APS RPAC Meeting

7/22/2026

MEETING AGENDA

Welcome & Meeting Agenda
Adam Constable
APS

Cholla Conversion
Mike Eugenis
APS

IRP Base Case & Sensitivities
Akhil Mandadi
APS

Break

Summer Preparedness
Tim Rusert
APS

2026 IRP Filing Extension
Mike Eugenis
APS

Next Steps & Closing Remarks
Adam Constable
APS

Meeting Guidelines

Member Engagement

RPAC Member engagement is critical. Clarifying questions are welcome at any time. There will be discussion time allotted to each presentation/agenda item, as well as at the end of each meeting.

Action Items

We will keep a parking lot for items to be addressed at later meetings.

Meeting Minutes

Meeting minutes will be posted to the public website along with pending questions and items needing follow up. We will monitor and address questions in a timely fashion.

Preliminary Content

Meetings and content are preliminary in nature and prepared for RPAC discussion purposes.

April Meeting Recap

- APS discussed the results of its 2024 All-Source Request for Proposals (ASRFP) and provided an overview of the proposals received in response to its 2025 ASRFP.
- APS and E3 outlined how market prices are incorporated into IRP modeling and discussed key assumptions related to western regional markets.
- E3 provided a follow-up discussion on resource adequacy, including Planning Reserve Margins (PRM) and APS’s transition to Perfect Capacity Accounting (PCAP).
- APS previewed the scenarios it will evaluate as part of the 2026 IRP, including a technology-neutral base case and sensitivities related to market participation, Four Corners operations, load growth, fuel prices, and resource costs.

Following Up

- Future Topics:

These items will be brought to future agendas as developments arise.

  - IRP Preferred Portfolio
  - Western Markets
  - 2025 ASRFP Updates
  - Desert Sun / Saguaro Natural Gas Generation
  - Four Corners Continued Operation

Cholla Conversion Update

Mike Eugenis, APS

Cholla Power Plant Conversion Plan

APS recently announced plans to convert two units from coal to natural gas at its Cholla Power Plant

Background

- Located in Joseph City, AZ
- In service since 1962
- EPA Requirements mandated APS to cease coal operations in 2025
- Last coal burn occurred in March 2025
- Conversion would add 380 MW of dispatchable capacity

Cholla Power Plant Conversion Plan – Past Studies and Next Steps

Previous Economic Evaluation Did Not Support Natural Gas Conversion

- APS evaluated converting Cholla Units 1-3 to natural gas as part of the 2014 IRP
- Conversion was not cost-effective due to required boiler modifications, a new natural gas pipeline, and potential coal contract damages
- The analysis reflected a different planning environment
  - Replacement capacity was procured in the 2020 and 2022 ASRFP
  - APS's 2023 & 2024 ASRFPs resulted in over 3 GW of signed renewable resources

Where We Are Today

- Avoided capacity cost analysis has been directionally favorable
- Additional cost, engineering, and operational evaluations are underway
- APS is comparing the Cholla conversion opportunity against 2025 ASRFP bids
- APS will proceed only if the project is determined to be competitive and supports customer needs at least cost
- Will provide an update following the close of the 2025 ASRFP

2026 IRP Base Case & Sensitivities

Akhil Mandadi, APS

Agenda

Modernizing the Planning Framework

- AURORA -> PLEXOS migration (Enhanced representation)
- Updated Reference Database

Establishing Analytical Baseline

- Reference Case – Purpose
- Key Assumptions

Early Results and On-going work

- Early Cost and Resource insights
- Scenario analysis under evaluation

Modernizing the Planning Framework

The Journey - Why APS Transitioned

IRP Modeling Evolution

APS used AURORA in its 2023 IRP; a deliberate, multi-phase transition through 2025 brings PLEXOS to the center of the 2026 IRP, enabling a more sophisticated analytical foundation.

Phase 1 — 2023 IRP
AURORA

- AURORA served as APS's long-term capacity expansion (LTCE) tool for the 2023 IRP
- Established baseline capacity expansion and production costing capability

Baseline established

Phase 2 — 2025
Transition Year

- Model conversion, parallel validation, and reporting compatibility work undertaken
- PLEXOS Reporting Engine outputs developed to replicate prior AURORA Excel workbook structures
- Python-based workflow built to bridge PLEXOS outputs with AURORA-compatible data formats

Phase 3 — 2026 IRP
PLEXOS

- Fully operational in PLEXOS — capacity expansion and production costing both conducted in the new platform
- 2026 IRP transitions to a zonal topology with expanded transmission representation along with other significant enhancements

Current platform

What PLEXOS Unlocks: Key Capabilities

PLEXOS delivers faster, more realistic, and more flexible analysis, enabling APS to model the full energy system in a single integrated environment.

Faster Run Times

Significantly accelerated simulation speeds compared to AURORA, enabling faster troubleshooting.

Expanded Modeling Capability

Broader scope of resource types and system dynamics supported; additional modeling capabilities to be detailed in forthcoming slides.

Greater Analytical Flexibility

Configurable scenarios, customized constraints, and multiple simulation horizons within a single platform.

More Realistic System Representation

Integrated modeling of natural gas, energy markets, ancillary services, and transmission in one co-optimized environment — a step beyond AURORA's siloed approach.

Better Reporting

PLEXOS Reporting Engine generates repeatable, standardized outputs; report templates shareable across analysts; reduces manual querying effort and error risk.

Applications

- Capacity Expansion — long-term investment planning
- Production Costing — short- and medium-term dispatch simulation

Overview of Enhancements

2026 IRP Model Enhancements

Five interconnected modeling innovations add significant rigor to the 2026 IRP Modeling.

1

Transmission Expansion Co-Optimization

Simultaneous generation and network investment decisions in a single mathematical framework

2

Cost and Perpetuity Treatment

Accurate capture of unit economics across varying sizes and terms, including terminal value

3

Advanced Generation Modeling

Combined cycle operating modes and first-principles environmental permit limits

4

Reliability Modeling

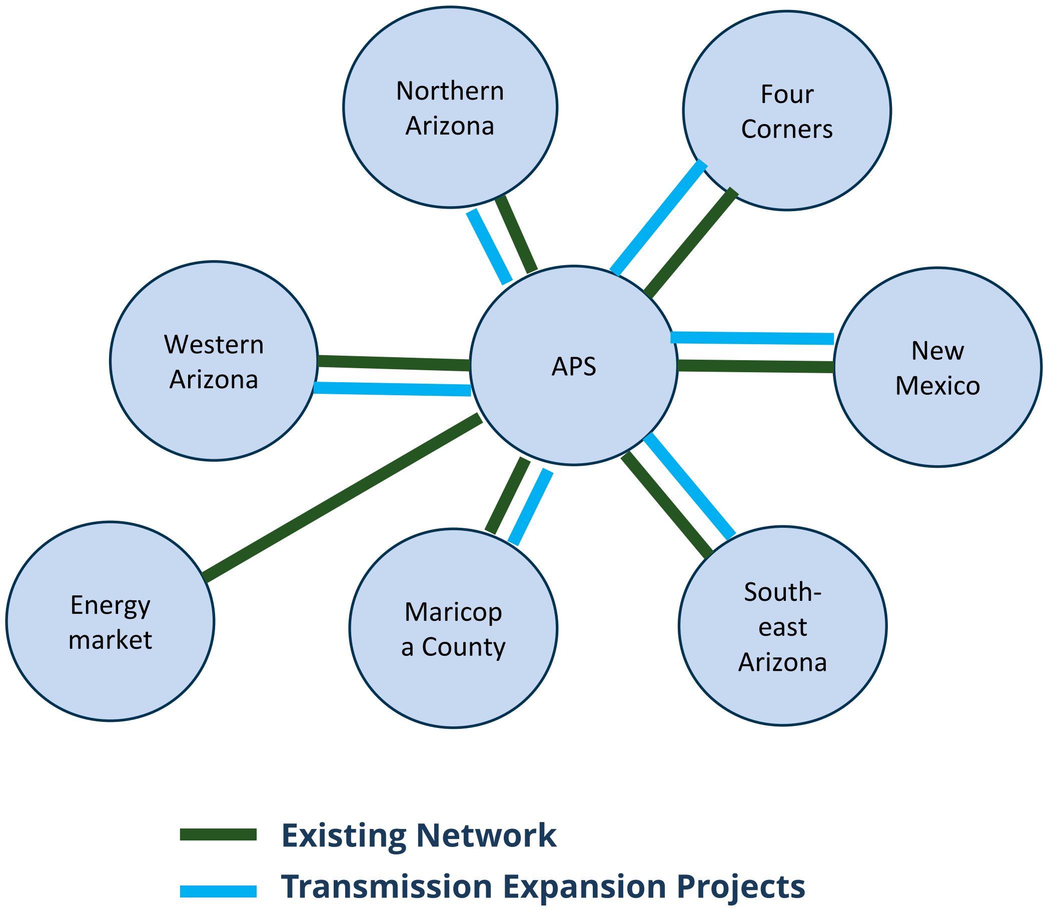
Six ancillary service products and seasonal forced outage rate forecasting at individual unit levels

5

Continuing Modeling Features from AURORA

Firm fuel transport rights, equitable supply and demand side resource treatment, and resource accreditation through perfect capacity

1. Transmission Expansion Co-Optimization with Generation



Modeling Complexity Dimensions

ELCC Considerations
Model meets reserve targets using Effective Load Carrying Capability (ELCC) which decline with increasing penetration

Deliverability Constraint
Each transmission line must physically deliver capacity during hours of reliability need to assure the ELCCs.

Hourly Limit Enforcement
Simultaneous flow limits enforced every hour across all lines. A line upgrade is only selected if it unlocks sufficient deliverable capacity to justify capital cost.

Discrete Project Selection
Transmission upgrades are binary (build or not) discrete investment decisions sourced from APS transmission planning and are not generic capacity cost increments.

2. Cost and Perpetuity Treatment

Improved cost representation across units of different sizes, fuel types, and contract lengths forming a stronger economic foundation.

Capital Cost Treatment

- **Build Cost Treatment:** capital costs for generation and transmission candidates are entered as their Net Present Value of Revenue Requirements consistently
- **Transmission Cost Parity:** expansion line costs are provided similar to generation, ensuring transmission upgrades compete fairly in the co-optimization

Perpetuity & Long-Horizon Value

- **Perpetuity Capture:** for long-lived assets extending beyond the 2041 IRP planning horizon, the model captures terminal value using a perpetuity construct
- Avoids artificial bias against long-life investments that deliver value beyond the study window

Unit Size & Contract Fidelity

- **Different Unit Sizes:** per-unit cost structures preserved so the optimizer does not inadvertently favor large or small units
- **Contract Term Fidelity:** liquidated damages clauses and fuel contract terms are embedded directly so the model does not simplify them

With consistent cost treatment, this enhancement ensures the model finds the ***least-cost portfolio*** *across every scenario and planning horizon.*

3. Advanced Generation Modeling

Realistic dispatch of combined cycle units and first-principles environmental limits allow the model to better reflect actual operational constraints

Combined Cycle Operating Modes

1×1 Mode	2×1 Mode	Duct Burner
1 gas turbine + 1 steam turbine	2 gas turbines + 1 steam turbine	Augmentation at higher heat rates

- **Distinct physics per mode:** each mode has unique heat rate, minimum load, ramp rate, and capacity
- **Sequential state transitions:** mode changes are modeled step-by-step, reflecting real plant physics
- **Duct burner separate:** incremental capacity captured independently to avoid distorting dispatch economics

Environmental Permitting Limits

	Oper. Hours	Heat Input	No. Starts
Plant 1	✓	✓	✓
Plant 2	✓	✓	–
Plant 3	–	✓	–

Rather than simplified run-hour caps, limits are encoded from physical drivers: heat input (MMBtu), emissions mass (tons), operating hours, and number of starts.

4. Improved Reliability Modeling

Modeling distinct reserve products in both directions, while accounting for seasonal forced outage rates, produces a reliability picture more grounded in the operating requirements APS must meet.

Six Ancillary Service / Operating Reserve Products

Up Direction		Down Direction
Regulation Up		Regulation Down
Spinning Reserve	UNIT MW	Flexibility Down
Flexibility Up		Non-Spinning Reserve

1. Requirements vary by hour with Reg Up/Down scale with load
2. Non-Spin tracks contingency
3. Flex Up/Down driven by renewable variability

Enhanced EFOR Modeling

- Unit-level Equivalent Forced Outage Rate (EFOR) forecast from historical performance data on a **seasonal basis** replacing static annual EFOR assumptions
- Dual feed: Seasonal EFORs feed both capacity expansion (firm capacity credit) and production cost model (expected availability in high-need hours)
- Unit-level, not fleet average: Each unit's outage history drives its individual seasonal EFOR forecast

5. Continuing Modeling Features from AURORA

Key features from AURORA implemented through 2023 IRP were also incorporated into PLEXOS

Natural Gas Firm Transport Rights

- **Daily firm gas transport** rights varying by month on pipelines are explicitly modeled as hard constraints. In 2023 IRP, monthly firm gas transport rights were implemented
- Existing and future units share firm capacity allocations correctly with **dual-fuel accounting**
- Additional **delivered gas,** if applicable, is modeled in the production costing model with appropriate cost and availability assumptions

Integrated Supply & Demand Resource Candidates

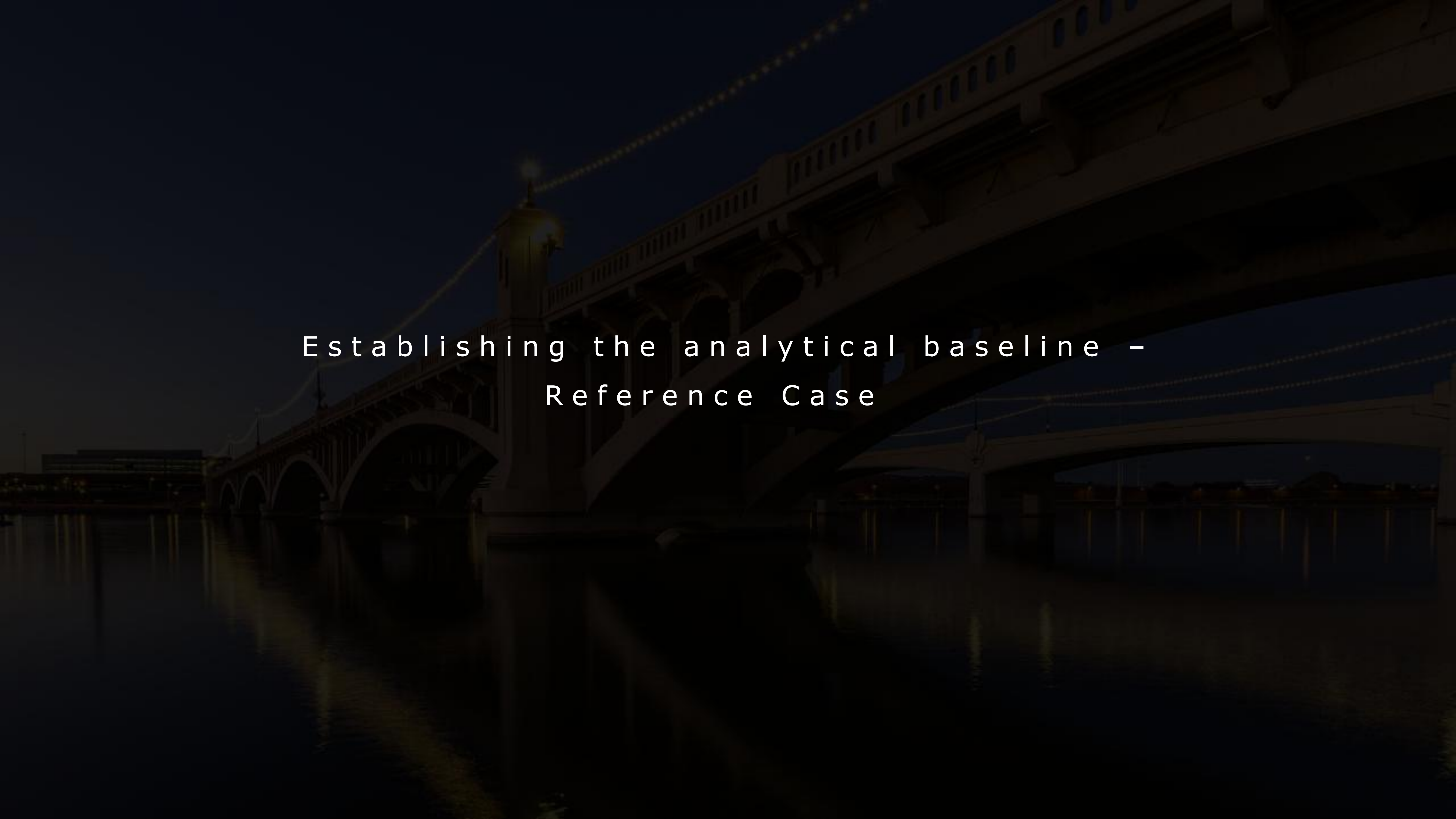
Preserved from AURORA

- Model simultaneously optimizes **supply-side** (new generation) and **demand-side** resources (DSM, DSR)
- Supply/demand integration amidst co-optimizing around transmission as well as ancillary services
- True least-cost: supply and demand compete on equal footing in the same optimization

Contract & Capacity Expansion Features

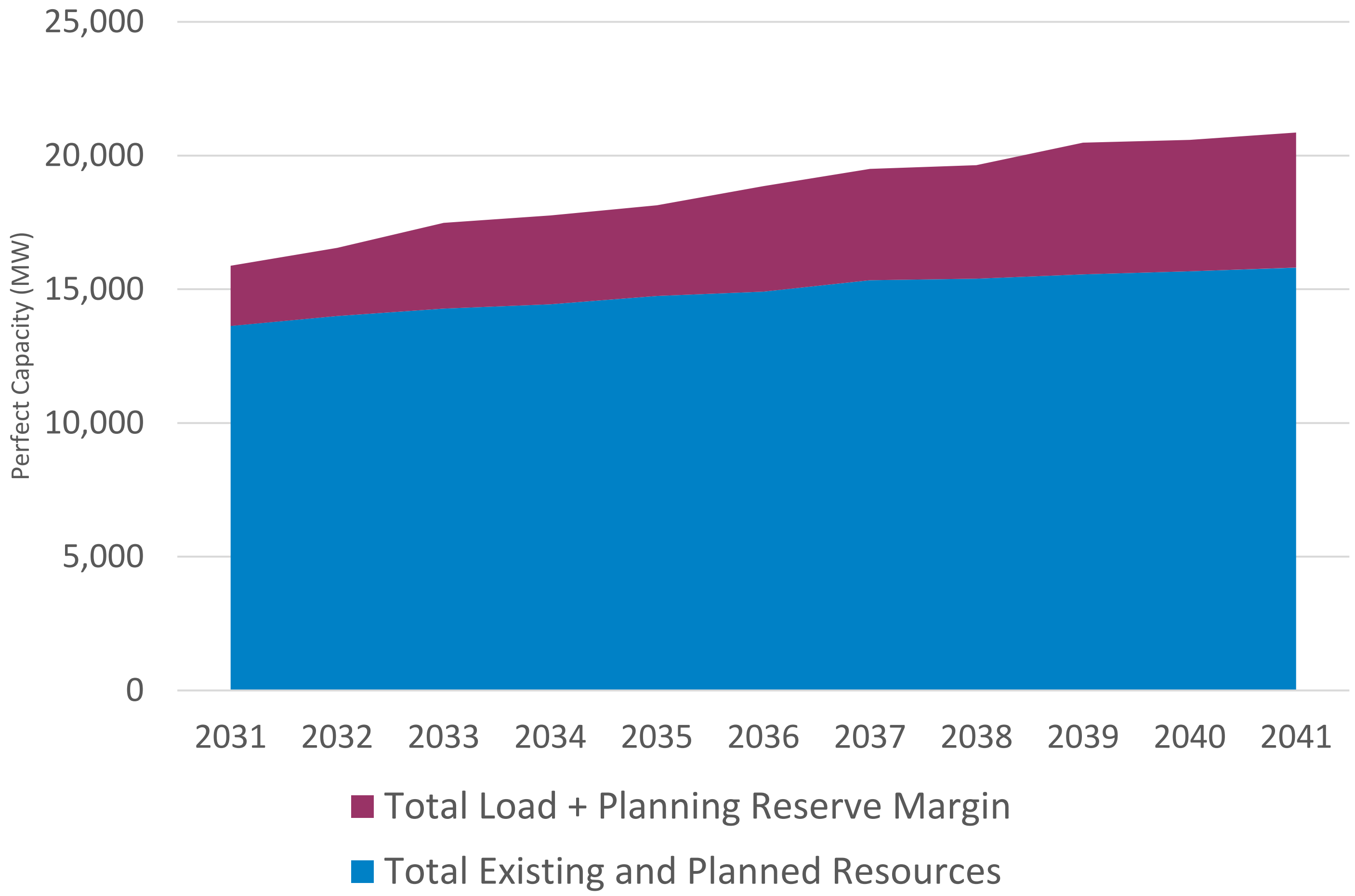
Preserved from AURORA

- **Liquidated Damages:** take-or-pay fuel contract provisions included and model internalizes cost of underutilizing contracted quantities
- Iterative Capacity Expansion Construct with updated ELCCs
- The production cost model is set to run iteratively with the capacity expansion model to assure no unserved energy



Establishing the analytical baseline – Reference Case

Future Resource Needs and Capacity Expansion Requirement



What must be solved: Remaining system need after existing and committed resources are recognized.

What the model considers: Hourly reliability, energy balance, transmission constraints, and ancillary service requirements along with all build, fixed, and variable operating costs.

How solutions emerge: Resource portfolios are selected through **least-cost** optimization across all available planning levers.

How to read the chart: Values are cumulative through time and do not represent incremental annual additions.

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2026 IRP Reference Case – Key Assumptions

Technology-neutral resource access, updated deliverability treatment, and study-based Resource Adequacy (RA) inputs.

May 5 reference database package update Notice

RPAC NDA members to receive change log + refreshed database; key updates include transmission deliverability treatment enhancements and operating-characteristic corrections.

Key Portfolio Design Assumptions

- Technology-agnostic resource candidates
- No voluntary clean energy targets
- Distributed generation treated as a resource

Fuel & thermal unit assumptions

- Four Corners exit in 2031
- New gas pipeline; molecules flowing by 2030

Transmission & market inputs

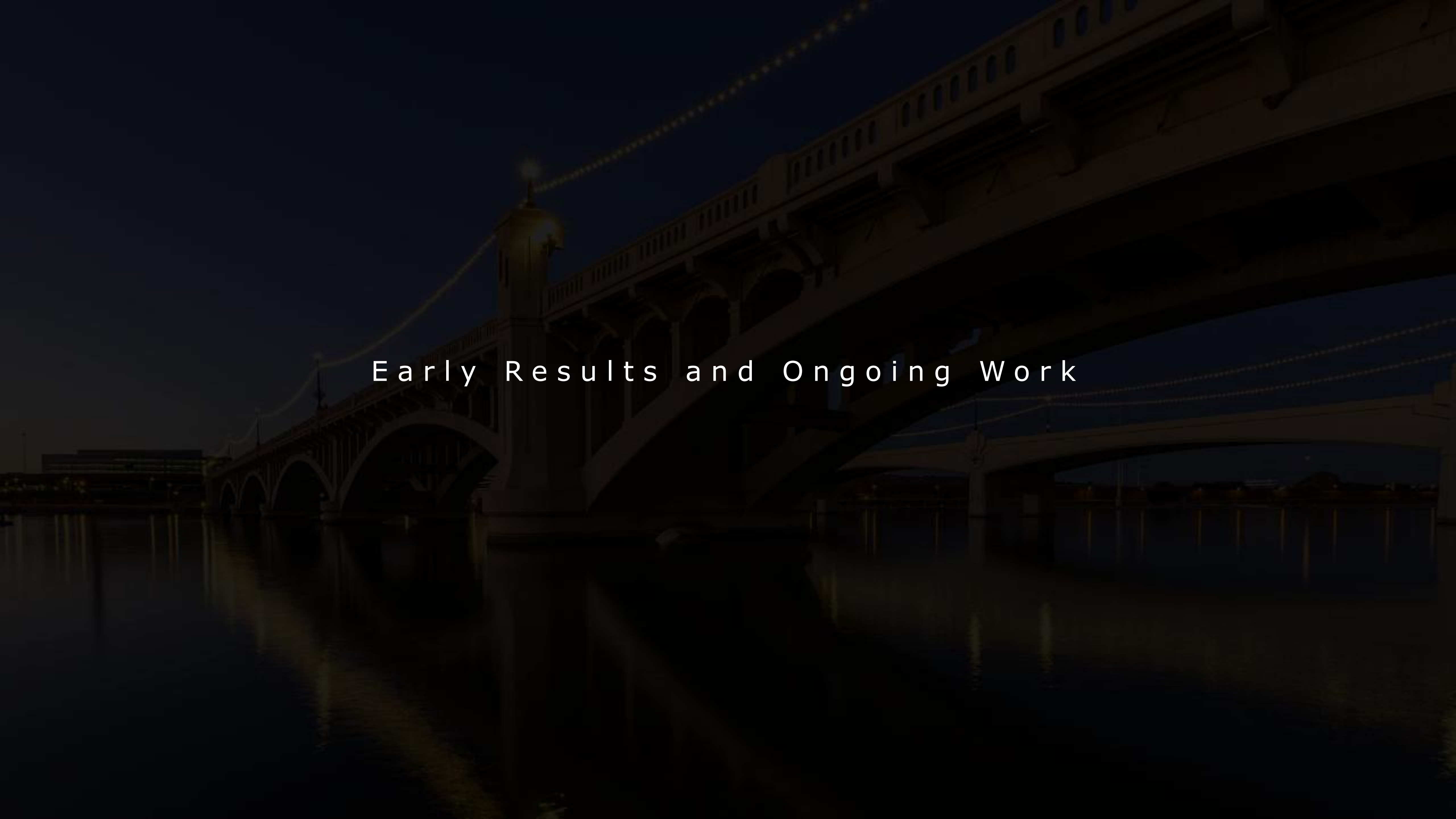
- Additional transmission upgrades included
- Enhanced deliverability treatment
- Market prices/depth based on E3-forecasted prices

Reliability & accreditation

- Planning Reserve based on perfect capacity margin from 2025 APS RA study
- Resource accreditation based on 2025 APS RA study work

Resource Candidate Menu

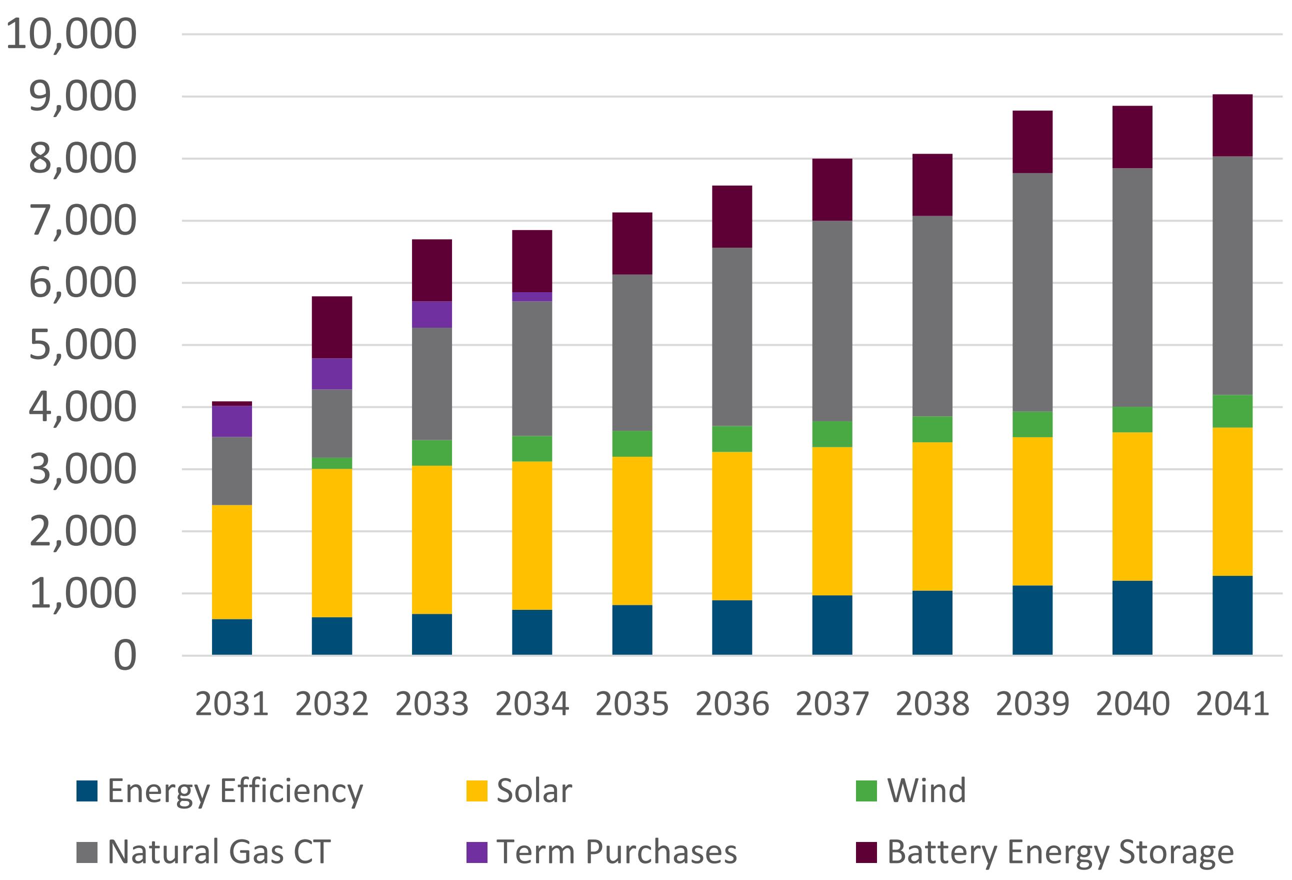
BESS (6-8 Hr)	Bio	Cholla Conversion Project
Concentrated Solar Power	Energy Efficiency	Combined Cycle
Combustion Turbine	Geo-Thermal	Nuclear
Pumped Hydro	Solar	Wind



Early Results and Ongoing Work

Directional Resource and Transmission Buildout identified by PLEXOS

Raw optimization output illustrating the resource and transmission investments selected to satisfy long-term system needs.



- Represents the direct PLEXOS capacity expansion solution, not the final reference case portfolio.
- Final portfolio will be developed after ELCC reruns and Loads & Resources reconciliation.
- Portfolio costs shown below are not the total revenue requirement.
- Transmission additions indicate material deliverability needs.

$38.8B
Modeled Portfolio Costs = Annualized Build + Production Costs

$1.7B
In Transmission Investments with 8 New Transmission projects

PLEXOS Resource Picks → Create Loads and Resources Table → Finalize portfolio → Revenue Requirements

Ongoing Scenario & Sensitivity Analysis

Extensive PLEXOS scenario work is underway to test portfolio robustness across major fuel, infrastructure, cost, load, transmission, and market-participation uncertainties to determine the Preferred Portfolio.

CAPACITY EXPANSION AND PRODUCTION ECONOMICS: PLEXOS ENGINE

Natural gas fuel prices

Test portfolio economics under alternative commodity and delivery-cost trajectories.

No new gas pipeline

Evaluate costs and feasibility of resource-selections if incremental fuel infrastructure is unavailable.

Four Corners exit timing

Compare alternative exit timing for existing coal capacity.

Resource candidate capital costs

Stress relative economics across renewable, storage, thermal, and emerging resources.

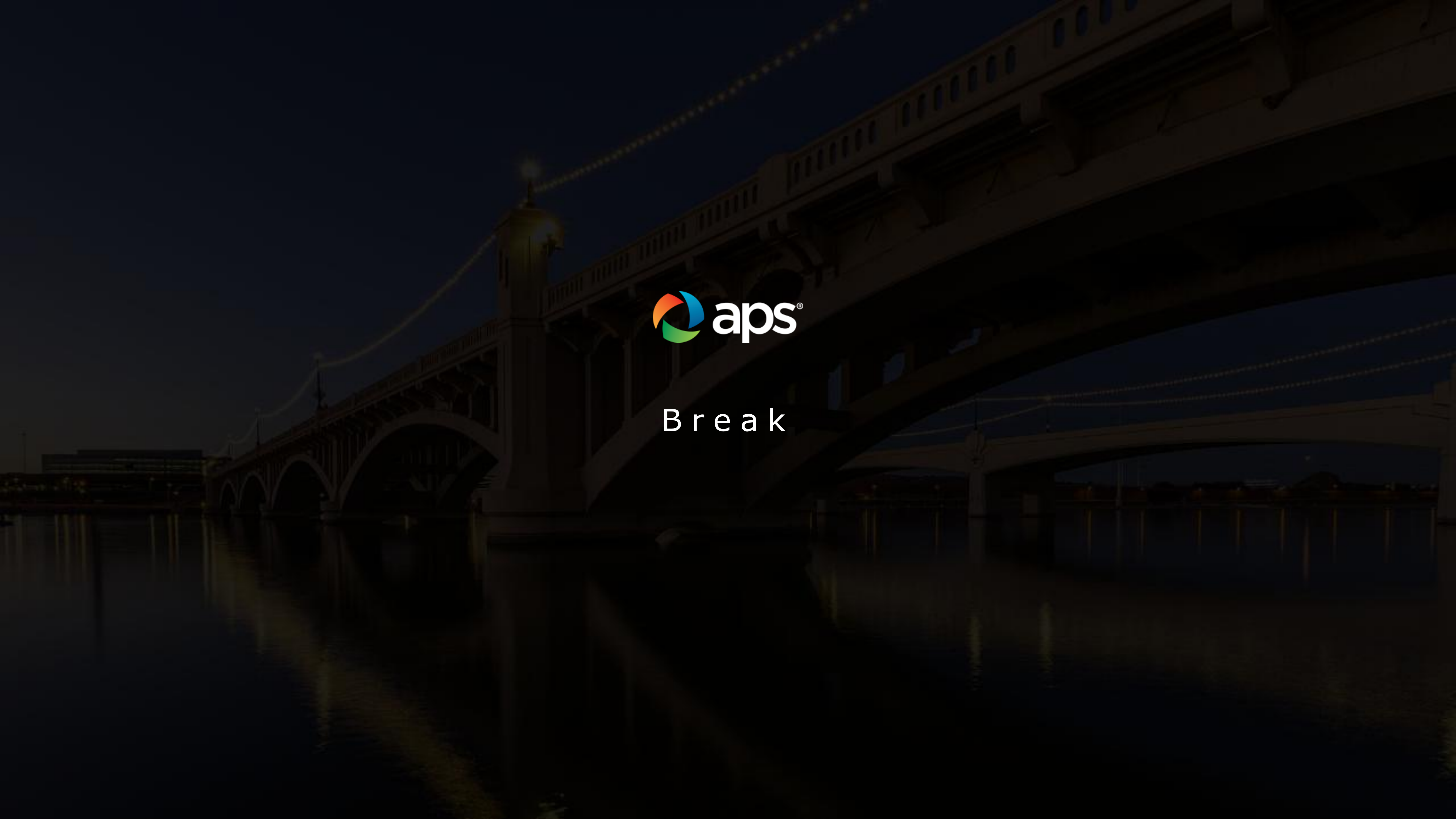
Transmission buildout capability

Study how deliverability and expansion limits shape resource selection and cost.

Load forecast uncertainty

Assess resource and transmission requirements under alternative growth trajectories.

Reserve margin implications of WRAP and Markets+ participation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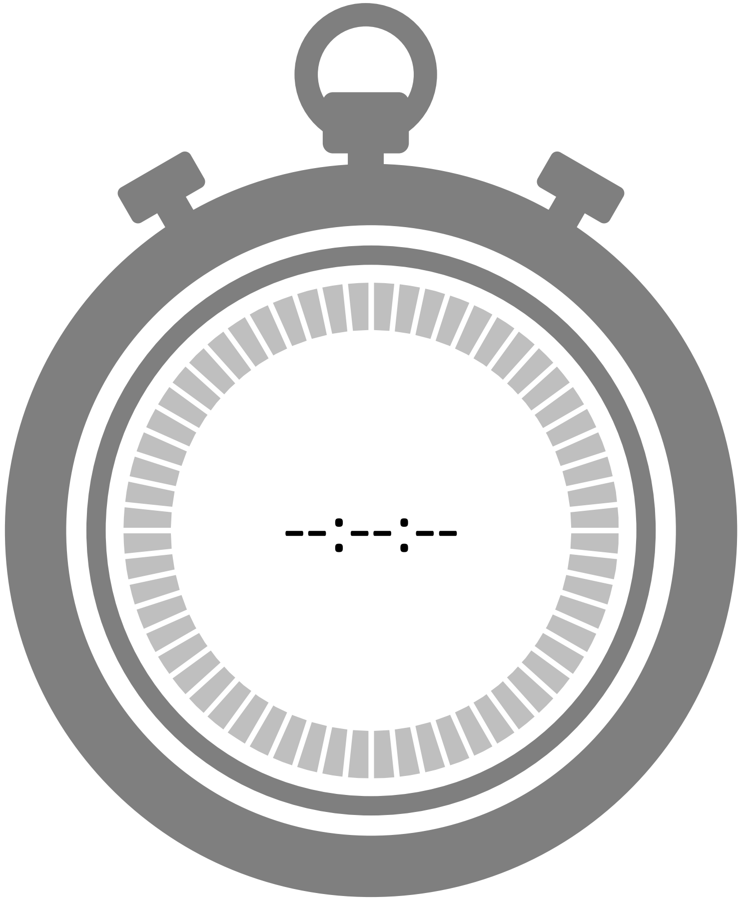
Break

Time for a Break



Break Duration 5 min.

Meeting will resume at hh:mm

Summer Preparedness

Tim Rusert, APS

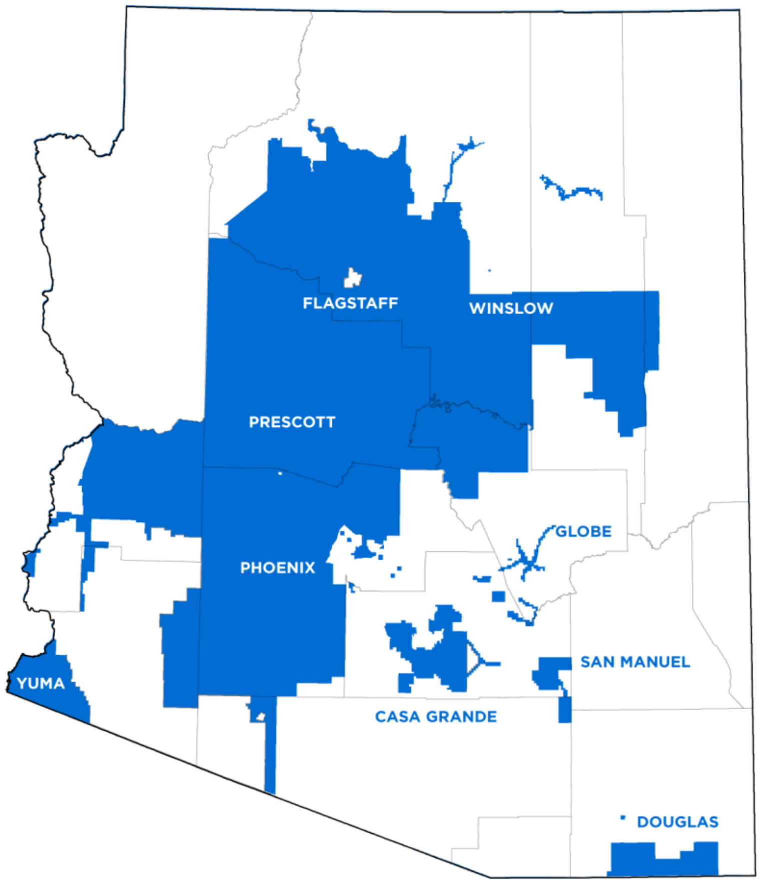
APS Service Territory

Since 1886, Arizona's largest and longest-serving utility

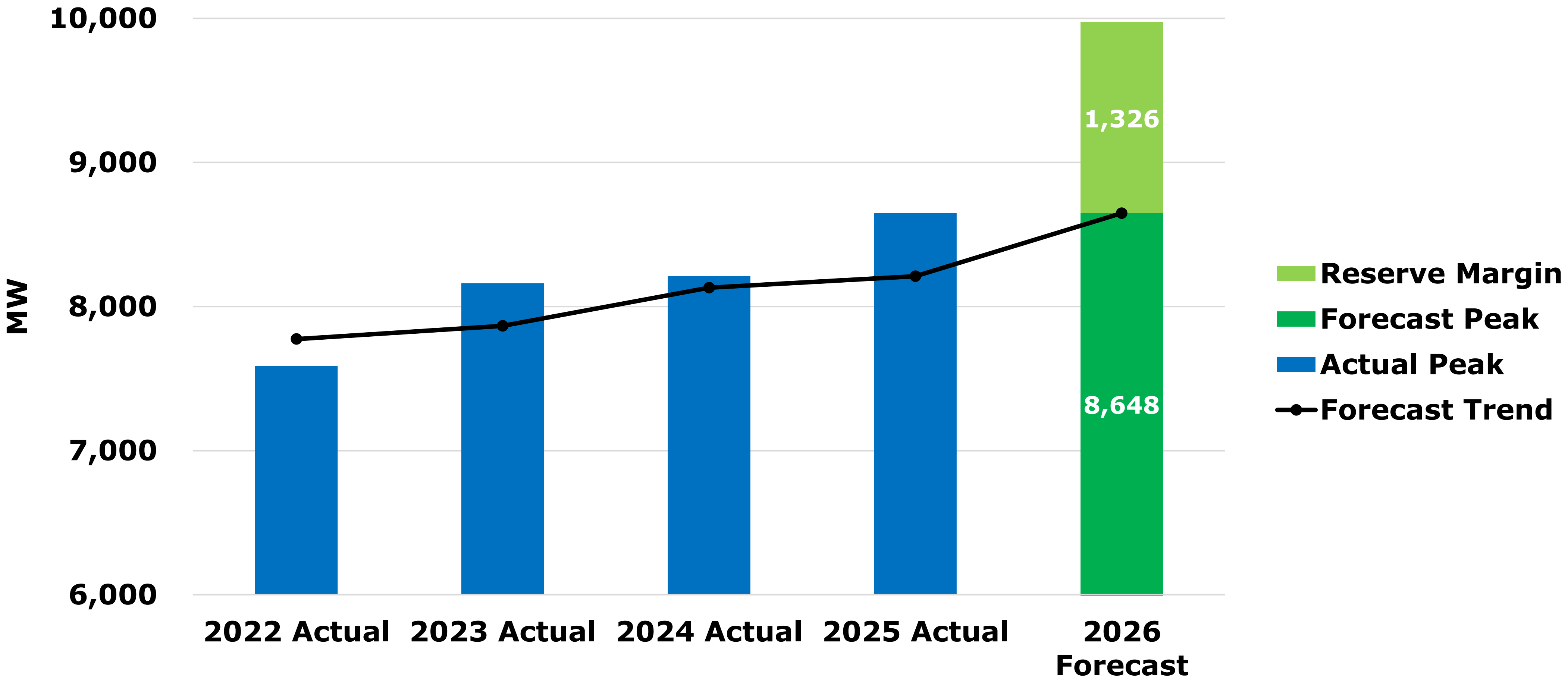
- 34,646 square mile service territory
- 11 of 15 counties
- 1.4 million customers

Our transmission and distribution system includes:

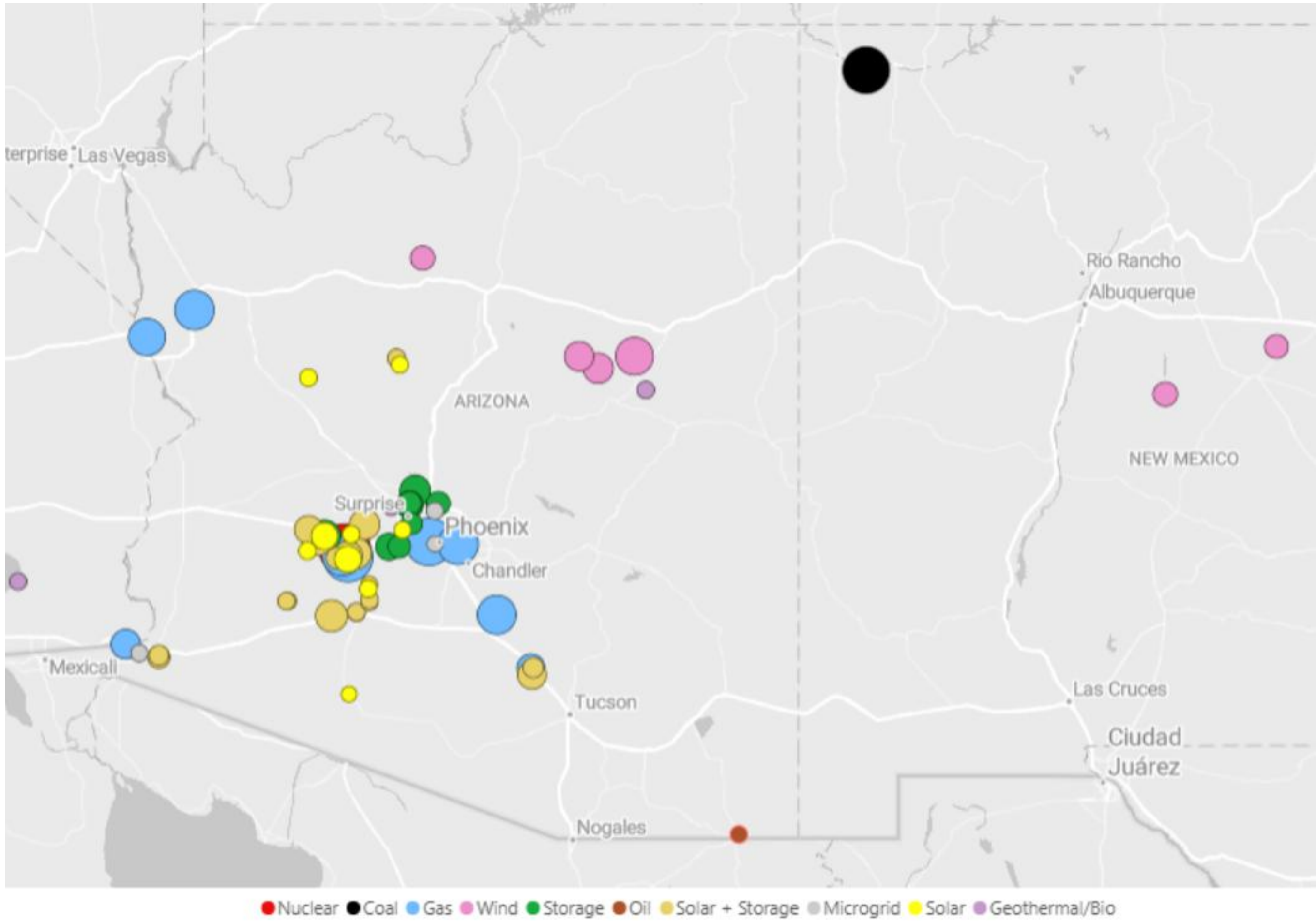
- 5,939 miles of transmission lines
- 32,210 miles of distribution lines
- 2,124 distribution feeders
- 477 substations



2026 Peak Demand and Reserves

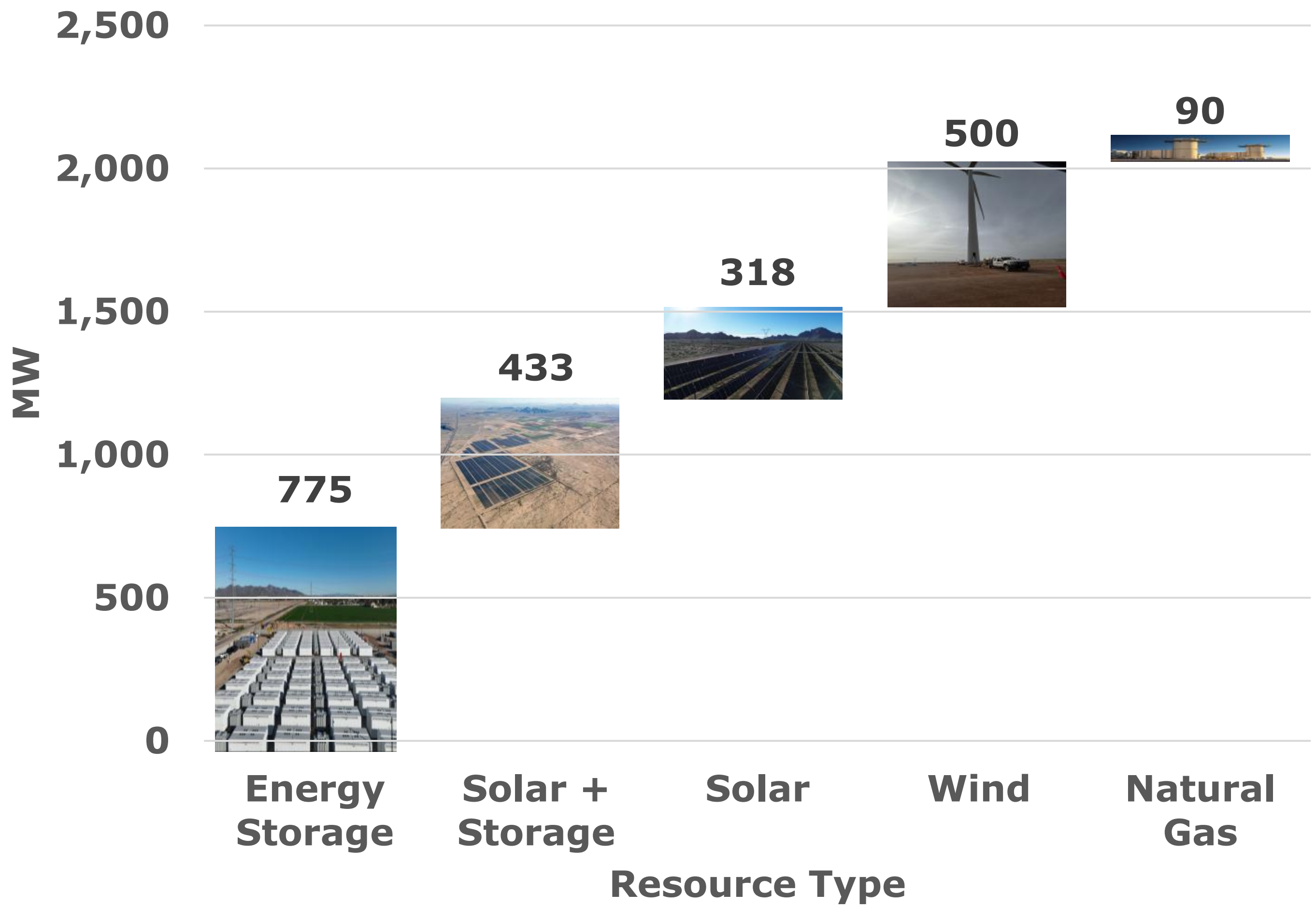


2026 APS Resources



	ACCREDITED CAPACITY	NAMEPLATE CAPACITY
Nuclear	**978**	**1,146**
Coal	**828**	**970**
Natural Gas	**4,523**	**5,409**
Short-term Purchase	**235**	**235**
Microgrid	**32**	**39**
Renewable	**2,373**	**3,985**
Solar	127	294
Solar + Storage	1,912	2,311
Wind	314	1,353
Other Renewable	20	27
Energy Storage	**889**	**1,280**
Demand Response	**116**	**290**
TOTAL	**9,974**	**13,354**

Resource Additions for Summer 2026



775 MW Energy Storage
- Agave (150 MW)
- Beehive (250 MW)
- Desert Bloom (150 MW)
- Justice (150 MW)
- Pluto (75 MW)

433 MW Solar + Storage
- Catclaw (250 MW)
- Maricopa Energy Center (183 MW)

318 MW Solar
- Ironwood (168 MW)
- Papago Solar (150 MW)

500 MW Wind
- West Camp (500 MW)

90 MW Natural Gas
- Sundance CT expansion (90 MW)

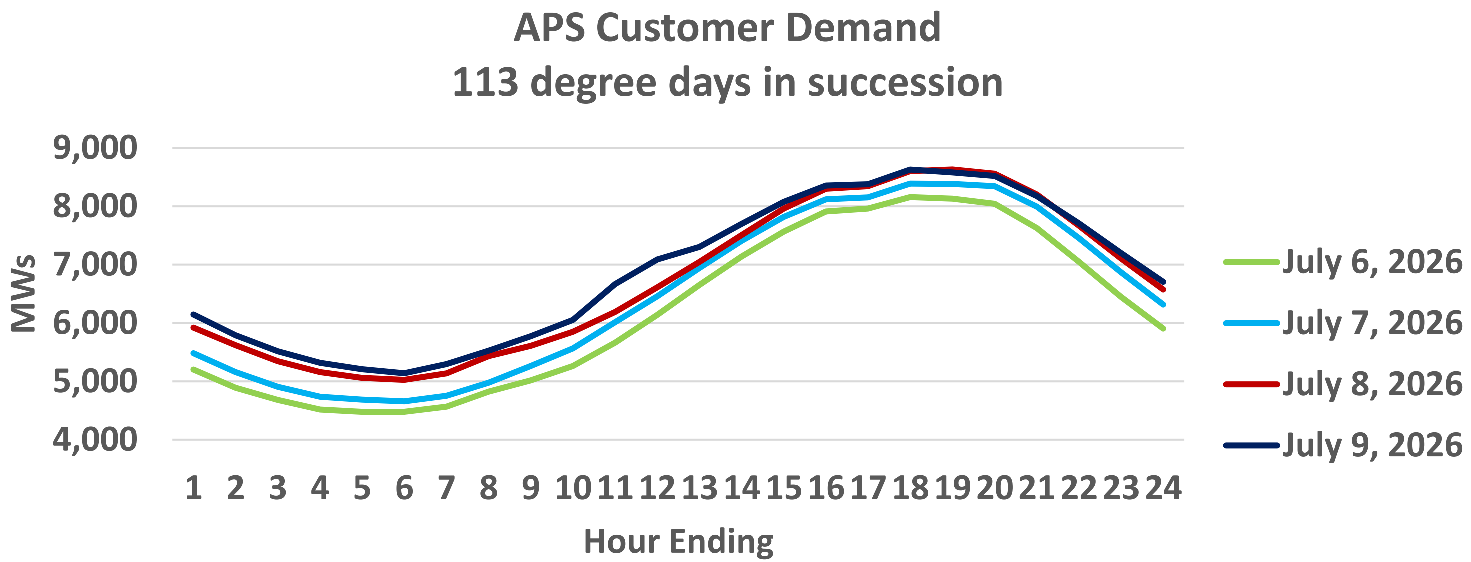
2026 Summer Results

Summer-to-date

- Single heat wave
  - June max 112°
  - July max 113°
- Monsoon pattern set up in mid July
- Peak demand 8,629 MW
- 9 days > 8,000 MW

Phoenix Sky Harbor Recorded Temperatures

July	5	6	7	8	9	10	11
High temp	110°	113°	113°	113°	113°	111°	109°
Low temp	88°	87°	90°	92°	93°	89°	90°

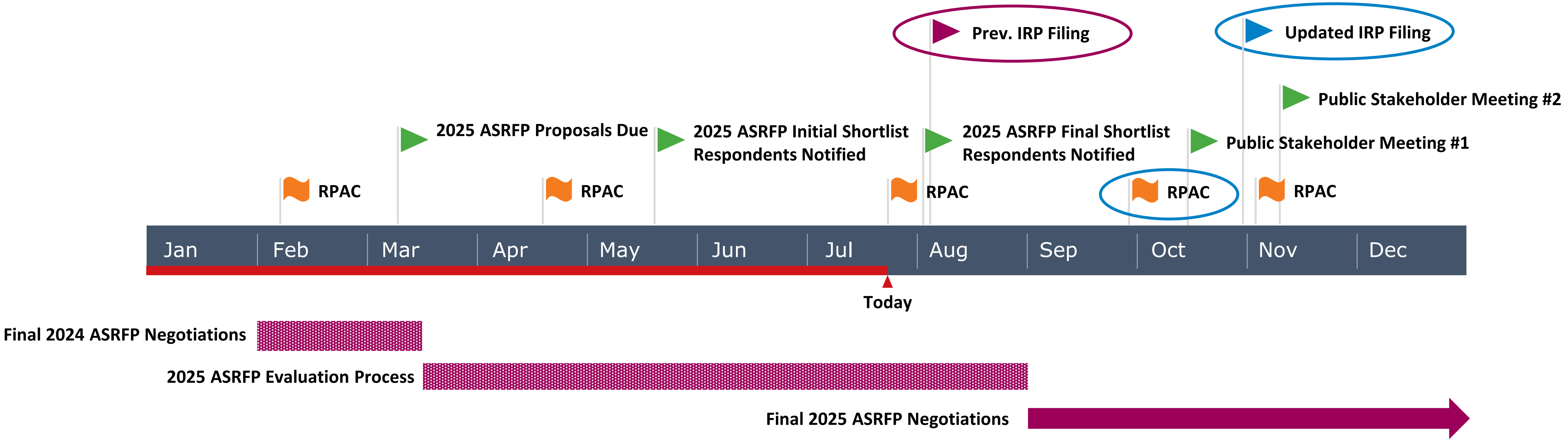


2026 IRP Filing Extension

Mike Eugenis, APS

2026 IRP Filing Extension

On July 8th, 2026, the Arizona Corporation Commission approved an extension of the 2026 IRP filing deadline to **October 30th, 2026**.



While APS has been granted an additional 90 days to file the 2026 IRP, development of the plan continues at full pace.

2026 IRP Filing Extension

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Updated Filing Timeline

APS Files IRP	Stakeholder Comments & Deliverables Due	Staff Proposed Order Regarding Stakeholder License Fee Reimbursement	APS Response to Stakeholder Comments	Staff Assessment and Proposed Order
October 30th, 2026	February 10th, 2027	April 12th, 2027	June 10th, 2027	September 13th, 2027

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Next Steps & Closing Remarks

Adam Constable, APS

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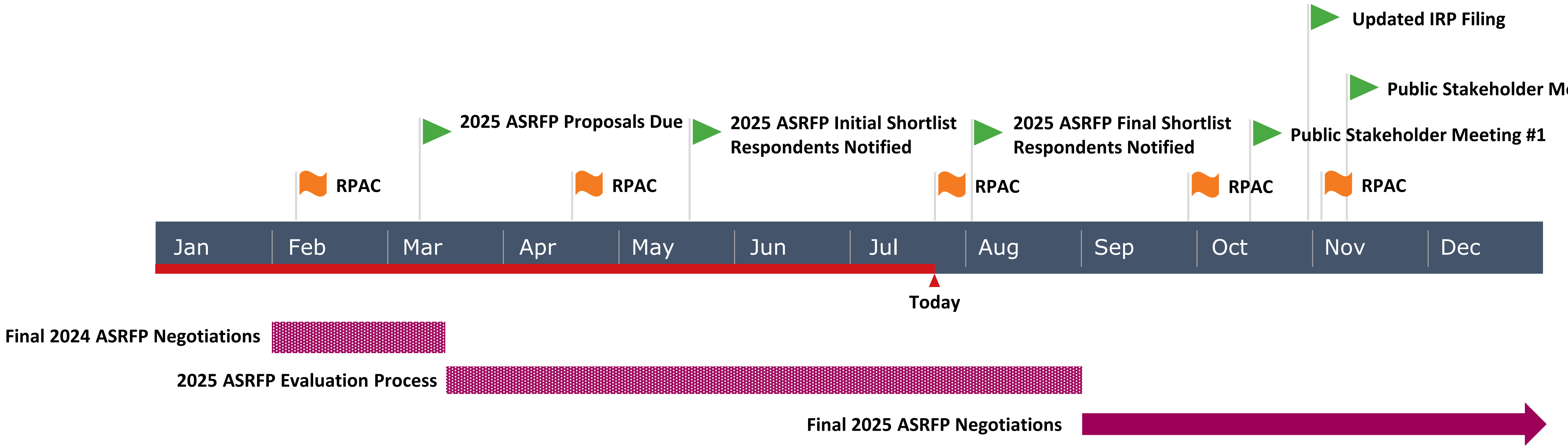
Forward Plans and Meetings



Key Milestones

September RPAC: September 30, 2026 (Tentative)
Time: 9:00 am

Saguaro CEC Filing: July 24, 2026