Federal river power beat the market in ten of eleven months of 2026.

A preference customer taking its full Colorado River allocation avoids the $12.36 a megawatt-hour energy rate and nothing else, because the capacity charge is paid either way. On 2026 prices that beat the Palo Verde peak index in ten months of eleven, and the January to March election closes on 4 December 2026.

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Key points

• The capacity charge is billed on contract capacity whether or not a megawatt-hour is delivered, so the only saving from taking federal energy is the energy rate.

• On 2026 prices federal energy was cheaper than the Palo Verde peak index in ten months of eleven, losing April by 48 cents.

• The allocation is seasonally inverted: Colorado Springs Utilities reports 15 megawatts in summer against 60 in winter, in a summer-peaking market.

• The Cost Recovery Charge waiver pays only where the charge exceeds your replacement price less the energy rate.

• Elect the quarter's firming option within 14 days of the notice, which for January to March closes on 4 December 2026.

$31.38	Composite rate for the federal allocation at full delivery
$12.36	Energy rate a customer avoids by taking a federal megawatt-hour
$45.25m	Drought margin the pool buys outside the federal rate, at 2026 prices

$63m	Capacity revenue on capacity the plant cannot currently produce, an upper bound

The federal allocation costs $31.38 a megawatt-hour at the composite rate in the current rate order [s1]. The capacity charge is billed on contract capacity whether or not a megawatt-hour is delivered [s1] [s9]. The drought therefore reaches a customer through which megawatt-hours it chooses to take.

That leaves one saving on the energy side. Taking federal power avoids the $12.36 a megawatt-hour energy rate, plus any Cost Recovery Charge on it, and nothing else [s1]. Against the 2026 Palo Verde peak index it made federal energy cheaper in ten months of eleven [s6]. April was the exception [s6].

The pool carries a $180.24m annual revenue requirement over 5,743.8 gigawatt-hours of firm energy and 130 customers [s1] [s13]. Three amounts move inside it. A drought margin of $45.25m a year at 2026 prices. A Cost Recovery Charge worth $5.74m a year for every $1 a megawatt-hour. Up to $63m of capacity revenue on capacity Glen Canyon cannot currently produce [s1] [s7].

The waiver is the only money in a customer's hands. It is tested, not assumed: it pays only where the charge exceeds your replacement price less $12.36 a megawatt-hour [s1]. What to do first: elect the January to March firming option by 4 December 2026 [s1]. The notice falls on 20 November and customers get at least 14 days [s1].

The bottom line. Keep the allocation and work the two elections. The market did not beat the federal energy rate in 2026, and the only lever with a date is the waiver.

How the bill works

The product is a fixed capacity charge with energy delivered against a quarterly forecast. Under Rate Order WAPA-206, published on 27 November 2023, the capacity rate is $5.25 a kilowatt-month, and billing demand is the greater of the month's highest 30-minute demand up to the delivery obligation or the contract rate of delivery [s1]. The charge therefore does not fall when deliveries fall. That is the whole mechanism, and it is why the allocation's cost per delivered megawatt-hour rises with the drought while its marginal cost does not.

Energy is offered at the deliverable sales amount, the marketable generation level above which the Western Area Power Administration will not purchase firming power [s1]. The amount is updated quarterly, and customers have at least 14 days to elect Western Replacement Power, which carries no losses and no administrative fee [s1]. A customer that declines it is not charged and takes its share of deliverable capacity instead [s1]. Table 3 of Rate Order WAPA-206 sets the quarterly schedule, and it labels the notification dates as estimated [s1]. Contract SLIP-F13 is the rate schedule that carries the composite rate of 31.38 mills [s1].

Two further claims bear on the decision. The Cost Recovery Charge is levied on all long-term energy sales and recalculated at a minimum before 1 July each year [s1]. It is triggered when the projected Glen Canyon release falls below 8.23 million acre-feet, and it comes with 45 days' notice to request a waiver [s1]. On the release projected in the Bureau of Reclamation's October 2026 two-year study, 6.00 to 7.00 million acre-feet for water year 2027, the trigger is already met by 1.23 to 2.23 million acre-feet [s2] [s3]. A recalculation notice therefore falls no later than about 17 May 2027, and the request window closes before 1 July 2027.

What it means for the industry

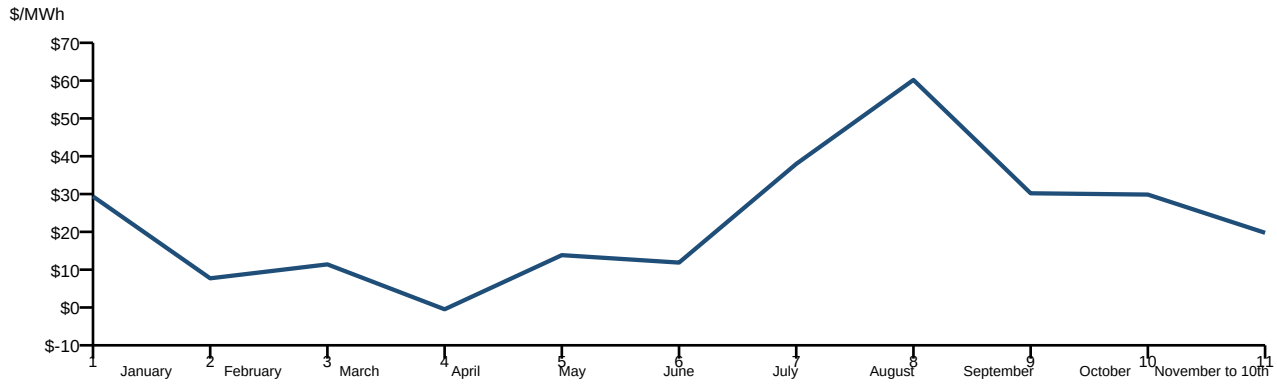
Hydropower generation in the Southwest from April to August 2026 was 19 per cent below the same months of 2025 and 28 per cent below the ten-year average [s12]. The pool is not the whole Colorado River system. It is 130 long-term firm electric service customers across six states, including 54 Native American tribes, serving about five million people [s13]. A specialist trade count puts the customers at about 140, and the difference moves every per-customer figure below by about 7 per cent [s14].

The pool splits by what a customer owns rather than by what it buys. A customer with its own generation or a trading desk can decline federal energy and source elsewhere while still paying the capacity charge. A municipal of a few megawatts cannot. Outside the pool, the gainers are sellers of Palo Verde on-peak energy and holders of firm desert capacity.

The finding no captured source states is a seasonal inversion. Colorado Springs Utilities' 2026 Electric Integrated Resource Plan discloses that its federal contract provides 15 megawatts in the summer and 60 megawatts in the winter [s5]. On four summer months at 15 MW and eight winter months at 60 MW it averages 45 MW and carries $2,835,000 a year at $63 a kilowatt-year [s5]. The allocation is largest in the months the market is cheapest and smallest in the month it is dearest, which contradicts the reason a summer-peaking load holds it.

The marginal test, month by month. Federal energy beat the 2026 Palo Verde peak index by $29.37 in January, $7.71 in February, $11.40 in March, $13.84 in May and $11.87 in June. It beat it by $37.97 in July, $60.18 in August, $30.20 in September, $29.86 in October and $19.75 to 10 November [s6]. In April the advantage was -$0.48 a megawatt-hour [s6]. The annual volume-weighted market price was $34.87 [s6].

Exhibit 1: What taking a federal megawatt-hour saved against the Palo Verde peak index in 2026



Monthly volume-weighted Palo Verde day-ahead peak values less the federal energy rate of $12.36 a megawatt-hour. April is the only month the market won.

Source: US Energy Information Administration, ICE Palo Verde daily series for 2026 [s6]; rate order WAPA-206 [s1]; Mosaic Singularity Strategic Intelligence Division analysis

The gain goes to a customer with a trading desk, which can decline federal energy and still hold the capacity. The loss falls on a small municipal that must take what it is offered at the quarter's price, and on any load whose consumption peaks in July and August against an allocation that is smallest then.

Exhibit 2: The allocation's all-in cost per megawatt-hour delivered, as the shortfall deepens

Shortfall against contract volume	All-in cost per MWh delivered	Market price it matches
None	$31.38	$31.38
10 per cent	$33.49	$33.49
20 per cent	$36.13	$36.13

Shortfall against contract volume	All-in cost per MWh delivered	Market price it matches
35 per cent	$41.62	$41.62
50 per cent	$50.40	$50.40
65 per cent	$66.70	$66.70

Source: Rate order WAPA-206 [s1]; Mosaic Singularity Strategic Intelligence Division analysis

The curve is the holding measure, and it answers a different question from the election. It says the allocation is dearer than the 2026 market at any shortfall above about 20 per cent: $41.62 at 35 per cent, $50.40 at 50 and $66.70 at 65, against an annual market price of $34.87 [s1] [s6]. It cannot time a scheduling decision, because the capacity charge behind it is paid either way.

The 35 per cent is history, not the 2027 shortfall. It is what the Arkansas River Power Authority told its board in a note of August 2023, describing a programme for calendar 2022 and 2023 that the same document says was extended for five years [s4]. The deliverable sales amount is reset quarterly, so the 2027 level is not yet known [s1]. Read the curve as the cost at a given shortfall, not as the price now.

What it is worth

The industry total. Within the $180.24m annual bill, the drought margin, at the 35 per cent shortfall the record discloses rather than a forecast for 2027, is $45.25m a year at the 2026 margin of $22.51 a megawatt-hour. It is $120.98m at August's $60.18, and $31.08m at $15.46, which is the margin at the 2026 median price of $27.82 [s6]. That margin is what the drought costs the pool through the allocation's design, not the cost of any decision, because the shortfall is bought in every scenario.

The typical company, on two points rather than one. The average customer takes 44.18 GWh a year, which puts its drought margin at $239,073 to $930,621 across those three prices [s1] [s6]. The one customer with published megawatts, Colorado Springs Utilities at an average of 45 MW, carries $2,835,000 a year, or 3.4 times the pool average [s5]. This is therefore a range across prices plus the one ratio across companies, not a customer distribution.

The sensitivities are computed. Each $1 a megawatt-hour of Cost Recovery Charge is $5.74m a year across the pool and $44,183 for the average customer [s1]. Each $10 a megawatt-hour of replacement margin on the shortfall volume is $20.1m across the pool and $154,640 for the average customer, which is also what prices a hedge of its share of that volume [s1] [s6].

All three amounts reach purchased-power expense, which a regulated utility recovers through its energy charge or power cost adjustment and an unregulated load pays directly.

Your own figure. Take federal energy if your replacement price plus transaction cost exceeds $12.36 a megawatt-hour plus any charge. Request the waiver only if the charge exceeds your replacement price less $12.36. Your annual exposure to the shortfall is the megawatt-hours between the contract level and the deliverable sales amount, times your replacement price less $12.36. A hedge is priced at the forward price less $12.36, times the megawatt-hours hedged. The Palo Verde day-ahead peak future is cash-settled and monthly, and no 2027 settlement price is public, so the hedge is a formula here and not a claimed saving [s10].

The options and our recommendation

The options open to a preference customer

Option	Cost	Risk	What it forecloses
Keep the full allocation and elect Western Replacement Power in each quarter where firm volume is wanted (recommended)	Market rates for the replacement purchase, with no losses or administrative fee, plus the full drought margin at the pool's own rates [s1].	The purchase is made in the quarter that sets the price, and the Cost Recovery Charge applies unless it is waived.	Nothing, but it leaves the capacity charge unchallenged.
Schedule down to the Waiver Level to escape the Cost Recovery Charge	The margin forgone on every megawatt-hour not taken, which was $7.71 to $60.18 a megawatt-hour in the ten months of 2026 in which federal energy won [s6].	The charge is unknown by tier, so the trade can run against the customer; a prior-year adjustment applies to customers who do not elect the waiver level [s1].	The energy margin in the months the market is tightest.
Decline federal energy and buy in the market	The full market price, against a federal energy rate of $12.36 that won ten months of eleven in 2026 [s6].	The capacity charge is still payable, so the decision adds cost rather than avoiding it.	Nothing permanently, and it can be reversed at the next quarterly election [s1].

We would take the first. The capacity charge is sunk for any decision about a megawatt-hour, so the election is decided on $12.36 plus the charge against a replacement price, and on 2026 prices that test favoured the federal energy in ten months of eleven [s1] [s6]. We would not schedule down to escape the charge before the charge rate is published. This is a judgement on the dates and the money, and it holds whether the drought deepens or eases, because the shortfall is bought either way.

What to do in the next 90 days

First actions

Owner	Action	By
Head of energy supply	Elect the January to March firming option within 14 days of the notice, testing the deliverable sales amount against your own replacement price before you elect [s1].	2026-12-04
Head of regulatory affairs	Put the capacity charge on capacity the pool cannot currently deliver to WAPA in writing, stating the comparison as the pool's contract capacity less Glen Canyon's capability [s1] [s7].	2026-12-31
Head of regulatory affairs	Compute the waiver threshold and file the request within 45 days of the recalculation notice, which falls no later than 17 May 2027 [s1].	2027-05-17

The metric is the election itself: every quarter's firming decision taken before the 14-day window closes, and the waiver requested only where the charge exceeds your replacement price less $12.36. The threshold that shows the call worked is the quarterly market price against $12.36. A quarter in which the replacement price falls below that rate is the one in which the federal energy was not the cheaper source, and 2026 had one such month in eleven [s6]. Report the result to the chief financial officer and the audit committee each quarter.

Scenarios and signposts

Three ways the year behaves

Scenario	Outcome	Move	Signpost
Dry and dear	The projected release stays near the bottom of Reclamation's range, the charge is triggered again, and the market stays above the federal energy rate.	Keep the allocation, elect replacement firming where volume is wanted, and test the waiver each year.	The 24-month study in April 2027 projects a release below 8.23 million acre-feet [s1] [s3].

Scenario	Outcome	Move	Signpost
Wet reprieve	A wet winter lifts the projection above the trigger and the charge falls away for the year.	Nothing changes in the elections; the waiver question disappears for the year.	The April 2027 determination projects a release above 8.23 million acre-feet [s1] [s3].
Mechanical squeeze	Units stay out and generating capability falls further, so the gap between contract capacity and deliverable capacity widens.	Put the capacity charge to WAPA in writing and price the shortfall before the next rate case.	Reclamation's 2027 operating plan keeps Glen Canyon units 3 and 4 unavailable [s2].

The scope of all of this. The piece covers the Salt Lake City Area Integrated Projects pool and its preference customers. Hoover is not in it: it belongs to the Boulder Canyon Project, with its own allocation, customers and rates, none of which is in our record, so no per-customer figure here applies to a Boulder Canyon customer. On capacity, the $63m is an upper bound and not a measured loss. It is the pool's 1,734 MW of contract rate of delivery against Glen Canyon's 730 MW at the current pool, before the other Colorado River Storage Project units are counted [s1] [s7] [s8]. The record does not establish that contract capacity is charged for capacity that cannot physically be delivered. Nor does it reconcile the two published capacity figures for Hoover: 382 MW on the Western Electricity Coordinating Council's figures for September 2026, and a reported fall to about 317 MW by April 2027 [s7] [s11].

How we did this

How we did this

The load-bearing documents are Rate Order WAPA-206 of 27 November 2023, the Bureau of Reclamation's 24-month study of October 2026, the draft 2027 annual operating plan, Colorado Springs Utilities' 2026 integrated resource plan and the Arkansas River Power Authority note of August 2023. The pool is derived from the rate order, not from a published sales table: capacity revenue is 1,734 MW of contract rate of delivery at $63 a kilowatt-year, or $109.25m, and the rest of the $180.239m revenue requirement at 12.36 mills is 5,743.8 GWh [s1]. That is the deliverable sales amount by construction, since the energy charge is levied on deliverable sales energy, and it is the base the holding measure uses. Table 3 of Rate Order WAPA-206 governs the quarterly elections. The holding measure re-spreads the capacity revenue over a smaller volume: at a 35 per cent cut the same dollars sit on 3,734 GWh, giving $29.26 plus $12.36, or $41.62 a megawatt-hour. The marginal test uses the monthly volume-weighted Palo Verde day-ahead peak values recomputed from the daily series, less $12.36. The drought margin is the shortfall volume, 2,010 GWh at the 35 per cent shortfall the record discloses, times the margin at each price. The capacity figures are Glen Canyon's 730 MW at 3,517 feet on WECC's basis against the pool's 1,734 MW, and the $63m applies $63 a kilowatt-year to the difference. Colorado Springs' 45 MW average assumes four summer months at 15 MW and eight winter months at 60 MW, which is an assumption about the month split, not a disclosure. Not established: the Cost Recovery Charge rate by tier, so the waiver test is a threshold and not a forecast; any 2027 forward price, so the hedge is priced by the formula and not claimed as a saving; allocation megawatts by customer beyond the one customer that publishes them; Boulder Canyon Project allocations and rates; and the generating capability of the other storage project units at current water. Data cut-off 18 November 2026.

Researched and written by Sofia Lindqvist, the division's AI analyst for utilities. Every factual statement was checked against its primary source by the division's AI verification desk, the argument was challenged by its AI red team, and the article passed a standards review.

Sources. Fourteen documents: one binding rate order, one operating plan, one hydrology study and one project page from the Bureau of Reclamation; one national laboratory study; one integrated resource plan and one customer board note; four price and capacity datasets; one market product specification; and two press reports. The rate order carries the billing mechanics and the waiver; the price series carries the marginal test.