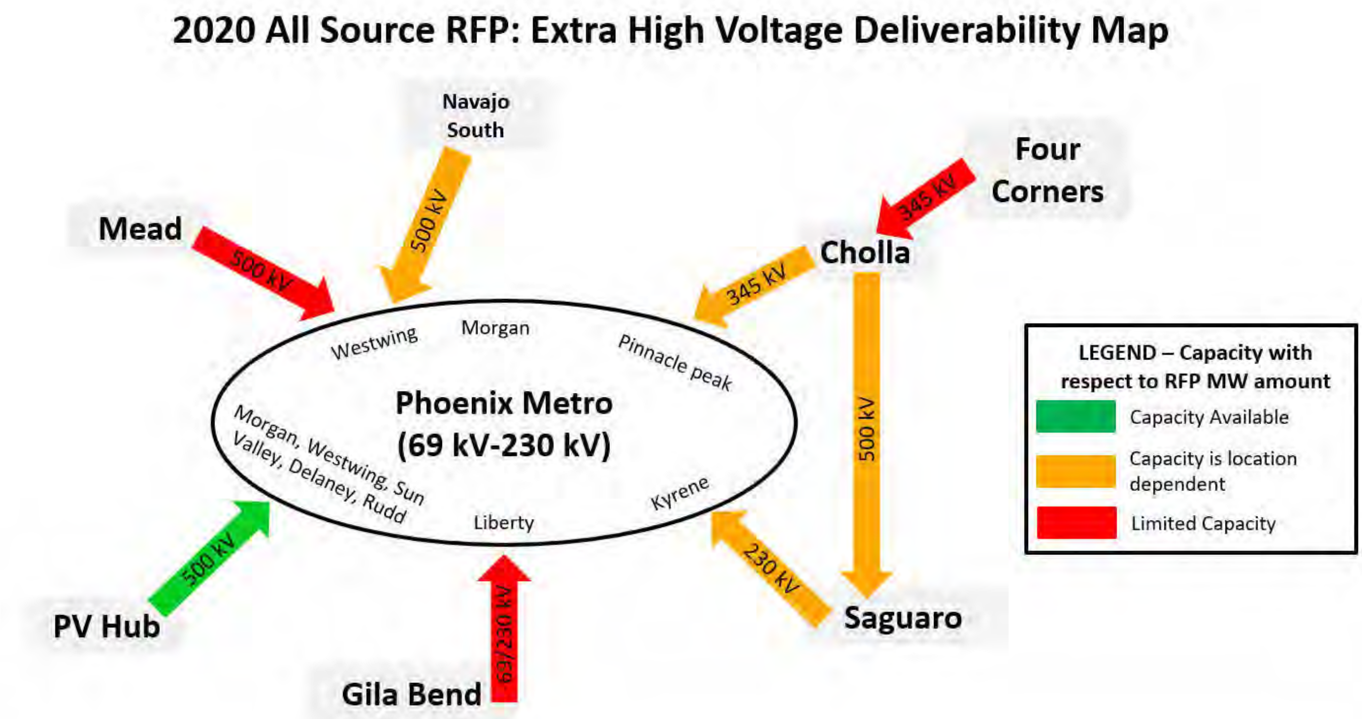
f. Preliminary one-line diagram for the project with meter location and specified delivery location, which shall be the Delivery Point as that term is defined in the resulting agreement

g. Technical Data form, which identifies certain criteria used to calculate the expected energy production for the proposed facility. Although APS has provided certain default assumptions based on industry standards, Respondents may use criteria that differs from these assumptions by identifying the difference and reason for this variation. The energy production profile submitted by each Respondent must be calculated based on the same set of technical criteria supplied to APS by the Respondent in the Technical Data form.

Appendix A


2020 All Source RFP: Heat Map
Hour Ending
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Month
1 2 3 4 5 6 7 8 9 10 11 12
High Energy + Capacity Value
High Energy Value & Low/Moderate Capacity Value
Moderate Energy Value
Low Energy Value

Appendix B



2023 Indicative guidelines for Deliverability of Product to APS Phoenix Metro load pocket for purposes of the 2020 All Source RFP:

1. Information represented here has been prepared by Resource Planning as an indicative guideline for 2023 Deliverability of Product to APS Phoenix Metro load pocket as currently estimated for purposes of the 2020 All Source RFP.
2. Deliverability rating is representative of current estimations of Deliverability in 2023.
3. Information does not represent official Available Transmission Capacity.
4. Official Available Transmission Capacity can be found on OASIS (http://www.oasis.oati.com/azps/index.html).
5. Information in these figures is NOT intended to provide definitive guidance to any potential bidder regarding the specifics of the transmission system that may be applicable to bidder's proposed facility. All bidders are responsible for performing their own independent evaluation of the transmission system as it may affect their proposed facilities.
6. Projects should be inclusive of all costs to deliver to the APS system.

Arizona Public Service Company

Addendum to the 2020 All Source Request for Proposals (“RFP Addendum”)

April 30, 2021

Table of Contents

A. OVERVIEW

1. Introduction

Arizona Public Service Company ("APS") is a regulated public utility that generates, transmits and distributes electricity for sale in Arizona. APS is headquartered in Phoenix, Arizona. As Arizona's largest and longest-serving electric company, we generate safe, affordable and reliable electricity for more than 1.3 million commercial and residential customers in 11 of Arizona's 15 counties.

Through a comprehensive planning process, APS determines how to meet future customer needs for reliable and affordable electricity, while achieving regulatory targets and reducing environmental impacts during the planning period. APS has worked with our team of resource experts, energy planners, and cross-sector stakeholders to develop a strategic roadmap on our path to a 100% carbon-free generation mix by 2050. Our Integrated Resource Plan ("IRP"), which is filed with the Arizona Corporation Commission ("ACC"), initiates that process and provides both a near-term action plan and a longer term vision that show how we plan to meet our customer and resource needs for the next 15 years. The IRP provides the strategic direction for APS's acquisition of a clean, diversified, balanced resource portfolio that meets customer needs, maintains reliability, results in reasonable energy supply costs, and mitigates market risks. It includes an interim target of achieving a 65% clean energy mix by 2030. We're focused on integrating renewable resources, empowering customers with flexible energy options and incorporating advanced technology to produce clean and affordable energy—all while providing reliable service and remaining good stewards of Arizona's diverse environment.

On December 11, 2020, APS issued its 2020 All Source Request for Proposals (the "RFP"), which represents a comprehensive step toward providing APS's growing customer base with clean, reliable, and affordable energy. Through this Addendum to the RFP (the "RFP Addendum"), APS is soliciting competitive proposals ("Proposals") for the engineering, procurement, construction, and warranty (collectively referred to herein as "EPC Services") of a photovoltaic solar ("PV Solar") resource (referred to herein as the "PV Solar Resource") to be built on APS land adjacent to the Redhawk generating station with an in-service date in Q4 2022 or Q1 2023. APS is requesting that each Respondent submit both a 100 MWAC and 150 MWAC design, only one design of which will ultimately be selected based on the selection process outlined in Section C below. This RFP Addendum provides an additional opportunity for the development of renewable resources to support APS's expanding clean energy portfolio.

Persons or entities responding to this RFP Addendum are referred to herein individually as a "Respondent" or collectively as "Respondents." A Respondent may consist of one or more persons or entities.

2. Product Requested

a. Scope of Solicitation. In this RFP Addendum, APS seeks competitive Proposals for EPC Services for two facility designs: a 100 MWAC and a 150 MWAC PV Solar Resource (only one of which will ultimately be selected for development). APS will own and operate the PV Solar Resource developed pursuant to this RFP Addendum. Additional information regarding the PV Solar Resource capacity can be found in Section B(3) below.

b. Affiliate Bids. APS corporate affiliates are NOT eligible to submit a Proposal in this RFP Addendum.

c. Additional Services. APS is NOT seeking Proposals for services beyond those that are specified in this RFP Addendum or in the associated PV Solar EPC Services pro forma agreement (the "Agreement"), and APS will NOT consider Proposals for power purchase agreements or any other asset lease scenarios.

d. Location. APS-owned land at Redhawk Generating Station. APS owns approximately 1,100 acres of land adjacent to the natural gas-fired Redhawk Generating Station ("Redhawk") located in Arlington, AZ. Respondents must execute the Confidentiality Agreement ("CA") found in the "Download Documents" tab of PowerAdvocate prior to receiving any site-specific supporting documentation. APS will send such documentation via the PowerAdvocate messaging system upon receipt of Respondent's executed CA. APS will be conducting a tour of the Redhawk site per the schedule in Section D(4) and any Respondent tour participant must submit its executed CA prior to the tour.

3. Interconnection

The PV Solar Resource must deliver capacity and energy by directly interconnecting to the APS-provided solar collector substation or the APS Redhawk switchyard, as detailed further below. Respondents must meet all requirements of the interconnection agreement which will be based on the APS OATT pro forma. For interconnection-related questions, please contact: INTERDEV@apsc.com.

a. General. Proposals must include a detailed strategy for interconnection of the PV Solar Resource by the date of Final Acceptance. APS will initiate the interconnection process for the PV Solar Resource. At a minimum, the Respondent must install and connect the solar medium-voltage collector system into an APS-provided solar collector substation as noted on the site plans in the "Download Documents" tab in PowerAdvocate. Respondent's base Proposal pricing should assume that APS will design and install the solar collector substation and high-voltage interconnection into the

Redhawk switchyard and will undertake all activities necessary to support the interconnection application process.

b. Substation and Interconnection OPTION. In addition to the base Proposal pricing described in subparagraph 3(a) above, any Respondent may provide Proposal pricing that assumes the Respondent will design and construct the solar collector substation, including the interconnection of the solar collector substation into the Redhawk 500kV switchyard. The scope of work for this pricing alternative should include design and construction of the solar collector substation, towers, and lines, but not the generator step-up transformer (which shall remain in the APS scope of work). See the site plans in the "Download Documents" tab in PowerAdvocate for more details. For this pricing option, Respondent should also assume that APS would initiate the interconnection application, which would then be assigned to the Respondent after execution of the EPC Agreement. The Respondent would be expected to manage the interconnection process and interconnection construction as part of its scope of work.

B. General Eligibility Minimum Requirements

In addition to satisfying the interconnection and deliverability requirements described in Sections A(3) above, Proposals must meet the following minimum requirements. Proposals that do not satisfy all applicable requirements will be considered non-conforming and may not be evaluated by APS.

In addition to the minimum requirements, some items may be listed as "OPTIONAL." Satisfaction of any of the APS OPTIONAL items is not required for a Proposal to be deemed conforming, but Proposals that contain more of the APS OPTIONAL items may be more competitive than those that contain fewer of the APS OPTIONAL items.

1. Timely Document Submittal

Each Respondent must complete and submit all required documents, together with the Proposal fee, each as specified in Sections D and E below and in PowerAdvocate, no later than the due dates detailed in the schedule found in Section D(4) below. (APS's use of the PowerAdvocate platform for purposes of this RFP Addendum is explained in Section E(10) below.)

2. Commercial Experience

Each Respondent (or Respondent and its partner(s) if applicable) must demonstrate in its Proposal that it has successfully designed and constructed a minimum fifteen (15) MW PV Solar resource in North America and that such resource has been in operation for at least twelve (12) consecutive months as of June 25, 2021. Respondent must provide commercial experience information in the "Commercial Data" tab in PowerAdvocate and in its Executive Summary.

Any Respondent that requires a partner to satisfy the commercial viability requirement set forth in this Section B(2) must also demonstrate, to APS's satisfaction, that the partner relationship has been legally established, is legally enforceable, and supports the Proposal being submitted.

3. Technical Characteristics

a. Proposal Size. In this RFP Addendum, APS seeks competitive Proposals for EPC Services for a 100 MWAC and a 150 MWAC PV Solar Resource as described in Section A(2) above. APS will own and operate the PV Solar Resource developed pursuant to this RFP Addendum.

b. PV Solar. The PV Solar Resource must utilize crystalline, thin-film (CdTe only), or bifacial PV solar technology in a single axis tracking configuration. All major equipment and components must meet industry standards. APS is NOT seeking Proposals utilizing technologies such as solar thermal, concentrated solar, fixed or dual axis tracking PV. In order to be considered, the technology for the PV Solar Resource and key components thereof must be backed by a minimum of twelve (12) months of established production history at a scale of fifty (50) MW or larger at a single plant located in North America. A complete list of the PV Solar Resource technical requirements can be found in the "Download Documents" tab in PowerAdvocate.

c. Production Profiles. Any Proposal for a solar photovoltaic facility shall include three (3) hourly production profiles (i.e.,8760 profiles), which represent the hourly output of the project at the APS Delivery Point in Mountain Standard Time ("MST") generated using the P90, P75 and P50 US TMY3 ("Typical Meteorological Year") Solar Anywhere data sets. The Solar Anywhere data sets should be based on site specific 1km x 1km grids/tiles.

d. Additional Technical Requirements. Proposals must adhere to the complete set of Technical Requirements which can be found in the "Download Documents" tab in PowerAdvocate. Respondents must also complete the "RFP Addendum Data Sheet" for the PV Solar Resource (located in RFx "Download Documents" tab in PowerAdvocate).

e. Automatic Generation Control. The PV Solar Resource must be fully dispatchable and capable of automatic generation control ("AGC"). AGC must enable the PV Solar Resource to automatically respond to a dispatch signal provided by APS's energy management system ("EMS"). These commands will come through the APS RTU located in the project control house and communicated via DNP3.

f. Ancillary Services. Proposals must include any ancillary services that can be provided by the PV Solar Resource. Given the requirement that the PV

Solar Resource must be fully dispatchable, the PV Solar Resource must be capable of providing the following ancillary services: over-frequency response (frequency droop down), spinning reserve, non-spinning reserve, fixed reactive power control, automatic voltage regulation, and fixed power factor.

Proposals that are capable of providing frequency regulation from the PV Solar Resource will be evaluated more favorably than Proposals that do not include this capability.

Proposals that are capable of providing access to the full reactive capabilities of the inverters, including grid-sourced reactive power (a.k.a. "Q at night"), will be evaluated more favorably than Proposals that do not include this capability.

4. Warranty

Each Proposal must include a full wrap standard parts and labor (i.e. workmanship) warranty ("Warranty") offering for a minimum of one (1) year (the "Warranty Period"). Proposals with a Warranty Period greater than one (1) year will be evaluated more favorably. Such Warranty must include full coverage of site construction, the PV Solar Resource and all component parts, communications equipment, erosion design performance, and the PV Solar Resource's software and controls system. During the Warranty Period, APS will not be responsible for any parts or labor required to maintain the PV Solar Resource at full nameplate rating. Original equipment warranties ("Equipment Warranties") for the solar modules, inverters, and trackers/tracker structure shall be 30, 5, and 5/10 years, respectively. Any original equipment manufacturer warranties that extend beyond the term of the Warranty Period must be fully transferable to APS. Respondents should provide information on what other equipment warranties are included in their prices.

Respondents should provide Warranty information in PowerAdvocate in the tab labeled "Commercial Data" in the "General Company Information" section, as well as in the Executive Summary. The Warranty must also include a component replacement policy (parts and labor) to ensure that the PV Solar Resource continues to perform as designed for the entire design life. If a Respondent's standard Warranty covers less than a one (1)-year period, Respondent must provide the cost and terms of its standard warranty period plus any additional cost and terms of providing the required one (1)-year Warranty Period. If applicable, Respondents must provide this information in the "Pricing Data" tab within PowerAdvocate and in its Executive Summary. The Warranty Period must begin upon final acceptance of the PV Solar Resource by APS.

5. Maintenance

Each Proposal must detail the following performance guarantees. This information must be included in the "RFP Addendum Data Sheet". Respondents will be financially responsible (via liquidated damages) for failing to meet the performance guarantees.

6. Performance Guarantees

APS will perform all preventative and predictive maintenance for the PV Solar Resource unless a Respondent (a) offers such maintenance program at no cost to APS; or (b) requires that maintenance be provided by the Respondent in order to comply with any performance guarantees and/or warranties, in which case Respondent must provide the annual cost (expressed in dollars) of such maintenance in the "RFP Addendum Data Sheet" and in its Executive Summary.

i. PV Solar Capacity Guarantee. The Respondent must guarantee that the PV Solar Resource will produce power in an amount that is at least ninety-nine percent (99%) of the minimum power rating, as calculated by a PVsyst simulation model at reporting conditions, and measured using industry standard methods (i.e. ASTM 2848). This will be required to meet final acceptance.

ii. PV Solar Energy Test: The Respondent must guarantee that the PV Solar Resource will produce energy in an amount that is a least ninety-seven percent (97%) of the calculated PVsyst energy model during the first ninety (90) days following final acceptance.

7. Interface for Communication and Cybersecurity with APS Systems

APS views cybersecurity as critically important and highly encourages Respondents to carefully review the cybersecurity documents described below. Respondents will be responsible for the design, procurement, installation and integration of the communication and security requirements using DNP3 protocols for APS to remotely communicate with the PV Solar Resource. To facilitate Respondent's understanding of APS's cybersecurity requirements and APS's assessment of each Respondent's cyber risk, APS has provided the Data Security and Privacy Addendum ("DSPA") and the Third-Party Risk Review ("TPRR") spreadsheet, both of which are located on the "Download Documents" tab in PowerAdvocate. The DSPA will be part of the Agreement and is representative of, but not the entirety of, APS's cybersecurity requirements. The TPRR spreadsheet must be completed by Respondents and is fundamental to APS's evaluation of Proposals as the basis to approve a Respondent for storing restricted and confidential APS data. Additionally, APS has provided a Cybersecurity Specifications Spreadsheet in PowerAdvocate that contains additional cybersecurity requirements with which the PV Solar Resource will need to comply.

8. Recycling and Disposal

Proposals must include the cost of recycling and disposal of any failed components for the duration of the Warranty Period. Respondents will be required to provide APS with the complete chain of custody documentation for any materials removed from the site for recycling or disposal purposes. Respondent must submit to APS, for its review, Toxicity Characteristic Leaching Protocol (TCLP) data, testing, and sampling procedures for the PV Solar Resource modules to be installed. Due to end-of-life costs, APS highly prefers PV Solar modules that are deemed non-hazardous by the TCLP.

9. Project Permits

In addition to the general compliance requirements referenced in Section E(2) below, Respondents are responsible for complying with the permitting requirements of the PV Solar Resource site's jurisdiction. Respondents are responsible for acquiring a valid General Contractor's License ("GCL") issued by the State of Arizona by the Shortlist notification date specified in Section B(1) below. If Respondent does not have a valid GCL at the time of Proposal submission, Respondent must describe how it will obtain its GCL by the final selection date in the "General Company Information" section of the "Commercial Data" tab in PowerAdvocate and in its Executive Summary.

10. Construction Power, Auxiliary Power and Construction Water

APS can provide Respondents with a distribution connected power supply for construction and auxiliary power necessary for development and operation of the PV Solar Resource. Water is available for the Respondents to use for construction purposes.

11. Payment Schedule

Each Respondent must propose an expected payment schedule/schedule of values including the dates and amounts of all payments expected to be made by APS to Respondent. Each Respondent must provide this information in the "Pricing Data" tab in PowerAdvocate and in its Executive Summary.

12. Collateral

APS will apply a fixed collateral requirement to any Agreement executed as a result of this RFP Addendum: $100/kW upon execution of the Agreement, which shall be reduced to $40/kW upon commercial operation of the associated PV Solar Resource and held by APS until the expiration of the Warranty Period. Notwithstanding the foregoing, APS reserves the right to consider

Respondent's credit rating, proposed construction costs, any prior or existing transactions between Respondent and APS, and other associated information to determine if any increase in collateral requirements is necessary to support the execution of any Agreement.

Collateral must be posted in the form of a letter of credit or cash deposit no later than five (5) days after execution of the Agreement and must remain in effect through the Warranty Period as described above.

13. Tax Credit Strategy

APS is committed to maximizing the federal investment tax credit ("ITC") for this RFP Addendum. APS's evaluation of Proposals will take into consideration each Respondent's proposed project schedule and its ability to satisfy ITC requirements pursuant to either the "physical work test" or the "five percent (5%) safe harbor," at the earliest realistic time to capture the maximum ITC.

Each Respondent must provide a detailed description of its tax credit strategy in the "RFP Addendum Data Sheet" in the RFx tab in PowerAdvocate and in its Executive Summary, including the following information:

- Explanation of holistic strategy regarding ITC capture
- Identification of the critical path items for meeting its proposed ITC physical work/5% safe harbor deadline (must be supported by a proposed project schedule)
- If applicable, project cost comparison for achieving ITC physical work/5% safe harbor in the earliest year Respondent believes possible, versus the overall lower price by satisfying the ITC commence construction guidance in a later year.

14. Pricing

Pricing contained in any Proposal must include all costs associated with EPC Services, and any other work necessary to deliver the proposed PV Solar Resource to APS consistent with Respondent's Proposal and all of the requirements specified in this RFP Addendum and the Agreement. Respondent must include Proposal pricing information in the "Pricing Data" tab in PowerAdvocate and in its Executive Summary.

All Proposal terms, conditions and pricing will remain binding until the execution of a binding Agreement (if any) between APS and the respective Respondent as a result of this RFP Addendum, as well as any applicable regulatory approval (as referenced in Section C(5)(d) below). All prices must be clearly stated in United States Dollars and entered in the "Pricing Data" tab in PowerAdvocate and in the Respondent's Executive Summary.

C. General Evaluation Process

1. Process Overview

APS will use both quantitative and qualitative criteria to evaluate Proposals. APS may eliminate any Proposal it deems insufficient at any point throughout the evaluation process. First, APS will determine if each Proposal satisfies the minimum requirements. If the proposal meets minimum requirements, the proposal will undergo a screening evaluation process described below. Only those Proposals that both satisfy the minimum requirements and perform well in the screening evaluation will be further evaluated through a portfolio evaluation.

The portfolio evaluation considers the fit of a Proposal relative to APS's existing resources, other Proposals, projected resource needs, and further qualitative evaluation. If at any time during the evaluation process APS determines that a Proposal does not meet its requirements, including timely submission of all documents and fees required pursuant to this RFP Addendum, or fails to remain competitive with other Proposals though screening, portfolio analysis, or qualitative analysis, such Proposal may no longer be considered, and APS will notify the Respondent accordingly during its notification process. Respondents are advised that price will be a major factor in APS's evaluation, but APS will also consider qualitative factors for highly ranked Proposals as described below.

2. Evaluation for Compliance with Minimum Requirements

a. Compliance with Minimum Requirements. Proposals will be reviewed for compliance with the general eligibility minimum requirements described in Section B.

b. Failure of Proposal to Meet Minimum Requirements. APS may reject a Proposal if the Proposal fails to meet the minimum requirements, or otherwise contains incomplete or inaccurate responses, as determined by APS in its sole discretion. APS may, in its sole discretion, seek clarification or remedying of a Respondent's Proposal prior to making a final determination regarding acceptance or rejection of a Proposal.

3. Screening Evaluation

a. Screening of Proposals. APS will screen and rank same-sized Proposals by cost. Proposals with prices significantly higher than other Proposals with similar characteristics may be removed from further consideration in APS's discretion. The screening process consists of a quantitative analysis (such as levelized busbar costs) to identify superior or highly ranked Proposals for further analysis.

4. Short List Selection of Proposal(s)

At APS's sole discretion, Proposals that satisfy the screening evaluation described in Section C(3) above may be shortlisted for further detailed evaluation by APS, which will include both a portfolio analysis and a broad qualitative analysis. APS will notify shortlisted Respondents, if any, along with those Respondents whose Proposals have been eliminated from further consideration, in accordance with the schedule set forth in Section D(4) below.

a. Portfolio Analysis. APS will utilize resource planning models and production cost modeling software to evaluate how well any shortlisted Proposal meets system reliability requirements while minimizing projected APS system costs. Resources will be evaluated within the APS portfolio based on present value revenue requirements ("PVRR") for the APS system.

   APS will not disclose to Respondents the generation cost estimates used for Proposal evaluation but will provide that information to the Independent Monitor ("IM") referenced in Section D below. Further, APS's avoided capacity and energy values are proprietary data and will not be disclosed to Respondents.

b. Qualitative Analysis. The qualitative analysis is comprised of a holistic risk assessment considering numerous factors, including but not limited to technology, project viability, developer experience, safety record, safety features, quality assurance and quality control experience, credit risk, counterparty viability, supply chain risk, and contract risk related to the development of the proposed project. APS will also evaluate the Respondent's proposed modifications to the relevant pro forma agreement or term sheet. Those Proposals that contain fewer changes to the pro forma agreement or term sheet may be more competitive than those that contain more changes (either in number or scope).

5. Detailed Evaluation of Shortlisted and Final Selection of Proposal(s)

a. Meetings with Shortlisted Parties. APS may conduct meetings or phone calls with shortlisted Respondents to gain a greater understanding of each Proposal. APS may also require shortlisted Respondents to submit project and/or Respondent-specific pro forma financial statements by year for the applicable facility development and construction period, including income statements, balance sheets and statements of cash flows. APS may then re-evaluate each shortlisted Respondent's Proposal including any new information provided during or as a result of the shortlist meetings, in a manner similar to the evaluation process described in Sections C(3) and C(4) above.

b. Final Evaluation and Selection. Following the shortlist process described above, APS may make a final selection of one or more Proposals for negotiation of an agreement in a form substantially similar to that set forth in the relevant pro forma agreement (or based on the terms contained in the relevant term sheet). APS will notify shortlisted Respondents whose Proposals are eliminated from further consideration in accordance with the schedule set forth in Section D(4) below. APS reserves the right, in its sole discretion, to not select any Proposals for negotiation of an agreement if warranted by its evaluation.

c. Right to Terminate Negotiations. If APS cannot reach an agreement with the final selected Respondent or Respondents, APS reserves the right to terminate negotiations with such Respondents and begin discussions with other Respondents, begin a new solicitation, and/or cancel this RFP Addendum.

d. Regulatory Approval. Any final Agreement resulting from this RFP Addendum may be conditioned upon actions and/or approvals by regulatory authorities, satisfactory to APS in its sole discretion.

D. RFP Addendum Process and Schedule

1. Independent Monitor

APS uses an IM to monitor the RFP Addendum process and ensure that it is conducted in a fair and unbiased manner. The IM will have access to all documentation provided by the Respondents in response to this RFP Addendum and will produce a final report summarizing its observations for use by APS, which may include submission to the ACC in connection with APS's regulatory requirements. The IM is obligated to maintain the confidentiality of all information that it reviews.

2. RFP Addendum Website and PowerAdvocate

a. Registration. Respondents must register online using the webform provided at http://www.aps.com/rfp (the "RFP Website"). Registration will open on April 30, 2021. Registration enables each Respondent to access all RFP-related documents and to receive relevant messages and notices from APS through PowerAdvocate, a third-party web-based platform for hosting solicitations. PowerAdvocate is subject to a confidentiality agreement with APS that prohibits the disclosure of confidential information submitted via the platform to unauthorized third parties. APS encourages each Respondent to carefully review the PowerAdvocate Terms of Use before submitting a Proposal. The Terms of Use are located at: https://www.poweradvocate.com/web/terms-of-use.html.

b. Communications. All communications from Respondents to APS, including questions regarding this RFP Addendum, should be submitted in writing via the PowerAdvocate messaging system. Depending upon the nature and frequency of the questions APS receives, APS will choose to either respond to individual Respondents directly or post a response to the question in PowerAdvocate (without disclosing the Respondent's name).

c. APS Contact. The PowerAdvocate messaging tool is the sole medium of communication for this RFP Addendum and will be monitored and responded to by APS. Respondents that experience any difficulty should contact:

Arizona Public Service Company
Subject Line: RFP Addendum
Email: ResourceAcquisition@aps.com

3. Confidentiality Agreement

Each Respondent must sign the Confidentiality Agreement ("CA") that is available in PowerAdvocate and upload the signed copy via PowerAdvocate no later than May 21, 2021, as specified in the RFP Addendum schedule found in Section D(4). Upon receipt, APS will then execute and return a copy for the Respondent's records. APS encourages Respondents to refrain from making changes to the CA. Modified CAs should not be executed by Respondents without APS's agreement; rather, a Respondent should make requested modifications using PowerAdvocate and such requests may be reviewed and either approved or rejected by APS. APS does not guarantee that any requested changes will be made, nor does it guarantee its ability to review such requests, depending upon the nature and volume of requested changes.

Any Respondent that fails to upload in PowerAdvocate its clean, signed Confidentiality Agreement (i.e., with no changes, or with changes expressly agreed upon by APS) by 2:00 PM Arizona time on May 21, 2021, shall be eliminated from further participation in this RFP Addendum.

4. RFP Addendum Schedule

Proposals shall be submitted in strict accordance with the RFP schedule. APS will not grant any extensions to the RFP Addendum schedule and will not accept late Proposals. Any Proposal received after the scheduled date will be rejected and the Respondent will be notified accordingly.

The following schedule applies to this RFP Addendum:

Activity	RFP Addendum Deadline Date
PowerAdvocate Registration Open	April 30, 2021
RFP Addendum issued	April 30, 2021
Confidentiality Agreement DUE	May 21, 2021 at 2:00 p.m.
Redhawk site visits complete	June 4, 2021
Respondent Proposal and Proposal Fee DUE	June 25, 2021 at 2:00 p.m.
Shortlisted Respondents notified	July 16, 2021
Final selections	August 6, 2021
Contract execution	September 30, 2021

E. Miscellaneous Proposal Submittal Information

1. Currency

All prices must be clearly stated in United States Dollars.

2. Compliance

Each Respondent is responsible for acquiring and/or verifying that it is in compliance with all licenses, permits, certifications, studies, reporting requirements and approvals required by federal, state and local government laws, regulations and policies in order for it to contract for and perform in accordance with its Proposal(s).

3. Costs

Respondent is liable for all of its costs and APS is not be responsible for any of Respondent's costs incurred in responding to this RFP Addendum or in connection with the negotiation and execution of any contract as a result of the RFP Addendum process.

4. APS Safety Standards

In the event an agreement is executed between APS and Respondent, Respondent will be required to subscribe to ISNetworld, a third party safety assessment system utilized by APS. If not already a subscriber, the Respondent will be required to: (a) subscribe to ISNetworld (subscribe at www.ISNetworld.com); (b) furnish ISNetworld with the information requested by ISNetworld in connection with each subscription; and (c) maintain a subscription with ISNetworld with a "GREEN" status for the duration of the Agreement with APS. Subscribing to ISNetworld and furnishing such information will be a condition precedent to the full execution of the Agreement. There is a fee for this subscription which must be paid by the Respondent. Respondent must reply to questions on this subject in the "Commercial Data" tab under "Respondent Experience" in PowerAdvocate.

5. Reservation of Rights

APS reserves the right to accept or reject in its sole discretion any or all Proposals for any reason at any time after submittal. APS also reserves the right to select an offer that is not the lowest price, if APS determines that in its judgment the overall Proposal may result in the greatest value to APS's retail customers.

6. No Liability

Respondents that submit Proposals do so without legal recourse against APS or its officers, directors, employees, agents, contractors or the Independent Monitor based on APS's rejection of any Proposal or for failure to execute any agreement in connection with this RFP Addendum. Neither APS, nor any of its officers, directors, employees, agents, or contractors shall be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to APS's acts or omissions arising out of or in connection with this RFP Addendum.

7. Return of Documents

None of the materials received by APS from Respondents in response to this RFP Addendum will be returned. All Proposals and exhibits will become the property of APS, subject to the provisions of the Confidentiality Agreement described in Section D(3) above.

8. Proposal Fee

A non-refundable RFP Addendum submission fee (the "Proposal Fee") of ten thousand dollars ($10,000) must be submitted with each Proposal.

APS must receive the Proposal Fee by the response date shown in Section D(4) above and funds must be wired using the information below. Any costs or fees associated with wiring the funds shall be paid directly by the Respondent.

Company:	Arizona Public Service Company
Bank:	Wells Fargo
ABA/Routing No.:	121000248
Account No.:	4159540921
OBI Field:	114903; AR114903202; RFP Addendum Bid Fee; Respondent's name

9. Terms, Conditions and Pricing

Respondent shall include in each Proposal all costs necessary to deliver capacity and energy to the APS system including, but not limited to, construction of the project, transmission (if necessary), development security, post-development security, and all costs related to interconnection. Respondent will be bound to honor all terms of its Proposal, including but not limited to its price, which shall remain binding through the final selection notification and subsequent contract negotiations, as well as ACC approval (if required).

10. PowerAdvocate

Respondents are required to use PowerAdvocate to enter or upload all requested information. Respondents are encouraged to submit their Proposals as early as possible in order to avoid filing delays due to heavy use of PowerAdvocate immediately prior to the Proposal submission deadline. In order for a Respondent's proposal to be considered conforming, the Respondent shall timely post to PowerAdvocate the following documents:

a. Completed Proposal

b. Executed CA posted in PowerAdvocate no later than May 21, 2021 at 2:00 PM AZ time

c. A complete response to each question, and a legible copy of each document specified on the commercial, technical and pricing tabs of PowerAdvocate

d. Executed certification page which demonstrates that the signatory has full authority to bind the Respondent to all of the terms and conditions contained in its Proposal. Respondents must use the certification page posted by APS on PowerAdvocate.

e. Project schedule shown in weeks, based on an assumed date for contract execution (which shall be stated in the schedule)

f. Preliminary one-line diagram for the project with meter location and specified delivery location, which shall be the Delivery Point as that term is defined in the resulting agreement

g. Technical Data form, which identifies certain criteria used to calculate the expected energy production for the proposed facility. Although APS has provided certain default assumptions based on industry standards, Respondents may use criteria that differs from these assumptions by identifying the difference and reason for this variation. The energy production profile submitted by each Respondent must be calculated based on the same set of technical criteria supplied to APS by the Respondent in the Technical Data form.

Arizona Public Service Company

2022 All Source
Request for Proposals

May 16, 2022

Table of Contents

I. Overview

Arizona Public Service Company ("APS") is a regulated public utility that generates, transmits, and distributes electricity for sale in Arizona. APS is headquartered in Phoenix, Arizona. As Arizona's largest and longest-serving electric company, we generate safe, affordable, and reliable electricity for more than 1.3 million commercial and residential customers in 11 of Arizona's 15 counties.

Through a comprehensive planning process, APS determines how to meet future customer needs for reliable and affordable electricity while achieving regulatory targets and reducing environmental impacts during the planning period. APS has worked with our team of resource experts, energy planners, and cross-sector stakeholders to develop a strategic roadmap on our path to a 100% carbon-free generation mix by 2050.

This All Source Request for Proposals ("RFP") solicits competitive Proposals ("Proposal" or "Proposals") for approximately 1000 MW to 1500 MW of resources, including up to 600 MW to 800 MW of renewable resources to meet the needs identified through the Integrated Resource Plan ("IRP"), which is filed with the Arizona Corporation Commission ("ACC"). The IRP provides the strategic direction for APS's acquisition of a clean, diversified, balanced resource portfolio that meets customer needs, maintains reliability, results in reasonable energy supply costs, and mitigates market risks. It includes an interim target of achieving a 65% clean energy mix and a 45% renewable energy mix by 2030. APS is focused on integrating renewable resources, empowering customers with flexible energy options, and incorporating advanced technology to produce clean and affordable energy while providing reliable service and remaining good stewards of Arizona's diverse environment.

APS's IRP indicates a need for additional flexible summer capacity resources to meet reliability requirements and additional renewable energy resources. The identified resources support APS's commitment to clean energy and are necessary to maintain system reliability in an environment of continued customer growth, coal retirements and expiring wholesale contracts. APS's primary goal is to identify cost-effective resources that provide capacity while supporting APS's Clean Energy Commitment.

Resources offered through this RFP will be evaluated on their ability to meet one or both of the reliability and clean energy objectives.

II. Administrative Information

A. Role of 1898 & Co.

APS has retained the services of an independent consultant, 1898 & Co. ("1898 & Co."), a division of Burns & McDonnell Engineering Co. Inc. ("Burns & McDonnell"), to support the RFP process and work with APS to coordinate communications and perform the quantitative and qualitative evaluations of all Proposals. 1898 & Co. will assist with Proposal evaluations; however, APS will make the final decisions about this RFP at its sole discretion.

1. **Communications**. All Respondents will interface with 1898 & Co. for all communications related to this RFP, including questions, RFP clarification issues, and RFP Proposal submittal. All communications from Respondents to 1898 & Co., including questions regarding this RFP, should be submitted in writing via the PowerAdvocate "Messaging" tab. Depending upon the nature and frequency of the questions 1898 & Co. receives, 1898 & Co. will either respond to individual Respondents directly or post a response to the question to all Respondents in PowerAdvocate (without disclosing the Respondent's name).

2. **Questions**. Respondents can submit any questions related to the RFP on the "Messaging" tab in PowerAdvocate. However, 1898 & Co. will only respond to RFP questions received from Respondents who have submitted an executed confidentiality agreement ("CA") via the PowerAdvocate platform. As needed, a Frequently Asked Questions ("FAQ") document will be available in the "Download Documents" tab in PowerAdvocate.

3. **1898 & Co. Contact**. The PowerAdvocate "Messaging" tab is the sole medium of communication for this RFP and will be monitored and responded to by 1898 & Co. Respondents that experience any difficulty accessing PowerAdvocate should contact:

   Email: support@poweradvocate.com
   Helpdesk: 857-453-5800

   1898 & Co. will NOT respond to any questions about the RFP outside of PowerAdvocate.

B. Role of Independent Monitor

APS has also engaged an independent monitor ("IM") throughout the RFP process to ensure that it is conducted in a fair and unbiased manner. The IM provides oversight during the selection process and will have access to all documentation provided by the Respondents in response to this RFP. The IM will produce a final report summarizing its observations for use by APS, which may include submission to the ACC in connection with APS's regulatory requirements.

The IM is obligated to maintain the confidentiality of all information that it reviews.

C. PowerAdvocate Platform

Interested parties will be required to register online using the web form provided at http://www.aps.com/rfp. Registration will open on May 16, 2022. Registration enables each Respondent to access the 2022 RFP, the CA, and any FAQ document that is developed.

PowerAdvocate is subject to a confidentiality agreement with APS that prohibits the disclosure of confidential information submitted via the platform to unauthorized third parties. APS encourages each Respondent to carefully review the PowerAdvocate Terms of Use before submitting a Proposal. The Terms of Use are located at: https://www.poweradvocate.com/web/terms-of-use.html.

D. RFP Schedule

Proposals shall be submitted in strict accordance with the below RFP schedule. APS will not grant any extensions to the RFP schedule and will not accept late Proposals. Any Proposal received after the scheduled date will be rejected, and the Respondent will be notified accordingly.

Event	Important Dates
RFP Release	May 16, 2022
Confidentiality agreement DUE	May 30, 2022
Bidder's Conference	June 8, 2022
Proposal(s) DUE	July 8, 2022
Proposal fee(s) DUE	July 8, 2022
Shortlist Respondents notified	August 2022
Final selections	September 2022
Anticipated contract execution	September – December 2022

1. **Bidder's Conference**. A bidder's conference will be held virtually on June 8, 2022, to provide information and answer questions that potential Respondents have about the RFP. We expect to focus on aspects of the RFP that may be new to our audience, such as the index pricing for solar and battery energy storage resources. Instructions on how to participate in the bidder's conference will be made available in PowerAdvocate.

III. Summary of Resources Needed

APS is requesting resources that will provide reliable capacity to meet summer peak needs plus reserve margins and provide additional renewable energy as part of our energy mix. APS is seeking approximately 1000 MW to 1500 MW of resources, including up to 600 MW to 800 MW of renewable resources.

APS requests competitive Proposals for capacity resources and renewable energy resources providing a minimum of 5 MW with in-service dates in either 2025 or 2026. Several variables may impact the specific type and timing of resource additions, such as contribution to peak, higher production levels of renewables, and costs associated with project timing. Projects may achieve in-service in phases over multiple years, beginning as early as December 1, 2024, and as late as December 31, 2026. To further accommodate a phased-in approach and optimize customer value, APS will accept Proposals for projects that reach full completion and commercial operation as late as June 1, 2027, provided that construction on any such project must begin no later than 2026 and the project must be partially in service in 2026.

If a significant number of Proposals are received, APS will prioritize negotiations for 2025 resources ahead of 2026 resources. It is expected that 2026 negotiations may occur up to a few months after 2025 negotiations.

APS expects a resource that provides reliable summer capacity and energy to have significant economic value. Energy that is non-dispatchable by APS and is proposed as must-take energy will generally be viewed and evaluated less favorably. In addition, clean, flexible, dispatchable resources are increasingly important in helping APS meet its clean energy goals, maintain system reliability, and will be valued accordingly. APS needs flexible resources that are shapeable and responsive to changes in actual customer demand.

APS must maintain a reliable electric system, which includes having firm capacity plus reserves to meet customer demands and reliability needs during summer system peak load times. APS must be able to respond to changes in customer demands or supply needs in real-time, and APS seeks to develop a portfolio of resources that will enable it to do so.

APS will consider the value for both the capacity component and the energy component for all Proposals.

IV. Eligible Respondents and Resources

A. Respondent Experience

APS is seeking Respondents that have demonstrated significant previous experience developing resources (or resource options) of a similar nature to those resources included in Respondent Proposal(s).

For any Proposal with a project size greater than 25 MW, Respondent must demonstrate that it and its Partner(s), as applicable have previously developed a project to the point of commercial operation that is at least 50% of the MW or MWh of the size of the proposed project and have been operational for electric grid service for at least three years with an average annual availability greater than 90%.

In the case of a Proposal with a project size less than or equal to 25 MW, Respondent must demonstrate that it and its Partner(s), as applicable, have previously developed a project to the point of commercial operation that is at least ten percent (10%) of the size of the proposed project, and that is of similar technology.

Information about other characteristics that speak to Respondent experience is solicited in PowerAdvocate and will be considered in the Proposal evaluation process.

B. Front of the Meter Resources

APS will accept Proposals for existing or new resources for the following supply side, or front of the meter ("FTM"), technologies (either stand-alone or in combination, such as solar plus storage):

- Solar
- Energy Storage
- Wind
- Biomass/Biogas
- Geothermal
- Landfill Gas
- Reciprocating Units
- Simple cycle combustion turbines
- Combined cycle combustion turbines
- Hybrid resources (alternating current ("AC") coupled)

APS will <u>not</u> accept Proposals for transactions not directly backed by a specific generating asset or utility system, such as call options or wholesale market products. In addition, APS is seeking Proposals for FTM resources that operate autonomously and can be controlled remotely with the APS Automatic Generation Controls ("AGC"), with an interface to APS's Energy Management System ("EMS") through APS's Remote Terminal Unit ("RTU") to be installed at the Respondent's project site. APS may include the associated capacity and energy sold to APS for use in the California Independent System Operator ("CAISO") Energy Imbalance Market. APS will accept Proposals that offer a minimum of 5 MW per site with a preference for Proposals greater than 200 MW. For Proposals that combine technologies, the aggregate offering must be 5 MW or greater. To safeguard system integrity and mitigate risk, APS prefers proposed resource interconnection configurations that limit any single point of failure to 400 MW.

C. Behind the Meter Resources

APS will accept Proposals for the following demand side, or behind the meter ("BTM"), resources or programs (either singular or in combination):

- Demand Response (both commercial & industrial and residential)
- Energy Efficiency

For BTM resources, APS is seeking Proposals that offer a minimum of 5 MW and aggregate APS customer load accordingly. For Proposals that combine resources or programs, the aggregate offering must be 5 MW or greater. Any Respondent that submits a Proposal for a BTM resource should consider whether such resource could be capable of AGC control by APS and potential use in the CAISO Energy Imbalance Market. Proposals that include such capability may be more favorably evaluated than those that do not.

D. Site / Land Control

APS expects each Respondent to demonstrate sufficient site control, effective as of Proposal submission and continuing through the term of the associated agreement with APS. The types of agreements that can be used to demonstrate site control appear as a drop-down selection within each technical data sheet under the "Technical Data" tab in PowerAdvocate and do not include a letter of intent or any other similar non-firm agreement. Additionally, APS expects any Proposal for a resource to be developed wholly or partially on state-owned land to demonstrate that Respondent is scheduled for lease approval on the AZ State Land Board of Appeals Meeting Notice and Agenda on a date before Proposals are shortlisted (August 2022) to satisfy APS's site control requirement. APS will NOT consider any Proposal for a facility to be developed on an existing APS-owned site.

V.Eligible Transaction Structures

APS will evaluate Proposals that incorporate any one of the transaction structures included in the list below. APS expects Respondents to submit a copy of the relevant term sheet, redlined to reflect Respondent's required modifications, if any. APS's term sheets for each type of transaction structure can be found in the "Download Documents" tab in PowerAdvocate.

Power Purchase Agreement ("PPA"):

- Renewable energy Tolling*
- Renewable energy plus energy storage Tolling*
- Renewable energy
- Energy storage Tolling*
- Thermal Tolling

Build-Transfer Agreement ("BTA"):

- Renewable energy
- Renewable energy plus energy storage
- Energy Storage

Load Management Agreement:

- BTM demand response programs
- BTM energy efficiency programs

*For Proposals offering a PPA or tolling agreement structure (other than for a thermal resource), APS prefers that Proposals incorporate an option for APS to ultimately purchase the resource.

NOTE: If the Respondent's Proposal represents a combination of technologies, it is incumbent upon the Respondent to review the term sheet applicable to each type of technology and include any applicable term sheet as part of its Proposal, together with any required modifications described above.

VI. Proposal Pricing

A. General

APS expects final Proposal pricing to include all costs, including but not limited to interconnection network upgrade costs, financing costs, energy delivery costs, project direct interconnection costs, and provision of required collateral for pre-and post-development security. If specific interconnection costs are not known, Respondents are expected to make reasonable estimates and include those in their Proposal pricing. More specific information about pre-and post-security is set forth in Section VI.C. Pricing should assume the tax credit strategy applicable to the Proposal, as set forth in Appendix B and described in Respondent's Executive Summary. Pricing should also assume only such antidumping duty/countervailing duty ("AC/CVD") tariffs as apply to the Proposal at the time of submission and not any tariffs that may result from the current Department of Commerce investigation. The potential impact of any future AD/CVD tariffs that could be imposed in the future, and Respondents' risk mitigation strategies therefor, should be addressed in the Executive Summary as set forth in Appendix B.

Respondents should note that the "Pricing" tab in PowerAdvocate is not used for this RFP. Instead, APS expects Respondent to provide Proposal pricing with each applicable technical data sheet under the "Technical Data" tab in PowerAdvocate. All prices must be clearly stated in United States Dollars. Failure by a Respondent to include all costs in Proposal pricing, which enables fair comparison of all Proposals, may result in a Respondent's Proposal being eliminated from further evaluation.

B. Pricing Structure

APS expects the Proposal price for a PPA tolling agreement to either be fixed for the duration of the proposed agreement term or to escalate at a fixed annual escalation rate. APS will not accept Proposals with escalation rates tied to any index, with the exception of the specific indices applicable to solar and battery storage technologies as described below. APS acknowledges the current uncertainty associated with tariffs, supply chain, and logistics for solar panels and batteries. To manage that uncertainty while also enabling fair comparison of prices for all Proposals, APS requires that Proposals for solar and/or battery storage resources include pricing based on costs expected at the time of Proposal submission. Then, APS requires that each Respondent indicate the weighted average impact of each of the indices listed below on the total Proposed price. Proposal pricing would be subject to fluctuations in the following indices, in proportion to the weighted averages proposed by Respondent, until contract execution:

- Marine cargo – Freightos FBXO1 Index
- Overland freight – Bureau of Labor Statistics Index # PCU484121484121
- Steel – CME Group CRU Index

- Aluminum – Mining.com Aluminum Index
- Copper – Mining.com Copper Index

In addition, the price of materials such as lithium carbonate and polysilicon may also materially impact the pricing of solar and battery storage Proposals. APS has not included specific indices for those materials in the weighted average, but is interested in knowing each Respondent's assessment of the impact of price fluctuations for such materials on its Proposal(s). That assessment should be included in the appropriate fields where requested in PowerAdvocate.

APS anticipates that during negotiations for any solar or battery storage resource with index-based pricing that there will be established a price cap, above which APS would expect to terminate negotiations.

C. Collateral

APS requires collateral to be posted, in the form of cash or a letter of credit only, to secure Respondent's obligations in connection with any transaction contracted for as a result of this RFP. In the case of a letter of credit, it must be in the form and from an issuing bank acceptable to APS in its sole discretion. As described in Section VI.A, APS requires that all costs of such collateral be included in Proposal pricing. The following information should be used by each Respondent to determine the collateral that will be required in connection with its Proposal(s) and to include the costs of such collateral in Proposal price accordingly.

Resource	Contract Structure	Contract Execution	Post COD
New Energy Storage	PPA	$70/kWh	$55/kWh
Existing Energy Storage	PPA	$55/kWh	$55/kWh
New Energy Storage	BTA	$70/kWh	$55/kWh held until warranty period expires
New Renewable or Thermal	PPA	$100/kW	$40/kW
Existing Renewable or Thermal	PPA	$40/kW	$40/kW
Renewable	BTA	$100/kW	$40/kW held until warranty period expires
Energy Efficiency (EE)	Load Mgmt. Agreement	$100/kW	$40/kW
Demand Response (DR)	Load Mgmt. Agreement	$100/kW	$40/kW

**If a combined technology is being offered (i.e., solar plus battery storage), the higher of the two collateral requirement amounts (in such case, battery storage) is the collateral requirement that must be used.*

D. Interconnection

The following information is intended to guide Respondents as they consider the interconnection of their proposed resources and include all the associated costs in their Proposal pricing. Note, however, that nothing in this Section VI.D. or elsewhere in this RFP is intended to provide definitive guidance to any potential Respondent regarding the specifics of the interconnection process that may apply to the Respondent's proposed facility.

APS is seeking Proposals that interconnect directly to the APS transmission system. Each Respondent must demonstrate that it has or can secure firm transmission for delivery from the facility to the APS transmission system for the entire proposed term of the relevant transaction. Respondents should be aware that connection to an APS substation may not guarantee connection to the APS transmission system as required. Any additional firm transmission service needed to connect a proposed facility to the APS transmission system is the Respondent's responsibility and should be included in the Respondent's Proposal.

Respondents are advised to review the most complete and up-to-date information regarding interconnection on APS's Open Access Transmission Tariff ("OATT"). http://www.oasis.oati.com/azps/index.html.

1. **Interconnection Application and Studies:** APS recognizes that the timeline for executing an interconnection agreement is critical in the development process. For purposes of this RFP, APS will not require any Respondent to enter the APS interconnection queue process unless and until its Proposal is selected for Shortlist evaluation, which APS expects to determine on or around September 1, 2022. Respondents should note that there are locations within the APS system that have more interconnection requests than other locations; the application processing time for those more active locations may be greater. Each proposed facility must be constructed and interconnected to meet proposed capacity and energy deliveries by the in-service dates established in this RFP. The interconnection queue at each location is available to the Respondents at the APS OASIS site referenced above. Nevertheless, each Respondent is responsible for performing its diligence regarding the interconnection process and determining when it should submit its application to the APS interconnection queue and otherwise participate in the interconnection process to meet the requirements of this RFP.

2. **Energy Delivery Costs:** Pricing included in any Proposal must be based on delivery to the APS system. If the Respondent proposes to interconnect directly to the APS system, all losses between the generating station and the demarcation point for equipment ownership and transfer to APS (typically referred to as the Delivery Point in the relevant agreement with APS) are the Respondent's responsibility. If the Respondent proposes to interconnect to another utility's system, all

transmission wheeling costs to transmit project energy to the APS system on a firm basis are also the Respondent's responsibility and must be included in the Proposal price.

3. **Project Interconnection Costs:** Each Respondent must include reasonable interconnection cost estimates as part of its submitted Proposal. Interconnection costs must be provided within the appropriate technical data sheet under the "Technical Data" tab in PowerAdvocate. Respondents may, at their discretion, utilize third-party consultants to determine accurate interconnection estimates. A detailed description of such interconnection costs must accompany each Proposal and include a breakdown of the significant equipment costs. For interconnection related questions or information, please contact:

APS Interconnections
e-mail: INTERDEV@apsc.com
URL: http://www.oatioasis.com/azps/index.html

VII. Technical Requirements

APS expects Respondents to provide technical information for each resource in the appropriate technical data sheet found in the "Technical Data" tab in PowerAdvocate. The technical data sheets identify specific criteria used to calculate the expected energy production for the proposed facility. Although APS has provided certain default assumptions based on industry standards, Respondents may use criteria that differ from these assumptions by identifying the difference and reason for this variation. The energy production profile submitted by each Respondent must be calculated based on the same set of technical criteria supplied to APS by the Respondent in the technical data form.

All available capacity, energy, and ancillary services are for use exclusively by APS. Ancillary services may include frequency response, spinning reserve, non-spinning reserve, reactive power control, fixed power factor, and automatic voltage regulation. Any Proposal for a generating or energy storage resource must include pricing for the proposed resource for any preceding ancillary service capabilities included in the Proposal.

The following sections list additional minimum requirements for each technology type and "APS Preferences" associated with each. Satisfaction with any APS Preferences is not required for a Proposal to be deemed conforming. Proposals that contain more of the APS Preferences may be more competitive than those with fewer APS Preferences.

A. Energy Storage

1. **Requirements:** Any energy storage Proposal must conform to the requirements for all Proposals set forth in Section IX and the following requirements:
   a. Transaction Structure. PPA or tolling agreement term at least five (5) years and not more than twenty (20) years. If the proposed term is something other than ten (10) years, Respondent must provide indicative ten (10)-year pricing in its Executive Summary, as described in Appendix B.
   b. Technology. Proposals may include only the following technologies:
      i. Battery energy storage system ("BESS")
      ii. Flywheel
      iii. Pumped storage hydropower
      iv. Compressed air energy storage system ("CAES")
      v. Other energy storage technologies that meet the minimum requirements of this RFP
   c. Technical Characteristics
      i. Any proposed facility must meet all BESS safety requirements specified in the APS "Appendix W" (which specifies APS's safety standards and will be provided to Respondents separately through PowerAdvocate), which can be found in the "Download Documents" tab in PowerAdvocate. Proposal pricing shall include

all testing, equipment, and design necessary to satisfy such safety requirements.

ii. Any proposed facility must be capable of operating within the 50-year Extreme Annual Design Conditions, as detailed in the American Society of Heating, Refrigeration, and Air Conditioning Engineers ("ASHRAE") Handbook, using a weather station nearest to the project location, at 100% of the proposed contract capacity discharging for a minimum of four (4) consecutive hours.

iii. Proposed projects must allow for 365 equivalent cycles per year with an average annual state of charge of 50%. To maximize the flexibility that APS seeks, the 365 annual cycles can assume days where the resource is cycled more than once and days where the resource is not cycled at all. Information related to alternate duty cycles can be included in the Executive Summary. Respondents are encouraged to propose other technical or commercial methods that will enable APS flexibility to adjust the number of annual cycles over the term of the agreement (i.e., adjustments/credits, cycle banking, etc.)

iv. Any proposed facility must be capable of satisfying a monthly availability requirement (as that term is defined in the applicable agreement with APS) of at least 97% for non-summer periods and 98% for summer periods during the term of the agreement.

v. If included as a hybrid resource to utilize the value of the ITC, BESS must be capable of grid charging post expiration of the ITC.

vi. BTA agreements must be AC coupled and include an augmentation plan.

vii. PPA proposal pricing does not require an augmentation plan and can either be AC or DC coupled.

2. **Preferences:** Though not required, APS prefers the following characteristics in Proposals for energy storage resources:

a. APS prefers a technology that has already undergone safety testing, safety evaluations, and safety designs, as evidenced by test results and other supporting documentation included in the Proposal in accordance with "Appendix W" (which specifies APS's safety standards and will be provided to Respondents separately through PowerAdvocate). Proposals that plan to undergo safety testing, safety evaluations, or safety designs for the proposed technology after contract execution will be viewed less favorably.

b. APS prefers a facility able to deliver the full proposed contract capacity for a duration of longer than four (4) consecutive hours to meet peak needs.

c. APS prefers a facility located in APS's service territory and interconnected to APS's transmission or sub-transmission system (69kV or higher).

d. APS prefers a facility that charges in a timeframe as close to matching the amount of time it takes to discharge and does not de-rate the power capacity of the facility as it reaches the high or low end of the state of charge. A facility with the ability to have more than one equivalent cycle per day will be viewed favorably.
e. APS prefers land owned by the developer or purchase option. For land lease agreements, APS prefers at least 42 years.
f. APS prefers a facility that can provide reactive capabilities in excess of the minimum Interconnection Requirements and can also provide reactive capabilities without the need to be producing real power (i.e., grid-sourced reactive power).

B. Renewable Energy Technologies

1. **Requirements:** Any renewable energy technology Proposal must conform to the conforming requirements for all Proposals outlined in Section IX and the following requirements.
   a. Transaction Structure. PPA or tolling agreement term at least five (5) years and not more than twenty (20) years, or build own transfer agreement. If the proposed term is something other than ten (10) years, Respondent must provide indicative ten (10)-year pricing in its Executive Summary, as described in Appendix B. The PPA or tolling agreement must give APS ownership of all environmental attributes, as that term will be defined therein.
   b. Technology. Eligible renewable energy resources are those defined in A.A.C. R14-2-1802(B): Eligible Renewable Energy Resources are applications of the following defined technologies that would otherwise be used to provide electricity to APS customers:
      i. Biogas Electricity Generator
      ii. Biomass Electricity Generator
      iii. Eligible Hydro Facilities
      iv. Fuel Cells that Use Renewable Fuels
      v. Geothermal Generator
      vi. Hybrid Wind and Solar Electric Generator
      vii. Landfill Gas Generator
      viii. Solar Electricity Resources
      ix. Wind Generator
   c. Technical Characteristics
      i. Renewable energy projects must offer operational flexibility, which can be achieved through a tolling agreement structure or a PPA that includes curtailment rights. Proposals should be clear about the operational flexibility being offered and how that flexibility can be maximized to achieve the greatest value for APS.
      ii. Any proposed facility must be capable of operating within the fifty-year Extreme Annual Design Conditions, as detailed in the ASHRAE Handbook, using a weather station nearest to the project location at 100% of the proposed contract capacity.

iii. Any Proposal for a solar photovoltaic facility shall include four (4) hourly production profiles (i.e., 8760 profiles), which represent the hourly output of the project at the APS Delivery Point in Mountain Standard Time ("MST") for years 2006, 2007, 2009 and Typical Meteorological Year ("TMY"). The TMY, 2006, 2007, and 2009 profiles shall be based on site-specific data derived from National Renewable Energy Laboratory ("NREL") Solar Prospector in .tmz and .csv file formats.
iv. Any Proposal for a wind facility shall provide on-site wind data used in preparing 8760 production profiles as well as the method(s) for collecting on-site wind data in the
v. spreadsheet found in the "Download Documents" tab in PowerAdvocate

2. **Preferences:** Though not required, APS prefers the following characteristics in Proposals for renewable energy resources:
   a. APS prefers a facility that maximizes the amount of energy production that it will generate and deliver during the months of June through September between the hours of 3:00 pm and 9:00 pm Arizona time.
   b. APS prefers a facility that can provide reactive capabilities in excess of the minimum Interconnection Requirements and can also provide reactive capabilities without the need to be producing real power (i.e., grid-sourced reactive power).

C. Energy Efficiency

1. **Requirements:** Any Proposal for energy efficiency or other BTM, non-dispatchable resource (referred to herein as "Energy Efficiency") must conform to the minimum requirements for all Proposals outlined in Section IX and the following requirements.

   Respondents assume the risk and impact of any future APS rate design changes when submitting a Proposal for an Energy Efficiency resource. In addition, nothing in this RFP shall limit APS's ability to offer its own Energy Efficiency programs in the future, regardless of whether or not it enters into a load management agreement for an Energy Efficiency resource as a result of this RFP.
   a. Transaction Structure. Must offer an energy efficiency resource pursuant to a Load Management agreement that satisfies the terms specified in the term sheet found on the PowerAdvocate "Download Documents" tab for a term of at least five (5) years but not more than ten (10) years. The agreement must permit APS to count any energy savings resulting from the proposed resource toward any established ACC Energy Efficiency goal and/or any other future regulatory requirements.
   b. Technical Characteristics

i. Any proposed resource must pass the Societal Cost Test ("SCT") as defined by the ACC Energy Efficiency Standards defined in Arizona Administrative Code R14-2-2401(36). APS will screen all Energy Efficiency Proposals using the SCT as prescribed by the ACC. All Respondents must provide input assumptions and calculations to pass the Societal Cost Test.
ii. Any proposed resource must be APS-branded.
iii. Any proposed resource may only aggregate customers within the APS service territory.
iv. Any Proposal must include a proposed Measurement and Verification Plan ("M&V Plan") to verify actual MWh & MW savings delivered, including estimated costs for implementing the M&V Plan. Load reductions must be verifiable by APS by using then-available APS metering. Resources that are educational in nature only (i.e., do not include tangible energy efficiency products) and do not result in MWh and MW savings delivered are not eligible.

2. **Preferences:** Though not required, APS prefers the following characteristics in Proposals for energy efficiency programs
   a. APS prefers a system that passes the Ratepayer Impact Measure ("RIM") test and otherwise demonstrates cost-effectiveness through other tests such as the utility cost test and the participant test.
   b. APS prefers a system capable of operating at 115° F and twenty percent (20%) humidity, at 100% displaced capacity for a minimum of four (4) consecutive hours.
   c. APS prefers a system that displaces energy during the months of June through September and between the hours of 3:00 pm and 9:00 pm Arizona time.

D. Demand Response

1. **Requirements:** Any Proposal for demand response or other BTM dispatchable resource (referred to herein as "Demand Response") must conform to the minimum requirements for all Proposals outlined in Section IX and the following requirements.

   Respondents assume the risk and impact of any future APS rate design changes when submitting a Proposal to APS. In addition, nothing in this RFP is intended to limit APS's ability to offer its own demand response programs of any type in the future, regardless of whether or not it enters into a demand response load management agreement as a result of this RFP.

   Consistent with the premise that APS does not intend to provide multiple compensation streams for the same demand side management services, Proposals may not include capacity already participating in existing APS demand-side incentive programs. In other words, the capacity included in the Proposal must be distinct from capacity that APS has already secured through existing APS demand response programs, including, but not limited to, the residential Cool Rewards, the Commercial/Industrial Peak Solutions program, and the Residential Energy Storage Pilot.

Similarly, while APS does not prohibit distributed demand side management technologies that have received a rebate or been counted towards energy efficiency, demand-side management, or renewable mandates from participating in this RFP, Proposals shall only include DDSRs that are incremental to and not in conflict with their participation in current APS programs. For example, a smart thermostat that received an APS rebate for energy efficiency at the time of installation would be eligible to participate in DDSR aggregation offering demand response services. However, if this same thermostat is currently enrolled in the APS Cool Rewards demand response program, it would be ineligible to offer demand response peak capacity value in a DDSR aggregation. This same thermostat could still participate by providing other grid services, such as load shifting. As another example, from the Residential Energy Storage Pilot, only those enrolled in the data-only portion of the pilot can participate. Customers enrolled in the capacity-sharing portion of the pilot will be ineligible. All Proposals that include dual participation DDSRs should clearly identify these resources in Proposals and clearly demonstrate how they provide incremental grid value. Note that the basis of compensation for these dual participation resources will be limited to their incremental value only after accounting for grid services that APS has already paid for through other mechanisms (i.e., incentives or retail rates). Respondents must also indicate how any grid services they propose for dual participation resources will not conflict with any current grid services that APS has already obtained from these DDSRs while considering potential customer experience issues that could occur related to dual participation (e.g., fatigue from too many demand response and load shifting events).

Proposals may also not include residential, commercial, or industrial customers enrolled on a rate schedule/tariff where third-party providers provide the generation component. These programs/rates currently include Alternative Generation-X, Interruptible Rate Rider, and Critical Peak Pricing-General Service.

a. <u>Transaction Structure.</u> Must offer a demand response program pursuant to a load management agreement that satisfies the terms specified in the term sheet found on the "Download Documents" tab in Power Advocate with a term of at least five (5) years but not more than ten (10) years. The agreement must permit APS to count any energy savings that result from the proposed program toward any ACC Energy Efficiency goal and/or any other future regulatory requirements.
b. <u>Technical Characteristics</u>

i. Any Proposals must provide for commercial operation and delivery of capacity beginning on June 1, 2025 or June 1, 2026. All Proposals must provide capacity during the months of June through September during each year of the term of the load management agreement (the "Control Season").

ii. Proposals must offer a minimum of 5 MW of (incremental or additional) capacity per year, aggregated from eligible APS commercial and industrial ("C&I") or residential customer load.

iii. The resource must be dispatchable a minimum of eighteen (18) times during each Control Season, June through September, during any Program Availability Hour, 4:00 PM to 9:00 PM, Arizona Time.

iv. The resource must respond with two (2) hours prior notice.

v. The resource must be capable of delivering guaranteed load reduction for five (5) consecutive hours.

vi. The resource must be capable of performing for a minimum of three (3) consecutive days.

vii. The resource must provide one hundred percent (100%) of the contracted load reduction each Monday through Friday and eighty percent (80%) of the contracted load reduction each Saturday, Sunday, July 4th, and Labor Day during the Control Season.

viii. Load reductions must be verifiable by APS using APS-owned Advanced Metering Infrastructure ("AMI") metering.

ix. The resource may only aggregate eligible customers within the APS service territory.

x. The resource must be APS-branded.

2. **Preferences:** Though not required, APS prefers the following characteristics in Proposals for energy efficiency programs
   a. APS prefers a resource capable of more than eighteen (18) dispatches per Control Season.
   b. APS prefers a resource that responds with one (1) hour prior notice. Respondents should explain (in the Executive Summary) if responding with one (1) hour prior notice will result in any cost increase to APS, as compared to a two (2)-hour prior notice requirement.
   c. APS prefers a resource that can reduce the load for longer than five (5) hours.
   d. APS prefers a resource that can reduce the load if called upon by APS for five (5) consecutive days or more.
   e. APS prefers a resource that can provide one hundred percent (100%) of the DR Capacity during all seven (7) days of the week, including July 4th and Labor Day, during the Control Season.
   f. APS prefers a resource that can be contracted with APS for a shorter term rather than a longer term to enable APS to be responsive to future load changes.

E. Thermal Generation

1. **Requirements:** Any Proposal for a thermal generation resource must conform to the minimum requirements for all Proposals outlined in Section IX and the following requirements.
    a. Transaction Structure. Must be in the form of a tolling power purchase agreement with a delivery term of at least three (3) years and not more than eight (8) years and a delivery period of May 1 through October 30. Proposals must also include the Respondent's plan, if any, to reduce carbon emissions over the term of the proposed transaction, including through the use of clean hydrogen or by other means. APS considers "clean hydrogen" to be hydrogen produced through means that release few to no carbon emissions during the reaction period.
    b. Technical Characteristics
        i. Proposed gas-fired generation resources must be able to connect to a viable interstate natural gas pipeline. APS will evaluate the proposed point of connection to see if any constraints are specific to that location.
        ii. Proposed resource must have adequate water rights to support performance for the full contract capacity and the proposed term of the tolling agreement.
        iii. Proposed resource shall be capable of operating at 100% contract capacity for a minimum of six (6) consecutive hours.
        iv. The Proposed resource must be fully dispatchable by APS using AGC.
        v. To the extent that carbon allowances are allocated to the proposed resource or part thereof, those allowances must be provided to APS for the term of the associated tolling agreement at no additional charge. APS may allocate them toward its requirements pursuant to any applicable regulatory requirements.
        vi. APS evaluates gas turbine performance on the following parameters:
            1. Assumed elevation of 1,000 ft.
            2. June-September temperatures at 105°F and Relative Humidity of 19%
                a. Equivalent to 115°F and Relative Humidity of 9.5%.
                b. Assumes inlet cooling
            3. October, March-May temperature 73°F and Relative Humidity of 37%
                a. Assumes inlet cooling
            4. November-February temperature 41°F and Relative Humidity of 51%
                a. Inlet Cooling is assumed off

2. **Preferences:** Though not required, APS prefers the following characteristics in Proposals for thermal resources
    a. APS prefers a resource capable of stable operation at a minimum operating level of twenty-five percent (25%) loading or lower without exceeding the legal limits for emissions (CO, CO2, NOx, SO2, VOC, PM10) pursuant to an applicable air permit or otherwise.
    b. APS prefers a resource capable of at least two (2) starts per day.
    c. APS prefers a resource with a minimum ramp rate of ten percent (10%) per minute of summer capacity rating.
    d. APS prefers a resource capable of full contract capacity at 118°F and Relative Humidity of 20%.
    e. APS prefers a transaction that allows APS the option to supply any fuel and related gas transportation for delivery to the lateral pipeline interconnection for the facility.
    f. APS prefers a connection to both the El Paso and Transwestern pipelines for a natural gas resource.

VIII. Selection Process

If at any time during the Proposal evaluation process, APS determines that a Proposal does not meet the requirements, including timely submission of all documents and fees required pursuant to this RFP, or fails to remain competitive with other Proposals through screening or other more detailed analyses, such Proposal will be eliminated from further consideration and the Respondent will be notified accordingly.

The Proposal evaluation process includes three primary parts: initial screening, a qualitative/quantitative analysis, and a portfolio evaluation, the details of which are provided below. Additionally, APS is requesting a wide range of information that may not all be formally included in the three aforementioned parts of the evaluation. That does not mean that the information won't be factored into APS's short list or final selection of Proposals. Rather, that information, in the aggregate, will inform APS selections between otherwise competitive Proposals. APS will also apply an overall risk evaluation that considers diversity of suppliers and technologies in order to appropriately mitigate risks associated with single points of failure in our resource acquisition plan.

A. Initial Screening

APS expects all Proposals to be complete in accordance with the requirements set forth in this RFP. APS and 1898 & Co. will initially screen all Proposal for completeness and APS reserves the right to make a reasonable judgment about the degree to which any Proposal does or does not conform to the requirements. Respondents may be given an opportunity to cure modest deviations from the requirements, but any significant deviations (either in substance or quantity) may result in a Proposal being rejected as non-conforming.

To facilitate the initial screening, each Respondent must complete the "Proposal Checklist" found in the "Commercial" tab in PowerAdvocate.

B. Quantitative / Qualitative Analysis

For Proposals that satisfy the initial screening for completeness, APS and 1898 & Co. will perform an analysis that applies specific quantitative and qualitative criteria. Proposals will be grouped by technology and ranked following the application of the scoring matrix set forth in Appendix C. Proposals that score competitively will be further evaluated through a portfolio evaluation.

C. Portfolio Evaluation

The portfolio evaluation considers the fit of a Proposal relative to APS's existing resources, other Proposals, projected resource needs, and further qualitative evaluation.

APS will utilize resource planning models, and production cost modeling software to evaluate how well a Proposal meets system reliability requirements while minimizing projected APS system costs. Resources will be evaluated within the APS portfolio based on present value revenue requirements ("PVRR") for the APS system. For non-supply side resources APS may perform Ratepayer Impact and Total Resource Cost tests.

APS will not disclose to Respondents the generation cost estimates used for Proposal evaluation but will provide that information to the Independent Monitor referenced in Section II.B. Further, APS's avoided capacity and energy values are proprietary data and will not be disclosed to Respondents.

D. Shortlisting Process

At APS's sole discretion, Proposals that satisfy the qualitative/quantitative screening and portfolio evaluation may be shortlisted for further evaluation. APS will notify shortlisted Respondents, if any, along with those Respondents whose Proposals have been eliminated from further consideration, in accordance with the RFP schedule outlined in Section II.D.

APS may conduct meetings or phone calls with shortlisted Respondents to better understand each Proposal. APS may also require shortlisted Respondents to submit the project and/or Respondent-specific pro forma financial statements by year for the applicable facility development and construction period, including income statements, balance sheets, and statements of cash flows. APS may then re-evaluate each shortlisted Respondent's Proposal, including any new information provided during or as a result of the shortlist meetings, in a manner similar to the evaluation process described above.

E. Shortlisting Final Evaluation and Selection

Following the shortlist process described above, APS may make a final selection of one or more Proposals for negotiation of an agreement in a form substantially similar to that set forth in the relevant term sheet. APS will notify shortlisted Respondents whose Proposals are eliminated from further consideration in accordance with the RFP schedule outlined in Section II.D. APS reserves the right, in its sole discretion, to not select any Proposals for negotiation of an agreement if warranted by its evaluation.

IX. Required Documents and Information

A. Confidentiality Agreement

Each Respondent must sign the CA available in the "Download Documents" tab in PowerAdvocate and upload the signed copy via the "Upload Documents" tab no later than May 30, 2022. Any Respondent that fails to upload in PowerAdvocate its executed CA by this deadline will be ineligible for further participation in this RFP.

APS requires all Respondents to execute the CA as written without any changes. Upon receipt, APS will execute and upload a copy of the fully executed CA to each Respondent in PowerAdvocate. Respondents can then download the executed CA from PowerAdvocate at their convenience. Once APS has executed the CA, the Respondent will receive relevant messages and notices through the "Messaging" tab in PowerAdvocate. Once the May 30th due date for CA agreements from Respondents has passed, the Respondent will have access to all RFP-related documents. RFP-related documents include term sheets and data sheets necessary to submit Proposals.

In some cases, a Respondent may partner with another entity (each such entity, a "Partner") to meet the minimum experience requirements established in this RFP. In such cases, the Respondent must include the signature of authorized representatives of each such Partner as part of its fully executed CA. Any Respondent that requires a Partner to submit the Proposal must also demonstrate to APS's reasonable satisfaction that the partner relationship has been legally established, is legally enforceable, and allows Respondent to meet the minimum experience requirements.

Without the signature of any applicable Partner, a Respondent does not have permission to share confidential information (as defined in the CA) with such Partner, and such Partners' experience will not be considered in APS's evaluation of the relevant Proposal.

B. Proposal

The information provided by Respondent in PowerAdvocate constitutes the Proposal. Each Respondent must use the PowerAdvocate platform to upload all information pertaining to its Proposal(s), in accordance with all requirements and instructions set forth in this RFP and in PowerAdvocate. Respondents are encouraged to submit their Proposals as early as possible to avoid filing delays due to heavy use of PowerAdvocate immediately before the Proposal submission deadline of July 8, 2022.

For a Respondent's Proposal to be considered conforming, the Respondent must complete and/or upload (in the case of documents) the following, within the PowerAdvocate platform and in the format required, no later than July 8, 2022.

Non-conforming Proposals may be eliminated from further consideration, as described in Section VIII.A.

1. **Conforming Proposal:**
   a. A complete response to each question and a legible copy of each document specified in "Download Documents" tab in PowerAdvocate.
      i. This includes, but is not limited to, the Cybersecurity Third Party Risk Review Questionnaire ("TPRR") and the Data Security and Privacy Addendum ("DSPA").
   b. Executive Summary, described in Section IX.C.
   c. Executed Proposal certification, described in Section IX.D.
   d. Project schedule, shown in weeks, based on an assumed date for contract execution (which shall be stated in the schedule).
   e. Preliminary one-line diagram for the project with meter location(s) and specified delivery location, which shall be the Delivery Point as that term is defined in the resulting agreement.
   f. Technical Data form, which identifies specific criteria used to calculate the expected energy production for the proposed facility. Although APS has provided certain default assumptions based on industry standards, Respondents may use criteria that differ from these assumptions by identifying the difference and reason for this variation. The energy production profile submitted by each Respondent must be calculated based on the same set of technical criteria supplied to APS by the Respondent in the Technical Data form.
   g. If proposing energy storage, include documentation that supports compliance with "Appendix W" (which specifies APS's safety standards and will be provided to Respondents separately through PowerAdvocate) and demonstrates product and personnel safety.

C. Executive Summary

Respondents are expected to provide an Executive Summary for ease of initial Proposal review by APS and 1898 & Co. Details and requirements for the Executive Summary are set forth in Appendix B to this RFP

D. Proposal Certification

APS expects Respondents to provide a Proposal certification form that demonstrates that the signatory has full authority to bind the Respondent to all of the terms and conditions contained in its Proposal. The Proposal certification document that all Respondents must use is located in the "Download Documents" tab in PowerAdvocate.

E. Cybersecurity Documents

Cybersecurity is critically important to the APS system and must be evaluated in connection with any resources that will directly or indirectly touch the system. Following the CA deadline, APS will provide to participating Respondents certain documents that allow APS to assess Respondents' cybersecurity maturity and any cybersecurity risks that may be associated with proposed resources.

X. Proposal Fee and Proposal Submittal Guidelines

Respondents may submit one or more Proposals. A Respondent that wishes to submit more than one Proposal must register on the PowerAdvocate platform as a separate entity for each Proposal in addition to its first Proposal. For example, if "Power Company" wishes to submit three (3) Proposals, it must register the three proposals as "Power Company 1", "Power Company 2", and "Power Company 3" separately on the PowerAdvocate platform.

Each Proposal is subject to a non-refundable RFP submission fee (the "Proposal Fee"), in accordance with the following fee schedule:

Project size less than or equal to 25 MW:	$5,000
Project size greater than 25 MW:	$10,000

A single Proposal fee allows a Respondent to offer both a PPA and BTA price for the same proposed resource. Further, Respondents are permitted to submit both a flat price and an escalating price within the same single Proposal for resource bid under a PPA transaction structure. Any other variations to project/Proposal characteristics are required to be submitted via a separate Proposal and additional Proposal fee:

- Pricing variations outside of fixed/escalated PPA pricing described above
- Term of transaction
- In-service date
- Technology
- Site/Location of facility
- Size/Capacity

Wiring instructions for the submittal of the Proposal fee will be made available to participating Respondents along with other documents following the CA submittal deadline.

XI. Miscellaneous

A. Right to Terminate Negotiations

If APS cannot reach an agreement with the final selected Respondent or Respondents, APS reserves the right to terminate negotiations with such Respondents and begin discussions with other Respondents, begin a new solicitation, and/or cancel this RFP.

B. Regulatory Approval

Any final agreement resulting from this RFP may be conditioned upon actions and/or approvals by regulatory authorities, satisfactory to APS in its sole discretion.

C. Reservation of Rights

APS reserves the right to accept or reject in its sole discretion any or all Proposals for any reason at any time after submittal. APS also reserves the right to select an offer that is not the lowest price if APS determines that, in its judgment, the overall Proposal may result in the greatest value to APS's retail customers.

D. No Liability

Respondents that submit Proposals do so without legal recourse against APS or its officers, directors, employees, agents, contractors, 1898 & Co. or the Independent Monitor based on APS's rejection of any Proposal or failure to execute any agreement in connection with this RFP. Neither APS nor any of its officers, directors, employees, agents, contractors, 1898 & Co. or the Independent Monitor shall be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to APS's acts or omissions arising out of or in connection with this RFP.

E. Return of Documents

None of the materials received by APS from Respondents in response to this RFP will be returned. All Proposals and exhibits will become the property of APS, subject to the provisions of the CA described in Section IX.A.

Appendix A – Table of Acronyms Used in this RFP

Acronym	Definition
1898 & Co.	1898 & Co., a division of Burns & McDonnell
AC	alternating current
ACC	Arizona Corporation Commission
AD/CVD	antidumping duty / countervailing duty
AGC	automatic generation controls
AMI	advanced metering infrastructure
APS	Arizona Public Service
ASHRAE	American Society of Heating, Refrigeration, and Air-Conditioning Engineers
BESS	battery energy storage system
BTA	or any similar agreement that enables the development of the resource by Respondent and the ownership of the resource by APS
BTM	behind the meter
C&I	commercial and industrial
CA	confidentiality agreement
CAES	compressed air energy storage
CAISO	California Independent System Operator
CO	carbon monoxide
COD	Commercial Operation Date
DC	direct current
DR	demand response
DSPA	Data Security and Privacy Addendum
EE	energy efficiency
EMS	energy management system
EPC	engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
FMV	fair market value
FTM	front of the meter
IM	independent monitor
IRP	Integrated Resource Plan
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
LMR	load modifying resource
MST	Mountain Standard Time
MW	megawatt
MWh	Megawatt-hour
NOx	nitrogen oxide(s)
NREL	National Renewable Energy Laboratory
OASIS	Open Access Same Time Information System
OATT	Open Access Transmission Tariff
OEM	original equipment manufacturer

Acronym	Definition
PM	particulate matter
PPA	Power Purchase Agreement
PTC	production tax credit
PVRR	present value revenue requirement
RFP	All Source Request for Proposal
RIM	ratepayer impact measure
RTU	remote terminal unit
SCT	societal cost test
SO_2	sulfur dioxide
TA	tolling agreement
TMY	typical meteorological year
TPRR	Third-Party Risk Review

Appendix B – Executive Summary

APS requires a brief Executive Summary to accompany all Proposal information. The summary should be no more than 10 pages and should serve as a general summary of the Proposal, including the information specified below, to the extent it is applicable to the Proposal.

I. Introduction / Overview

a. Proposed Project/Program overview, including company proposing project, and high-level summary of the project
b. Describe if Proposal is for a new facility/Program, an existing facility, and if Respondent is proposing an asset sale

II. Capacity

a. Provide the nameplate capacity in MW
b. Provide the maximum delivered capacity MWac
c. What is the proposed project's annual capacity factor?
d. What is the expected delivered annual energy (MWh)?

III. Transaction Structure / Term / Pricing

a. Provide transaction structure
b. Provide PPA term length
c. Provide baseline pricing structure
   i. BTA price and/or PPA Price
   ii. PPA base escalation rate, if applicable
d. Provide indicative pricing on PPA for a ten (10)-year term if PPA term in Proposal is something other than ten (10) years. This applies only to renewable, energy storage, and combined renewable and energy storage projects, as described in Sections VII(A) and (B) in the RFP.
e. Provide a description of any deviation from requirements set forth in the RFP that Respondent believes would result in greater efficiencies or cost effectiveness of its Proposal. Quantify any price impact that would result from such deviations.

IV. Summary of Technology including Key Equipment

a. Provide Gas Turbine Generators/reciprocating engines/PV Panels/Inverters/ Wind Turbines/Batteries/Thermostats, etc.
b. Specify any emissions control equipment
c. Include OEM, model, and quantity
d. Specify the country of origin for all material equipment
e. Provide a description of the configuration of equipment

V. Interconnection Status

a. List the primary interconnection voltage

b. What is the interconnection point (i.e., substation, developer property)? ("Interconnection Point" means the physical point at which electrical interconnection is made to allow parallel operation of the Facility with the APS electrical distribution system, as more fully described in the Interconnection Agreement)

c. What is the APS delivery point (i.e., substation)?

d. Has Respondent submitted an application for generator interconnection?

   i. If yes, when did Respondent submit the application and what is the status of Respondent's interconnect application?

   ii. If no, what is Respondent's plan to ensure that the proposed resource will meet the proposed in-service date without any interconnection delay?

VI. Past Experience

a. Number of projects larger than 25 MW in the past five (5) years

b. Types/technologies for projects listed above

c. Project locations for projects listed above

d. Aggregate capacity installed by Respondent over time (MW)

e. Highest single project capacity installed (MW)

f. Total capacity of projects in pipeline (under contract) (MW)

VII. Fuel and Water Supply Arrangements (if applicable)

a. Describe the fuel transportation and supply arrangements for the project. Describe the proposed interconnection point for Fuel, including distance needed for interconnection

b. Indicate if Respondent has applied for a Request for Gas Service and if Respondent has firm water rights for the life of the proposed project.

VIII. Project Development Schedule

a. Provide a summary of the project schedule for the project. Include a brief description of the key milestone dates for the project, including financing and construction milestones and execution of contracts for major equipment.

b. Describe the process of signing up customers for non-supply side Proposals

IX. Project Siting Strategy

a. Provide proposed site location (including map), coordinates and parcel size

b. Include description of site's current and previous use
c. Describe the status of site control including what type of site control has been exercised (e.g., ownership, option, Right of Way grant?)
d. Any resource to be developed wholly or partially on state-owned land must demonstrate that Respondent is scheduled for lease approval on the AZ State Land Board of Appeals Meeting Notice and Agenda on a date prior to shortlisting

X. Project permitting plan

a. Identify the permits required, status of approvals, and plans with schedules to finalize all required permits for construction and operation of the facility, including all certification and land use approvals
b. If the project is permitted and in operation, list the following:
   i. Permit source and expiration date (include all sub-conditions)
   ii. Operating hours
   iii. Emissions limitations
   iv. Start/stop limitations
   v. Minimum run times
   vi. Other embedded permit limitations, e.g., zero discharge requirement, air-cooled condenser requirement, recycled cooling water requirement, etc.

XI. Financial Strategy

a. Provide a description of the financing plan for the project including sources of debt and equity financing and recent experience financing similar projects

XII. Tax Strategy

a. Provide a detailed description of Respondent's holistic strategy regarding the investment tax credit ("ITC")/production tax credit ("PTC") capture for the project
b. Provide Respondent's specific strategy, including critical path items, to satisfy the ITC and PTC commence construction guidance, pursuant to either the "physical work test" or the "five percent (5%) safe harbor," at the earliest realistic time to capture the maximum ITC/PTC

XIII. AD/CVD Mitigation Strategy

a. Provide Respondent's view of expected outcome of current Department of Commerce tariff investigation and impacts on proposed project (including price, availability of equipment, and schedule)
b. Provide a detailed description of Respondent's strategy to

mitigate the impacts described above

XIV. Slave Labor Strategy

a. Provide a brief description of Respondent's plan for avoiding the use of slave labor when building the proposed facility/program and acquiring equipment for the proposed facility/program

XV. Safety

a. Provide a brief description of Respondent's strategy for ensuring safety at its project sites and in connection with any of its proposed programs.

b. Provide current OSHA Total Recordable Injury Rate ("TRIR") and Worker's Experience Modification Rating ("EMR")

Appendix C – Scoring Matrix

Categories	Criteria	Weightage	Total Points	Points	Proposed Scoring
Resource Alignment	Dispatchability	25%	500	100	100-APS has full dispatchability 25- APS has limited dispatchability 0- APS has no dispatchability
Resource Alignment	Carbon Emissions Profile			200	200 - zero emissions 50- Greater than zero but less than average APS emissions rate (lbs/MWh) 0 - Greater than average APS emissions rate (lbs/MWh)
Resource Alignment	Load Factor Impacts			100	This category will only give bonus points for being available fully or partially during the High Energy and Capacity Value hours. 100 - Available all hours from HE17 to HE22 from June to September at full capacity (100% capacity factor) Points will be reduced by a formula to capture actual capacity factor of the project during those hours only. HE = Hour ending; (4pm-10pm).
Resource Alignment	Flexibility			100	100- Ramp rates of 10% per minute of nameplate capacity or higher 50 - Ramp rates of at least 3% per minute of nameplate capacity 0 - Ramp rates less than 3% per minute of nameplate capacity
Technology /Project Risk	Site Control	12.5%	250	50	50: Respondent possess direct ownership of the site, free and clear with no encumbrances. 25: Respondent possess direct ownership of the site, with encumbrances OR Respondent is a lessee on an existing lease of the site OR Respondent possesses an exclusive and non-contingent option to purchase or lease the site. 0: Respondent does not possess direct ownership of the site, free and clear with no encumbrances. A letter of intent is NOT an acceptable form of site control.
Technology /Project Risk	Interconnection Status			100	100- Executed IA/Negotiations. 75- FIS completed 25- SIS completed. 0 - Applied/Will apply
Technology /Project Risk	Supply Chain			100	100 – New Project has less than 50% of major equipment of system sourced from China, Cambodia, Malaysia, Thailand, and Vietnam AND Respondent has a preferred supplier agreement for Proposal; OR Proposal is for an existing project 50 – Less than 50% of major equipment of system sourced from China, Cambodia, Malaysia, Thailand, and Vietnam OR Respondent has a preferred supplier agreement for Proposal 0 –More than 50% of major equipment sourced from China, Cambodia, Malaysia, Thailand, and Vietnam. Respondent does not have a preferred supplier agreement for proposal.

Respondent Risk	**Respondent Commercial Experience**	12.5%	250	100	For existing or new/to-be constructed projects 100 : Respondent has previously developed a project with a capacity over 75% of proposed project size 50: Respondent has previously developed a project with a capacity between at least 50%-75% of proposed project size
Respondent Risk	**Respondent Safety**			50	50: – Respondent has NONE of the following; Worker's Experience Modification Rating (EMR) > 1.0, and OSHA Total Recordable Injury Rate (TRIR) - TRIR >2.0 25 - Respondent has ONE of the following; EMR > 1.0, TRIR > 2.0 12 – Respondent has both of the following; EMR > 1.0, TRIR > 2.0
Respondent Risk	**Financial Strength**			100	100 - The Bidder has obtained financing for at least 3 projects of similar technology and size; has proven financial capability with a favorable bond rating; and provided 3 years of financial statements demonstrating it is financially capable; is not in bankruptcy proceedings; or any current or threatened litigation with APS. 50 - The Bidder has financed at least 1 power project; has demonstrated reasonable financial capability based on financials and/or has a favorable bond rating; is not in bankruptcy proceedings or any current or threatened litigation with APS. 0 - None of the above
Cost	**Reliable LCOC**	40%	800	800	800 points for top decile. 100 point reduction for each subsequent decile in LCOC value. Minimum score 100 points.
Cost	**LCOE**	10%	200	200	200 points for lowest LCOE. 1% reduction in point for every 1% increase in LCOE value. Minimum score 50 points.

STAFF'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
FEBRUARY 16, 2023

Staff 1.14: Four Corners.

a. Please identify and provide all economic, financial, and operational analysis for Four Corners operations and dispatching that was performed by or for APS in 2021, 2022 and to-date in 2023.

b. Please provide and explain the Company's evaluation of whether to go to seasonal operation for one unit of Four Corners and identify the expected impacts on costs of partial seasonal operation of one unit at Four Corners, versus operating both units year-round.

c. Since its last rate case, has APS performed any updated economic analysis related to Four Corners' operations or the Four Corners' generating units' retirement dates? If not, explain fully why not. If so, please identify and provide the analysis.

Response: a-b. APS follows the process outlined in the Company's response to Staff 1.42 when making dispatching decisions for Four Corners.

APS recently revised its fuel contract and operating agreement to include the option to exercise seasonal operations at Four Corners based on actual conditions such as cost of fuel, purchased power cost or other market conditions, with the ability to return to normal operations should conditions change. In October 2022, APS evaluated pursuing seasonal operations at Four Corners in the fall of 2023, which is the first season contractually capable of seasonal operations. The results of the evaluation, which are included as attachment APS22RC02419, note that any forecasted future fuel costs are subject to assumptions at the time of study and will be reevaluated if conditions materially change. As such, APS continues to monitor for conditions that would trigger reevaluating the option to pursue seasonal operations in 2023 and future years. This document is Highly Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

c. The October 2022 analysis referenced in the Company's response to Staff 1.14(a) and (b) represents the only analysis related to Four Corners' operations since its last rate case. The Company has not performed an updated economic analysis related to Four Corners' retirement date since its

Response to Staff 1.14 (cont.)	last rate case but is required to include an analysis in its forthcoming 2023 IRP.

SIERRA CLUB'S SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
MAY 5, 2023

SC 6.2: State whether APS's 2020 IRP analysis included the capital cost and any associated incremental O&M costs associated with both the ELG upgrades at Four Corners and the Redhawk and Sundance chiller upgrades, that APS is including in its PTYP in this rate case.

Response: The 2020 Integrated Resource Plan (IRP) did not include any costs associated with the Redhawk and Sundance chiller upgrades, as the Company had not committed to completing those projects at the time of the IRP filing. Forecasted costs for the ELG upgrade at Four Corners were included in the IRP analysis.

Witness: Justin Joiner

DATE: July 25, 2022

TO: PARTICIPANTS

FROM: Jeffrey Jenkins
Sta. # 4900
Ext. # 863-200

SUBJECT: ***2023-2024 Seasonal Operations Update***

As we all have experienced over the past several months, inflationary and supply chain pressures are having a tremendous impact on our businesses. The price of natural gas is no exception.

As we have been preparing the 2023 Budget for your review, we have simultaneously been evaluating the merits of executing on the Seasonal Operations plan outlined in Amendment 21 to the Four Corners Project Operating Agreement dated June 25, 2021. As per the Amended Operating Agreement, the Participant Owners have certain rights and responsibilities with respect to the operation of the units during the Seasonal Period. As stated in Section 25, and more specifically in Section 25.9, any Secondary Seasonal Participant can request Normal Operations which would have the effect of bringing Unit 5 online (or keeping it online, depending on the status of the unit at the time of the request) within 7 days or as soon as practicable.

After reviewing the economic benefits and risks of Normal Operations during the Seasonal period of November 1, 2023 through May 31, 2024, APS has determined that it is in our best interests to request Normal Operations during the upcoming Seasonal period for Fall 2023 – Spring 2024. Although only required to provide seven days notice, we feel that it is imperative to be as transparent as possible and to provide ample time for discussion with our partners. While changing economic conditions over the course of the next 15 months may impact our analysis, please accept this letter as notification of our intent to request Normal Operations. The 2023 Budget to be distributed on August 3rd will reflect this intent on the behalf of APS.

If you have any questions, please give me a call at (505) 598-8200.

Sincerely,

Jeffrey Jenkins
Four Corners Plant Manager

SIERRA CLUB'S SIXTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
MAY 5, 2023

SC 6.6: Refer to APS response to Staff Data Request 1.8.

a. Explain how shortfall payments are reflected in APS's historical cost data provided in Sierra Club Data Request 1.15. Specifically, are the shortfall costs included in total fuel costs or other O&M?

b. Does APS project any shortfall costs in its future analysis? Specifically, in its IRP modeling included in APS's response to Sierra Club Data Request 1.10, does APS include any shortfall costs?

Response:

a. Payments needed to meet the minimum fuel contract requirements are reflected in total fuel costs.

b. Yes. Please see the attached spreadsheet ExcelAPS22RC03420 for the estimates used to reach the minimum fuel contract requirements within each of the 2020 IRP bridge, shift, and accelerate portfolios. These estimates were used in addition to the busbar information in APS's response to SC 1.10 to develop the various portfolios. This document is Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

Witness: Justin Joiner

SIERRA CLUB'S FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
APRIL 27, 2023

SC 5.4: Regarding APS's investments related to compliance with the Effluent Limitation Guidelines (ELG) at Four Corners, did APS analyze whether those investments could have been reduced or avoided if Four Corners were closed by 2028?

a. If yes, please provide that analysis.
b. If no such analysis was conducted, why not?

Response:

a. N/A

b. An analysis was not conducted because it would not be feasible for the Company to replace Four Corners with equivalent dispatchable capacity by 2028. This is due to the market for capacity resources being incredibly tight in the West, with very few existing facilities that APS can contract with that provide this magnitude of reliable capacity. APS continues to invest heavily in battery energy storage technologies; however, there are still significant supply chain, technology, and operations challenges that need to be resolved prior to such a large-scale replacement of capacity. Other large scale capacity resources (such as pumped hydro) have extremely long development timeframes. Therefore, it was necessary to invest in the ELG project to ensure grid reliability and continued operation of Four Corners operations until APS exits the plant in 2031.

Witness: Jacob Tetlow

SIERRA CLUB'S SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
MAY 5, 2023

SC 6.1: Regarding the Busbar values APS calculated for the Redhawk and Sundance plants that APS included in its 2020 IRP, indicate whether these values include the cost of the chillers in addition to the additional O&M costs incurred from installing and operating the chillers.

a. If no, state whether APS has calculated any updated LCOE values for the Redhawk and Sundance plants that include the cost of the chillers as well as the additional O&M costs incurred with the chillers.

b. If yes, provide the updated LCOE values.

Response: a-b. No, the values provided in the 2020 IRP do not include the cost of the chillers. APS has calculated updated LCOE values which are included in attachment ExcelAPS22RC03428. This document is Confidential and being provided pursuant to an executed Protective Agreement in this matter.

Witness: Justin Joiner

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
APRIL 21, 2023

SC 4.6: Regarding APS's investment in chillers at the Sundance and Redhawk Power Plants:

a. Provide the total cost for the chiller projects at Sundance and Redhawk Power Plants, broken down by the year the expenses were incurred.
b. Provide APS's projections of ongoing O&M costs associated with the chiller projects.

Response: a. Please see the table below that reflects only the direct costs for the portion of the chiller projects at Sundance and Redhawk that the Company is requesting in its PTYP request.

	Sundance Chiller	Redhawk Chiller
2021	$ 71,724	$ 73,937
2022	$ 27,157,367	$ 29,143,165
2023	$ 15,239,478	$ 13,402,849
Total	$ 42,468,569	$ 42,619,951

b. Each project is anticipated to require an additional $300,000 in O&M support per year for a total of $600,000 in O&M per year.

Witness: Jacob Tetlow

SC 1.27: Please identify and produce each and any analysis carried out in the past five years comparing the cost of meeting the energy and capacity needs that provide the basis for the Sundance and Redhawk Chiller Projects (separate out analyses if carried out separately).

a. Energy efficiency.
b. Battery storage.
c. Demand response.
d. Market purchases.
e. Power purchase agreements
f. Existing natural gas combined cycle or combustion turbine capacity.
g. New natural gas combined cycle or combustion turbine capacity.
h. Conversion of natural gas combustion turbines to natural gas combined cycle units.
i. Combined heat and power.
j. Wind.
k. Solar.
l. Solar and battery combined.
m. Geothermal.
n. Any combination of the above resources.

Response: a-n. The Redhawk and Sundance chiller projects upgrade existing facilities to provide more capacity during peak summer periods. APS utilizes avoided costs when evaluating potential projects to determine benefit for the Company's customers. This process considers both the energy value and the capacity value brought by the project. These values are determined in comparison to a least-cost incremental resource on APS's system and show if there is a benefit to the Company's customers when an investment is made. Because the avoided resource represents the investment that would have otherwise been made, the valuation inherently reflects comparisons to other technology types. Resources are evaluated within the APS portfolio based on present value revenue requirements ("PVRR") for the APS system.

Please see ExcelAPS22RC03197 for the PVRR showing benefit to APS's customers for this project.

Witness: Justin Joiner

SC 4.7: Refer to APS response to Sierra Club Data Request 1.27, Attachment SC 1.27_ExcelAPS22RC03197_All Unit Chillers Total Value_CONF.

a. State which modeling software APS used to conduct this analysis.
b. Explain what the column headings mean in each row.
c. State whether the calculations are for the entire system or just the specific gas plants.
d. Provide all workpapers in native form with formulas intact that were used perform this analysis.
e. Explain the methodology used, in detail.

Response:

a. APS used Aurora, its production cost modeling software in the calculation of production costs.

b. With regard to attachment ExcelAPS22RC03197, Column C refers to the production costs of the model when run with the chillers added to Redhawk and Sundance. Column D is the production costs without the chillers, with the delta (column E) being the difference between the two. Avoided capacity is calculated in Columns H and I, with Column I being scaled by the increase in summer peak generation ability due to the upgrade. Column K is the revenue requirement, which captures all the costs relative to the project outside of the production model. Total Net benefit (Column M) subtracts the delta between cases and the revenue requirement from the avoided capacity benefit.

c. Calculations reflect APS's total portfolio of resources.

d. Please see attachments ExcelAPS22RC03349 through ExcelAPS22CC03354. These documents are Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

e. APS utilized avoided energy and capacity costs to determine if the capital costs resulted in a net benefit to its customers. By doing a production cost model delta run, APS can see the benefit of using these more efficient units more than others in the fleet. The avoided capacity is calculated based on a comparison resource which would need to be procured to maintain reliability should these upgrades not be pursued. Total revenue requirements consider depreciation, taxes, and the Company's rate of return to capture all relevant costs outside of the production cost model.

Witness: Justin Joiner

SC 6.4: State whether Sundance and Redhawk are served by firm gas contracts. If yes, state whether the firm quantity of gas under contract will increase or has increased after the chiller projects are operational.

Response: Yes, Sundance and Redhawk are served by firm gas transportation contracts. APS does not anticipate expanding its firm gas transportation to these plants as a result of the chiller projects.

SC 4.5: Regarding APS's investments related to compliance with the Effluent Limitation Guidelines (ELG) at Four Corners:

a. Please provide all analysis APS completed at the time the ELG investments were made at the Four Corners Power Plant.
b. State whether APS conducted a similar analysis to what it provided in response to Sierra Club Data Request 1.27 when evaluating whether to install the ELG investments.
    i. If yes, please provide the analysis.
    ii. If no, explain why no such analysis was conducted.
c. Provide the total ELG project cost, broken down by the year expenses were incurred.
d. Provide APS's projections of ongoing O&M costs associated with the ELG project.

Response:

a. Please see the Company's response to Staff 3.26.

b. No. This project is being implemented to satisfy requirements under the federal Clean Water Act and regulations codified at 40 C.F.R. Part 423. APS's cost analysis and alternative solution review for this project are included in the Confidential Capital Budget Item (CBI) documents and spreadsheet provided in the Company's response to Staff 3.26.

c. Please see the table below. Note that the table includes APS direct costs only and does not demonstrate the breakout of costs by participant. The project will go into service in 2023 and forecasted dollars in 2024 are for final commissioning.

Life to Date Actuals			**Remaining Forecast**	
2021	**2022**	**2023**	**2023**	**2024**
$ 3,293,336	$ 20,182,363	$ 8,733,833	$ 17,484,973	$ 419,782

d. Overall projected O&M costs for the Four Corners Power Plant account for the O&M costs for the ELG, but APS does not separately estimate future O&M costs for the ELG project because of the interrelationship it has with various existing plant components.

Witness: Jacob Tetlow

SC 5.7: Please provide the Company's most recent forecasts of water availability for power generation at its Four Corners and Cholla plants.

Response: <u>Cholla</u>

Water use at Cholla is forecasted to vary between 5,000 acre-feet and 7,000 acre-feet until coal-fired generation ceases in 2025. APS projects that existing on-site wellfield operations can provide sufficient water to meet demands for power generation at Cholla.

<u>Four Corners</u>

Water use at Four Corners is forecasted to range between 15,000 and 18,000 acre feet per year. APS projects that existing water diversion rights through the San Juan River (Permit 2838) will provide sufficient water supplies to meet demands for power generation from Four Corners for the foreseeable future.

Witness: Jacob Tetlow

SOUTHWEST ENERGY EFFICIENCY PROJECT'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-22-0144
April 17, 2023

SWEEP 2.4: For APS demand response programs, please provide the most recently developed APS demand response plan. Please include any internal forecasts on demand response program demand reductions by year and the associated value or benefits.

Response: In alignment with Commission policy direction and stakeholder interest, APS has been working diligently to increase demand response capacity since 2016, resulting in a 250% increase in reported demand side management program peak capacity MWs between 2016 and 2022.

The 2023 APS Demand Side Management (DSM) Implementation Plan, attached as APS22RC03334, includes the most recent annual forecast for demand response programs over the next year of program implementation.

The 2020 APS Integrated Resource Plan (IRP), provided in the Company's response to RUCO 2.12, includes the most recent long range demand response plan and forecast. APS is currently working to update demand response plans and is conducting an energy efficiency and demand response potential study with Guidehouse Consulting which will be used to inform the 2023 IRP.

Witness: Jessica Hobbick

SC 1.19: Explain what efforts APS has undertaken to manage its peak demand over the past five years. Include explanations of decisions of actions that APS considered and did not take.

Response: Peak demand is a function of customer consumption which APS has limited ability to control directly. APS does offer a suite of programs and rates to assist customers in managing their demand and energy consumption.

Over the past five years, APS has undertaken a wide range of efforts to manage peak demand including customer programs in peak focused energy efficiency, load shifting, demand response and energy storage. As reported in the 2022 Demand Side Management (DSM) Annual Progress Report, provided in the Company's response to SC 1.18, the current APS DSM portfolio delivered more than 323 MWs of peak demand reduction in 2022 (including 176 MWs of dispatchable demand response capacity) – this represents a 285% increase compared to 2017 portfolio performance. As described in the DSM Annual Progress Report, some examples of the many efforts to manage peak demand include:

1. APS has maintained, evolved, and expanded a comprehensive portfolio of peak focused Energy Efficiency (EE) programs for all major APS customer segments (Ongoing since 2005)
2. Launched the Cool Rewards Smart Thermostat Demand Response program for Residential Customers (2018)
3. Request For Proposal (RFP) to expand the Peak Solutions Commercial/Industrial Demand Response Program from 25 to 75 MWs (2020)
4. RFPs for "All Source" resource acquisitions each year include requests for demand response/energy efficiency peak capacity and energy resources (ongoing since 2019)
5. RFP for "All DDSR" aggregation of distributed demand side resources to provide multiple grid service including summer peak capacity (2021)
6. Launched APS Marketplace to help customers find rebates and special offers on EE/DR technologies (2020)
7. Launched APS Rate Plan Coach (2021)
8. Launched APS Residential Battery Storage Pilot (2021)
9. Launched Connected Water Heating Controls in the Multifamily and Existing Homes programs (2022)
10. Launched Behavioral Demand Response – Energy Saving Days program (2022)
11. Launching EV Managed Charging Programs (2021-2023)

Response to SC 1.19 (cont.)

APS has a number of rate options designed to help customers control their energy consumption during peak periods. APS offers time of use rates to both residential and non-residential customers and has one of the highest levels of non-mandatory time of use participation in the nation. During the Test Year, the Company had approximately 55% of its customers on a TOU rate. Additionally, APS has added a super off-peak period to residential time of use rates to incentivize consumption during excess solar production hours. Peak demand savings from TOU rate plans are in addition to the 323 MWs saved from DSM programs. Daily savings vary, however, on the highest demand days of the year, peak demand savings from TOU rate plans can be upwards of 100 MW.

Table D.27 in the 2020 APS Integrated Resource Plan, provided as attachment APS22RC00426 in APS's response to RUCO 2.12, includes a list of DSM measures that APS has considered but not yet included in its demand side management portfolio, typically due to a lack of cost effectiveness. These include offering incentives for energy efficient appliances such as dishwashers, clothes washers, and clothes dryers as well as some water heating technologies. Instead of rebates for these technologies, APS offers the Online Marketplace to help customers choose the most efficient appliances and conducts education and outreach to help customers understand how to shift these energy uses off-peak.

Attachment DG-3

APS Confidential Responses to Discovery Requests

Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-4

APS Highly Confidential Responses to Discovery Requests

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-5

Excerpt of APS 2020 Integrated Resource Plan (June 26, 2020)

2020
INTEGRATED RESOURCE PLAN

JUNE 2020 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

Water Conservation

Water is growing in importance as a factor in assessing the viability of new energy projects for all utilities. Utilities operating in water-constrained areas – such as APS's service territory – face greater challenges. To meet those challenges while maximizing the use of renewable water resources and minimizing the use of non-renewable resources, it is important to consistently monitor water use, both in terms of the amount of water used and water intensity (gallons per MWh). Reductions for the period 2012–2035 are associated with unit retirements at APS owned and operated plants Saguaro, Four Corners, Cholla and Ocotillo, increased reliance on renewable energy that does not use water (wind, PV solar) and increased energy efficiency.

FIGURE 1-1. WATER SOURCE BY FACILITY (APS-OPERATED)

We will continue to conduct water efficiency audits of power plants, implement leak reduction programs and ensure equipment is functioning as designed, which will help the Company achieve conservation of groundwater resources. In 2016, APS developed and implemented a groundwater conservation strategy designed to reduce fleetwide consumption of groundwater by 8% compared to the reference year 2014. Goals of 10%, 12%, and 14% reductions were established for 2017, 2018, and 2019, respectively. In 2019, the actual reduction was 22.4% below 2014 consumption. This strategy supports an APS Tier I metric entitled Conservation of Non-Renewable Water Supplies, which is achieved by implementing water conservation measures at APS plants.

The use of reclaimed water at both Redhawk and Palo Verde are examples of water strategies that have most clearly defined APS's water footprint in Arizona. In 2019, 71% of all water used by the APS fleet was reclaimed water, which frees up fresh water for other uses by the communities we serve. Between 2019 and 2035, APS will further reduce use of groundwater, increase the proportion of treated effluent to support power generation, and use very small quantities of surface water at Sundance.

APS STAKEHOLDER ENGAGEMENT

To bolster water efficiency efforts and improve communication with other water stakeholders, APS is a member of the Governor's Water Augmentation, Innovation, and Conservation Council, the Kyl Center for Water Policy at the Morrison Institute, the Groundwater Users Advisory Council, the Post-2025 Active Management Area Committee, the Colorado River Water Users Association, the Water Reuse Association and the ADWR 5th Management Plan Workgroup. Participation in these water stakeholder groups improves the Company's understanding of water needs and trends and allows it to communicate and model plans to support sustainable water practices.

OUTLOOK FOR WATER INTENSITY IN APS OPERATIONS

Over the 2020-2035 Planning Period, water intensity is expected to decrease due to:
- Increased penetration of renewable energy resources;
- Increased penetration of energy efficiency;

- Retirement of older, water-intensive units;
- Technological advancements in new power plants that use efficient water-cooling strategies such as hybrid cooling systems; and
- Implementing water conservation measures at existing plants.

A forecast of the reduction in water intensity measured as gallons per MWh for the Resource Plans is included in the response to Rule D.17.

APS WELL SURVEY PROGRAM

Water Resource Management undertook a statewide survey of the location and condition of wells associated with APS power plants and other properties in Arizona and New Mexico. This evaluation included production wells, monitoring wells, remediation wells, drinking water wells, agricultural wells, cathodic protection wells and grounding wells. Wells were evaluated for safety, degraded operational condition and potential to allow aquifer cross-contamination or surface water intrusion. The intent was to map all APS well infrastructure and to identify the current status of each well, with a focus on identifying wells in need of maintenance or abandonment. Eleven of the highest priority wells were abandoned in 2019 and another 41 wells were planned for abandonment in 2020. This program will continue to evaluate future needs for maintenance or abandonment consistent with regulatory requirements.

WATER OVERVIEW BY FACILITY

APS manages the water use at nine APS-owned/operated facilities. The focus is on non-renewable water (i.e., groundwater) because this supply is at the greatest risk of depletion and is a significant source of supply at seven of nine APS power plants.

NUCLEAR

PALO VERDE

Source: Treated effluent (reclaimed) water

With operating licenses in place for Units 1, 2 and 3 through June 2045, April 2046 and November 2047, respectively, the current water supply contract ensures a reliable supply will be available through 2050. We will evaluate a second license renewal request for an additional 20 years in the future. Opportunities include working with state and federal agencies as well as West Valley communities to develop alternative water supplies, which can be used directly or indirectly through recharge and recovery.

Palo Verde uses treated effluent for cooling water and a comparatively small quantity of groundwater for drinking water and industrial process water. Avoidance of groundwater use as cooling water is very important because two adjacent power plants, Mesquite and Arlington Valley, rely upon groundwater from the same aquifer. APS (for Palo Verde and Redhawk), Mesquite and Arlington Valley send a report every five years to the ACC, ADWR and U.S. Geological Survey (USGS) concerning subsidence and land fissure development around the four power plants. Use of effluent by Palo Verde and Redhawk in lieu of groundwater reduces the probability of subsidence in the area.

In 2016, Palo Verde's Water Reclamation Facility built a seventh treatment train that provides redundancy and allows rehabilitation of existing equipment with no loss of treatment capacity. In 2019, rehabilitation of the original six treatment trains was in progress. This provides greater reliability of treated effluent for use at Palo Verde and Redhawk.

COAL

FOUR CORNERS

Source: Surface water from the San Juan River

Following a drought in 2000, a shortage sharing agreement was executed between the Bureau of Reclamation (BOR) and the parties utilizing San Juan River surface water as their water supply. The current agreement will expire in December 2020, and plans are in place to continue this significant partnership that reduces the probability of adverse impacts to participants in the event that a shortage is declared on the Colorado River. In 2019, APS worked with the BOR and other major water users on the San Juan River to keep more water in Navajo Reservoir, ensuring that all of the water needs, including environmental needs, are met while minimizing the potential of future water shortages.

In 2017, APS implemented commitments under the National Environmental Policy Act to support endangered fish and bird populations near the Four Corners Power Plant. Actions in 2019 included providing funds to the National Fish and Wildlife Foundation to support fish stocking and studies, maintaining a non-native fish control structure on Morgan Lake, supporting development of a fish ladder around the APS pump station in the San Juan River that will improve endangered fish passage, coordinating river pumping with fish stocking and spawning, and performing endangered bird studies.

CHOLLA

Source: Groundwater from 18 production wells located on both sides of the Little Colorado River

To mitigate concerns of the wells' proximity to the Little Colorado River, a Cholla groundwater flow model was developed in 2014 and a groundwater monitoring program has been conducted since 2012. Further development of this model is ongoing and is expected to minimize possible adverse impacts on groundwater levels, water quality and surface water flows. Cholla's groundwater modeling and water quality sampling has enabled development of a Cholla Wellfield Operations Plan that has identified variable water quality in wells and directs plant staff to use higher quality water first. This optimizes the water quality available for use as cooling water, drinking water and industrial process water, and also results in reduced overall water consumption.

PacifiCorp, a Cholla Power Plant participant, announced in 2019 that they would cease operation of Unit 4 by the end of 2020. This will reduce water consumption at Cholla by approximately 40% and the remaining water consumption for Cholla generation will be eliminated by 2025. APS is working closely with the Coconino Plateau Watershed Partnership to understand groundwater conditions in Northern Arizona and partner with other stakeholders to protect water supplies.

NATURAL GAS

OCOTILLO

Source: Groundwater in the Phoenix Active Management Area

As part of the 2019 Ocotillo Modernization Project, APS replaced the two existing 1960s-era steam units with five new quick-start combustion turbines (CTs) that incorporate hybrid (wet/dry) cooling towers into the design. The new CTs used 164 gallons/MWh in 2019 compared to the steam unit consumption in 2018 of 827 gallons/MWh, thereby reducing the quantity of groundwater required to support plant operations. To increase reliability of water supply, Ocotillo's existing wells were rehabilitated, and a new well was placed in service in 2019.

WEST PHOENIX

Source: Groundwater in the Phoenix Active Management Area

The West Phoenix Power Plant utilizes a zero-liquid discharge (ZLD) brine concentrator and evaporator that allows reclamation and reuse of treated water, reducing reliance on groundwater. A new well was placed into service at West Phoenix in 2019, increasing water delivery reliability at the plant.

REDHAWK

Source: Treated municipal effluent (reclaimed water) provided by the Palo Verde Water Reclamation Facility (PVWRF) as the primary cooling water supply plus groundwater.

The effluent is delivered to the Redhawk reservoir with a minimum 20-day supply at 100% capacity factor and is ready for use. Groundwater reliability was enhanced in 2019 with equipment installation in the new East Well.

In 2016, the PVWRF built a seventh treatment train that provides redundancy and allows rehabilitation of existing equipment with no loss of treatment capacity. In 2020, rehabilitation of the original six treatment trains was in progress, with two complete and the third expected to be complete in September. This provides greater reliability of treated effluent for use at Palo Verde and Redhawk.

SAGUARO

Source: Groundwater from four on-site wells

Decommissioning of the two steam turbines has significantly reduced the need for water to support generation. However, smaller quantity water needs persist for the plant's combustion turbines. Saguaro Well #5 was drilled in 2019, increasing water delivery reliability.

SUNDANCE

Source: Surface water

In addition to its rights for excess Central Arizona Project (CAP) water, APS has purchased as an alternative 5,000 AF of water from the Gila River Indian Community (GRIC) and entered into a recovery and exchange agreement with the GRIC for the next 45 years, continuing its reliance on renewable surface water.

YUCCA

Source: Surface water from the Colorado River and groundwater from three on-site wells

A new well was drilled in 2014 and placed into service in 2015. This well is out of the Colorado River accounting surface, pumps groundwater and will meet the needs of the plant in the event of a Colorado River shortage. APS entered into an agreement with the CAP and USBR to forego use of 5^{th}-6^{th} priority surface water rights and instead use groundwater whenever possible, conserving the surface water in Lake Mead as a hedge against future shortage.

To report the renewable energy share, the accounting conventions specified in the existing Arizona RES are used, under which each utility's share of renewables is expressed as a percentage of its retail sales,[4] relative to total sales to customers. As indicated above, APS also reports the share of each type of resource as a share of its total energy mix, including DSM. By including DSM in the energy mix, we are able to show its contribution to the total portfolio. This metric provides a more holistic presentation of the portfolio and treats all resources equally; this metric is used as the primary convention to report the share of clean energy in the portfolio.

These two metrics differ in two respects: retail sales do not include generation losses, and the energy mix is explicitly adjusted to include the load impact of DSM programs. One implication of the differences between these methods is that the Company's portfolios meet the 45% renewable goal by 2030 according to the state's RES accounting conventions, but the reported share of renewables in the energy mix will appear lower. The table below provides an illustrative example for why this result occurs.

TABLE 7-1 – RENEWABLE ENERGY REQUIREMENT AND CLEAN ENERGY MIX EXAMPLE

Energy Requirements (GWh)	40,000
Losses	7%
Retail Sales (GWh)	37,383
Renewable Requirement (% of retail sales)	45%
Renewable Requirement (GWh)	16,822
DSM Load Impact (GWh)	10,000
Energy Requirements – Including DSM (GWh)	50,000
Renewable Share of Energy Mix (% of energy requirements including DSM)	34%

Portfolios

Three portfolios were developed to support the Company's efforts to achieve its clean energy commitment and were based on Commission requirements and insights gained from stakeholder meetings. They all include significant amounts of customer resources such as EE, demand response and microgrids as well as varying levels of grid-scale renewable additions and energy storage deployment. A fourth portfolio is included for reference as a more traditional "least cost" technology agnostic portfolio based on technology costs and performance as seen today by APS and was developed by running ABB's Strategist resource optimization software. This portfolio would not allow the Company to meet its clean energy commitment and carries significantly more gas availability and price risk than the others, and so it was not carried into the sensitivity analysis phase of the IRP.

All four of the portfolios have a few common elements. First, they all meet APS's commitment to exit coal generation by 2031 by assuming retirement of Cholla 1 and 3 in 2024, followed by retirement of Four Corners 4 and 5 in 2031. The Cholla retirement timing is driven by an agreement with the EPA (described in the State and Federal Regulation chapter of the IRP) and Four Corners retirement timing is driven by the expiration of the coal supply agreement. Second, although the Commission's EES ends in 2020, all four portfolios continue to implement peak focused EE at levels similar to that achieved in recent years. Finally, they all include the assumption that customers will continue installation of DE resources at a pace consistent with recent trends.

[4] This approach to accounting for renewable generation is the same as the methods used in neighboring states for RPS accounting.

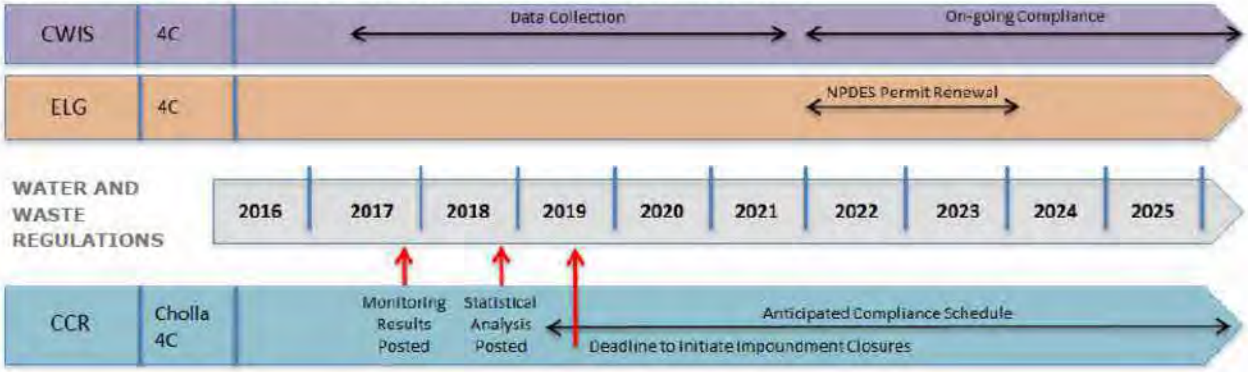
FIGURE 7-4. 2020 & 2024 – ENERGY MIX

TABLE 7-4. CAPACITY AND ENERGY MIX (2024)

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Description	Retire coal by 2031; demand reducing DSM; RE and ESS to meet CEC, gas bridge - extend gas tolling PPAs and add new gas generation	Retire coal by 2031; demand reducing DSM; shift to more RE and ESS, extend gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; accelerate RE and ESS, no gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; limited RE and ESS, extend gas tolling PPAs, new gas generation not constrained
Resource Contributions (2024 Nameplate Capacity/% Energy Mix)				
Clean Energy	55%	55%	55%	51%
RES Achieved	25%	25%	25%	20%
Nuclear	1,146 MW / 21.3%	1,146 MW / 21.3%	1,146 MW / 21.3%	1,146 MW / 21.3%
Coal	1,357 MW / 15.5%	1,357 MW / 15.5%	1,357 MW / 15.5%	1,357 MW / 15.5%
Natural Gas	5,179 MW / 26.6%	5,179 MW / 26.6%	5,179 MW / 26.2%	5,541 MW / 30.3%
Renewable Energy (RE & DE)	3,286 MW / 18.2%	3,286 MW / 18.2%	3,311 MW / 18.5%	2,774 MW / 14.6%
Demand Side Management	575 MW / 15.4%	575 MW / 15.4%	575 MW / 15.4%	575 MW / 15.4%
Demand Response[6]	253 MW	253 MW	253 MW	253 MW
Microgrids[6]	38 MW	38 MW	38 MW	38 MW
Energy Storage[7]	752 MW	752 MW	752 MW	552 MW
Market Purchase[8]	160 MW / 3.0%	160 MW / 3.1%	160 MW / 3.1%	160 MW / 3.0%

[6] DR and microgrids are considered capacity resources and are not included in the energy mix.
[7] Energy storage does not create its own energy, so energy associated with it is reported under the source that provided the charging energy.
[8] Market Purchase capacity (MW) reflects firm power acquired through PPAs, while Market Purchase energy mix % includes firm purchases plus non-firm market wholesale purchases.

FIGURE D-2. REDUCTION OF ENVIRONMENTAL IMPACTS TO WATER



COMPANY RESPONSE TO CLIMATE CHANGE INITIATIVES

APS has undertaken a number of initiatives to address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on the Pinnacle West website (*pinnaclewest.com*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance.

EPA ENVIRONMENTAL REGULATIONS

REGIONAL HAZE RULES

In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal lands, EPA) to develop plans to achieve natural visibility conditions by 2064. The first planning period during which the regional haze rules were required to be implemented occurs between 2008 and 2018. The most impactful provisions of the rules were the requirement to determine what pollution control technologies constitute the Best Available Retrofit Technology (BART) for certain older major stationary sources. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis. The second planning period begins in 2018, but the plans that will demonstrate continued progress toward the goal of natural visibility conditions will not be submitted to EPA until July 31, 2021. It is possible that additional air pollution control technologies will be required to further reduce visibility impairing air pollution.

Cholla BART

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA partially approved and partially disapproved the State's BART determinations, and imposed its own sulfur dioxide ($SO2$) removal efficiency requirement and oxides of nitrogen (NO_x) emissions limitations within a Federal Implementation Plan (FIP). In order to comply with the new limits, APS would have been required to upgrade the $SO2$ scrubbing efficiency and install selective catalytic reduction (SCR) technology on Units 2, 3 and 4. The state of Arizona, APS, and others sued EPA over this determination, along with other related-BART determinations. Concurrent to the litigation, APS offered an alternative BART Reassessment, which was premised on a commitment by APS shut down Unit 2 in 2016 and either shutdown the other units by April of 2025 or convert them to natural gas while operating at no more than a 20% capacity factor. In exchange for this commitment, Units 3 and 4 could continue operation without SCR.

On October 22, 2015, the state of Arizona submitted a State Implementation Plan Revision to EPA for approval that contained this alternative BART Reassessment. Public comment on EPA's proposed approval of the alternative BART Reassessment closed on September 1, 2016, and a final action was signed by former EPA Administrator Gina McCarthy on January 13, 2017. As soon as new EPA leadership selected by President Donald Trump has reviewed and approved this final rule, the Company expects the final rule containing the Cholla BART Reassessment will be published in the Federal Register and allowed to take effect. APS also anticipates additional review from the U.S. Office of Management and Budget may also be required before the rule takes effect. During this time, APS's litigation over the 2012 BART FIP as applied to Cholla remains in abeyance.

Four Corners BART

On August 6, 2012, EPA issued its final BART determination for Four Corners. On December 30, 2013, on behalf of itself and the Four Corners co-owners, APS notified EPA that the co-owners selected the BART alternative, which required APS to permanently shut down Four Corners Units 1-3, and install and operate SCR control technology on Units 4 and 5 by July 31, 2018. EPA also required a 95% SO2 removal rate, which requires some upgrades and restorations to the Flue Gas Desulfurization (FGD) systems. Consistent with this alternative, APS retired Units 1-3 on December 30, 2013, and permanent decommissioning of those facilities is complete. The addition of SCRs necessitated the addition of a Dry Sorbent Injection system to remove sulfuric acid mist created in the SCRs. Upgrades and restorations to the FGD systems and installation of the SCR control technology have been completed and are operational.

Navajo BART

EPA accepted SRP's proposal for an alternative to BART, which provides the Navajo Plant with additional time to install the SCR technology. Under this "better-than-BART" alternative, the Navajo Generating Station participants are required to shut down one unit or curtail the equivalent of one unit by January 1, 2020 and install SCR technology on the two remaining units by December 31, 2030.

MERCURY AND OTHER HAZARDOUS AIR POLLUTANTS

On December 16, 2011, EPA issued the final Mercury and Air Toxics Standard (MATS) rule, which established maximum achievable control technology (MACT) standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. APS has met all of its regulatory obligations for installing activated carbon injection on Units 1 and 3 at Cholla. Four Corners Units 4 and 5 were able to meet the mercury limit with existing equipment. Both facilities are fully compliant with the applicable emissions limitations.

COOLING WATER INTAKE STRUCTURES

EPA issued its final cooling water intake structures rule on August 15, 2014, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the Clean Water Act. The rule is intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). The rule requires existing facilities such as Four Corners and Navajo Generating Station that use surface water to comply with the impingement mortality requirements as soon as possible, but in no event later than eight years after the effective date of the rule. Cholla is not impacted because its cooling water is supplied from well water. Existing facilities subject to the rule are required to comply with the entrainment requirements as soon as possible under a schedule of compliance established by the permitting authority. The Four Corners cooling water intake structure on the San Juan River was modified in 2017, connecting the two pump train sumps and reducing intake velocity to 0.5 fps, eliminating potential for impingement.

COAL COMBUSTION RESIDUALS (CCR)

On December 19, 2014, EPA issued its final regulations governing the handling and disposal of Coal Combustion Residuals (CCR), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit the pond with a liner, or close. All CCR landfills or surface impoundments that cannot meet the applicable performance criteria for location restrictions or structural integrity are required to close. The provisions of this rule are self-implementing and currently rely upon citizens' lawsuits for enforcement of its requirements.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production. The known impacts of the rule are to initiate closure of two impoundments at Four Corners on or before June 17, 2019. In compliance with the requirements of the rule, APS is conducting on-going groundwater monitoring at both locations. All monitoring results are required to be made publicly available through a company-controlled website on or before October 17, 2017 and must update this information annually until 30 years after the closure of the ash ponds or dry storage areas. A statistical analysis of the collected data and an analysis of any required remedial actions must be completed and posted to the same website on or before October 17, 2018.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation (WIIN) Act into law. This act contains a number of provisions that require EPA to modify the self-implementing provisions of the Agency's current CCR rules. Specifically, EPA is provided with the authority to directly enforce the CCR rules through the use of administrative orders and, pending congressional appropriation, the obligation to develop a federal permitting program. EPA was also provided the authority to delegate permitting authority to the States through the approval of a state-proposed permitting program. Because EPA has yet to undertake implementation of the CCR provisions of the WIIN Act, and Arizona has yet to determine whether it will develop a state-specific permitting program, it is unclear what effects the CCR provisions of the WIIN Act will have on APS's management of CCR.

EFFLUENT LIMITATION GUIDELINES

On September 30, 2015, EPA finalized its revisions to the effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil fuel-fired Electric Generating Units (EGUs). The final regulation is intended to reduce metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero-discharge" from fly ash and bottom ash handling, and impoundments for coal ash disposal leachate. Compliance with these limitations will be required as a part of the plant's National Pollution Discharge Elimination System (NPDES) permit which renews in five-year intervals. The NPDES program only impacts the Four Corners power plant. APS anticipates renewing the NPDES permit for the Four Corners plant between 2018 and 2023. Until a draft NPDES permit for Four Corners is proposed, APS is uncertain about what additional controls, if any, might be required to ensure that discharges from the facility are in compliance with the finalized effluent limitation guidelines.

OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

On October 26, 2015, EPA adopted a new ozone NAAQS and set it at 70 parts per billion. This decision was legally challenged by various industry organizations yet supported by various states and environmental groups. The lawsuit is currently on-going. During this time, both the 2008 and the 2015 ozone NAAQS remain in effect.

In accordance with Clean Air Act requirements, on September 27, 2016, the state of Arizona made an initial recommendation that EPA classify the air quality in portions of Gila, Maricopa, and Pinal counties (e.g., Phoenix area) as a single non-attainment area, and a portion of Yuma County as a separate non-attainment area. The recommendation also suggested three other data-contingent alternatives for the

ATTACHMENT D.3: GENERATION TECHNOLOGIES

Conventional Generation Technologies Assumptions											
Plant	Location	Annual Capacity	Summer Capacity	Capital Cost ($/kW)	Book Life (Years)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Heat Rate (BTU/kWh)	Capacity Factor %	CO2 Emmissions (lbs/mmBTU)	Water Consumption (gal/MWh)
NUCLEAR											
Advanced Nuclear	Palo Verde	2156 MW	2156 MW	6,830	40	121.13	2.54	10,461	92%	0	767
Small Modular Reactor (SMR)	Palo Verde	600 MW	600 MW	5,605	40	173.35	15.50	10,710	95%	0	740
NATURAL GAS											
Large Frame Combustion Turbine	Maricopa	384 MW	362 MW	652	40	11.58	2.10	9,319	10%	125	15
Aeroderivative Combust on Turbine	Maricopa	104 MW	103 MW	1,512	40	8.86	2.68	9,138	10%	122	141
Combined Cycle	Maricopa	547 MW	542 MW	994	40	7.72	2.72	6,672	50%	122	20
MICROGRID											
Genset	Maricopa	100 MW	100 MW	946	40	5.88	0	8,300	2%	161	0
ENERGY STORAGE											
Battery Energy Storage System (Li-ion)	Maricopa	100 MW	100 MW	1,225	20	24.50	0	*85%	15%	0	0
Compressed Air Energy Storage (CAES)	Maricopa	100 MW	100 MW	3,878	30	22.74	1.88	4,000	15%	122	0
Pumped Storage Hydro	Maricopa	100 MW	100 MW	3,546	30	49.64	0	*75%	15%	0	0
Flow Battery	Maricopa	100 MW	100 MW	1,570	30	31.40	0	*75%	15%	0	0

Renewable Generation Technologies Assumptions									
Generation Resource Options	Summer Capacity	Capital Cost ($/kW)	Book Life (Years)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Capacity Factor %	CO2 Emmissions (lbs/mmBTU)	Water Consumption (gal/MWh)	Fuel Cost ($/MWh)
GRID-SCALE SOLAR									
Thin Film Solar PV - Single Axis Util ty	100 MW	1,160	40	17.86	0	35%	0	0	0
Thin Film Solar PV - Fixed Util ty	100 MW	1,084	40	17.86	0	25%	0	0	0
Solar PV + Battery Energy Storage System (PVS)	100 MW	2,385	40	42.36	0	34%	0	0	0
Solar Thermal Tower with Storage	130 MW	7,107	40	83.46	0	54%	0	134	0
Distributed Solar									
Thin Film Solar PV - Fixed Commercial	150 kW	1,260	40	21.00	0	20%	0	0	0
Thin Film Solar PV - Fixed Res dential	5 kW	2,687	40	30.77	0	22%	0	0	0
OTHER RENEWABLE ENERGY SOURCES									
Southwest Wind	150 MW	1,343	40	34.73	0	50%	0	0	0
Geothermal	50 MW	3,034	30	122.00	1.25	80%	0	221	0
Biomass	50 MW	4,666	30	134.82	5.18	80%	0	553	36

Notes:

* Efficiency

1 Costs are in year-2022 dollars

2 Capital costs are overnight construction costs; $/kW is based on summer capacity rating

3 Duration for each energy storage technology is 4 hours

ATTACHMENT F.1(A)(1): BRIDGE PORTFOLIO L&R AND ENERGY MIX

	Bridge Portfolio - Loads & Resources - MW Energy Contribution at Peak																
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-X	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	B omass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,146	5,169	5,165	5,140	5,143	5,136
23	**Customer Resources**																
24	Future Energy Efficiency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	212	224	262	274	312	324	337
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,135	1,246	1,338	1,439	1,567	1,667	1,768
28	**Future Resources**																
29	Natural Gas	150	237	134	50	37	0	565	1,135	1,497	1,497	1,497	1,859	1,859	1,859	1,859	1,859
30	Combined Cycle	0	0	0	0	0	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
31	Combustion Turbines	0	0	0	0	0	0	0	0	362	362	362	724	724	724	724	724
32	Short-Term Market Purchases	150	237	134	50	37	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	153	150	279	272	351	343	399	475	544	532	585	561	619
34	Wind	0	0	64	153	150	279	272	351	343	399	475	544	532	585	561	619
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	B o/Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	PVS (PV + BESS)	0	0	98	193	393	863	1,077	1,222	1,487	1,606	1,774	2,150	2,338	2,452	2,647	2,805
38	Energy Storage	0	0	109	238	236	235	237	236	239	242	244	516	511	507	498	486
39	Microgr d	0	6	6	6	6	31	31	56	56	56	56	106	106	131	131	131
40	**Total Future Resources**	150	243	411	640	821	1,408	2,182	3,000	3,622	3,800	4,045	5,175	5,346	5,534	5,697	5,900
41	**TOTAL RESOURCES**	8,524	8,763	9,029	9,307	9,583	9,875	10,174	10,517	10,782	11,090	11,437	11,682	11,950	12,241	12,507	12,804

Attachment DG-6

Highly Confidential Attachment 6: APS natural gas PPA tolling agreements

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-7

Highly Confidential Attachment 7: Summary of recent procurements by APS

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-8

Highly Confidential Attachment 8: Recent solar PV and wind PPAs in the Southwest

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-9

Highly Confidential Attachment 9: Recent solar PV + battery energy storage system (BESS) projects

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-10

Highly Confidential Attachment 10: APS recent battery storage projects

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-11

Highly Confidential Attachment 11: Summary of APS recent firm energy and capacity contracts

Highly Confidential Information

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

Attachment DG-12

Excerpt of APS Presentation from APS RPAC Meeting (Apr. 21, 2023)

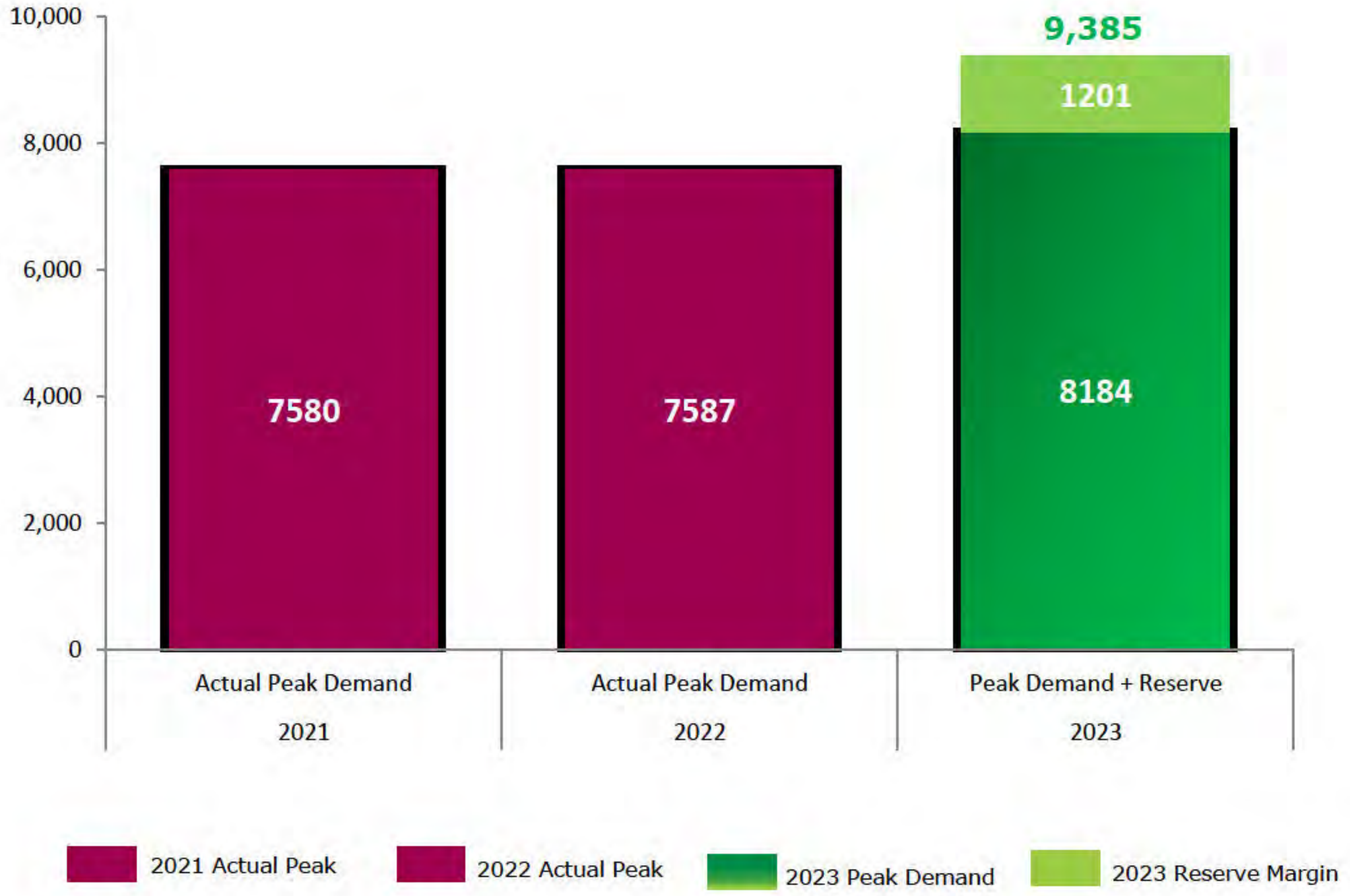
APS RPAC Meeting

04/21/2023

2023 Summer Preparedness

APS is ready to reliably serve its customers' needs for summer 2023:

- Diverse generation resources
- Adequate fuel supplies
- Transmission capacity
- Emergency preparedness

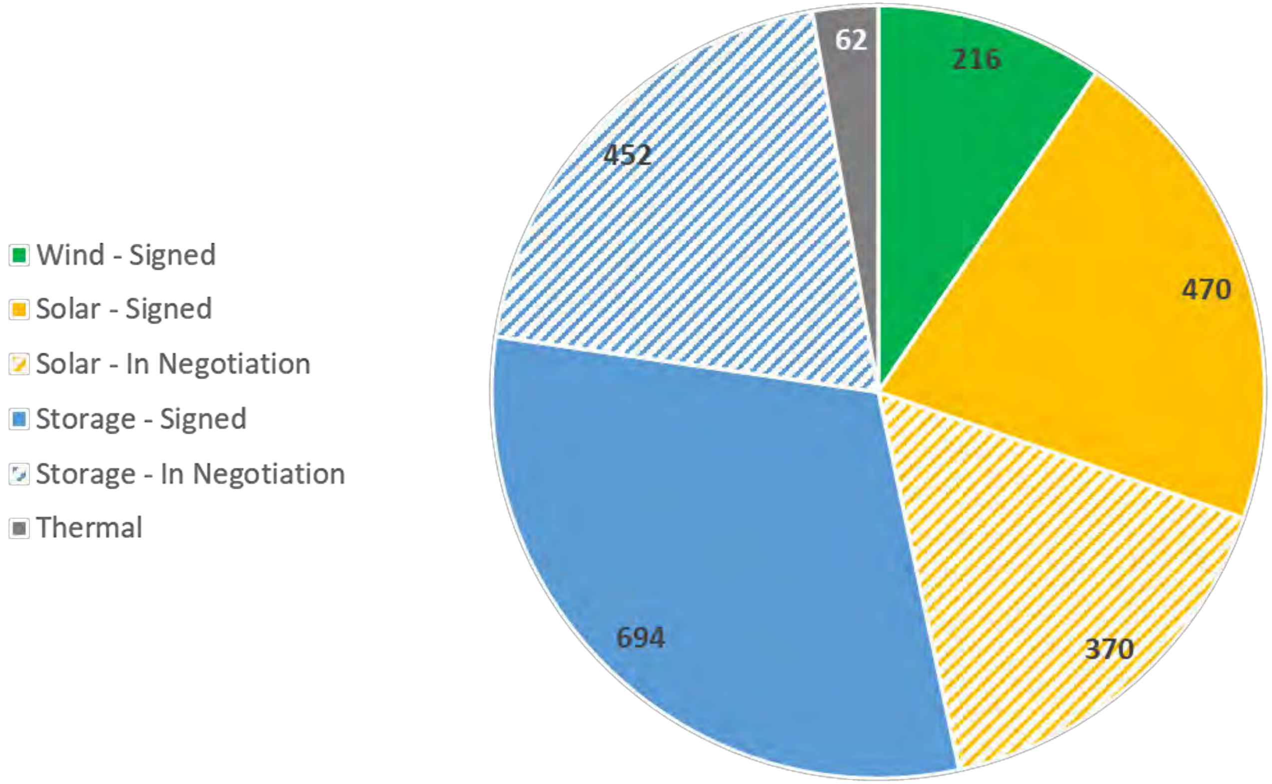


Securing a Diverse Resource Mix

APS is meeting customer growth and energy demand through a balanced, flexible approach to resource investments.

- **2023 Integrated Resource Plan**
  - Under development
- **Clean Energy Commitment**
  - Contracted for 2,000+ MW clean resources in service 2023-2025
- **2023 All-Source RFP**
  - To be released in late Q2; focus on resources in service in 2027-2028
- **Flexible natural gas generation**
  - Extended two summer tolling power purchase agreements

2022 ASRFP – Anticipated 2025 Resources



2022 ASRFP by the Numbers

- Sought 1,000 – 1,500 MWs of Resources and 600 – 800 MWs of renewables.
- Expected 2025 Resources
  - 2,264 MWs
  - 1,056 MWs - renewable energy
- 2026 negotiations underway
- Extension of two gas tolling agreements

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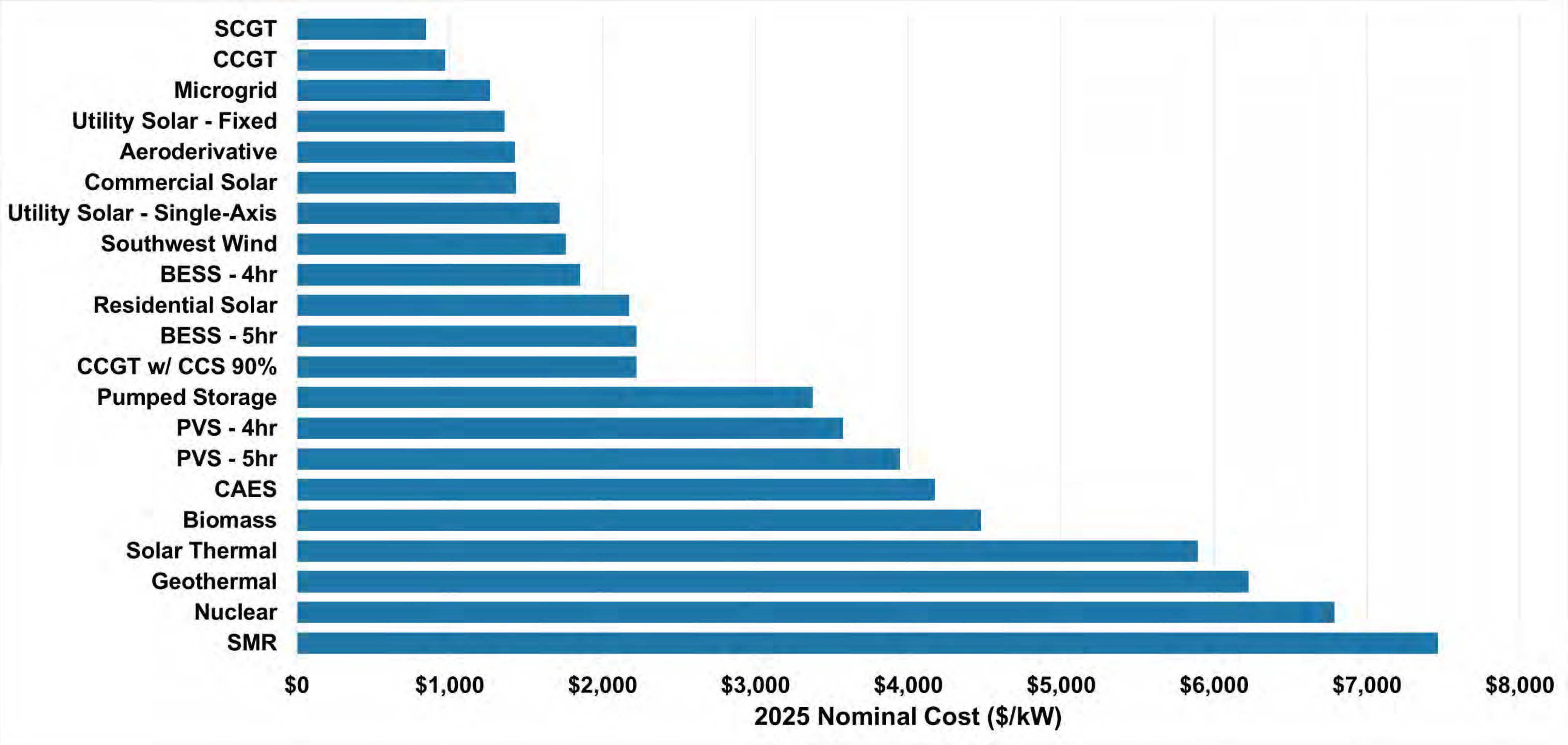
2023 ASRFP Specific Opportunities

- Agave batteries – EPC
  - Up to 400 MWs of energy storage
- Ironwood batteries and/or solar – EPC
  - 168 MWs of solar and/or energy storage
- Coal Community Transition - clean generation on Navajo Nation land (PPA and ownership considered)
- C&I DR
- Incremental generation at our existing gas plants
  - Up to 400MW APS-owned and/or third party-owned (PPA)
  - Clean capable/capable of conversion to hydrogen or other clean technology in the future

2025 New Resource Capital Costs



*Cost data is not indicative of total value or technology maturity

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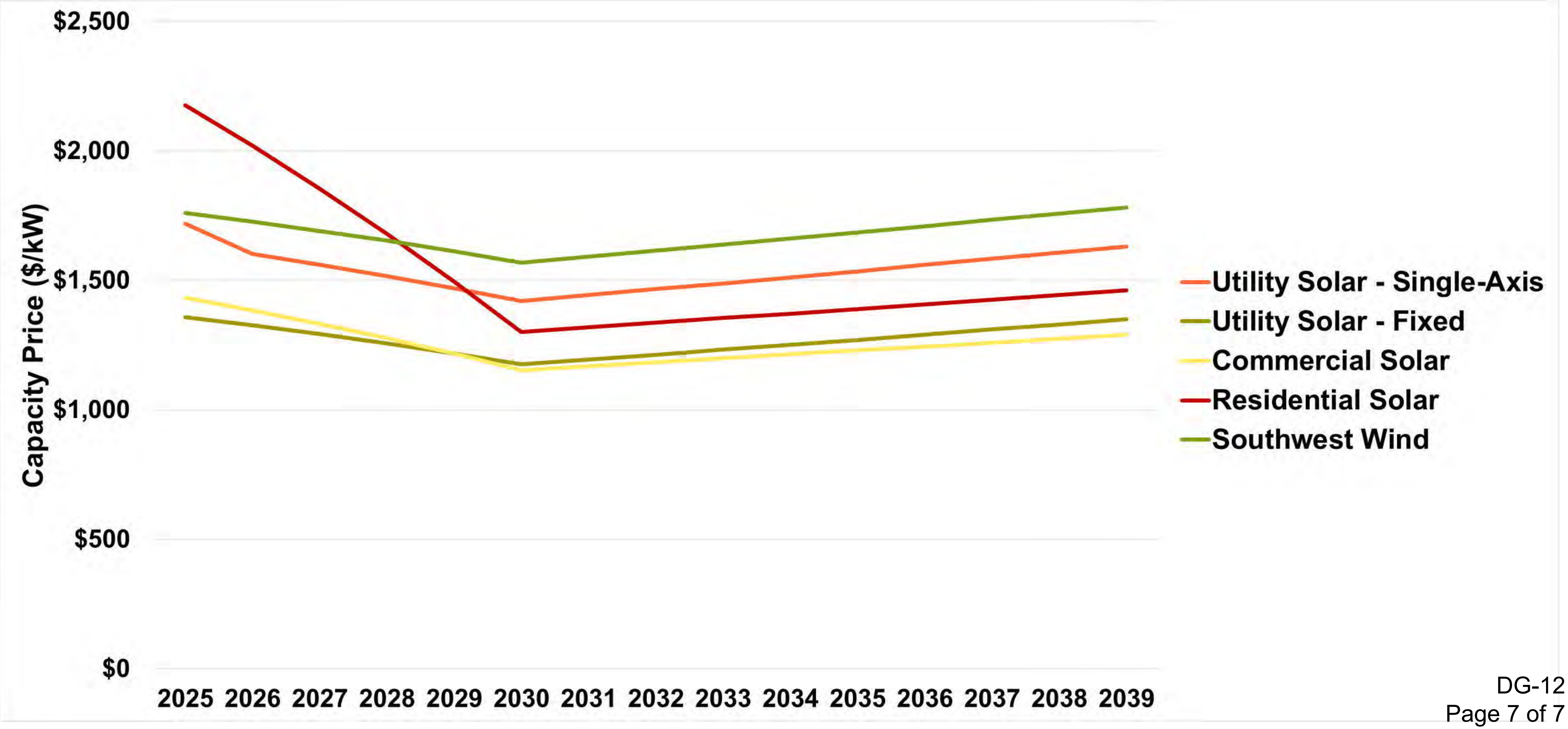
New Resource Capital Costs by Year – Renewable



Attachment DG-13

Excerpt of APS Presentation from APS RPAC Meeting (May 17, 2023)

APS RPAC Meeting

05/17/2023

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aps

2023 All Source RFP Key Features

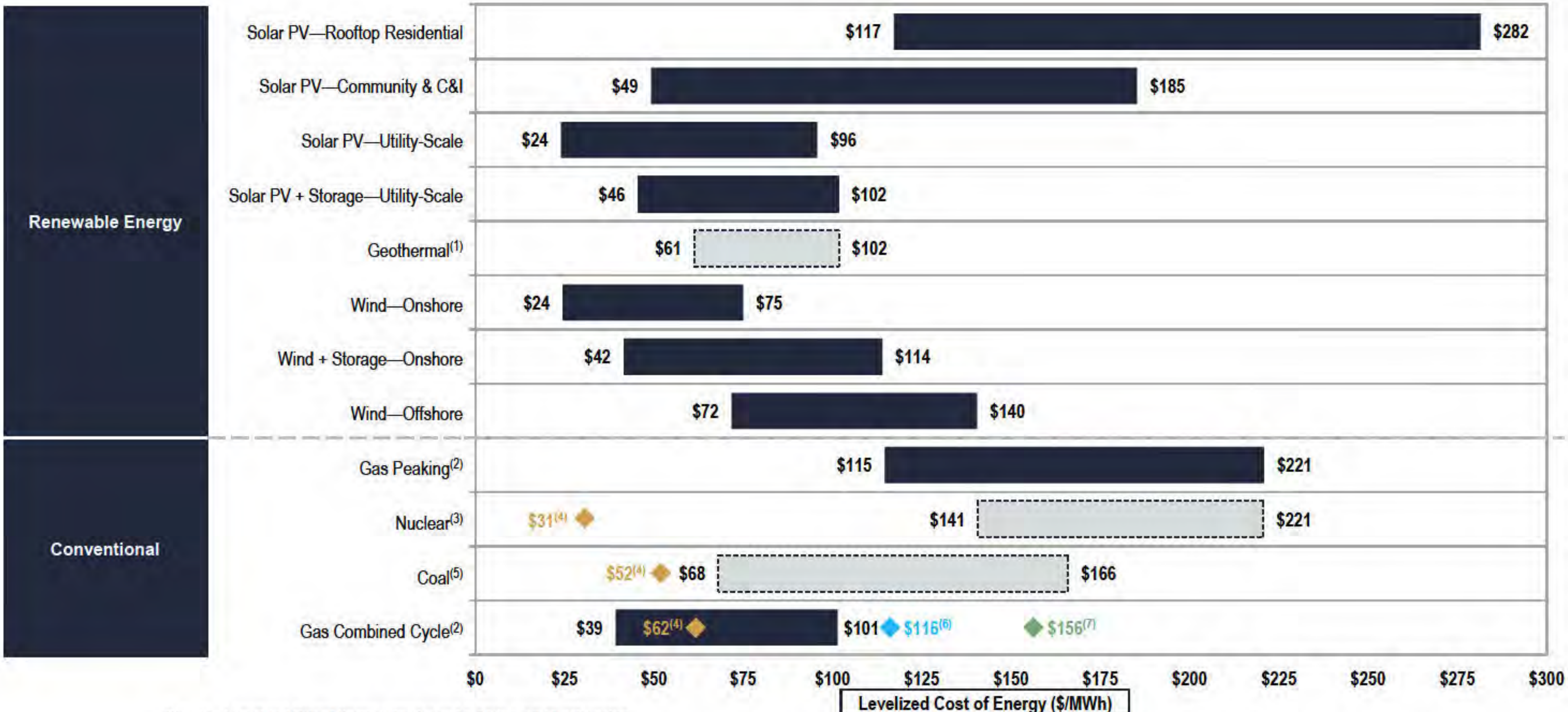
Agave	Ironwood	CCT	Cholla	Incremental Gas Generation
• 150 – 400 MW ESS • 4-hr Duration • Must meet APS Safety Standards • COD: 2026/2027	• 168 MW Solar + 168 MWs ESS • Selected through Green Power Partners • COD: 2026/2027	• Up to 250 MW • Competitive renewable generation located on Navajo Nation • Third party-owned (PPA) • COD: May 2027 or 2028	• Up to 115 MW • New generation on existing site of Cholla Generating Station • APS owned or third-party owned (PPA) • COD: ASAP following Cholla retirement.	• Up to 400 MW • APS-owned and third party-owned (PPA) • COD: ASAP, but no later than March 2027

Attachment DG-14

Excerpt of Lazard's Levelized Cost of Energy +
(Apr. 2023)

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Selected renewable energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities.

(1) Given the limited data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.

(2) The fuel cost assumption for Lazard's unsubsidized analysis for gas-fired generation resources is $3.45/MMBTU for year-over-year comparison purposes. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices" for fuel price sensitivities.

(3) Given the limited public and/or observable data set available for new-build nuclear projects and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15 0 results adjusted for inflation (results are based on then-estimated costs of the Vogtle Plant and are U.S.-focused).

(4) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper- and lower-quartile estimates derived from Lazard's research. See page titled "Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies" for additional details.

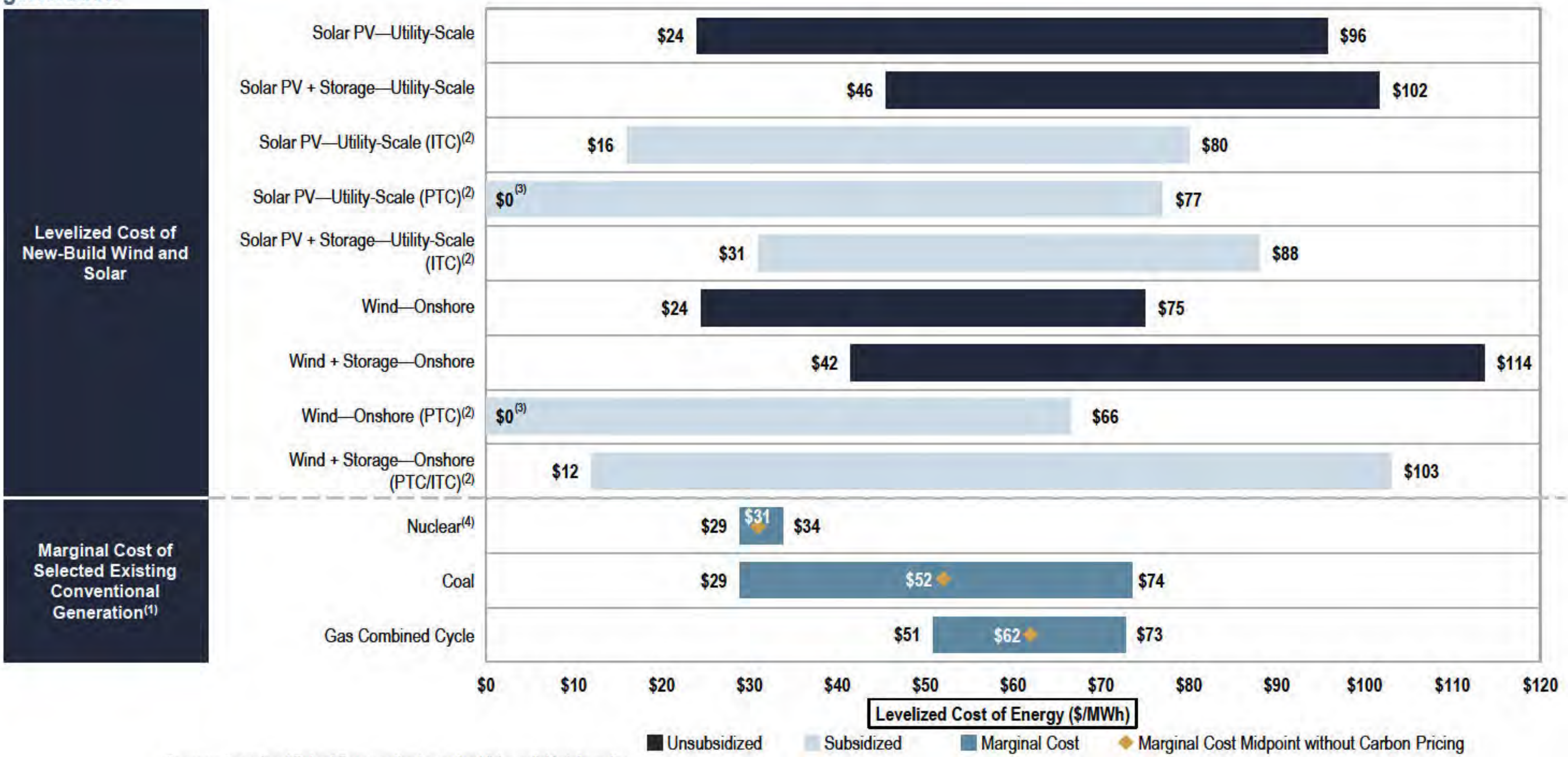
(5) Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation. High end incorporates 90% carbon capture and storage ("CCS"). Does not include cost of transportation and storage.

(6) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Blue" hydrogen, (i.e., hydrogen produced from a steam-methane reformer, using natural gas as a feedstock, and sequestering the resulting CO_2 in a nearby saline aquifer). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is $5.20/MMBTU, assuming ~$1.40/kg for Blue hydrogen.

(7) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Green" hydrogen, (i e., hydrogen produced from an electrolyzer powered by a mix of wind and solar generation and stored in a nearby salt cavern). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is $10.05/MMBTU, assuming ~$4.15/kg for Green hydrogen.

Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies

Certain renewable energy generation technologies have an LCOE that is competitive with the marginal cost of existing conventional generation



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Represents the marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle and coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed O&M are based on upper- and lower-quartile estimates derived from Lazard's research. Assumes a fuel cost of $0.79/MMBTU for Nuclear, $3.11/MMBTU for Coal and $6.85/MMBTU for Gas Combined Cycle.

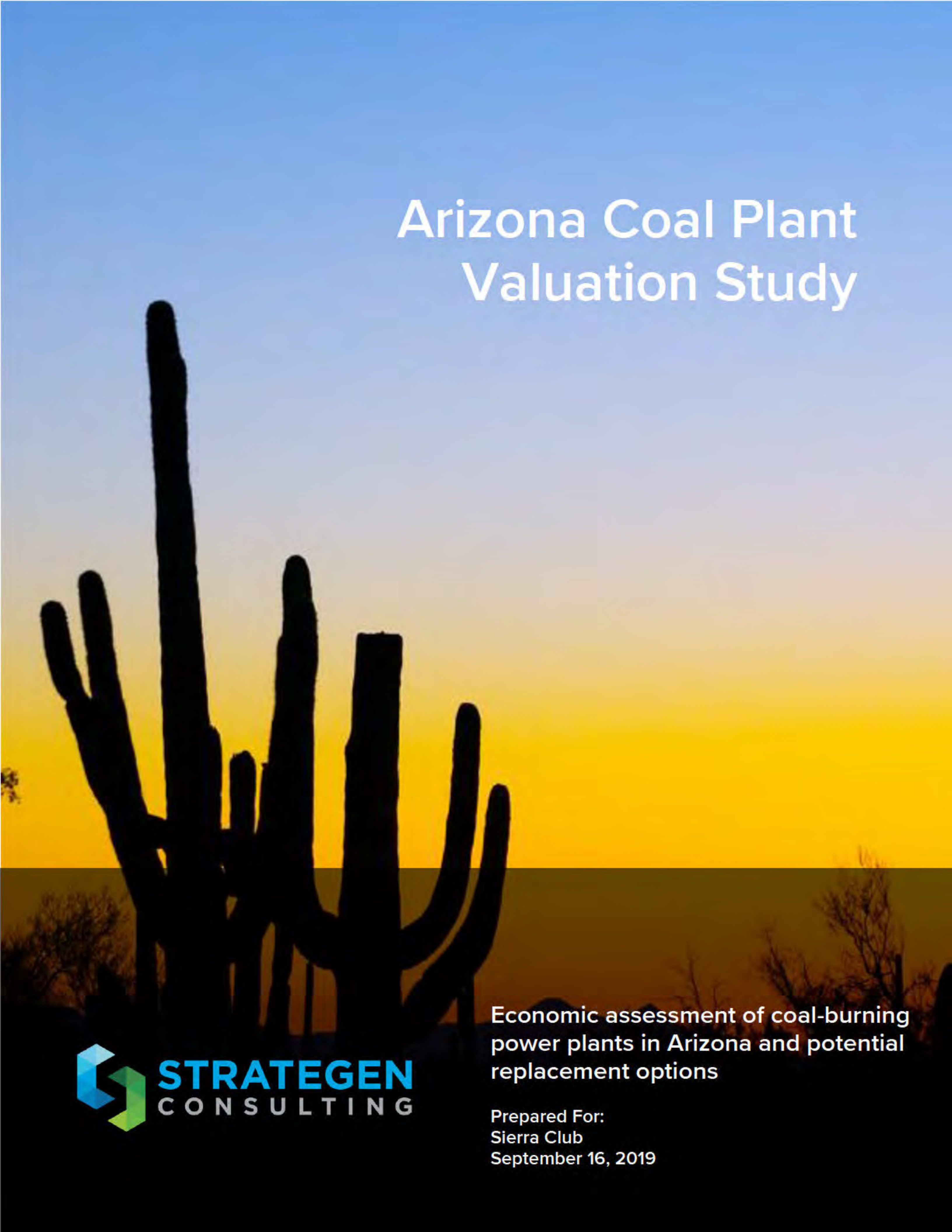
(2) See page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

(3) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Lazard's Unsubsidized LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying an after-tax IRR/WACC of 7.7%). Implied IRRs at this level for Solar PV—Utility-Scale (PTC) equals 17% (excl. Domestic Content) and 22% (incl. Domestic Content) and implied IRRs at this level for Wind—Onshore (PTC) equals 17% (excl. Domestic Content) and 25% (incl. Domestic Content).

(4) The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA (e.g., nuclear subsidies) are not included in our analysis and could impact outcomes.

Attachment DG-15

Strategen Consulting, *Arizona Coal Plant Valuation Study* (2019)



Arizona Coal Plant Valuation Study

STRATEGEN CONSULTING

Economic assessment of coal-burning power plants in Arizona and potential replacement options

Prepared For:
Sierra Club
September 16, 2019

Arizona Coal Plant Valuation Study

Prepared for:
Sierra Club

Prepared by:
Maria Roumpani
Edward Burgess
Sophia Ahmed
Jack Chang

Strategen Consulting, LLC
2150 Allston Way, Suite 400
Berkeley, California 94704
www.strategen.com

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Table of Contents

Executive Summary

Coal-burning generation serving Arizona customers is no longer economically competitive when compared to renewable energy resources such as wind and solar, or market purchases. Already, older coal-burning units powering the state have higher levelized costs of energy (LCOE) on a going forward basis than their replacement options. More specifically, retiring all 11 units at the six coal facilities examined in this study and replacing them with a solar PV plus storage or wind resource can save Arizona customers upwards of $3.5 billion.

Coal unit replacement with alternative resource options in the 2023 timeframe provides significant economic benefits to electricity consumers due to reduced operating and maintenance costs (including fuel) and avoided incremental capital costs, while at the same time dramatically reducing emissions. Among replacement options, solar generation plus storage is less expensive on a LCOE basis when compared to all the coal-burning units analyzed. Wind from New Mexico is also cheaper than the continuing operation of most of those units.

In addition to the operating and fuel savings that come from the replacement of coal-burning units with cleaner resources, there are also potential savings for ratepayers based on the regulatory treatment of the undepreciated value of the assets. An illustrative example of securitization in case of retirement of the first unit at Springerville shows significant additional savings on top of those achieved by the avoidance of its operating and fuel expenses.

The study also analyzed the Four Corners plant, one of the largest coal plants to service Arizona, and concluded that despite the coal supply agreement with the Navajo Transitional Energy Company through 2031, its continuing operation is more expensive than replacement options. The potential benefits from a Four Corners plant retirement, although significantly reduced by the plant's existing coal supply obligation, are still high enough to justify its replacement by other generation options in the near term.

1. Introduction

The U.S. coal-burning plant fleet is aging and facing increasing economic pressure due to the falling costs of renewable energy generation. Nationally, in 2018 and 2019, 100 units with a combined capacity 32,649 megawatts (MW) retired or are scheduled to retire. This trend has been particularly strong in the West and includes Arizona's Navajo Generating Station (NGS) -- the largest coal-fired power plant operating in the western U.S. -- which will close at the end of 2019. The transition away from coal increasingly makes economic sense due to reductions in the cost and the technology advancement of renewable energy and energy storage.

On behalf of the Sierra Club, Strategen conducted an economic analysis to better understand which of the coal units that serve Arizona's load may be most suitable for replacement with clean energy on an economic basis. The study concluded that all the coal units serving Arizona load are more expensive than currently available cleaner options. Arizona ratepayers stand to save money on their electricity bills by the retirement of coal-burning units and their replacement with renewable resources.

Recognizing the economic trend, Arizona Public Service (APS) has announced its plans to cease coal generation by 2038.[1] Similarly, Tri-state Generation and Transmission, a wholesale power supplier to western energy co-ops, has retired one coal-burning plant and plans to retire two more by the end of 2025, in addition to installing 100 MWs of solar and 104 MWs of wind in 2019[2]. Salt River Project (SRP) aims to reduce its coal fleet carbon emissions by 30% by 2035 and reduce its CO_2 emissions by 90% from 2005 levels by 2050[3]. Tucson Electric Power (TEP) plans to reduce reliance on coal to 38% of retail energy deliveries by 2030 and serve 30% of its retail load with renewable generation by 2030[4].

While there is a clear intention to move away from coal-burning generation, the pace is not fast enough to fully capture the economic benefits of this transition, and Arizona ratepayers might end up paying more than they should to keep expensive coal units operating for several more decades. Other western states are more ambitious in their plans to reduce coal-burning generation and increase renewables. For example, in spring 2019, Nevada passed a bill that would require the state to generate 50% of its electricity from renewable resources by 2030 and aim for 100% carbon-free resources by 2050. NV Energy supported the bill and has plans to add over 1.2 GW of solar and 590 MW of battery storage to its generation mix, pushing it past its target to double renewable energy capacity between 2018 and 2023.[5] Similarly, New Mexico has committed to 100% carbon-free electricity by 2045. The Public Service Company of New Mexico aims to

[1] Arizona Public Service Integrated Resource Plan Stakeholder Meeting Presentation, April 4, 2019. Accessed at https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

[2] Tri-State Generation and Transmission, Responsible Energy Plan. Accessed at: https://www.tristategt.org/responsibleenergyplan

[3] Salt River Project, 2035 Sustainability Goals. Accessed at: https://www.srpnet.com/environment/sustainability/2035-goals.aspx

[4] Tuscon Electric Power, 2018 Action Plan Update. Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[5] See: https://www.greentechmedia.com/articles/read/nv-energy-signs-a-whopping-1-2-gigawatts-of-solar-and-590-megawatts-of-stor#gs.16tp1m

eliminate carbon emissions from its power generation by 2040.[6] The Colorado Energy Plan is Xcel Energy's roadmap to develop a significantly cleaner energy mix and reduce carbon emissions in Colorado aiming for nearly 55% renewable energy by 2026, and a 60% reduction of carbon emissions from 2005 levels.[7] Within this context, Arizona utilities could speed up the retirement of coal units and invest in renewable energy, all while achieving net savings for their ratepayers, as shown in the study.

On the policy front, the Arizona Corporation Commission (ACC) adopted a Renewable Energy Standard (RES) in 2006 that calls for 15% of Arizona's power fleet that is regulated by the ACC to be powered by renewables by 2025, and for 30% of that renewable energy to come from distributed energy technologies. The Commission is now considering whether to expand this standard to account for the increasingly favorable economics and customer preference for renewable energy infrastructure. For example, the Commission Staff recently put forward a proposal that includes a voluntary renewable energy goal of 45% by 2035.[8] In response, 25 stakeholders developed a joint proposal that includes enforceable standards for 100% clean energy by 2045 and 50% renewable energy by 2030, aligning Arizona's goals with those of other western states.[9]

As mentioned above SRP has committed to a significant carbon emissions reduction goal in addition to deploying over 1000 MW of solar energy resources by 2025.

Strategen conducted a discounted cash flow analysis examining a "business-as-usual" case of energy production at 11 coal-burning generation units serving Arizona electricity customers. This analysis estimated the levelized cost of energy (LCOE) and the net present value (NPV) of costs for each coal unit's operating, maintenance, and incremental capital costs. Strategen then compared those results with the economics of three replacement portfolios: solar photovoltaics (PV) paired with battery storage, wind, and market-purchased energy. The analysis relied on data from publicly available sources as well as S&P Global Market Intelligence (formerly SNL) to estimate the levelized costs of renewable energy and coal-burning power.

Additionally, the study calculated the societal benefits of coal retirements based on the assumed future carbon price included in Arizona Public Service's Integrated Resource Plan. The study also included the effects that the existing must-take coal contract for the Four Corners plant would have on an early retirement decision, and finally the economic impact of installing pollution control equipment in the second unit of Coronado. Finally, the study includes an illustrative example of the additional savings for ratepayers that a refinancing mechanism could bring about. Arizona's utilities can both save families money on their electricity bills and clear pollution out of our communities and national parks by quickly replacing all coal power with new renewable infrastructure to take advantage of the state's abundant solar resources.

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[6] See: https://www.utilitydive.com/news/pnm-avista-commit-to-carbon-free-goals-on-heels-of-state-mandates/553240/
[7] Colorado Energy Plan. Accessed at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/CO-Energy-Plan-Fact-Sheet.pdf
[8] See: https://docket.images.azcc.gov/0000198875.pdf
[9] See: https://docket.images.azcc.gov/E000002141.pdf

2. Arizona's Coal Fleet

2.1. Coal Fleet

Arizona hosts five coal-burning generation stations. Two of those plants, Navajo and Cholla, are scheduled to be retired in 2019 and 2025 respectively and were not examined in this study. The three remaining plants, with seven generating units, are scheduled to operate until 2035 or later were analyzed in this study. Additionally, Arizona draws power from four coal-burning generation units at three plants outside the state -- Craig, Four Corners, and Hayden -- which were also examined. Together, the 11 coal-burning units that this study analyzed have a combined operating capacity of 4,792 MWs. Seven of those 11 units are 39 years or older, with Four Corners Unit 5 being the oldest. Springerville's four units are newer, with the most recently constructed Unit 4 beginning operations in 2009. Owners of the coal units examined in this study include utilities serving Arizona customers such as Arizona Public Service, Tucson Electric Power, Salt River Project, and Arizona Electric Power Cooperative. Additionally, some of the plants are co-owned by non-Arizona utilities including PacifiCorp, Xcel Energy, PNM Resources, Platte River Power Authority, and Tri-State Generation and Transmission Association. The Navajo Transitional Energy Company (NTEC) also owns a 7% stake in the Four Corners plant.

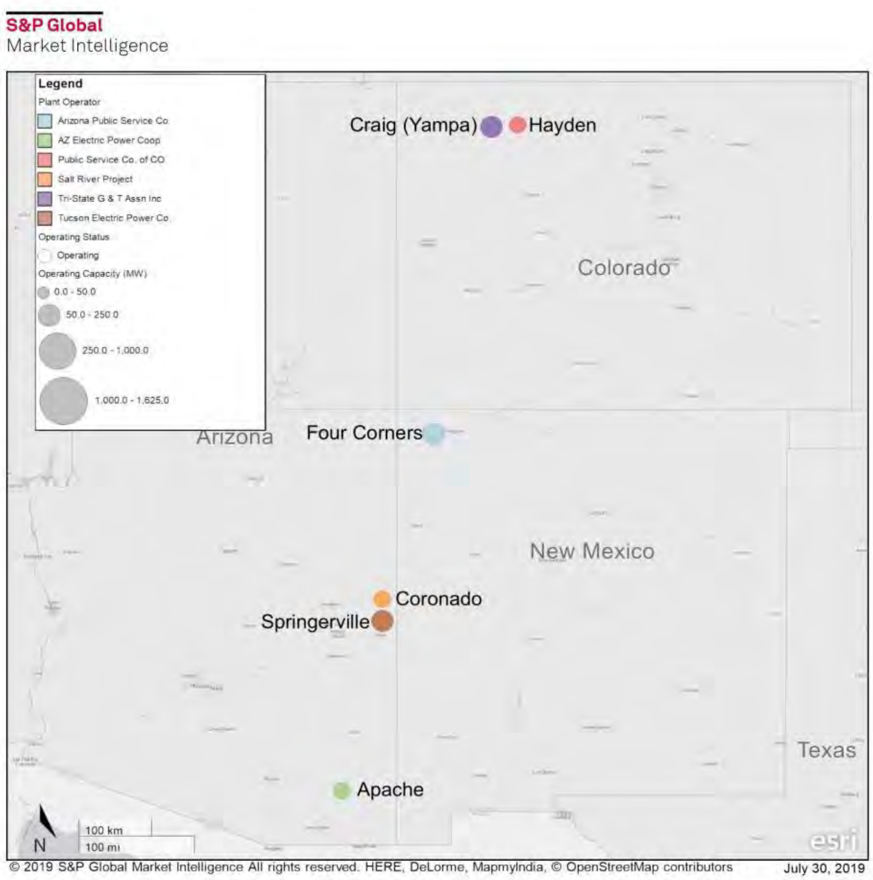

Figure 1: Analyzed coal-burning generation units serving Arizona consumers

The Cholla (1,021 MW) and Navajo (2,250 MW) coal-burning plants also serve Arizona with a combined total capacity of 3,271 MWs. Cholla has four units, one of which retired in 2015, and one that is scheduled for retirement in 2020. The final two units are scheduled for retirement in 2025. Navajo has scheduled the retirement of all three of its units by the end of 2019. As such, we excluded these five operating Navajo and Cholla units from our analysis. The 11 units analyzed are all currently slated to operate through at least 2035.

Prior to 2035 however, co-owners of these plants face key decisions. For example, the coal supply agreements at Craig, Hayden, and Four Corners expire in 2020, 2027, and 2031, respectively. The agreements would either need to be renewed or a new fuel supply would need to be secured for the plants to continue operating. Additionally, Salt River Project has a transmission service agreement with the Western Area Power Administration to deliver power from Craig, Hayden, and Four Corners that could expire in 2024 unless it is renewed.

P ant – Unit	Operating Capacity (MW)	Owner	On ine Date	Current y P anned Retirement Date
Apache 3	325	Arizona E ectric Power Cooperative nc.	1979	2035
Coronado 1	380	Sa t River Project	1979	None Announced
Coronado 2	382	Sa t River Project	1980	None Announced
Craig 2	428	SRP (29%), TSG&T (24%), P atte River (18%), PacifiCorp (19.28%), Xce (9.72%)	1979	2039
Four Corners 4	770	APS (63%), PNM (13%), SRP (10%), NTEC (7%), TEP (7%)	1969	2038 (APS), 2031 (TEP)
Four Corners 5	770	APS (63%), PNM (13%), SRP (10%), NTEC (7%), TEP (7%)	1970	2038 (APS), 2031 (TEP)
Hayden 2	262	SRP (50%), Xce (37.4%), PacifiCorp (12.6%)	1976	2036
Springervi e 1	387	Tucson E ectric Power Company	1985	2040
Springervi e 2	406	Tucson E ectric Power Company	1990	2045
Springervi e 3	417	Tri-State Generation & Transmission Association, nc.	2006	None Announced
Springervi e 4	415	Sa t River Project	2009	None Announced
Tota	4,942			

Table 1: Operating Capacity, Ownership, and Retirement data for all studied units

Of the six plants included in this analysis, Springerville is the largest and is owned and operated by TEP. In December 2016, TEP purchased an undivided ownership in the common facilities at the plant and is party to a lease agreement with the other two plant owners (SRP and Tri-State) that expires in January 2021. If the common facilities leases are not renewed, the other parties may be obligated to buy a portion of these facilities or continue to make payments to TEP for their use of the plant. Thus, the terms of any lease extension or purchase could have implications for the retirement or future use of Springerville's facilities by parties other than TEP.

3. Comparative Cost Assessment of Arizona Coal Units

3.1. Overview

A cash flow analysis was used to calculate the cost of generating electricity from 11 coal-burning generation units at six power plants serving Arizona electricity customers. The methodology for this analysis is described in Appendix A, while key assumptions are described in Appendix B.

The analysis estimated the electricity generation costs of three resource comparison portfolios: (1) market purchases; (2) solar PV paired with battery storage (supplemented by market energy purchases); and (3) wind generation supplemented by capacity purchases (all replacement options are further characterized in Appendix A). The analysis compared generation costs in terms of both the LCOE (in $/MWh) as well as the NPV of total costs in 2019 dollars. We also conducted this analysis for a scenario including a hypothetical carbon price.

3.2. Levelized Cost Comparison

Based on our projections of costs through 2050 under a "business as usual" scenario, the LCOE for coal units serving Arizona ranges from the mid $40s per MWh for the Coronado units to the mid $60s per MWh for Four Corners. Among all coal-burning units in Arizona, the LCOE of generation is highest for the Four Corners units, both of which have already been in operation for about 50 years.

For a simple initial comparison, we compared the coal unit costs (in LCOE terms) to the costs of recent new wind projects in the eastern New Mexico region[10] and a recent new solar plus storage project in the central Arizona region.[11] An incremental transmission cost was added to the wind power purchase agreement (PPA) to reflect the cost of new transmission assets or wheeling charges that may be necessary to deliver renewable energy resources from New Mexico, which rendered the wind resource more expensive than the continued operation of one coal unit. Meanwhile, replacing coal-burning generation with market energy purchases or solar plus storage is significantly cheaper than all coal units.

[10] Based on SPS' recent procurement of the Sagamore and Hale wind projects with appropriate adjustments made for the phase out of the federal production tax credit. See Appendix A for more details.
[11] Based on the Central Arizona Project's recent procurement of a 20 MW solar plus 60 MWh storage facility. See Appendix A for more details.

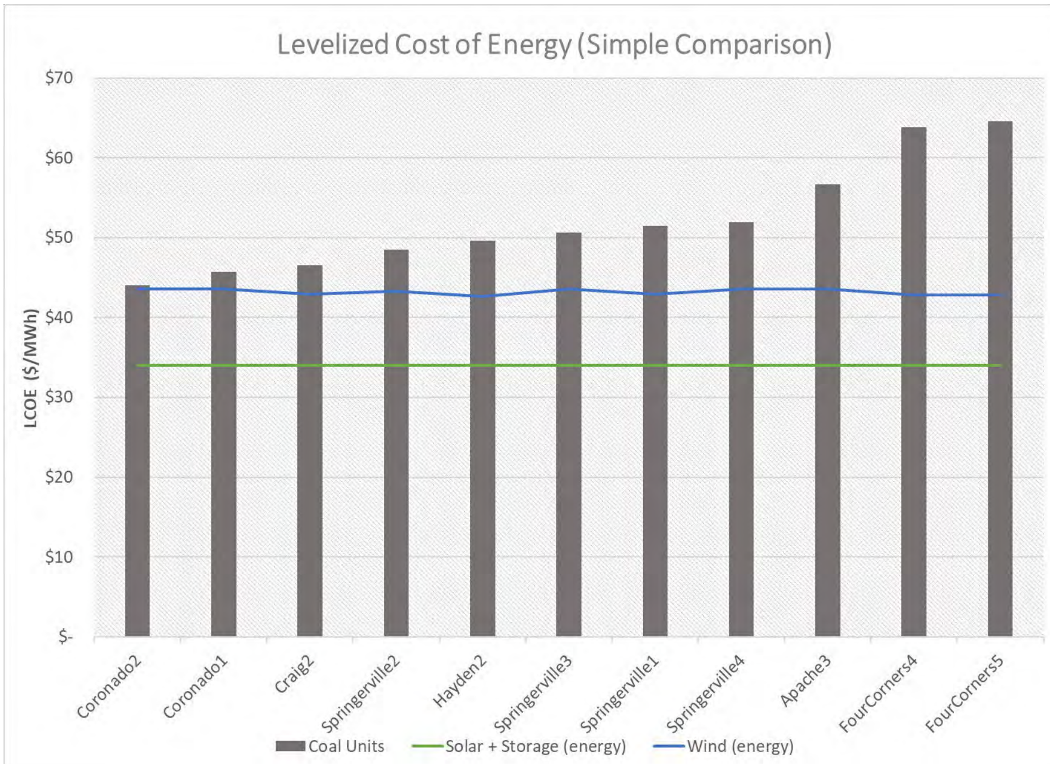

Figure 2: LCOE of coal units (2019 through 2050, or expected retirement date if sooner) compared to Sagamore Wind Energy PPA rate (with a transmission cost adder) and the solar plus storage PPA estimated by the Central Arizona Project (energy only)

While a simple LCOE comparison of wind and solar prices is useful, it does not fully capture the fact that individual wind and solar resources provide different capabilities than conventional fossil resources in terms of the availability of energy and capacity. Figure 3, below, compares the coal unit costs to three different "replacement resources" designed to provide an equivalent amount of energy and peak capacity as each of the coal units. Since wind resources are generally higher in energy value (i.e., higher capacity factor relative to solar), the wind replacement was sized to yield equivalent energy (MWh) as the coal unit and supplemented with market purchases to provide equivalent capacity (MW).[12] In contrast, since solar resources are generally higher in capacity value (i.e., higher effective load-carrying capability, or ELCC, value relative to wind), the solar replacement was sized to yield equivalent capacity (MW) as the coal unit and supplemented with market purchases to provide equivalent energy (MWh). Storage dispatch was optimized to minimize the cost of purchasing additional energy from the grid.

Furthermore, the second unit of the Coronado plant was assumed to install Selective Catalytic Reduction to control emissions that contribute to regional haze. Assuming a $110 million installation cost in 2029[13], and a 20-year lifetime, the installation increases the LCOE of the unit by approximately $2.80 per MWh.

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[12] For many years, a significant amount of excess generation capacity has existed near the Palo Verde and Mead trading hubs and may be available for purchase as a capacity resource. The amount of excess capacity has diminished in recent years through asset purchases and long-term contracts however a portion of uncontracted capacity still remains.

[13] See: https://www.azcentral.com/story/money/business/energy/2016/07/21/partial-shutdowns-proposed-srp-salt-river-project-coronado-generating-station-coal-plant-northern-arizona/87389718/

On August 20, 2019, the Environmental Protection Agency (EPA) issued new guidance to help states prepare for the second implementation period of the federal regional haze program. This new guidance puts emphasis on "discretion and flexibilities" for complying with long-standing mandates to protect visibility in federal areas. More specifically, EPA recommended that "visibility is the ultimate focus of the program and states ought to consider that against the costs and other impacts associated with the control measures." In the draft guidance, there was a recommendation that the older coal-burning power plants like Coronado, which were regulated under the first 10-year State Implementation Plan (SIP) period, could be forced to apply even more stringent pollution controls. This language is gone in the final guidance. Another recommendation reminds states they do not have to do everything during this 10-year period.[14] However, based on our analysis, a solar and storage resource remains more economic than the second unit of the Coronado plant, even in the absence of a regional haze control requirement.

Finally, the Four Corners plant has a coal supply agreement with the Navajo Transitional Energy Company through 2031. The agreement initially required a minimum tonnage of approximately 5.2 million tons per year but was amended in the summer of 2018 to reduce the coal tonnage to approximately 4.7 million tons each year. The minimum tonnage falls below that level in later years. If the plant retires before 2031, the operators will still have to pay for the minimum tonnage per year. Thus, although the LCOE in Four Corners is high, the levelized cost of an alternative would have to be significantly lower to compare favorably to the coal unit, due to the cost of the continuing coal supply obligation. Figure 3 presents the avoided LCOE in case of retirement (full height of the bar for Four Corners), as well as the reduction in this benefit by the unavoidable cost of the coal supply agreement (dotted bar is a negative benefit, subtracting from the total potential benefit of retirement). Our analysis indicates that the Four Corners units are uneconomic when compared to other options, even when the "must take" provisions of the coal supply obligation are accounted for. Their retirement could free up transmission that will allow Arizona to access more renewable energy options.

[14] https://www.law360.com/articles/1190628/4-takeaways-from-epa-s-regional-haze-rule-guidance?copied=1

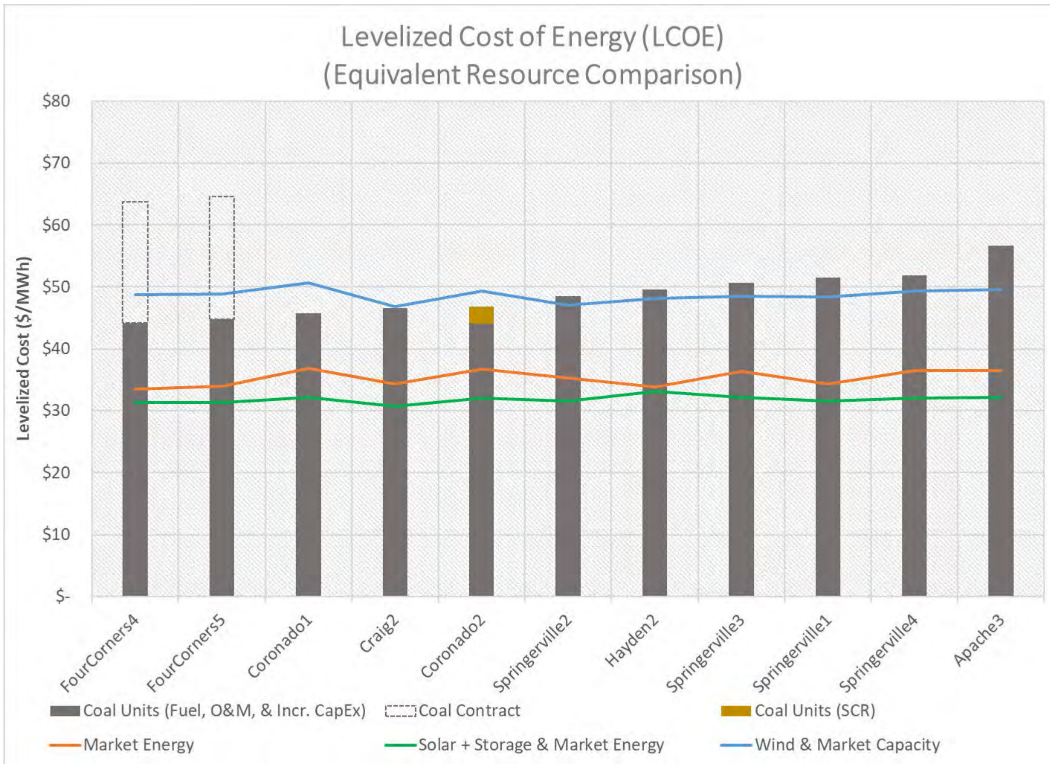

Figure 3: LCOE of coal units (2019 through 2050 or expected retirement date if sooner) versus replacement resource options. Replacements include: 1) forward market purchases (energy only), 2) solar PV plus storage supplemented with market energy purchases, 3) wind energy supplemented with market capacity purchases. A 2023 replacement start date was assumed.

Of the plants being considered, the analysis of Four Corners is worth further attention for several reasons:

1. After the retirement of Navajo Generating Station, Four Corners will be one of the largest coal-burning power plants serving Arizona customers.
2. The plant is located in a critical location for delivery of high-quality wind energy resources from central and eastern New Mexico to markets in Arizona and California. Continued operation of the plant creates a bottleneck on the transmission system that may prevent Arizona from accessing a more diverse portfolio of clean energy resources (especially wind) without construction of costly new transmission lines.
3. The plant is a significant limiting factor in the ability of Arizona utilities to invest in additional low-cost solar, due to concerns about overgeneration resulting from the minimum generation characteristics of baseload units.
4. APS currently intends to operate the plant through 2038, though other owners have indicated their plans to exit the plant on a more accelerated timeline.

Our analysis indicates that the Four Corners units are uneconomic when compared to other options, even when the "must take" provisions of the coal supply obligation are accounted for. Their retirement could free up transmission that will allow Arizona to access more energy options, as well as alleviate concerns associated with overgeneration of solar.

The analysis concludes that operating any coal unit is more expensive than other alternatives examined.

3.3. Coal Replacement Analysis: Operations, Maintenance, and Incremental Capital Expenditures

In total, the retirement of the 11 units examined results in avoided costs of $10 billion (NPV) in fuel, operation and maintenance (O&M), and capital expenditures (prior to replacements). Some replacement options come in at a significantly lower cost and can thus provide net benefits to Arizona ratepayers.

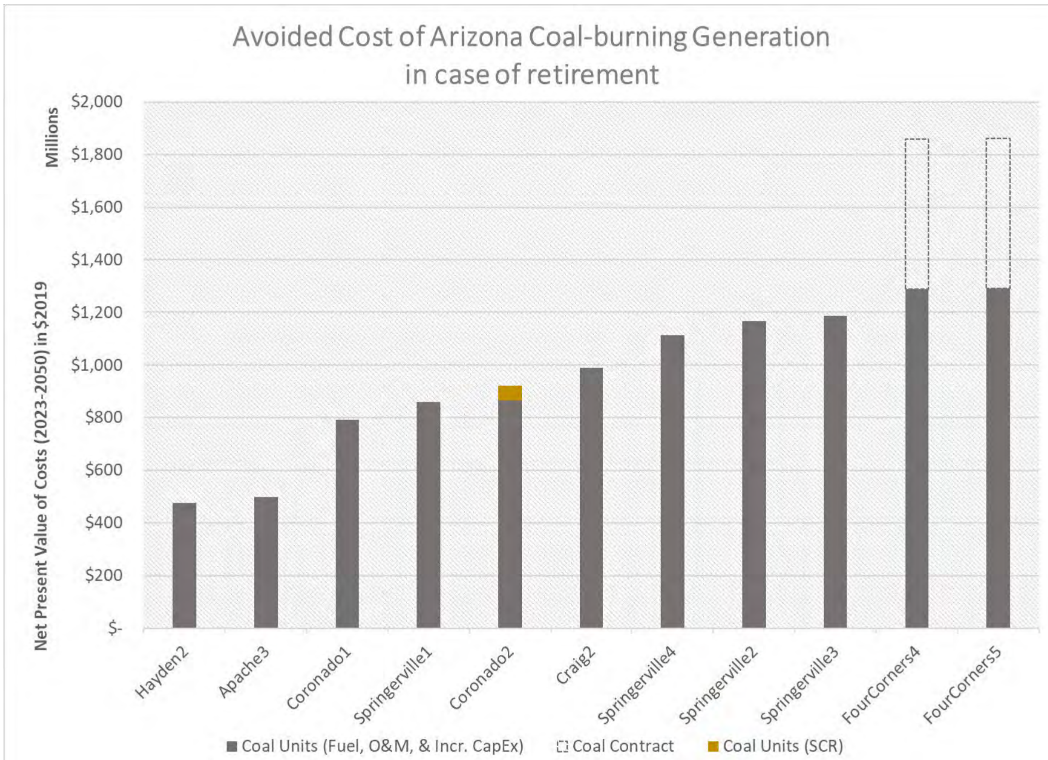

Figure 4: NPV cost for continued operation of Arizona's coal-burning fleet from 2019 through 2050 (or announced retirement date if sooner). Includes total operating and incremental capital costs and depreciation expenses of coal-burning generation units. Assumes currently announced retirement dates for all units.

Replacement with a combined Solar PV and Storage Resource

For the second replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Arizona's coal units with a solar PV resource with storage. The paired resource was complemented with market energy purchases in instances that the resource cannot meet the coal output. Storage was assumed to only charge from the solar resource and dispatch optimally to minimize the cost of additional energy purchases. The resource matched both the peak capacity value and energy provided by the coal unit (see Figure 6). This solar and storage "replacement resource" is further characterized in Appendix A.

For example, replacing the 175 MW Apache 3 unit with an equivalent-capacity resource requires a 220 MW-ac solar PV resource paired with storage. This resource is estimated to replace about 62% of the coal unit's energy. The remaining energy is accounted for through market energy purchases so that the solar resource provides equivalent energy and capacity as the coal unit it is replacing. The majority of those purchases (83%) happen during off-peak hours.

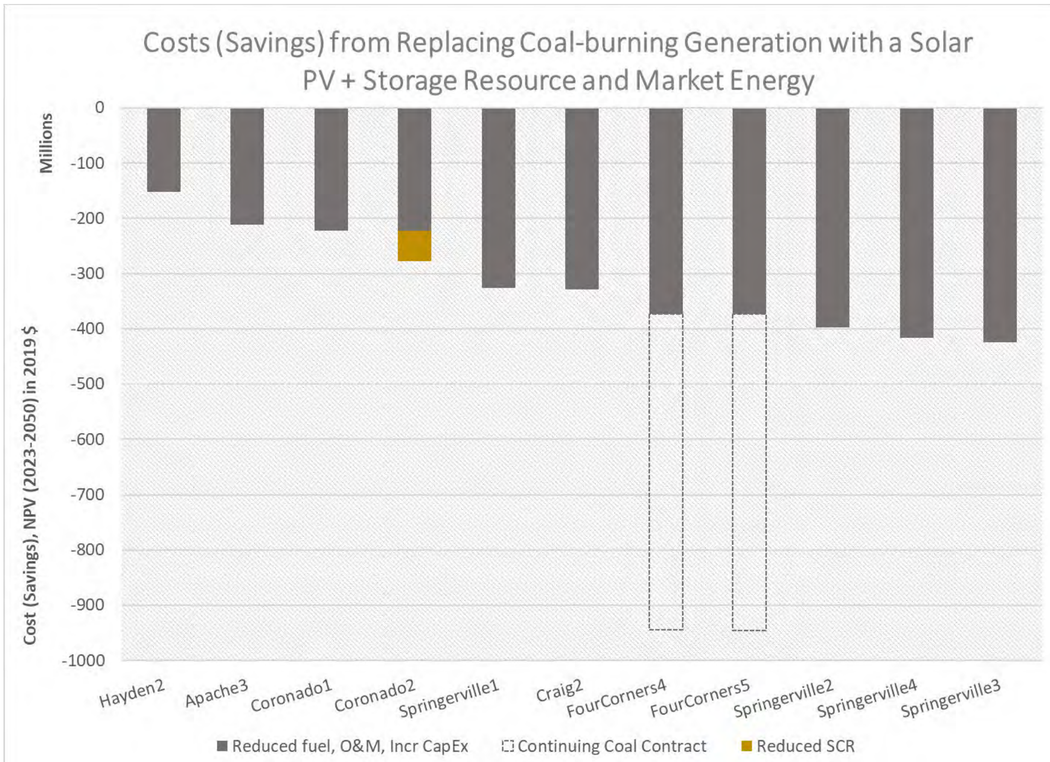

Figure 5: NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with a solar PV resource starting in 2023 that provides equivalent energy and capacity. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

We estimate that replacing all 11 coal units with solar resources in this fashion could yield approximately $3.5 billion in total savings (NPV).

Replacement with Market Purchases

The NPV of incremental costs (or savings) was projected from replacing the generation of each coal unit on an hourly basis with forward market purchases based on the Palo Verde forward index (OTC Holdings). This market purchase "replacement resource" is characterized in Appendix A below.

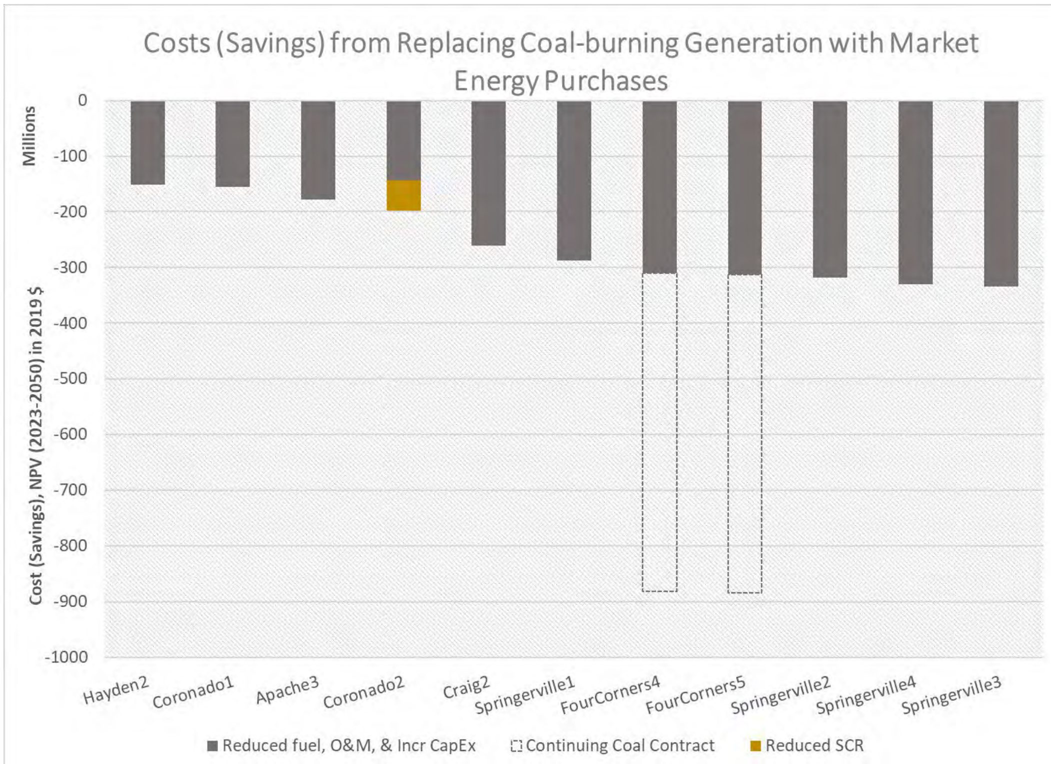

Figure 6: NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with Forward Market Purchases starting in 2023. Negative values correspond to potential benefits for the plant owner's customers.

Cost savings were observed for replacing all of the units with market purchases starting in 2023. Total cost savings were calculated to amount to \$2.8 billion.[15]

Replacement with Wind

For the third replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Arizona's coal units with a wind resource, combined with additional market capacity purchases, to provide an equivalent resource starting in 2023 (see Figure 7). This wind "replacement resource" is further characterized in Appendix A.

For example, replacing the 891 GWh of annual production from the Apache Unit 3 with an equivalent-energy resource requires approximately a 231 MW-ac wind resource (assuming a 44% capacity factor). This resource is estimated to provide about 70 MW in terms of capacity value (based on a 30% wind capacity credit).[16] The remaining 216 MW were accounted for through capacity purchases to provide an equivalent resource in terms of both energy and capacity.

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[15] The market replacement option does not provide an equivalent resource, as it does not necessarily reflect firm capacity. Thus, expected savings might be lower.

[16] Based on the APS IRP Stakeholder Meeting presentation in April 2019, 30% approximates the capacity value of a wind resource in New Mexico.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

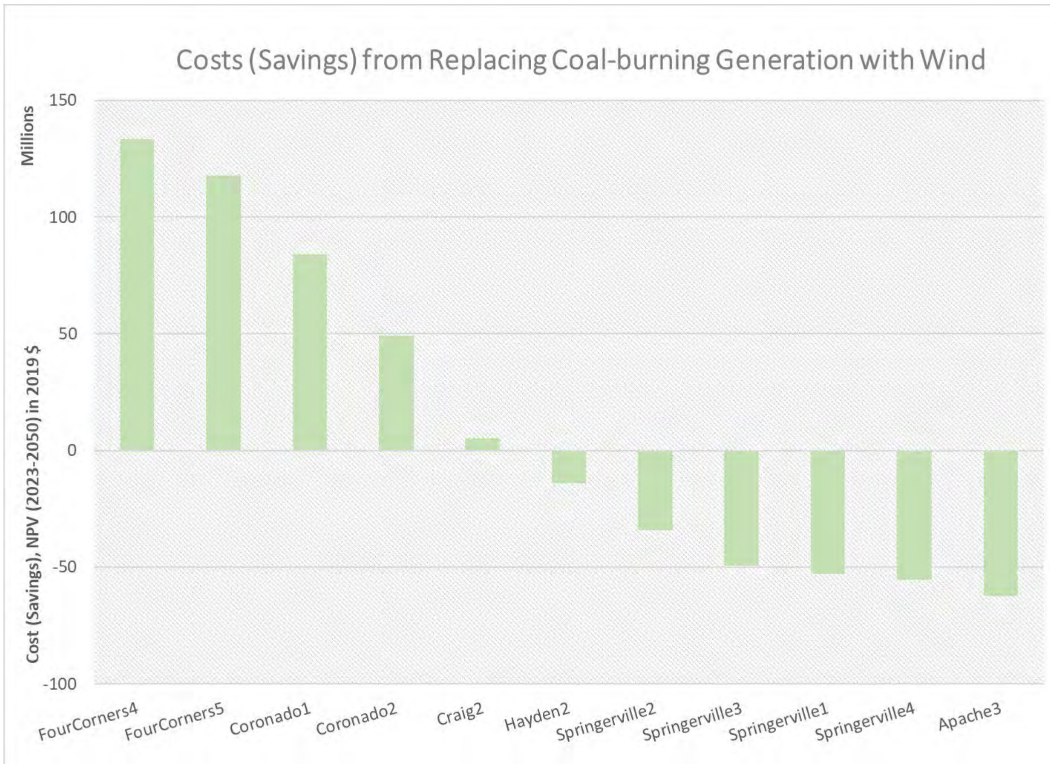

Figure 7. NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with a wind resource starting in 2023 that provides equivalent energy and capacity. The green bars encompass the O&M and incremental Capital expenditure costs/savings for each unit, as well as the impact of the coal contracts in Four Corners and that of the SCR installation in Coronado. They are presented as a single number for the sake of clarity. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

Although a New Mexico wind PPA is estimated to be significantly lower than the LCOE of the coal units, the addition of the transmission cost, as well as the fact that the Production Tax Credit is phasing out, renders this replacement option more expensive than the other replacement options. However, it does still yield savings in comparison to continuing operation of some of the coal units. Replacing the four units of the Springerville plant, as well as unit 3 of the Apache plant, and unit 2 of Hayden with a wind resource results in total savings of $263 million.

The results are sensitive to the transmission cost assumption. Absent additional transmission cost, the replacement of all coal units with wind resources would result in savings for Arizona ratepayers. One option that was not fully investigated in this analysis would be the replacement of the units with Arizona wind. Although, the quality of the resource in Arizona might be lower than wind in New Mexico, newer technologies with higher hub height might enable increased generation, which would make Arizona wind a realistic alternative to ratepayers while eliminating considerations of additional transmission cost from New Mexico. Secondly, adding wind increases the diversity of resources, which increases its value, especially as wind and solar have different generation profiles and can be complementary to each other. Finally, the retirement of Four Corners could open up transmission capacity that could potentially be used to transfer wind from New Mexico to Arizona at a lower cost.

3.4. Carbon Pricing Risk Assessment

In addition to projecting operating costs and capital expenditures of coal-burning generation in Arizona, Strategen conducted an analysis of the societal costs associated with greenhouse gas emissions from the plants. As described in Appendix A, we assumed a carbon price of $15.99 per short ton in 2025, which is the price specified in the APS 2017 Integrated Resource Plan. In accordance with that plan, this analysis escalated the carbon price at an annual rate of 2.5%. A discount rate of 3% was applied to these carbon costs in the NPV analysis, which is reflective of a societal discount rate more typically used for carbon cost analysis.

Requiring coal plants to internalize the cost of carbon pollution through the application of a carbon price increases the total costs for Arizona's coal-burning generation units, adding to the benefits of the three replacement options. Figure 8 compares the cost of energy for each coal unit with alternatives on a levelized basis with the addition of the carbon cost (maroon bar). For market energy purchases (including those associated with the solar PV replacement resource), a carbon price that equates to the emissions associated with a natural gas combined cycle unit was applied.[17]

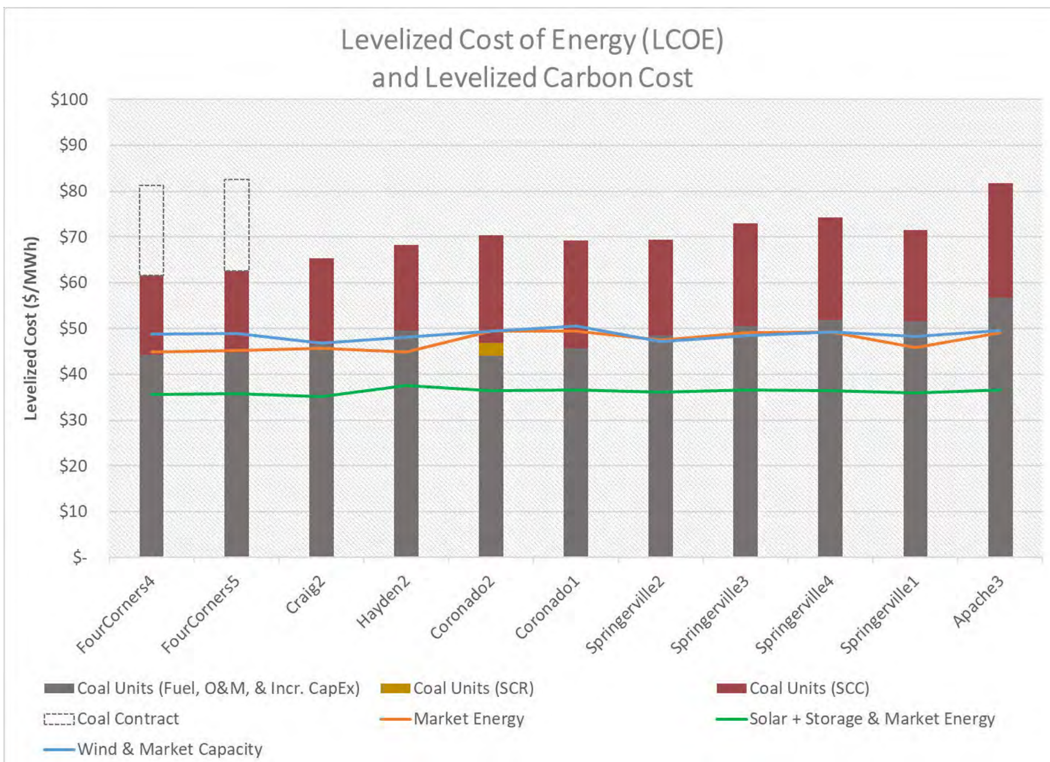

Figure 7: LCOE of coal units with added levelized carbon cost versus replacement resource options. The gray bars represent the operating costs (and incremental capital costs) of the plant, while the maroon bars represent the cost of carbon.

[17] As a simplifying assumption we assume that the marginal unit available for market purchases would most typically be a natural gas combined cycle unit. We also assume a heat rate of 7,649 BTU/kWh consistent with the following: https://www.eia.gov/electricity/annual/html/epa_08_02.html

The NPV analysis was conducted for the wind and solar replacement resources with the inclusion of a hypothetical carbon price. In all cases, adding the carbon cost substantially increases the NPV costs of coal units. It also adds to the market energy replacement option, as such energy is not necessarily clean.

Figure 8 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all 11 coal units with the solar PV plus storage replacement option in 2023 once the carbon price was factored in. The total net benefits of this scenario exclusively from avoided carbon costs are found to be $6.9 billion. The equivalent resource of solar plus storage is not completely carbon free due to the additional energy purchases. Even so, total benefits from replacing coal burning generation with solar plus storage, including both operating costs and carbon costs, can bring about $10.2 billion in benefits.

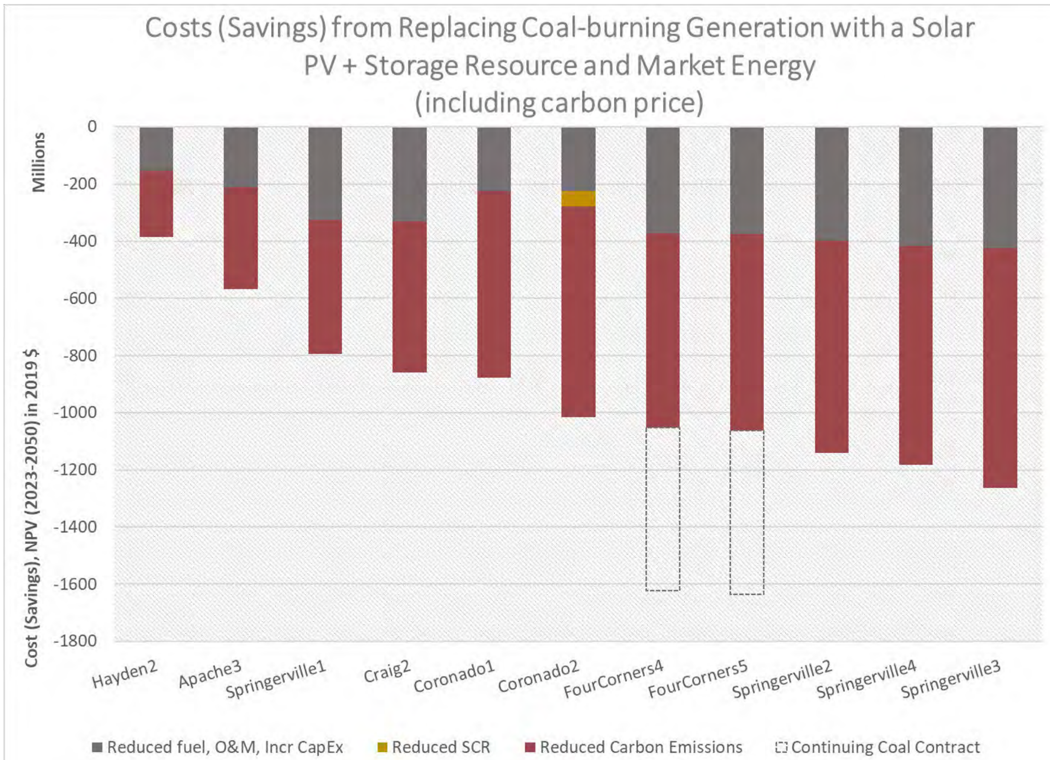

Figure 8: Savings in NPV from retiring coal units in 2023 compared to the solar PV plus storage replacement resource, when factoring in a carbon price.

Figure 9 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all 11 coal units with the wind replacement option in 2023 once the carbon price was factored in. Even though replacing coal-burning generation with a wind resource was not found to be economic for all units without factoring in the carbon emissions cost, once we accounted for a carbon price, the wind option became more economic than coal-burning generation for all units. The total net benefits of retiring all 11 units to this scenario are $7.3 billion.

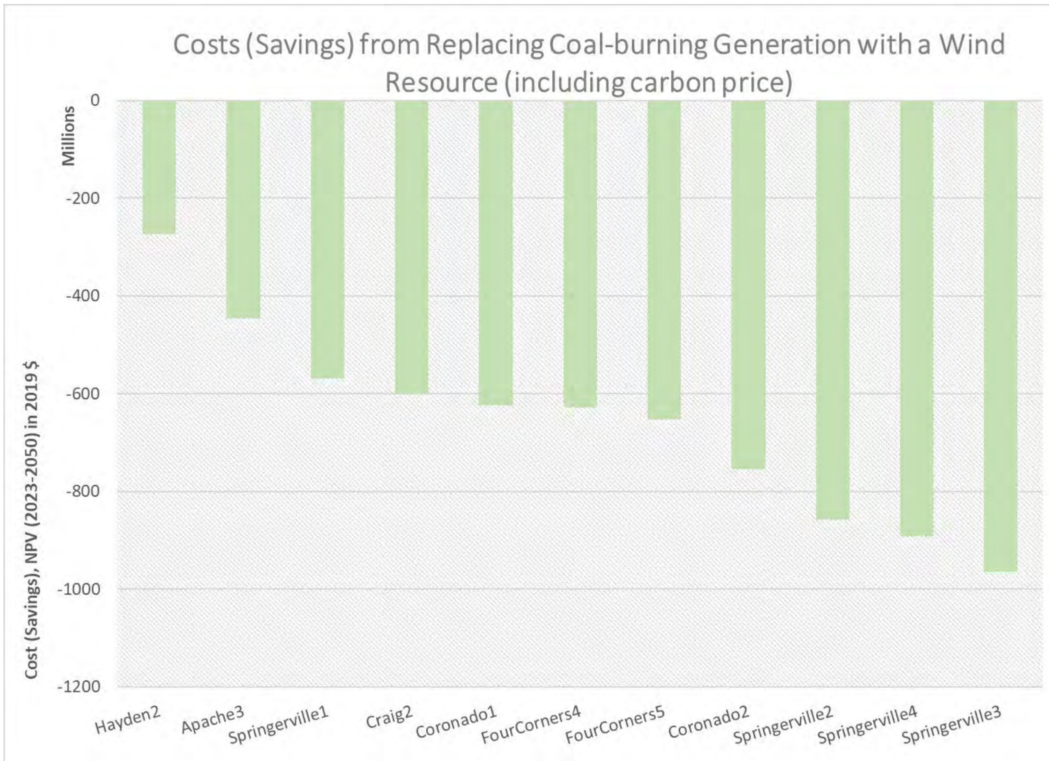

Figure 9: Savings in NPV from retiring Arizona coal generation units in 2023 compared to the wind replacement, when factoring in a carbon price.

3.5. Stranded Costs Analysis

Accelerated retirement of existing coal plants has the potential for significant ratepayer savings, simply by replacing the high operational costs of coal with cheaper, cleaner options as already analyzed in this study.

However, existing plants can have a substantial amount of capital invested in the plant that has not yet been fully depreciated. This capital invested in a plant is a cost that ratepayers have to pay if the plant continues to operate. However, in the case of a unit retirement, regulators have options to treat the remaining value of investment differently and potentially achieve even higher savings for ratepayers, beyond those previously quantified in the study.

Regulators may choose to let the utility continue to charge customers the full rate of return for capital invested in the plant and continue depreciating the plant as if it continued to operate, an option that would result in neither an increase nor a decrease in costs to ratepayers versus the status quo. However, other options available to regulators include the accelerated depreciation of the plant (potentially increasing rates in the near-term but getting the regulatory asset off the books quicker), the exclusion of some investments in the plant from earning a rate of return (if making such investments in an uneconomic plant was determined to be imprudent), or refinancing the unrecovered plant value at a lower interest rate, using a ratepayer-backed bond. All those options can result in significant ratepayer savings, in addition to the savings from O&M and fuel costs discussed earlier in the study.

To better understand the additional ratepayer savings that might result from one of those options, we looked at the refinancing option for the first unit of Springerville. Refinancing of a utility-owned asset like this can generally be done through the issuance of ratepayer-backed bonds which are used to repay the remaining undepreciated plant costs and decommissioning costs (net of salvage value). This mechanism is called securitization.

The benefits of securitization were estimated by determining differences in ratepayer capital costs under a "business as usual" (BAU) scenario, and a securitization scenario. Under the BAU scenario, these capital costs include annual depreciation expenses, and annual return on net plant (plus a gross up for taxes). For TEP, the current rate of return was assumed to be 7.04% based on TEP's current WACC[18]. For the securitization scenario, a 20-year bond was assumed with a starting value equal to the net plant balance in the year 2023, and an interest rate of 3.5%, which approximates the interest rate for a AAA-rated bond. Ratepayer costs were assumed to be equal to the principal and interest of the bond in each year of its tenor.

[18] Starting plant balance, depreciation reserve balance, and depreciation expenses for Springerville, unit 1, and TEP's current Weighted Average Cost of Capital (WACC) were based on TEP's recent rate application. Accessed at: https://docket.images.azcc.gov/0000197043.pdf

The NPV was calculated for both cases and the cost difference was estimated to be the overall benefit to TEP customers from securitization. Based on the depreciation study filed as part of TEP's 2019 rate application, the Springerville Unit 1's initial investment was $470 million, 70% of which has already been depreciated. The ratepayer benefits of refinancing through securitization were estimated to be $23 million.[19] This would be in addition to the net savings of approximately $326 million from replacing the unit with an equivalent solar plus storage option as described earlier.

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[19] While the analysis presented here represents a reasonable first approximation of the benefits of securitization, we recognize there are other factors that were not explicitly analyzed and could influence the final outcome. These include the following:
• Additional capital expenditures associated with plant common costs (only unit costs were considered)
• Additional interim adjustments to depreciation schedules or plant balances
• Adjustments to net plant balance due to Accumulated Deferred Income Taxes (ADIT) were estimated for both the BAU and securitization case, however additional information is needed for a more precise estimate.

4. Key Findings & Conclusions

Arizona utilities can realize billions in savings for their customers through an orderly retirement of their coal fleets and replacement with clean energy alternatives. As this analysis shows, it is clear that coal is no longer an economic resource for utilities in the state when compared to clean energy replacement options.

Based on our analysis of operating and incremental capital costs, the highest-cost coal-burning units serving Arizona load (on an LCOE basis) are those at the Four Corners plant. However, the existing coal supply agreement reduces the potential savings that the plant retirement could bring about. Even with lower benefits, the retirement of the fourth and fifth units of Four Corners is an economically sound decision, as the savings from O&M and incremental capital costs are very high.

When replacement options were evaluated on an equivalent peak capacity basis, the results of this analysis did not change significantly when compared to an energy-only analysis. All the plants ended up being more expensive to operate than the solar plus storage replacement, while most of them are also more expensive than wind from New Mexico despite the additional transmission cost.

Accounting for a hypothetical carbon price reinforces the economics of replacing coal-burning generation, and also makes New Mexico wind more favorable for all units.

Solar PV generation plus storage in sun-rich Arizona has the greatest potential to produce energy at a lower cost than coal-burning power, even after including market purchases to provide an equivalent amount of energy output and peak capacity contribution.

Appendix A: Methodology

A.1. Coal Fleet Cash Flow Analysis

Strategen conducted a discounted cash flow analysis for the Arizona coal units identified in Section 2. This analysis relied upon plant- and unit-specific cost data obtained from publicly available sources as well as the S&P Global Market Intelligence database and was supplemented by unit-specific data from other sources, including regulatory filings available via the Arizona Corporation Commission.

For each coal unit, the cost elements included fuel, operations and maintenance (O&M, both fixed and variable), incremental new capital expenditures, and dismantling costs. These cost elements were projected for each year through 2050 and discounted to present value using a discount rate equal to that used in TEP's current Action Plan.[20] While the analysis extended through year 2050, we assumed unit retirements would occur based on currently announced retirement dates. In the case of Springerville units 3 and 4, there are no publicly announced retirement dates, and it was thus assumed that the units will operate until 2050. However, for the purposes of our analysis no incremental operating costs beyond 2050 were included.[21] For future years, plant output (i.e., capacity factor) at each plant was assumed to be equal to the average of the three most recent years, 2016-2018. Exceptions to this assumption include the Coronado plant which according to SRP's 2018 Integrated Resource Plan (IRP) will curtail operations during non-peak months as a result of an agreement with the EPA in lieu of installing additional emissions reduction equipment to Unit 1.[22] For this reason, when projecting the generation of the first unit of Coronado in the future, a heavier weight was given to later years when lower generation was reported compared to earlier years. The calculation of the generation of Four Corners Units 4 and 5 was also adjusted as the units were down for prolonged periods in 2017 and 2018.

Non-fuel O&M costs were estimated based on plant-level data collected from S&P Global for years 2016-2018 and escalated at an assumed annual rate of inflation (1.8%).[23] These costs are based on data reported in EIA Form 923 and FERC Form 1. Similarly, fuel costs were based on inflation adjusted averages of the previous 3 years' reported fuel costs for each plant and escalated each year at the inflation rate.

Dismantling costs for Craig Unit 2 and Hayden Unit 2, were based on documents filed by Xcel with the Colorado Public Utilities Commission. A cost per MW average of these units was calculated and used to estimate the dismantling costs of other units.

[20] Tuscon Electric Power, 2018 Action Plan Update.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[21] As such, the avoided fuel and O&M costs for Springerville 3 & 4 might be conservative.

[22] Salt River Project, Integrated Resource Plan Report 2017-2018.
Accessed at: https://www.srpnet.com/about/stations/pdfx/2018irp.pdf

[23] Some plants in Arizona have recently experienced extended outages due to operational issues (e.g. Four Corners). For these plants, years containing extended outages were excluded. Costs in the remaining years were benchmarked against prior years in the S&P Global database to ensure that more recent cost estimates were consistent with past performance.

Incremental capital expenditures were approximated based on the EIA NEMS modeling approach, which includes an annualized cost of $20/kW-yr for coal plants (in 2015 dollars), which increases by $7/kW-yr for plants over 30 years in age. Capital expenditures were assumed to decline during the years prior to retirement (whether retirement occurs early or not).

A.2. Replacement Analysis

As an initial screen, the LCOE of the coal units was compared to the LCOE of a market purchase resource, a solar PV plus storage resource, and a wind resource.

The cash flow for each coal unit was compared to several hypothetical "replacement resources" (or combinations of resources) that provided equivalent or nearly equivalent energy and capacity as the coal units. Three replacement portfolios were examined that represented different combinations of zero- or low-emissions resources – 1) forward market purchases, 2) solar PV plus storage plus market energy purchases, and 3) wind generation plus market capacity purchases. The portfolios were designed to capture a representative range of clean energy alternatives, while providing an equivalent amount of energy (MWh) as the coal unit being replaced. In addition, the wind and solar alternatives were constructed to provide equivalent capacity value (MW) as the coal unit being replaced. In each replacement case, the analysis assumed that the coal unit would operate until December 31, 2022, at which point the replacement resource would be placed into service. Replacement resource cost information was based on publicly available reports and data sources, as explained below.

Fuel supplies for at least three of the coal plants examined, Craig, Hayden, and Four Corners are currently subject to Coal Supply Agreements, ending in 2020, 2027, and 2031 respectively. While Strategen is not privy to the exact terms of these contracts, it is possible that they include "take or pay" provisions that are common to many Coal Supply Agreements. Strategen examined the impact of the Four Corners Coal Supply Agreement, as presented in the NPV Analysis. If "take or pay" provisions exist for the other two plants, we expect this would yield a modest reduction in the benefits of replacing the Hayden units prior to 2027 versus the BAU case, as the analysis has already showed for the Four Corners units.

Solar PV + Storage Replacement

A combined solar PV and storage replacement option was considered. The cost of a solar PV system was estimated assuming a fixed PPA rate of $33.99/MWh.[24] The PPA rate is based on a project that received full 30 percent investment tax credits (ITC). Absent the ITC, PPA rates could be higher. However, solar projects may qualify for the full ITC through 2019, as long as they are placed into service before 2024.[25]

The storage provides the ability to flatten the solar output across the on-peak hours, eliminating the need for a firming resource. No integration costs were assumed, while the duration of the storage was assumed to be 3.5 hours and the incremental capacity value of the combined resource was assumed to be 80% of the nameplate of the solar.[26]

The hourly MWh output of each solar PV system was estimated using NREL's System Advisor Model based on a 1-Axis tracking system being constructed near the location of each retired coal plant. The hourly generation profile of each coal unit was accessed through the S&P Market Intelligence Platform. The two were compared and in hours during which the solar output was not sufficient to cover the load otherwise served by the coal unit, additional energy purchases were assumed. Storage dispatch was optimized to minimize the cost of such additional purchases, while only being allowed to charge from the solar system. Hourly market prices were modeled as on/off peak[27] according to the forward curve at Palo Verde Index published by OTC Global Holdings (as of end of August 2019).

Below are three graphs of the average (over a year) hourly coal unit generation, solar generation, and storage charging profile. This example comes from the modeling of the third unit at Apache and includes a constraint that at least 75% of the energy used to charge the battery should come from solar.

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[24] The rate is based on a 20-year PPA for 20 MW of solar generation capacity with 60 MWh of battery storage. The bulk of the energy would be at the full contract rate of $33.99/MWh, but a portion of the energy over certain hourly thresholds will be charged at a discount rate of $19.00/MWh. Strategen used the full contract rate for all energy generated by the combined resource. Accounting for the discounted rate would result in additional savings of coal unit replacements. More information can be found at: https://www.cap-az.com/documents/meetings/2019-05-02/1754-050219-WEB-Final-Packet-Board-Meeting.pdf

[25] Internal Revenue Service Notice 2018-59

[26] The Central Arizona Project PPA is based on a minimum dispatch capability of the battery of 17MW, and a total energy capacity of 60MWh, which implies a duration of 3.5 hours. Assuming a 20% incremental capacity value for utility solar, and a 100% value for solar plus 4 hours of storage, Strategen estimates a conservative 80% capacity value for solar of 20MW plus storage of 17MW, 60MWh.

[27] On peak hours: 6am-10pm

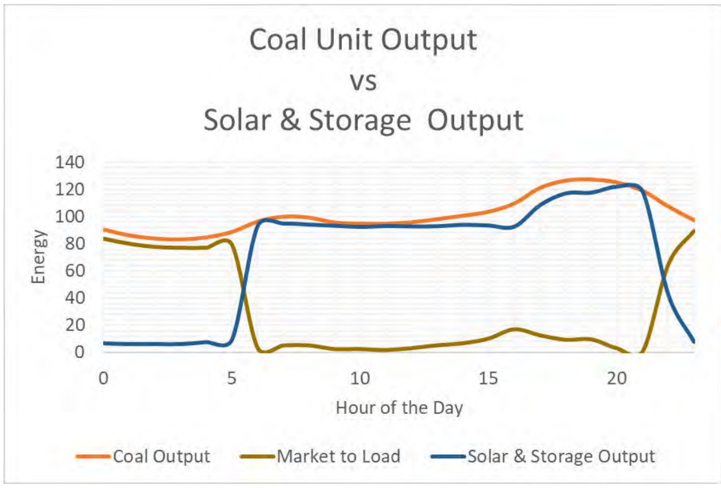

Figure 10: Coal unit output, Market Purchases to serve the load, and Solar & Storage Output

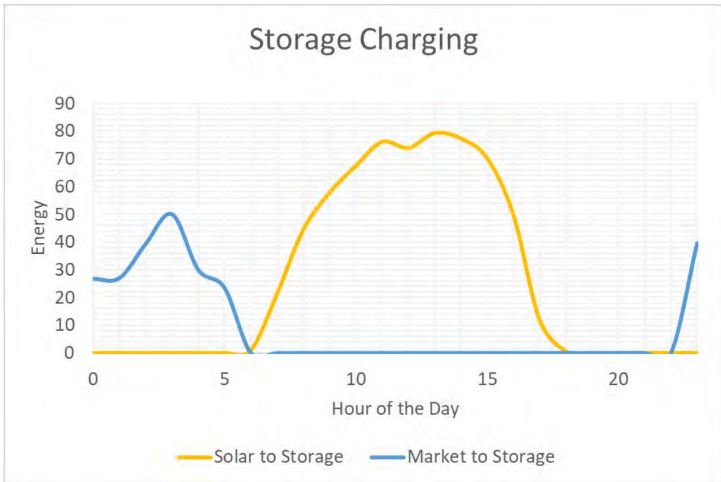

Figure 11: Storage charging profile

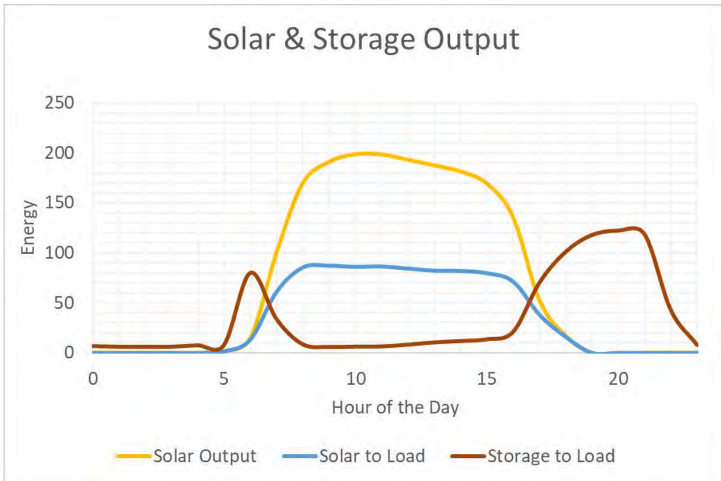

Figure 12: Solar & Storage Resource output

Forward Market Purchases

The cost of a market purchase replacement resource option was estimated based on the prices consistent with that in the Palo Verde Index published by OTC Global Holdings (as reported by S&P Global) as of end of August 2019. Annual on-peak and off-peak forward power prices were available through 2029. For the remaining periods (2029- 2050), power prices were assumed to escalate at the inflation rate. Market energy purchases were simulated to match hourly coal unit generation (as available through the S&P Global Market Intelligence database). The market replacement cost was calculated as the product of hourly prices (simulated as on/off peak Palo Verde forward prices) with the hourly coal unit generation.

Wind Replacement

A wind replacement option was also considered. The wind resource was assumed to have a capacity factor of 44%.[28] The cost of the wind generation was estimated assuming an average fixed PPA price of $18.97/MWh, escalating at 2% annually[29]. The Sagamore PPA price qualifies for a 100% Production Tax Credit (PTC). However, newer wind projects considered in this analysis would qualify for a lower PTC. Recent analysis has indicated that a substantial amount of wind projects in development for 2022 delivery have commenced construction in 2018 and would qualify for a 60% PTC.[30] Taking a conservative approach, we assumed that half of new wind resources entering service by December 2022 would qualify for a 60% PTC and half would qualify for a 40% PTC. The PPA price was thus adjusted upwards by $11.84/MWh.

Each wind system was sized to provide equivalent energy (MWh) to the coal unit being replaced. While sized to provide equivalent energy as the coal resource, a wind resource provides significantly less capacity value. As such, additional market capacity purchases were also included to ensure the MW of replacement capacity would be equal to the coal unit's capacity.

The capacity value for the wind resource was assumed to be equal to 30%, consistent with the value presented in the APS IRP Stakeholder meeting in April 2019. Additional capacity was purchased at an assumed cost of $39.48/kW-yr in 2019. This reflects an assumed blended average of $11.59/kW-yr in $2018 for short-term market purchases[31] and $69.60/kW-yr in $2021 cost for a new gas resource[32]. The capacity cost was assumed to escalate at the rate of inflation.

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[28] APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

[29] Direct Testimony of David T. Hudson on behalf of Southwestern Public Service Company, Case No. 17-00044-UT. Accessed at: http://164.64.85.108/infodocs/2017/3/PRS20236617DOC.PDF

[30] See: https://www.windpowerengineering.com/business-news-projects/more-than-61-gw-of-u-s-wind-turbine-equipment-has-qualified-for-the-ptc-since-2016/

[31] APS 2017 IRP, Table D-5.
Accessed at: https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf

[32] Average price of new gas resource according to APS 2019 Preliminary IRP
Accessed at: https://docket.images.azcc.gov/0000199276.pdf

The analysis assumed a $10/MWh transmission cost adder in 2019 reflecting the wheeling cost for transporting wind resources from New Mexico to Arizona. The adder was assumed to increase at the inflation rate.[33]

A.3. Carbon Pricing Risk Assessment

This analysis calculated the carbon cost of each coal plant's carbon-dioxide emissions using Arizona Public Service's guidelines for pricing, start date and escalation and discount rates. Based on APS parameters, the analysis set an initial carbon price at $15.99 starting in 2025, with an annual escalation rate of 2.5% and a discount rate of 3%.

[33] Consistent with the APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

Appendix B: Key Assumptions and Data Sources

Global Assumptions:

Assumption /Input	Value	Source & Description
Discount Rate	6.78%	Discount rate for Tuscon Electric Power consistent with its 2018 Action Plan 2016[34]
Inflation Rate	1.8%	Based on current inflation rate for the past 12 months (US inflation calculator)
Early Retirement Year	2023	Assuming last day of operations on 12/31/2022

Coal Plant Inputs & Assumptions:

Assumption/ Input	Value	Source & Description
Fuel Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. Average of 2016-2018 values adjusted for inflation were assumed in 2019 and escalated at inflation rate for subsequent years.
Variable O&M Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. Average of 2016-2018 values adjusted for inflation were assumed in 2019 and escalated at inflation rate for subsequent years.
Fixed O&M Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. 2019 values are based on average costs of 2016-2018 adjusted for inflation. Future costs were escalated at inflation rate. Fixed O&M costs for Four Corners were averaged over 5 years as late years might be considered higher than normal due to significant down time.
Incremental Capital Costs	$20-27/kW-yr	Based on EIA NEMS model:[35] $20/kW-yr (adjusted for inflation) assumed for plants <30 years and, $27/kW-yr (adjusted for inflation) assumed for plants >30 yrs.
Dismantling Costs	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E[36] for the Craig and Hayden plants. For other units, dismantling costs were assumed to be equal to the per-MW average costs of the Xcel units.
Capacity Factor	Varies by plant	Based on average of 2016-2018 as reported in S&P Global Market Intelligence database

[34] TEP Action Plan 2018.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[35] See:
https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/2016_EMM%20Coal%20Workshop%20Presentation%20(6-13-16).pdf

[36] See:
https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=

Retirement Date ("Business as Usual" Case)	Varies by plant	Based on utilities IRPs.[37]

Replacement Resource Inputs & Assumptions:

Assumption/Input	Value	Source & Description
Solar + Storage PPA	$33.99/MWh	Based on proposal to Central Arizona Project for a 20-year PPA for 20 MW of solar generation capacity with 60 MWh of battery storage.[38]
Wind Cost	$18.97/MWh	Sagamore PPA escalating at 2%.[39]
Wind Transmission Cost (2019)	$10/MWh	Consistent with the analysis presented at APS IRP stakeholder Meeting in April, 2019
Market Energy Prices	Varies	Based on OTC Global Holdings Forward Power Index for Palo Verde as of 30/08/2019.
Capacity Price (2019)	$39.48/kW-yr	Blended cost between short- and long- term cost of a gas resource according to APS IPR 2017 & 2019 (preliminary).

Carbon Pricing Risk Assessment Inputs and Assumptions:

Assumption/Input	Value	Source & Description
Carbon price (2025)	$16/metric ton	Based on APS's IRP carbon assumption, which is based on California price, and begins in 2025.[40]
Escalation rate	2.5%	
Discount Rate	3%	Used only for computing the net present value of the cost of carbon portion of the analysis.

[37] Arizona Electric Power Cooperative. Accessed at: https://docket.images.azcc.gov/0000179477.pdf
Tri-State Generation and Transmission Association, Inc. Accessed at:
https://www.tristategt.org/sites/tristate/files/PDF/resourceplan/2015%20Electric%20resource%20plan.pdf
Arizona Public Service IRP. Accessed at:
https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf
Tuscon Electric Company. Accessed at:
https://www.tep.com/wp-content/uploads/2019/07/TEP-Preliminary-Integrated-Resource-Plan-070119-FINAL-Version-2.pdf

[38] See: https://www.cap-az.com/documents/meetings/2019-05-02/1754-050219-WEB-Final-Packet-Board-Meeting.pdf

[39] Direct Testimony of David T. Hudson on behalf of Southwestern Public Service Company, Case No. 17-00044-UT. Accessed at: http://164.64.85.108/infodocs/2017/3/PRS20236617DOC.PDF

[40] APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

Appendix C: Results

Plant	Coal Units				Solar plus Storage + Market Energy	Market Energy	Wind + Market Capacity
	Fuel, O&M, & Incr. CapEx	Coal Contract	SCR	Total Cost			
Apache3	$ 498,384,272	$ -	$ -	$ 498,384,272	$ 286,907,824	$ 320,754,721	$ 436,032,796
Coronado1	$ 792,125,301	$ -	$ -	$ 792,125,301	$ 569,634,144	$ 637,059,928	$ 876,160,519
Coronado2	$ 865,626,248	$ -	$ 54,951,732	$ 920,577,980	$ 642,959,355	$ 721,944,578	$ 969,637,675
Craig2	$ 989,755,707	$ -	$ -	$ 989,755,707	$ 660,437,245	$ 728,997,484	$ 994,918,447
FourCorners4	$1,858,982,946	$ (571,609,746)	$ -	$1,287,373,200	$ 914,760,152	$ 976,750,086	$1,420,784,366
FourCorners5	$1,862,499,108	$ (571,609,746)	$ -	$1,290,889,361	$ 917,060,335	$ 978,432,311	$1,408,607,970
Hayden2	$ 474,480,007	$ -	$ -	$ 474,480,007	$ 321,743,713	$ 323,440,325	$ 460,405,600
Springerville1	$ 860,548,900	$ -	$ -	$ 860,548,900	$ 534,247,461	$ 573,313,091	$ 807,809,590
Springerville2	$1,167,459,444	$ -	$ -	$1,167,459,444	$ 769,341,045	$ 849,578,346	$1,133,266,989
Springerville3	$1,187,885,222	$ -	$ -	$1,187,885,222	$ 763,685,587	$ 853,471,934	$1,138,434,270
Springerville4	$1,112,980,259	$ -	$ -	$1,112,980,259	$ 697,265,769	$ 783,214,978	$1,057,640,955

Table 2: Summary results: Avoided Cost (NPV) of coal units in case of retirement in 2023. and replacement options (by 2023). Each column represents a distinct set of and not a cumulative total. Results are in 2019$

Plant	Coal Units		Solar plus Storage + Market Energy		Market Energy		Wind + Market Capacity
	Avoided Cost in case of retirement	Avoided Carbon Cost	Resource Cost	Carbon Cost	Resource Cost	Carbon Cost	Resource Cost
Apache3	$ 498,384,272	$ 382,952,321	$ 286,907,824	$ 26,764,376	$ 320,754,721	$ 194,607,703	$ 436,032,796
Coronado1	$ 792,125,301	$ 707,538,708	$ 569,634,144	$ 53,311,340	$ 637,059,928	$ 383,166,900	$ 876,160,519
Coronado2	$ 920,577,980	$ 803,268,803	$ 642,959,355	$ 65,945,794	$ 721,944,578	$ 434,751,990	$ 969,637,675
Craig2	$ 989,755,707	$ 606,140,443	$ 660,437,245	$ 76,996,202	$ 728,997,484	$ 369,288,755	$ 994,918,447
FourCorners4	$1,287,373,200	$ 762,292,257	$ 914,760,152	$ 82,716,075	$ 976,750,086	$ 492,755,508	$1,420,784,366
FourCorners5	$1,290,889,361	$ 770,263,295	$ 917,060,335	$ 81,078,665	$ 978,432,311	$ 487,493,862	$1,408,607,970
Hayden2	$ 474,480,007	$ 259,828,776	$ 321,743,713	$ 27,776,451	$ 323,440,325	$ 152,449,979	$ 460,405,600
Springerville1	$ 860,548,900	$ 516,422,127	$ 534,247,461	$ 47,287,574	$ 573,313,091	$ 298,091,579	$ 807,809,590
Springerville2	$1,167,459,444	$ 823,666,864	$ 769,341,045	$ 81,494,684	$ 849,578,346	$ 481,808,026	$1,133,266,989
Springerville3	$1,187,885,222	$ 915,554,258	$ 763,685,587	$ 75,240,385	$ 853,471,934	$ 519,183,614	$1,138,434,270
Springerville4	$1,112,980,259	$ 836,926,208	$ 697,265,769	$ 71,165,310	$ 783,214,978	$ 474,673,440	$1,057,640,955

Table 3: Summary results: Cost (NPV) of replacing coal units with the three replacement options by 2023, including carbon cost. Each column represents a distinct set of benefits and not a cumulative total. Results are in 2019$

STRATEGEN
CONSULTING

Strategen Consulting, LLC
2150 Allston Way, Suite 400
Berkeley, California 94704
www.strategen.com

Attachment DG-16

Excerpt of APS 2023 IRP Stakeholder Meeting

(Apr. 7, 2023)

aps

2023 IRP Stakeholder Meeting

April 7th, 2023

2023 IRP Load Forecast Summary

- Datacenter and large manufacturing customers (Extra High Load Factor – "XHLF") are expected to be the major source of load growth during 2023-2038
  - XHLF share of total energy sales (MWh) increasing from 3% to 34%
  - XHLF share of summer peak demand (MW) increasing from 2% to 21%
- Slower projected "core" load growth compared to 2020 IRP due to declining usage, increased solar generation, energy efficiency, and DSM savings, and forecasting model improvements
  - "Core" load includes residential and non-XHLF commercial and industrial (C&I) customers
- Electric vehicle (EV) charging also expected to drive sales and peak growth:
  - EV share of total energy sales (MWh) increasing from 0% to 6%
  - EV share of summer peak demand (MW) increasing from 0% to 4%

Average Annual Growth Rates For the 15-Year Planning Period	Customers	Retail Sales (MWh)	Peak Demand (MW)
2020 IRP (2020-2035)	1.6%	2.7%	2.0%
2023 IRP (2023-2038)	**1.5%**	**4.0%**	**2.4%**

IRP Cases are being developed around a reference case set of assumptions

External environment

Load growth

Peak load growth of ~3.5% p.a. from 2023-2032
(23Q1 w/ probability-weighting)

Capital costs

Reflect 2022 ASRFP baseline pricing & utilize NREL ATB for future price curves

Natural gas prices

2023: ~$3.98-8.22 / MMBtu
Future: $4.38-5.32 / MMBtu

Market prices

E3 revised 2023 prices
(reflects updated clean and renewable technologies throughout WECC)

APS-specific assumptions

Financial

2.5 % Inflation
6.74% Weighted Average Cost of Capital (WACC)

EE and DSM deployment

In accordance with most recent DSM Implementation Plan

Four Corners replacement

Retire in 2031
Additional cases include retire in 2027, 2028, 2029, 2030, and 2031 with natural gas replacement

Internal carbon price

$20.72/ton CO2e
(internal assumption)

Clean Energy Commitment

45% Renewable / 65% Clean by 2030

Four Corners coal operation retirement date sensitivities will be analyzed in the 2023 IRP.

Commission Required

Case Name	Load Forecast	Gas Prices	Carbon Tax	Technology Cost	APS CEC and RPS Targets Included	Coal Dispatch	Four Corners Retirement	Storage Constraint	New Natural Gas	EE Constraint	Demand-Side Resource Constraint
Reference	Base	Base	Base	Base	Yes	Base	2031	<=25% of Peak Load + Peak Reserves though 2027	Yes	N/A	N/A
Four Corners Retire 2027	–	–	–	–	–	–	↓ 2027	–	–	–	–
Four Corners Retire 2028	–	–	–	–	–	–	↓ 2028	–	–	–	–
Four Corners Retire 2029	–	–	–	–	–	–	↓ 2029	–	–	–	–
Four Corners Retire 2030	–	–	–	–	–	–	↓ 2030	–	–	–	–
Four Corners Retire 2031 Replace w/ Nat. Gas	–	–	–	–	–	–	2031 with Natural Gas Replacement	–	–	–	–

Key							
–	Same as Reference Case	↓	Lower Than Reference Case	↑	Higher than Reference Case	⃠	Not Included

DG-16
Page 4 of 4

Attachment DG-17

Excerpt of Direct Testimony of Susan Gray, Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n June 17, 2022)

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
LEA MÁRQUEZ PETERSON - CHAIR
SANDRA D. KENNEDY
JUSTIN OLSON
ANNA TOVAR
JIM O'CONNOR

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.))))))))))	DOCKET NO. E-01933A-22-0107

Direct Testimony of

Susan M. Gray

on Behalf of

Tucson Electric Power Company

June 17, 2022

the expectations of its customers. Now TEP seeks the support of this Commission for rates that allow recovery of prudently incurred costs and the execution of a resource transition plan that will provide cleaner, less carbon-intensive energy without compromising on the safety or reliability of its service.

V. RESPONSE TO COMMISSIONER O'CONNOR'S LETTER.

Q. In response to Question 1 in Commissioner O'Connor's May 11, 2022 letter regarding this rate request and planned coal plant closures, can you please provide an update on the scheduled retirement dates for each of the Company's coal-fired power plants and the key reasons for those closures?

A. TEP owns a 50% stake in Unit 1 at the coal-fired San Juan Generating Station ("San Juan"), which is scheduled for retirement on June 30, 2022. TEP's decision not to extend its participation in that unit was motivated by a desire to reduce costs for customers, as it was determined that the December 2019 acquisition of Gila River Unit 2, a combined-cycle natural gas-fired generating unit, could replace the output of that unit and TEP's share of retiring units at the Navajo Generating Station ("Navajo") at a much lower cost for customers. Replacing TEP's units at both Navajo and San Juan (including San Juan Unit 2, which was retired in 2017) with Gila River Unit 2 also reduced TEP's water usage and reduced emissions of carbon dioxide ("CO_2"), nitrogen oxides ("NOx"), and sulfur dioxide ("SO_2"). More details about the Company's analysis are included in TEP's 2018 Action Plan Update to its 2017 IRP.[1]

TEP owns a 7% share of Units 4 and 5 at the Four Corners Power Plant ("Four Corners") operated by Arizona Public Service ("APS"). Both units are scheduled to retire at the end

[1] See Pages 21-25 of TEP's 2018 Action Plan Updated filed April 2018. https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf.

of 2031, coinciding with the expiration of the plant's current coal supply contract. From TEP's perspective, the key reasons for retirement were outlined in the Company's 2020 IRP, which the ACC deemed to be reasonable and in the public interest on March 2, 2022.[2] The preferred portfolio that emerged from extensive analysis in the 2020 IRP process offsets the loss of 110 MW from Four Corners with less costly energy from wind and solar resources, producing cost savings for customers while reducing emissions, mitigating the risk of additional environmental control or carbon-related costs and supporting progress toward the Company's carbon reduction goal.

TEP owns and operates Units 1 and 2 at the coal-fired SGS; the Company also operates Units 3 and 4 at the plant on behalf of Tri-State Generation and Transmission Association ("Tri-State") and Salt River Project ("SRP"). As discussed in its 2020 IRP, the Company plans to retire Units 1 and 2 in 2027 and 2032, respectively. As outlined in the 2020 IRP, the retirements are necessary to achieve the goal of reducing TEP's CO_2 emissions 80% below 2005 levels by 2035. The retirements also are necessary to support other environmental goals articulated in the 2020 IRP, including a plan to provide 70% of power from renewable resources by 2035 and a 70% decrease in groundwater consumption for power generation. These goals were developed in partnership with a broad group of stakeholders who participated in the Company's IRP Advisory Council and with support from the University of Arizona's Institute of the Environment. TEP's 2020 IRP cited several other factors as contributing to a decision to retire SGS Units 1 and 2, including:

- The risk that TEP would be unable to secure an affordable coal supply that allows the units to meet certain environmental requirements;
- A determination that coal is no longer the lowest-cost year-round energy supply resource;

[2] https://docket.images.azcc.gov/0000206081.pdf?i=1650552626228.

- The risk of over-generation during non-summer months as the level of solar generation increases on TEP's system; and
- The risk of diminished water availability for power generation.

Q. In response to Question 2 in Commissioner O'Connor's letter, can you provide an estimate of stranded costs that might result from the retirement of coal-fired power plants?

A. TEP does not anticipate that costs incurred to develop and upgrade coal-fired power plants will be "stranded" upon their retirement because the Company would retain the right to continued recovery of the remaining book value, pursuant to previous ACC decisions regarding the prudency of those investments. Moreover, because current rates reflect the anticipated retirement dates of the San Juan and Four Corners units, the Company does not expect that significant costs related to those plants will remain unrecovered upon their retirement. The Company estimates that approximately $540 million invested in SGS Units 1 and 2 would remain unrecovered upon their retirements if its proposal to reduce their useful lives is approved as part of this proceeding; if not, that combined level would be approximately $640 million. TEP plans to take gradual steps in future rate cases to adjust the depreciation on these units to further reduce their respective book values upon retirement. The potential for securitization is addressed in testimony from Ms. Pritz.

Q. In response to Question 3 in Commissioner O'Connor's letter, can you provide an economic impact study addressing the impact of coal plant retirement on the relevant geographic area?

A. TEP is most directly engaged in coal-fired generation at SGS, where it is the sole owner of two units and operates all four units. Its engagement is much more limited as partial owner of units operated by other utilities at the San Juan and Four Corners plants. For that reason, I will limit my responses to this and other subsequent questions from Commissioner

O'Connor to address only SGS, a plant where about 360 TEP employees are working to provide safe, reliable energy for the Company's customers. I am very proud of their efforts, and the Company is committed to supporting a successful transition for them and their communities as we work toward the operational changes and retirement timelines for Units 1 and 2 that were established in TEP's 2020 IRP.

TEP and SRP are sponsoring an ongoing study by the Seidman Research Institute at Arizona State University that seeks to estimate the combined economic impacts of reduced operations and retirement of both SGS and SRP's Coronado Generating Station, located nearby in St. Johns, Arizona. TEP will file a copy of the final report from that study in this docket once it is complete.

Q. In response to Question 4 in Commissioner O'Connor's letter, can the Company compare the additional cost of continued operations of SGS Units 1 and 2 to the negative economic impact their retirement will create in the relevant geographic area, as established in the study noted above?

A The accuracy of any such effort would be undermined by uncertainty about the costs and impacts associated with continued operations beyond the units' scheduled retirement. The ongoing availability of coal, including availability at current pricing, cannot be assumed, in part because so many utilities have announced plans to accelerate the retirement of coal-fired power plants.[3] Moreover, the coal for SGS Units 1 and 2 is delivered by rail, adding another level of uncertainty regarding long-term fuel and delivery costs.

These closures can be expected to create economic pressure on operators of coal mines that could result in the unavailability of fuel of a quality that would allow Units 1 and 2 to

[3] Energy Information Administration Update, Dec. 15, 2021, https://www.eia.gov/todayinenergy/detail.php?id=50658.

operate in compliance with environmental regulations. The cost of compliance with future environmental regulations, including a potential carbon tax or limitations on CO_2 emissions, also cannot be known. These risks are among those highlighted in TEP's 2020 IRP, which concluded that continued operation of SGS Units 1 and 2 beyond the retirement dates identified as part of the Company's Preferred Portfolio would not serve the best interests of customers.

Q. In response to Question 5 in Commissioner O'Connor's letter, what shareholder-funded assistance will the Company provide to assist communities impacted by the retirements of its coal-fired generating units, and what customer-funded support would it recommend be provided?

A. As noted above, TEP is committed to providing appropriate support for communities that will be affected by coal plant retirements. We do so with appreciation for the many positive benefits that fossil-fueled power plants provide for their surrounding communities as well as respect for those who contend quite the opposite – that their operations have negatively impacted the regions that surround them through water use, plant emissions and waste and the associated impact of coal mining. The fact that both perspectives have been voiced in support of what has come to be called a just and equitable transition – that assistance is owed because the plants have had such a negative impact *and* because they have had such a positive impact – reflects, I believe, widespread uncertainty about what duty might be owed upon a plant's retirement, and by whom.

In Docket No. E-00000A-21-0010, Commissioners and Staff are overseeing stakeholder workgroups addressing the potential funding to support communities impacted by the retirement of fossil-fueled power plants and associated impacts on ratepayers as well as the potential repurposing of power generation facilities. TEP continues to be an active participant in this docket and has asserted therein its commitment to supporting a just and

Attachment DG-18

Excerpt of Direct Testimony of Devi Glick, Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Jan. 11, 2023)

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA FOR RELATED APPROVALS.	DOCKET NO. E-01933A-22-0107

Direct Testimony
of
Devi Glick

PUBLIC VERSION

On Behalf of
Sierra Club

January 11, 2023

Q What near-term resource procurement efforts has TEP made?

A TEP has brought online 465 MW of new renewables and 60 MWh of battery storage since the Company's last rate case.[10] This includes the 250 MW Oso Grande Wind project which came online in December 2020. TEP is requesting to add Oso Grande to base rates in this docket.[11]

In addition, the Company issued an all-source request for proposals (RFP) in April 2022 for 250 MW of renewables and energy efficiency resources. This could include new wind, solar photovoltaics ("PV"), energy efficiency, and demand response.[12] The RFP also seeks 300 MW of a firm capacity resource that can be called on at any time. This includes 4-hour energy storage and demand response.[13] The evaluation for both procurements is currently ongoing.

Q What are TEP 's carbon dioxide ("CO_2") reduction and renewable energy goals?

A TEP has a goal to reduce CO_2 emissions 80 percent below 2005 levels by 2035 and serve 70 percent of retail load with cost-effective renewables by 2035. This is up from serving only 21 percent of retail load with renewables in 2021.[14] To achieve this goal, TEP must reduce its reliance on fossil fuels, retire its coal plants, and build out substantial new renewable capacity.

[10] Bakken Direct at 2:8-12.

[11] Gray Direct at 2:16-19.

[12] Direct Testimony of Dallas Dukes at 5:3-7 [hereinafter "Dukes Direct"].

[13] *Id*. at 3:8-13.

[14] Bakken Direct at 3:3-8.

will be facing a net present value ("NPV") of $66.9 million in capex costs beyond what it currently projected.

For O&M, over the remaining life of each plant, TEP's projected O&M spending at each plant will cost its ratepayers $71.5 million more on an NPV basis than ratepayers at peer utilities are spending for coal plant O&M.

ii. ***<u>TEP has provided no current analysis to justify the proposed test-year spending at Springerville Units 1 and 2 and Four Corners</u>***

Q What analysis has TEP conducted to demonstrate the reasonableness of continuing to operate Springerville and Four Corners relative to alternatives?

A I am not aware of TEP having conducted any recent analysis on the reasonableness of continuing to operate Four Corners through 2031. Although TEP did test a scenario for its 2020 IRP where all coal retired by 2027, it did not evaluate the economics of Four Corners alone. TEP's most recent analysis on Springerville, which determined the unit's retirement dates of 2027 and 2032, was conducted as part of its prior IRP process in 2020. The Company has begun its next IRP process, but in the meantime, it is requesting to place the costs associated with maintaining both plants into rates and rate base without providing any contemporaneous evidence that doing so is in the best interest of ratepayers. Meanwhile, TEP's analysis, as well as my own, shows that earlier retirement of the Company's coal fleet—and thus avoidance of these maintenance and sustaining capital costs—are in the best interest of TEP ratepayers. This leads me to conclude that continued operation of and spending on Springerville and Four Corners without robust updated analysis is imprudent.

Q How did TEP determine the proposed retirement dates for Springerville Units 1 and 2 and Four Corners?

A The 2031 retirement date for Four Corners was set by APS to align with the expiration of its coal contract in 2031. I am not aware of TEP conducting any analysis, either as part of its last IRP or any time subsequently, on whether it was cheaper to retire Four Corners earlier than 2031, pay off the coal contract, and build or procure alternative resource options. The Company did test one scenario where all coal retired by 2027 but this was not helpful in evaluating the economics of any plant or unit individually.

TEP determined the 2027 and 2032 retirement dates for Springerville Units 1 and 2 as part of its 2020 IRP. The Company did not have a planned retirement date for Springerville prior to the last IRP. The Company did not utilize optimized capacity expansion modeling software to create the IRP but instead tested a series of scenarios head-to-head to determine which was lower cost. This means that TEP did not allow a resource planning model to test optimized retirement dates or resource additions. Instead, the Company programmed in specific retirement dates and resource additions and the model produced the results for each scenario. TEP conducted no subsequent modeling to confirm that continued operation of the units for another five and ten years is the lowest-cost solution for ratepayers.

Q What did TEP find about the cost of continuing to operate Four Corners relative to alternatives?

A In its IRP analysis, TEP found that retiring the Company's share of Four Corners once the coal contract expires in 2031 and replacing it with less costly wind and solar would produce cost savings for customers while reducing emissions, thereby mitigating the risk of additional carbon control or carbon-related costs and supporting progress towards TEPs carbon reduction goals.[36] But, as discussed

[36] Gray Direct at 10:1-8.

above, TEP conducted very limited modeling to evaluate whether an even earlier retirement would produce additional savings. Given the savings and benefits TEP found in 2031, it is likely that even the Company's own modeling would have found additional savings from retiring TEP's share of the plant early and replacing it with alternatives.

Q What did TEP find about the cost of continuing to operate Springerville Units 1 and 2 relative to alternatives?

A In its last IRP, TEP found that retiring Springerville Units 1 and 2 in 2027 and 2032 respectively was necessary to achieve TEP's goals of (1) reducing CO_2 emissions 80 percent below 2005 levels by 2035; (2) generating 70 percent of power from renewables by 2035; and (3) reducing groundwater consumption for power generation by 70 percent. TEP also indicated in its application that these retirement dates would mitigate the risk associated with TEP's ability to secure an affordable coal supply and sufficient water for power generation.[37] TEP's preferred portfolio, which included the 2027 and 2032 retirement dates for Springerville, did not have the lowest revenue requirement of all the portfolios that TEP tested, but it did minimize emissions and manage risk. If this scenario were re-run today, with updated market conditions, coal and gas prices, and costs for existing and replacement resources, as discussed below, it would likely be one of the lowest cost scenarios, if not the lowest cost scenario.

Notably, TEP also stated in its rate case application that these retirement dates were driven by "a determination that coal is no longer the lowest-cost year-round energy-supply resource."[38] Given TEP's clear acknowledgement of the risks of continuing to rely on coal, it is concerning that it still opted to keep Springerville online for another ten years. The economic and risk factors that drove TEP to select 2027 and 2032 as Springerville retirement dates are not new issues that will

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[37] *Id*. at 10:15-11:3.
[38] *Id*. at 10:24-25.

will be implemented, what form the final rules will take, and when the rules will be finalized, the direction of impact from increased environmental regulations is clear: coal plants will become more highly regulated and therefore more costly and riskier to operate.

Q What takeaways do you have about Springerville Units 1 and 2 after reviewing TEP's application and analysis?

A TEP should work to procure replacement resources for Springerville to reduce reliance on the units and ease the path to retirement. The risks that the cost of operation will increase are substantial, while the chance that coal will become a competitive or more desirable resource option is almost non-existent. Coal prices are high and coal availability is constrained, water scarcity risks are increasing, there is a high risk of increasing environmental regulations, and the costs of cleaner alternatives are falling.

Q What takeaways do you have about Four Corners after reviewing TEP's application and analysis?

A TEP has stated that, as a minority owner, it has limited control over the ongoing operations and retirement of Four Corners. But this does not justify the minimal oversight TEP has exercised over the units' operation and planning, especially given the high unit costs TEP expects to pass along to its customers. With the limited information we do have about the Four Corners plant's recent historical performance and projected future economics, I find it is in the best interest of ratepayers for TEP to evaluate a pre-2031 retirement date and retire the unit as soon as it can secure replacement resources. In the meantime, TEP should limit future spending at the unit. Four Corners has been costly to operate, it has a high unforced outage rate, and is likely to only become more costly in the future.

Attachment DG-19

Congressional Research Service, *The Energy Credit or Energy Investment Tax Credit* (2021)

Updated April 23, 2021

The Energy Credit or Energy Investment Tax Credit (ITC)

Internal Revenue Code (IRC) Section 48 provides an investment tax credit (ITC) for certain energy-related property. This In Focus summarizes the current renewable energy ITC and reviews its legislative history.

Current Law

Certain investments in renewable energy property qualify for an ITC. The amount of the credit is determined as a percentage of the taxpayer's basis in eligible property (generally, the cost of acquiring or constructing eligible property). The tax credit rate and other credit parameters depend on the type of property or technology for which the credit is being claimed, as summarized in **Table 1**.

Table 1. Energy Credit: Summary of Current Law

Eligible Technology	Credit Rate	Expiration Date (End of Year)
Solar, Fiber Optic Solar, Fuel Cells, Small Wind, and Waste Energy Recovery Property[a]	30%	2019
	26%	2022
	22%	2023
Microturbines, Combined Heat and Power, Geothermal Heat Pump	10%	2023
Offshore Wind[b]	30%	2025
Solar, Geothermal Energy	10%	Permanent

Notes: Credit expiration dates are start-of-construction deadlines. For nonpermanent credits, property generally must be placed in service four years after the start of construction to qualify (five years if construction started in 2016 or 2017).

a. Waste energy recovery property is eligible starting in 2021.

b. Offshore wind facilities that began construction after 2016 are eligible. Facilities that began construction before 2017 may claim the ITC in lieu of the production tax credit (PTC).

Solar energy has a permanent 10% ITC. Temporarily, the credit rate for solar was increased to 30% through 2019, before being reduced to 26% through 2022 and 22% in 2023. Investments in small wind property (a wind turbine with 100 kilowatts of capacity or less) qualified for the 30% ITC through 2019, with the credit rate reduced to 26% through 2022 and 22% in 2023. Investments in fuel cell power plants and fiber optic solar may qualify for the ITC at these same rates. The credit for fuel cells is limited to $1,500 per 0.5 kilowatts in capacity. Waste energy recovery property that is not part of a combined heat and power (CHP) system and has a maximum capacity of 50 megawatts or less can qualify for the 26% credit if construction begins in 2021 or 2022, and a 22% credit if construction begins in 2023. Investments in microturbines, CHP systems, and geothermal heat pumps qualify for a 10% ITC. There is a 30% ITC for offshore wind property beginning construction by the end of 2025.

The expiration dates for the ITC are commence construction deadlines. For example, solar property that was under construction by the end of 2019 may qualify for the 30% tax credit, even if the property is not placed in service (or ready for use) until a later date.

Like the 10% ITC for solar, the 10% ITC for geothermal energy property is permanent. Geothermal energy property may also qualify for the renewable energy production tax credit (PTC) under IRC Section 45.

Legislative History

The Early Years

The energy tax credit was first enacted in the Energy Tax Act of 1978 (P.L. 95-618), which created a temporary 10% tax credit for business energy property and equipment using energy resources other than oil or natural gas. Tax credits for solar and wind energy property were refundable (credits could be received as a payment if the taxpayer did not have tax liability to offset), with nonrefundable credits available for a wide range of other qualifying technologies and property. The rationale behind the credits was to reduce U.S. consumption of oil and natural gas by encouraging the commercialization of a broader range of energy technologies and resources. Generally, the energy credits were scheduled to expire December 31, 1982.

The Windfall Profit Tax Act of 1980 (P.L. 96-223) expanded the energy credit to further the objective of developing an abundant range of energy resources and promoting investment in energy conservation. Tax credits for solar and wind energy property investments were extended for three years, through 1985. Additionally, the credit rate for solar and wind was increased to 15%, and the credit was made nonrefundable. The tax credit for geothermal was also increased from 10% to 15% and ocean thermal equipment was added as qualifying property. The 10% credit for biomass was also extended for three years, through 1985. The definition of biomass included materials such as municipal solid waste. The act also provided an 11% credit for small-scale hydroelectric generating property, through 1985. A 10% credit was provided for co-generation property (e.g., property that produces heat or other useful energy in addition to electricity) through 1982. The act made a number of other changes to the business energy ITC (the changes noted here are those most closely related to the current energy ITC).

When considering the Tax Reform Act of 1986 (TRA86; P.L. 99-514), Congress believed it desirable to maintain tax credits for renewable energy to continue stimulating technological development and the use of renewable energy sources. While there was not support for a broad extension of the energy credit (investment credits generally were repealed or allowed to expire in TRA86), investment tax credits for solar and geothermal energy property were extended, but phased down to 10% before being set to expire December 31, 1988. The credit for biomass was also extended, but reduced to 10% in 1987, when it was set to expire. The credit for ocean thermal property was extended at 15% through 1988. The credit for wind was not extended. The energy credit for many other types of property had expired at the end of 1982, as scheduled.

There were a number of short-term extensions to the energy credit in the late 1980s and early 1990s. The Miscellaneous Revenue Act of 1988 (P.L. 100-647) extended the solar, geothermal, and ocean thermal investment credits at their 1988 rates. The Omnibus Budget Reconciliation Act of 1989 (P.L. 101-239) again extended the credits for solar, geothermal, and ocean thermal equipment. The Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508) extended the tax credits for solar and geothermal, as did the Tax Extension Act of 1991 (P.L. 102-227).

The Energy Policy Act of 1992 (P.L. 102-486) made the credits for solar and geothermal permanent. After P.L. 102-486, the only tax credits remaining from the Energy Tax Act of 1978 (P.L. 95-618) were the newly permanent 10% solar and geothermal credits.

Evolution of the Current Credit

The Energy Policy Act of 2005 (EPACT05; P.L. 109-58) increased the solar ITC from 10% to 30% for 2006 and 2007. The legislation also provided that fiber-optic distributed sunlight property was eligible for the tax credit, while solar property used to heat a swimming pool was not. EPACT05 also provided a 30% ITC for fuel cell power plants and a 10% ITC for stationary microturbine power plants that were placed in service during 2006 or 2007. The temporary components of the ITC and EPACT05 credit rates were extended through 2008 in the Tax Relief and Health Care Act of 2006 (P.L. 109-432).

The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) substantially expanded and provided a long-term extension of the temporary components of the energy credit. The objective was to promote the continued development of alternative energy resources. In P.L. 110-343, the EPACT05 credits for solar, fuel cells, and microturbines were extended for eight years, through December 31, 2016. The legislation also provided a 10% credit for geothermal heat pump property, a 30% credit for small wind energy property, and a 10% credit for CHP property, each with a placed-in-service deadline of December 31, 2016. The purpose of the tax credit for CHP was to encourage more efficient use of fossil fuel power generation. The energy ITC was modified as part of the American Recovery and Reinvestment Act (ARRA; P.L. 111-5) in 2009, with certain limitations and restrictions relaxed. Changes in credit rates and expiration dates were not part of the ARRA modifications.

In 2015, the Consolidated Appropriations Act, 2016 (P.L. 114-113) further extended the credit. The 30% credit rate for solar electric or heating property (but not fiber-optic solar) was extended through 2019. The termination date was changed from a placed-in-service deadline to a construction start date. The higher rate was scheduled to phase out, with a 26% credit for property beginning construction in 2020, and 22% for property beginning construction in 2021.

The Bipartisan Budget Act of 2018 (P.L. 115-123) extended the ITC for five years for fiber-optic solar, fuels cell, small wind, microturbine, CHP, and geothermal heat pump property. For property eligible for a 30% credit through 2019, the credit rate is reduced following the reduction schedule for solar enacted in P.L. 114-113. All termination dates were changed to construction start deadlines.

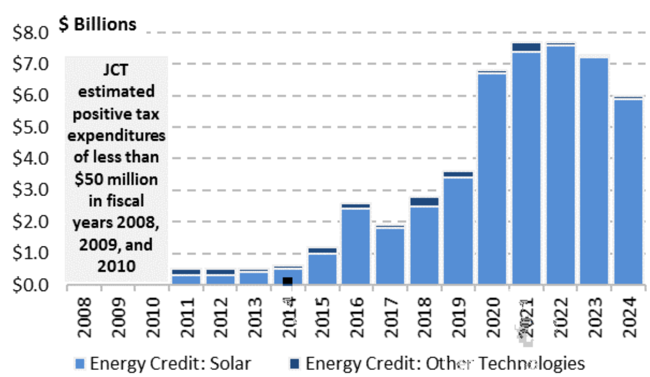
The energy credit deadlines were generally extended by two years in the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (Division EE of P.L. 116-260). This legislation expanded the credit to include waste energy recovery property and to allow an ITC for offshore wind. For offshore wind, the credit is allowed for property that begins construction by the end of 2025. The tax credit rate for offshore wind is 30% and does not phase out.

Cost of the Credit

For much of its history, there was little cost associated with the energy credit. From the credit's inception in 1978 through 2007, the Joint Committee on Taxation (JCT) estimated that tax expenditures—or forgone revenue—associated with the energy credit were generally *de minimis* (less than $50 million per year; fiscal years 1997, 1998, and 2007 were exceptions, when the tax expenditure estimate for the credit was $0.1 billion).

JCT provided energy credit tax expenditure estimates by type of qualifying technology starting in 2008 (**Figure 1**). Energy credit tax expenditure estimates have increased in recent years. The majority of the cost is for solar credits.

Figure 1. Tax Expenditures for the Energy Credit
FY2008-FY2024



Source: Joint Committee on Taxation.

For 2020, the JCT estimated energy credit tax expenditures to be $6.8 billion, with the majority of tax expenditures ($6.7 billion) attributable to solar. Between 2020 and 2024, the JCT has estimated energy credit tax expenditures to be $35.5 billion, with $34.9 billion for solar.

Molly F. Sherlock, Specialist in Public Finance

IF10479

Disclaimer

Attachment DG-20

Congressional Research Service, *Energy Tax Provisions: Overview and Budgetary Cost* (2021)

Congressional Research Service
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Energy Tax Provisions: Overview and Budgetary Cost

August 3, 2021

Congressional Research Service
https://crsreports.congress.gov
R46865

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The 117th Congress is considering multiple proposals that would deploy energy tax provisions to pursue climate-related or infrastructure investment policy objectives. On May 26, 2021, the Senate Finance Committee passed the Clean Energy for America Act (S. 1298).[1] This legislation proposes tax credits for non-greenhouse gas (GHG)-emitting electricity generating technologies, with the provisions phasing out once emissions reductions targets are achieved. The legislation also proposes tax incentives for clean fuels (as defined in the bill) and transportation electrification, as well as for building energy efficiency, and would provide various other tax incentives for "clean energy." Qualifying projects would be required to meet certain workforce development requirements and pay prevailing wages. Tax incentives supporting fossil fuels would be repealed. The Joint Committee on Taxation (JCT) has estimated that this proposal would reduce federal revenues by $259.4 billion between FY2022 and FY2031.[2]

The Biden Administration's "American Jobs Plan" also proposes substantial modifications to energy tax policy. The Administration's proposal would expand and extend existing tax incentives supporting renewables, provide incentives for zero-emissions vehicles and electric vehicle infrastructure, expand tax incentives for building energy efficiency, and provide various other "clean energy" tax incentives. Tax incentives supporting fossil fuels would be repealed. The Treasury has estimated that the Administration's proposed energy tax policies would reduce federal revenues by $302.9 billion between FY2022 and FY2031.[3]

This report provides background information on current-law energy tax provisions. Specifically, the report includes a series of tables, each of which includes (1) the name of the provision and its Internal Revenue Code (IRC) citation; (2) a brief description of the provision; (3) the law first enacting the provision; (4) when the provision expires (if applicable) under current law; and (5) a cost estimate (if available).[4] For the purposes of this report, energy tax provisions have been categorized as follows:

- Renewable energy tax incentives (**Table 1**)
- Energy efficiency tax incentives (**Table 2**)
- Tax incentives for vehicles and vehicle infrastructure (**Table 3**)
- Renewable and alternative fuels tax incentives (**Table 4**)
- Fossil fuel tax incentives (**Table 5**)
- Carbon capture and sequestration (CCS), nuclear, and other tax incentives (**Table 6**)

[1] Information and files related to Senate Finance Committee consideration of this legislation can be found at https://www finance.senate.gov/hearings/open-executive-session-to-consider-an-original-bill-entitled-the-clean-energy-for-america-act. On June 17, 2021, the Clean Energy for America Act (S. 2118) was introduced.

[2] Joint Committee on Taxation, *Estimated Revenue Effects of the Revenue Provisions Contained in the Chairman's Modification of the "Clean Energy for America Act," Scheduled for Markup by the Committee on Finance on May 26, 2021*, JCX-29-21, May 26, 2021, at https://www.jct.gov/publications/2021/jcx-29-21/.

[3] Department of the Treasury, *General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals*, May 2021, at https://home.treasury.gov/system/files/131/General-Explanations-FY2022.pdf.

[4] The cost estimates are generally tax expenditure estimates, as provided in Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020. These estimates reflect tax laws enacted through September 30, 2020, and assume that temporary provisions expire as scheduled. If legislation enacted after September 30, 2020, extended the provision, the cost estimate associated with that extension is noted.

Table 1. Renewable Energy Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Residential energy-efficient property credit (IRC §25D)	A tax credit for the purchase of solar electric property, solar water heating property, fuel cells, geothermal heat pump property, or small wind energy property. Through 2019, the tax credit was 30% of the cost of qualifying property. Qualified biomass fuel property is eligible after 2020. The tax credit is reduced to 26% for property placed in service in 2020, 2021, and 2022 and 22% for property placed in service in 2023. The tax credit for fuel cells is limited to $500 for each 0.5 kilowatt of capacity.	Energy Policy Act of 2005 (EPACT05; P.L. 109-58)	Property placed in service by December 31, 2023.	FY2020: $1.8 FY2020-FY2024: $3.6 Extension in P.L. 116-260: $3.8 (FY2021-FY2030)
Renewable electricity production tax credit (PTC) (IRC §45)	A tax credit for electricity produced using qualifying renewable energy resources. The tax credit equals 2.5 cents per kWh for electricity produced from wind, closed-loop biomass, and geothermal energy in 2021. The tax credit equals 1.3 cents per kWh for electricity produced from open-loop biomass, landfill gas, trash combustion, qualified hydropower, and marine and hydrokinetic sources in 2021. Tax credit amounts are adjusted annually for inflation. The tax credit is available for 10 years after the date the facility is placed in service. Taxpayers may elect to receive a 30% investment tax credit (ITC) in lieu of the PTC. The tax credit for wind is reduced by 20% for facilities that began construction in 2017, 40% for facilities that began construction in 2018; 60% for facilities that began construction in 2019; and 40% for facilities that began construction in 2020 or 2021. For more, see CRS Report R43453, *The Renewable Electricity Production Tax Credit: In Brief*, by Molly F. Sherlock.	Energy Policy Act of 1992 (EPACT92; P.L. 102-486)	Construction must begin by December 31, 2021.	FY2020: $4.6 FY2020-FY2024: $17.0 Extension in P.L. 116-260: $1.7 (FY2021-FY2030)

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Energy investment tax credit (ITC)(IRC §48)	A tax credit for investments in qualifying energy property. Investments in geothermal, microturbine, or combined heat and power (CHP) property qualify for a 10% credit. From 2006 through 2019 the credit rate was increased to 30% for solar, fuel cells, and small wind property. The tax credit rate for these technologies is 26% through 2022 and 22% in 2023. Waste energy recovery property is eligible for the ITC after 2020, at the increased credit amounts. Offshore wind facilities that begin construction after 2016 are eligible for a 30% credit. For more, see CRS In Focus IF10479, *The Energy Credit or Energy Investment Tax Credit (ITC)*, by Molly F. Sherlock.	The Energy Tax Act of 1978 (P.L. 95-618)	Construction must begin by December 31, 2023, except for geothermal and solar, where there is a permanent 10% credit. For offshore wind property, construction must begin by December 31, 2025.	FY2020: $6.8 FY2020-FY2024: $35.5 Extension in P.L. 116-260: $7.0 (FY2021-FY2030) Application of credit to waste energy recovery and offshore wind in P.L. 116-260: $0.6 (FY2021-FY2030)
Credit for investment in advanced energy property (IRC §48C)	A 30% tax credit for selected qualified investments in advanced energy property. A total of $2.3 billion was allocated for advanced energy property investment tax credits, which were competitively awarded by the Departments of Energy (DOE) and the Treasury.	American Recovery and Reinvestment Act (ARRA; P.L. 111-5)	Allocation limit; credits fully allocated.	FY2020: (i) FY2020-FY2024: $0.4
Credit for holders of clean renewable energy bonds (IRC §§54, 54C)	An income tax credit for holders of the bond. Clean Renewable Energy Bonds (CREBs) are subject to a volume cap of $1.2 billion with a credit rate set to allow the bond to be issued at par and without interest. New Clean Renewable Energy Bonds (New CREBs) are subject to a volume cap of $2.4 billion with a credit rate set at 70% of what would permit the bond to be issued at par and without interest. Tax credit bonds were repealed in the 2017 tax revision (commonly called the "Tax Cuts and Jobs Act" [TCJA]; P.L. 115-97).	EPACT05 (P.L. 109-58) Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Allocation limit; authority to issue repealed in P.L. 115-97.	FY2020: (i) FY2020-FY2024: $0.3

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Depreciation recovery periods for energy-specific items: five-year MACRS for certain energy property (IRC §168(e)(3)(B)(vi))	Accelerated depreciation allowances are provided under the modified accelerated cost recovery system (MACRS) for investments in certain energy property. Specifically, certain solar, wind, geothermal, fuel cell, microturbine, CHP, waste energy recovery, and biomass property have a five-year recovery period.	Tax Reform Act of 1986 (P.L. 99-514)	Construction must begin by December 31, 2023, for solar illumination, fuel cell, microturbine, CHP, small wind, geothermal heat pump, and waste energy recovery property. None otherwise.	FY2020: (i) FY2020-FY2024: $0.3

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. kWh = kilowatt-hour. MACRS = modified accelerated cost recovery system. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

Table 2. Energy Efficiency Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Credit for energy-efficient improvements to existing homes/nonbusiness energy property credit (IRC §25C)	A 10% tax credit for qualified energy-efficiency improvements and expenditures for residential energy property including qualifying improvements to the building's envelope, the HVAC system, furnaces, or boilers. The credit is subject to a $500 per taxpayer lifetime limit. Property must be installed in the taxpayer's primary residence.	EPACT05 (P.L. 109-58)	Property installed by December 31, 2021.	FY2020: $0.5 FY2020-FY2024: $0.8 Extension in P.L. 116-260: $0.4 (FY2021-FY2030)
Credit for energy-efficient new homes (IRC §45L)	A tax credit for eligible contractors for building and selling qualifying energy-efficient new homes. The credit is equal to $2,000, with certain manufactured homes qualifying for a $1,000 credit.	EPACT05 (P.L. 109-58)	Property acquired by December 31, 2021.	FY2020: $0.2 FY2020-FY2024: $0.6 Extension in P.L. 116-260: $0.3 (FY2021-FY2030)
Credit for holders of qualified energy conservation bonds (IRC §54D)	The federal government has authorized the issue of $3.2 billion in Qualified Energy Conservation Bonds (QECBs). QECBs provide a tax credit worth 70% of the tax credit bond rate stipulated by the Secretary of the Treasury. QECBs issued by state and local governments must fund an energy-savings project, such as the green renovation of a public building, R&D in alternative fuels, and public transportation projects. Tax credit bonds were repealed in the 2017 tax revision (TCJA; P.L. 115-97).	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Allocation limit (allocated to the states); authority to issue repealed in P.L. 115-97.	FY2020: (i) FY2020-FY2024: $0.1
Exclusion of energy conservation subsidies provided by public utilities (IRC §136)	Subsidies provided by public utilities to customers for the purchase or installation of energy conservation measures are excluded from taxable income. For the purposes of this provision, public utilities are entities selling electricity or natural gas.	EPACT92 (P.L. 102-486)	none	FY2020: (i) FY2020-FY2024: $0.1

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Exclusion of interest on state and local qualified private activity bonds for green buildings and sustainable design projects (IRC §142(a)(14))	Tax-exempt private activity bonds can be issued to finance (or refinance) qualified green building and sustainable design projects.	American Jobs Creation Act of 2004 (P.L. 108-357)	Does not apply to any bond issued after September 30, 2012.	*de minimis*
Energy-efficient commercial building deduction (IRC §179D)	A deduction of up to $1.80 per square foot is allowed for certain energy-saving property used in domestic commercial buildings. Qualifying energy-efficient commercial building property includes property installed as part of (1) the interior lighting system; (2) the heating, cooling, ventilation, or hot water system; or (3) the building envelope. To be deductible, property must reduce a building's annual energy and power costs by 50% or more as compared to a similar reference building meeting certain minimum energy standards. A reduced deduction may be available if a single system is upgraded (lighting, heating and cooling, or building envelope) and the 50% reduction threshold is not met. Government entities making energy-efficiency upgrades to public buildings, such as schools, can allocate the Section 179D deduction to designers of energy-efficient commercial building property.	EPACT05 (P.L. 109-58)	none	FY2020: (i) FY2020-FY2024: $0.1 Extension in P.L. 116-260: $0.7 (FY2021-FY2030)

Source: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

Table 3. Tax Incentives for Vehicles and Vehicle Infrastructure

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Credits for fuel cell vehicles (IRC §30B)	A tax credit for fuel cell vehicles. Fuel cell vehicles receive a base credit of $4,000 for vehicles weighing less than 8,500 pounds. Heavier vehicles qualify for up to a $40,000 credit. An additional credit of up to $4,000 is available for cars and light trucks that exceed the 2002 base fuel economy.	EPACT05 (P.L. 109-58)	Property purchased by 12/31/2021.	*de minimis*
Credit for alternative fuel refueling property (IRC §30C)	A tax credit for the cost of any qualified alternative fuel vehicle refueling property installed by a business or at a taxpayer's principal residence. The credit is equal to 30% of these costs, limited to $30,000 for businesses at each separate location with qualifying property, and $1,000 for residences.	EPACT05 (P.L. 109-58)	Property placed in service by 12/31/2021.	FY2020: (i) FY2020-FY2024: $0.1 Extension in P.L. 116-260: $0.2 (FY2021-FY2030)
Credit for plug-in electric vehicles (IRC §30D)	A tax credit for the purchase of qualifying plug-in electric vehicles. The credit ranges from $2,500 to $7,500 per vehicle, depending on the vehicle's battery capacity. The tax credit phases out once a vehicle manufacturer has sold 200,000 qualifying vehicles. If the vehicle is purchased by a tax-exempt organization, the seller of the vehicle may be able to claim the credit. For more, see CRS In Focus IF11017, *The Plug-In Electric Vehicle Tax Credit*, by Molly F. Sherlock.	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Credit phases out after reaching a 200,000 per-manufacturer limit.	FY2020: $0.7 FY2020-FY2024: $3.0
Credit for electric motorcycles (IRC §30D)	A 10% credit, up to $2,500, is available for the cost of two-wheeled plug-in electric vehicles. Eligible vehicles must have a weight rating of less than 14,000 pounds; be propelled by a battery-powered electric motor with a battery capacity of at least 2.5 kilowatt-hours; be manufactured for use on streets, roads, and highways; and be capable of achieving a speed of at least 45 miles per hour.	ARRA (P.L. 111-5)	Property purchased by 12/31/2021.	*de minimis*

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

Table 4. Renewable and Alternative Fuels Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Credit for second-generation biofuel production (IRC §40(a)(4))	A per-gallon tax credit for qualified second-generation biofuel production. The amount of the credit is generally $1.01 per gallon. Qualifying fuels include cellulosic biofuel, which is produced using lignocellulosic or hemicellulosic matter (cellulosic feedstock) available on a renewable or recurring basis, as well as second-generation biofuels, which include cultivated algae, cyanobacteria, or lemna.	The Food, Conservation, and Energy Act of 2008 (P.L. 110-246)	Fuel produced by 12/31/2021.	*de minimis* Extension in P.L. 116-260: (i) (FY2021-FY2030)
Credits for biodiesel and renewable diesel fuel (IRC §§40A, 6526, & 6427)	There are three tax credits for biodiesel: the biodiesel mixture credit, the biodiesel credit, and the small agri-biodiesel producer credit. Each gallon of biodiesel, including agri-biodiesel (biodiesel made from virgin oils), may be eligible for a $1.00 tax credit. Additionally, an eligible small agri-biodiesel producer credit of 10 cents is available for each gallon of "qualified agri-biodiesel production." The mixtures tax credit may be claimed as an instant excise tax credit against the blender's motor and aviation fuels excise taxes. Credits in excess of excise tax liability may be refunded. The biodiesel and small agri-biodiesel credits may be claimed as income tax credits.	American Jobs Creation Act of 2004 (P.L. 108-357)	Fuel sold, used, or removed by 12/31/2022.	FY2020: $8.1[b] FY2020-FY2024: $15.2[b]
50-percent expensing of cellulosic biofuel plant property (IRC §168(l))	Second-generation biofuel plant property was allowed an additional first-year depreciation deduction equal to 50% of the property's adjusted basis.	Tax Relief and Health Care Act of 2006 (P.L. 109-432)	Property placed in service by 12/31/2020.	*de minimis*

Provision	Description	Enacting Legislation	Expiration Date	Cost or Tax Expenditure Estimate (billions)[a]
Alternative Fuels and Alternative Fuels Mixture Credit (IRC §§6426 & 6427)	A tax credit for certain alternative fuels and alternative fuels mixtures. The credit is a 50-cents-per-gallon excise tax credit for certain alternative fuels used as fuel in a motor vehicle, motor boat, or airplane and a 50-cents-per-gallon credit for alternative fuels mixed with a traditional fuel (gasoline, diesel, or kerosene) for use as a fuel. Qualifying fuels include liquefied petroleum gas; P Series fuels (certain renewable, nonpetroleum, liquid fuels); compressed or liquefied natural gas (CNG or LNG); any liquefied fuel derived from coal or peat through the Fischer-Tropsch process that meets certain carbon-capture requirements; liquefied hydrocarbons derived from biomass; and liquefied hydrogen.	Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU; P.L. 109-59)	Fuel sold or used by 12/31/2021.	FY2020: $0.2[c] FY2020-FY2024: $0.3[c] Extension in P.L. 116-260: $0.2 (FY2021-FY2030)

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021",* JCX-24-20, December 21, 2020; Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In The House Amendment To The Senate Amendment To H.R. 1865, the Further Consolidated Appropriations Act, 2020*, JCX-54R-19, December 17, 2019.

Notes: IRC = Internal Revenue Code. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

b. The tax incentives for biodiesel and renewable diesel were extended for five years, through 2022, in the Further Consolidated Appropriations Act of 2020 (P.L. 116-94). This cost estimate reflects the extension, as estimated in Joint Committee on Taxation, *Estimated Budget Effects of the Revenue Provisions Contained in the House Amendment to the Senate Amendment to H.R. 1865, the Further Consolidated Appropriations Act 2020 (Rules Committee Print 116-44)*, JCX-54R-19, December 17, 2019. The income tax credit portion is *de minimis*.

c. The tax incentives for alternative fuels and alternative fuel mixtures were extended for one year, through 2021, in the Consolidated Appropriations Act, 2021 (P.L. 116-260). This cost estimate is the estimate associated with that extension.

Table 5. Fossil Fuels Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Enhanced Oil Recovery (EOR) Credit (IRC §43)	A tax credit for Enhanced Oil Recovery (EOR) costs available when oil prices are below a certain threshold. The credit amount is 15% of qualified domestic EOR costs. The EOR credit phases out over a $6 range once oil's reference price exceeds $28 per barrel (adjusted for inflation after 1991; $49.392 in 2019). The EOR credit was fully phased out every year from 2006 through 2016. Low oil prices led to the EOR credit becoming available in 2016 and 2017. A partial credit was available for 2018, but it was fully phased out in 2019 and 2020. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock; and CRS Insight IN11381, *Low Oil Prices May Trigger Certain Tax Benefits, but Not Others*, by Molly F. Sherlock and Phillip Brown.	Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508)	None	*de minimis*
Coal Production Credits: Refined Coal and Indian Coal (IRC §45)	A tax credit for Indian coal produced from reserves that were owned by an Indian tribe or held in trust by the United States for a tribe on June 14, 2005. The amount of the credit is $2.00 per ton (adjusted for inflation; $2.60 per ton in 2021). Tax credits may also be available for refined coal produced at refined coal production facilities placed in service after the date of the enactment of the American Jobs Creation Act of 2004 and before January 1, 2012.	EPACT05 (P.L. 109-58)	Coal produced by 12/31/2021	FY2020: (i) FY2020-FY2024: $0.2 Extension in P.L. 116-260: (i) (FY2021-FY2030)

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Credit for producing oil and gas from marginal wells (IRC §45I)	A tax credit for producing oil and gas from marginal wells, available when oil and gas prices are below certain thresholds. The credit amount is $3 per barrel of qualified crude oil and 50 cents per 1,000 cubic feet (mcf) of qualified natural gas (adjusted for inflation after 2005; $3.90 for oil and 65¢ for gas in 2019; 66¢ for gas in 2020). The credit starts phasing out if the reference price for oil exceeds $15 per barrel or natural gas exceeds $1.67 per mcf for the preceding year (adjusted for inflation after 2005; $19.52 for oil and $2.17 for gas in 2019; $2.21 for gas in 2020). The credit is fully phased out if the reference price exceeds $18 per barrel or $2.00 per mcf (adjusted for inflation after 2005; $23.43 for oil and $2.60 for gas in 2019). The credit for crude oil has never been triggered. In 2016 and 2017, and again in 2019, a partial credit (in the phaseout range) was available for natural gas. For 2020 the credit for natural gas was not phased out; the full 66¢ per mcf credit was available. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock; and CRS Insight IN11381, *Low Oil Prices May Trigger Certain Tax Benefits, but Not Others*, by Molly F. Sherlock and Phillip Brown.	American Jobs Creation Act of 2004 (P.L. 108-357)	None	*de minimis*
Credits for Investments in Clean Coal Facilities (IRC §§48A and 48B)	A tax credit allocated for investment in certain advanced coal technologies. In EPACT05, the tax credit was 20% of investment for integrated gasification combined cycle (IGCC) systems and 15% for other advanced coal-based generation technologies. Additional allocations for a 30% advanced coal-based generation technologies credit were provided in the Energy Improvement and Extension Act of 2008 (P.L. 110-343). Credit allocations are available due to forfeitures of previously allocated credits. Round 3 Phase III credits being allocated in 2021 are 30% for IGCC or other advanced coal-based generation technologies. Credits were also allocated for gasification projects, with the credit amount equal to 30% (20% for credits allocated or reallocated before October 4, 2008). In 2016 the IRS announced no additional allocation rounds would be conducted under the qualifying gasification project program.	EPACT05 (P.L. 109-58)	Credits allocated. $2 billion of §48A credits are available for allocation in Round 3 of the Phase III Program, taking place in 2021.	FY2020: $0.2 FY2020-FY2024: $1.2

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Safe harbor from arbitrage rules for prepaid natural gas (IRC §148(b)(4))	This provision allows tax-exempt bonds to be used to finance prepaid natural gas contracts without applying otherwise applicable arbitrage rules.	EPACT05 (P.L. 109-58)	None	Not available.
Amortization of Geological and Geophysical Expenditures Associated with Oil and Gas Exploration (IRC §167(h))	Geological and geophysical (G&G) expenditures are costs associated with determining the location and potential size of a natural resource or mineral deposit. Generally, these costs are viewed as capital costs, and as such would be recovered over the same time frame as other capital costs. Most producers amortize G&G expenditures over two years. Major integrated oil companies amortize G&G expenditures over seven years. A major integrated oil company, as defined in statute, has (1) average daily worldwide production of crude oil of at least 500,000 barrels; (2) gross receipts in excess of $1 billion in its tax year ending during 2005; and (3) at least 15% ownership interest in a crude oil refinery. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	EPACT05 (P.L. 109-58)	None	FY2020: $0.1 FY2020-FY2024: $0.5
Seven-year MACRS Alaska natural gas pipeline (IRC §168(e)(3)(C)(iii))	A seven-year MACRS recovery period is provided for any natural gas pipeline system located in the State of Alaska that has a capacity of more than 500 billion Btu of natural gas per day.	American Jobs Creation Act of 2004 (P.L. 108-357)	None	*de minimis*
Seven-year MACRS for natural gas gathering lines (IRC §168(e)(3)(C)(iv))	Natural gas gathering lines are treated as 7-year property. A natural gas gathering line consists of the pipe, equipment, and appurtenances determined to be a gathering line by the Federal Energy Regulatory Commission (FERC) or a gathering line used to deliver natural gas to a gas processing plant, an interconnection with a transmission pipeline, or an interconnection with a local distribution company, a gas storage facility, or an industrial consumer.	EPACT05 (P.L. 109-58)	None	Not available.
15-year MACRS Depreciation Recovery Period for Natural Gas Distribution Lines (IRC §168(e)(3)(E)(vi))	A natural gas distribution line, the original use of which commences with the taxpayer after April 11, 2005, and which is placed in service before January 1, 2011, is treated as 15-year property.	EPACT05 (P.L. 109-58)	12/31/2010	FY2020: $0.1 FY2020-FY2024: $0.3

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Amortization of Air Pollution Control Facilities (§§169 and 291(a)(4))	Five-year (60-month) amortization applies to a "certified pollution control facility" used in connection with a plant or other property in operation before January 1, 1976, and to an "atmospheric pollution control facility" placed in service after April 11, 2005, and used in connection with an electric generation plant or other property that is primarily coal fired. Seven-year (84-month) amortization applies only to an "atmospheric pollution control facility" placed in service after April 11, 2005, and used in connection with an electric generation plant or other property that is primarily coal fired and that was placed in operation after December 31, 1975. If an election is made under §169 with respect to any certified pollution control facility, the amortizable basis of the facility is reduced by 20%.	EPACT05 (P.L. 109-58)	None	FY2020: $0.4 FY2020-FY2024: $2.1
Expensing of tertiary injectants (IRC §193)	Taxpayers can deduct tertiary injectant expenses, other than expenses for recoverable hydrocarbon injectants, in the year costs are incurred. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	The Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223)	None	*de minimis*
Expensing of Intangible Drilling Costs (IDCs) and Exploration and Development Costs (IRC §§263A(c)(3), 263(c), 291(b), 616, 617)	IDCs include expenses on items without salvage value (e.g., wages, fuel, and drilling site preparations). Integrated oil and gas producers (producers who also have substantial refining or retail activities) must capitalize 30% of IDCs and then recover those costs over a five-year period. The remaining 70% of IDCs can be fully expensed (costs deducted in the year they are incurred). Nonintegrated producers can fully expense IDCs. The election to deduct intangible drilling and development costs applies to oil and gas wells and to wells drilled for any geothermal deposit. For mineral properties, exploration and development expenditures are deductible as an expense in the year paid, as opposed to being capitalized. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	1916 Treasury regulation (T.D. 45, article 223); codified in 1954 (P.L. 83-591)	None	*Oil and Gas* FY2020: $0.5 FY2020-FY2024: $2.3 *Other Fuels* FY2020: (i) FY2020-FY2024: $0.3

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Passive loss rules for working interests in oil and gas property (IRC §469(c)(3))	Deductions from passive trade or business activities, to the extent they exceed income from all such passive activities, generally may not be deducted against other income (salary, interest, dividends, and active business income). These passive activity loss rules are not applicable to working interests in oil or gas property. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	Tax Reform Act of 1986 (P.L. 99-514)	None	FY2020: (i)[b] FY2021-FY2030: $0.2[b] (10-year estimate)
Percentage Depletion (IRC §§611, 613, and 613A)	Certain independent oil and gas producers (producers who are not retailers or refiners) may elect to claim percentage depletion as opposed to cost depletion. The percentage depletion allowance is 15% of gross income from the property, not to exceed (1) 100% of taxable income from the property, and (2) 65% of the taxpayer's taxable income. Oil and gas producers may claim percentage depletion on up to 1,000 barrels of average daily production (or an equivalent amount of domestic natural gas). Percentage depletion rates for other minerals range from 5% to 22%. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock.	Revenue Act of 1926 (P.L. 69-20)	None	*Oil and Gas* FY2020: $0.6 FY2020-FY2024: $2.9 *Other Fuels* FY2020: $0.1 FY2020-FY2024: $0.7
Fossil fuel capital gains treatment (IRC §631(c))	Certain sales of coal under royalty contracts qualify for taxation as capital gains rather than ordinary income. Income from these sales is taxed at the preferred 20% rate applied to capital gains, as opposed to being taxed as ordinary income.	Revenue Act of 1964 (P.L. 88-272)	None	FY2020: $0.1[b] FY2020-FY2029: $1.6[b] (10-year estimate)
Exceptions for Publicly Traded Partnerships with Qualified Income Derived from Certain Energy-Related Activities (IRC §7704)	Publicly traded partnerships are generally treated as corporations. The exception from this rule occurs if at least 90% of its gross income is derived from interest, dividends, real property rents, or certain other types of qualifying income. Qualifying income includes income derived from certain energy-related activities, such as fossil fuel or geothermal exploration, development, mining, production, refining, transportation, and marketing. For more, see CRS In Focus IF11528, *Oil and Gas Tax Preferences*, by Molly F. Sherlock; and CRS Report R41893, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry*, by Molly F. Sherlock and Mark P. Keightley.	Revenue Act of 1987 (P.L. 100-203)	None	FY2020: $0.3 FY2020-FY2024: $1.8

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021"*, JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. MACRS = modified accelerated cost recovery system. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

b. Exceptions to the passive activity loss rules are not classified as tax expenditures by JCT. These estimates are from the Treasury Department. Treasury Department tax expenditure estimates are available at https://home.treasury.gov/policy-issues/tax-policy/tax-expenditures.

Table 6. Carbon Capture and Sequestration, Nuclear, and Other Tax Incentives

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
Credit for production of electricity from qualifying advanced nuclear power facilities (IRC §45J)	A tax credit for electricity produced from qualifying nuclear facilities. The advanced nuclear production tax credit (PTC) provides a 1.8 cent per kWh tax credit for electricity sold that was produced at qualifying facilities. Criteria for qualifying facilities include that they must use nuclear reactor designs approved by the Nuclear Regulatory Commission after 1993. Qualifying facilities can claim tax credits during the first eight years of production. The credit is restricted to 6,000 megawatts (MW) of total electric generating capacity for all qualifying facilities, with the 6,000 MW allocated by the Internal Revenue Service (IRS). Taxpayers can claim no more than $125 million in tax credits per 1,000 MW of the allocated capacity in any single year.	EPACT05 (P.L. 109-58)	Facilities placed in service by January 1, 2021. The IRS is to allocate unutilized national megawatt capacity after that date.	*de minimis*
Credit for Carbon Oxide Sequestration (IRC §45Q)	A credit for the capture and sequestration of carbon emissions (including carbon dioxide and carbon monoxide). The credit is the sum of four components: (1) $20 (adjusted to $23.82 for 2020) per metric ton of carbon oxide captured using carbon capture equipment placed in service before February 9, 2018, that is not used as a tertiary injectant; (2) $10 (adjusted to $11.91 for 2020) per metric ton of carbon oxide captured using carbon capture equipment placed in service before February 9, 2018, that is used as a tertiary injectant; (3) $31.77 in 2020 per metric ton of carbon oxide captured using carbon capture equipment placed in service on or after February 9,	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	Construction must begin by December 31, 2025.	FY2020: (i) FY2020-FY2024: $0.1 Extension in P.L. 116-260: $0.6 (FY2021-FY2030)

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
	2018, that is not used as a tertiary injectant, during the first 12 years following the facility being placed in service; and (4) $20.22 in 2020 per metric ton of carbon oxide captured using carbon capture equipment placed in service on or after February 9, 2018, that is used as a tertiary injectant, during the first 12 years following the facility being placed in service. Carbon oxide that is not used as a tertiary injectant must be disposed of in a secure geological facility. For carbon dioxide captured at facilities placed in service before February 9, 2018, the credit applies until the IRS, in consultation with the Environmental Protection Agency, certifies that 75 million metric tons of carbon dioxide has been captured or used as a tertiary injectant. As of June 2020, 72 million metric tons of qualified carbon oxide had been taken into account.[b] For more, see CRS In Focus IF11455, *The Tax Credit for Carbon Sequestration (Section 45Q)*, by Angela C. Jones and Molly F. Sherlock.			
10-year MACRS for smart electric distribution property (IRC §§168(e)(3)(D)(iii) and 168(e)(3)(D)(iv))	10-year property includes any qualified smart electric meter and any qualified smart electric grid system. A smart electric meter is a time-based meter and related communication equipment. Smart electric grid systems include property that is used as part of a system for electric distribution grid communications, monitoring, and management.	Energy Improvement and Extension Act of 2008 (P.L. 110-343)	None	FY2020: (i) FY2020-FY2024: $0.2
Transmission Property Treated as 15-year Property (IRC §168(e)(3)(E)(v))	15-year property includes original-use electricity transmission property that is used in the transmission of electricity for sale at 69 or more kilovolts.	EPACT05 (P.L. 109-58)	None	FY2020: (i) FY2020-FY2024: $0.2
Accelerated deductions for nuclear decommissioning costs (IRC §468A)	An eligible taxpayer may deduct cash payments made by the taxpayer to a nuclear decommissioning reserve fund, and to deduct the ratable portion of any special transfer to the fund, even if under the applicable method of accounting the taxpayer would typically claim the deduction in a later tax year.	Deficit Reduction Act of 1984 (P.L. 98-369)	None	Not available
Special tax rate for nuclear decommissioning	A special 20% tax rate for investments made by nuclear decommissioning reserve funds.	Deficit Reduction	None	FY2020: (i) FY2020-FY2024: $0.1

Provision	Description	Enacting Legislation	Expiration Date	Cost[a]
reserve funds (IRC §468A(e)(2))		Act of 1984 (P.L. 98-369)		

Sources: CRS analysis of the Internal Revenue Code; Joint Committee on Taxation, *Estimates Of Federal Tax Expenditures For Fiscal Years 2020-2024*, JCX-23-20, November 5, 2020; and Joint Committee on Taxation, *Estimated Budget Effects Of The Revenue Provisions Contained In Rules Committee Print 116-68, The "Consolidated Appropriations Act, 2021",* JCX-24-20, December 21, 2020.

Notes: IRC = Internal Revenue Code. kWh = kilowatt-hour. MACRS = modified accelerated cost recovery system. An "(i)" indicates a revenue loss of less than $50 million. A *de minimis* tax expenditure is less than $50 million FY2020-FY2024.

a. This column provides Joint Committee on Taxation tax expenditure estimates for the provision, unless otherwise noted.

b. Internal Revenue Service, *Inflation Adjustment Factor Issued for Sequestration Credit*, IRS Notice 2020-40, June 15, 2020.

Author Information

Molly F. Sherlock
Specialist in Public Finance

Disclaimer

Attachment DG-21

Tony Lenoir, *Mapping Communities Eligible for Additional Inflation Reduction Act Incentives,* S&P Global Market Intelligence (Oct. 11, 2022)

RESEARCH — 11 Oct, 2022

Mapping communities eligible for additional Inflation Reduction Act incentives

Author Tony Lenoir

Theme Energy, Energy Transition, Renewables

Introduction

Mapping out energy communities based on criteria specified in the Inflation Reduction Act of 2022 revealed that large swaths of the U.S. may currently qualify for 10% tax credit adders on new energy infrastructure. Further coal power plant retirements and coal mine closures could also contribute to expanding the pool of qualifying geographies, as might changes in the local unemployment rate, while the U.S. Federal Reserve further tightens monetary policy to bring down inflation.

The Take

With its "energy community" special rule, the Inflation Reduction Act incentivizes clean energy development in communities historically reliant on environmentally damaging fossil fuel industries, overlaying an economic revitalization strategy on top of energy transition objectives.

The law's energy community-qualifying employment criteria suggest that over 100 metropolitan and nonmetropolitan statistical areas, or MSAs and non-MSAs, will be eligible for the 10% tax credit step-up. Criteria on closed and retired coal assets, meanwhile, point to more than 2,800 identified U.S. census tracts across 42 states.

Further coal mine closures and coal power plant retirements will likely expand the qualifying census tract footprint, while an economic recession could lead to more eligible MSAs and non-MSAs.

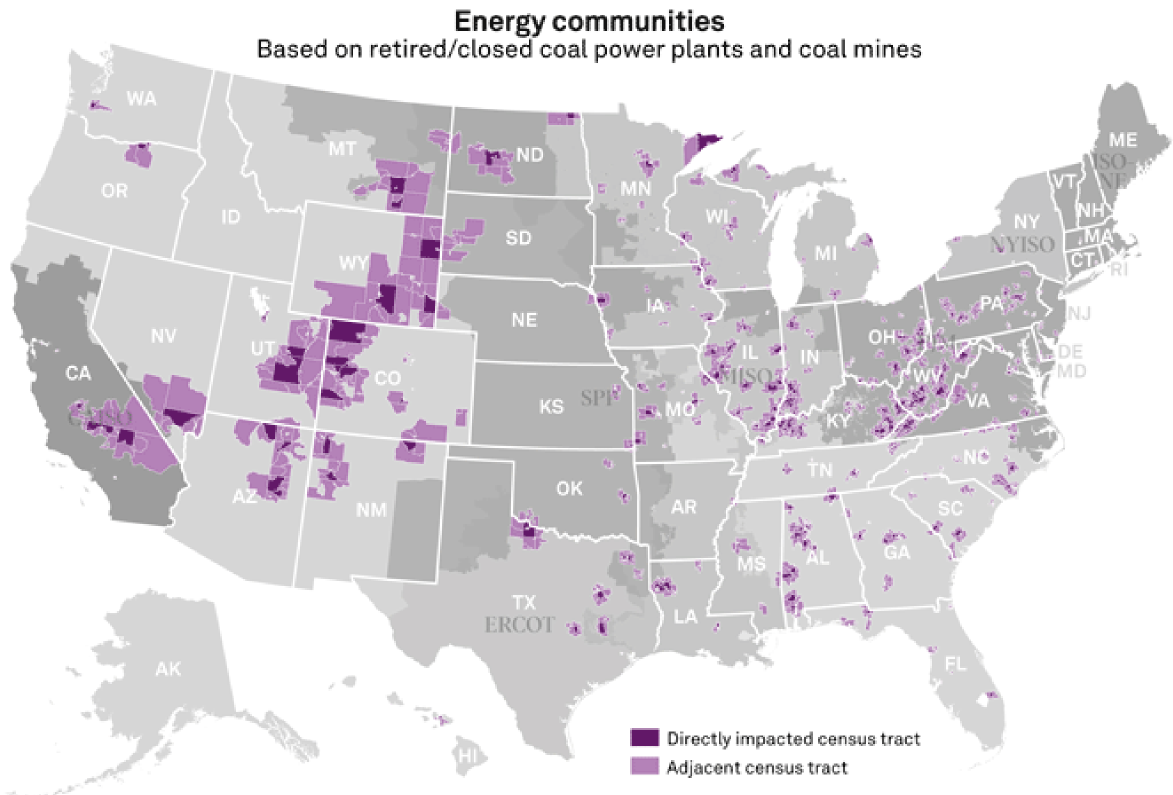
Qualifying energy communities

As per the act, the qualifying energy communities include the following:

* Census tracts — and all adjacent ones — in which any coal mine has closed after Dec. 31, 1999, or in which any coal power plant has been retired after Dec. 31, 2009.

* MSAs and non-MSAs where, after Dec. 31, 2009, industries tied to fossil fuels have accounted for at least 0.17% of direct employment or 25% of local tax revenues, and where the unemployment rate is above the national average for the previous year.

* Brownfield sites — broadly land where the presence or potential presence of pollutants, contaminants or hazardous substances impedes development. The U.S. Environmental Protection Agency estimates there to be more than 450,000 — and possibly as high as a million — brownfield sites in the country.



As of Sep. 14, 2022.
Census tracts — and all adjacent ones — in which any coal mine has closed after Dec. 31, 1999, or any coal power plant has been retired after Dec. 31, 2009.
Map credit: Ciaralou Agpalo Palicpic.
Source: S&P Global Market Intelligence.

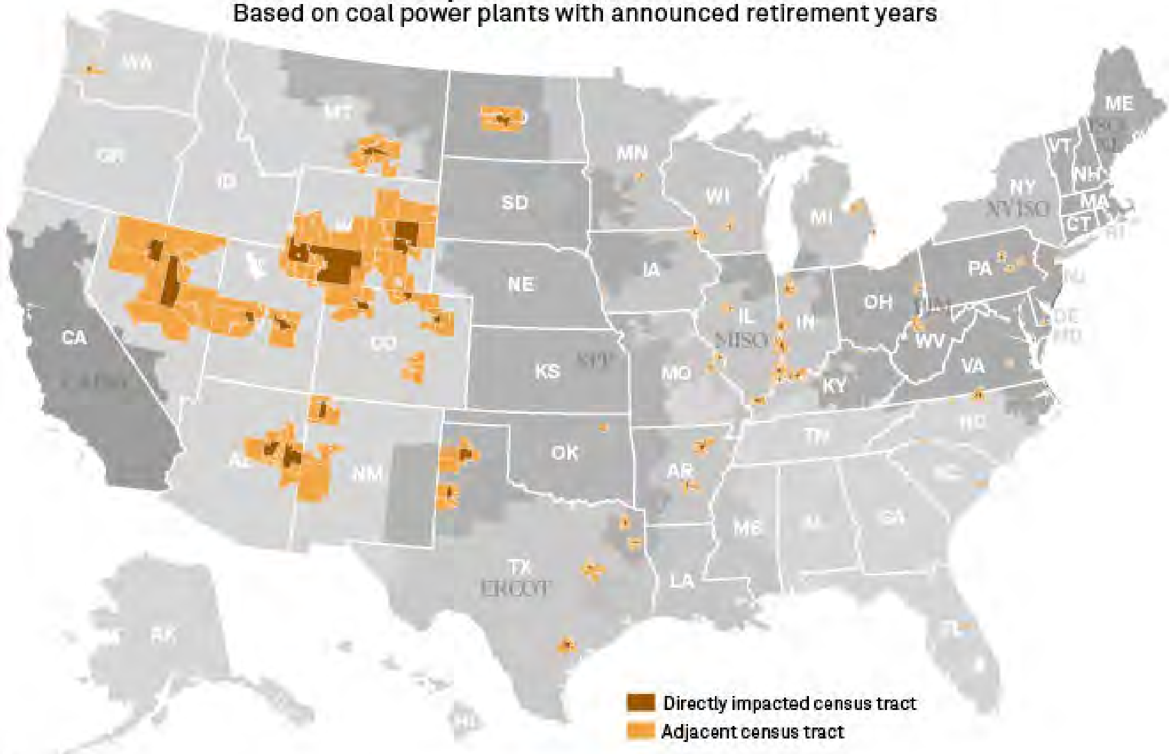
S&P Global Market Intelligence data shows 142 coal mines have closed in the U.S. since 2000. States across or bordering the Appalachian mountains were particularly impacted, with Alabama, Kentucky, Maryland, Ohio, Pennsylvania, Virginia and West Virginia accounting for nearly 79% of all U.S. coal mine closures in the last 22 years.

Plotting U.S. coal power plants retired since 2010 paints an economically and socially similar but geographically contrasting picture. The phasing out of fossil fuels as a major source of power generation in the U.S. has led, among other things, to the closing of 339 coal power plants from 2010 through 2022 year-to-date as of Sept. 14, according to S&P Global Market Intelligence data. Inventoried coal power plant retirements were more geographically diverse than identified coal mine closures, affecting not only coal-rich Appalachia but stretching all the way to the West Coast, particularly affecting the Rockies.

Overall, S&P Global Commodity Insights identified over 2,800 census tracts qualifying for the eligible 10% increase to the act's baseline production and investment tax credits based on the law's closed mine and retired coal power plant criteria. Numbering nearly 4.7 million households, these census tracts are scattered across 42 states. Rust Belt states of Pennsylvania, Illinois and Ohio, with their historical trends of industrial decline over the past half-century, top the energy community charts based on the act's closed or retired coal asset criteria, displaying the largest amount of qualifying census tracts, as well as the largest pool of impacted households. That said, our map of the identified areas displays larger census tracts west of the Mississippi — a feature giving developers more geographical options, particularly when pursuing outsized solar and wind projects.

An additional 77 U.S. coal power plants, including 21 in Rust Belt states, have announced plans to retire in future years. An incremental 309 census tracts across 27 states could become eligible for the 10% increase in the act's tax credits based on these announcements alone, with Texas ranking first in impacted census tracts and households. Colorado and Missouri are neck and neck for the number two spot. Michigan rounds out the top four. Ultimately, all U.S. coal power plants may face a retirement decision if the U.S stays the course on its clean energy goals and commitments. The U.S. currently operates 261 coal power plants, with an aggregate operating capacity of 200 GW, according to Market Intelligence data.

Anticipated energy communities
Based on coal power plants with announced retirement years



As of Sep. 14, 2022.
Census tracts — and all adjacent ones — in which operating coal power plants have announced retirements years.
Map credit: Ciaralou Agpalo Palicpic.
Source: S&P Global Market Intelligence.

Zooming in on the employment criteria for the act's energy community eligibility indicates at least 114 MSAs and non-MSAs qualifying, based on local and national unemployment rates from June 2021 to June 2022. It is important to note that the language used in the act suggests annual unemployment rates through regular calendar years as the benchmark for eligibility. However, this and other provisions of the law will likely need clarification from the U.S. Energy Department.

With employment and unemployment levels in constant flux, the act's employment criteria for extra energy community tax credits embody the proverbial "moving target." A potentially deteriorating employment environment on monetary tightening by the Fed, for example, could lead to an expansion of the pool of eligible MSAs and non-MSAs.

Commodity Insights identified an additional 120 MSAs and non-MSAs likely meeting the fossil fuel employment criteria — areas that would qualify for the act's 10% tax credit step-up if the local unemployment rate were to rise above the national average. Given the trend away from fossil fuels, our analysis assumes few changes to the identified fossil fuel employment footprint throughout the act's life.

While the act's clean energy production and investment tax credits have been making headlines, economic revitalization objectives underlie the law — hence its domestic manufacturing and sourcing quotas. By incentivizing developers and investors to focus on energy communities to build solar, wind and battery projects and clean-energy manufacturing facilities, the law seeks to accelerate the U.S. transition to clean energy while revitalizing communities historically reliant on fossil fuel industries.

Regulatory Research Associates is a group within S&P Global Commodity Insights.

Tanya Peevey and Ciaralou Palicpic contributed to this article.

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Attachment DG-22

TEP Response to Staff Data Request 5.11, Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Nov. 23, 2022)

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF's 5th SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
November 23, 2022

STAFF 5.11

During 2019, 2020, 2021, and to-date in 2022, did any of TEP's coal suppliers with whom TEP had coal supply contracts, declare force majeure events that excused having to make coal deliveries? If so, please identify and explain each such instance. Also describe how that affected TEP's access to coal supply and the delivery of coal to each of TEP's generating plants, and whether and how it impacted TEP's coal inventory and coal procurement decision

RESPONSE:

Several times during 2021 and prior to San Juan Generation Station Unit's 1 closure in 2022, Westmoreland Coal Company, which is the coal supplier, issued a force majeure due to non-normal conditions at the mine. There were numerous mitigation efforts made. TEP did agree to derating our ownership in Unit 1, in conjunction with the other owners of both remaining Units, in order to ensure coal supply through the end of June 2022, when Unit 1 was scheduled to close. The derate strategy was short term.

RESPONDENT:

Molly Mitchell

WITNESS:

Molly Mitchell

Attachment DG-23

TEP Response to Staff Data Request 5.04(a), Docket No. E-01933A-22-0107 (Ariz. Corp. Comm'n Dec. 1, 2022)

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSES TO STAFF's 5th SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
December 1, 2022

STAFF 5.04

Order 77856 at page 46-47 (quoting TEP) states that "Springerville Units 1 and 2 are a reliable solid fuel resource with an average of 45 days of on-site fuel inventory offering a measure of protection against weather events and natural gas infrastructure interruptions. These unique attributes enable Springerville to play a critical role in maintaining system reliability and grid reliability within the Company's resource portfolio."

a. During each month of 2021 and in 2022 to-date, has the Company been able to maintain at least a 45-day supply of on-site fuel inventory at the Springerville plant? If not, identify each month of 2021 and 2022 in which the level of fuel inventory at the Springerville plant fell below the minimum 45-day supply that was stated to be needed, and explain fully why the Springerville fuel supply fell below the 45-day level.

b. Show and explain in detail how Springerville performed in February 2021 during Winter Storm Uri.

c. Does the Company have any estimates of fuel savings associated with being able to operate the Springerville generating station in February 2021 including the periods affected by Winter Storm Uri? If so, please identify and provide those estimates.

d. Was the operation of Springerville constrained in any months of 2021 or 2022 due to having an inadequate on-site fuel supply? If so, identify, quantify, and explain each such instance.

RESPONSE: ORIGINAL RESPONSE DATE November 23, 2022

b. While the regional cold weather condition primarily impacted Texas, TEP also faced some challenges related to the cold weather. That said, SGS was able to provide the power necessary to meet our customer's needs during Winter Storm Uri.

Springerville, Unit 1	0007	2/1/2021 19:00	2/2/2021 00:54	D1	8521	209.00	Unit derated due to SDA slurry lines plugged up restricting flow.
Springerville, Unit 1	0008	2/9/2021 14:22	2/11/2021 11:57	U2	1000		Unit offline to repair boiler water wall tube leak
Springerville, Unit 1	0009	2/15/2021 14:57	2/15/2021 20:40	U1	8531		Unit tripped due to SDA Atomizer feeder breaker tripped
Springerville, Unit 1	0010	2/16/2021 04:00	2/16/2021 06:58	D1	0330	304.00	Unit derated due to coal mill coal leak and no spare avail.
Springerville, Unit 1	0011	2/17/2021 10:00	2/17/2021 18:30	D1	0110	319.00	Unit derated due to coal silos plugged from wet coal
Springerville, Unit 1	0012	2/22/2021 06:14	2/22/2021 12:28	D1	0310	309.00	Unit derated due to coal mill tripped due to grounded wiring. No spare avail.

Springerville, Unit 2	0002	2/19/2021 00:24	2/21/2021 08:46	U1	1000		Unit offline for boiler tube leak repairs.
Springerville, Unit 2	0003	2/25/2021 04:57	2/28/2021 23:59	D1	3411	209.00	Unit derated due to loss of BFP when motor went to ground

RESPONDENT:

a., c-d Molly Mitchell

b. Erik Bakken

WITNESS:

Molly Mitchell

**TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSES TO STAFF's 5th SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
December 1, 2022**

SUPPLEMENTAL RESPONSE: December 1, 2022

a. From January 2021 through May 2022, there were no months where the coal inventory for Springerville Units 1 and 2 fell below 45 days of inventory. Beginning in June 2022 and continuing today, the inventory for Units 1 and 2 have been below 45 days. As explained in response to Staff's 4.103 data request, in late May, the Burlington Northern Santa Fe ("BNSF") Railroad notified TEP that it would be unable to meet its 2022 delivery obligations due to the lack of workforce availability. This situation resulted in a significant reduction of both coal and lime to SGS. As a result, the coal and lime inventories onsite were reduced to the lowest levels seen during the life of the plant.

c. Based on the output from the Springerville Generating Station from February 14, 2021 through February 18, 2021, the Company estimates it would have incurred approximately $15 million in replacement power costs during this same time period if both SGS units were unavailable.

Estimated Replacement Power Costs during Winter Storm Uri 2/14/21-2/18/21			
Date	**SGS Unit 1&2 MWh**	**Palo Verde Market Prices $/MWh**	**Replacement Power Costs**
14-Feb	16,572	$68.80	$725,862
15-Feb	14,134	$229.05	$2,884,124
16-Feb	16,374	$237.40	$3,477,753
17-Feb	15,727	$342.29	$4,990,083
18-Feb	16,194	$237.56	$3,442,282
Total Replacement Power Costs			**$15,520,104**

d. Due to the ongoing issues with the BNSF, Springerville Units 1 and 2 have been in a derated position almost daily since late June 2022 and this is scheduled to continue until the inventory recovers and BNSF deliveries rebound. Additionally, the Company took a coal conservation outage on Unit 1 during October 2022 to build inventory going into winter outage season. The failure of the BNSF to deliver the coal TEP forecasted to burn from June 2022 through October 2022 is ~460k tons.

RESPONDENT:

a., c-d Molly Mitchell

b. Erik Bakken

WITNESS: Molly Mitchell

Attachment DG-24

Excerpt of Direct Testimony of Devi Glick, Docket No. 19-00170-UT (N.M. Pub. Reg. Comm’n Nov. 22, 2019)

BEFORE THE
NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR: (1) REVISION OF ITS RETAIL RATES UNDER ADVICE NOTICE NO. 282; (2) AUTHORIZATION AND APPROVAL TO SHORTEN THE SERVICE LIFE AND ABANDON ITS TOLK GENERATING STATION UNITS AND (3) OTHER RELATED RELIEF	**CASE NO. 19-00170-UT**

PUBLIC (REDACTED) VERSION

Direct Testimony of Devi Glick

On Behalf of

Sierra Club

November 22, 2019

i. SPS's economic analysis does not properly evaluate the risk that the amount of economically recoverable water may fall faster than SPS currently contemplates

Q Please summarize this section.

A First, I discuss my concerns with the way SPS incorporated, and relied upon, the WSP groundwater modeling into the Company's economic modeling and its plan to operate Tolk seasonally given the level of uncertainty in the WSP groundwater modeling. Second, I outline the implications of SPS's failure to incorporate the risks that agricultural and municipal pumping will deplete the aquifer faster than anticipated into its SPS's spreadsheet water model. Finally, I conclude that SPS has not presented adequate evidence to demonstrate that the aquifer can economically supply the water needed to support operations through 2031.

Q Do you have concerns with the Company's use of the WSP groundwater modeling to develop its plan to operate Tolk seasonally?

A Yes, SPS asserts that the WSP groundwater modeling "confirms that reduced operations can extend the useful lives of the Tolk units until 2030–2032 relative to typical operations."[62] However, the results presented by WSP actually do not fully support this statement. While the report finds that the difference between the available water supply and demand was likely to be significantly lower under an optimized demand scenario (relative to a tradition demand scenario), the report clearly states:

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[62] Direct Testimony of M. Lytal at 75; Exhibit DG-6, *2018 Groundwater Modeling Results*, Xcel Energy (Nov. 2018).

SPS will likely have challenges meeting the average annual groundwater demands throughout both scenarios, with these challenges accelerating in the year 2024. Meeting peak demands in the summer will also likely be a challenge for the wellfields starting in 2019.[63]

Moreover, WSP acknowledges that its model may have underestimated depletion rates, most notably because of the uncertainty about groundwater pumping rates from irrigators located close to the SPS Water Rights Area ("XWRA") boundary.[64]

Q What are the implications of WSP's findings that meeting peak water demands will be challenging starting in 2019, and accelerating starting in 2024?

A WSP's findings indicate that it will be difficult for SPS to ensure access to sufficient water at peak times through 2032, even assuming a baseline-level of additional wells. This means that water could be depleted more quickly than modeled in SPS's water model, and the Company would therefore need to spend more money than currently included in the Tolk Strategist analysis to maintain access to sufficient water. Any wells required beyond that baseline will make Tolk more uneconomic. Therefore SPS's Strategist economic analysis should have included robust evaluation of sensitives for deviations from (1) the water depletion windows calculated in SPS's water model, and thus (2) an increase in the number of wells required to supply peak water demands.

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[63] Direct Testimony of M. Lytal, at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3; Exhibit DG-6, *2018 Groundwater Modeling Results*, Xcel Energy (Nov. 2018).

[64] *Id.*

Instead, SPS's economic analysis relies on a best-case scenario input assumption around water availability, without also including any evaluation of the costs and impact on ratepayers if the water actually costs more to procure going forward. Just as prudent utilities evaluate a range of fuel and capital cost assumptions, energy prices, and load forecasts, SPS should have evaluated a high-band water depletion scenario that reflects the very real risk that SPS's baseline assumption is overly optimistic.

Q Please explain why pumping by irrigators located close to the SPS Water Rights Area ("XWRA") is relevant to SPS's analysis.

A The amount of water available to Tolk is critically influenced not just by how much water the Company uses at the plant, but also by how much water agricultural and municipal entities in the area are using.[65] SPS witness Lytal acknowledged this in stating that "one of the most significant variables in the WSP model relates to the amount of agricultural water used in the model domain outside of the SPS wellfield, which drives overall water usage in the area."[66] This means that SPS has no control over a main factor driving depletion of its water supply.[67]

Q How large of an impact could changes in agricultural and municipal pumping have on the aquifer depletion rates?

A SPS does not quantify how large of an impact changes in area water pumping could have on depletion rates; therefore, we have no information on how the

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[65] Direct Testimony of M. Lytal at 66-67.
[66] *Id.*
[67] *Id.* at 76.

Attachment DG-25

U.S. Environmental Protection Agency, *Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule*

FACT SHEET

GREENHOUSE GAS STANDARDS AND GUIDELINES FOR FOSSIL FUEL-FIRED POWER PLANTS PROPOSED RULE

Summary

On May 11, 2023, the U.S. Environmental Protection Agency (EPA) announced proposed new carbon pollution standards for coal and gas-fired power plants that will protect public health, reduce harmful pollutants and deliver up to $85 billion in climate and public health benefits over the next two decades. Consistent with EPA's traditional approach to establishing pollution standards under the Clean Air Act, the proposed limits and guidelines require ambitious reductions in carbon pollution based on proven and cost-effective control technologies that can be applied directly to power plants. They also provide owners and operators of power plants with ample lead time and substantial compliance flexibilities, allowing power companies and grid operators to make sound long-term planning and investment decisions, and supporting the power sector's ability to continue delivering reliable and affordable electricity.

President Biden's policy agenda has driven momentum in the power sector to cut GHGs and is moving us closer to avoiding the worst impacts of climate change. Together with other recent EPA actions to address health-harming pollution from the power sector, the proposed rules deliver on the Administration's commitment to reduce pollution from the power sector while providing long-term regulatory certainty and operational flexibility.

Overview

- EPA is proposing Clean Air Act emission limits and guidelines for carbon dioxide (CO_2) from fossil fuel-fired power plants based on cost-effective and available control technologies. The power sector is the largest stationary source of greenhouse gases (GHGs), emitting 25 percent of the overall domestic emissions in 2021. These emissions are almost entirely the result of the combustion of fossil fuels in the electric generating units (EGUs) that are the subjects of these proposals.
- The proposals would set limits for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines. Consistent with EPA's traditional approach to establishing pollution standards for power plants under section 111 of the Clean Air Act, the proposed standards are based on technologies such as carbon capture and sequestration/storage (CCS), low-GHG hydrogen co-firing, and natural gas co-firing, which can be applied directly to power plants that use fossil fuels to generate electricity.
- As laid out in section 111 of the Clean Air Act, the proposed new source performance standards (NSPS) and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated for the purpose of improving the emissions performance of the covered electric generating units.

- EPA has evaluated the emissions reductions, benefits, and costs of the proposals to limit CO2 from the existing coal fleet and new natural gas units. EPA projects these proposals would cut 617 million metric tons of CO2 through 2042 along with tens of thousands of tons of PM2.5, SO2, and NOx – harmful air pollutants that are known to endanger public health.
    - Between 2024 and 2042, projected net climate and health benefits from these emissions reductions range from $64 billion-to $85 billion, an annual net benefit that ranges from $5.4 billion to $5.9 billion.
    - These estimates do not include the impact of the proposed requirements for existing gas-fired combustion turbines or third phase of the NSPS. EPA performed a separate analysis of these proposed requirements that estimates they would reduce between 214 and 407 million metric tons of CO2 cumulatively through 2042.
- In 2030 alone, the health benefits of the proposals on new gas and existing coal include approximately 1,300 avoided premature deaths; more than 800 avoided hospital and emergency room visits; approximately 2,000 avoided cases of asthma onset; more than 300,000 avoided cases of asthma symptoms; 38,000 avoided school absence days; and 66,000 lost work days.
- The quantified climate and health benefits include the value of multiple climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services.
- The proposals provide utilities options for meeting these standards as well as the time needed to plan and invest for compliance and continue to support a reliable supply of affordable electricity.
- The more frequently and longer a unit operates, and the greater its capacity, the more cost-effective it is to install controls for CO2 emissions. These proposals considered this fact to create subcategories in the standards and guidelines. For some subcategories, the proposals phase in technology standards over time in recognition of the time needed to plan for and install controls.
- EPA is also simultaneously proposing to repeal the Affordable Clean Energy (ACE) rule.
- The proposals build on and respond to extensive stakeholder engagement. EPA looks forward to continuing to engage stakeholders as we work toward finalizing these proposals.
- EPA will take comment on these proposals for 60 days after publication in the Federal Register and hold a virtual public hearing. Registration for the public hearing will open after the proposal is published in the Federal Register.
- EPA will host virtual trainings on June 6 and 7 to provide communities and Tribes with information about the proposal and about participating in the public comment process. Registration information will be available on the web at Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants.

Proposed Technology-Based Standards

- The technology-based standards EPA is proposing that would cut CO_2 from power plants include:
    - o Updates to the New Source Performance Standards (NSPS) for fossil fuel-fired stationary combustion turbines (generally natural gas-fired)
    - o Emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired)
    - o Emission guidelines for existing fossil fuel-fired steam generating EGUs (generally coal-fired)
- These proposed actions consider the extensive input received from a broad range of stakeholders on a variety of topics, including the operation of these regulated sources, in light of the rapid evolution of the power sector. At the same time, these proposed actions ensure that new and certain existing natural gas-fired combustion turbines and existing steam EGUs achieve significant and cost-effective reductions in GHG emissions through the application of adequately demonstrated control technologies.
- These proposed standards are designed to allow the power sector continued resource and operational flexibility and to facilitate long-term planning. Among other things, these elements include:
    - o subcategories of new natural gas-fired combustion turbines that allow for the stringency of GHG emission standards to vary by capacity factor;
    - o subcategories for existing steam EGUs that are based on operating horizons and fuel, and that accommodate the stated plans of many power companies to voluntarily cease operation of some sources;
    - o compliance deadlines for both new and existing EGUs that provide ample lead time for states and utilities to plan; and
    - o proposed state plan flexibilities.
- Starting in 2030, the proposals would generally require more CO2 emissions control at fossil fuel-fired power plants that operate more frequently and for more years and would phase in increasingly stringent CO2 requirements over time. The proposed requirements vary by the type of unit (new or existing, combustion turbine or utility boiler, coal-fired or natural gas-fired), how frequently it operates (base load, intermediate load, or low load (peaking) and its operating horizon (i.e., planned operation after certain future dates).
- State plans would reflect limits that go into place in 2030 for existing coal-fired units. Depending on the expected length of the units' period of operation, those proposed limits are based on CO2 emission rates achieved by natural gas co-firing or CCS.
- Limits for natural gas-fired combustion turbines are based on CCS and/or use of low-GHG hydrogen and vary based on whether the units are new or existing, and whether they are used for baseload or intermediate load generation.

- State plans would reflect limits that go into place for existing natural gas-fired combustion turbines in 2035, for turbines that install CCS; or 2032 and 2038, for turbines that co-fire with low-GHG hydrogen.
- Limits for new natural gas-fired combustion turbines would apply as soon as they are constructed and , similar to limits for existing sources, become more stringent in 2035, for turbines that install CCS; or 2032 and 2038, for turbines that co-fire with low-GHG hydrogen.

- EPA has designed these proposed standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.
  - EPA has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals. These proposed NSPS and emission guidelines provide extensive lead time and compliance flexibilities, preserving the ability of power companies and grid operators to maintain the reliability of the nation's electric power system.

Updates to the New Source Performance Standards for Fossil Fuel-fired Stationary Combustion Turbines (Primarily New Natural Gas Units)

- EPA is proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs that are based on highly efficient generating practices in addition to CCS or co-firing low-GHG hydrogen.
- For new and reconstructed fossil fuel-fired combustion turbines, EPA is proposing to create three subcategories based on the function the combustion turbine serves:
  - a low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor of less than 20 percent;
  - an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine;
  - and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines.
- This subcategorization approach is similar to the current NSPS for these sources, which, in 2015, established subcategories for base load and non-base load units.
- This revised approach to subcategories recognizes that power companies are building new natural gas-fired combustion turbines with plans to operate them at varying levels of capacity, in coordination with existing and expected energy sources.
- For each subcategory, EPA is proposing a distinct BSER and standard of performance based on its evaluation of the statutory factors, including feasibility, emissions reductions, and cost-reasonableness of available controls.

- For the low load subcategory, EPA is proposing that the BSER is the use of lower emitting fuels (*e.g.*, natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted.
- For the intermediate load and baseload subcategories, EPA is proposing an approach in which the BSER has several components: (1) highly efficient generation; and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen.
- These components form the basis of a standard of performance that applies to affected facilities in phases. Affected facilities are those that commence construction or reconstruction after the date of publication in the *Federal Register* of this proposed rulemaking.
    - Phase 1: Affected facilities must meet a first phase standard of performance, based on highly efficient generation, by the date the rule is promulgated or upon initial startup of the facility for units that commence construction after the date of promulgation.
    - Phases 2 and 3: Affected facilities in the intermediate load and base load subcategories must also meet more stringent phases of the standard of performance at specified compliance deadlines in the future. These compliance deadlines allow time for affected sources to plan for and install controls.
        - Intermediate load affected facilities must meet a second phase standard based on 30% low-GHG hydrogen (by volume) by 2032.
        - Base load affected facilities that follow the CCS pathway must meet a second phase standard based on 90% capture of CO2, using CCS, by 2035
        - Baseload affected facilities that follow the low-GHG hydrogen pathway must meet a second phase standard based on co-firing 30% low-GHG hydrogen by volume by 2032 and a third phase standard based on co-firing 96% by volume low-GHG hydrogen by 2038.
- EPA is proposing to define low-GHG hydrogen as that produced with an overall emissions intensity of less than 0.45 kgCO2e/kgH2 with the boundary conditions of well-to-gate, consistent with the Congressional definitions provided in section 45V(b)(2)(D) of the Inflation Reduction Act. This definition ensures that only lowest-GHG hydrogen can qualify as part of the combustion turbine co-firing BSER.

Emission Guidelines for Large and Frequently Used Existing Fossil Fuel-Fired Stationary Combustion Turbines (Primarily Existing Natural Gas Units)

- EPA is proposing emission guidelines for large and frequently used existing stationary combustion turbines.
- Large, frequently operated turbines are larger than 300 MW with a capacity factor of greater than 50 percent.

- Because these existing combustion turbines are similar to new stationary combustion turbines, EPA is proposing a BSER that is consistent with the second and third phases of the BSER for new base load combustion turbines.
- Specifically, EPA is proposing that BSER for these units is based on either 90 percent capture of CO2 using CCS by 2035, or co-firing of 30% by volume low-GHG hydrogen beginning in 2032 and co-firing 96% by volume low-GHG hydrogen beginning in 2038.
- Further, EPA is soliciting comment on how the Agency should approach its legal obligation to establish emission guidelines for the remaining existing fossil fuel-fired combustion turbines not covered by this proposal, including smaller frequently used existing fossil fuel-fired combustion turbine EGUs and less frequently used existing fossil fuel-fired combustion turbines.

Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating EGUs (Primarily Existing Coal Units)

- EPA is proposing to establish new emission guidelines for existing fossil fuel-fired steam generating EGUs that reflect the application of CCS and the availability of natural gas co-firing.
- EPA is proposing that the BSER for coal-fired steam EGUs that will operate in the long-term (i.e., after December 31, 2039) is the use of carbon capture and storage (CCS) with 90 percent capture of CO2. The associated degree of emission limitation is an 88.4 percent reduction in emission rate (lb CO2/MWh-gross basis).
- EPA has determined that CCS satisfies the BSER criteria for these sources because it is adequately demonstrated, achieves significant reductions in GHG emissions, and is highly cost-effective.
- Although the EPA considers CCS to be a broadly applicable BSER, the Agency also recognizes that CCS will be most cost-effective for existing steam EGUs that are in a position to recover the capital costs associated with CCS over a sufficiently long period of time.
- In response to industry input, and recognizing that the cost-effectiveness of CO2 controls depends on the period of time over which a plant will be operated, EPA is proposing to divide the subcategory for coal-fired units into additional subcategories based on operating horizon (*i.e.*, dates for electing to permanently cease operation) and, for one of those subcategories, load level (*i.e.*, annual capacity factor), with a separate BSER and degree of emission limitation corresponding to each subcategory. For each subcategory, EPA is proposing standards of performance reflecting controls that are cost-effective and achievable for existing plants in that subcategory.
    - For units that elect to commit to permanently cease operations prior to January 1, 2040, and that are not in other subcategories, EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis. The associated degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross basis).

- For units that elect to commit to permanently cease operations prior to January 1, 2035, and commit to operate with an annual capacity factor limit of 20 percent, EPA is proposing that the BSER is routine methods of operation and maintenance. The associated degree of emission limitation is no increase in emission rate.
- For units that elect to commit to permanently cease operations prior to January 1, 2032, EPA is proposing that the BSER is routine methods of operation and maintenance. The associated degree of emission limitation is no increase in emission rate.

- EPA is also proposing emission guidelines for natural gas- and oil-fired steam generating units, with additional subcategorization by capacity factor. For each of the proposed subcategories, the BSER is routine methods of operation and maintenance and the degree of emission limitation is no increase in emission rate.

Standards for New, Reconstructed and Modified Coal Units

- The 2015 standards for new coal units, based on CCS, and for reconstructed coal units, based on efficiency, remain in place.
- EPA determined not to review the new and reconstructed standards because we anticipate no further new units.
- EPA reviewed and is proposing to revise the standards for modified units to be based on the BSER of CCS with 90 percent capture, to ensure consistency for any existing units currently subject to the emission guidelines that may modify and become subject to the NSPS.

Additional Areas of Comment

- EPA is soliciting comment on a number of variations to the subcategories and BSER determinations, as well as the associated degrees of emission limitation and standards of performance.
- EPA is also soliciting comment on BSER options and associated degrees of emission limitation for existing fossil fuel-fired stationary combustion turbines for which no BSER is being proposed (i.e., fossil fuel-fired stationary combustion turbines that are not large, frequently operated turbines).

Emissions Changes, Benefits and Costs

- EPA estimated the national emissions changes, benefits and costs in a Regulatory Impact Analysis (RIA). The RIA presents information about the NSPS for new gas turbines and the emission guidelines for existing coal units together. The RIA also provides estimates about the emission changes associated with the existing source gas proposal and another element of the NSPS for new gas turbines.

- The RIA estimates are presented two ways – as present values (PV) and equivalent annualized values (EAV). The PV is the costs or benefits over the 19-year period of 2024 to 2042. The EAV represents the value for each year of the analysis.
- EPA projects the proposals to limit CO_2 from the existing coal fleet and new natural gas units will avoid 617 million metric tons total of CO_2 from 2028-2042 along with tens of thousands of tons of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and fine particulate matter ($PM_{2.5}$). Climate and health benefits exceed the costs by \$64 billion-\$85 billion from 2024-2042, which is an annual net benefit of \$5.4 billion to \$5.9 billion.
    - These estimates do not include the impact of the proposed requirements for existing gas-fired combustion turbines. EPA performed a separate analysis of these proposed requirements that estimates they would reduce 214-407 million metric tons of CO_2 cumulatively between 2028-2042.
- In 2030 alone, the health benefits of the proposals on existing coal and new natural gas power plants include approximately 1,300 avoided premature deaths; more than 600 avoided hospital and emergency room visits; more than 1,400 avoided cases of asthma onset; more than 300,000 avoided cases of asthma symptoms; 38,000 avoided school absence days; and 66,000 lost work days.
- EPA's national-level analysis of emission reduction and public health impacts finds that these proposals would achieve nationwide reductions in EGU emissions of multiple health-harming air pollutants including nitrogen oxides (NO_x), sulfur dioxide (SO_2), and fine particulate matter ($PM_{2.5}$). These reductions in health-harming pollution would result in significant public health benefits including avoided premature deaths, reductions in new asthma cases and incidences of asthma symptoms, reductions in hospital admissions and emergency department visits, and reductions in lost work and school days.
- The quantified climate and health benefits include the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services.
- The monetized benefits estimates provide an incomplete overview of the beneficial impacts of the proposals. The monetized benefits estimates do not include important climate benefits that were not monetized in the RIA. In addition, important health, welfare, and water quality benefits anticipated under these proposed rules are not quantified or monetized. EPA anticipates that taking non-monetized effects into account would show the proposals to be more net beneficial than the tables in this section reflect.

State Plans for Existing Power Plants

- Under section 111(d) of the Clean Air Act, states must submit plans to EPA that provide for the establishment, implementation and enforcement of standards of performance for existing sources. These state plans must generally establish standards that are at least as stringent as EPA's emission guidelines. States may take into account remaining useful life and other factors when applying standards of performance to individual existing sources.

- EPA proposed revisions to the general implementing regulations for emission guidelines under CAA section 111 (also referred to as "subpart Ba") in December 2022 that, if finalized, would also apply to these emission guidelines.
- A few areas specific to existing power plants and CO2 in state plans include:
  - **State plan submission deadline:** EPA is proposing to require that states submit plans to EPA within 24 months of the effective date of the emissions guidelines.
  - **State plan components:** EPA is proposing requirements specific to these emission guidelines to ensure transparency, including a website hosted by EGU owners/operators to publish documentation and information related to compliance with the state plan.
  - **Compliance deadline for sources:** EPA is proposing that existing steam generating units must start complying with their standards of performance on January 1, 2030. Existing combustion turbine units must start complying with their standards of performance on January 1, 2032, or January 1, 2035, depending on their subcategory.
  - **Presumptive standards:** EPA is proposing methodologies for states to use in establishing presumptively approvable standards of performance for most types of affected EGUs.
  - **Remaining Useful Life and Other Factors (RULOF):** States would apply EPA's framework, as we proposed to revise it in the subpart Ba rulemaking, for applying a less stringent standards based on a particular facility's remaining useful life or other factors. To receive a less stringent standard, a state must demonstrate that a facility cannot reasonably achieve the stringency achievable through application of the BSER.
  - **Compliance flexibilities/trading:** In the proposed rule for existing power plants, EPA is proposing to allow trading and averaging for state plans under the particular circumstances of these emission guidelines. EPA is taking comment on what limitations or requirements should apply to ensure that trading and averaging mechanisms are at least as protective as EPA's emission guidelines. If EPA determines that trading and averaging are appropriate, states would not be required to allow for such compliance mechanisms in their state plans, but could elect to include them.

Environmental Justice Analysis

- President Biden's policy agenda has driven momentum in the power sector to cut GHGs and is moving us closer to avoiding the worst impacts of climate change, which is already having a disproportionate impact on communities disproportionately burdened by pollution. The proposed rules deliver on the Administration's commitment to reduce pollution from the power sector and reduce climate impacts for communities.

- These proposals include an environmental justice analysis that quantitatively evaluates:
  - the proximity of affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by these proposals and
  - the distribution of ozone and PM2.5 concentrations in the baseline and changes due to the proposed rulemakings across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation.
- The environmental justice assessment also includes discussions of climate impacts across various demographic groups.
- EPA has evaluated how the air quality impacts associated with these proposals would be distributed, with particular focus on potentially vulnerable populations.
  - These proposals are anticipated to lead to modest but widespread reductions in ambient levels of PM2.5 for a large majority of the nation's population, as well as reductions in ambient PM2.5 exposures that are similar in magnitude across all racial, ethnic, income and linguistic groups.
  - Similarly, EPA found that the proposed standards are anticipated to lead to modest but widespread reductions in ambient levels of ground-level ozone for some of the nation's population, and that in all but one of the years evaluated the proposed standards would lead to similar reductions in ambient ozone exposures across all demographic groups.
  - Although reductions in PM2.5 and ozone exposures are small relative to baseline levels, and although disparities in PM2.5 and ozone exposure would continue to persist following these proposals, EPA's analysis indicates that the air quality benefits of these proposals would be broadly distributed.
- EPA has evaluated the percent of potentially vulnerable and/or overburdened populations living near three categories of facilities associated with these proposals. These proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors, such as local hazardous air pollution, emitted from sources affected by the regulatory action for certain population groups of concern.
- The following subsets of affected facilities were separately evaluated:
  - All coal plants (140 facilities) with units potentially subject to the proposed 111 rules: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.
  - Coal plants retiring by January 1, 2032 (3 facilities) with units potentially subject to the proposed 111 rules: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.

- Coal plants retiring between January 1, 2032, to January 1, 2040, (19 facilities) with units potentially subject to the proposed 111 rules: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.

- The proximity analysis of the full population of potentially affected units greater than 25 MW indicated that the demographic percentages of the population within 10 km and 50 km of the facilities are relatively similar to the national averages.
  - The proximity analysis of the 19 units that will retire from January 1, 2032, to January 1, 2040 (a subset of the total 140 units) found that the percent of the population within 10 km that is African American is higher than the national average.
  - The proximity analysis for the 3 units that will retire by January 1, 2032 (a subset of the total 140 units) found that for both the 10 km and 50 km populations the percent of the population that is American Indian for one facility is significantly above the national average, the percent of the population that is Hispanic/Latino for another facility is substantially above the national average, and all three facilities were well above the national average for both the percent below the poverty level and the percent below two times the poverty level.

Meaningful Engagement

- EPA's proposed emission guidelines for existing fossil fuel-fired steam generating units as well as existing fossil fuel-fired stationary combustion turbines would require states to undertake meaningful engagement with affected stakeholders, including communities that are most affected by and vulnerable to emissions from these EGUs. This ensures that the priorities, concerns and perspectives of these communities are heard during the planning process.
- Meaningful engagement requirements are intended to ensure that the perspectives, priorities and concerns of affected communities are included in the process of establishing and implementing standards of performance for existing EGUs, including decisions about compliance strategies and compliance flexibilities that may be included in a state plan.
- In engaging with stakeholders in the development of these proposed emission guidelines, community representatives raised strongly held concerns about the potential health, environmental, and safety impacts of CCS.
- In outreach with potentially vulnerable communities, residents voiced two primary concerns. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS and hydrogen, they may continue to face disproportionate burdens.
- With regards to CCS, the EPA is proposing that CCS is a component of the BSER for new base load stationary combustion turbine EGUs, existing coal-fired steam generating units that

intend to operate after 2040, and large and frequently operated existing stationary combustion turbine EGUs.

- EPA recognizes and has given careful consideration to the various concerns that potentially vulnerable communities have raised with regards to the use of CCS.
- EPA's proposal follows guidance from the Council on Environmental Quality to ensure that the advancement of carbon capture, utilization, and sequestration technologies are done in a responsible manner that incorporates the input of communities and reflects the best available science. Consistent with this guidance, EPA will engage with communities and stakeholders on opportunities to improve environmental review of carbon capture and sequestration.

Repeal of the Affordable Clean Energy Rule

- EPA is simultaneously proposing to repeal the Affordable Clean Energy (ACE) rule because the emission guidelines established in ACE do not reflect the BSER for steam generating EGUs and are inconsistent with section 111 of the CAA in other respects.

Background

- In October 2015, EPA issued a final rule to regulate GHGs from new power plants under section 111(b) of the CAA and issued a final rule to regulate GHGs from existing power plants under CAA section 111(d), which was more commonly referred to as the clean power plan (CPP).
- On June 19, 2019, EPA issued the Affordable Clean Energy (ACE) Rule which replaced the 2015 CPP and established emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants.
- On January 19, 2021, the ACE Rule was vacated and remained vacated through October 26, 2022. The rule was then reinstated on October 27, 2022, which meant states were once again obligated to submit the state plans required under the rule.
- On March 7, 2023, EPA extended the state submittal deadline under the ACE Rule to April 15, 2024, making it clear that states are not expected to take immediate action to develop and submit plans under Clean Air Act section 111(d) with respect to greenhouse gas emissions from power plants at this time.

Public Hearing and Comment

- EPA will hold a virtual public hearing for this proposed action. Further details will be announced at Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants.

- EPA will accept comment on the proposal for 60 days after publication in the *Federal Register*. Comments, identified by Docket ID No. EPA-HQ-OAR-2023-0072, may be submitted by one of the following methods:
    - Go to https://www.regulations.gov/ and follow the online instructions for submitting comments.
    - Send comments by email to a-and-r-docket@epa.gov, Attention Docket ID No. EPA-HQ-OAR-2023-0072 in the subject line of the message.
    - Fax your comments to: (202) 566-9744, Attention Docket ID No. EPA-HQ-OAR-2023-0072.
    - Mail your comments to: EPA Docket Center, Environmental Protection Agency, Mail Code: 28221T, 1200 Pennsylvania Ave, NW, Washington, DC 20460, Attention Docket ID No. EPA-HQ-OAR-2023-0072.
    - Deliver comments in person to: EPA Docket Center, 1301 Constitution Ave., NW, Room 3334, Washington, DC. Note: In-person deliveries (including courier deliveries) are only accepted during the Docket Center's normal hours of operation. Special arrangements should be made for deliveries of boxed information.

For More Information

- Interested parties can download a copy of the proposed rule from Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants
- Today's action and other background information are also available electronically at https://www.regulations.gov/, EPA's electronic public docket and comment system.
    - The Public Reading Room is located at the EPA Headquarters library, room number 3334 in the EPA WJC West Building, 1301 Constitution Avenue, NW, Washington, DC. Hours of operation are 8:30 a.m. to 4:30 p.m., eastern standard time, Monday through Friday, excluding federal holidays.
    - Visitors are required to show photographic identification, pass through a metal detector, and sign the EPA visitor log. All visitor materials will be processed through an X-ray machine as well. Visitors will be provided a badge that must be visible at all times.
    - Materials for this proposed action can be accessed using Docket ID No. EPA-HQ-OAR-2023-0072.

Attachment DG-26

Excerpt of Ryan Hledik et al., *The National Potential for Load Flexibility: Value and Market Potential through 2030*

The National Potential for Load Flexibility

VALUE AND MARKET POTENTIAL THROUGH 2030

PREPARED BY
Ryan Hledik
Ahmad Faruqui
Tony Lee
John Higham

June 2019

THE Brattle GROUP

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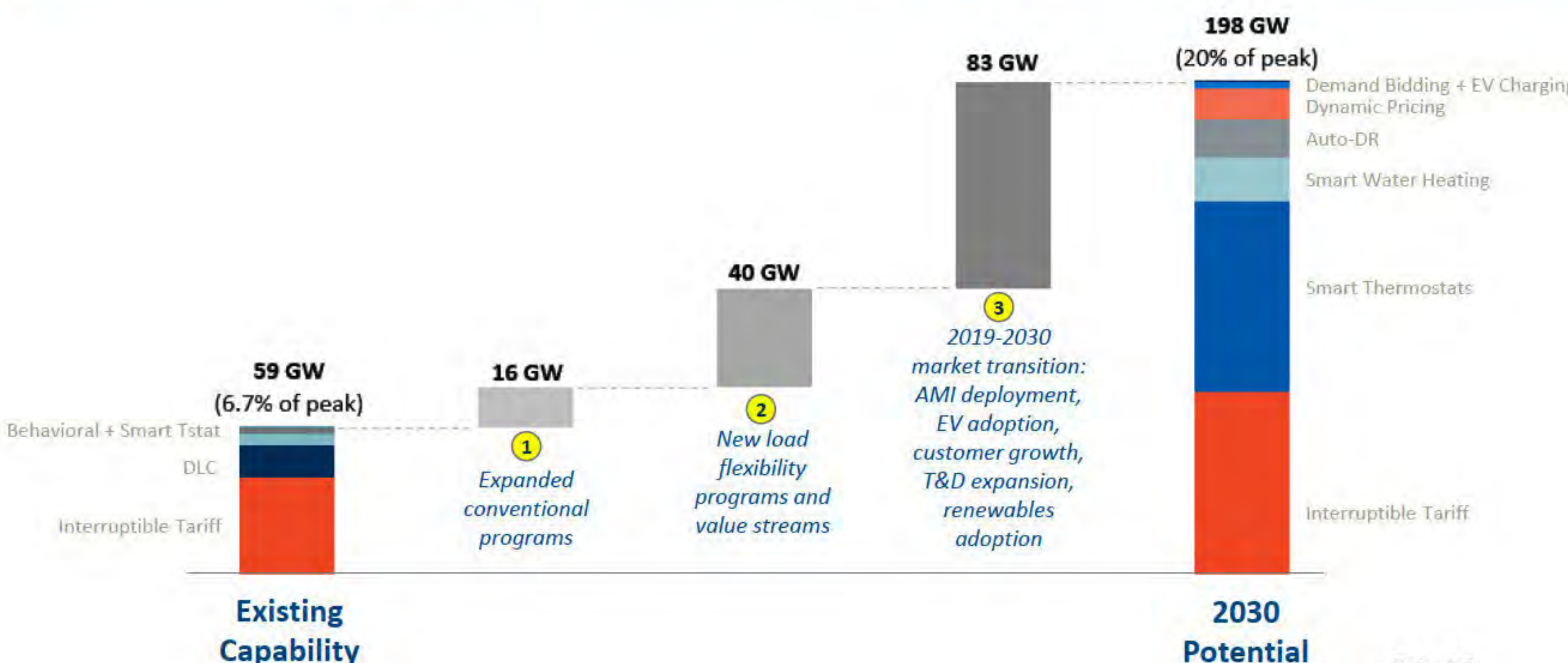
The National Potential for Load Flexibility

The national potential for load flexibility

A portfolio of load flexibility programs could triple existing DR capability, approaching 200 GW (20% of system peak) by 2030

U.S. Cost-Effective Load Flexibility Potential



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Notes: Existing DR capability does not account for impacts of retail pricing programs, as fewer than 1% of customers are currently enrolled in dynamic pricing rates and the impacts of long-standing TOU rates are already embedded in utility load forecasts. See appendix for summary of key modeling assumptions.

The national potential for load flexibility

Three factors drive the national potential estimate of 198 GW

1 Expanded conventional programs

- Existing conventional programs often have untapped potential that can be harnessed through revamped customer marketing and outreach, modified program rules, and redesigned incentive structures
- These programs generally only provide peak capacity value, but often can do so cost-effectively by leveraging existing program infrastructure
- *Potential increase over existing DR capability: 16 GW (27% increase)*

2 New load flexibility programs

- Relative to existing conventional programs, new load flexibility programs capture additional value streams and leverage emerging load control technologies and sources of load
- Under current national average market conditions, the most significant cost-effective potential is in smart thermostat programs (residential) and dynamic pricing (all customer segments)
- *Potential increase over existing DR capability: 40 GW (67% increase)*

3 Market transition impacts (2019 – 2030)

- Growth in adoption of AMI, EVs, smart thermostats and other smart appliances over the forecast horizon enables expanded participation in load flexibility programs
- Increased renewable generation development introduces more energy price variability and a greater need for ancillary services, increasing the value of load flexibility programs with fast-response capability
- Continued expansion and modernization of the T&D system introduces a growing opportunity for non-wires alternatives
- These market developments justify greater incentive payments for customer participation in load flexibility programs and also justify the introduction of robust smart water heating and Auto-DR programs, among others
- *Potential increase over existing DR capability: 83 GW (140% increase)*

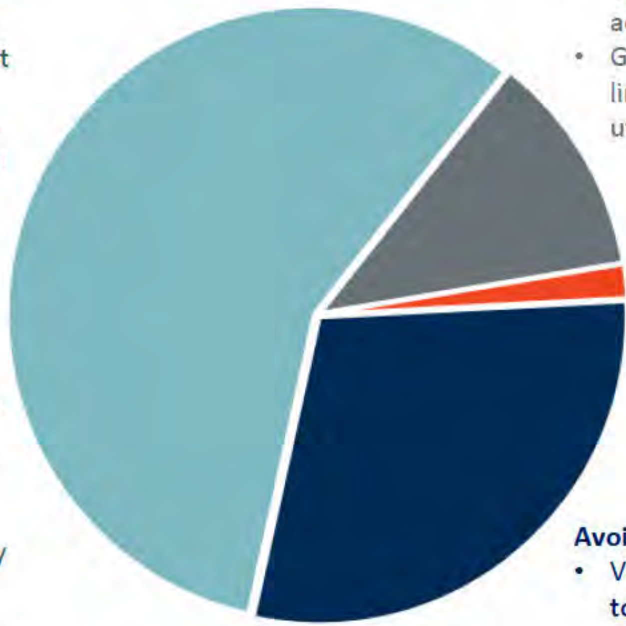
Load flexibility value

Avoided generation costs are the largest source of load flexibility value under national average conditions. There is significant regional variation in this finding.

2030 Annual Benefits of National Load Flexibility Portfolio

Avoided Generation Capacity, *$9.4 billion/yr (57%)*

- Value based on avoided cost of gas-fired combustion turbine, assuming no near-term peaking capacity need in some regions
- Capacity remains the dominant source of load flexibility value through at least 2030
- Capacity value will vary significantly by region; load flexibility poised to provide most capacity value in regions with pending capacity retirements, supply needs in transmission-constrained locations, or unexpected supply shortages



Avoided Transmission & Distribution Capacity, *$1.9 billion/yr (12%)*

- Value includes system-wide benefits of peak demand reduction, plus added benefit of geographically targeted T&D investment deferral
- Geo-targeted T&D deferral opportunities are typically high value but limited in quantity of near-term need; this value is likely to grow as utility T&D data collection and planning processes improve

Ancillary Services, *$0.3 billion/yr (2%)*

- Value accounts only for frequency regulation and assumes a need equal to 0.5% of system peak demand; additional value may exist if considering other ancillary services products
- Frequency regulation provides very high value to a small amount of capacity; in our analysis, the full need for frequency regulation can be served through a robust smart water heating program

Avoided Energy Costs, *$4.8 billion/yr (29%)*

- Value accounts for reduced resource costs associated with shifting load to hours with lower cost to serve; does not include consumer benefits from reductions in wholesale price of electricity
- Energy value is best captured through programs that provide daily flexibility year-round, such as Auto-DR for C&I customers, TOU rates, EV charging load control, and smart water heating

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Notes: Values shown in 2030 dollars. Values are gross benefits, before netting out costs of the load flexibility programs.

Attachment DG-27

APS, Comments in Response to Questions from Commissioner Sandra Kennedy, Docket No. E-01345A-21-0087 (Ariz. Corp. Comm’n Mar. 18, 2022)

ORIGINAL

E000018363

Elizabeth Lawrence
Manager, State Regulatory Strategy and Compliance

Mail Station 9774
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-3784
Elizabeth.Lawrence@aps.com

March 18, 2022

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: Arizona Public Service Company (APS or Company)
2022 Demand Side Management (DSM) Implementation Plan
Docket No. E-01345A-21-0087

APS appreciates the opportunity to address questions Commissioner Kennedy posed on February 28, 2022, in the above matter regarding APS's application for approval of its 2022 DSM Implementation Plan. APS's portfolio of demand response (DR) programs for both residential and commercial customers is an important component of the Company's Clean Energy Commitment. These DR programs and technologies allow APS to partner with customers to reduce peak needs, create a more flexible demand, and integrate more clean energy into APS's system. APS is an industry leader in DR programs and has won many awards for its rapid deployment and growth of successful programs.

DR technologies are still relatively new in their adoption curve, and APS is still pursuing ways to expand these programs as the technology advances and new technologies become available. In addition to the APS Cool Rewards program, APS has DSM programs for connected batteries, hot water heaters, and electric vehicles (EVs) through managed charging programs. Some barriers to adoption and adding new technologies include internet bandwidth in customer homes (particularly in garages and near pools), device connectivity, and concerns about privacy and cybersecurity. The Company is looking to add connected pool pumps in the future and reintroduce its Behavioral DR Program this summer, which will send emails to customers asking them to voluntarily reduce their load on specific peak demand days.

In response to the posed questions, APS provides the following:

Question 1: What percentage of your peak load *today* is "controllable" across all existing demand response programs? What level of megawatt does this percentage equal?

In the 2021 DSM Annual Progress Report filed on March 1, 2022, APS reported 113 MWs of controllable load in the Cool Rewards residential smart thermostat DR

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program and 28 MWs in the Peak Solutions commercial DR program for a total of 141 MWs. This is based on the maximum one-hour DR capacity for each program and does not represent 141 MWs of resource equivalency for the entire peak period. The 141 MWs of controllable capacity represents approximately 2% of the 2021 summer peak of 7,580 MWs. In addition, while not providing directly controllable load, APS's time differentiated rate plans provide additional rate responsive DR capacity.

According to APS thermostat program partners, the APS program added more capacity in 2021 than any other individual utility company service territory of any size in North America. In the 2022 APS DSM Plan, APS is proposing to almost double the size of the program again, with a goal of up to 110,000 smart thermostats in the program by the end of 2022 (there were 56,616 thermostats in the program at the end of 2021). APS estimates approximately 20-25% of residential households in APS's service territory currently have connected smart thermostats installed, with the rest of the households yet to adopt the technology.

Question 2: Theoretically, what percentage of your peak load is *potentially* controllable in the event of heightened demand response efforts?

It is difficult to provide an exact percentage of potentially controllable peak load, but it is clear that this DR potential is growing with the evolution of connected devices, energy storage, and transportation electrification. APS has been aggressively pursuing this growing potential with successful customer focused programs that are being nationally recognized for their effectiveness.

There are a wide range of variables that must be considered to assess what percentage of peak load is potentially controllable, including:

1. The cost effectiveness of the potentially controllable load to be included in a utility DR program.
2. Customer interest and willingness to participate in the potential programs.
3. Technology development and customer adoption, which changes rapidly due to the evolution of new technologies like energy storage and the proliferation of connected devices that provide new opportunities for DR programs.

While these complex variables make it difficult to estimate the theoretical potential controllable load, it is clear that greater numbers of customers are adopting demand flexible technologies, and that the future potential continues to grow. APS is working closely with its strategic partners to aggressively scale successful programs like Cool Rewards and Peak Solutions while adding new pilots like Energy Storage and Managed EV Charging that are early in their adoption curve. APS is also simultaneously exploring third party aggregation of DR capacity through the all-DDSR Request for Proposal (RFP) that APS issued in 2021. The result of these efforts will be a growing customer-focused clean energy resource that will support APS's Clean Energy Commitments and the Commission's DSM policy objectives.

Question 3: If there is a difference between answers No. 1 and No. 2 above, please explain why.

See response to Question 2. Many flexible DR capacity opportunities are currently emerging and growing as customers adopt new energy technologies and connected devices. APS will continue to grow its programs as technologies advance by encouraging greater technology adoption through customer incentives (e.g., offering free smart thermostats to customers who agree to participate in one season in the Cool Rewards DR program). In addition, as additional market actors and lower price point products enter the marketplace for technologies like connected thermostats, we anticipate that technology adoption will grow.

Question 4: Could you describe any instances where your existing demand response program(s) allowed your utility to avoid firing up a fossil fuel peaker unit, or assisted your utility in maintaining grid stability?

Yes. One instance where DR programs provided critical reliability services occurred during the summer of 2021, when the Bootleg fire in Oregon rapidly impacted the ability to transmit energy out of the Pacific Northwest region. This resulted in a regional constraint of resources on July 9th that was not anticipated during the day-ahead timeframe. As solar resource production declined after sunset, the most critical hour for regional grid stability became the hour from 7 p.m. until 8 p.m. as demand remained high. Multiple neighboring balancing authorities initiated active Energy Emergency Alert level 3, indicating customer shutoffs could be imminent. At the same time, supplies from unspecified resources, including much of scheduled AG-X imports, were cut. On this day, APS was able to avoid such situations for our customers by calling both Cool Rewards and Peak Solutions DR events. These events provided 54 MWs of load reduction during the day's most important hour (7 p.m. to 8 p.m.), complimenting solar production and supporting grid stability.

The situation above demonstrates how DR is a valuable customer partnership and resource that provides benefits to customers and the grid. In order to continue to see the benefits of these programs, APS needs continued flexibility to run DR events during the grid's most critical hours, which are often 7 p.m. to 8 p.m. and fall outside of the new time-of-use window. APS sought clarification regarding the timing of events in its 2022 DSM Plan to allow the programs to continue to provide benefits customers have seen in previous years.

Question 5: Within your demand response programs, please describe limitations that restrict the quantity or extent to which your utility may adjust thermostats or other devices, such as APS's "20-event per year limit," or temperature range adjustment limits (example: restrict thermostat increases/decreases to 3 degrees) etc.

APS carefully works with partners and stakeholders to design successful DR programs that consider the right balance between the needs of individual program participants, the overall needs of the grid, and the capabilities offered by energy device partners. For instance, the example provided references a limit of 20 events per summer season for smart thermostat DR events. This limit has typically been established by thermostat partners who restrict utility access to call more than a set number of events during a season out of concerns about potential customer dissatisfaction, which could cause customers to leave the program and lower potential savings. In addition, as part of the recently launched Residential Battery Pilot, APS works with participating battery partners to dispatch batteries to serve grid needs while also maintaining a reserve of energy in the battery at all times to be used in the event of an outage.

For the reasons described in response to Question 4, APS believes the most critical parameter that currently needs to be addressed is the timing when events are allowed to be called. In so doing, DR programs can be designed to reduce snapback in the hour after the on-peak time-of-use period ends and APS continues to experience peak demand conditions from 7 p.m. to 8 p.m. In addition, to be consistent with other thermostat programs nationwide and have increased ability to respond to grid emergencies, the Commission could lift the advanced notification requirements implemented in Decision No. 77763. Most thermostat manufacturers do not support two-hour advanced notifications as they have found customers prefer shorter notification times.

Question 6: Can enrolled customers in all your demand response programs override/refuse APS's request to reduce their demand?

All participants in the residential Cool Rewards program can override a DR event by simply adjusting their thermostat settings at any time during an event. Preserving a customer's ability to opt out increases customer satisfaction. All participants in the commercial Peak Solutions program have the option whether they choose to participate in each event. For the recently launched Residential Battery Pilot, APS is working with battery partners to provide options for customers to be able to override events. While it is APS's preference that customers retain override ability, currently not all battery partners support the ability for customers to opt out of DR events.

Question 7: Are free or discounted smart thermostats or other smart devices offered to customers for any of your demand response programs?

Yes, APS offers free or deeply discounted smart thermostats for customers who choose to purchase smart thermostats and pre-enroll them in the Cool Rewards DR program at the time of purchase. APS has been an industry leader in pioneering approaches for offering free pre-enrolled thermostats, and in 2021 APS provided almost 34,000 free smart thermostats for APS customers (customers who received free smart thermostats paid for shipping and taxes costs only). In addition, APS recently launched a new measure in the multifamily program that provides free connected water heating controls for participating multifamily communities. APS also recently launched incentives that provide discounts on residential batteries and connected Level 2 EV chargers.

Question 8: How did you calculate the annual Cool Rewards participation incentive amount (currently $25 and proposed to increase to $35) and what percentage of program savings are returned to participating customers in this payment versus retained by APS?

To determine the incentive amount, APS compared the estimated avoided cost savings value from the program against the total program delivery costs, including customer incentives and the payments required by thermostat manufacturer partners for access to call events on their devices. APS also used industry knowledge and discussions with other utilities and program partners about what incentive levels were needed to drive participation and customer retention in other states. After covering program costs, APS returns program savings to customers in the form of incentives for participants and any potential fuel savings to customers through the PSA. APS provided notice to the Commission in December[1] that it increased the incentive from $25 to $35 in February 2022 for the upcoming summer season in recognition of three-hour DR setback events. In addition, the increased incentive will help better retain customers to enable greater scaling of the program.

Question 9: APS recently launched a "connected water heating" program. Could this effort be integrated withing Cool Rewards or Peak Solutions to boost participation and positive impact? Similarly, could electric charging, pool pumps, or any other possible opportunities for "connected devices" be included?

Yes, although these are separate programs from a regulatory approval standpoint, they are delivered to customers in an integrated fashion.

Please let me know if you have any questions.

Sincerely,

/s/ Elizabeth Lawrence

Elizabeth Lawrence

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[1] *See* Docket No. E-01345A-20-0151. https://docket.images.azcc.gov/E000016867.pdf

Attachment DG-28

Excerpt of APS 2023 Demand Side Management Implementation Plan

Arizona Public Service Company

2023 Demand Side Management Implementation Plan

November 30, 2022

DSM Energy Savings and Benefits

Table 4 below provides details of the expected annual and lifetime energy savings and peak demand reductions from each DSM program and initiative, and a summary of the net benefits generated in the 2023 DSM Plan. The lifetime energy savings are the estimated savings that will result over the expected lifetime of all program measures installed in 2023. The savings and benefits listed in Table 4 are in addition to energy savings, costs and net benefits associated with APS DSM activities undertaken during the 2005 through 2022 timeframe, which are reported each year in APS's Semi-Annual DSM Report filings.

Table 4
2023 DSM Savings and Benefits

Program	Annual Coincident Demand Savings at Generator (MW)	Annual Energy Savings at Generator (MWh)	Lifetime Energy Savings (MWh)	Cost Test Benefits ($)	Cost Test Costs ($)	Lifetime Net Benefits ($)
RESIDENTIAL						
Existing Homes	49.4	43,984	603,413	$ 38,362,718	$ 15,959,092	$ 22,403,625
Residential New Construction	18.2	31,917	917,964	$ 31,650,355	$ 16,568,903	$ 15,081,451
Multi-Family Energy Efficiency	3.6	14,407	270,725	$ 9,056,010	$ 5,540,612	$ 3,515,399
Limited Income Weatherization	1.9	3,774	67,926	$ 5,795,059	$ 3,840,336	$ 1,954,724
Conservation Behavior	34.2	77,106	77,106	$ 4,804,261	$ 2,608,184	$ 2,196,077
Energy Storage Pilot	1.6	0	0	$ -	$ -	$ -
Shade Trees	0.2	669	20,061	$ 540,488	$ 293,859	$ 246,629
Totals for Residential	**109.1**	**171,856**	**1,957,194**	**$ 90,208,890**	**$ 44,810,986**	**$ 45,397,904**
NON-RESIDENTIAL						
Existing Facilities	17.6	69,507	960,451	$ 35,540,349	$ 15,876,399	$ 19,663,949
New Construction and Major Renovation	27.4	110,755	1,579,291	$ 58,893,859	$ 24,997,372	$ 33,896,487
Energy Information Services	5.3	5,054	25,271	$ 2,281,579	$ 588,452	$ 1,693,127
Schools	5.9	18,893	271,387	$ 10,565,974	$ 4,907,697	$ 5,658,276
Advanced Rooftop Controls Pilot	2.1	7,815	91,020	$ -	$ -	$ -
Totals for Non-Residential	**58.2**	**212,024**	**2,927,420**	**$ 107,281,760**	**$ 46,369,920**	**$ 60,911,840**
DEMAND SIDE MANAGEMENT INITIATIVES						
Demand Response	67.0	0	0	$ -	$ -	$ -
Energy Storage and Load Management ("Rewards")	151.9	793	793	$ -	$ -	$ -
Building Code and Appliance Standards	7.8	30,111	289,364	$ -	$ -	$ -
APS System Savings	0.0	6,020	90,294	$ -	$ -	$ -
Managed EV Charging Pilot	2.0	256	2,562	$ -	$ -	$ -
Energy and Demand Education	0.0	0	0	$ -	$ -	$ -
Distributed Demand Side Resource Aggregation Pilot	3.9	0	0	$ -	$ -	$ -
Tribal Community Energy Efficiency	0.2	428	6,155	$ -	$ -	$ -
Totals for Demand Side Management Initiatives	**232.8**	**37,608**	**389,168**	**$ -**	**$ -**	**$ -**
TOTAL	**400.2**	**421,489**	**5,273,782**	**$ 197,490,651**	**$ 91,180,906**	**$ 106,309,744**

Attachment DG-29

Excerpt of APS 2022 Demand Side Management Implementation Plan

Arizona Public Service Company

2022 Demand Side Management Implementation Plan

December 17, 2021

DSM Energy Savings and Benefits

Table 4 below provides details of the expected annual and lifetime energy savings and peak demand reductions from each DSM program and initiative, and a summary of the net benefits generated in the 2022 DSM Plan. The lifetime energy savings are the estimated savings that will result over the expected lifetime of all program measures installed in 2022. The savings and benefits listed in Table 4 are in addition to energy savings, costs and net benefits associated with APS DSM activities undertaken during the 2005 through 2021 timeframe, which are reported each year in APS's Semi-Annual DSM Report filings.

Table 4
2022 DSM Savings and Benefits

Program	Annual Coincident Demand Savings at Generator (MW)	Annual Savings at Generator (MWh)	Lifetime Energy Savings (MWh)	Cost Test Benefits ($)	Cost Test Costs ($)	Lifetime Net Benefits ($)
RESIDENTIAL						
Existing Homes	47.1	39,598	534,824	$ 29,407,280	$ 15,571,095	$ 13,836,185
Residential New Construction	20.7	32,155	621,192	$ 22,383,887	$ 17,328,421	$ 5,055,465
Multi-Family Energy Efficiency	3.5	10,569	194,370	$ 4,806,122	$ 3,989,157	$ 816,965
Limited Income Weatherization	2.1	4,061	73,098	$ 5,337,798	$ 4,007,657	$ 1,330,141
Conservation Behavior	38.5	77,319	152,721	$ 6,793,858	$ 3,178,692	$ 3,615,166
Energy Storage Pilot	1.5	0	0	$ -	$ -	$ -
Shade Trees	0.2	669	20,059	$ 347,263	$ 278,394	$ 68,869
Totals for Residential	**113.6**	**164,372**	**1,596,264**	**$ 69,076,208**	**$ 44,353,417**	**$ 24,722,791**
NON-RESIDENTIAL						
Existing Facilities	30.1	102,644	1,492,789	$ 40,289,039	$ 22,920,156	$ 17,368,882
New Construction and Major Renovation	15.7	65,485	925,751	$ 23,398,006	$ 14,038,428	$ 9,359,578
Energy Information Services	5.8	5,616	28,079	$ 2,200,265	$ 639,601	$ 1,560,664
Schools	6.2	24,445	316,411	$ 8,521,564	$ 4,995,570	$ 3,525,995
ARC Pilot	3.3	8,790	103,369	$ -	$ -	$ -
Totals for Non-Residential	**61.1**	**206,979**	**2,866,398**	**$ 74,408,874**	**$ 42,593,755**	**$ 31,815,119**
DEMAND SIDE MANAGEMENT INITIATIVES						
Demand Response	57.8	0	0	$ -	$ -	$ -
Energy Storage and Load Management ("Rewards")	215.7	66	66	$ -	$ -	$ -
Building Code and Appliance Standards	5.4	26,960	238,102	$ -	$ -	$ -
APS System Savings	0.0	6,020	90,294	$ -	$ -	$ -
Managed EV Charging Pilot	2.1	363	3,634	$ -	$ -	$ -
Energy and Demand Education	0.0	0	0	$ -	$ -	$ -
Peak Rewards	0.0	0	0	$ -	$ -	$ -
Tribal Community Energy Efficiency	0.1	242	3,472	$ -	$ -	$ -
Totals for Demand Side Management Initiatives	**281.2**	**33,652**	**335,569**	**$ -**	**$ -**	**$ -**
TOTAL	**455.9**	**405,002**	**4,798,230**	**$ 143,485,082**	**$ 86,947,172**	**$ 56,537,910**

Attachment DG-30

Congressional Research Service, *Electricity Transmission Provisions in the Inflation Reduction Act* (2022)

Electricity Transmission Provisions in the Inflation Reduction Act of 2022

Updated August 23, 2022

On August 16, 2022, President Biden signed into law P.L. 117-169, commonly known as the Inflation Reduction Act of 2022 (IRA). The IRA contains several provisions aimed at incentivizing increased development of electricity transmission infrastructure in the United States. Many stakeholders view an enhanced U.S. transmission system as key to enabling increased use of wind and solar energy for electricity generation and improving resilience to extreme weather events such as Winter Storm Uri. This analysis summarizes the three transmission provisions in Part 5 of Subtitle A of Title V of the law. In total, this part would appropriate almost $2.9 billion for transmission provisions. Other provisions in the IRA, such as those related to loan programs administered by the U.S. Department of Agriculture, could potentially incentivize transmission development, but this analysis does not include them.

Section 50151 (Transmission Facility Financing) would appropriate $2 billion to remain available until September 30, 2030, for a direct loan program for certain transmission project development. To be eligible for a direct loan, a transmission project would need to be located in a National Interest Electric Transmission Corridor (NIETC). The U.S. Department of Energy (DOE) may designate an area as an NIETC pursuant to 16 U.S.C. §824p if it meets certain criteria, such as promoting energy security or enabling the use of intermittent energy sources such as wind and solar. No NIETCs currently exist. Absent an NIETC designation, the appropriations this section would provide may not be accessible to industry participants. The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) amended the NIETC designation process, but it remains unclear to what extent DOE will use its authority to designate NIETCs.

Section 50152 (Grants to Facilitate the Siting of Interstate Electricity Transmission Lines) would appropriate $760 million to remain available through September 30, 2029, for making grants aimed at facilitating the siting of certain onshore and offshore transmission lines. In general, state and local governments have authority for siting electricity transmission infrastructure in the United States. This section would allow relevant siting authorities to receive grants to be used for purposes including transmission project studies, examination of alternative siting corridors, hosting negotiations with project backers and opponents, participating in federal and state regulatory proceedings, and promoting economic development in affected communities. Grants under this section would be contingent on the siting authority agreeing to make a final decision (approval or denial) on the transmission project within two years. The bill does not specify consequences should the siting authority fail to make a final decision.

Congressional Research Service
https://crsreports.congress.gov
IN11981

Section 50153 (Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis) would appropriate $100 million to remain available until September 30, 2031, for expenses for convening stakeholders and conducting analysis related to interregional transmission development and development of transmission for offshore wind energy. The continental U.S. transmission system is comprised of three interconnections (i.e., grids) with limited connection among them: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas. The Eastern Interconnection is the largest and is itself comprised of different regions, including five separate power markets overseen by independent system operators or regional transmission organizations. Currently, transmission development involving two or more regions is relatively rare. Some analysis indicates that a greater amount of interregional electricity connection would promote greater use of renewable energy and potentially lower costs for consumers. The Federal Energy Regulatory Commission (FERC), which regulates rates for interstate electricity transmission, began a rulemaking in July 2021 aimed at potentially modifying multiple aspects of transmission development. An April 2022 FERC Notice of Proposed Rulemaking focuses primarily on regional transmission planning and cost allocation. FERC continues to examine interregional transmission planning, for example, as part of the Joint Federal-State Task Force on Electric Transmission.

The IRA is the third significant energy-related law of the past two years (following the Energy Act of 2020, enacted as part of P.L. 116-260, and IIJA). Such successive lawmaking is relatively rare for the electricity sector. Arguably, the last time a similar set of events took place was when Congress enacted the Energy Policy Act of 2005 (P.L. 109-58) followed by the Energy Independence and Security Act of 2007 (P.L. 110-140) and the American Recovery and Reinvestment Act of 2009 (P.L. 111-5). The electricity sector changed significantly in the years following enactment of those laws, with a marked increase in the use of natural gas, wind, and solar for electricity generation accompanied by increased efficiency, which kept electricity demand growth low. The change was in part driven by federal energy laws (especially tax credits), though market forces, state policies, and other factors influenced the electricity sector as well. As in the mid-2000s, recently enacted energy laws may drive significant changes in the electricity sector, though market forces and other factors are likely to be important too.

Evaluating the potential impact of the transmission provisions in the IRA is complicated by three factors. First, the other recently enacted energy laws are still being implemented, and their eventual impact on the electricity sector remains unknown. Second, FERC's rulemakings on transmission are not finalized and may affect future transmission development. Lastly, electricity sector participants and regulators are responding to numerous issues—including reliability challenges, nominal cost increases, and weather-related risks—all of which may influence transmission infrastructure development in the years to come. The IRA's transmission provisions are an additional change to which the electricity sector will respond moving forward.

Author Information

Ashley J. Lawson
Analyst in Energy Policy

Disclaimer