

NRG Energy: Who Pays for the Next Megawatt?

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A new kind of power deal?

In August 2026, NRG Energy said it had aligned with a large cloud and AI customer on principal commercial terms for a proposed 1.2-gigawatt (GW) combined-cycle gas plant in Texas. The company called the arrangement “Bring Your Own Power” (BYOP): a customer-backed approach to adding generation alongside a large new load.

The proposal could offer NRG a long-term customer relationship and an opportunity to build new generation in a fast-growing market. It also raised a harder question: how should NRG decide what it is willing to finance, build, and promise before the contract, interconnection path, project approvals, cost allocation, and operating obligations are settled?

You are advising NRG’s executive team on its hypothetical FY2027 planning choices. Should NRG continue toward the current project and prepare to apply BYOP to additional Texas loads, stage major commitments behind specific contract and system gates, or first focus on its existing generation and demand-response plans? The company has not publicly assigned this exact decision to its leadership; the exercise asks you to make a recommendation from the record available on October 4, 2026.

NRG’s changing portfolio

NRG sells retail electricity and natural gas, operates competitive generation, offers commercial demand response, and owns Vivint Smart Home. Its FY2025 Form 10-K described about eight million residential customers: roughly six million retail-energy customers and two million smart-home customers. The businesses overlap in NRG’s broader strategy, but they serve different needs and face different economics.

On January 30, 2026, NRG completed its acquisition of 18 natural-gas and dual-fuel generation facilities, about 13 GW of capacity, and CPower, a commercial and industrial demand-response platform. NRG described its post-acquisition generation fleet as roughly 25 GW. FY2025 generation data predate the acquisition; the acquisition’s assets contributed to NRG’s Q2 2026 results.

NRG reports geographic Texas, East, and West/Other segments, along with Vivint Smart Home. In Texas, its competitive retail supply business and wholesale generation can interact through energy positions and hedges, but neither is the regulated transmission-and-distribution utility. ERCOT administers the wholesale market and large-load process; the Public Utility Commission of Texas (PUCT) has regulatory authority. Vivint’s home-services subscribers and CPower’s

commercial customers are not the same as residential retail-power customers, and neither segment's results demonstrate that a data-center load can be supplied reliably.

The proposed BYOP facility

NRG's August 4 Q2 release said the company and an unnamed leading global cloud and AI hyperscaler were aligned on principal commercial terms for a proposed 1.2 GW Texas combined-cycle gas facility. The release said final documentation and approvals remained outstanding. On the Q2 earnings call, management said the customer had made a financial commitment to advance development. NRG's materials described land-related matters and the company's internal investment decision as ongoing. NRG was targeting a late-2029 commercial-operation date, but that is a company target, not a completed milestone.

NRG's earnings presentation described a proposed arrangement with a minimum 15-year term from commercial operation. The company said a capacity payment would be designed to recover project investment and a targeted return, with a separate operating payment for fuel and plant operating costs. NRG also described a parent guarantee, potential expansion of the relationship to 2.4 GW, and an expectation that about 95% of the project's free cash flow would be supported by capacity payments rather than customer utilization. These are issuer descriptions of proposed terms. The public record does not contain an executed agreement or the full contract, payment formula, guarantee, conditions, or termination rights.

NRG presented BYOP as a way to match large-load growth with customer-backed generation while protecting grid reliability and affordability. It also said the proposed plant would be larger than the data-center load and suggested the pairing could reduce incremental transmission needs. These are NRG's claims. Publicly reviewed sources do not identify the project's final topology, interconnection classification, transmission study or cost allocation, fuel arrangements, dispatch rights, outage or curtailment protocols, or hourly load profile. Customer support may allocate some payment risk; it does not establish that generation, fuel, construction, system, emissions, or network effects are isolated from other parties.

Connecting a large load in Texas

In June 2026, the PUCT approved ERCOT's transitional Batch Zero process for evaluating certain large-load interconnection requests. The process became effective July 11. ERCOT's Planning Guide and later verification notices describe documentation, classification, verification, and study steps. In September ERCOT described conditional or provisional classifications and warned that failure to complete required verification could exclude a load from the process. Public notices do not identify NRG's customer or show this project's classification or verification outcome.

ERCOT reported 438 GW of large-load requests in June. A request in a queue is not a signed customer contract, completed interconnection, construction, energized capacity, or metered consumption. ERCOT also requested an exception from producing a May 2026 Capacity, Demand and Reserves (CDR) report while it revised its long-term load forecast. It posted other resource information, but there was no May 2026 CDR. The December 2025 CDR and ERCOT's Monthly Outlook for Resource Adequacy (MORA) are different reports; neither establishes a named customer's commitment or project readiness.

The proposed BYOP development is not the same as NRG's Texas Energy Fund (TEF) construction program. NRG reported that its 415-megawatt T.H. Wharton unit entered commercial operation on May 26. A performance-based grant agreement provides for up to \$54.72 million in ten annual installments, with the first payment dependent on testing and

facility performance. Cedar Bayou 5 and Greens Bayou 6 were separate TEF projects under construction. NRG said the two remaining projects were on time and on budget and planned for all three TEF units, totaling 1.5 GW, to be online by mid-2028. Those timing statements are company-reported status and forecasts.

Generation, retail service, and flexibility

NRG's post-acquisition capabilities make the resource choice more complex. The LS Power transaction expanded its wholesale generation footprint and added CPower's demand-response platform. Before that transaction, NRG described a Texas residential virtual power plant (VPP) as exceeding 200 MW and targeting 1 GW by 2035. The company did not define the MW measure sufficiently to determine how much is firm, coincident with peak, contracted, or dispatchable. Q2 materials did not update the figure.

CPower demand response, a residential VPP, a gas-fired power plant, competitive retail supply, and Vivint's smart-home services are different products. Demand-response capacity depends on customer enrollment, baseline measurement, dispatch rights, event performance, and customer limits. Smart-home subscription growth is not evidence of electricity load flexibility. None of the public metrics shows that residential or commercial flexibility can replace a 1.2 GW plant for a continuous load.

Operating and capital context

NRG's Q2 release reported segment Adjusted EBITDA of \$381 million in Texas, \$469 million in East, \$66 million in West/Other, and \$301 million in Vivint Smart Home. East's Q2 result included contributions from the acquired generation assets and CPower, along with higher capacity prices; Texas results reflected weather, retail load, supply costs, and new generation operating expenses. These are non-GAAP segment measures and do not reveal the proposed project's economics. Acquisition and market effects also make a simple comparison with pre-close results misleading.

NRG reported Q2 GAAP net income of \$506 million and GAAP cash from operations of \$1.117 billion. It also reported non-GAAP Adjusted EBITDA of \$1.217 billion and free cash flow before growth investments (FCFbG) of \$1.025 billion. NRG reaffirmed full-year 2026 Adjusted EBITDA guidance of \$5.325 billion to \$5.825 billion and FCFbG guidance of \$2.8 billion to \$3.3 billion. These company measures differ in definition and period; guidance is not an outcome or a BYOP budget.

Possible paths

1. **Advance the current BYOP proposal.** Complete final commercial documents and development work, then move toward investment decision when specified contract, customer, siting, interconnection, approval, construction, and reliability conditions are satisfied. Decide whether the structure is suitable for future large-load opportunities.
2. **Stage major commitments.** Preserve development progress but release substantial investment only as customer, land, ERCOT/TSP, transmission, cost-allocation, fuel, and construction milestones are verified. Define which work continues during the gate period and when the decision is revisited.

3. **Prioritize existing grid-facing and flexible resources first.** Complete the TEF projects and integrate the acquired fleet and CPower before committing to additional BYOP development. Establish what further operating, interconnection, and customer evidence would make a new large-load contract acceptable.

The paths may be combined, but delay, duplicated development work, operating coordination, customer expectations, and construction readiness have costs. Customer backing may reduce some utilization or payment risk but does not prove that interconnection, transmission, fuel, outage, or system costs disappear. Avoid treating “protect reliability and affordability” as an established outcome.

Questions for discussion

1. What decision is before the hypothetical FY2027 planning team: whether to continue development, sign definitive terms, make an investment decision, or expand the BYOP model? Which are separate gates?
2. What risks do NRG’s proposed capacity and operating payments allocate to the customer, NRG, or other parties? What contract evidence would you require before relying on those protections?
3. What evidence should be required from ERCOT, the TSP/DSP, and NRG before treating the proposed load as approved, deliverable, or operating? How should the company use the Batch Zero process and load forecasts without equating requests with demand?
4. How should NRG compare the proposal with separate TEF construction, the acquired generation fleet, CPower, and residential VPPs? Which capabilities are complements, and which cannot be compared directly?
5. How would you test who bears system and customer costs, including transmission, fuel, backup, curtailment, outages, emissions, and a delayed or smaller load?
6. What staged indicators, owners, and thresholds would make you proceed, pause, or redesign the proposal? Which data would change your recommendation?

Exhibit 1. Selected facts at the cutoff

Item	Reported status	What it does not establish
BYOP project	NRG aligned on principal commercial terms for a proposed 1.2 GW Texas CCGT with an unnamed hyperscaler	Definitive agreement, final approvals, NRG FID, ERCOT classification, construction, or operation
Proposed economics	NRG described a 15-year minimum term, capacity/operating payments, parent guarantee and ~95% FCF supported by capacity payments	Executed terms, enforceability, full pricing, project return, customer cost, or system-cost isolation
ERCOT Batch Zero	Approved June 18; effective July 11; September verification process active	Public identification or classification of NRG's project; all queue MW as signed/operating loads
CDR	ERCOT did not prepare a May 2026 CDR while revising its long-term load forecast	May generation-capacity information or MORA is not a May CDR or project-specific study
TEF	Wharton 415 MW operating; grant up to \$54.72m conditional on testing/performance; two other projects under construction	TEF units are not BYOP; "on time and on budget"/mid-2028 are company-reported status/forecast
LS Power/CPower	Closed Jan. 30, adding 18 facilities/~13 GW and CPower; NRG later described fleet at ~25 GW	Pre-close and post-close fleet measures are not like-for-like; demand response is not generation
Residential VPP	NRG reported >200 MW and path to 1 GW by 2035 in Q1 materials	MW definition, dependable capacity, Q2 update, or equivalence to a continuous 1.2 GW load

Selected source locators

- NRG [Q2 2026 results release](#), including "Advanced BYOP Data Center Strategy," TEF, results and guidance sections.
- NRG [Q2 2026 presentation and corrected call transcript](#), presentation pp. 5-8 and transcript pp. 3-9 for proposed terms/status.
- NRG [Q2 2026 Form 10-Q](#), Texas/TEF pp. 51-53; Significant Events pp. 55-57; acquisition Note 4 pp. 18-25; segment Note 11 pp. 42-45.
- ERCOT [Batch Zero approval](#), [large-load integration materials](#), [May CDR notice](#), and [resource/MORA page](#).

Cutoff rule: This case uses information available through October 4, 2026. It excludes later-quarter earnings and all subsequent contract, interconnection, construction, project, or operating outcomes.