

The grid's hardest day is decided before it arrives

AI hazard forecasting leapt ahead in 2025 and 2026. Utilities are still deciding storm and wildfire response the old way: late, by hand, with rules that live in people's heads. The value of the forecast is lost in the gap between knowing and acting.

By the 6th Wave R&D team · 13 minute read

On the evening of Friday, October 9, 2026, Hurricane Isaias made landfall near Destin, Florida, as a Category 2 storm with winds of 105 mph. Forecasts before landfall had called for a Category 3. Florida Power & Light had already mobilized 16,000 workers from 29 states; by Saturday afternoon it still had about 332,000 customers out.¹ In Alabama, more than 267,000 Alabama Power customers lost power, and the utility brought in more than 6,400 additional personnel.² Every one of those workers was placed days earlier, on a forecast, by people deciding how bad it would be, where, and what to do about it before anyone knew.

That is the grid's hardest day, and it is decided before it arrives. The forecast now arrives earlier and better than ever: 2025 was the first season the National Hurricane Center used AI models in real-time operations, and on Atlantic storms an AI ensemble beat the official forecast at lead times out to 72 hours.³ What has not changed is what happens between the forecast and the action. Which crews to stage, which circuits to de-energize, which to switch, what to restore first and what to tell customers about when the lights come back: those decisions are still made late, by hand, under the least information, and by rules that are mostly unwritten. This paper sets out the evidence and a framework for the utility CEO, COO and head of emergency management who must decide where AI should go first.

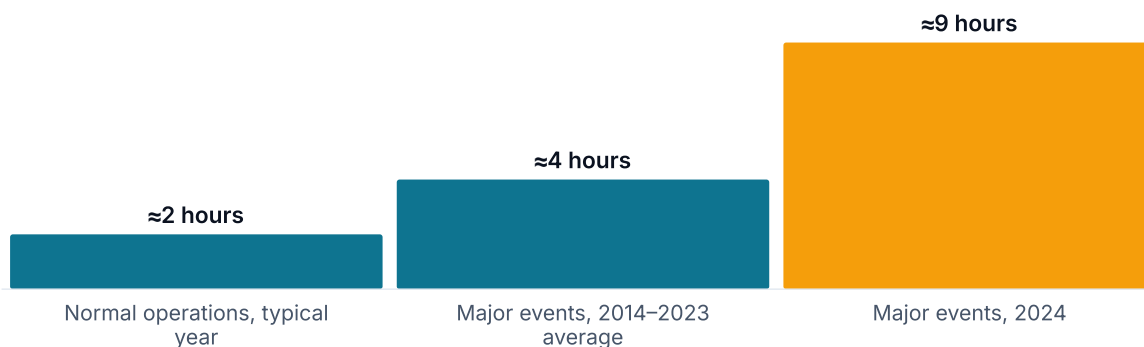
The bad days are now the grid's real performance

The everyday grid is managed well. In 2024 interruptions not caused by major events averaged about two hours per US customer, as they routinely do. But customers averaged 11 hours without power in total, the most in ten years, and "major events such as Hurricanes Beryl, Helene, and Milton accounted for 80% of the hours without electricity." Major-event interruptions averaged nearly 9 hours in 2024, against nearly 4 hours a year from 2014 to 2023 (Exhibit 1). Helene alone cut power to 5.9 million customers in 10 states, and customers in South Carolina averaged nearly 53 hours without power for the year.⁴

EXHIBIT 1

Major events now account for most of the time US customers spend without power

Average hours of electricity interruption per customer per year



Source: US Energy Information Administration, *Today in Energy*, December 1, 2025. 2024 is the latest national reliability year; major events produced 80% of 2024 outage hours.

The losses have not slowed. Climate Central, which took over the federal billion-dollar disaster database after NOAA stopped it in May 2025, counted 23 billion-dollar US disasters in 2025 at a total direct cost of about \$115 billion, the third-highest count since 1980.^{5,6} The Los Angeles wildfires of January 2025 alone exceeded \$60 billion.⁶ Winter Storm Fern in January 2026 left more than 800,000 customers out on the morning of January 26, including more than 175,000 of Nashville Electric Service's customers;⁷ NES's total reached 230,000, its worst storm on record, and its chief executive, Teresa Broyles-Aplin, said afterward, "We did not meet the expectations of our customers through this storm."⁸ Duke Energy put its own Fern restoration cost at \$268 million, and its Florida utility's actual costs for Debby, Helene and Milton totaled \$903 million, recovered through storm securitization charges that customers cannot bypass.⁹

For a utility leader the implication is direct. Reliability, cost and reputation are now set on a handful of days a year. The capability that matters most is not running the grid on an ordinary Tuesday. It is deciding well, early, when the hazard is still a forecast.

The forecast has leapt ahead

The forecasting side of that problem changed faster in 2025 and 2026 than in the previous decade. The National Hurricane Center's verification report for 2025, published March 30, 2026, records that "the 2025 season marked the first time that NHC incorporated AI-based models into real-time operations." On Atlantic storms, the Google DeepMind ensemble mean "slightly outperformed NHC at the shorter lead times from 12 to 72 h." At 72 hours its average track error was 66.5 nautical miles (77 miles), against 81.4 (94 miles) for the official forecast, 102.7 for the ECMWF model and 128.6 for the GFS (Exhibit 2). In the eastern Pacific it "beat the official forecast and all of the consensus aids at 48–120 h."³ DeepMind's peer-reviewed results claim more than a full day of lead-time advantage: its "three-day forecasts are as good as what prior models were able to provide for only the next two days."¹⁰

EXHIBIT 2

In 2025 an AI ensemble beat the official hurricane track forecast at three days

Atlantic track error at 72 hours, nautical miles (lower is better), homogeneous sample of 103 forecasts



Source: NOAA National Hurricane Center, *Forecast Verification Report: 2025 Hurricane Season*, March 30, 2026. 1 n mi = 1.151 statute miles.

The other agencies followed. ECMWF made its AI ensemble operational on July 1, 2025, with gains of up to 20 percent on measures including surface temperature, at "roughly 1,000 times less energy."¹¹ NOAA put three AI global models into operations in December 2025; its AI ensemble extends forecast skill by 18 to 24 hours using 9 percent of the computing of its

physics-based counterpart.¹² NVIDIA released open nowcasting and medium-range models in January 2026, and Southwest Power Pool is using them for wind forecasting.¹³

Two caveats belong here, and both matter for utilities. First, the leap is uneven for the variable that brings down lines: ECMWF's own evaluation found that "for 10-metre windspeed, IFS ENS is more skilful than AIFS ENS" against surface observations.¹⁴ Second, NHC noted that AI models "were not consistently available on a timely basis for routine use by forecasters," and its science operations officer said "we need trusted experts in the loop to observe, synthesize, and make sense" of them.^{3,15} Even so, the direction is not in doubt. The hazard is being seen earlier and more precisely than at any time in the history of the grid.

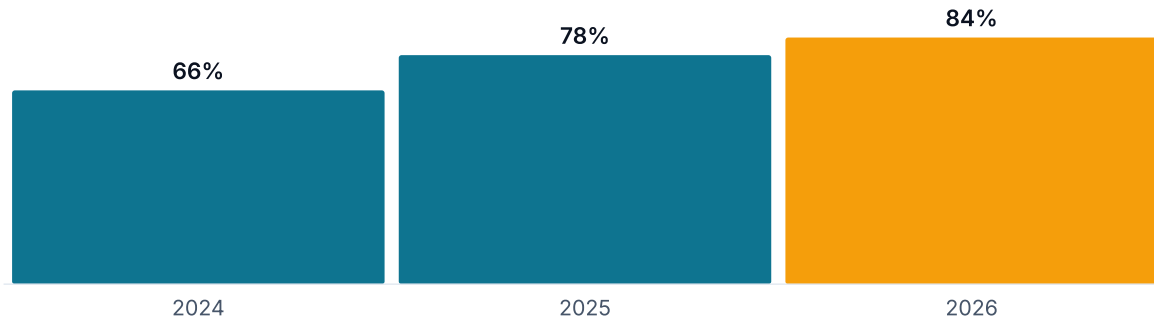
The decision layer has not moved

The utility side tells a different story. National Grid Partners' 2026 survey of 134 US utility innovation leaders, fielded from May to July, found that 84 percent now take more than a year to move a project from pilot to full rollout, up from 78 percent in 2025 and 66 percent in 2024 (Exhibit 3). Eighty-seven percent said returns are limited by "regulatory and rate-case frameworks developed before the current AI-driven demand boom," and 59 percent of innovation spending goes to incremental improvements.¹⁶ Itron's survey of 500 North American utility executives found 41 percent reporting AI "fully integrated," but the leading uses were grid optimization at 57 percent and demand forecasting at 51 percent.¹⁷ Storm and wildfire response did not appear among the headline uses. NERC's most recent survey of control-room practice found 38 percent using AI to predict events such as weather and prices and only 11 percent using it to predict equipment failures, and NERC's position is that "the operator should have the final input on the decision for AI/ML-generated actions."¹⁸

EXHIBIT 3

Utilities are taking longer, not shorter, to move from pilot to rollout

Share of US utility innovation leaders whose organizations take more than a year from pilot to full rollout, %



Source: National Grid Partners, *2026 Utility Innovation Survey*, September 18, 2026 (n=134; fielded May 20 to July 7, 2026). National Grid Partners is the venture arm of National Grid.

The money follows the same pattern. In August 2025 Texas regulators approved about \$2.7 billion of CenterPoint resiliency spending for 2026 to 2028, mostly hardening, which the utility projects will avoid more than 755 million outage minutes.¹⁹ In October 2026 PG&E filed a ten-year plan to underground about 5,000 miles of distribution lines.²⁰ Steel and cable are necessary, and their benefits are well understood. But none of these programs funds the faster, better decision about where the next storm will hit hardest and what to do about it before it does. The forecast is now a day better. The decisions it should inform are made no earlier than they were.

Where the decisions actually live

The clearest view of the gap comes from utilities' own filings. In January 2025, during the Santa Ana wind event that coincided with the Eaton and Palisades fires, Southern California Edison de-energized 363,196 customers in 8 counties and 373 circuits, "the largest and most complex since the inception of SCE's PSPS program." Its officer-verified report to the California Public Utilities Commission records two things that matter for this paper. As conditions worsened, "SCE quickly decided to adjust its de-energization criteria," and some customers were cut off without notice. And circuit-level status could not be shared with public safety officials in time because "the manual process could not keep pace with the size of the event."²¹ Ten days later a second event de-energized 152,393 customers.²² These were

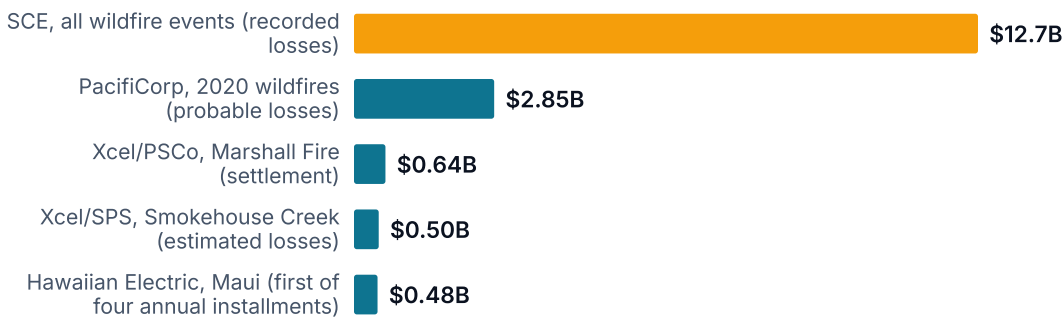
capable people doing their best. The rule they were applying was being rewritten in the moment, and the process that carried it ran by hand.

The cost of getting such decisions wrong is now measured in billions. As of June 30, 2026, SCE had recorded \$12.7 billion in losses across its wildfire events and \$1.6 billion in Eaton Fire settlements, says it believes it is likely its equipment was associated with the Eaton ignition, and cannot yet estimate a range of losses; a bellwether trial is set for January 2027.²³ PacifiCorp has recorded \$2.85 billion in probable losses for its 2020 fires.²⁴ Xcel Energy estimates \$503 million for the Smokehouse Creek fires, which the Texas A&M Forest Service found were caused by its subsidiary's power lines, and paid \$640 million to settle the Marshall Fire without admitting fault.²⁵ Hawaiian Electric made the first of four \$479 million annual payments for the Maui fires on April 10, 2026 (Exhibit 4).²⁶

EXHIBIT 4

The cost of a wrong call on the hardest day is now counted in billions

Wildfire losses recorded or settlement amounts disclosed in 2026 filings, \$ billion



Source: Form 10-Q filings for the quarter ended June 30, 2026 of Edison International, Berkshire Hathaway Energy and Xcel Energy; Hawaiian Electric Industries Form 8-K, April 2026. Amounts are not comparable measures; each is as the company reports it.

Across the storm and wildfire cycle, five decisions carry most of the consequence. In most utilities each is made by experienced people from a mix of emergency plans, tribal knowledge and judgment under pressure.

The five decisions that set the outcome of a hard day

Pre-staging	How many crews and which skills to stage, where and when, on a forecast that may change category. Usually an emergency-operations judgment, informed by past storms.
De-energization	When wind, fuel and equipment conditions justify shutting off a circuit, and who is told first. SCE's criteria changed mid-event in January 2025.
Switching and sectionalizing	Which devices to open or close to isolate damage and keep the most customers served. Partly automated where self-healing exists; elsewhere, operator judgment.
Restoration priority	Which circuits and customers come back first after hospitals, 911 centers and first responders. Often a plan, rarely an executable rule.
Restoration time estimate	When to publish the global and local ETR, and how. Most utilities release it mid-event, once damage is known.

There is evidence that writing one of these down changes the result. Omaha Public Power District added an ETR coordinator role to its storm manual in 2024. Before 2023, its global restoration estimate was "generally released toward the middle of a storm event"; now it is "set very early, sometimes within hours of a storm declaration," and the utility reports "~97% global ETR accuracy since August of 2024."²⁷ That is one utility's self-reported result, and we found no rigorous before-and-after study of codified storm decisions anywhere in the industry. The scarcity is itself a finding. Utilities measure outage minutes precisely and the quality of their storm decisions hardly at all.

The value is in the gap between knowing and acting

The economic case for closing that gap is better established than the case for any single model. The International Energy Agency estimates that AI-based fault detection can reduce outage durations by 30 to 50 percent by locating faults rapidly and precisely.²⁸ Boston Consulting Group estimates that moving from reactive response to predictive outage

planning could shorten outages by 15 to 30 percent, while warning that "pilot mode does not lead to scaled value."²⁹ Both estimates assume something the industry rarely has: a decision that can be triggered by the forecast rather than by the damage report.

A forecast that improves by a day is worth a day only if someone acts on it a day earlier. A utility that still releases its first restoration estimate in the middle of the event, still adjusts its de-energization criteria in the moment and still stages crews from memory of the last storm has not captured the improvement. It has watched it. The constraint is not the quality of the hazard model. It is that the rules connecting a forecast to a decision were never written in a form a system, or a newly promoted storm director, could apply.

Supervisors and reliability bodies are asking the same question

Reliability bodies spent 2026 reviewing how the grid handled its hard days. The joint FERC and NERC review of the January 2026 cold period, covering Winter Storms Fern and Gianna, found improvements on the bulk system, but NERC's chief executive, Jim Robb, warned, "We cannot let this be the new norm of operating the grid." FERC Chairman Laura Swett said "careful analysis and action can protect critical infrastructure."³⁰ Unplanned generator outages still peaked at 68,169 MW on January 26, and more than 3,000 generators logged nearly 17,000 forced outages, derates or failures to start.³¹

State regulators are pushing utilities toward resilience spending and, increasingly, toward evidence that it works. Texas trimmed CenterPoint's plan from a \$5.75 billion request to about \$2.7 billion and cut measures that seemed "more about replacing materials that have come to the end of their useful life."¹⁹ California's legislature passed SB 254 in September 2025, changing how wildfire-mitigation capital is financed.²³ The direction of travel is that regulators will ask what each dollar of resilience buys in avoided outage minutes and avoided ignitions. A utility that can show how its decisions use the forecast will have a better answer than one that can only show what it built.

What the people shaping the next four years expect

Forecasts from people with a mandate at stake converged on a few points in 2025 and 2026.

- **The forecast will keep improving, and experts will stay in the loop.** NHC is partnering directly with Google DeepMind on a new hurricane model, and its science operations

officer says "none of the models are perfect, and they never will be."¹⁵ ECMWF calls its AI and physics systems "complementary."¹¹

- **Reliability is rising up the executive agenda.** In National Grid Partners' survey, reliability is a top-three priority for 73 percent of innovation leaders, up from 43 percent a year earlier.¹⁶
- **The skills are not yet in the sector.** The IEA notes that "the prevalence of AI-related skills is much lower in the energy sector compared with other sectors."²⁸
- **The legal exposure will not shrink on its own.** SCE's Eaton trial begins in January 2027, and the Oregon Supreme Court hears PacifiCorp's appeal on November 3, 2026.^{23,24}

Our own expectation follows from the evidence. Hazard forecasting will be largely solved as a technology problem within a few years: open, cheap, a day or more better than in 2024, and available to every utility. The difference between utilities will be how fast and how well they turn that forecast into staged crews, de-energization calls, switching plans, restoration priorities and restoration estimates. We expect the utilities that lead on outage minutes by 2030 to be those that wrote those decisions down as explicit, owned, testable rules, rehearsed them against forecast scenarios before the season, and used AI to run them earlier rather than to describe the damage afterward. We expect regulators to start asking for that evidence in resilience proceedings within the next two rate cycles.

A decision framework for the CEO, COO and head of emergency management: four moves

The evidence points to four moves, in roughly this order.

1. Name the decisions that set the outcome of a hard day, and who owns each

Start from the five in the table above: pre-staging, de-energization, switching, restoration priority and restoration estimates. For each, write down who decides, on what inputs, at what trigger and with what authority to change the rule in the moment. SCE's January 2025 report shows what happens when the criteria change under pressure without a recorded owner and process.²¹

CONCRETE MARKER

Each of the five hard-day decisions has a named owner, a written trigger and a recorded authority to deviate.

CONCRETE MARKER

Every deviation during an event is logged with its reason and reviewed after the season.

2. Connect the forecast to the decision, not to a dashboard

The hazard forecast is now good enough to act on a day earlier.^{3,10} Write the rule that turns a forecast state into an action: a wind threshold and fuel condition into a de-energization watch, a track and intensity cone into a staging plan, a damage projection into an initial restoration estimate. OPPD's experience suggests the restoration estimate can move from the middle of the event to within hours of the declaration once the role and rule are written.²⁷

CONCRETE MARKER

For each decision, the forecast inputs and thresholds that trigger action are written down and versioned before the season.

CONCRETE MARKER

The first global restoration estimate is published on a set clock, not when damage assessment is complete.

3. Rehearse the season before it arrives

A rule that has never been run against a realistic storm is a hope. Use the new forecast models and a model of the network to run the decisions against plausible events before the season: where crews should be, which circuits would be shut off, what customers would be told and when. Measure the decisions, not only the outage minutes, so the industry's missing before-and-after evidence starts to exist inside the utility.

CONCRETE MARKER

Before each storm or fire season, the hard-day decisions are rehearsed against at least three forecast scenarios, and the gaps are fixed in the rules.

CONCRETE MARKER

After each event, decision timing and quality are scored alongside customer minutes interrupted.

4. Govern AI by the decisions it touches

Fund AI where it moves a hard-day decision earlier or makes it more accurate, and hold it to the same standard as the rule it supports. NERC's position, that the operator keeps the final input on AI-generated actions, is the right starting point.¹⁸ Record for each tool which decision it prepares or proposes, what evidence it shows, and who approves. Report to the board the time from forecast to decision on the last three major events, not the number of AI pilots.

CONCRETE MARKER

Every AI tool in storm and wildfire operations is registered against the decisions it touches, with an owner and an approval rule.

CONCRETE MARKER

Board reporting shows forecast-to-decision time and ETR accuracy for each major event.

The leadership test

Leaders can locate their utility by asking six questions:

1. On our last three major events, how many hours passed between the first credible forecast and our staging, de-energization and restoration-estimate decisions?
2. If our storm director were unavailable tomorrow, which of those decisions could their deputy make from written rules, and which only from experience?
3. When we changed a decision rule during an event, who authorized it, and is that change now in the plan?
4. Do we publish our first restoration estimate on a set clock, or when damage assessment is done, and how accurate has it been?
5. Have we ever run our hard-day decisions against a forecast scenario before the season, and what did we change as a result?
6. If a regulator asked what our last resilience dollar bought in decisions, not equipment, what would we show them?

Utilities that can answer these questions are ready to use the new forecasts. Those that cannot will receive a better forecast every year and make the same decisions at the same time.

The forecast has leapt ahead. The grid's hardest days are now visible further out and more precisely than ever before, and that advantage is available to every utility at almost no cost. What remains scarce is the ability to act on it: to decide, earlier and by rule, where the crews go, which lines go dark and when the lights come back. The forecast is the easy part. The decisions are the work, and on most utilities' hardest days they are still being made the old way.

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About 6th Wave R&D

6th Wave R&D is the research and development team of 6th Wave Ventures. It publishes independent analysis on how utilities forecast, assess and act on their hardest days, and what that means for AI and autonomy on the grid. Every figure in this paper is drawn from public sources, listed in the notes.