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## Stampede To Gas

Fossil Fuel Transition Case Studies:

One Failing Grade, One A, and One Incomplete

### Introduction

The push to build new U.S. gas-fired generation capacity is unmistakable, with utilities, developers, and even many regulators rushing to approve projects without fully considering the risks. As this report demonstrates, those risks are significant, particularly for consumers.

Gas price volatility can cost consumers billions of dollars, even for relatively short-term price increases. The independent monitor for PJM, the largest organized power market in the U.S., reported that the system's wholesale energy costs soared to \$15.4 billion in January, more than double the cost from a year earlier.<sup>1</sup> The driving force for that increase was a sharp rise in gas prices due to the cold temperatures and snowfall that blanketed much of the U.S. in the second half of the month. That pushed Henry Hub gas prices skyward; they averaged \$7.72 per million British thermal units (MMBtu) in January, up 81% from December and more than double the 2025 annual average. Similar spikes hit the six-state New England region, with the system operator reporting that energy costs in January totaled \$2.7 billion – the highest total since the market was organized in 2003.<sup>2</sup> Essentially, all those costs will be passed on to consumers.

This year's spike was not an anomaly. Previous increases in 2021 and 2022, driven by weather and geopolitical events, led to similarly sharp increases in power costs for consumers. In Virginia, in fact, consumers are still paying for those events even as the costs of this year's spike have not yet been passed through to their bills.

Utilities are largely insulated from these spikes, since fuel purchases are generally treated as pass-through costs to be paid by consumers. Given that, regulators need to require utilities and project developers to more carefully consider these risks when proposing new gas-fired power plants. There are competitive options that do not pose the same threat for consumers; that benefit needs to be factored into the project approval process.



The following case studies examine the decisions made by three utilities as they seek to meet anticipated growth in electricity demand while transitioning away from fossil fuels. The high-level takeaway is that state policies matter, particularly now that federal leadership on transition issues is absent. Another takeaway is that utilities will stick with what they know, even in the face of outside pressure, regardless of the cost implications for their customers.

The three case studies examine one large investor-owned utility, Entergy Corporation, which serves a four-state area along the Gulf coast; one mid-sized IOU, Portland General Electric, the largest utility in Oregon; and a small cooperative, Colorado-based Holy Cross Energy. IEEFA's findings are straightforward:

- Entergy earns an F on the transition test. It plans to build substantial new gas-fired generation capacity, which will pose significant cost risks for its consumers. This build-out will also pose substantial stranded-cost risks if projected electricity demand growth does not materialize. At the same time, it is slowing the development of fuel-free renewables that can be built quickly and scaled as needed to support actual growth.
- Portland General Electric has made significant progress toward moving away from fossil fuels, having closed its only coal plant in Oregon and planning to exit its 20% stake in the Colstrip coal station in Montana. It is also building or contracting for substantial amounts of new wind, solar, and battery storage capacity, which will help it meet new demand without the threat of fuel price spikes. Still, it owns five gas-fired power plants that currently provide 40% of its generation needs and has not yet indicated when it will be able to close them. PGE's progress is promising, but its grade is an Incomplete.
- Holy Cross Energy, the smallest of the three utilities by far, has made the biggest progress. Its electricity mix in 2025 was 85% renewable, and its electricity costs were 33% lower than the national average. HCE has aced the test; its A grade is well deserved.



## Case Study 1: Entergy Is Failing the Transition Test

### *Utility's massive gas plans put consumers at risk*

How to fail at the energy transition? Entergy is a prime example.

During Entergy's fourth quarter 2025 earnings call on Feb. 12, 2026, CEO Andrew Marsh told analysts that the company has almost 9 gigawatts (GW) of new capacity under construction to meet projected demand growth over the next four years.<sup>3</sup> What he failed to explain is that virtually all of this new capacity—more than 8.2 GW—will be gas-fired.

The enormity of the utility's gas-fired build-out is evident in the graphic below. Entergy now has 11 gas projects underway, up from just one a couple of years ago. That first project, the 1,306 MW Orange County combined cycle facility in Texas, is slated to begin commercial operation later this year. Following that, a rash of new gas-fired projects, all announced in 2024 or later, are scheduled to begin commercial operations in 2028 and 2029. Most of these new projects are combined-cycle units to be supplied by Mitsubishi.

The picture does not improve when looking further into the future. Entergy just proposed two additional 754 MW CCGT projects in Louisiana, Westlake and Waterford 6, scheduled for completion in 2030. And it announced plans in December to buy an existing CCGT plant in Texas, the 1,263 MW Cottonwood facility that came online in 2003.

Beyond that, there are two unaccounted-for blue slots in Entergy's current gas build-out plan, plus 11 gray slots that are less certain, but still indicate the company's plans for meeting future growth. It is, in short, all gas, all the time.

Kimberly Fontan, Entergy's CFO, told analysts on the February earnings call that the still-unallocated turbine slots in its planning scenario total roughly 8 GW of capacity. "We have about 8 gigawatts of [gas] turbines and other plant island equipment available for growth. We have not turned those into specific projects tied to ESAs [electric service agreements] at [this] point."<sup>4</sup>

But that does not worry Entergy's Marsh, who told analysts that he has no concerns regarding those orders. "First of all, we fully expect to utilize the turbines that we have ordered on the timeline that we have them ordered. We have customers that would move them forward if they could. And we fully expect to utilize the turbines that we have."<sup>5</sup>





640 MW, and some of the others may not be built.<sup>11</sup>

In other words, far from the 11 GW of renewable capacity projected in early 2022, Entergy is now on track to have just over 4 GW of solar capacity online by 2030. In contrast, the utility has more than 11 GW of gas-fired capacity in its near-term queue. And that does not include the unallocated turbine slots it identifies as “available for growth.”

Entergy’s embrace of gas could be extremely costly for its customers. The utility says new contracting arrangements will shield existing customers from having to pay for these new, largely data center-driven capital investments. But there is a real possibility that existing consumers could end up footing the bill for billions of dollars in capital costs if the projected demand from data centers does not materialize as expected and/or does not persist. Further, the 15- to 20-year power agreements the utility is signing to facilitate the construction of these new plants do not cover the projected life expectancy of a new, 35-year-plus gas generation asset, which also could prove costly for existing customers.

Beyond this, none of those contractual arrangements can shield customers from the inevitable price volatility of gas supplies, either due to geopolitical or extreme weather events. These costs can be high and push electricity costs up sharply, as detailed in our main report, “Stampede to Gas.” On the other hand, renewables, which Entergy is clearly downplaying, shield customers from those costs.

Entergy has clearly failed the transition test. Unfortunately, utility consumers, not management, will be the ones forced to pay the bill for that failure.

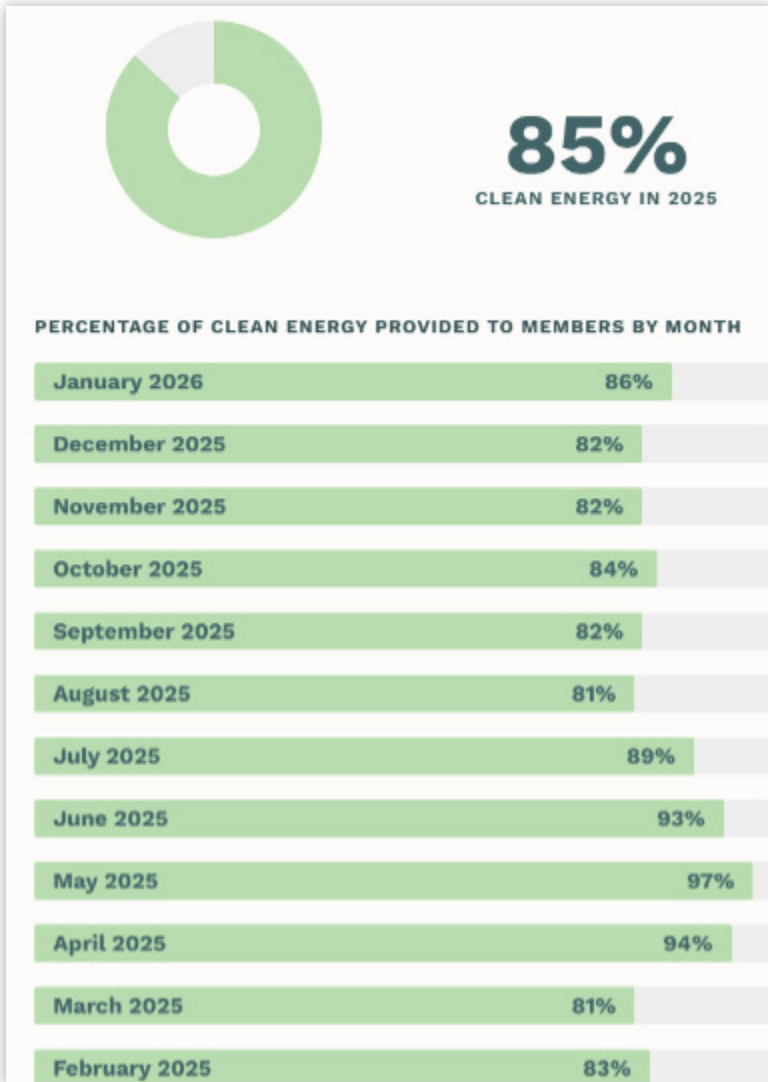


## Case Study 2: Holy Cross Aces the Transition Test

*Colorado co-op shows that reliable, cost-competitive electricity does not require fossil fuels*

Holy Cross Energy (HCE) is a small cooperative in Colorado with big plans—to be fossil fuel-free by 2030. It is well on the way to reaching that goal. In 2025, the co-op’s energy supply was 85% clean, more than double the 39% level in 2018 when the utility began its transition efforts.

**Figure 2: Holy Cross Hits 85% Clean Energy in 2025**



Source: Holy Cross Energy website

The co-op’s work serves as an important example for other utilities. It shows that a transition is feasible, a possibility that many fossil fuel advocates still dismiss, and provides a template for other utilities to follow, regardless of their size.



Holy Cross, founded in 1939 and headquartered in Glenwood Springs, serves 45,000 customers in the Rocky Mountains west of Denver. Its peak demand in 2025 was just 281 megawatts (MW), but that small size does not invalidate its transition efforts. Its customers used an average of 1,178 kilowatt-hours (kWh) a month in 2024, slightly more than the U.S. residential average, according to the Energy Information Administration (EIA).<sup>12</sup> Like all ratepayers, HCE's customers also expect reliable service and affordable prices. Holy Cross has provided both throughout its transition efforts. Its electricity prices are in the lower third of its Colorado competitors, 33% below the national average, and its reliability metrics have improved steadily.<sup>13</sup> The gross numbers may be of a different order of magnitude, but the percentage changes remain relevant. If Holy Cross can go from 39% clean energy to 85%, so can other, larger utilities.

The co-op took its first step toward the transition in 2018, when it adopted a plan to have renewables supply 70% of its energy needs by 2030 and to reduce the greenhouse gas emissions associated with its power supply by 70%. A key result of that initial goal was a 2019 contract signed by Holy Cross and Guzman Energy that enabled the co-op to offload its 8% share of the unreliable Comanche 3 coal-fired power plant, which is majority-owned by Xcel Energy. The deal was effectively a two-way power purchase agreement, with Holy Cross becoming the anchor buyer for a to-be-built 100-MW wind project and Guzman getting the output from HCE's 60-MW stake in Comanche as well as the remaining capacity from the new wind farm.<sup>14</sup>

In 2020, Holy Cross took the next step, unveiling a 10-year plan to move toward 100% renewable energy. In announcing the plan, HCE CEO Bryan Hannegan touted its ambitious nature, noting that "it's one of the most aggressive renewable energy and greenhouse gas reduction goals anywhere in the country."<sup>15</sup>

But it is ambitious in another sense of the word as well; it has required HCE to think through the transition and figure out how best to make it work. One example of this "thinking through" process was HCE's early embrace of battery storage. In 2021, the co-op initiated a program, dubbed Power+, designed to help its members finance distributed battery storage units. In return for the financial backing, HCE can tap those behind-the-meter resources to help it cut peak demand, saving money for all co-op members. As of year-end 2024, more than 200 of the co-op's members were participating, providing almost 4 MW of capacity for HCE to dispatch during peak demand.<sup>16</sup>

The utility also recognized early on that battery storage would be essential in front-of-the-meter applications. The co-op's 2023 energy strategy, adopted when installed battery storage was still largely confined to California and Texas, said that new solar generation added to the system needed to be paired with battery storage with a three- to four-hour duration.<sup>17</sup> This storage, the co-op said, will enable it to capture solar generation when it is not directly needed for system supply and send it back into the system during higher demand periods, either in the evening



or early morning hours. Or, as HCE's Hannegan explained it, the co-op's storage capacity "basically behaves like gas turbines would on a normal power grid."<sup>18</sup> Better, in fact, since the storage capacity doesn't rely on supplies of volatile-priced gas and has no greenhouse gas emissions.

In keeping with its plan, the two solar projects HCE has brought online since the 2023 strategy have both been co-located with battery storage.

Further, that early strategy recommended adding battery storage to the co-op's existing Pitkin Solar project, both to capture otherwise curtailed solar generation and to provide system capacity. HCE has not moved forward with that recommendation, but the co-location concept has since become standard across the utility industry.

For example, NextEra, the largest renewable developer in the U.S., is strongly in favor of such backfilling plans. NextEra CEO John Ketchum told analysts during the company's fourth quarter 2025 earnings call that the company was looking at adding battery storage to virtually all its existing wind and solar projects: "Nearly every region in the country needs capacity, and battery storage is the only new capacity resource available at scale."<sup>19</sup>

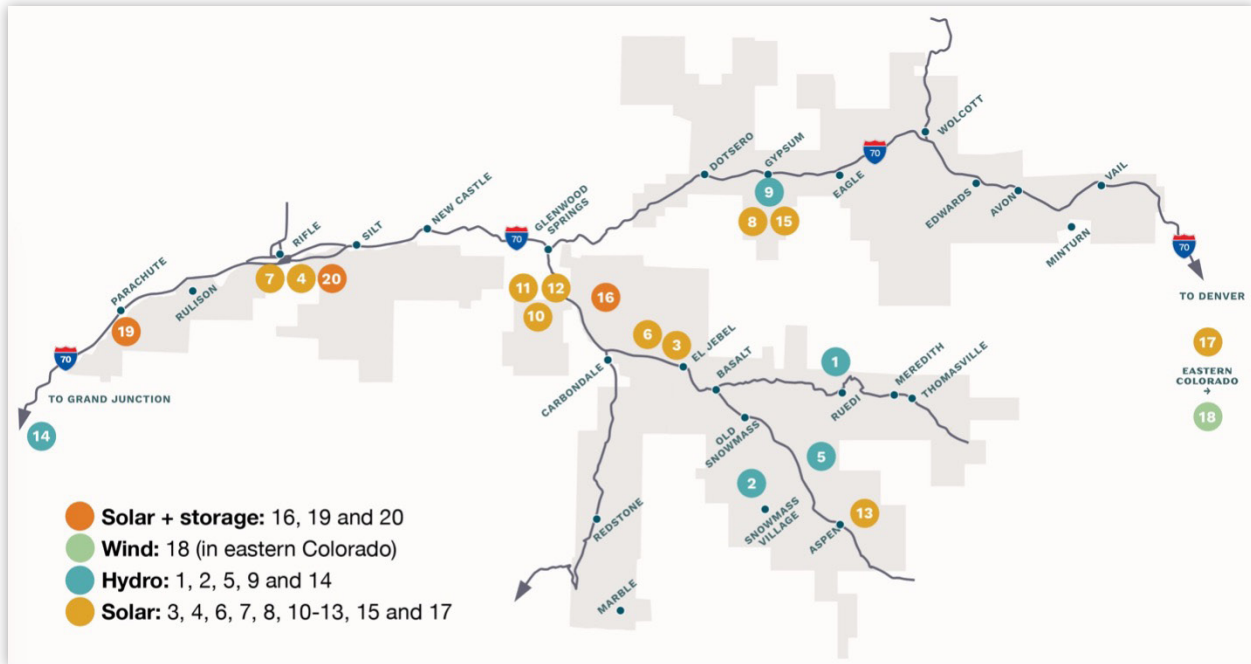
Another key factor behind HCE's successful transition efforts has been its willingness to look for solutions across the board. This outside-the-box attitude stands in stark contrast to the approach of many utilities, which see new gas-fired generation as the only solution to rising power demand. The co-op has been particularly aggressive in working with its members to cut demand through efficiency programs, shape demand to better fit renewable generation profiles, and install distributed resources to provide power to the co-op. This too contrasts with the generally disinterested approach of many utilities to such consumer-friendly programs, particularly investor-owned utilities driven by the incentive of returns on their rate base. Among HCE's consumer-facing programs are:

- Net metered solar, which provides 23 MW;
- Community solar, which adds 8.5 MW;
- Distributed battery storage, which contributes almost 4 MW; and
- Peak time programs that cut demand by 1-2 MW.<sup>20</sup>

The co-op plans to keep adding these consumer-based resources, projecting that it will add 2 MW/year of distributed solar capacity going forward and that its distributed battery storage capacity will reach 10 MW by 2030.

While operating these distributed resources – both the consumer-facing ones and those owned by the co-op – poses some operational challenges, Holy Cross' Hanagan also sees the benefits. "It's less likely that all of those resources are going to be out of commission all at once."<sup>21</sup>

**Figure 3: Holy Cross Energy’s Generation Resources**



Source: Holy Cross Energy

A final benefit that has aided Holy Cross’ transition is its longstanding transmission deal with Xcel. Under the terms of the agreement, Holy Cross can access power from eastern Colorado, which has strong wind and solar resources and the space to build them, at relatively low rates. For a geographically small utility, that access is extremely valuable.

The lesson here is straightforward. Transmission availability is essential to keep the cost of both meeting new demand and transitioning away from fossil fuels as low as possible.

Holy Cross’ transition is not yet complete, but they are far along in the effort to exit fossil fuels, and that deserves commendation. Still, they did nothing unheard of and did not saddle their members with higher costs. In other words, other utilities can do the same thing.



### Case Study 3: Portland General Making Big Strides in Transition

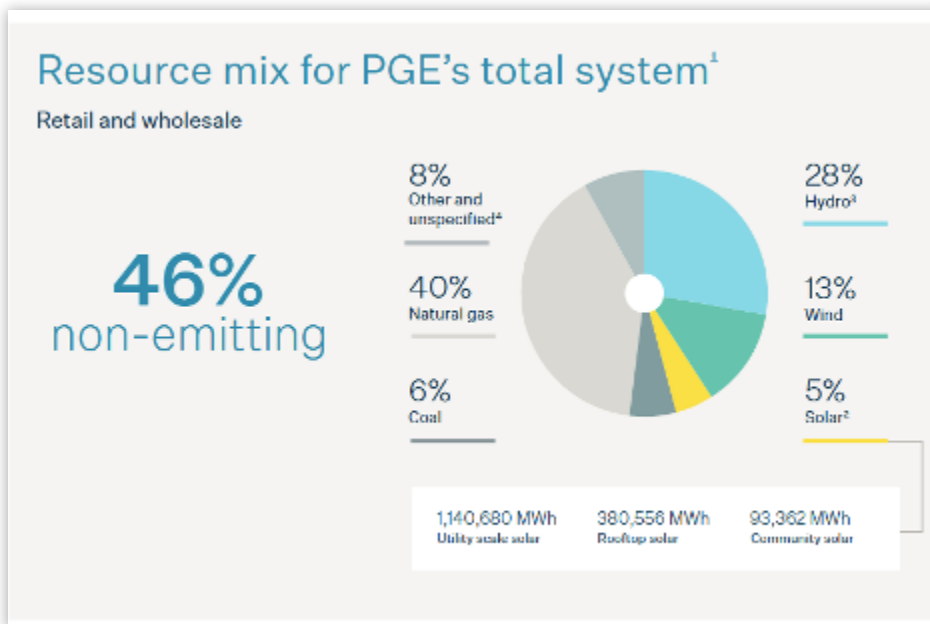
#### Oregon mandates pushing utility to move away from fossil fuels

Portland General Electric (PGE) did not voluntarily enter the transition away from fossil fuels. The closure of its 585 MW Boardman coal plant in 2020 was the result of a lawsuit targeting alleged violations of the Clean Air Act. That 2008 lawsuit led to a 2010 agreement involving the utility, state regulators, and environmental groups that committed PGE to closing the facility, the state’s only coal-fired power plant. Then, in 2021, the state enacted legislation (HB 2021) directing PGE and Pacific Power, Oregon’s other large electric utility, to decarbonize their generation resources by 2040, beginning with an 80% reduction by 2030.

While perhaps pushed to act, PGE has moved forward rapidly with its fossil fuel transition efforts since then.

In its 2025 sustainability report, the utility reported that 46% of its electricity generation came from renewable resources during the year, on par with its generation from gas and coal. This represents a significant change from 2019, the year before the Boardman plant was closed. That year, gas and coal accounted for 55% of its system demand. The change is also notable since it occurred even as the utility’s retail load rose 16.5% during the period. This means that non-emitting sources are providing a larger share of a growing market.

Figure 4: PGE System is Nearing 50% Clean



Source: 2025 PGE Sustainability Report

In addition to the sharp decline in coal generation due to Boardman’s closure, another notable change since 2019 is the significant increase in PGE’s solar resources. The utility had no solar on its system (owned or purchased) in 2019; by the end of 2025, solar accounted for 5% of its generation.



In total, PGE (and its customers, via rooftop and community-based solar and other programs) have committed to adding more than 4,200 MW of clean energy resources since 2021. This represents significant growth for a utility of PGE’s size. Five years ago, its generation resources totaled 5,314 MW—3,450 MW of utility-owned generation and 1,864 MW of power purchase contracts.

In addition to solar, PGE is pursuing a significant build-out of battery storage. Three projects, totaling 475 MW of capacity, began commercial operation last year.<sup>22</sup> Four others, two being developed by PGE and two by independent developers, were finalized in February. Together, these seven projects total 1,125 MW of capacity; they are all expected to be commercially operational by 2028.<sup>13</sup>

Beyond these announced projects, PGE is moving forward with plans to secure an additional 2,500 MW of new clean generation and battery storage. It has submitted project plans to Oregon regulators and has said it hopes to have development agreements in hand by the third quarter of 2026, with expected in-service dates of 2028-29.<sup>24</sup>

**Figure 5: Clean Energy, Battery Storage Additions to PGE System Total 4,200MW Since 2021**



Source: 2025 PGE Sustainability Report



Another takeaway from PGE's clean energy build-out efforts is the utility's embrace of customer-sited and/or customer-focused options. In particular, the utility is strongly behind efforts to develop and use distributed resources. According to its 2025 sustainability report, more than 25% of its residential customers (about 230,000 people) participate in its various virtual power plant programs.<sup>25</sup> These programs are designed for regular use, the utility says, not just during emergencies, as is common with many other VPPs. But they will also play a key role during peak demand periods, such as summer heat waves and winter cold snaps. Altogether, PGE says, these customer VPP programs can meet 13% of its peak capacity needs.<sup>26</sup>

Another focus for PGE is transmission. It plans to build new lines to better integrate utilities across the West and boost the capability of its existing system.

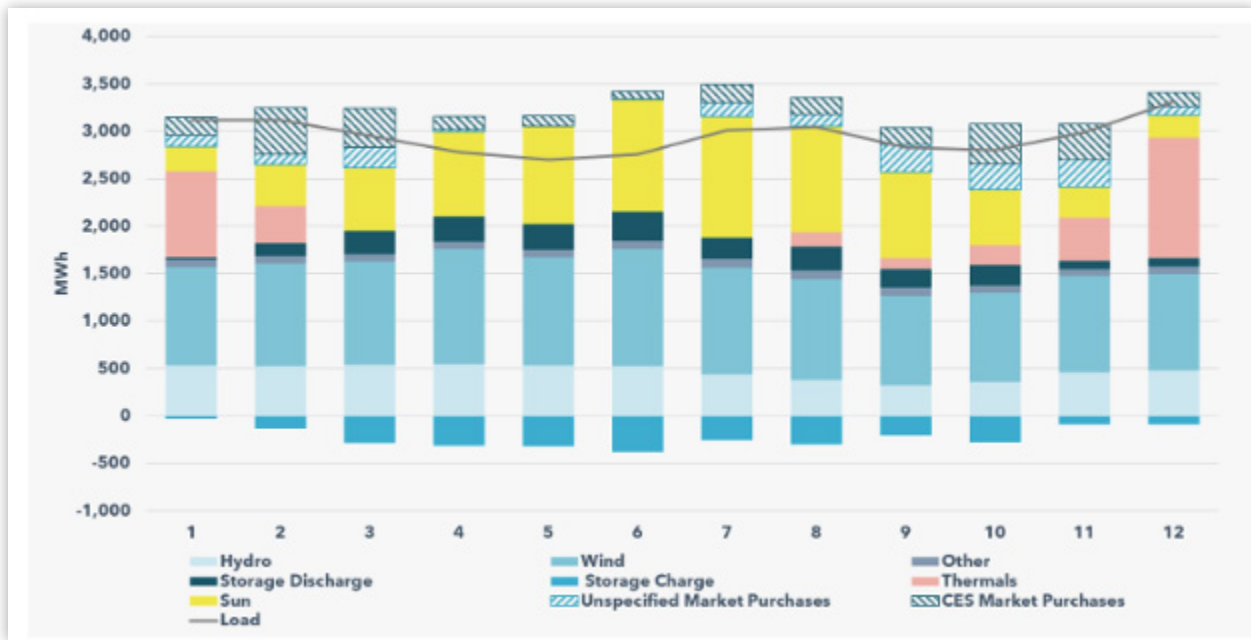
The reality is, PGE is going to need all these developments, and probably more, to complete its transition away from fossil fuels. The utility has longstanding plans to exit its 20% ownership stake in the 1,480 MW Colstrip coal plant in Montana, and the plans outlined above should enable that process. But planning for the closure of its five gas-fired power plants, which have a combined capacity of 1,827 MW, is likely to require additional work.

The graphic below illustrates the issue.<sup>27</sup> Modeling done by PGE for its 2023 long-range resource plan (That plan was updated in 2025; the utility is currently working on its new plan, which is due to be submitted to regulators later this year.) shows that by 2030 it will not need any thermal generation (shown in the pink shading) for five full months of the year, and only minimal contributions in three other months. In other words, PGE's modeling shows that its fossil fuel exit will require some additional dispatchable generation from another resource to complete the transition.

What the new resource(s) will be is uncertain, but the company has said its 2026 IRP will model the potential of enhanced geothermal and long-duration energy storage to meet this residual demand. Both technologies have advanced significantly in the past 18 months and may offer a cost-effective solution for PGE winter-time generation needs. The utility also plans to study the viability of using small modular nuclear reactors. Still, given the expected cost of this option and the likelihood that it would need to run consistently to keep costs low, its value in meeting this projected generation gap is questionable.



**Figure 6: PGE Modelling Shows Significant Reduction in Fossil Fuel Generation by 2030**



Source: PGE 2023 IRP Update

PGE, with a major push from state legislators, has made significant progress in reducing its reliance on fossil-fuel generation. Plans to build additional clean energy and battery storage resources, either utility-owned or contracted from independent developers, promise to continue that transition through 2030. How PGE clears the final hurdles regarding its gas-fired generation remains uncertain. Given that, while its current transition work looks deserving of an A grade, it must go down as an incomplete for now.



## Conclusion

These case studies underscore two realities about the electric power sector. First, it is possible to transition away from fossil fuels without massive consumer price increases. Second, it is easy for utilities to stick with what they know, even if that puts consumers at significant financial risk.

The work done by Holy Cross Energy clearly shows that utilities can serve their customers reliably and cost-effectively while phasing out their reliance on fossil fuels. Critics may dismiss the utility's successes because of HCE's small size and question whether it can complete the remaining 15% of its transition. The first critique is misleading. A utility's size, by itself, doesn't help or hinder the transition; it simply changes the magnitude of the investments and effort required. The second concern, about a 100% transition, highlights how far utilities already can move toward a fossil-free future. The takeaway: Move as far as you can and then figure out the rest. Do not stand still because you cannot see a path all the way to the end.

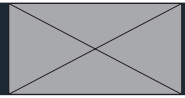
Portland General Electric is also moving quickly to reduce its reliance on fossil fuels. Its plans will see it exit coal and significantly reduce its need for gas-fired generation by 2030. The utility's work shows that quick transitions are possible, even for larger utilities.

Entergy's lack of work highlights the second point: Changing direction is hard for utilities, particularly without external direction. The utility has significantly reduced its earlier commitments to renewable energy and is moving ahead with a massive build-out of new gas-fired power plants. Those plans could add almost 20 GW of new combined-cycle gas capacity to the utility's generation system by 2032—more than its current installed gas capacity. This would commit consumers to paying for billions of dollars in new capital investments and leave them vulnerable to costly gas price spikes. This is not a path that will enhance energy affordability in the utility's service territory.



## Endnotes

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